DEPARTMENT OF MARKET MONITORING

# 2024 ANNUAL REPORT ON MARKET ISSUES & PERFORMANCE

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# Executive summary

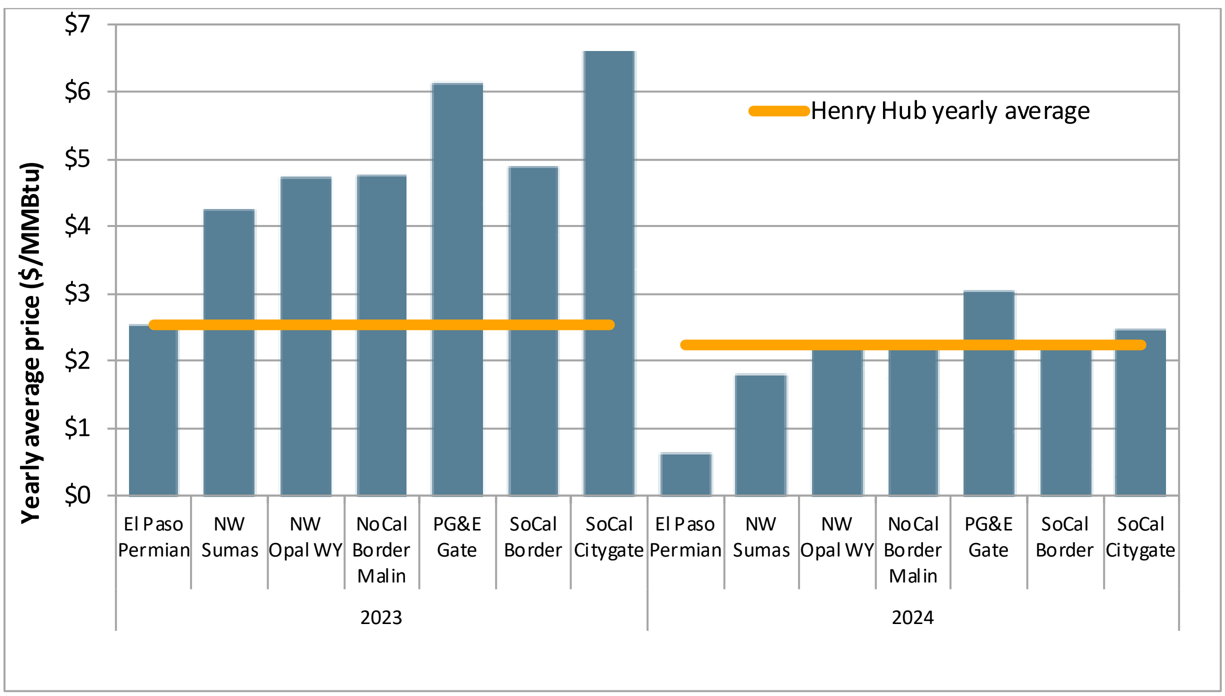
This annual report provides analysis and recommendations by the Department of Market Monitoring (DMM) on market issues and performance of the ISO's day-ahead wholesale energy market and real-time Western Energy Imbalance Market (WEIM). The report includes a summary of DMM's recommendations on key issues after the executive summary.

These markets continued to perform efficiently and competitively in 2024. Key highlights include the following:

## Load and resources

Natural gas prices in the West were down significantly compared to 2023, bringing electricity prices down with them. Figure E. 1 shows prices at Henry Hub, the national reference point, were down a modest 12 percent compared to 2023. However, El Paso Permian prices were down 75 percent, and prices at NW Sumas, NW Opal WY, NorCal Border, and SoCal Border declined between 50 percent and 63 percent in 2024 relative to 2023.

**Figure E. 1 Yearly average natural gas prices compared to Henry Hub**




Other highlights from the chapter covering load and resources include:

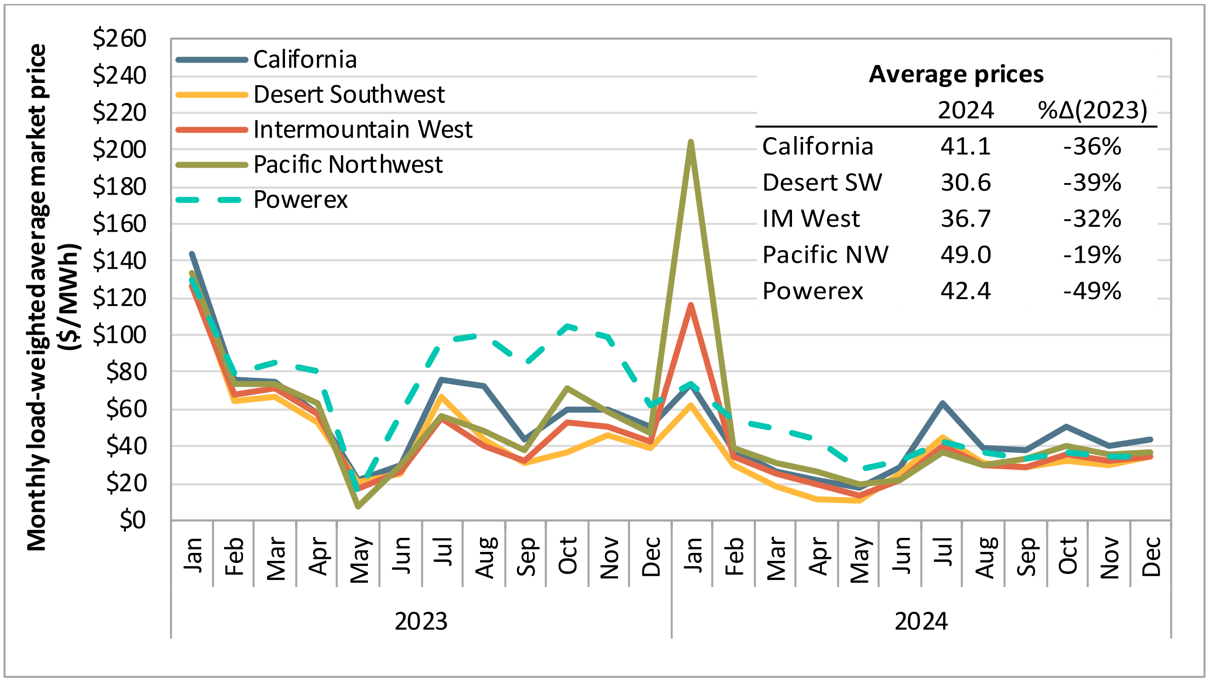
- **Load across the WEIM averaged 78.3 GW, about 2 percent more than 2023.** Load increased in all WEIM regions in 2024 compared to 2023. The Pacific Northwest region had the largest load increase at about 4 percent.
- **Peak 5-minute market load for the year was 135.3 GW on July 10, 2024, hour-ending 18, interval 11,** a 2 percent increase over 2023 peak load (132.6 GW).

- **The largest sources of generation in 2024** in California balancing areas were natural gas and non-hydro renewables, similar to 2023. Hydroelectric generation dominates the generation mix in the Pacific Northwest, accounting for about 65 percent of total generation. In the Intermountain West, generation is approximately equally split between four main types—natural gas, coal, hydro, and renewables. Natural gas is the largest source of generation in the Desert Southwest.
- **The Pacific Northwest region was a net exporter during the summer months**, while the Desert Southwest was a net exporter outside the summer months. The California and Intermountain West regions were net importers throughout most of 2024.
- **Wind and hydroelectric generation increased in all hours in the Pacific Northwest in 2024** compared to 2023. Net imports and net dynamic transfers displayed the largest changes, with an average increase in net dynamic WEIM transfers into the region of about 600 MW in all hours and a decrease in net imports (i.e., more exports) of about 1,500 MW in all hours.
- **In the California region, natural gas generation decreased in all hours in 2024 compared to 2023.** Batteries increasingly participated in energy arbitrage by charging during the high solar hours and discharging during the high net load periods in the evening. Solar production was up 18 percent. Correspondingly, WEIM transfers into the region decreased during the mid-day solar hours.
- **Coal generation in the Intermountain West decreased about 650 MW (18 percent) each** hour compared to 2023. Much of this generation was replaced with solar generation (200 MW) in the mid-day hours and natural gas (450 MW) in the non-solar hours.
- **In the Desert Southwest region, solar generation increased by about 700 MW (51 percent) in 2024**, and net imports and net dynamic WEIM transfers decreased by about 700 MW and 400 MW, respectively.
- **Over 354,000 GWh of generation in the WEIM system came from renewable resources.** 47 percent of that generation was from non-hydroelectric resources. Renewable resources produced over 40 GW of power on average across the year, accounting for more than half of total WEIM system load.
- **Total downward dispatch of wind and solar resources was higher in 2024 than in 2023 in all regions except the Intermountain West.** Downward dispatch of economic bids accounted for about 4,230 GWh (97 percent) of wind and solar downward dispatch during the year, while curtailment of self-scheduled wind and solar production accounted for about 46 GWh (1 percent).
- **By the end of 2024, roughly 5,000 MW of battery capacity was participating in non-CAISO WEIM balancing areas.** The CAISO balancing area had nearly 13,000 MW of battery capacity.
- **California greenhouse gas allowances averaged \$38.09/mtCO$_2$e in bilateral markets in 2024.** This represented an additional cost of about \$16.19/MWh for a relatively efficient gas unit.
- **Washington greenhouse gas allowances averaged \$40.18/mtCO$_2$e in bilateral markets in 2024.** This represented an additional cost of about \$17.07/MWh for a relatively efficient gas unit.
- **DMM estimates that the net energy market revenues for a hypothetical new gas unit participating in both the day-ahead and real-time markets in 2024 were about \$14 to \$19/kW-yr for a typical combined cycle unit and \$10 to \$16/kW-year for a typical combustion turbine unit.** Net market revenues were significantly lower than DMM's estimates of going-forward fixed costs for these units. These results continue to underscore the need for gas resources necessary for local or system reliability to recover fixed costs from long-term bilateral contracts.
- **DMM's simulated revenues for hypothetical batteries across all CAISO balancing area pricing nodes averaged \$52/kW-yr for energy and \$28/kW-yr for ancillary services.** Actual batteries in the CAISO balancing area with a full year of operation in 2024 had nearly \$43/kW-yr in market revenues for energy and \$7/kW-yr for regulation.

## Energy market prices

Prices across the WEIM were about 35 percent lower in 2024 compared to 2023, primarily due to lower natural gas prices. Figure E. 2 shows prices in the 15-minute market averaged about $40/MWh. Prices in the 5-minute market averaged around $39/MWh, and day-ahead market prices averaged $41/MWh.

**Figure E. 2 Weighted average monthly 15-minute market prices by region**




Other key findings in the chapter on energy market prices include:

- **Prices were highest on average in the Pacific Northwest region, at $49/MWh, and prices were lowest in the Desert Southwest, at $31/MWh.** This price spread was caused by extreme cold weather in January in the Pacific Northwest and south-to-north congestion during solar hours throughout much of the year. 15-minute market prices in Powerex, California, and the Intermountain West were $42, $41, and $37/MWh, respectively.
- **During mid-day solar hours, prices were generally higher in the Pacific Northwest, Northern California, and the Intermountain West than in the Desert Southwest and Southern California.** This pattern was primarily driven by congestion on major transmission corridors in the south-to-north direction during solar production hours.
- **During non-solar hours, California balancing authority areas had higher prices compared to the rest of the WEIM** due mainly to California greenhouse gas pricing.
- **15-minute market prices were significantly higher than 5-minute market prices over the evening peak net load hours, particularly in California balancing areas.** This was caused largely by CAISO balancing area operators adjusting up the load forecast much more in the 15-minute market than in the 5-minute market over these hours.

- **For most of the year, day-ahead bilateral prices from the Intercontinental Exchange at Mid-Columbia and Palo Verde were higher than prices at comparable locations from the ISO's day-ahead and 15-minute markets.**
- **Only two balancing areas, Public Service Company of New Mexico and El Paso Electric, did not have enough available, bid-in energy supply to meet demand in more than .1 percent of 15-minute market intervals.** Across the whole WEIM, these undersupply infeasibilities decreased to .05 percent of intervals in 2024 from .07 percent of intervals in 2023.
- **DMM estimates the total wholesale cost of serving load for balancing areas in the day-ahead market. Total wholesale costs for this balancing area (CAISO) decreased by 38 percent to $9.1 billion due to substantially lower natural gas prices.** Controlling for both natural gas costs and greenhouse gas prices, wholesale electric costs increased by about 7 percent.

## Energy market competitiveness and mitigation

Overall prices in the day-ahead market 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.

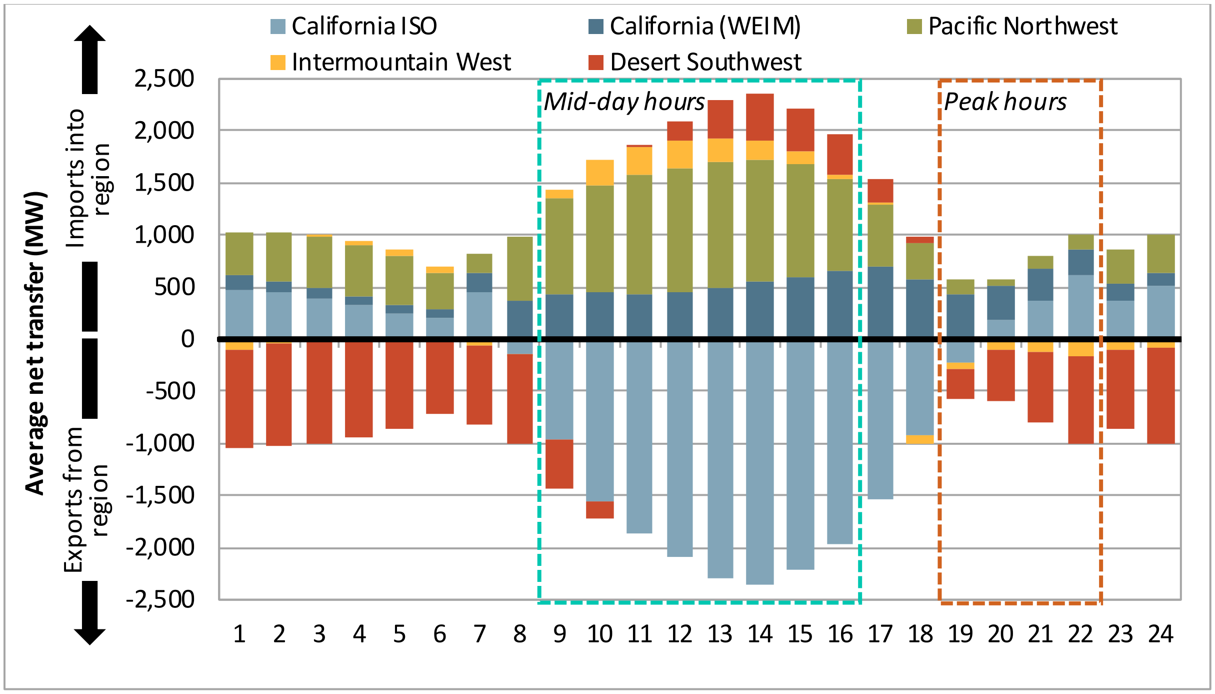
Other highlights of the chapter on energy market competitiveness and mitigation include:

- **The number of structurally uncompetitive hours in the day-ahead market in 2024 was slightly higher than 2023 but significantly lower than 2021.** Uncompetitive hours decreased significantly from 2021 to 2023.
- **The amount of energy downstream of non-competitive constraints, and therefore subject to potential mitigation, increased overall in the day-ahead and 15-minute markets.** A large increase in the frequency of binding transmission constraints within the CAISO balancing area in the day-ahead and real-time markets caused a significant rise in bids subject to mitigation in this balancing area. Bids subject to mitigation in all WEIM regions outside of California decreased compared to 2023.
- **Most resources subject to mitigation submitted competitive offer prices, so a low portion of bids was lowered as a result of the bid mitigation process.** Roughly 22 percent (1,060 MW) of the day-ahead bids and 15 percent (956 MW) of 15-minute market bids that were subject to mitigation were changed.
- **The potential increase in dispatch from bids lowered by mitigation remained very low**. In the day-ahead market, the average potential increase in dispatch averaged 48 MW. In the 15-minute market, system-wide potential increase in dispatch from mitigation averaged 108 MW.

## WEIM transfers and transfer limits

WEIM transfers between regions continued to be significantly different during mid-day solar hours than during evening and early morning hours. Figure E. 3 shows during solar hours, transfers were largely from the CAISO balancing area to other WEIM regions. During non-solar hours, transfers were lower, and largely from the Desert Southwest and Intermountain West regions to California and the Pacific Northwest.

**Figure E. 3 Average dynamic inter-regional WEIM transfers by hour (5-minute market, 2024)**



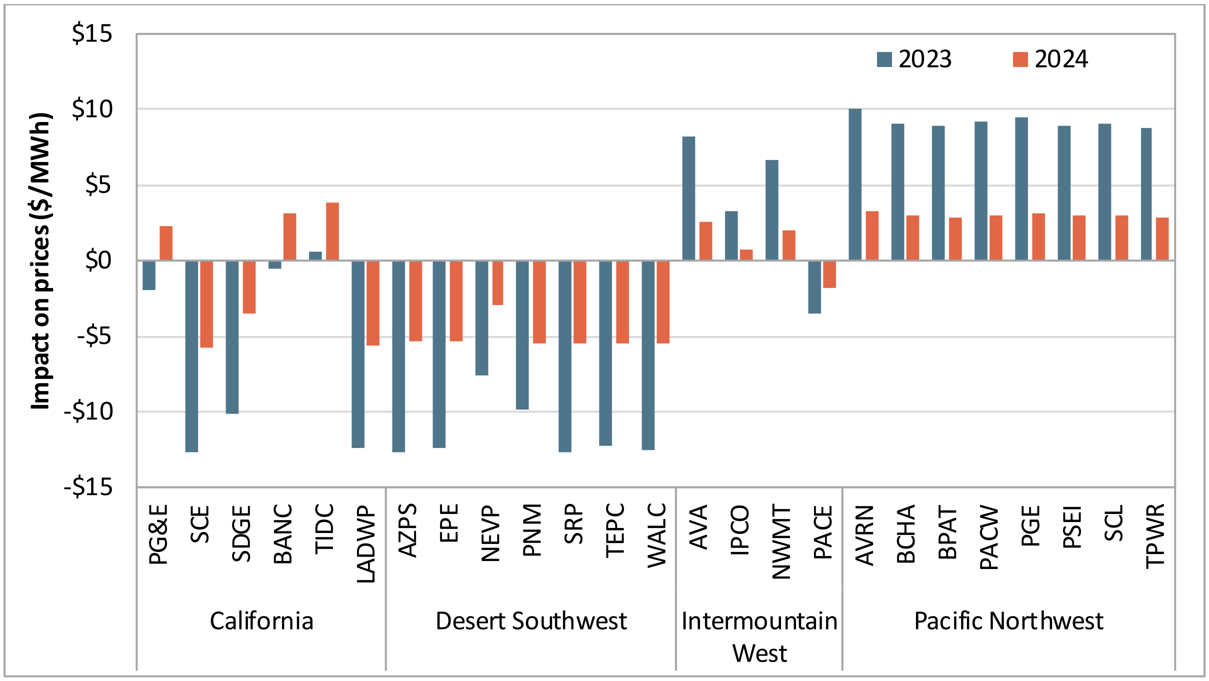

Other highlights from the chapter on WEIM transfers and transfer limits include:

- **The average volume of WEIM transfers across the system was 4,380 MW during 2024**, similar to 2023.
- **The Pacific Northwest and Intermountain West continued to have significantly lower transfer capacity into and out of their regions than the Desert Southwest and California.** This contributed to balancing areas in these regions being more frequently separated by congestion from the larger WEIM system.

## Congestion

Real-time market price separation driven by congestion on internal transmission constraints was less pronounced in 2024 than 2023, as shown in Figure E. 4. However, this price separation in the day-ahead market was more pronounced in 2024.

**Figure E. 4 Average impact of internal congestion on real-time market price (2023–2024)**




Other key trends from the chapter covering congestion include:

- **Most balancing areas in the Pacific Northwest, plus Avista and NorthWestern in the Intermountain West, were import transfer constrained relative to the CAISO balancing area in more than 10 percent of 15-minute market intervals.** Limited transfer capacity into these regions contributed to their relatively high rate of WEIM transfer congestion.
- **El Paso Electric, Tucson Electric Power, and Salt River Project were frequently export transfer constrained during the year.** These balancing areas were frequently transfer constrained because of intertie constraints that these balancing areas use to manage WEIM transfers into or out of their system.
- **Day-ahead market congestion rent in 2024 was $537 million, down 6 percent** from 2023. While congestion rent on internal constraints was down, intertie congestion rent in the export direction rose to $134 million in 2024 from $13 million in 2023. This rent was mainly over the Malin intertie during the extreme cold weather event in the Pacific Northwest in January 2024.
- **Payouts to congestion revenue rights sold in the California ISO auction exceeded auction revenues received for these rights by about $66 million in 2024**, up from $59 million in 2023. These losses are borne by transmission ratepayers who pay for the full cost of the transmission system through the transmission access charge. Changes to the auction implemented in 2019 have reduced, but not eliminated, losses to transmission ratepayers from the auction. The Department of Market Monitoring continues to recommend further changes to eliminate or further reduce these losses.

## Resource sufficiency evaluation

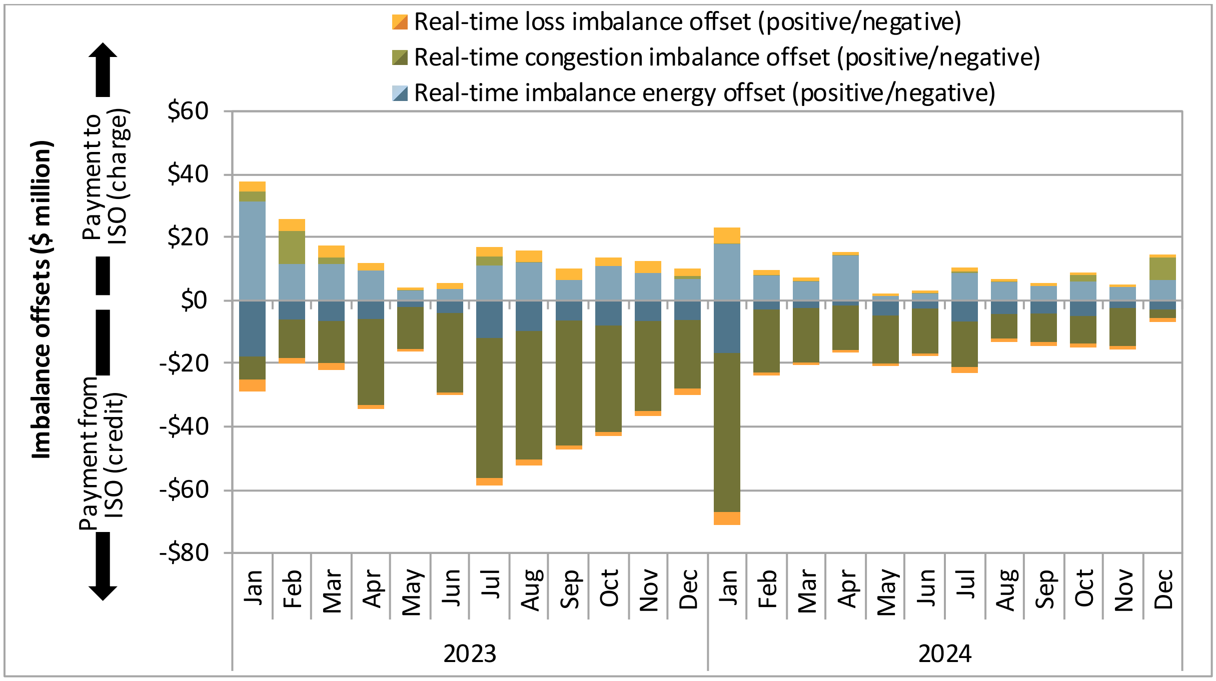
- **Most balancing areas failed each test in less than 0.5 percent of intervals.** Exceptions were the Public Service Company of New Mexico (PNM), WAPA Desert Southwest, and El Paso Electric, who failed the upward flexibility test in about 1.6 percent, 0.7 percent, and 0.6 percent of intervals, respectively. PNM also failed the downward flexibility test in about 0.5 percent of intervals.
- **Ten balancing areas opted in to the assistance energy transfer program on at least one day during the year.** Eight of these balancing areas received additional WEIM transfers during a resource sufficiency evaluation failure as a result of the program. Additional WEIM transfers received by each balancing area over the year ranged from 45 MWh to 973 MWh.
- **DMM is providing additional metrics, data, and analysis on the resource sufficiency tests in separate quarterly reports** as part of the *WEIM resource sufficiency evaluation* stakeholder initiative. These reports include many metrics and analyses not included in this report, such as the impact of several changes proposed or adopted through the stakeholder process.[1]

## Real-time imbalance offset costs and bid cost recovery

Real-time imbalance offset costs for balancing areas participating only in the WEIM real-time markets were a $157 million credit to WEIM entities in 2024, compared to a $237 million credit in 2023. Figure E. 5 shows the congestion portion of the offset, which is largely congestion rent from WEIM transfer constraints, was a $173 million credit. The energy portions of the offset were a $15 million charge.

[1] Department of Market Monitoring Reports and Presentations, *WEIM resource sufficiency evaluation reports*: https://www.caiso.com/market-operations/market-monitoring/reports-and-presentations#weim-resource

**Figure E. 5 Monthly real-time imbalance offset costs (balancing areas participating only in WEIM)**



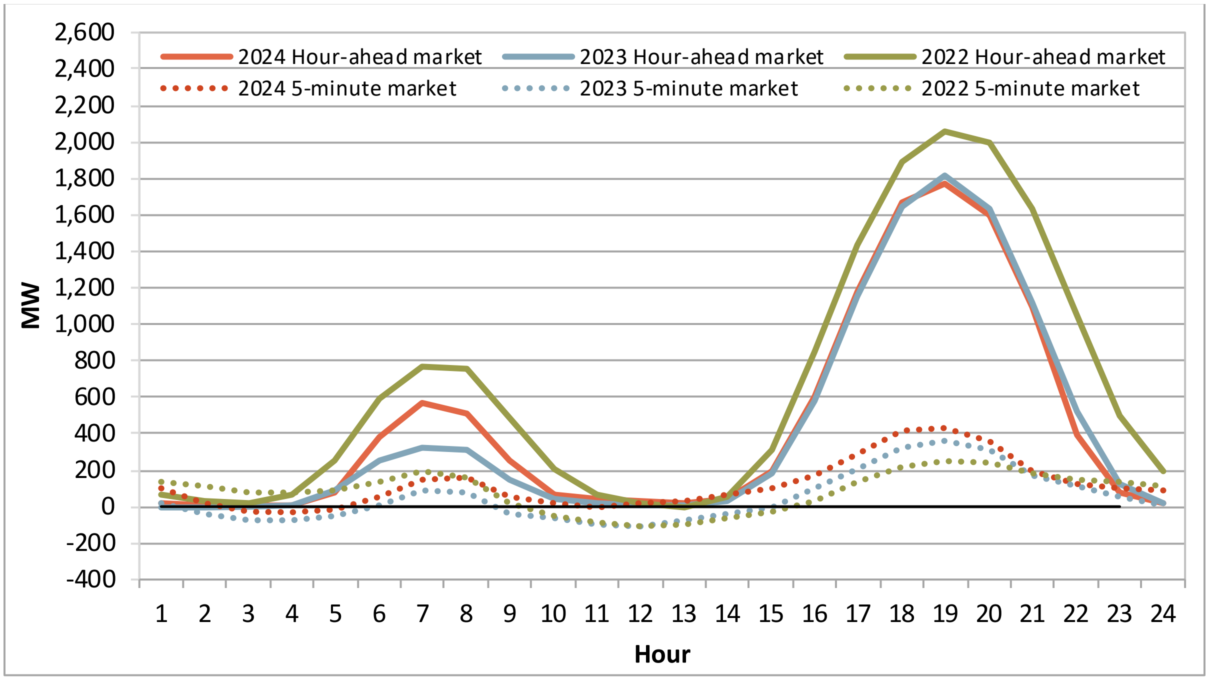

Other highlights from the chapters on real-time imbalance offsets and bid cost recovery include:

- **Real-time imbalance offset costs for balancing areas participating in the day-ahead market (CAISO) were $234 million** in 2024. This was a decrease from $358 million in 2023. During 2024, real-time *congestion* imbalance offset costs made up the majority of these costs ($197 million).
- **Bid cost recovery payments totaled $157 million for all balancing areas in 2024, down 49 percent** from 2023. Most of these payments ($141 million) came from the one balancing area (CAISO) participating in the day-ahead market.
- **Of the $16 million in bid cost recovery paid to generation in balancing areas only participating in the WEIM, $10.6 million went to the Desert Southwest region.**
- **Bid cost recovery payments associated with residual unit commitment during 2024 totaled about $27.5 million, or about $107.6 million (80 percent) lower than in 2023.**
- **The majority of bid cost recovery payments in every region went to gas resources.** The share of total bid cost recovery payments going to batteries in the CAISO balancing area increased to 13 percent in 2024 from 7 percent in 2023.

## Market adjustments

The CAISO balancing area's adjustments to load forecasts during the evening peak net load hours continued to be significantly larger in the hour-ahead and 15-minute markets than in the 5-minute market. As shown in Figure E. 6, for hour-ending 19, average hourly adjustments in the hour-ahead and 15-minute markets were about 1,770 MW, compared to 430 MW in the 5-minute market. This contributed to higher prices in the 15-minute market than in the 5-minute market over these peak hours.

**Figure E. 6 Average CAISO balancing area hourly imbalance conformance adjustment (2022–2024)**



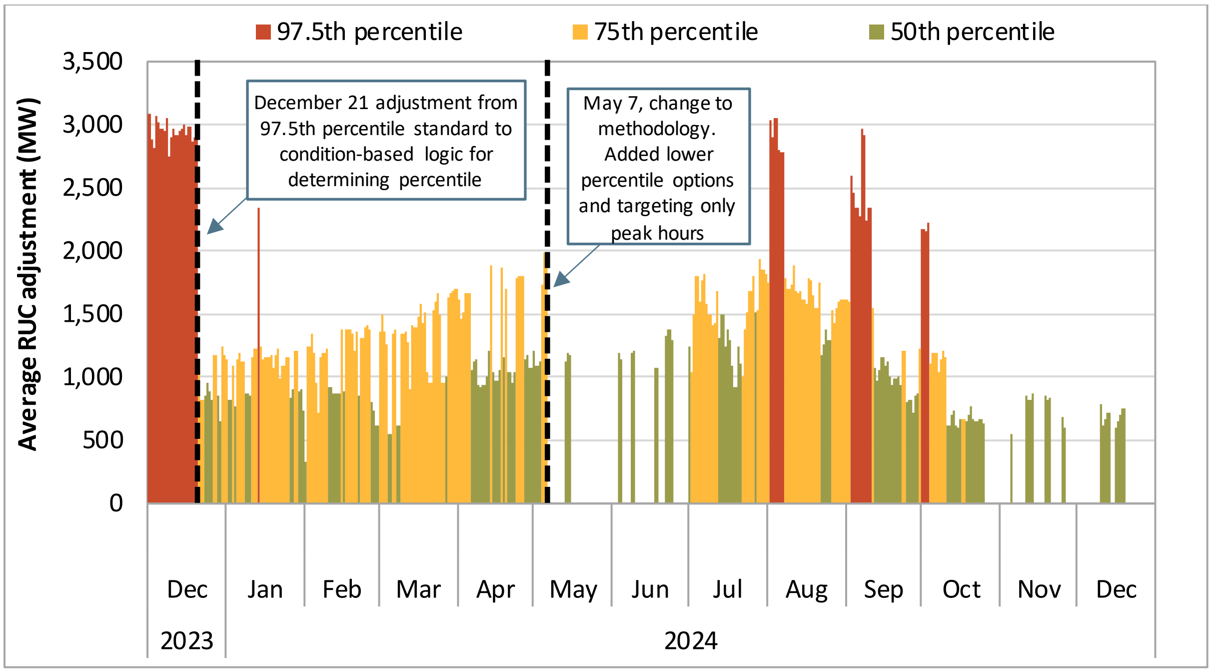

Other key trends from the chapter covering market adjustments include:

- **Most balancing areas made much higher adjustments to load forecasts in the 5-minute market than the 15-minute market,** with exceptions being the CAISO balancing area and Bonneville Power Administration (BPA).
- **CAISO balancing area operator adjustments to the residual unit commitment load forecast were significantly lower in 2024.** These adjustments, to account for load and intermittent renewable uncertainty, averaged 656 MW per hour in 2024, down 56 percent from 1,485 MW per hour in 2023.
- **Combined incremental and decremental manual dispatch energy** increased from 2023 to 2024 in the Desert Southwest and Intermountain West regions by 14 percent and 8 percent, respectively. Total manual dispatch energy decreased in the California (non-CAISO) and Pacific Northwest regions by 9 percent and 5 percent, respectively.
- **Total energy from exceptional dispatches in the CAISO balancing area averaged 0.34 percent of system loads in 2024**, up from 0.26 percent of system loads in 2023.

## Incorporating net load uncertainty

The ISO set the uncertainty adjustment to the residual unit commitment load forecast to cover the 97.5th percentile of net load uncertainty on only 5 percent of days in the year. As shown in Figure E. 7, the 75th percentile target was applied on 37 percent of days. The 50th percentile target was applied on 33 percent of days. No adjustment was applied on 26 percent of days. The imbalance reserve product for the extended day-ahead market is intended to procure capacity to address this same uncertainty, but the requirement will be set to cover the 97.5th percentile of uncertainty in all hours of all days. The low number of hours in which the ISO used the 97.5th percentile target in the residual unit commitment indicates that the imbalance reserve product demand curve may be much too high during most hours.

**Figure E. 7 Average residual unit commitment adjustment by day (peak morning and evening hours, 2024)**




Other highlights of the chapter covering how the ISO is incorporating net load uncertainty into its markets include:

- **Mosaic quantile regression uncertainty requirements for the flexible ramping product and resource sufficiency evaluation were on average lower than requirements would have been using the previous histogram method.**
- **For the flexible ramping product, the rate at which the regression method uncertainty requirements covered realized uncertainty was below the target coverage rate of 97.5 percent for each direction and market.** The regression coefficients were statistically different from zero in only 30 percent of intervals.
- **For the resource sufficiency evaluation, the coverage rate varied between 87 percent and 90 percent across balancing areas**. The target coverage rate is 95 percent. 37 percent of regression coefficients were statistically significant.
- **The regression model's predicted uncertainty for the resource sufficiency evaluation covered the realized uncertainty much less for intervals at the end of the hour than for intervals at the beginning of the hour.** This is because the model is designed to predict uncertainty in forecasts that are produced only 45 to 55 minutes before real-time. However, the time horizon of the resource

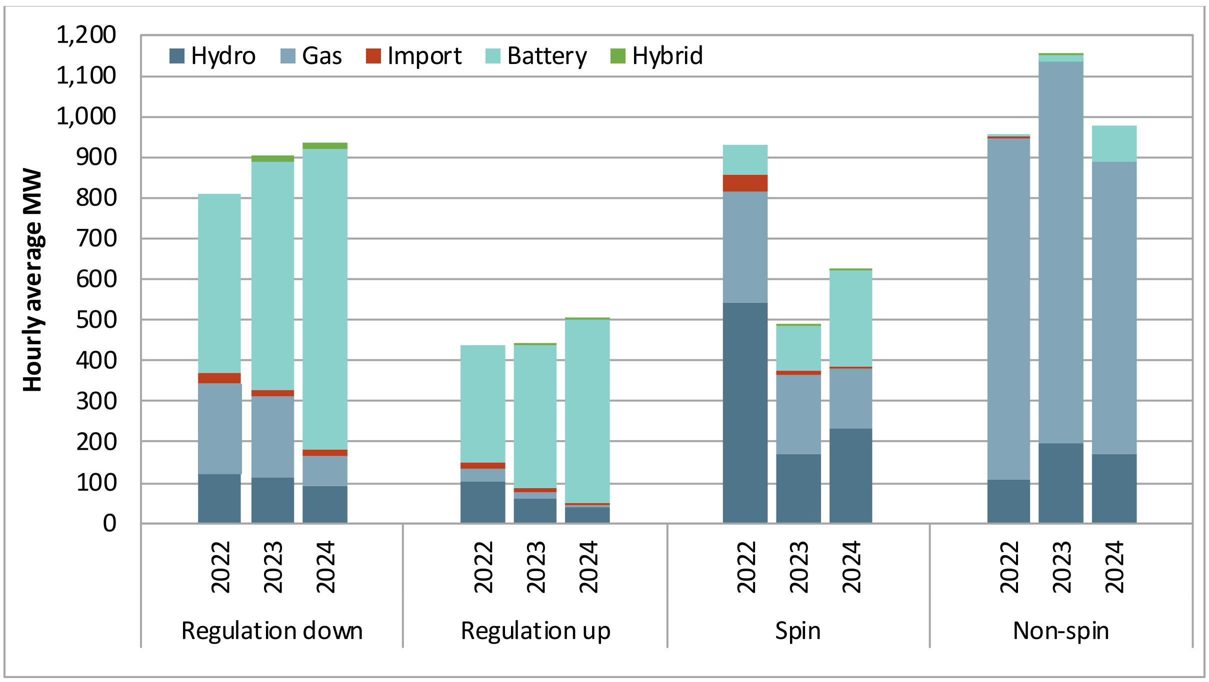
sufficiency evaluation includes four intervals, produced between 47.5 and 102.5 minutes before real-time.

## Ancillary services, available balancing capacity, and flexible ramping product

ISO markets procure ancillary services for the CAISO balancing area. Available balancing capacity is available to balancing areas only participating in the WEIM, while all balancing areas in the ISO's markets must procure the flexible ramping product in real-time.

Figure E. 8 shows provision of ancillary services from battery resources continued to increase, replacing procurement from natural gas resources. Average hourly procurement of ancillary services from battery resources increased by 46 percent compared to 2023, and batteries now provide 84 percent of CAISO balancing area regulation requirements.

**Figure E. 8 Ancillary service procurement by fuel type**




Other key trends from the chapters on ancillary services, available balancing capacity and flexible ramping product include:

- **Ancillary service costs decreased to $107 million,** down from $151 million in 2023.
- **Regulation up and regulation down requirements increased, while operating reserve requirements remained similar to those in 2023**. Regulation down requirements increased 4 percent to 935 MW. Regulation up requirements increased 8 percent to 440 MW.
- **There were no ancillary service scarcity events in 2024.** There were two intervals with ancillary service scarcities in 2023, and six in 2022.

- **Twelve percent of resources failed** unannounced ancillary service performance audits and compliance tests, compared to 15 percent in 2023, and 22 percent in 2022.
- **Most WEIM entities offered available balancing capacity into the market throughout 2024.** However, available balancing capacity was rarely dispatched to resolve capacity insufficiencies.
- **Non-zero upward flexible ramping product prices at the system level were very infrequent, occurring in about 0.3 percent of intervals** in the 15-minute market for the pass-group**.** At the balancing area level, the Public Service Company of New Mexico (PNM) had prices for flexible capacity following a failure of the resource sufficiency evaluation during around 3 percent of intervals.
- **Battery and hydro resources made up 55 percent and 32 percent of upward flexible ramping product, respectively.** Wind and solar combined to provide 38 percent of downward flexible capacity, and batteries provided 31 percent of downward flexible capacity.
- **The CAISO balancing area continued to make up the majority of upward and downward flexible ramping product awards, at around 61 percent of each**. Balancing areas in the Pacific Northwest made up 27 percent of upward flexible capacity and 17 percent of downward flexible capacity.

## Residual unit commitment

- **The average volume of capacity procured through the residual unit commitment process was 385 MW, down 47 percent from 2023.** The volume of procured capacity had increased 81 percent in 2023 over 2022.
- **The total direct cost of non-resource adequacy capacity procured in the residual unit commitment process decreased to about $1.6 million in 2024**, from a direct cost of about $5.4 million in 2023.
- **There was not enough supply to meet the residual unit commitment requirement for a total of nine hours on five separate days in 2024**. Five of these hours occurred on September 6.

## Convergence bidding

- **Annual profits paid to convergence bidders totaled around $50.8 million**, an increase of almost $18 million from 2023, after accounting for about $12 million in bid cost recovery charges allocated to virtual bids. Convergence bidders lost $10.1 million from virtual demand, and virtual supply earned $72.9 million, before accounting for bid cost recovery charges.
- **Virtual supply exceeded virtual demand by an average of about 430 MW per hour**, compared to 700 MW in 2023. The percent of bid-in virtual supply and demand clearing was around 50 percent, an increase from about 41 percent in 2023.
- **Financial entities and marketers continued to earn the most profits from virtual bidding**, receiving about 96 percent and 3 percent of positive net revenues, respectively. Load serving entities received nearly 1 percent of positive net revenues, and physical generators lost money from virtual positions overall.
- **Financial participants held the majority of cleared virtual positions (nearly 83 percent) throughout 2024**, continuing a multi-year trend. As with the previous years, financial participants bid more virtual supply than demand.

## Resource adequacy and wheeling-through capacity in the CAISO balancing area

Resource adequacy capacity provided sufficient coverage of annual instantaneous peak load. The annual instantaneous peak load for CAISO in 2024 reached 48,323 MW on September 5 during hour-ending 17. The total CAISO balancing area load requirement, including operating reserve (2,854 MW) and regulation up (680 MW) requirements, was 51,853 MW. Schedules from resource adequacy resources in the real-time market were over 53,000 MW. This included solar, wind, and other schedules in excess of a resource's resource adequacy capacity.

Other highlights of the chapters covering resource adequacy and high priority wheel-through capacity in the CAISO balancing area include:

- **The nameplate capacity of batteries and solar grew the most out of any resource type in the CAISO balancing area, adding 4.4 GW and 1.5 GW, respectively, since June 2024**. The CAISO fleet currently has 2.2 GW of capacity from resources with multiple generation technologies participating under the hybrid model, which is an increase of around 260 MW from last year. Overall, nameplate capacity has had a net increase of 5.6 GW since June 2024. In comparison, CAISO added 6.4 GW of nameplate capacity from June 2023 to June 2024.
- **Between June 2024 and June 2025, only 240 MW of capacity withdrew from CAISO**, including 80 MW of solar.
- **Four of the CAISO balancing area's 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.
- **Average resource adequacy capacity exceeded average load during the emergency notification hours in 2024**. There were 332 total hours with RMO+ emergency notifications, and seven EEA Watch+ hours in 2024, all occurring in July, August, and September. Average hourly load was about 37 GW during these hours, while average resource adequacy capacity was 53 GW.
- **Capacity available after reported outages and de-rates was 95 percent in the day-ahead market and 94 percent in the real-time market for RMO+ availability assessment hours**. Average resource adequacy capacity was around 52,805 MW during the RMO+ hours that occurred over evening peak net load hours in 2024.
- **Resources that are not availability-limited accounted for just 32 percent of system capacity.** About 16,900 MW of system capacity was subject to California ISO bid insertion during all hours. Gas-fired generation in this category made up about 15,600 MW (30 percent) of total resource adequacy capacity. Other generators accounted for less than 3 percent.
- **The amount of resource adequacy procured from storage resources increased significantly in 2024.** Storage resources accounted for the second largest portion (15 percent) of total capacity behind gas resources in 2024.
- **Investor-owned utilities procured most of the system capacity.** Investor-owned utilities accounted for about 30,700 MW (58 percent) of system resource adequacy procurement, community choice aggregators contributed 25 percent, municipal utilities contributed 9 percent, and direct access services contributed 8 percent. The remaining is a combination of the capacity procurement mechanism and the Central Procurement Entity.
- **Both year-ahead and actual flexible resource adequacy requirements were sufficient to meet the actual maximum three-hour net load ramp for all months in 2024.** The effectiveness of flexible requirements and must-offer rules in addressing supply during maximum load ramps depends on

the ability to predict the size and timing of the maximum net load ramp. This analysis suggests the 2024 requirements and must-offer hours were sufficient in reflecting actual ramping needs in all cases.

- **Resource adequacy availability incentive mechanism penalties totaled $75.3 million in 2024, an increase of about $24.4 million from 2023.** Much of this is attributable to flexible resource adequacy charges increasing to $47.7 million in 2024 from about $29.7 million in 2023.
- **Scheduling coordinators bought advance reservations for 675 MW of high priority wheel-through capacity on the CAISO balancing area transmission system in June, 690 MW in July, 735 MW in August, 510 MW in September, and 35 MW in October.**
- **Scheduling coordinators did not reserve all available capacity on the interties where they reserved any priority wheel-through capacity after June**. These interties had an additional 1,615 MW of available capacity in July, 2,136 MW in August, 159 MW in September, and 329 MW in October.
- **Priority wheel-through reservations plus native load needs exceeded the final available transmission capacity on the NOB intertie in June and September.** In June, this was due to the ISO awarding priority wheel-through reservations before a major transmission outage derated NOB to zero for part of the month. In September, final native load needs exceeded the estimates the ISO used when awarding priority wheel-through reservations in an early reservation window.
- **The ISO underestimated native load needs on the set of interties that market participants made priority wheel-through reservations on.** The ISO estimated native load needs on these interties would be about 1,553 MW in June, 2,955 MW in July, 5,903 MW in August, 5,702 MW in September, 3,106 MW in October, and 224 MW in November. This underestimated native load needs by about 596 MW (or 28 percent) in June, 677 MW (19 percent) in July, 288 MW (5 percent) in August, and 187 MW (6 percent) in October.

# Recommendations

As the independent market monitor for the California ISO and the Western Energy Imbalance Market, one of DMM's key duties is to provide recommendations on current market issues and new market design initiatives.[2] DMM actively participates in the ISO stakeholder process and provides recommendations in written comments throughout this process. DMM also provides recommendations in quarterly, annual, and other special reports, which are also posted on the ISO website. This chapter summarizes DMM's current recommendations on key market design initiatives and issues. Additional details on many of DMM's recommendations are provided in comments and other reports posted on DMM's page on the ISO website.[3]

## Extended day-ahead energy market

In 2026, the ISO is planning to implement an extended day-ahead market (EDAM) and day-ahead market enhancements (DAME). DMM strongly supports development of an extended day-ahead market to other balancing areas across the West. Adding a day-ahead market to the WEIM has the potential to provide significant efficiency, reliability, and greenhouse gas reduction benefits by facilitating trade between diverse areas and resource types.

### Congestion revenue allocation

Under the EDAM design approved by FERC in 2024, congestion revenue would be allocated to the balancing authority area (BAA) where the transmission constraint creating the congestion is located. This approach mirrors how congestion revenues from the real-time WEIM are allocated. During the EDAM stakeholder process, DMM understood that this rent allocation approach was intended to be transitional and that alternatives would be considered after EDAM was in operation.

In early 2025, Powerex and a group of other entities intending to join SPP's Markets+ day-ahead market filed objections to this approach at FERC. Citing data showing that the largest portion of congestion charges in WEIM has occurred due to congestion within the CAISO system, these entities contend that the EDAM design would be inequitable for other EDAM balancing areas. These Markets+ participants also argue that it would be inequitable for entities purchasing firm transmission rights from these EDAM balancing areas, since the EDAM areas would not collect enough congestion revenue to provide a full hedge against EDAM congestion charges for entities using firm transmission sold by EDAM balancing areas.

In response to these concerns, the ISO initiated a stakeholder process in early 2025 to modify the congestion revenue allocation rules for EDAM. Under a proposal approved by the ISO Board and WEM Governing Body in June 2025, congestion revenue associated with balanced self-schedules on long-term firm and network integration transmission service rights would be allocated to the balancing authority

[2] 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

[3] 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

area (BAA) where the energy is scheduled, rather than where the constraint is located. All other congestion revenue will continue to be allocated to the BAA in which the congestion occurs.

These revisions are likely to create economic incentives for some inefficient self-scheduling of resources. While this will reduce the efficiency benefits from managing congestion over an expanded EDAM footprint relative to the currently approved design, DMM believes there would still be significant benefits from an expanded market relative to the current pre-EDAM market. Therefore, DMM supports these revisions as an acceptable alternative on a transitional basis in order to ensure that EDAM moves forward toward implementation in 2026.[4]

The ISO has also suggested that it may seek to implement another change within the first year of EDAM operation that would extend the proposed congestion rent allocation to cleared balanced schedules that submitted price-based bids. This change is intended to reduce incentives to self-schedule and to allow users of network integration transmission service (including future potential EDAM participants) to receive parallel flow congestion revenues associated with economic schedules. However, DMM believes that such a change would distort bid prices and result in inefficient scheduling of a much wider range of resources submitting price-based bids. This change also directly impacts the amount of parallel flow congestion revenue that could be allocated to the California ISO balancing area, and therefore could also have significant impacts on holders of congestion revenue rights in the ISO system.

While DMM recognizes the importance of this issue to potential EDAM participants, DMM believes efforts to implement this additional change within the first year of EDAM should be abandoned in favor of shifting efforts toward reaching a more effective and complete solution, such as flow entitlements. A well-designed flow entitlement approach has the potential to provide a similarly valued allocation of congestion revenue to economic schedules, but without the inefficiencies of linking cleared schedule quantities with the congestion revenue allocation.

### Day-ahead imbalance reserve product

A key element of the EDAM and DAME proposals 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, but has provided several key recommendations regarding potential changes to the initial proposal, as summarized below.

**Demand curve for imbalance reserve.** The ISO has clarified that it is implementing the EDAM software so the demand for imbalance reserve will be set directly by a mosaic regression model of net load uncertainly (at a 95 percent confidence level).[5] DMM recommends that the ISO continue to work on developing more appropriate methods for determining the demand curve for imbalance reserves in the day-ahead market, and prepare to potentially reduce the initial $55/MWh cap after EDAM implementation. More discussion of DMM's concerns with this approach are provided later in this chapter, under the section on the mosaic regression model.

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4 Memo to ISO Board of Governors and Western Energy Markets Governing Body, June 12, 2025, Re: Department of Market Monitoring report. https://www.caiso.com/documents/decision-on-edam-congestion-revenue-allocation-dmm-comments-june-2025.pdf

5 *Tariff amendment to implement day-ahead market enhancements and extended day-ahead market*, Docket No. ER23-2686-000, California ISO, August 22, 2023, p 69: https://www.caiso.com/Documents/Aug22-2023-DAME-EDAM-Tariff-Amendment-ER23-2686.pdf

**Virtual supply.** Much of the potential benefit of procuring imbalance reserve capacity in the day-ahead energy market could be offset by virtual supply, which can displace more expensive and slower ramping physical supply in the day-ahead energy market. This could still require the subsequent residual unit commitment process to procure sufficient on-line physical capacity to address net load uncertainty. If significant procurement of extra capacity continues to occur in the residual unit commitment process, DMM recommends that the ISO reconsider whether it would be more efficient to procure imbalance reserves in the residual unit commitment market.

**Utilizing day-ahead imbalance reserves in the real-time market.** DMM continues to recommend that the ISO consider extending the uncertainty horizon of the real-time flexible ramping product or developing a real-time uncertainty product, so that there is a mechanism to maintain day-ahead reserves in real-time until the peak net load hours. Without such a mechanism in the real-time market, the value of procuring imbalance energy reserves in the day-ahead market could be significantly reduced. DMM's recommendation to extend the uncertainty horizon of the real-time flexible ramping product or develop a real-time uncertainty product is discussed in more detail under sections of this chapter on *the flexible ramping product* and *real-time uncertainty product*.

### Non-source specific supply used to meet resource sufficiency evaluation

The EDAM design allows contracts for non-source specific energy to count toward an EDAM balancing area's resource sufficiency evaluation. DMM recommends that as part of the process of enhancing the initial EDAM design, the ISO and stakeholders consider more nuanced rules and design changes that could better prevent the same capacity from being counted more than once towards EDAM balancing areas' resource sufficiency evaluations. For example, the overall design may benefit from crafting more explicit rules prohibiting supply that has received an EDAM energy or capacity award—and thus has a real-time must offer obligation—from supporting a non-source specific import that was counted towards each balancing area's EDAM resource sufficiency evaluation requirements.

## Congestion revenue rights

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 ISO 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). 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 system.

In response to the consistently large losses from sales of congestion revenue rights, the ISO instituted significant changes to the auction starting in the 2019 settlement year. Although changes implemented in 2019 reduced ratepayer auction losses, these losses have continued to be very significant.

- In the six years since the ISO implemented CRR reforms aimed at reducing these losses in 2019, ratepayers have lost an additional $379 million (or an average of $63 million per year) and have received only 67 cents in auction revenues per dollar paid out.

- In 2024, ratepayer losses from congestion revenue rights auctioned off by the ISO totaled $66 million and ratepayers received only 69 cents in auction revenues per dollar paid out.[6]

When changes to the auction were implemented in 2019, the ISO and its Market Surveillance Committee (MSC) committed to reviewing the effectiveness of these changes and making additional changes if significant losses continued. The ISO and MSC began some analysis and discussion of causes of losses from congestion revenue rights in November 2023. The ISO presented results of this analysis over 14 months later in February 2025.[7] The ISO's main findings are that three major causes that contribute to auction losses include the following:

1. Shift factors truncated by the minimum threshold;
2. Non-settled loop flows consuming transmission capacity; and
3. Differences between the CRR and day-ahead transmission models.

All of these three issues have existed as long as the ISO has had CRRs and have been subject to extensive analysis by the ISO. It is unclear what additional steps the ISO could take based on this analysis to eliminate or significantly reduce transmission ratepayer auction losses. For example, other RTOs with similar market designs incur millions of dollars in losses on financial rights sold by the RTOs.[8] Thus, DMM believes that continuing to dedicate time and resources in an attempt to make small improvements in these areas will not eliminate or significantly reduce transmission ratepayer losses from CRRs auctioned by the ISO.

### DMM recommends a willing seller market design for CRRs

DMM continues to believe that the current auction should be changed to a market for congestion revenue rights based only on bids submitted by entities willing to buy or sell congestion revenue rights. This approach (referred to as a *willing seller* market design) would provide a market in which load serving entities could continue to voluntarily sell back any congestion revenue rights acquired in the allocation process, and any entity could buy or sell additional contracts.

In October 2024, DMM released a more detailed report on the proposed willing seller approach. The report included analysis of this market design using only bids to sell and buy CRRs submitted by market participants, and without additional transmission that represents additional CRRs being offered by the ISO at a $0/MW bid price.[9] This analysis shows that under this proposed design, significant volumes of congestion revenue rights could be sold by financial entities, as well by load serving entities selling a portion of their allocated congestion revenue rights which are not needed to hedge their actual energy procurement. These results show that the willing seller design is workable and can provide an effective and efficient alternative to the current auction design. This approach eliminates losses from the current auction and allows all congestion rents to be returned to transmission ratepayers.

[6] See *2022 Annual Report on Market Issues and Performance*, Department of Market Monitoring, July 11, 2023, pp 18, 183-190: https://www.caiso.com/Documents/2022-Annual-Report-on-Market-Issues-and-Performance-Jul-11-2023.pdf

[7] California ISO, *Analysis of CRR Market Performance: Working Group Session 3*, February 27, 2025: https://stakeholdercenter.caiso.com/InitiativeDocuments/Presentation-Congestion-Revenue-Rights-Enhancements-Feb-27-2025.pdf

[8] https://www.caiso.com/documents/dmm-comments-on-crr-enhancements-apr-1-2025-working-group-meeting-no-5-apr-16-2025.pdf

[9] https://www.caiso.com/documents/willing-counterparty-whitepaper-oct-23-2024.pdf

In 2025, DMM has clarified that DMM is not proposing to "eliminate the CRR auction". Under DMM's recommended approach, the ISO would continue to allocate CRRs to load serving entities and exporters under the current allocation process. Entities that are allocated CRRs could continue to sell (or buy) additional CRRs as willing counterparties in the subsequent willing seller market for CRRs. Over the last three years, load serving entities have resold about 24 percent of the CRRs received in the allocation process.[10]

Furthermore, under the willing seller approach, restrictions implemented in 2019 on CRR allocations, bidding, and payouts would be removed, while also ensuring that CRR revenue inadequacy would be eliminated. For example, restrictions placed to lower transmission limits used in the CRR allocation process in 2019 would be raised, thereby increasing the amount of CRR nominations that would clear in the allocation process. Also, the *deficit offset* charge that was implemented in 2019 to reduce CRR losses would be eliminated. These deficit offset charges have averaged over 25 percent of the nominal value of CRRs allocated to load serving entities.[11] The collective impact of these changes would be to increase the ability of LSEs to acquire the CRRs and CRR payments needed to hedge their sources of supply.[12]

This approach is guaranteed to be revenue neutral for transmission ratepayers, and would allow the ISO to eliminate the need for deficit offset charges that occur when congestion revenues are not sufficient to fully fund congestion revenue rights sold in the auction by the ISO.

## Battery resources

The amount of battery storage resources in the CAISO and WEIM has increased significantly in recent years, and is projected to continue increasing in coming years. In May 2025, DMM released a special report on battery issues and performance during 2024, which highlights the projected growth of battery capacity in the CAISO and WEIM.[13]

### Bid cost recovery rules

The main purpose of bid cost recovery (BCR) for traditional generators is to incentivize efficient bidding by alleviating the risk that the net revenues from the difference between the locational marginal price (LMP) and the resource's energy bid costs will provide insufficient revenue to cover the unit's start-up and minimum load costs. Batteries do not have start-up, shut-down, minimum load, or transition costs—and thus lack the traditional drivers of BCR. However, in 2024, batteries received nearly $18 million in real-time bid cost recovery (or about 11 percent of all bid cost recovery).

The main limitations on battery dispatch that lead to real-time bid cost recovery payments stem from state-of-charge constraints that limit charging and discharging. For example, when a battery does not

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10 See Section 5.6

11 Thus, even if an LSE manages to acquire CRRs that perfectly fit the LSE's actual supply sources and load sinks, the LSE could end up receiving a hedge of only 75 percent of the LSE's actual congestion costs after the 25 percent deficit offsets are applied.

12 Comments on Congestion Revenue Rights Enhancements Scoping Discussion, Department of Market Monitoring, December 13, 2024: https://www.caiso.com/documents/dmm-comments-on-congestion-revenue-rightsenhancements-scoping-discussion-nov-14-2024-working-group-dec-13-2024.pdf

13 *2024 Special Report on Battery Storage*, Department of Market Monitoring, May 29, 2025: https://www.caiso.com/documents/2024-special-report-on-battery-storage-may-29-2025.pdf

have sufficient real-time state-of-charge to deliver a day-ahead market award, the real-time market software may force a battery to forgo charging or discharging out of merit order to "buy back" or "sell back" the day-ahead market award. Under the ISO's settlement rules, this can lead to payment of real-time bid cost recovery due to the difference between the battery's bid price and the real-time market clearing price. This design essentially removes the economic incentive for battery operators to bid in a way that is likely to ensure that batteries are fully charged up at the start of the peak net load hours when prices are highest and batteries are most needed for system reliability (e.g., hours 18 to 22).

When the state-of-charge constraint and other unit limitations were being designed for battery resources, DMM raised concerns about the potential use of these limitations and recommended that the ISO revisit this topic in future initiatives to address potential settlement implications. DMM and the California ISO's Market Surveillance Committee (MSC) have noted that the current real-time BCR design incents inefficient battery bidding behavior by removing batteries' exposure to real-time prices, and reduces the reliability benefits of these resources.[14,15]

In addition, the BCR design creates gaming opportunities, especially through manipulation of various biddable parameters used to manage state-of-charge. Gaming concerns are exacerbated by the fact that bid cost recovery payments are partly driven by submitted bid prices, meaning that inflated bids can cause BCR payments to drastically exceed any economic losses caused by reversal of day-ahead schedules. In November 2024, this particular gaming concern led the ISO to file a tariff amendment that caps battery bids when calculating bid cost recovery payments.[16] This policy change will largely address the ability of batteries to inflate unwarranted BCR payments. However, because the largest driver of real-time battery BCR is due to lost revenues of buying or selling back day-ahead schedules, these unwarranted BCR payments will continue after the policy change is implemented and therefore batteries with day-ahead schedules will continue to have distorted bidding incentives in the real-time.[17]

DMM continues to encourage the ISO to address the storage bid cost recovery concerns as a top priority, before undertaking additional storage design enhancements that may considerably slow the pace of development for needed storage bid cost recovery enhancements.[18] Rather than continuing to consider specific conditions under which it might be inappropriate for batteries to receive BCR, DMM recommends that the ISO start from the premise that batteries should generally be ineligible for BCR, and to then consider a limited number of conditions under which it may be appropriate to receive BCR.

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14 *Opinion on Storage Bid Cost Recovery*, James Bushnell, Scott M. Harvey, Benjamin F. Hobbs; Members of the Market Surveillance Committee, November 1, 2024: https://www.caiso.com/documents/market-surveillance-committee-final-opinion-storage-bid-cost-recovery-nov-01-2024.pdf

15 *Comments of the Department of Market Monitoring of the California Independent System Operator Corporation,* Department of Market Monitoring, ER25-576-000, December 17, 2024: https://www.caiso.com/documents/dmm-comments-on-er25-576-storage-bcr-dec-17-2024.pdf

16 *Tariff Amendment to Prevent Unwarranted Bid Cost Recovery Payments to Storage Resources, and Request for Effective Date on Shortened Notice,* California Independent System Operator Corporation, November 26, 2024: https://www.caiso.com/documents/nov-26-2024-tariff-amendment-bid-cost-recovery-to-storage-resources-er25-576.pdf

17 *Storage Bid Cost Recovery Presentation,* Department of Market Monitoring, June 30, 2025: https://stakeholdercenter.caiso.com/InitiativeDocuments/Presentation-StorageDesignandModeling-Jun30-2025.pdf

18 *Comments on Storage Design and Modeling Working Group Session 2 and 3*, Department of Market Monitoring, March 7, 2025: dmm-comments-on-storage-design-and-modeling-working-group-sessions-2-and-3-mar-07-2025.pdf

As a general principle, when batteries are constrained by operational parameters set by unit operators to manage battery operation, batteries should be ineligible for BCR payments.

### Local market power mitigation for batteries

In practice, most batteries are not frequently subject to bid mitigation under the ISO's local market power mitigation procedures. And when subject to mitigation, the impact of mitigation on the dispatch of batteries has been very low.[19]

Default energy bids for energy storage resources currently include three types of costs: (1) energy charging costs, (2) variable operations costs (including cycling and cell degradation costs), and (3) price-based intraday opportunity costs. The ISO's methodology estimates these opportunity costs based on batteries' maximum discharge duration. For example, a battery with a four-hour discharge duration in the real-time market would have opportunity cost based on the fourth highest price in the ISO's day-ahead market. The calculation is similar for the day-ahead default energy bid but based upon prices from the day-ahead market's advisory market power mitigation pass.

DMM has provided three main recommendations for how mitigation of batteries can be improved:

- **Establish different default energy bids for different hours of the day.** Currently, batteries can only have a single default energy bid that is static for all hours of the day. DMM has recommended allowing default energy bids to vary for different hours of the day. This would allow additional headroom to be included in default energy bids to capture estimated intraday opportunity costs during hours of the day when batteries are not usually discharging and potential market power is lowest. This would also allow use of lower default energy bids during the highest prices peak net load hours when batteries are typically scheduled to discharge, and potential market power is highest and intraday opportunity costs are lowest.

- **Create a standardized default energy bid for storage resources in the WEIM**. Currently, there are no default energy bids for batteries in the WEIM, and each battery must work with the ISO and DMM to establish a specially calculated default energy bid. This stems from the fact that the ISO's methodology for setting default energy bids for batteries uses prices from the ISO's day-ahead market as an input. DMM's believes that the ISO's current methodology could be easily extended to WEIM areas using some estimate of real-time prices in each WEIM area (e.g., from bilateral market prices, the historical correlation between WEIM prices and ISO day-ahead market prices, etc.).

- **Extend mitigation to include hybrid resources.** Currently, hybrid resources are not subject to any mitigation because the ISO has not developed a default energy bid for these resources. DMM believes that some reasonable approximation of the marginal or opportunity costs of hybrid resources could be developed for use in mitigation. This would be easier if default energy bids could vary by hour, rather than having to be a single static value for the entire day.

### Storage default energy bids should vary hourly, and reflect intraday opportunity cost

Currently, real-time default energy bids (DEB) are static throughout based off day-ahead prices and the duration of the storage resource. DMM recommends significant improvements to the DEB calculation

[19] *Comments on Storage Bid Cost Recovery and Default Energy Bid Enhancements Revised Straw Proposal*, Department of Market Monitoring, Figure 1, September 23, 2024: https://www.caiso.com/documents/dmm-comments-on-storage-bid-cost-recovery-and-default-energy-bid-enhancements-revised-straw-proposal-sep-23-2024.pdf

methodology to better capture the dynamic nature of intraday opportunity costs. The current static DEB values do not adequately reflect the true marginal (or intraday opportunity) costs of storage resources, leading to inefficiencies and potential market power issues. DMM recommends that DEBs be calculated on an hourly basis, allowing for a more accurate representation of costs that vary throughout the day.[20] This approach ensures that DEBs are aligned with real-time market conditions, thereby enhancing the overall efficiency and reliability of the market.

To ensure intraday opportunity costs are appropriately reflected in all hours, DMM supported the ISO developing a bid cap and a DEB that can exceed $1,000/MWh. DMM recommended only raising this bid cap to allow for bidding over $1,000/MWh in a limited number of hours where intraday opportunity costs are most likely to exceed $1,000/MWh.[21] The development of an hourly DEB would prevent the overstating of costs in many hours, as occurs under the ISO's recently approved real-time bid cap for storage resources on days with hours when bids may exceed $1,000/MWh.[22]

DMM recommends an hourly real-time DEB that reflects opportunity costs throughout the day that could include high opportunity costs (potentially exceeding $1,000/MWh) in the hours leading up to the highest priced peak net load hours, while noting that opportunity costs should be lower during the peak net load hours. This flexibility is crucial for accurately reflecting the true costs of storage resources, particularly during periods of high demand or limited supply.

### Batteries providing resource adequacy 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 its market awards in preceding hours. During critical periods in recent years, 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.

The new slice-of-day framework being developed by the California Public Utilities Commission (CPUC) for California's resource adequacy program addresses this issue from the perspective of capacity portfolio planning. Under this slice-of-day approach, resource adequacy portfolios of load serving entities will need to include sufficient surplus energy to ensure that batteries can be used to meet the 24-hour resource adequacy obligation.

On an operational level, however, additional software and rule enhancements are also needed to ensure that batteries are available when needed for reliability. 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 and WEIM systems will rely

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20 *Comments on Storage Design and Modeling*, Department of Market Monitoring, June 11, 2025: https://www.caiso.com/documents/dmm-comments-on-storage-design-and-modeling-may-28-2025-presentation-jun-11-2025.pdf

21 *Memorandum: Comments on Management's proposed changes to rules for bidding over the soft-offer cap*, Department of Market Monitoring, May 15, 2024: https://www.caiso.com/documents/departmentofmarketmonitoringcomments-softoffercap-memo-may2024.pdf

22 *Order Accepting Proposed Tariff Revisions – Soft-Offer Cap,* California ISO, ER24-2168-000, July 31, 2024: https://www.caiso.com/documents/jul-31-2024-order-accepting-tariff-amendment-price-formation-enhancements-er24-2168.pdf

on storage capacity the most. This could include changes to bid cost recovery rules aimed at ensuring battery storage resources are properly incentivized to reflect real-time intraday opportunity costs in energy bids during the hours preceding the highest net load hours of the day.

The current resource adequacy availability incentive mechanism (RAAIM) framework does not provide very strong financial incentive for resource availability. However, the current RAAIM framework could be improved by considering the impact of various parameters that can limit the actual availability of storage resources.[23]

## Flexible ramping product

The ISO's flexible ramping product is designed to procure additional ramping capacity to address uncertainty in imbalance demand through the real-time market software. This product is aimed at increasing reliability and efficiency, while reducing the need for manual load adjustments and other actions by grid operators to create sufficient ramping capacity to meet ramping needs and defend against uncertainty. Since being implemented in 2016, the ISO has expended considerable time and resources correcting and enhancing the flexible ramping product design.

In February 2023, the California ISO implemented nodal procurement as part of the flexible ramping product refinements stakeholder initiative. Even after locational procurement was correctly implemented, the flexible ramping product does not seem to effectively address net load uncertainty in the real-time market. The flexible ramping product continues to have a positive shadow price during a very small portion of intervals, indicating that the product is not changing the dispatch of resources significantly.

Moreover, grid operators continue to address the need for ramping capacity by entering a very high upward bias in the hour-ahead and 15-minute load forecast in the hours leading up to the peak net load hours each morning and evening. In addition to this very large upward load bias, operators take other manual actions to ensure additional ramping capacity is available during the afternoon peak net load hours. These operator actions include (1) increasing residual unit commitment requirements in the day-ahead market, (2) manually committing additional units after the day-ahead market, and (3) dispatching some slower ramping units out-of-sequence in the hours prior to the net load peak.

Since the flexible ramping product was implemented in 2016, DMM has recommended that the ISO consider increasing 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). A detailed explanation of this recommendation was provided in DMM's 2021 annual report.[24]

DMM continues to believe that the current 15-minute timeline of the flexible ramping product is too short to effectively address net load uncertainty in the real-time market. DMM continues to recommend

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23 DMM has previously recommended that the CAISO include how the following parameters limit a battery's availability when calculating the resource adequacy availability incentive mechanism (RAAIM): de-rates to maximum state-of-charge (SOC) 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 re-rates to PMIN or not offering charging bid range such that resources are unable to charge for later hours.

24 *2021 Annual Report on Market Issues & Performance*, Department of Market Monitoring, July 11, 2023, pp 276-278: https://www.caiso.com/documents/2021-annual-report-on-market-issues-performance.pdf

that the ISO consider addressing net load uncertainty through a real-time product with a longer time horizon (e.g., from 1 to 4 hours).

The section on *price formation enhancements* in this chapter provides additional discussion of how some kind of real-time uncertainty product with a longer time horizon than the flexible ramping product could improve price formation in the real-time market.

## Mosaic regression model of net load uncertainty

The ISO incorporates uncertainty about real-time supply and demand into a variety of market processes. In each of these processes, the ISO sets market requirements based on estimates of uncertainty derived from a mosaic quantile regression model. This mosaic regression model estimates total net load based on three determinants: real-time load, solar, and wind forecasts. Detailed descriptions and analysis of the mosaic model are provided in numerous DMM reports.[25] This model was initially developed for use in the real-time market to determine the demand curve for the flexible ramping product (FRP) and to set the uncertainty component that is included in the flexible ramp sufficiency test (flexibility test) included in the WEIM resource sufficiency evaluation, as described below:

- **Flexible ramping product.** The ISO's market model procures flexible capacity to cover net load uncertainty that may materialize in the real-time market. By design, the FRP uncertainty requirement captures the extreme ends of net load uncertainty and it can be optimally relaxed based on the trade-off between the cost of procuring additional flexible ramping capacity and the expected cost of a power balance relaxation. For the 15-minute market flexible ramping product, uncertainty is defined as the difference between the advisory 15-minute market net load forecast and the binding 5-minute market forecasts. For the 5-minute market flexible ramping product, uncertainty is defined as the difference between the advisory 5-minute market forecast and the binding 5-minute market forecast.

- **WEIM resource sufficiency evaluation**. Uncertainty about net load is included as an additional requirement in the flexible ramp sufficiency test (flexibility test) as part of the resource sufficiency evaluation (RSE). Balancing areas must show enough upward and downward ramping flexibility over an hour to meet both the forecasted change in demand as well as uncertainty. This additional requirement in the flexibility test is also based on a 95 percent confidence interval for net load uncertainty using the mosaic quantile regression model.

DMM has performed extensive analysis of the performance of the mosaic regression model in these real-time market processes. DMM has provided numerous recommendations concerning the mathematical formulation of this model and specific inputs used to estimate net load uncertainty in the real-time. Some of these issues have been addressed by the ISO.

DMM's analysis indicates that the mosaic model provides a slight improvement over much simpler approaches based on histograms that were previously used to incorporate net load uncertainty these market processes. While DMM believes some improvements could be made in the mosaic model, DMM also recognizes the difficulty of accurately estimating net load uncertainty in real-time. Given the

25 *Q4 2024 Report on Market Issues and Performance*, Department of Market Monitoring, March 26, 2025, pp 90-110: https://www.caiso.com/documents/2024-fourth-quarter-report-on-market-issues-and-performance-mar-26-2025.pdf

substantial time and resources that have been invested in the mosaic model, DMM does not believe that replacing the real-time mosaic model would be an efficient use of resources.

The mosaic model was developed for use in the ISO's real-time market. However, the ISO has expanded the use of the mosaic model to two key elements of the day-ahead market.

- **Residual unit commitment.** In 2023, the ISO expanded the use of the mosaic regression model approach to the residual unit commitment (RUC) process. As summarized in prior DMM reports, the mosaic model is used to generate a probabilistic estimate of net load uncertainty between the day-ahead and real-time markets. This statistical estimate of uncertainty can be included in manual adjustments in the RUC requirement made by operators.[26]

- **Imbalance reserve capacity**. The ISO is also planning to use the mosaic model to determine the demand curve for the new imbalance reserve product being implemented as part of EDAM. The ISO's EDAM filing indicates that the Business Practice Manual will specify that the demand curve for imbalance reserve up will be set directly (and automatically) at the 97.5th percentile of the mosaic model results.[27]

DMM has expressed concern about the use of the mosaic regression model in both these day-ahead market processes. Based on the ISO's experience using the model results in setting the RUC requirements, it appears the 97.5th percentile of model output may be far in excess of the amount of capacity that grid operators would actually procure to defend against overall uncertainty between the day-ahead timeframe and real-time.

The ISO's experience using the mosaic model to set RUC requirements is explained in detail and graphically illustrated in DMM's Q4 2024 report.[28] In 2023, when the ISO began adding the 97.5th percentile of estimated net load uncertainty directly in RUC requirements, RUC procurement and cost escalated sharply. In 2024, the ISO changed the RUC process so that ISO operators were given the discretion whether to use mosaic model results and, if so, what level of uncertainty to use in the adjustment for net load uncertainty.

In practice, the current operating procedures of setting RUC requirements allow operators to consider a wide range of supply and demand uncertainties, and then simply select from a range of mosaic model results they feel might correspond to their own assessment.[29] Since this change, grid operators do not include any adjustment specifically for net load uncertainty in RUC requirements during most hours, and set RUC requirements based on the 97.5th percentile of the model output only during an extremely low percentage of hours.

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[26] Ibid. pp 105-110

[27] California ISO, *Tariff amendment to implement day-ahead market enhancements and extended day-ahead market*, Docket No. ER23-2686-000, August 22, 2023, p 69: https://www.caiso.com/Documents/Aug22-2023-DAME-EDAM-Tariff-Amendment-ER23-2686.pdf

[28] *Q4 2024 Report on Market Issues and Performance*, March 26, 2025, pp 105-110: https://www.caiso.com/documents/2024-fourth-quarter-report-on-market-issues-and-performance-mar-26-2025.pdf

[29] *Day-Ahead Market Operating Procedure*, No. 1210, Section A.3.3.3, pp 12-13: https://www.caiso.com/documents/1210.pdf

Given this experience, it appears the mosaic model is likely to set the demand for imbalance reserve far in excess of what may be needed under most system conditions. Fortunately, the potential impact of this will be mitigated to some degree by the following factors.

- The demand curve for imbalance reserve in EDAM will be capped at $55/MWh. Analysis by DMM suggests that a very large portion of the imbalance reserve may be capped at $55/MWh. This will help reduce the price and quantity of imbalance reserves procured.
- When the supply offered in EDAM is significantly in excess of demand, the imbalance reserve product may clear at relatively low prices.

DMM has provided several recommendations relating to the imbalance reserve product as EDAM is implemented:

- The ISO should be prepared to potentially reduce the 97.5th percentile of estimated load uncertainty that will be used to set the imbalance reserve demand curve. This would require a change in the Business Practice Manual.
- The ISO should be prepared to reduce the initial $55/MWh cap after EDAM implementation if necessary. This would require a tariff change.
- The ISO should monitor how the RUC process interacts with the new day-ahead imbalance reserve product, and how much RUC capacity is procured. The amount of RUC procured may depend on the amount of imbalance reserve clearing the day-ahead market. While imbalance reserve will be procured based on a demand curve that cannot be adjusted, the ISO's RUC process provides operators with a very large degree of discretion in setting RUC requirements.
- The ISO should continue to work on developing more appropriate methods for determining the demand curve for imbalance reserves in the day-ahead market. Additional details of this are described below.

As mentioned above, the current operating procedure of setting the RUC requirement allows operators to consider a range of supply and demand uncertainties, and then select from a range of mosaic model results that might correspond to their assessment. This procedure specifies that operators may consider the following factors when assessing the need for adjusting the RUC requirements:

- Demand response
- Load forecast errors (using the Risk Predictor)
- Fire danger
- Weather changes
- Reliability Coordinator next-day analysis
- Potential loss of resources
- Stranded capacity

The list of factors in this procedure illustrates that actual uncertainty between the day-ahead and real-time is driven by factors other than uncertainty about load, wind, and solar resources.

Additionally, since the mosaic model is based on net load uncertainty between the day-ahead market and real-time, the mosaic model essentially assumes that the only way to defend against this uncertainty is to procure imbalance reserve (or RUC capacity) on a day-ahead basis. This approach does not account for the fact that additional capacity without a day-ahead energy, imbalance reserve up, or RUC award is available in real-time to address uncertainty under most conditions. If this additional capacity is taken into account, the demand for imbalance reserve (or RUC) capacity should be lower.

## Price formation enhancements

In 2022, the California ISO initiated a price formation enhancements working group, aimed at addressing multiple issues related to price formation in the CAISO and WEIM markets. DMM suggests the ISO consider placing a priority on foundational market enhancements that will improve price formation, such as:

- Extending the time-horizon of the flexible ramping product (or creating a new real-time uncertainty product that serves this purpose),
- Re-optimizing ancillary services in the real-time market, and
- More accurately incorporating intraday opportunity costs into default energy bids and bid caps for battery resources.

DMM suggests the ISO place a priority on this type of foundational market enhancement before embarking on more complicated market design changes, such as fast start pricing and scarcity pricing.

### Real-time uncertainty product

DMM continues to recommend the ISO create a capacity product to cover uncertainty over an extended time horizon longer than one interval out. In addition to the operational benefits of improved management of available capacity, an extended product could also fix a current problem where the real-time prices are not always set equal to marginal cost.[30] Because this product would include requirements for capacity above what is needed to meet load in the binding interval, it could also allow energy prices to rise as available unloaded capacity becomes scarcer.

The real-time markets are cleared with a multi-interval optimization. This optimization creates a set of prices for all intervals in the run. However, only the prices in one interval, the *binding* interval, are used for settlements. The prices from further out *advisory* intervals are not used for settlements. Resources can receive dispatches in the binding interval to procure sufficient capacity to make it feasible to meet expected net load in an advisory interval.

With this multi-interval optimization, the marginal cost of meeting the expected future net load is reflected in the advisory interval energy price, but not the settled binding interval energy price. In the subsequent market runs when this advisory interval becomes a binding interval, the actions taken to make meeting expected net load feasible have already occurred, and there is no longer a cost to meet that need in the optimization run that creates the binding prices. Because the costs to meet that need have already occurred, i.e., are sunk, the energy price the resource is actually settled on does not include the marginal cost of making it feasible to meet the expected net load.

[30] *Comments on Price Formation Enhancements Issue Paper*, Department of Market Monitoring, August 11, 2022: https://www.caiso.com/Documents/DMM-Comments-Price-Formation-Enhancements-Issue-Paper-Aug-11-2022.pdf

An uncertainty product with a longer time horizon in the real-time market could move the marginal costs of the advisory interval into the binding interval prices, which is when actions are taken to meet expected net load in the advisory intervals. Moving these costs into the binding interval prices would settle resources on real-time prices that include all marginal costs. Further, by procuring additional capacity to meet expected net load and uncertainty, energy prices in the binding interval can rise as available capacity becomes scarcer.

### Re-optimizing ancillary services in real-time

DMM recommends that the ISO re-optimize ancillary services with other products in the real-time. The ISO placed ancillary service real-time re-optimization and locational procurement of ancillary services on their policy road map in 2023.[31] This topic was also considered in initial price formation enhancements stakeholder discussions in 2024 and early 2025, but appears to potentially no longer be under consideration in that initiative. Real-time re-optimization of ancillary services could increase efficiency and allow real-time energy prices to better reflect real-time (ancillary service) conditions.

### Incorporating intraday opportunity costs into bid caps

The ISO's current approach for determining default energy bids (DEBs) and allowing batteries to bid over $1,000/MWh is based on a relatively simple calculation of intraday opportunity costs. These bid limits are currently based on day-ahead prices and are static values that do not vary on an hourly basis. As noted in the section on battery resources, DMM has recommended that the ISO continue to enhance the manner in which intraday opportunity costs are calculated and to allow bid caps reflecting these costs to vary by hour and be more dynamic in the real-time market. These enhancements could also be applicable to some hydro units that have intra-day energy limits.

### Scarcity pricing

DMM supports the ISO's efforts to consider changes to its scarcity pricing provisions. 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.

DMM also notes that a real-time uncertainty product with an extended time horizon would also serve a scarcity pricing purpose. Because there is a tradeoff between procuring capacity or energy, prices for both capacity and energy start to rise when the amount of available capacity declines. This allows prices to increase as available capacity falls, even before there is insufficient energy supply to meet load in the market. However, because the flexible ramping product currently only looks out to one advisory interval, real-time energy and flexible capacity prices do not reflect the potential scarcity of available capacity over a longer and more relevant timeframe.

An uncertainty product with a time-horizon longer than one interval (e.g., 1 to 4 hours) would allow capacity and energy prices to reflect upcoming scarcity in more distant advisory intervals. A longer horizon uncertainty product would improve price formation by allowing prices for energy and capacity to better reflect supply and demand conditions in the real-time market, and allow energy prices to rise as available unloaded capacity becomes scarcer.

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31 *2023 Policy Initiatives Catalog*, California ISO, March 29, 2023: https://www.caiso.com/InitiativeDocuments/Final2023PolicyInitiativesCatalog.pdf

### Fast start pricing

DMM has previously outlined reasons it believes fast start pricing is inconsistent with the features of locational marginal pricing that maximize market surplus and provide incentives for units to bid and operate at the most efficient, socially optimal dispatch level.[32] DMM understands that in response to requests from some stakeholders, the ISO has recently examined the possibility of adopting some form of fast start pricing in the CAISO and WEIM. However, the ISO's revised 2025 policy initiatives roadmap reports that further work the fast start pricing initiative has been suspended until at least 2026.

The ISO has provided analysis which suggests the impacts of fast start pricing are small on average, but can be large in a limited number of intervals.[33] The ISO's current analysis does not consider many complexities of the CAISO and WEIM markets. If stakeholders and the ISO decide to move forward with fast start pricing, additional testing in the actual market software will be needed.

DMM believes further analysis is needed for the ISO to assess whether the pattern of estimated price impacts could actually lead to meaningful increases of import bids into the WEIM. This is the main potential efficiency benefit cited by proponents of fast start pricing. Unlike most other RTOs, the ISO's real-time market and WEIM already allow imports and exports between balancing areas to be offered and cleared based on bid prices, rather than requiring imports and exports to be scheduled as price takers. DMM supports the ISO's suspension of further policy work on the fast start pricing initiative, and would support ultimately abandoning consideration of a fast start pricing framework in the CAISO and WEIM markets.

## WEIM resource sufficiency tests

The resource sufficiency tests for capacity and flexible ramping capacity are key elements of the Western Energy Imbalance Market (WEIM) 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. Since January 2023, DMM has provided analysis on resource sufficiency evaluation (RSE) performance, accuracy, and impacts in regular monthly and quarterly reports. These reports have included numerous recommendations for a series of improvements to the resource sufficiency test that have been implemented by the ISO over the last two years.

### Energy assistance option

Until 2023, when a WEIM area failed either the capacity test or flexible ramping test, WEIM transfers into the balancing area were not allowed to increase beyond the level of supply being transferred into the area just prior to the test failure. A major change taking effect in 2023 was implementation of an energy assistance option that allows WEIM areas to import additional energy through WEIM during intervals when they fail the resource sufficiency test. Areas importing additional energy under the emergency assistance option are subject to a penalty cost based on the amount by which the area failed the test, the amount transferred into the area from the WEIM, and the CAISO/WEIM penalty price in

32 *Comments of the Department of Market Monitoring for the California Independent System Operator* in RM17-3- 000: https://www.caiso.com/Documents/Feb28_2017_DMMComments-Fast-StartPricingNOPR_RM17-3.pdf

33 *Price Formation Enhancements, Analysis on Fast Start Pricing*, California ISO, April 8, 2024: https://www.caiso.com/InitiativeDocuments/Presentation-Price-Formation-Enhancements-Apr8-2024.pdf

effect ($1,000 or $2,000/MWh). With this approach, the total cost of the penalty is scaled closely with the degree to which areas may be relying on the WEIM when failing the test.

DMM supported the energy assistance option as a reasonable compromise that could be implemented in summer 2023, and would encourage a larger portion of WEIM balancing areas to participate in this option. However, if multiple balancing areas failed RSE tests while opting in to the assistance energy transfer (AET) program, this could indicate extensive reliance on AET during tight west-wide conditions. DMM and some WEIM entities have expressed this concern regarding the AET program.

Since the implementation of AET functionality in July 2023, DMM has regularly monitored AET utilization and published the results in quarterly WEIM resource sufficiency evaluation reports. In two years of monitoring, DMM's analysis has not indicated that any particular balancing area is systematically relying on the AET functionality to meet capacity shortfalls.[34] In addition, DMM identified very few intervals when there were two or more balancing areas simultaneously failing the RSE test while opting in to receive assistance energy transfers.

Given how the AET has been utilized by different balancing areas, DMM supports the ISO's proposal to extend the AET program past its December 31, 2025 sunset date.

## Export and wheeling schedules

The summer 2020 heat wave highlighted the need to review and clarify the California ISO's policies and procedures for curtailing load versus curtailing exports and wheeling schedules. During hours in August 2020, when the California ISO grid operators curtailed the CAISO balancing area load, operators did not curtail any non-high priority exports or wheeling schedules. DMM believes this was inconsistent with ISO tariff provisions and analogous provisions in the open access transmission tariffs (OATTs) of other balancing areas in the West. DMM recommended the ISO take steps to clarify priorities for curtailing native load versus non-high priority exports, and make ISO rules and procedures similar to those of other balancing areas in the West.

In advance of summer 2021, the ISO established export prioritization rules and interim rules for high priority wheeling through transactions.[35] In 2022, the ISO completed the transmission service and market scheduling priorities initiative.[36]

In the second phase of this initiative, the ISO established a process for making excess transmission not needed to serve native CAISO load available to other entities to wheel power on a longer-term forward basis. This approach represents a significant improvement from the previously established interim rules for high priority wheeling access, and makes the ISO's rules more closely resemble the open access transmission tariff (OATT) framework used across the West in balancing areas without organized markets.

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34 *Comments on WEIM Assistance Energy Transfer Extension*, Department of Market Monitoring, April 30, 2025: https://www.caiso.com/documents/dmm-comments-on-weim-assistance-energy-transfer-program-extension-apr-16-2025-meeting-apr-30-2025.pdf

35 Market Enhancements for Summer 2021 initiative page: https://stakeholdercenter.caiso.com/StakeholderInitiatives/Market-Enhancements-for-Summer-2021-Readiness

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

However, because the ISO's approach does not include a detailed analysis of the impact of wheeling schedules on flows within the CAISO, the proposal may make some additional wheeling capacity available, compared to DMM's understanding of how this OATT framework is typically applied. DMM continues to recommend that the ISO improve the modeling of the impact of high priority wheels on flows within the CAISO system.

DMM understands the ISO has committed to conduct an annual analysis of high priority wheeling impacts on Path 26, the major north to south transmission constraint within the CAISO footprint. As the ISO has begun to implement the new framework, DMM has learned that the ISO is only considering the flow impact from wheels importing to the CAISO at the Malin intertie. This intertie has been the import point of around 30 to 40 percent of high-priority wheel through transactions in recent years.[37] DMM believes the ISO also needs to study the impacts of high priority wheel though transactions importing at other interties.

Also, relying on historic wheel through patterns to determine which interties to include in the flow impact study and calculate the available transmission capacity (ATC) may not sufficiently mitigate the risk of reliability issues stemming from internal congestion caused by high-priority wheels. These patterns may change once reservations are restricted at historically used interties. Such changes in historical patterns have already occurred in the summer of 2024, due to limited ATC at Malin in the summer months.

Some entities hold transmission ownership rights (TORs) in the northern part of the CAISO system, from Malin to the Round Mountain 230 scheduling point. Historically, the owners of many of these TORs converted them to CRRs, and did not use them for transmission scheduling. The ISO excludes these TORs from the ATC calculated for a given intertie. As the ISO limited ATC at Malin, some owners of these TORs have used them to support schedules from Malin to the Round Mountain 230 scheduling point, where these entities gain access to additional ATC to support high priority wheel through transactions. Although these reservations could impact Path 26 congestion similar to imports at Malin, the ISO did not consider the added ATC at Round Mountain 230 in the analysis of priority wheeling impacts on Path 26.

## Demand response

Since 2020, DMM has provided special reports focusing on demand response in the California ISO during the most critical summer periods.[38] DMM also provides comments in ISO stakeholder processes and California Public Utilities Commission (CPUC) proceedings on demand response. In addition to reports and comments, DMM has engaged with WEIM entities on the topic of demand response and its role in their respective balancing areas.

Demand response accounted for about 2.6 percent (or 1,400 MW) of total California ISO system resource adequacy capacity during the summer of 2024, compared about 3 to 4 percent of total system resource adequacy capacity in the previous four summers.[39] Demand response also plays a role in

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37 California ISO wheeling and resource adequacy imports aggregate data, *Priority Wheeling Through Transaction Data*: https://www.caiso.com/Documents/PriorityWheelingThroughTransactionsData.xlsx

38 *Demand response issues and performance 2024*, Department of Market Monitoring, February 20, 2024: https://www.caiso.com/documents/demand-response-issues-and-performance-2024-feb-20-2025.pdf

39 Ibid.

meeting the capacity needs of WEIM entities. However, assessing such capacity is more difficult because it does not participate as a market resource.

In prior reports, DMM has highlighted some recommendations that the ISO and CPUC could consider to enhance the availability and performance of California ISO demand response resources.[40] Over the last few years, the CPUC has made a number of changes to the treatment of demand response resources that count towards resource adequacy requirements. In July 2023, the CPUC announced several significant changes and clarifications regarding treatment of reliability demand response, which took effect in 2024.[41]

- **Transmission loss gross-ups and the planning reserve margin adder totaling over 11 percent were removed from credited utility demand response resource adequacy values.[42]** DMM had previously recommended the CPUC reconsider the transmission and distribution loss factor gross-ups and the planning reserve margin (PRM) adder because evidence suggested the resource adequacy values of utility demand response was over-estimated. During high load days the past two summers, an average of only about 87 percent of demand response resource adequacy capacity was bid into the market. DMM noted this might be due in part to CPUC-jurisdictional demand response gross-ups and the PRM adder, which previously totaled over 11 percent.

- **Beginning in 2024, demand response resource adequacy capacity must be available during all days during which the ISO calls a Flex Alert, issues a Grid Warning, or the Governor's Office has issued an emergency notice**, in addition to the minimum of three days per week for at least four hours per day. The CPUC's Energy Division proposed this change following the 10-day heat wave in September 2022. DMM supported this proposal to incentivize resource adequacy demand response resources to bid in whatever capacity they have available during hours with tight system conditions.

- **Capacity awarded to demand response resources under the CPUC load impact protocol (LIP) process will be de-rated based on performance during test events.** Average performance results of each quarter will affect the capacity awarded through the LIPs for the respective sub-load aggregation point. DMM supported this proposal to incorporate the test results in capacity awards because it may incentivize resources to provide accurate capacity estimates and to perform better when dispatched, which could lead to improved reliability.

- **Proxy demand response resources can bid no higher than $949/MWh** to ensure proxy demand resources are dispatched before reliability demand response resources. DMM supported this proposal and agrees the proxy demand resources should be used prior to emergency reliability demand response.

In 2024, the ISO completed some limited penalty enhancements for demand response that include explicit deadlines and well-defined penalty structures regarding the submission of demand response monitoring data. DMM supported these enhancements, as it will improve the ability to monitor since it

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40 *2022 Annual report on market issues and performance,* July 11, 2023, pp 21-22: https://www.caiso.com/documents/2022-annual-report-on-market-issues-and-performance-jul-11-2023.pdf

41 CPUC Decision (D.) 23-06-029, July 5, 2023: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M513/K132/513132432.PDF

42 The CPUC removed transmission adders of about 2.5 to 3 percent, plus a planning reserve margin (PRM) of 9 percent.

increases incentives to submit demand response monitoring data. The changes are in effect as of January 6, 2025.

The ISO, CPUC, and California Energy Commission (CEC) also continue to work on addressing some additional issues pertaining to demand response, including enhancing resource adequacy counting methodologies to account for the variable nature of some demand response resources. DMM continues to recommend that the ISO consider other potential changes to enhance the reliability of demand response capacity. These include:

- **Re-examine demand response counting methodologies.** Demand response appeared to be over-counted in terms of these resources' contribution towards meeting resource adequacy requirements and their reported load curtailments. DMM supports efforts to better capture the capacity contribution of demand response whose load reduction capabilities vary across the day, and who may have limited output in general. The CPUC and CEC are currently working to develop an incentive-based qualifying capacity valuation for supply-side demand response resources.[43] DMM has recommended considering a performance-based penalty or incentive structure for resource adequacy resources. An incentive-based methodology for awarding qualifying capacity to resource adequacy demand response may improve the trend in recent years where availability and performance of proxy demand response resources fall below resource adequacy capacity. The CPUC and CEC were to submit a joint proposal in January 2025, but the report has been postponed.

- **Consider removing the exemption for long-start proxy demand response to be available in the residual unit commitment (RUC) process.** This exemption does not exist for other types of long-start resources providing resource adequacy. Long-start resources continue to make up a significant portion of the resource adequacy proxy demand response fleet. In July through September of 2024, about 58 percent of supply plan demand response was registered with start-up times of over 255 minutes.[44] If this capacity is not scheduled economically in the integrated forward market, then per the ISO tariff, this capacity has no obligation to be available in RUC.

- **Ensure that non-CPUC jurisdictional load serving entities that manage utility demand response programs used to meet resource adequacy requirements communicate the available capacity to the ISO on a daily basis, so that the ISO is aware of and can call this capacity when needed.** DMM understands that the ISO has reached out to non-CPUC jurisdictional load serving entities using demand response crediting to better ensure that the ISO has insight into these demand response programs. It will be important that the ISO have the same insight into other local regulatory authority demand response programs which are counted towards meeting resource adequacy, as the ISO does with CPUC-jurisdictional load-serving entity demand response programs.

In addition to the above recommendations for the California ISO balancing area, DMM recommends the development of a demand response model for WEIM (and ultimately EDAM)

43 CPUC Decision (D.) 21-10-002, June 29, 2023, pp 79-81: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M513/K132/513132432.PDF

44 Long-start resources have a cycle time greater than 240 minutes, where cycle time is a resource's startup time plus minimum run time.

entities. Currently, demand response for WEIM entities is implemented through load adjustments, and as a result are not incorporated into the market. As a result, the WEIM entities do not have a market method to assess availability or performance for their demand response resources, and have no WEIM market settlements data to compare against. DMM recommends the ISO develop a WEIM demand response model to improve the access and validity of the WEIM demand response resources.

## California resource adequacy

California relies on the state's long-term integrated resource planning process and resource adequacy program to maintain adequate system capacity and help mitigate market power through forward energy contracting. However, the state's resource adequacy framework needs significant changes to accommodate numerous regulatory and structural market changes in recent years.

### Resource adequacy imports

DMM has warned that existing California ISO rules could allow imports that may not be available during critical system and market conditions to meet resource adequacy requirements. For instance, under current ISO resource adequacy rules, imports can routinely bid significantly above projected prices in the day-ahead market to help ensure they do not clear, thus relieving the imports of any further offer obligations in the real-time market.[45]

The California Public Utilities Commission (CPUC) has addressed this concern with 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.[46] DMM supports the CPUC's approach as an effective interim mechanism for ensuring delivery of import resource adequacy during peak net load hours. Monitoring and analysis by DMM indicates this approach has proven effective at ensuring delivery of resource adequacy imports since being implemented in 2020.

DMM also recommends that the California ISO, CPUC, and stakeholders continue to consider alternative solutions to allow resource adequacy imports to participate more flexibly in the market. For example, DMM supported development of a recent proposal in CPUC proceedings to allow resource adequacy imports to bid up to the marginal cost of a typical gas resource rather than at or below $0/MWh during peak net load hours.[47] Over the longer term, DMM supports development of a more source-specific framework for resource adequacy imports that ensures other balancing areas cannot recall import energy, particularly when they also face supply shortages.

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[45] *Import Resource Adequacy*, Department of Market Monitoring Special Report, September 10, 2018, pp 1-2: http://www.caiso.com/Documents/ImportResourceAdequacySpecialReport-Sept102018.pdf

[46] *Decision adopting resource adequacy import requirements (D.20-06-028)*, CPUC Docket R.17-09-020, June 25, 2020: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M342/K516/342516267.pdf

[47] *Reply comments on proposed decision adopting local capacity obligations for 2024-2026, flexible capacity obligations for 2024, and program refinements*, Department of Market Monitoring, CPUC Rulemaking 21-10-002, June 19, 2023: http://www.caiso.com/Documents/Reply-Comments-R21-10-002-Adopting-Local-2024-26-and-Flexible-2024-Capacity-Obligations-and-ProgramRefinements-Jun-19-2023.pdf

### New slice-of-day resource adequacy framework

In April 2023, the CPUC issued a decision adopting implementation details for a 24-hour *slice-of-day* framework, which includes adopting compliance tools, resource counting rules, and a methodology to translate the current Planning Reserve Margin to the slice-of-day framework.[48] The CPUC has implemented the framework starting in the 2025 compliance year. DMM supports the CPUC's decision to adopt the slice-of-day framework because it aligns capacity sufficiency throughout the year with energy sufficiency throughout the day. DMM also supports the requirement to offset battery storage usage with excess energy and capacity from other resources needed to charge these storage resources.

DMM also supports the proposal to change the capacity counting methodology for solar and wind resources to the *exceedance* values, rather than values based on the *effective load carrying capacity* (ELCC) approach. Although exceedance values for wind and solar are conservatively low, DMM believes that too much reliance on these variable energy resources that may not actually be available during peak net load hours is a reliability risk.

### Resource adequacy performance incentives

An availability incentive uses bids to determine resource availability, while a performance incentive uses schedules and delivered supply to determine resource performance. The distinction between these two mechanisms is important because it leads to two separate behavioral incentives, and thus potentially two different outcomes.

The ISO does not currently have a resource performance incentive. The ISO's current mechanism for incentivizing the availability of resource adequacy capacity is the resource adequacy availability incentive mechanism (RAAIM). Resource unavailability can cause financial penalties associated with RAAIM based on 60 percent of the ISO's capacity procurement mechanism (CPM) soft offer cap, which has been $7.34/kW-month since June 1, 2024.[49]

As capacity becomes more limited and prices increase in the West, the difference between capacity payments and potential RAAIM penalties also increases. DMM is concerned that if 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 outages for a significant portion of the month. Since the RAAIM penalty is not performance based, a supplier could also avoid current availability penalties by offering capacity into the market, even though this capacity fails to perform when called upon.

Availability incentives provide financial motivation for resources to bid into the market, but do not provide a financial motivation to perform, i.e., meet the resource's schedule. As a result, DMM recommends the ISO additionally consider a performance incentive mechanism that would be a measure of a resource's schedule against their metered contribution to the system. A performance mechanism and an availability incentive are complementary, and could be considered as a package to meet the operational needs of the system. DMM believes the penalty structure should be priced to claw-back resource adequacy capacity payments that are associated with the difference between the

48 *Decision on Phase 2 of the Resource Adequacy Reform Track (D.23-04-010)*, CPUC Docket No. R.21-10-002, April 7, 2023: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M505/K753/505753716.PDF

49 California ISO Tariff Section 40.9.6.1(c): Section40-RADemonstration-for-SchedulingCoordinatorsintheCAISOBalancingAuthorityArea-asof-Nov1-2023.pdf

obligation and their availability and performance. Because the penalty is a claw-back, the penalty price should be designed as a function of resource adequacy market prices.

Incentivizing availability and performance of resource adequacy capacity could become increasingly important as resource adequacy payments increase compared to the magnitude of potential RAAIM charges. The addition of a performance mechanism could better incentivize suppliers to sell highly available, and dependable, capacity up front.

### Outage management enhancements

Currently, the ISO requires resources to acquire substitute resource adequacy capacity for planned outages. Due to tight conditions in the capacity market, acquiring substitution capacity is difficult. As a result, DMM has identified that under the current outage substitution rules, resources are transferring their outages into the forced outage timeframe (7 days or less) that does not require substitute capacity. Since forced outages receive less scrutiny and will be automatically approved, DMM is concerned a discretionary outage transferred into the forced timeframe may compromise reliability during tight grid conditions.

To address this concern, DMM recommends the ISO enhance outage reporting requirements to more clearly require the resource scheduling coordinator to identify if a forced outage is either (1) necessary immediately for plant operation, or (2) if the forced outage is for discretionary plant maintenance that could be postponed in the case of imminent system reliability concerns. Further, the ISO has recently proposed to allow for conditional approval of planned outages without substitution, or if there would be a reliability impact, to procure from an outage substitution pool.[50] DMM supports these policy developments. DMM recommends that if the ISO establishes an outage substitution pool, such a pool be established as an auction.[51]

50 *Resource Adequacy Modeling and Program Design Issue Paper*, California ISO, November 7, 2024: https://stakeholdercenter.caiso.com/InitiativeDocuments/Issue-Paper-Resource-Adequacy-Modeling-andProgram-Design-Nov-07-2024.pdf

51 *Comments on Resource Adequacy Modeling and Program Design Working Group*, Department of Market Monitoring, March 13, 2025: https://www.caiso.com/documents/dmm-comments-on-resource-adequacy-modeling-and-program-design-working-group-mar-13-2025.pdf

# 1 Load and resources

This chapter reviews key aspects of demand and supply conditions that affected overall market prices and performance. In 2024, wholesale electricity prices across the WEIM were lower due to decreases in natural gas prices despite a 2 percent increase in average system load. Since June 2020, roughly 130 GW of capacity has been added to the WEIM, 35 percent of which was hydroelectric and about 17 percent solar.

Specific trends highlighted in this chapter include the following:

- **Load across the WEIM averaged 78.3 GW, about 2 percent more than 2023.** Load increased in all WEIM regions in 2024 compared to 2023. The Pacific Northwest region had the largest load increase at about 4 percent. **Peak 5-minute market load for the year was 135.3 GW on July 10, 2024, hour-ending 18, interval 11,** a 2 percent increase over 2023 peak load (132.6 GW).
- **The largest sources of generation in 2024** in the California region were natural gas and non-hydro renewables, similar to 2023. Hydroelectric generation dominates the generation mix in the Pacific Northwest, accounting for about 65 percent of total generation. In the Intermountain West, generation is approximately equally split between four main types—natural gas, coal, hydro, and renewables. Natural gas is the largest source of generation in the Desert Southwest.
- **The Pacific Northwest region was a net exporter during the summer months**, while the Desert Southwest was a net exporter outside the summer months. The California and Intermountain West regions were net importers throughout most of 2024.
- **Wind and hydroelectric generation increased in all hours in the Pacific Northwest in 2024** compared to 2023. Net imports and net dynamic transfers displayed the largest changes, with an average increase in net dynamic WEIM transfers into the region of about 600 MW in all hours and a decrease in net imports (i.e., more exports) of about 1,500 MW in all hours.
- **In the California region, natural gas generation decreased in all hours in 2024 compared to 2023.** Batteries increasingly participated in energy arbitrage by charging during the high solar hours and discharging during the high net load periods in the evening. Solar production was up 18 percent. Correspondingly, WEIM transfers into the region decreased during the mid-day solar hours.
- **Coal generation in the Intermountain West decreased about 650 MW (18 percent)** each hour compared to 2023. Much of this generation was replaced with solar generation (200 MW) in the mid-day hours and natural gas (450 MW) in the non-solar hours.
- **In the Desert Southwest region, solar generation increased by about 700 MW (51 percent) in 2024**, and net imports and net dynamic WEIM transfers decreased by about 700 MW and 400 MW, respectively.
- **Over 354,000 GWh of generation in the WEIM system came from renewable resources.** 47 percent of that generation was from non-hydroelectric resources. Renewable resources produced over 40 GW of power on average across the year, accounting for more than half of total WEIM system load.
- **Total downward dispatch of wind and solar resources was higher in 2024 than in 2023 in all regions except the Intermountain West.** Downward dispatch of economic bids accounted for about 4,230 GWh (97 percent) of wind and solar downward dispatch during the year, while curtailment of self-scheduled wind and solar production accounted for about 46 GWh (1 percent).
- **By the end of 2024, roughly 5,000 MW of battery capacity was participating in non-CAISO WEIM balancing areas.** The CAISO balancing area had nearly 13,000 MW of battery capacity.

- **Natural gas prices in the West were down significantly compared to 2023, bringing electricity prices down with them**. Prices at Henry Hub, the national reference point, were down a modest 12 percent compared to 2023. However, El Paso Permian prices were down 75 percent, and prices at NW Sumas, NW Opal WY, NorCal Border, and SoCal Border declined between 50 percent and 63 percent in 2024 relative to 2023.
- **California greenhouse gas allowances averaged \$38.09/mt$CO_2$e in bilateral markets in 2024.** This represented an additional cost of about \$16.19/MWh for a relatively efficient gas unit.
- **Washington greenhouse gas allowances averaged \$40.18/mt$CO_2$e in bilateral markets in 2024.** This represented an additional cost of about \$17.07/MWh for a relatively efficient gas unit.
- **DMM estimates that the net energy market revenues for a hypothetical new gas unit in 2024 were about \$14 to \$19/kW-yr for a typical combined cycle unit and \$10 to \$16/kW-year for a typical combustion turbine unit.** Net market revenues were significantly lower than DMM's estimates of going-forward fixed costs for these units. These results continue to underscore the need for gas resources necessary for local or system reliability to recover fixed costs from long-term bilateral contracts.
- **DMM's simulated revenues for hypothetical batteries across all CAISO balancing area pricing nodes averaged \$52/kW-yr for energy and \$28/kW-yr for ancillary services.** Actual batteries in the CAISO balancing area with a full year of operation in 2024 had nearly \$43/kW-yr in market revenues for energy and \$7/kW-yr for regulation.

## 1.1 Load conditions

This section provides an overview of load conditions across WEIM regions. The analysis examines load conditions at annual, quarterly, monthly, and hourly levels, categorized by regional groups and individual balancing areas.

The regions are divided into five categories:

- **CAISO**: represents the California ISO balancing authority area.
- **California**: includes all balancing areas in California except CAISO, such as Balancing Authority of Northern California (BANC), Los Angeles Department of Water and Power (LADWP), and Turlock Irrigation District (TIDC).
- **Desert Southwest**: includes Arizona Public Service (AZPS), El Paso Electric (EPE), NV Energy (NEVP), Public Service Company of New Mexico (PNM), Salt River Project (SRP), Tucson Electric (TEPC), and WAPA-Desert Southwest.
- **Intermountain West**: includes Avista Corporation (AVA), Idaho Power Company (IPCO), NorthWestern Energy (NWMT), and PacifiCorp East (PACE).
- **Pacific Northwest**: includes Avangrid Power (AVRN), Bonneville Power Administration (BPA), PacifiCorp West (PACW), Portland General Electric (PGE), Powerex, Puget Sound Energy (PSE), Seattle City Light (SCL), and Tacoma Power (TPWR).

### 1.1.1 Average load and load distribution

Figure 1.1 shows the total market load distribution in the 5-minute market. The distribution incorporates all 5-minute load data for 2024 (blue line) and 2023 (grey dashed line).

The horizontal axis represents the load in gigawatts (GW), while the vertical axis displays the probability density function (PDF), which indicates the relative frequency of different load levels.

The distribution shows how the load values are distributed. Higher points on the curve represent load levels that occurred more frequently during the year. For instance, if the curve peaks around 70 GW, this indicates that 70 GW was a commonly observed load level.

The distribution shows more instances of high system loads—particularly above about 90 GW—in 2024, compared to 2023. The blue line is generally above the grey dashed line over 90 GW, reflecting an increased frequency of high-load intervals.

**Figure 1.1 Annual system-wide total load distribution**

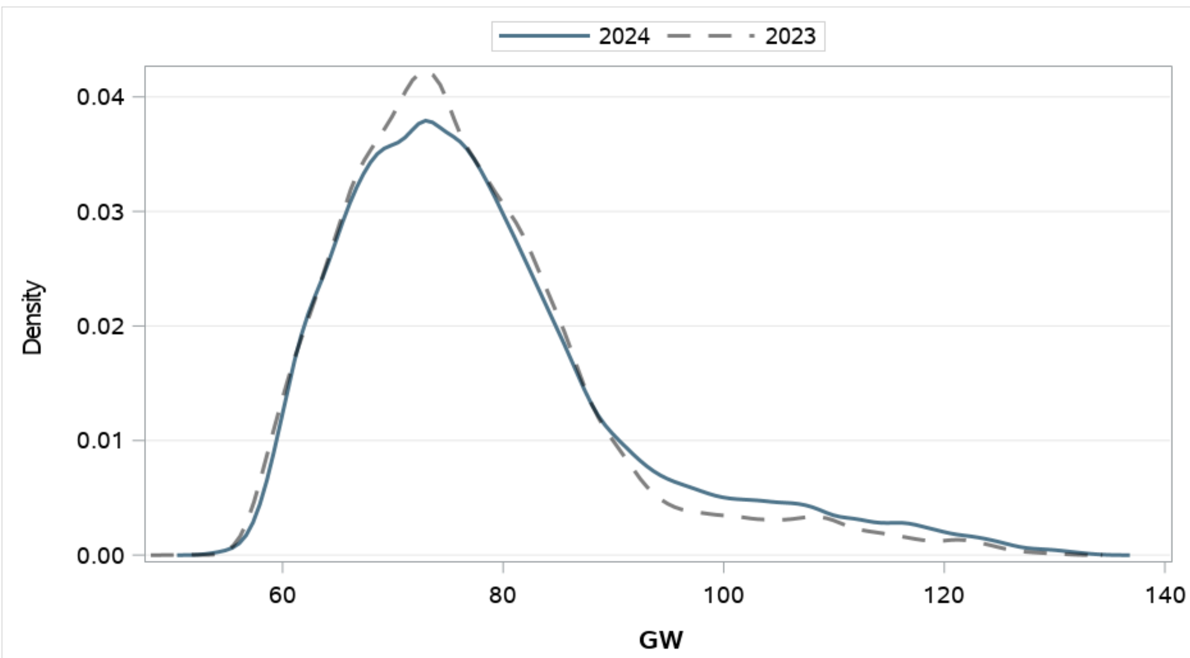



Figure 1.2 shows the quarterly average 5-minute market load categorized by region from Q1 2021 to Q4 2024. In 2024, the total system load for this year averaged 78.3 GW, representing an approximately 2 percent increase compared to 2023. Each region's average load increased relative to 2023, ranging from 1 percent to 4 percent:

- **CAISO** (dark blue) averaged **23.7 GW** and rose by 1 percent.
- **Pacific Northwest** (green) averaged **22.7 GW**, a 2 percent increase.
- **Desert Southwest** (yellow) averaged **16.9 GW**, a 4 percent increase.

- **Intermountain West** (red) averaged **10.2 GW** and rose by 2 percent.
- **California** (light blue) averaged **4.8 GW**, a 3 percent increase.

The WEIM total market load tends to be lowest in Q1 or Q2, and tends to be highest in Q3. Regions such as CAISO, California (non-CAISO), and Desert Southwest closely aligned with the overall seasonal trends of the total WEIM load, showing higher loads during the summer quarters. However, in the Pacific Northwest, quarterly average loads are highest in the winter quarters, with comparatively low load during summer, particularly in Q2 and Q3. The Intermountain West has its highest quarterly average loads in the summer while also maintaining high loads during winter.

**Figure 1.2 Quarterly average 5-minute market load by region (GW)**

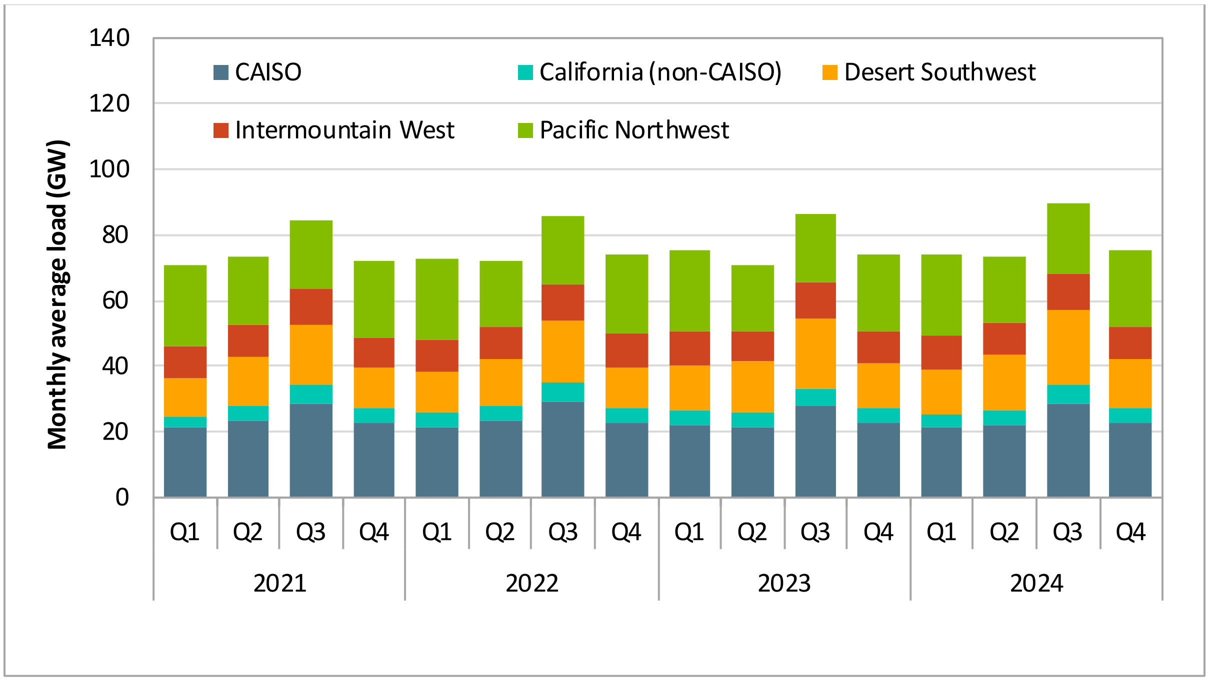



Figure 1.3 displays the hourly average 5-minute market load across different regions in 2024. Each color represents a specific region, while the black dashed line indicates the average system-wide WEIM total load for 2023.

The total WEIM hourly average load peaked at hour-ending 19, reaching 91.8 GW, while the lowest load occurred at hour-ending 4, at 66.4 GW. CAISO and the Pacific Northwest consistently recorded the two largest loads across all hours. From hour-ending 9 to hour-ending 15, the Pacific Northwest had the largest regional load. During the remaining hours, CAISO recorded the highest regional load.

In 2024, the peak average hourly load for each region was:

- **CAISO:** peak load of 28.8 GW at hour-ending 19.
- **Pacific Northwest:** peak load of 25.2 GW at hour-ending 19.
- **Desert Southwest:** peak load of 20.8 GW at hour-ending 18.

- **Intermountain West:** peak load of 11.5 GW at hour-ending 18.
- **California (non-CAISO):** peak load of 5.8 GW at hour-ending 18.

**Figure 1.3 Hourly average 5-minute market load by region (GW)**

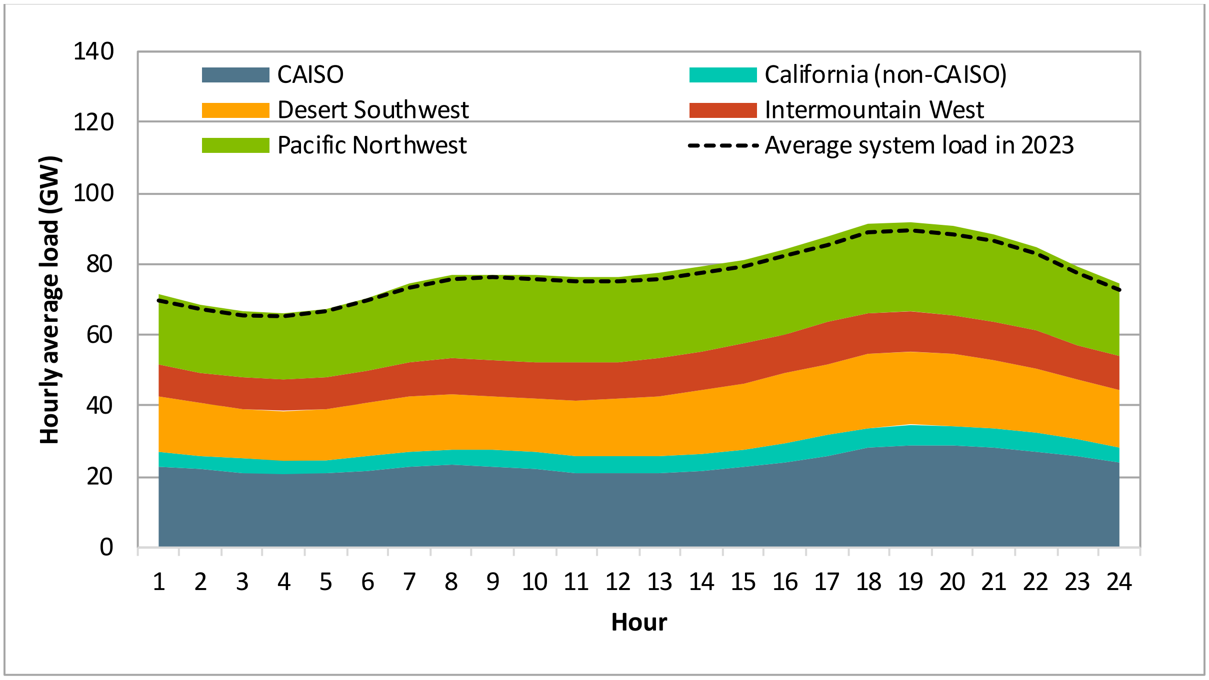


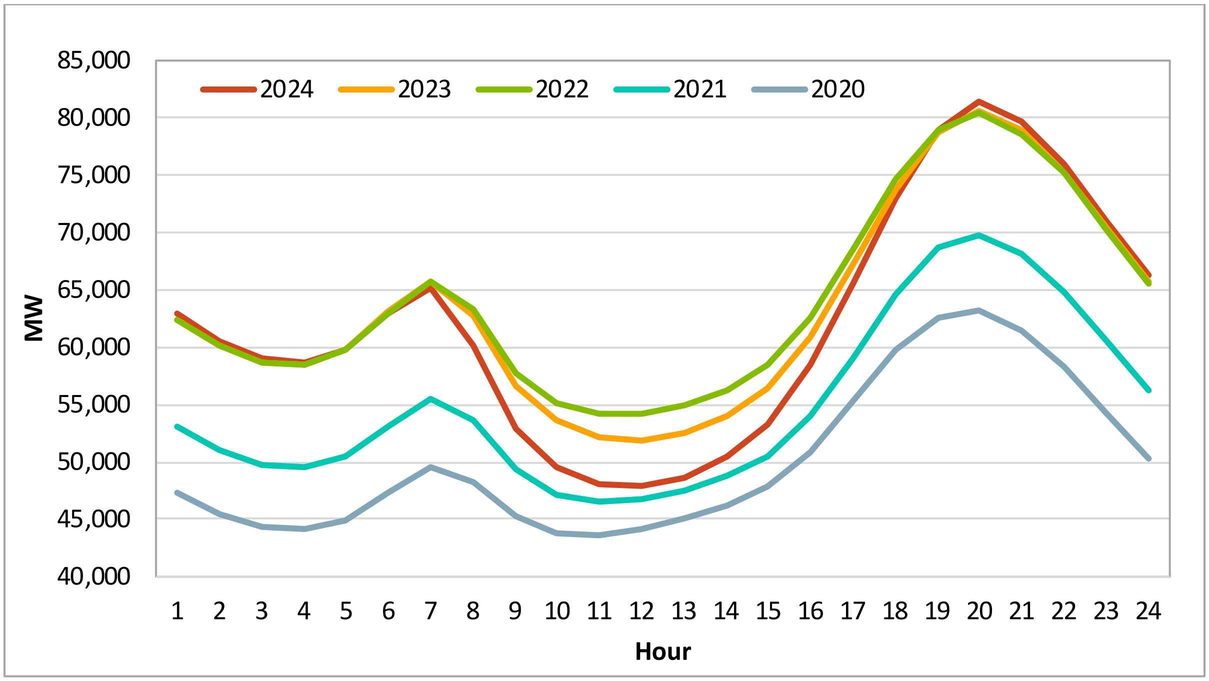

Figure 1.4 shows the hourly average system-wide net load in the 5-minute market from 2020 to 2024. Net-load is calculated by subtracting scheduled solar and wind resources from total load schedules. Year-over-year changes in the net load profile can reflect the expansion of the WEIM, as additional BAAs joined the market.[52]

From 2022 to 2024, net-load during solar hours declined, consistent with increased solar generation across the footprint. In 2024, the peak average net load reached 81,420 MW at hour-ending 20, representing a one percent increase from 2023, which also peaked at hour-ending 20. Over the past five years, the peak net load consistently occurred at hour-ending 20, with the magnitude increasing each year.

52 Since 2020, a total of 14 new BAAs have joined the WEIM market.

- 2020: SRP (Apr), SCL (Apr).
- 2021: BANC (Mar 2nd phase), TIDC (Mar), PNM (Apr), LADWP (Apr), NWMT (Jun).
- 2022: AVA (Mar), TPWR (Mar), BPAT (May), TEPC (May).
- 2023: AVRN (Apr), EPE (Apr), WALC (Apr).

**Figure 1.4 Average hourly system-wide net load in the 5-minute market by year**




## 1.1.2 Peak load

Figure 1.5 shows the highest 5-minute market *system* load forecast for each hour on July 10, 2024, the day with the highest system load during 2024. The figure also shows corresponding load forecast data for each balancing area for the same 5-minute interval as the system peak for each hour. On this day, the WEIM system load peaked at 135.3 GW during hour-ending 18, interval 11. This was higher than the 2023 peak WEIM load (132.6 GW).

This heatmap highlights the hour with the peak load for each balancing area on this day. Red indicates the hour of highest load for each balancing area and yellow indicates hours with above-average load for that day. Peak load for balancing areas varied across hours. While the system peak occurred during hour-ending 18, many balancing areas reached their peak at different times. Even within the same region, peaking hours varied among balancing areas.

**Figure 1.5 Hourly system and BAA load profiles (GW) on the system peak load day (5-minute market, July 10, 2024)**

| Hour | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| SYSTEM | 79.0 | 80.9 | 85.1 | 89.1 | 92.9 | 97.4 | 102.1 | 107.9 | 113.9 | 120.2 | 126.0 | 130.6 | 133.5 | 135.3 | 135.0 | 132.6 | 128.0 | 122.0 |
| CAISO | 24.8 | 25.5 | 26.5 | 27.0 | 27.2 | 27.6 | 28.1 | 29.5 | 31.6 | 34.1 | 36.6 | 39.0 | 40.8 | 42.4 | 42.5 | 42.5 | 41.3 | 40.0 |
| BANC | 1.70 | 1.73 | 1.84 | 1.95 | 2.07 | 2.25 | 2.49 | 2.81 | 3.13 | 3.53 | 3.87 | 4.14 | 4.27 | 4.32 | 4.29 | 4.23 | 4.02 | 3.78 |
| Turlock ID | 0.36 | 0.37 | 0.38 | 0.39 | 0.41 | 0.44 | 0.47 | 0.51 | 0.55 | 0.59 | 0.62 | 0.64 | 0.66 | 0.67 | 0.67 | 0.66 | 0.64 | 0.62 |
| LADWP | 2.32 | 2.39 | 2.56 | 2.73 | 2.98 | 3.20 | 3.46 | 3.71 | 3.93 | 4.18 | 4.42 | 4.61 | 4.69 | 4.69 | 4.68 | 4.50 | 4.20 | 4.06 |
| NV Energy | 5.31 | 5.14 | 5.33 | 5.59 | 6.04 | 6.55 | 7.09 | 7.65 | 8.20 | 8.70 | 9.13 | 9.34 | 9.57 | 9.67 | 9.69 | 9.27 | 8.83 | 8.47 |
| Arizona PS | 4.70 | 4.69 | 4.77 | 4.98 | 5.20 | 5.50 | 5.96 | 6.37 | 6.77 | 7.19 | 7.60 | 7.88 | 7.94 | 8.05 | 8.06 | 7.92 | 7.59 | 7.07 |
| Tucson Electric | 1.43 | 1.43 | 1.50 | 1.58 | 1.71 | 1.86 | 2.03 | 2.24 | 2.43 | 2.58 | 2.72 | 2.85 | 2.95 | 3.00 | 2.98 | 2.83 | 2.68 | 2.45 |
| Salt River Project | 4.44 | 4.42 | 4.60 | 4.93 | 5.40 | 5.88 | 6.38 | 6.84 | 7.25 | 7.53 | 7.73 | 7.90 | 7.94 | 7.91 | 7.94 | 7.68 | 7.42 | 6.93 |
| PSC New Mexico | 1.43 | 1.47 | 1.50 | 1.53 | 1.59 | 1.67 | 1.74 | 1.86 | 1.98 | 2.05 | 2.17 | 2.23 | 2.28 | 2.29 | 2.28 | 2.20 | 2.08 | 1.92 |
| WAPA - Desert SW | 0.83 | 0.83 | 0.85 | 0.91 | 1.00 | 1.09 | 1.19 | 1.27 | 1.37 | 1.44 | 1.52 | 1.54 | 1.59 | 1.55 | 1.55 | 1.48 | 1.40 | 1.31 |
| El Paso Electric | 0.99 | 1.03 | 1.10 | 1.18 | 1.28 | 1.41 | 1.52 | 1.63 | 1.75 | 1.85 | 1.95 | 1.99 | 1.89 | 1.76 | 1.71 | 1.58 | 1.50 | 1.36 |
| PacifiCorp East | 5.73 | 5.93 | 6.25 | 6.66 | 7.06 | 7.40 | 7.86 | 8.34 | 8.78 | 9.19 | 9.46 | 9.56 | 9.68 | 9.59 | 9.57 | 9.25 | 8.93 | 8.45 |
| Idaho Power | 2.56 | 2.64 | 2.78 | 2.89 | 3.04 | 3.31 | 3.48 | 3.66 | 3.69 | 3.96 | 4.11 | 4.18 | 4.08 | 4.06 | 4.05 | 4.03 | 3.94 | 3.72 |
| NorthWestern | 1.20 | 1.29 | 1.34 | 1.37 | 1.44 | 1.50 | 1.55 | 1.74 | 1.79 | 1.85 | 1.89 | 1.92 | 1.92 | 1.91 | 1.91 | 1.88 | 1.83 | 1.73 |
| Avista Utilities | 1.08 | 1.16 | 1.30 | 1.41 | 1.50 | 1.62 | 1.74 | 1.85 | 1.96 | 2.02 | 2.06 | 2.10 | 2.12 | 2.11 | 2.10 | 2.04 | 1.95 | 1.84 |
| BPA | 5.89 | 6.08 | 6.43 | 6.73 | 7.01 | 7.31 | 7.58 | 7.84 | 7.92 | 8.16 | 8.33 | 8.42 | 8.57 | 8.69 | 8.59 | 8.52 | 8.27 | 7.88 |
| Tacoma Power | 0.40 | 0.41 | 0.44 | 0.47 | 0.49 | 0.52 | 0.53 | 0.55 | 0.57 | 0.59 | 0.60 | 0.61 | 0.63 | 0.64 | 0.64 | 0.63 | 0.61 | 0.58 |
| PacifiCorp West | 2.26 | 2.36 | 2.55 | 2.72 | 2.84 | 3.03 | 3.18 | 3.34 | 3.50 | 3.63 | 3.73 | 3.78 | 3.83 | 3.86 | 3.85 | 3.76 | 3.64 | 3.41 |
| Portland GE | 2.47 | 2.52 | 2.67 | 2.80 | 2.89 | 3.02 | 3.17 | 3.33 | 3.50 | 3.66 | 3.79 | 3.87 | 3.99 | 3.98 | 3.98 | 3.91 | 3.76 | 3.53 |
| Puget Sound Energy | 2.29 | 2.37 | 2.58 | 2.77 | 2.90 | 3.01 | 3.13 | 3.23 | 3.37 | 3.46 | 3.58 | 3.68 | 3.73 | 3.78 | 3.76 | 3.68 | 3.54 | 3.40 |
| Seattle City Light | 0.89 | 0.92 | 1.03 | 1.08 | 1.12 | 1.15 | 1.18 | 1.21 | 1.25 | 1.26 | 1.32 | 1.31 | 1.31 | 1.30 | 1.29 | 1.26 | 1.23 | 1.19 |
| Powerex | 6.00 | 6.23 | 6.80 | 7.41 | 7.77 | 8.07 | 8.28 | 8.50 | 8.64 | 8.75 | 8.86 | 8.95 | 9.07 | 9.03 | 8.99 | 8.82 | 8.60 | 8.35 |

Table 1.1 shows the peak 5-minute market load and date for each balancing area (or region) during 2024. The California and Desert Southwest balancing areas all experienced peak load during the summer—typically in July, August, and September. In contrast, balancing areas in the Intermountain West and Pacific Northwest peaked either in January or July, indicating the presence of both summer- and winter-peaking BAAs in these regions. The last two columns show each balancing area's load during the system-wide peak on July 10, 2024, which reached 135,299 MW.

**Table 1.1 Peak WEIM load (January–December 2024)**

| Region/balancing area | Peak load (2024) Date | Peak load (2024) Load (MW) | Load during WEIM system peak (10-Jul-2024) Load (MW) | Load during WEIM system peak (10-Jul-2024) Percent |
|---|---|---|---|---|
| **WEIM system** | **10-Jul-24** | **135,299** | **135,299** | |
| **California** | **5-Sep-24** | **57,201** | **52,109** | **39%** |
| California ISO | 5-Sep-24 | 46,830 | 42,428 | 31% |
| BANC | 11-Jul-24 | 4,582 | 4,317 | 3% |
| LADWP | 6-Sep-24 | 6,371 | 4,694 | 3% |
| Turlock Irrig. District | 11-Jul-24 | 714 | 670 | .5% |
| **Desert Southwest** | **9-Jul-24** | **34,377** | **34,237** | **25%** |
| Arizona Public Service | 4-Aug-24 | 8,309 | 8,052 | 6% |
| El Paso Electric | 25-Jun-24 | 2,336 | 1,758 | 1.3% |
| NV Energy | 11-Jul-24 | 9,702 | 9,670 | 7% |
| PSC New Mexico | 20-Aug-24 | 2,645 | 2,288 | 2% |
| Salt River Project | 4-Aug-24 | 8,314 | 7,914 | 6% |
| Tucson Electric | 8-Jul-24 | 3,015 | 3,002 | 2% |
| WAPA - Desert SW | 10-Jul-24 | 1,588 | 1,553 | 1.1% |
| **Intermountain West** | **11-Jul-24** | **17,867** | **17,672** | **13%** |
| Avista Utilities | 13-Jan-24 | 2,345 | 2,108 | 2% |
| Idaho Power | 10-Jul-24 | 4,229 | 4,058 | 3% |
| NorthWestern Energy | 13-Jan-24 | 2,100 | 1,914 | 1% |
| PacifiCorp East | 11-Jul-24 | 9,932 | 9,593 | 7% |
| **Pacific Northwest** | **13-Jan-24** | **38,770** | **31,281** | **23%** |
| BPA | 13-Jan-24 | 11,371 | 8,688 | 6% |
| PacifiCorp West | 9-Jul-24 | 4,030 | 3,863 | 3% |
| Portland General Electric | 9-Jul-24 | 4,405 | 3,985 | 3% |
| Powerex | 12-Jan-24 | 12,271 | 9,031 | 7% |
| Puget Sound Energy | 12-Jan-24 | 5,344 | 3,778 | 3% |
| Seattle City Light | 12-Jan-24 | 1,949 | 1,300 | 1% |
| Tacoma Power | 12-Jan-24 | 971 | 636 | .5% |

## 1.2 Supply conditions

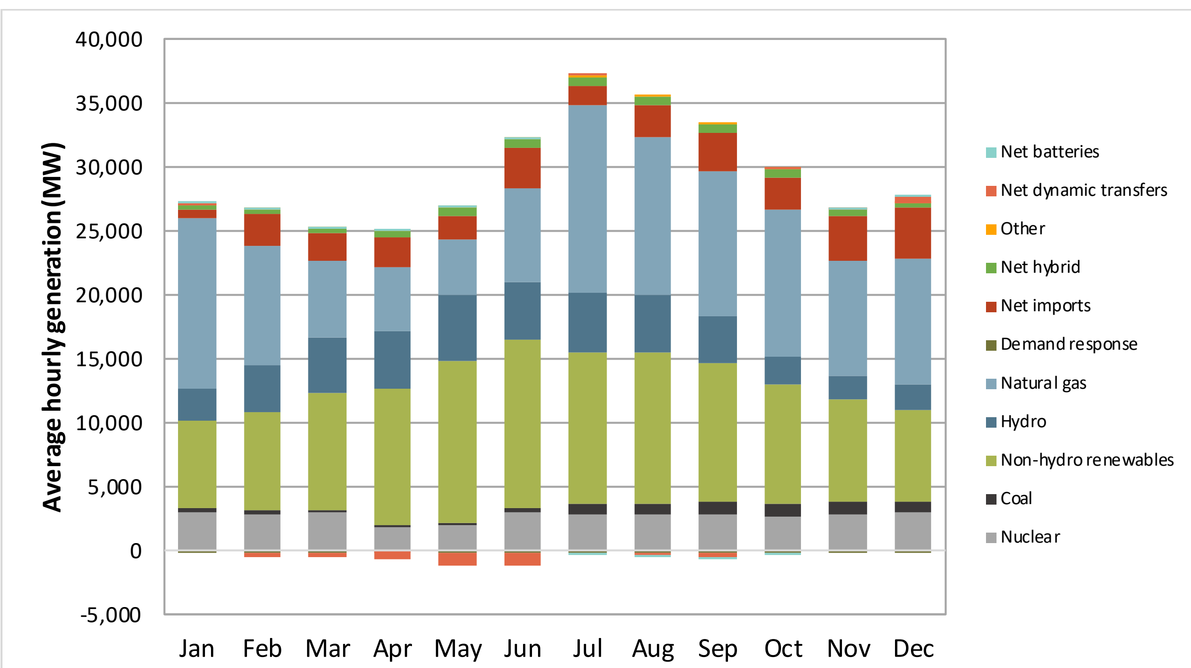
### 1.2.1 Generation mix

#### Monthly generation by fuel type

Figure 1.6, Figure 1.8, Figure 1.10, and Figure 1.12 provide a profile of average hourly generation by month and fuel type for the California, Pacific Northwest, Intermountain West, and Desert Southwest regions. Figure 1.7, Figure 1.9, Figure 1.11, and Figure 1.13[53] illustrate 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 the California region in 2024, similar to 2023. Hydroelectric generation dominates the generation mix in the Pacific Northwest, accounting for about 65 percent of total generation. In the Intermountain West, generation is approximately equally split between four main types—natural gas, coal, hydro, and renewables. Natural gas is the largest source of generation in the Desert Southwest.
- The Pacific Northwest region was a net exporter during the summer months, while the Desert Southwest was a net exporter outside the summer months. The California and Intermountain West regions were net importers throughout most of 2024.

**Figure 1.6 California - Average generation by month and fuel type (MW) in 2024**




53 These figures show each region's generation mix used to meet the load in each region. Net dynamic transfers, net hybrids, and net imports are only included if they are net positive.

**Figure 1.7 California - Average generation by month and fuel type (percentage) in 2024**

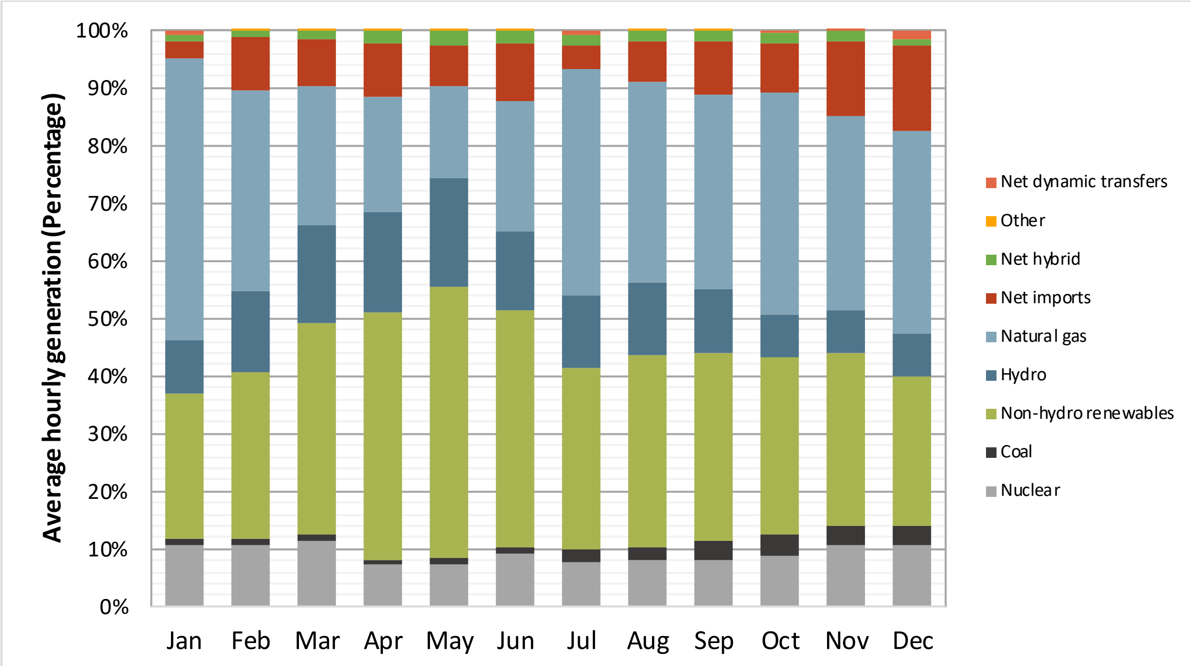



**Figure 1.8 Pacific Northwest - Average generation by month and fuel type (MW) in 2024**

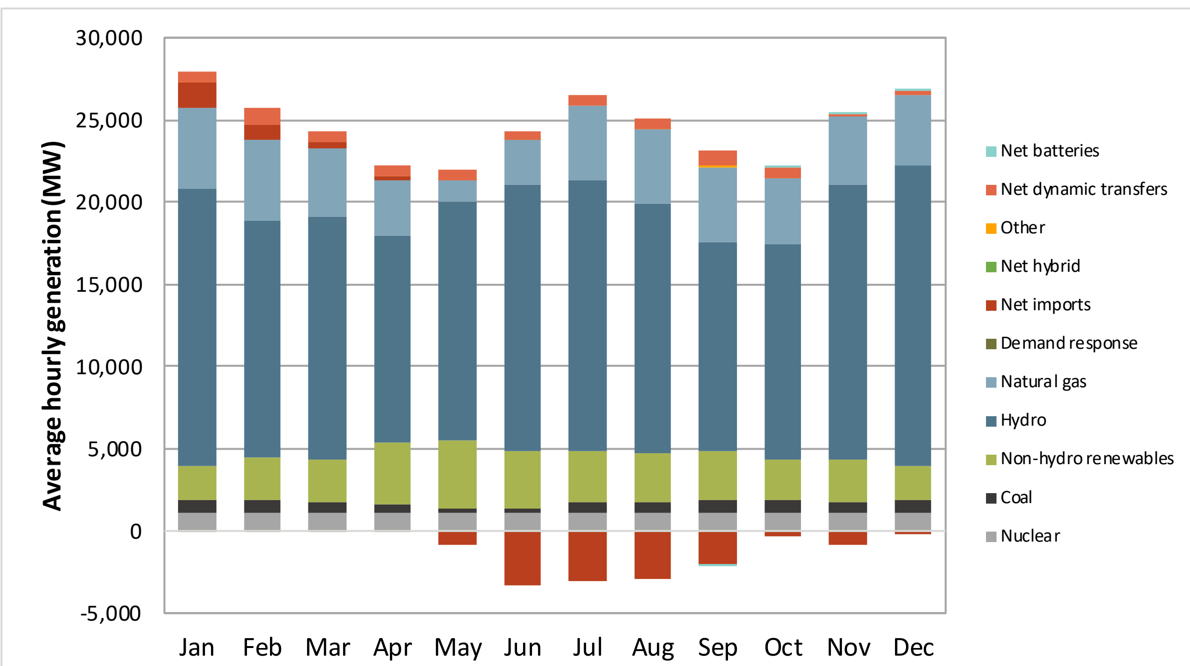


**Figure 1.9 Pacific Northwest - Average generation by month and fuel type (percentage) in 2024**

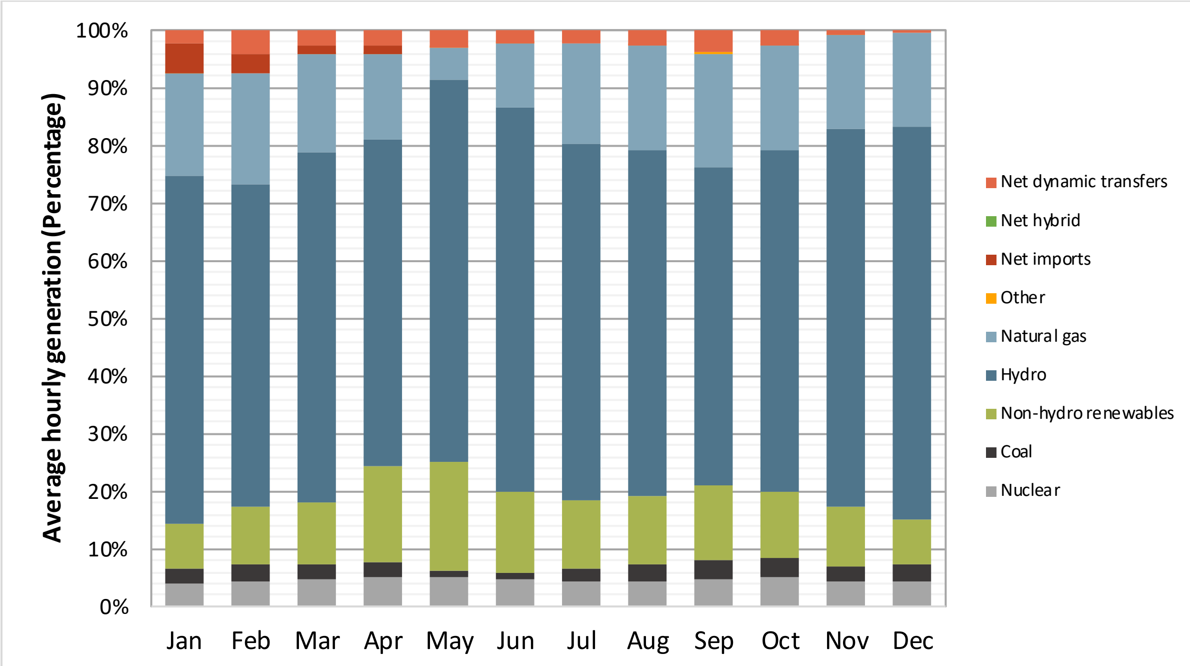



**Figure 1.10 Intermountain West - Average generation by month and fuel type (MW) in 2024**

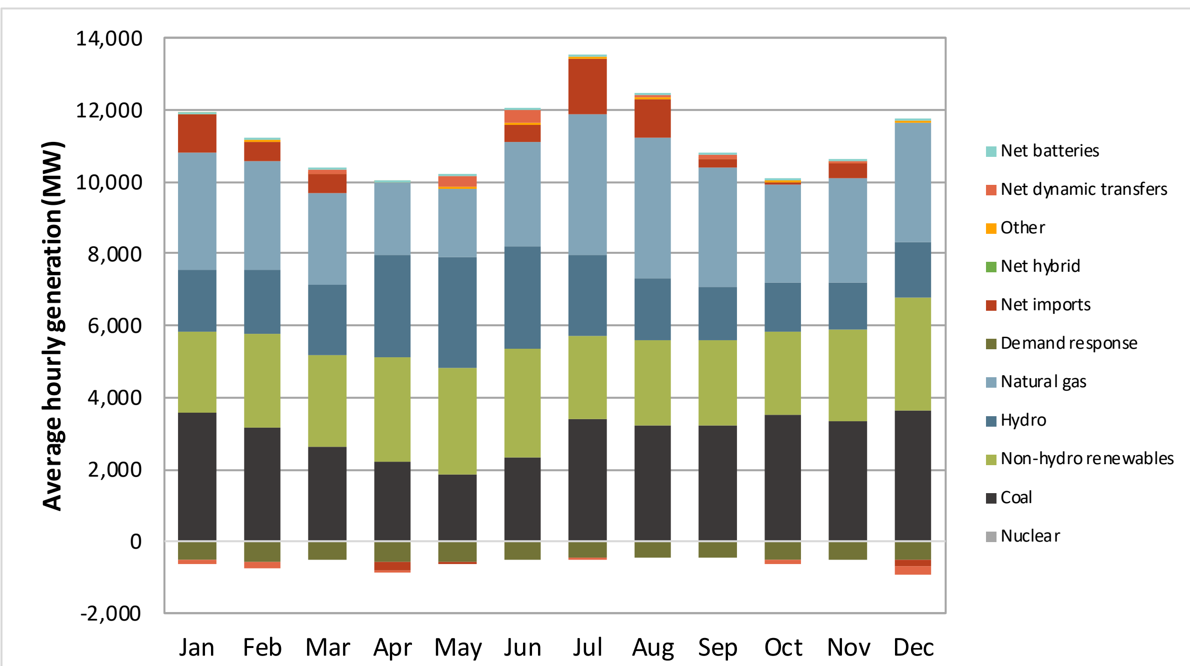


**Figure 1.11 Intermountain West - Average generation by month and fuel type (percentage) in 2024**

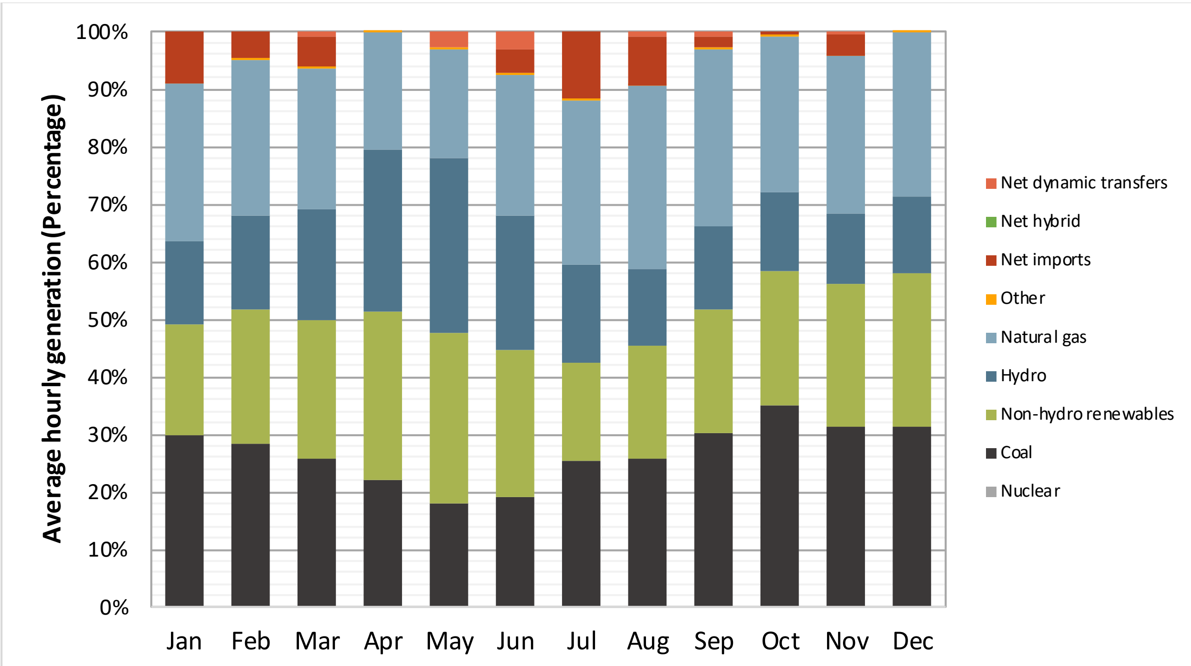



**Figure 1.12 Desert Southwest - Average generation by month and fuel type (MW) in 2024**

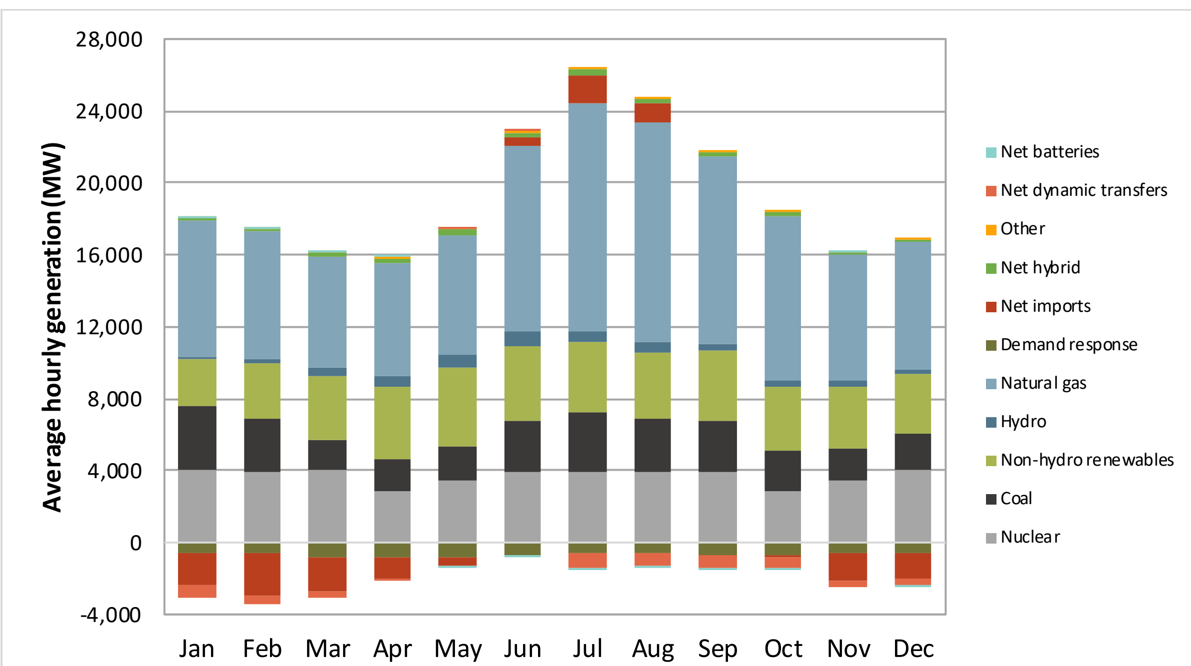
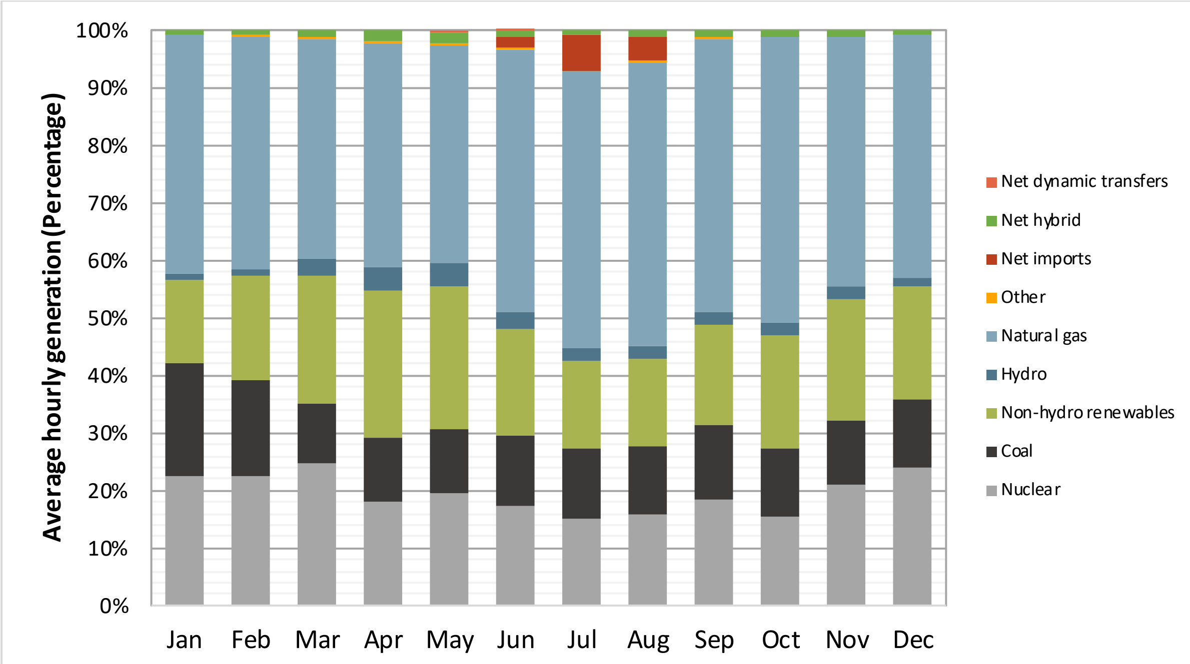


**Figure 1.13 Desert Southwest - Average generation by month and fuel type (percentage) in 2024**




### Hourly generation by fuel type

Figure 1.14, Figure 1.16, Figure 1.18, and Figure 1.20 show average hourly generation by fuel type over the year. Generation peaked in hours 18, 19, or 20 for all regions. Figure 1.15, Figure 1.17, Figure 1.19, and Figure 1.21 show the change in hourly generation by fuel type between 2023 and 2024. In the charts, positive values represent increased generation over the course of the year compared to 2023, while negative values represent a decrease in generation.

In the California region, natural gas generation decreased in all hours in 2024 compared to 2023. Batteries increasingly participated in energy arbitrage by charging during the high solar hours and discharging during the high net load periods in the evening. Correspondingly, WEIM transfers into the region decreased during the solar hours.

Wind and hydroelectric generation increased in all hours in the Pacific Northwest in 2024. Net imports and net dynamic transfers displayed the largest changes, with an average increase in net dynamic transfers of about 600 MW in all hours and a decrease in net imports (i.e., more exports) of about 1,500 MW in all hours.

Coal generation in the Intermountain West decreased about 650 MW (18 percent) each hour since 2023. Much of this generation was replaced with solar generation (200 MW) in the mid-day hours and natural gas (450 MW) in the non-solar hours.

In the Desert Southwest region, natural gas generation averaged about 8,500 MW per hour. Solar generation increased by about 700 MW (51 percent) in 2024, and net imports and net dynamic transfers decreased by about 700 MW and 400 MW, respectively.

**Figure 1.14 Average hourly generation by fuel type in the California region in 2023**

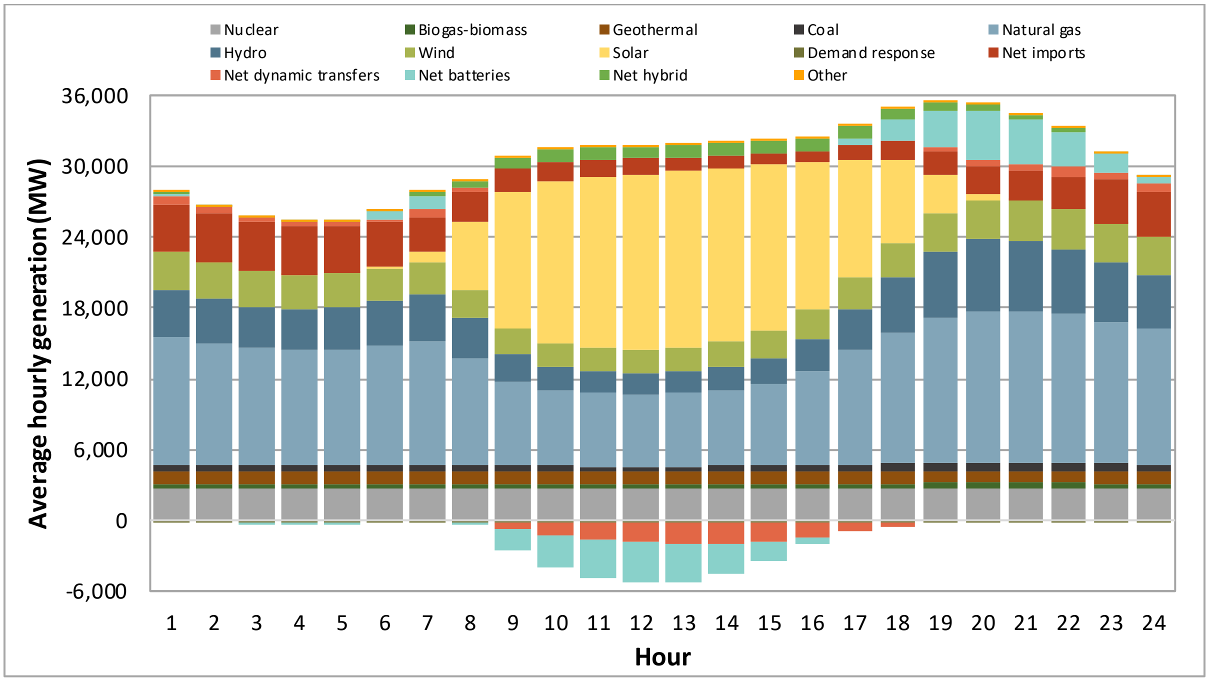



**Figure 1.15 Change in average hourly generation by fuel type in the California region (2024 compared to 2023)**

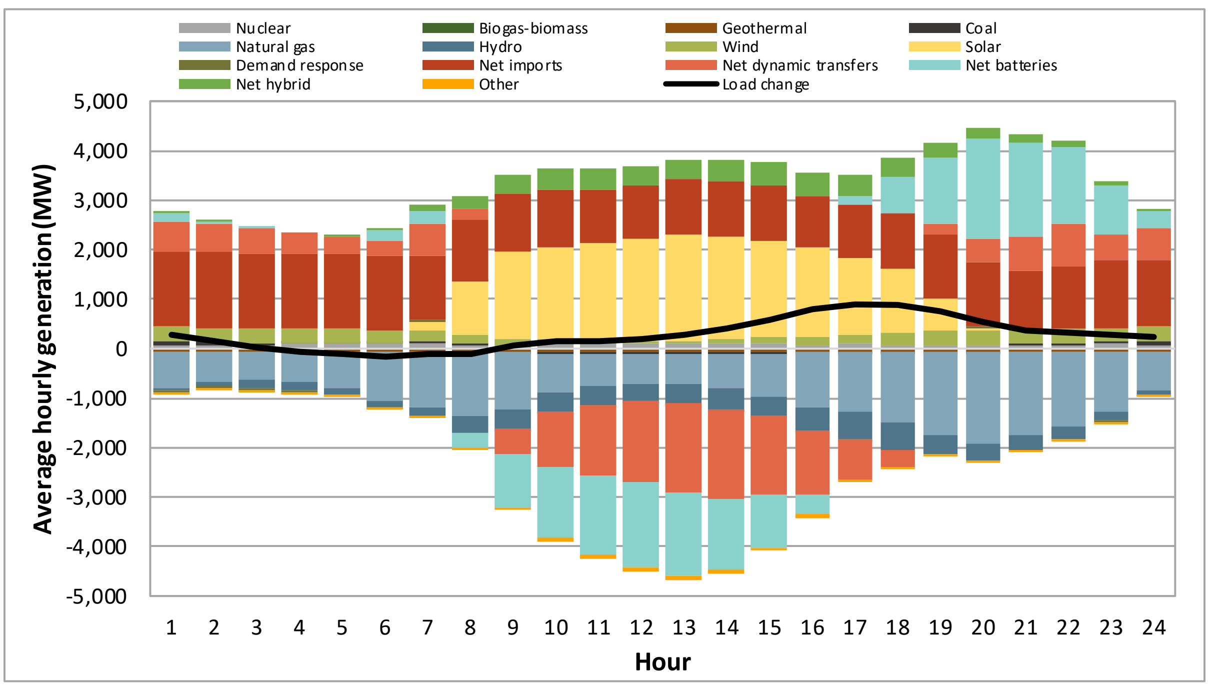


**Figure 1.16 Average hourly generation by fuel type in the Pacific Northwest region in 2024**

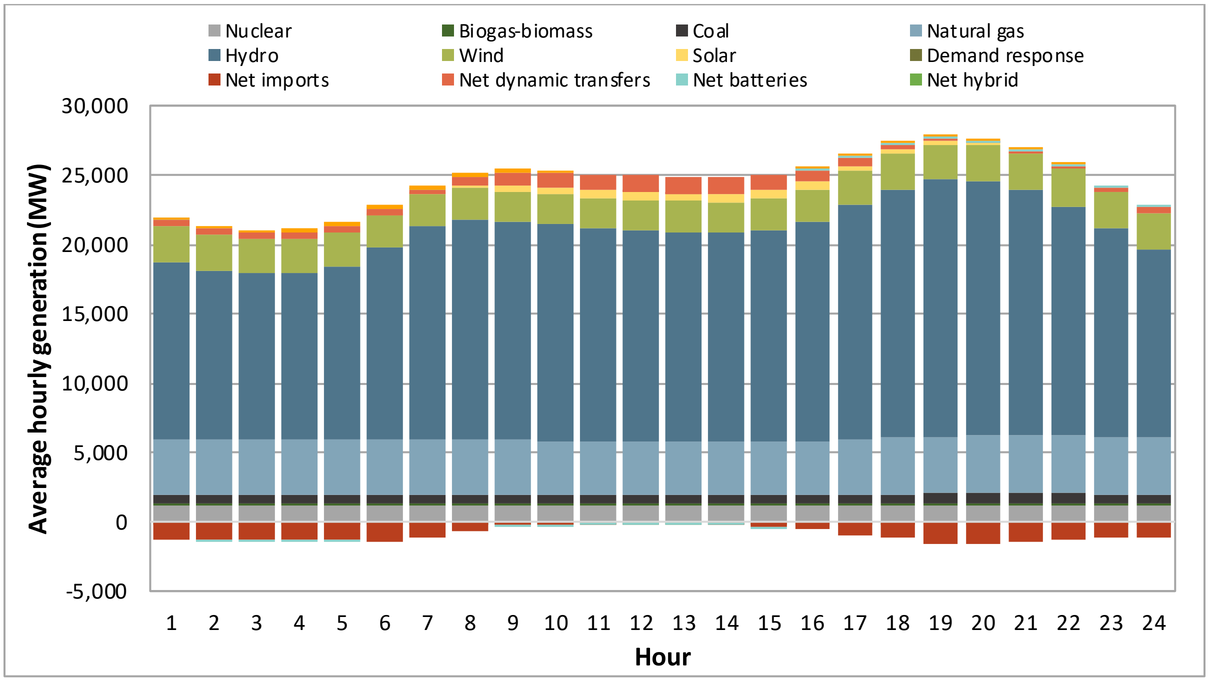



**Figure 1.17 Change in average hourly generation by fuel type in the Pacific Northwest region (2024 compared to 2023)**

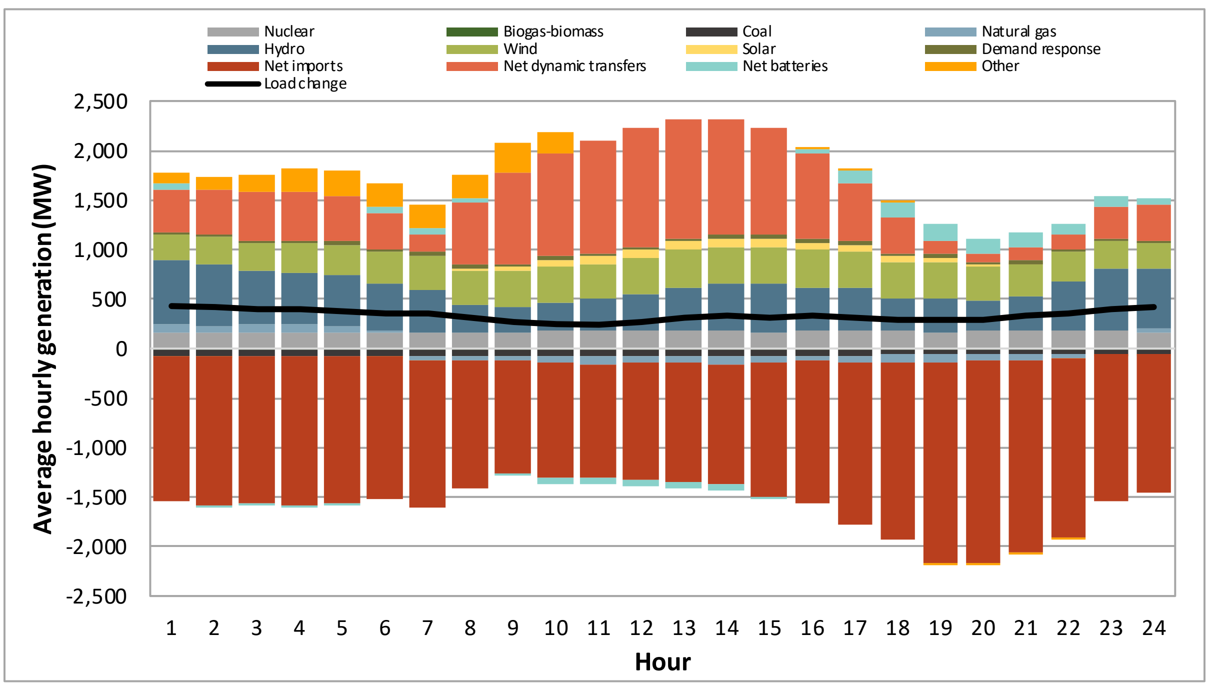


**Figure 1.18 Average hourly generation by fuel type in the Intermountain West region in 2024**

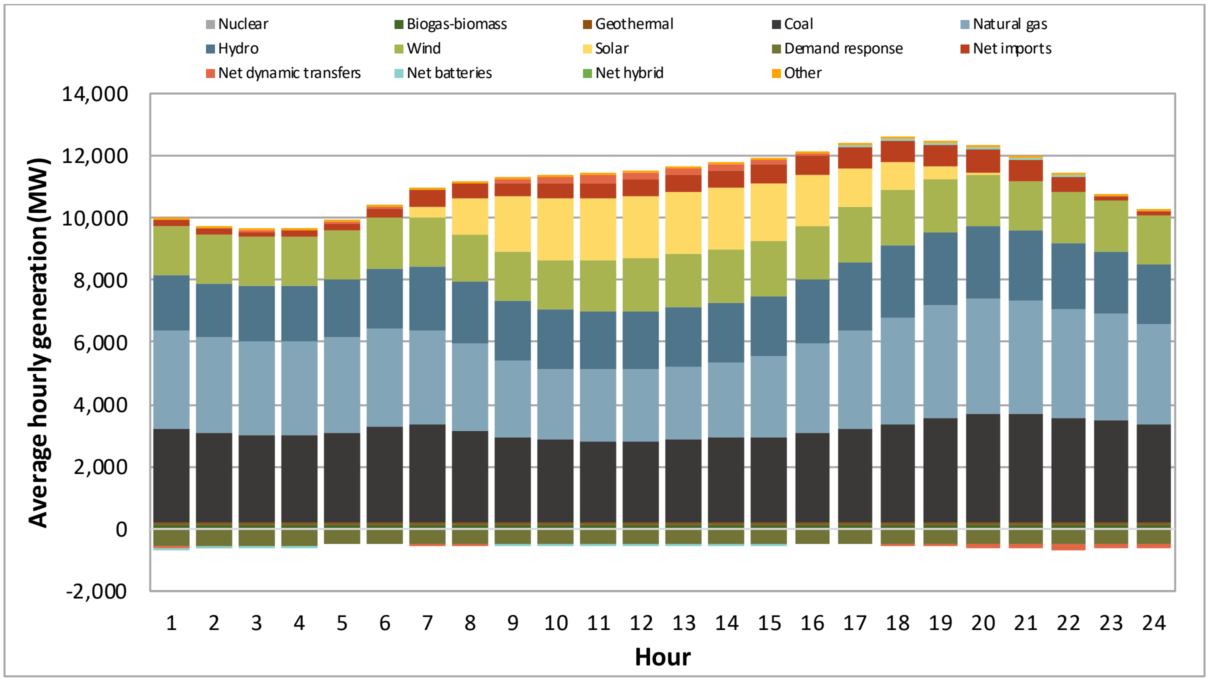



**Figure 1.19 Change in average hourly generation by fuel type in the Intermountain West region (2024 compared to 2023)**

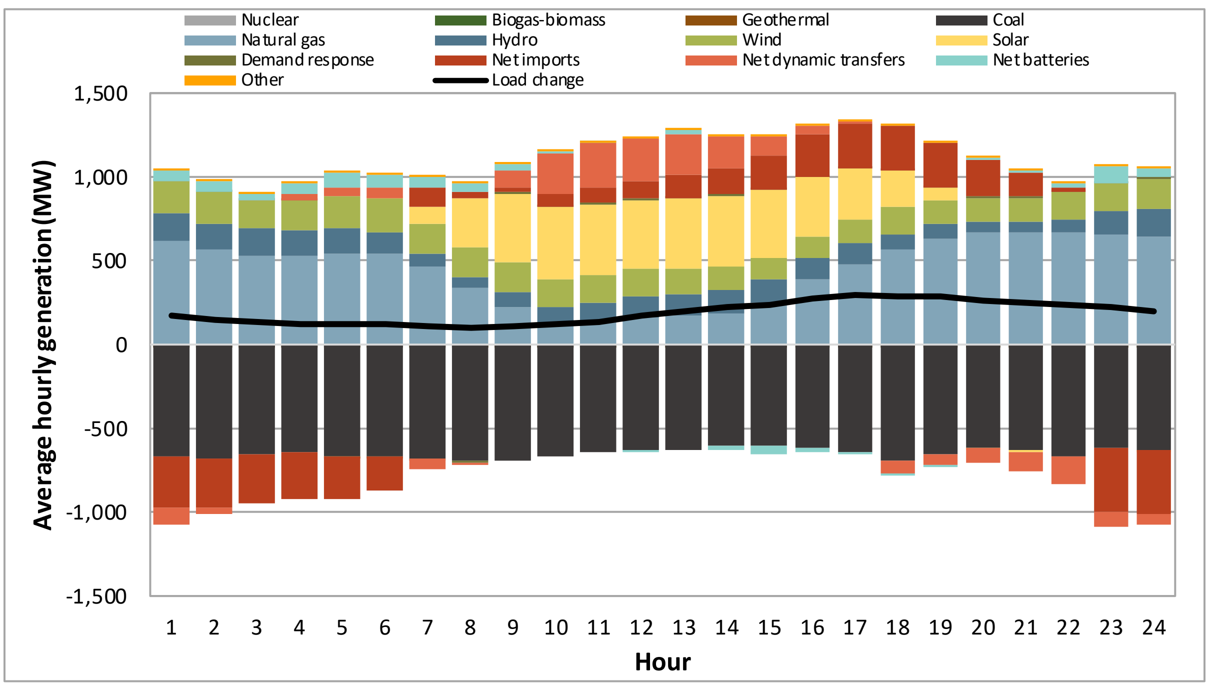


**Figure 1.20 Average hourly generation by fuel type in the Desert Southwest region in 2024**

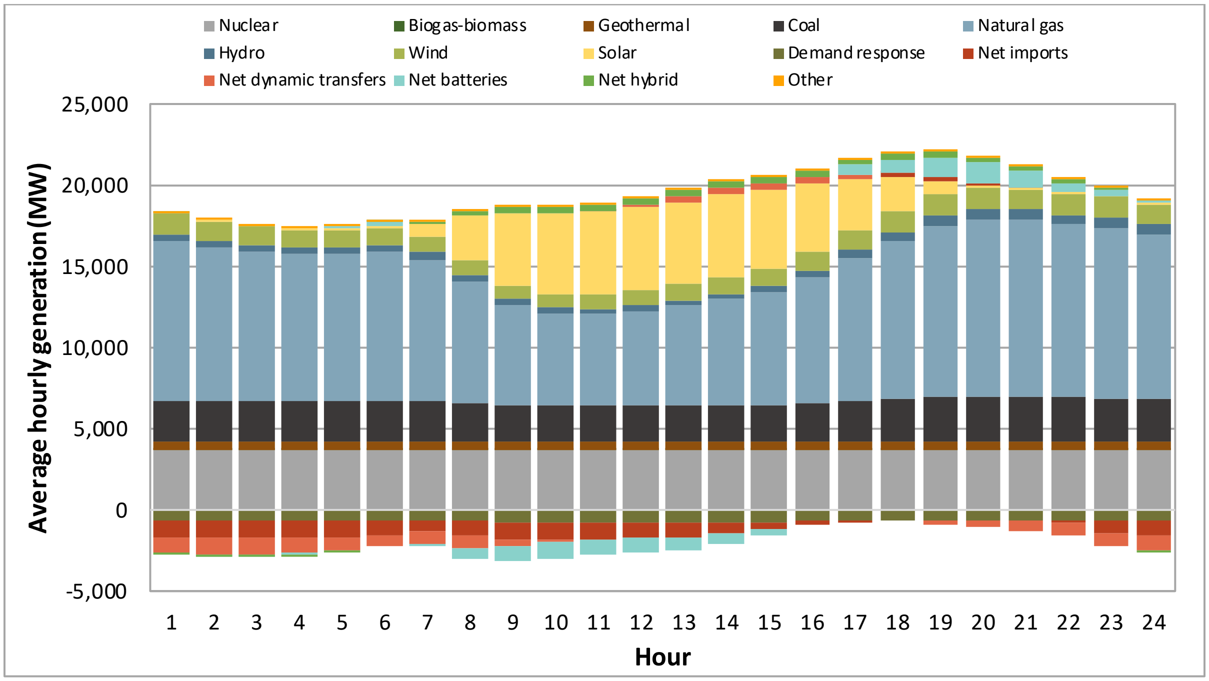
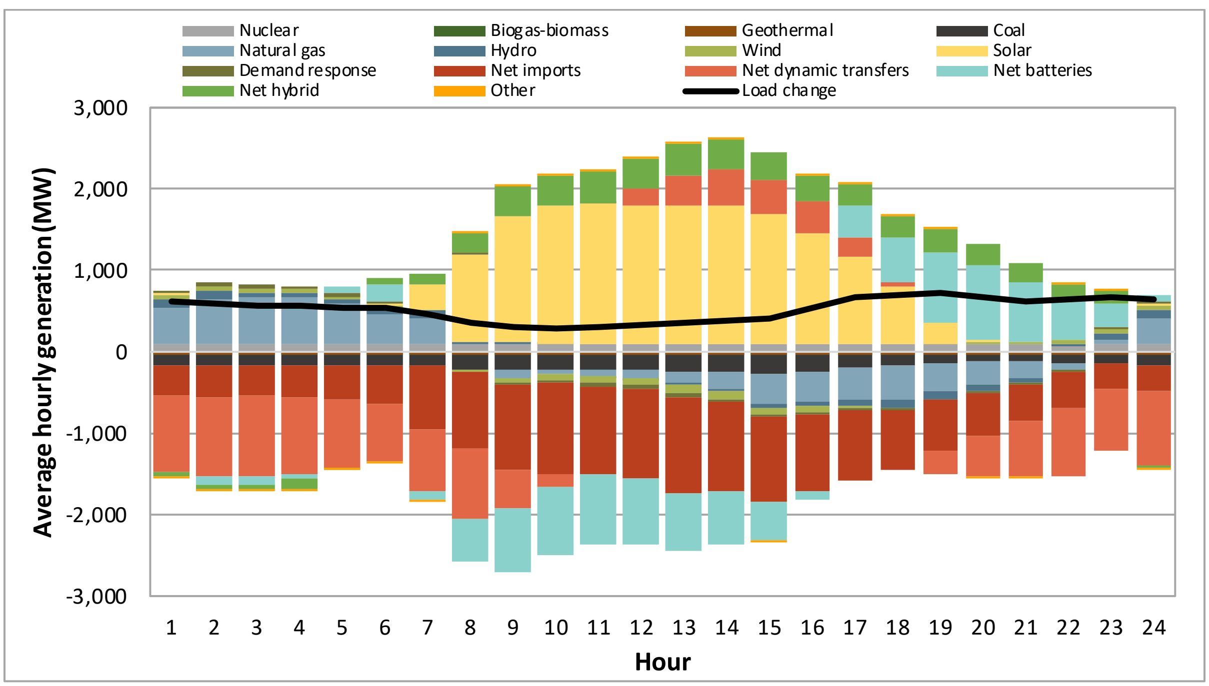



**Figure 1.21 Change in average hourly generation by fuel type in the Desert Southwest region (2024 compared to 2023)**



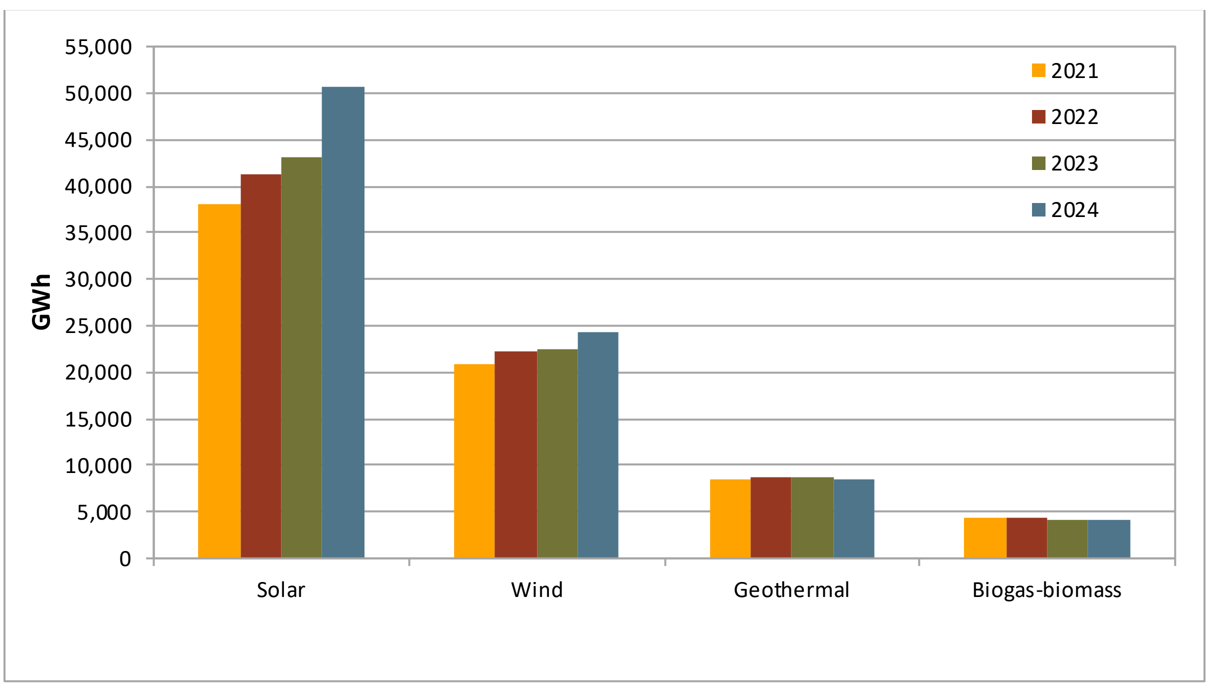
### 1.2.2 Renewable generation

In 2024, over 354,000 GWh of generation in the WEIM came from renewable resources. Of that renewable generation, 47 percent was from non-hydroelectric resources. This section provides additional detail about trends in renewable generation and the factors influencing renewable resource availability.

Figure 1.22 through Figure 1.25 provide a detailed breakdown of non-hydro renewable generation, including imports that are specifically identified as wind and solar resources.[54] These figures also illustrate:

- In 2024, generation from solar resources increased in every region in the WEIM. In the California and Desert Southwest regions, generation from solar resources accounted for 58 percent and 56 percent, respectively, of their total non-hydro renewable output. Solar generation increased by 18 percent in California and 54 percent in the Desert Southwest compared to 2023.
- Wind generation makes up a large share of the renewable fuel mix for the Intermountain West and Pacific Northwest regions. Wind output increased by 11 percent and 23 percent in the Intermountain West and Pacific Northwest, respectively, compared to 2023.
- The overall output from geothermal generation decreased 4 percent from 2023 across the WEIM, and continued to provide around 8 percent of all non-hydro renewable generation.
- Biogas, biomass, and waste generation decreased 5 percent from last year. Together, they accounted for around 4 percent of all non-hydro renewable generation.

**Figure 1.22 California - Total renewable generation by type (2021–2024)**




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

**Figure 1.23 Desert Southwest - Total renewable generation by type (2021–2024)**

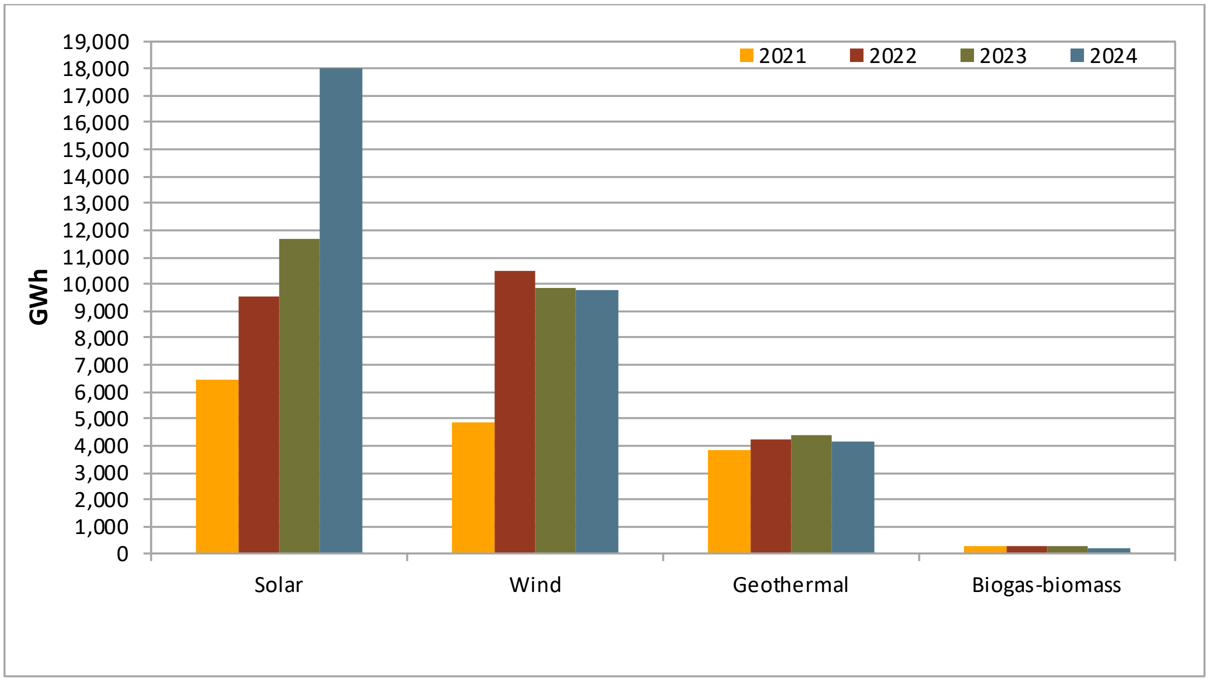



**Figure 1.24 Intermountain West - Total renewable generation by type (2021–2024)**

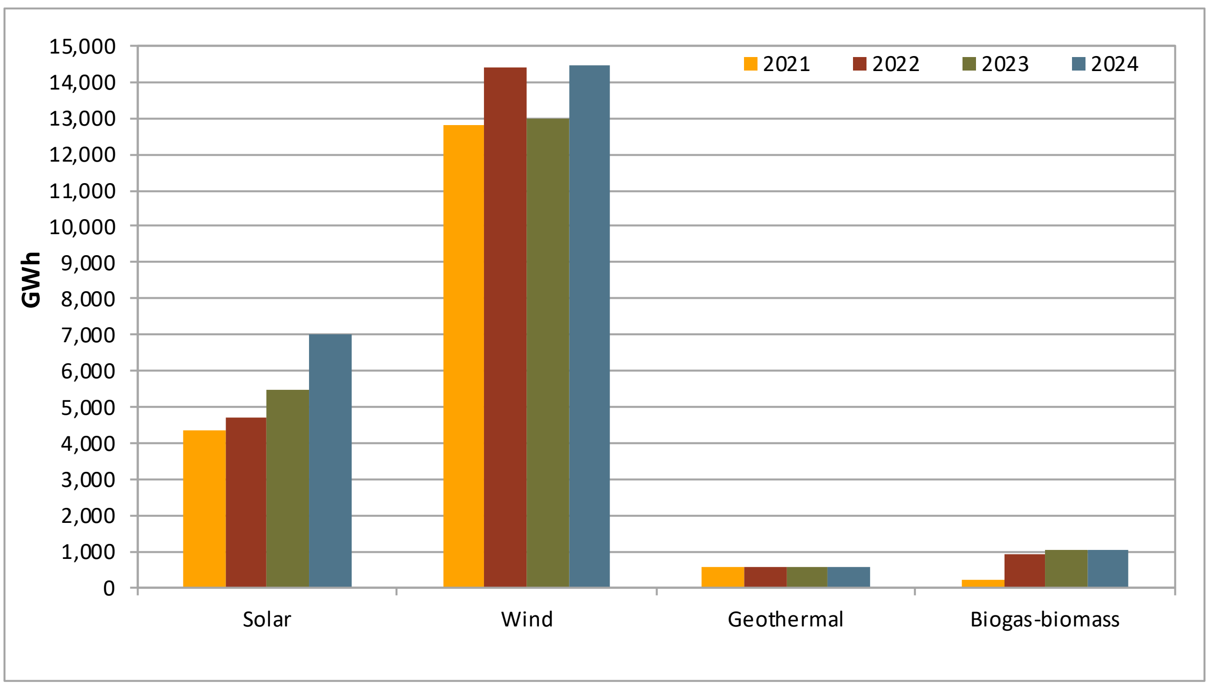


**Figure 1.25 Pacific Northwest - Total renewable generation by type (2021–2024)[55]**

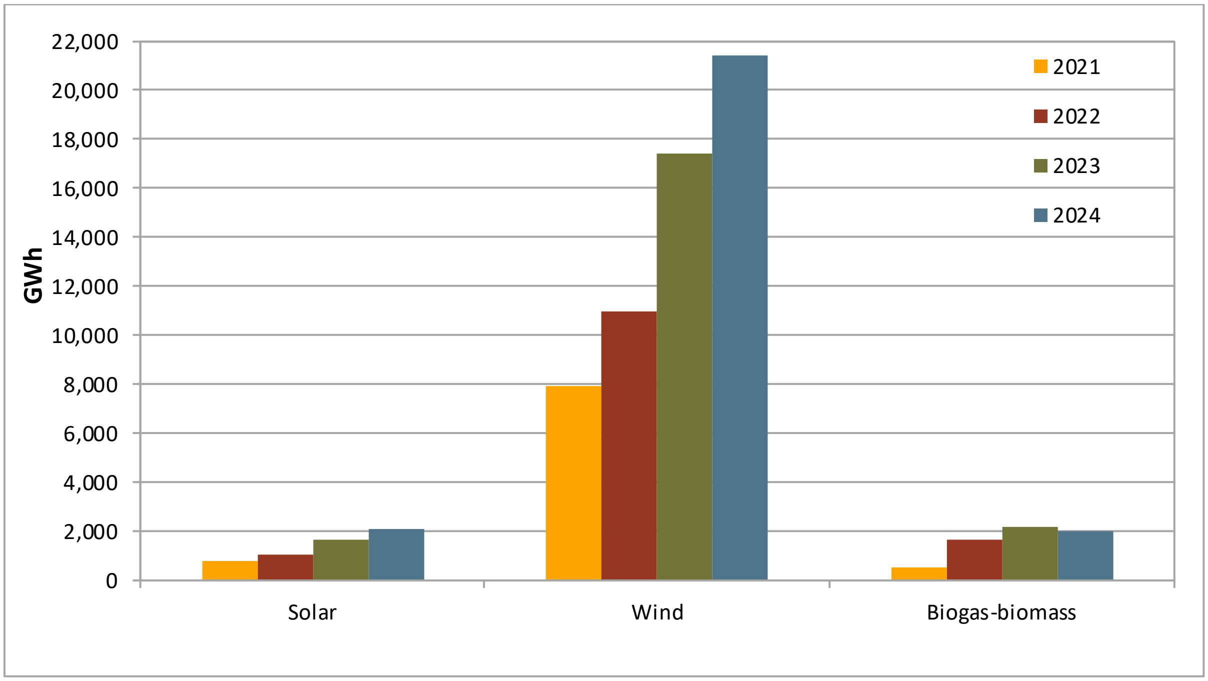



Figure 1.26 through Figure 1.29 compares average monthly generation of hydro, wind, and solar resources.

In 2024, average hourly solar generation peaked in June in the California, Intermountain West, and Pacific Northwest regions, while peaking in July in the Desert Southwest. Hydroelectric generation peaked in December for the Pacific Northwest and during the summer for the other regions. Wind generation peaked in May for both the California and Pacific Northwest regions, while the Desert Southwest and Intermountain West saw their wind peaks in the winter.

55 There is no geothermal generation in the Pacific Northwest.

**Figure 1.26 California - Monthly comparison of hydro, wind, and solar generation (2024)**

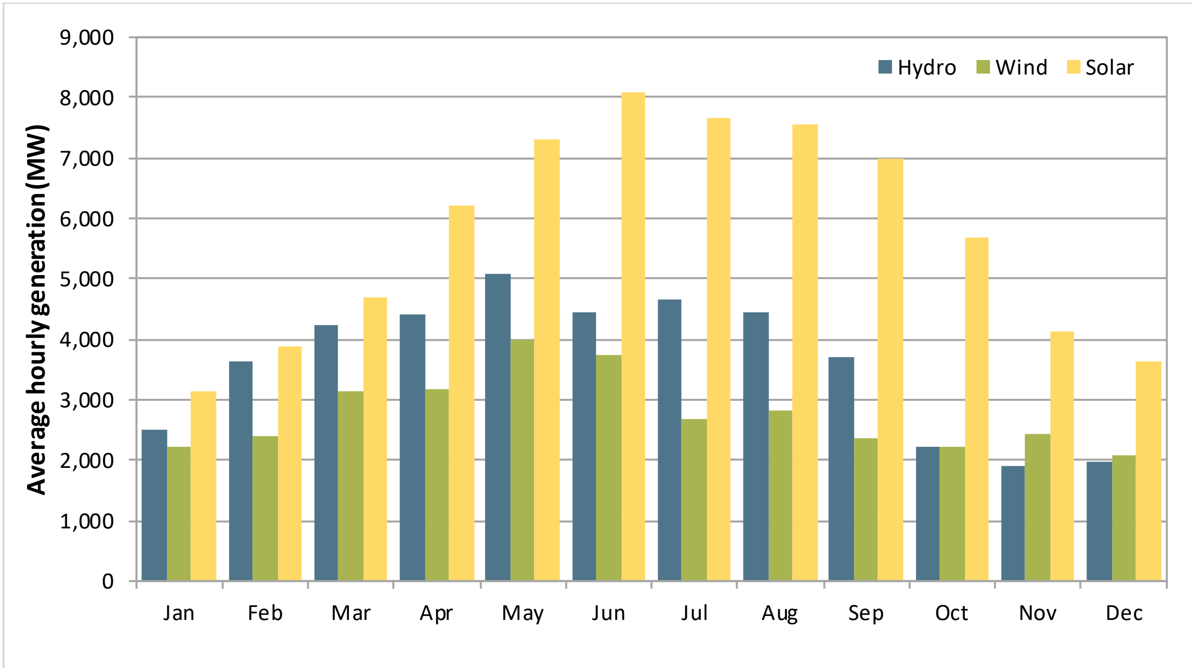



**Figure 1.27 Desert Southwest - Monthly comparison of hydro, wind, and solar generation (2024)**

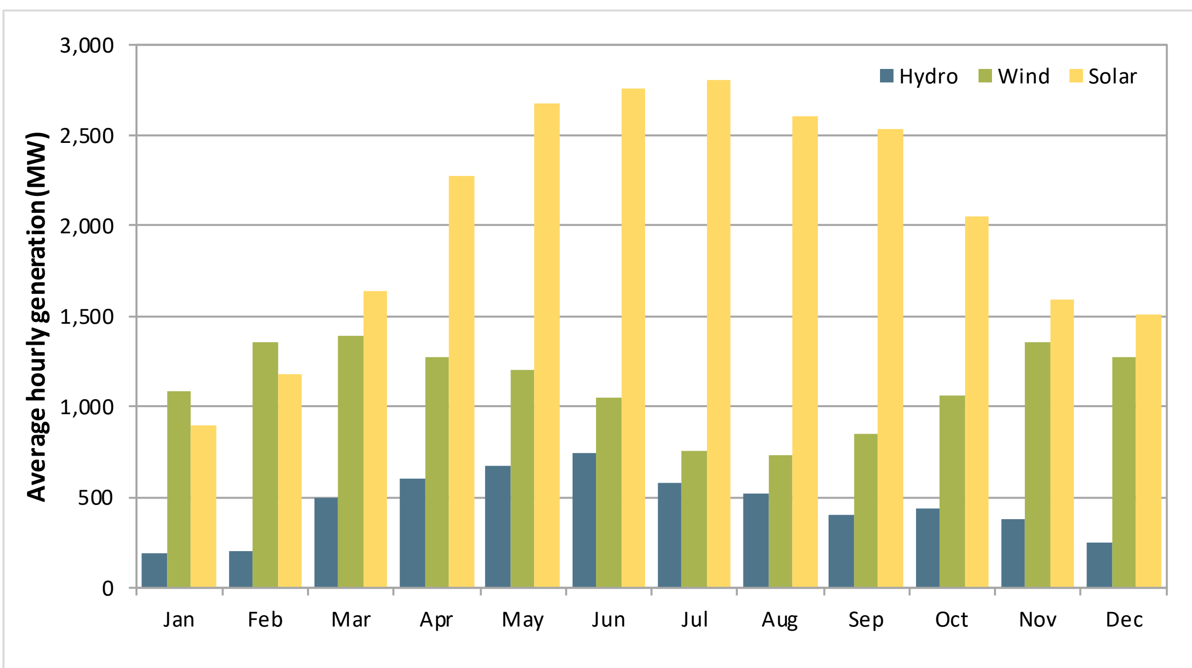


**Figure 1.28 Intermountain West - Monthly comparison of hydro, wind, and solar generation (2024)**

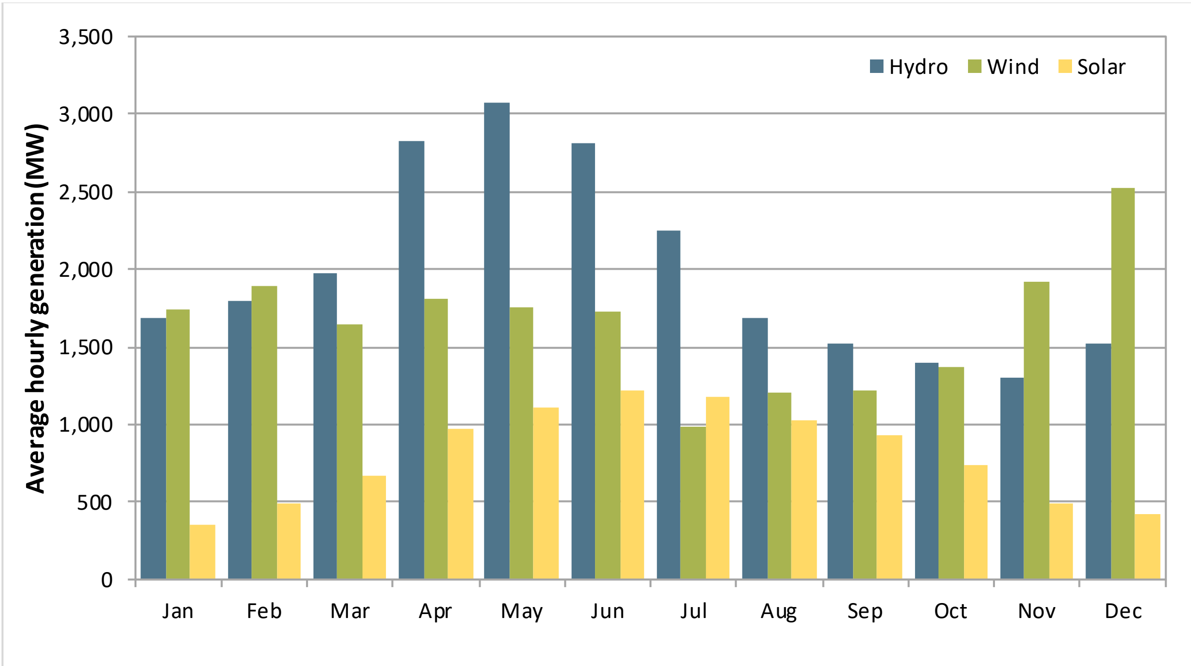
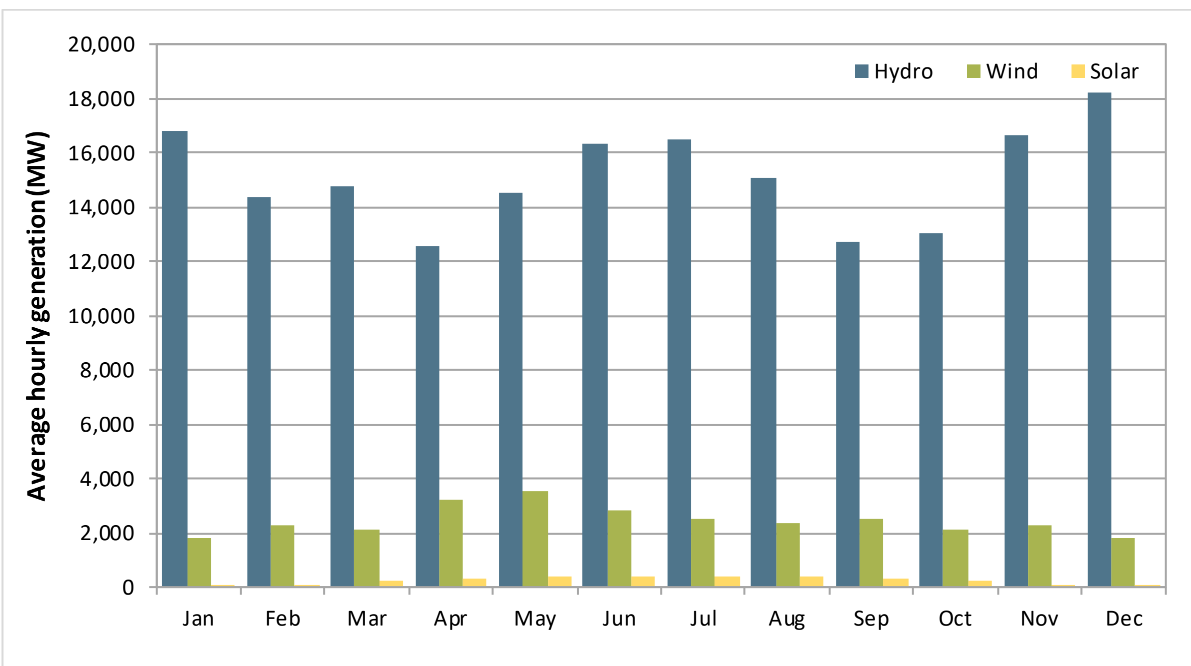



**Figure 1.29 Pacific Northwest - Monthly comparison of hydro, wind, and solar generation (2024)**



### Downward dispatch and curtailment of variable energy resources

In the WEIM, total downward dispatch in 2024 increased by 22 percent relative to 2023. The majority of the downward dispatch is economic.

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 1.30 through Figure 1.33 shows the curtailment of wind and solar resources by month in each of the WEIM regions. Curtailments fall into six categories[56]:

- **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;[57]
- **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 and Desert Southwest regions was from solar resources, as these resources typically bid more economic downward capacity than wind resources.

In all regions except the Intermountain West, total downward dispatch was higher in 2024 than in 2023. Economic downward dispatch accounted for about 4,230 GWh (97 percent) of curtailment during the year, while self-scheduled curtailment accounted for about 46 GWh (1 percent). Exceptional dispatch curtailments for both self-scheduled and economic bid resources remained low and were together about 3.5 GWh (less than 1 percent). The roughly 94 GWh (2.4 percent) of remaining curtailment came

[56] Exceptional economic downward dispatch and exceptional self-schedule curtailment is only applicable to the California ISO.

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

from “other” economic and self-scheduled curtailment. April was the highest month of downward dispatch in 2024 at 976 GWh.

**Figure 1.30 Reduction of wind and solar generation by month (California)**

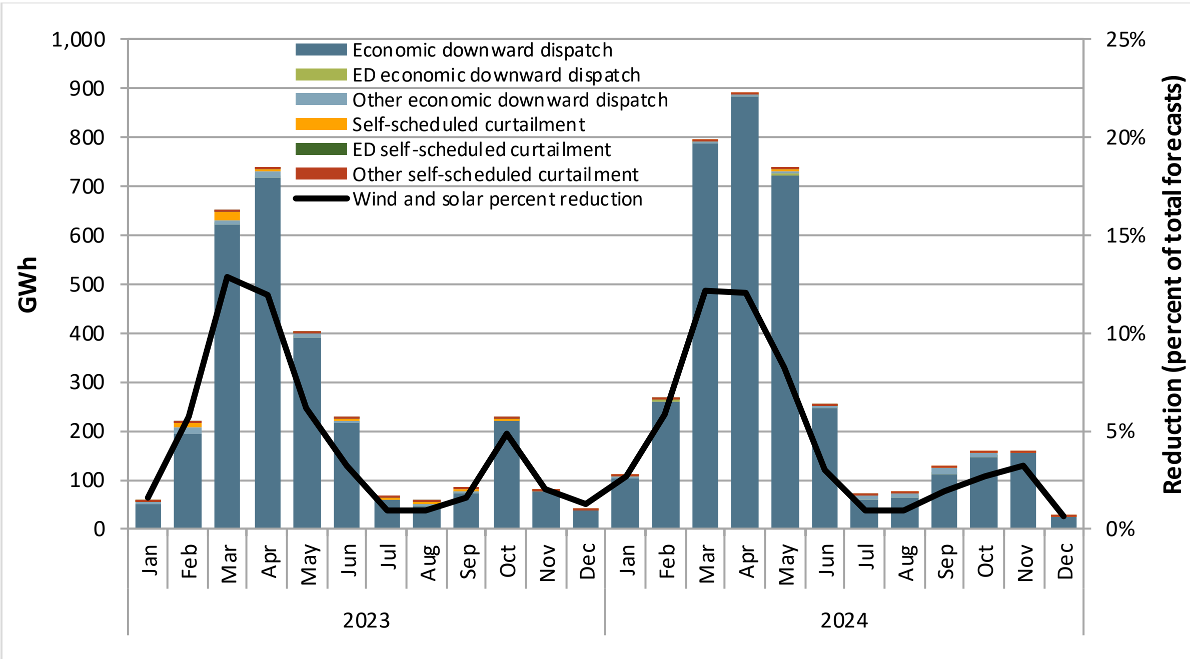



**Figure 1.31 Reduction of wind and solar generation by month (Desert Southwest)**

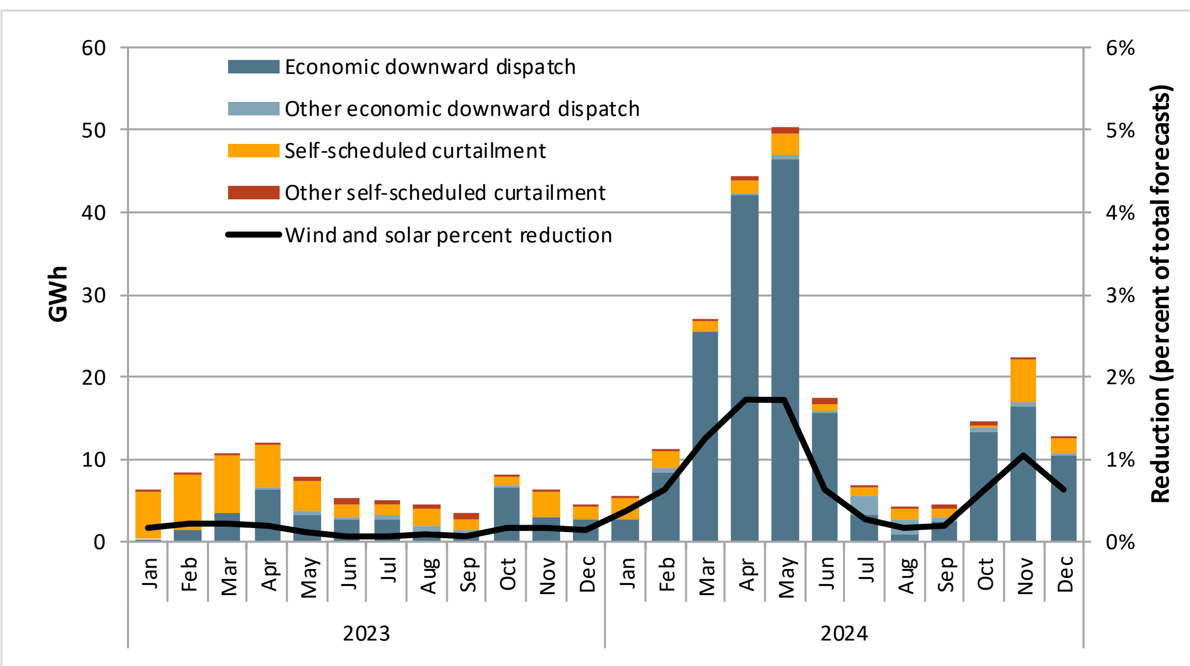


**Figure 1.32 Reduction of wind and solar generation by month (Intermountain West)**

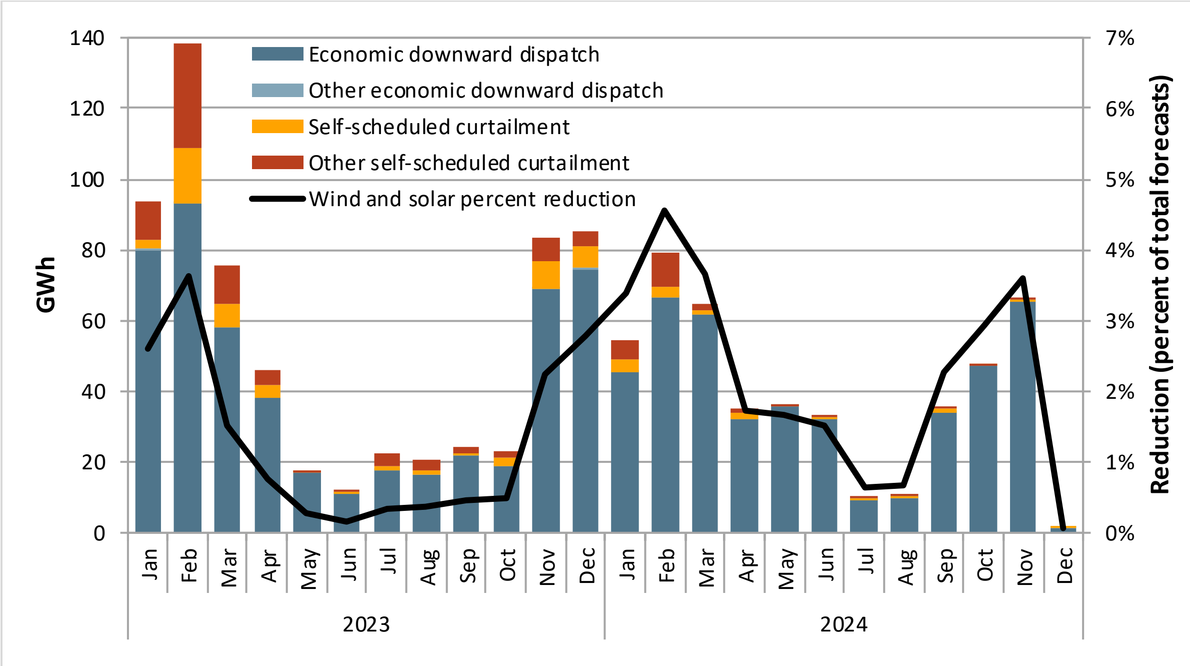
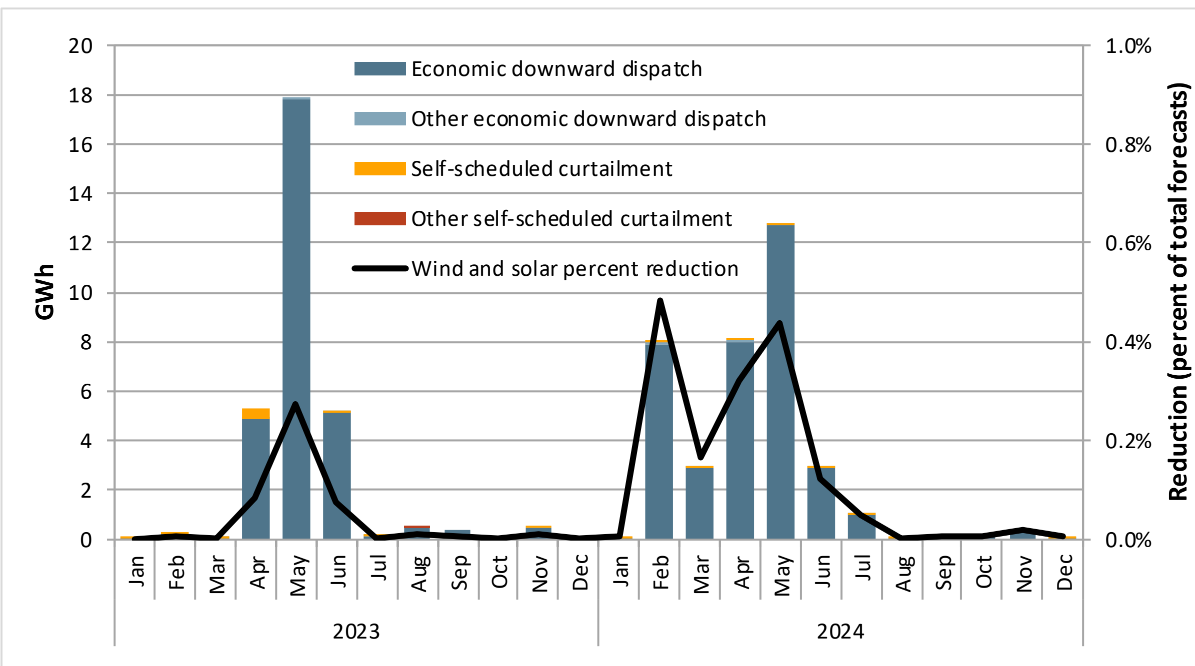



**Figure 1.33 Reduction of wind and solar generation by month (Pacific Northwest)**



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 1.34 through Figure 1.41 show monthly solar and wind compliance with economic downward dispatch instructions during the year. 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.

Solar resources were about 96 percent compliant with downward dispatch instructions in 2024 throughout the WEIM, which was about 2 percent higher than in 2023. Wind resources were 93 percent compliant with downward dispatch instructions, down from 95 percent the previous year. Under market rules, all market participants and resources are expected to follow dispatch instructions.

**Figure 1.34 Compliance with dispatch instructions in the California region – solar generation**

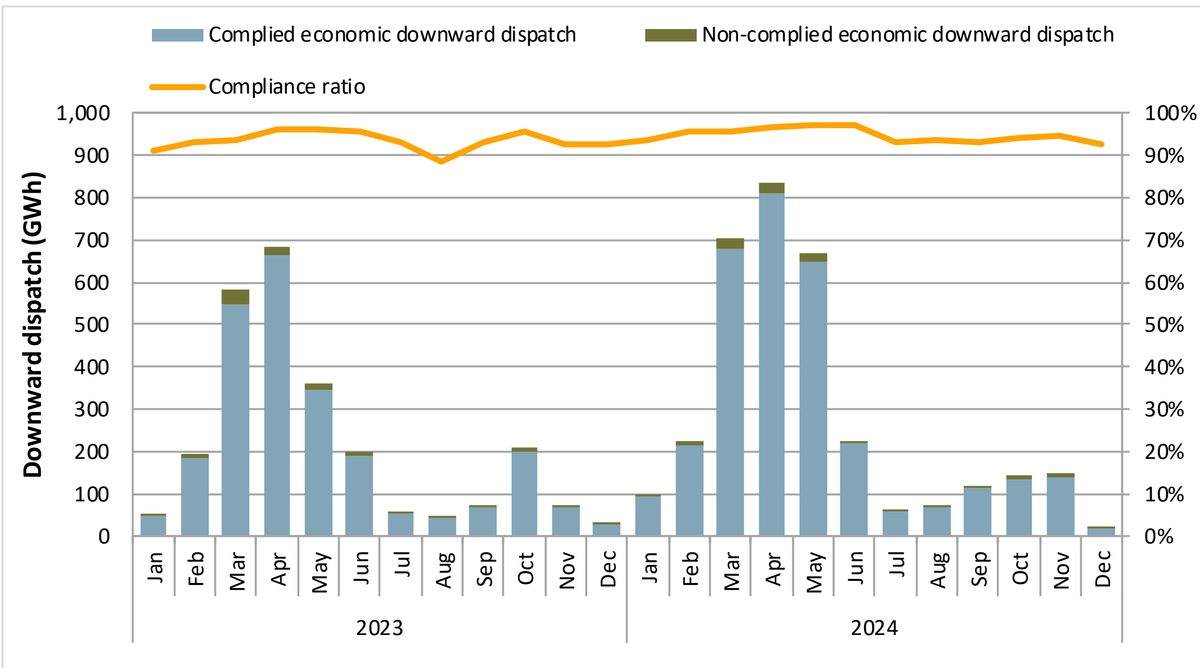


**Figure 1.35 Compliance with dispatch instructions in the California region – wind generation**

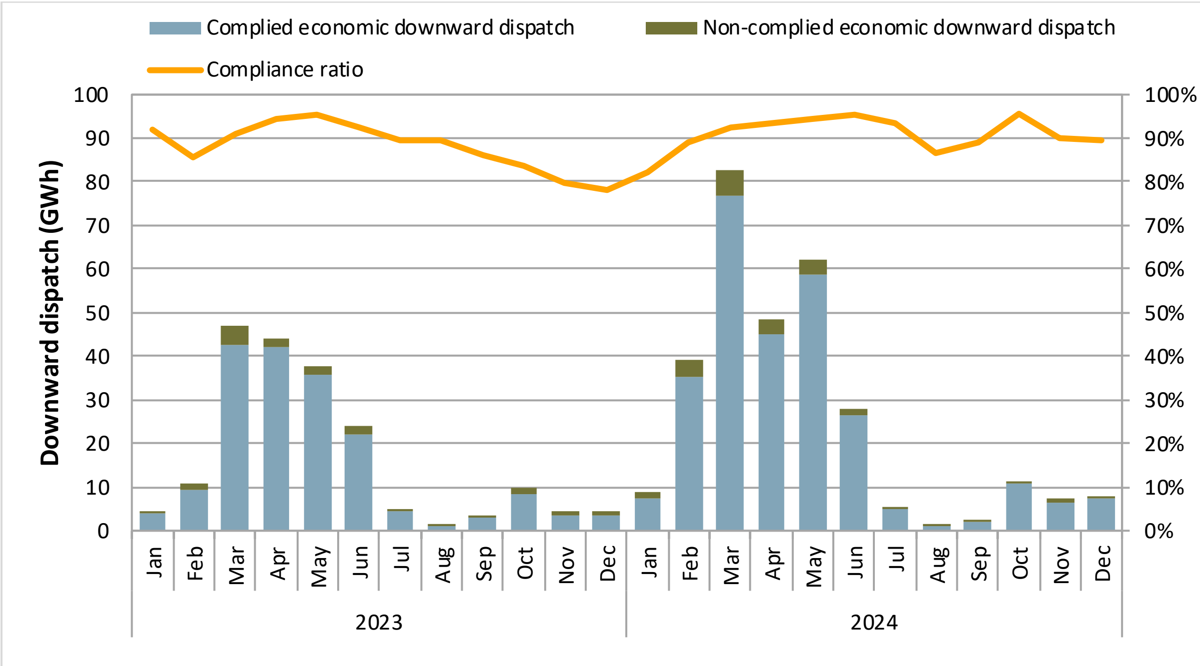



**Figure 1.36 Compliance with dispatch instructions in the Desert Southwest region – solar generation**

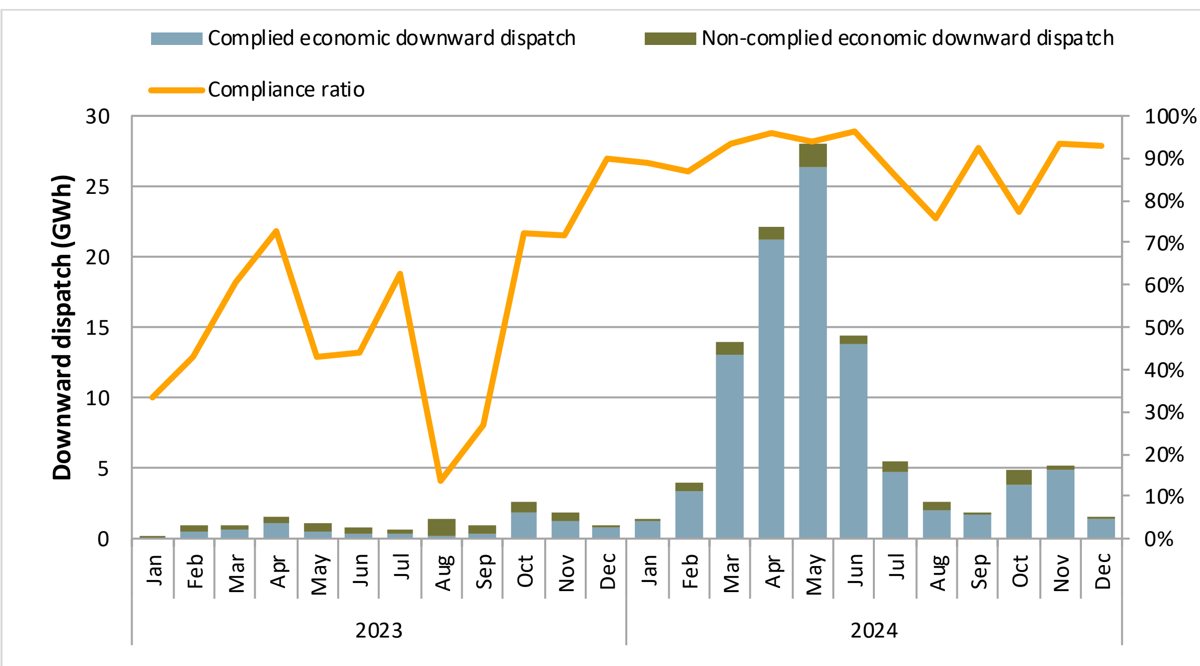


**Figure 1.37 Compliance with dispatch instructions in the Desert Southwest region – wind generation**

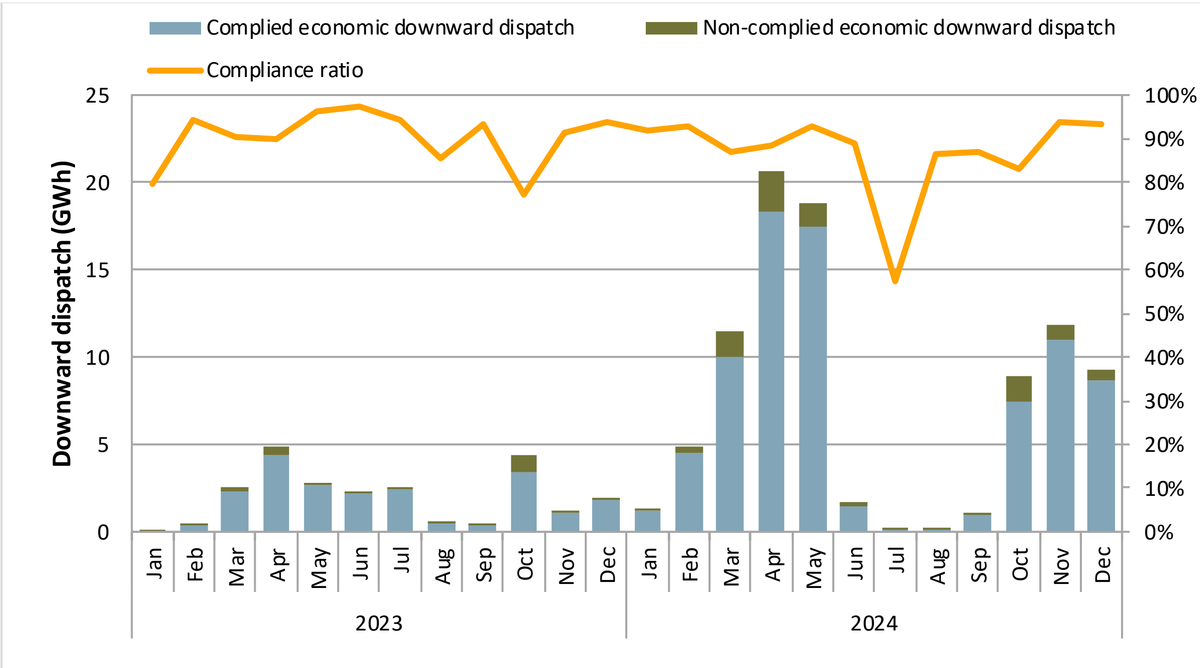



**Figure 1.38 Compliance with dispatch instructions in the Intermountain West region – solar generation**

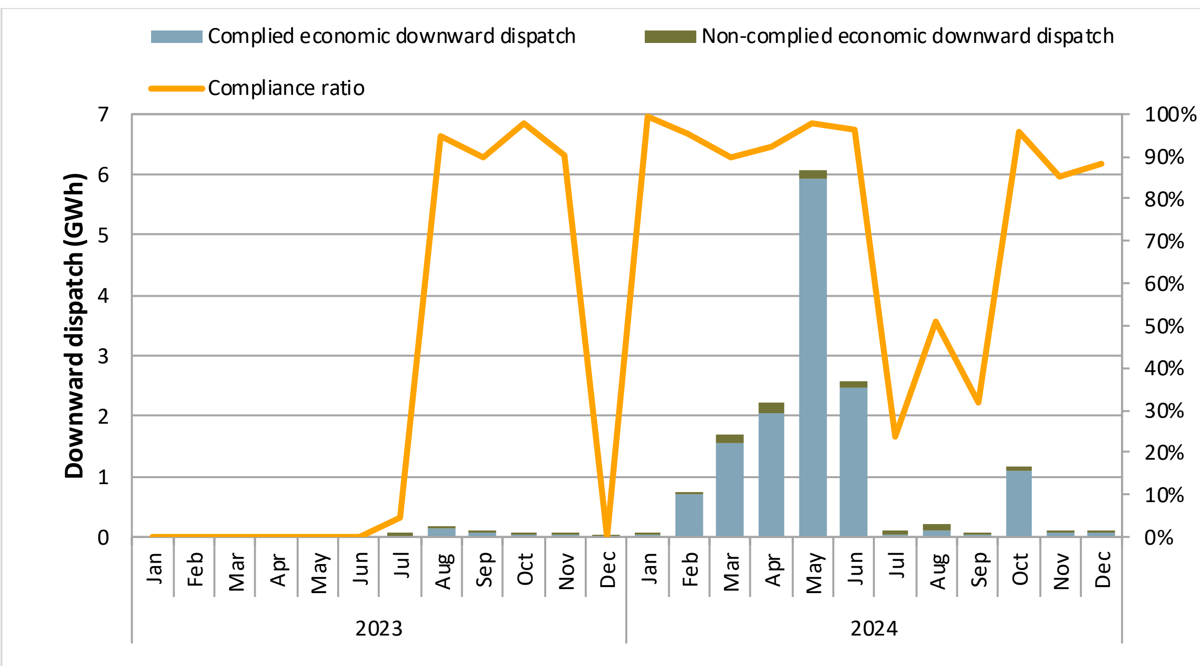


**Figure 1.39 Compliance with dispatch instructions in the Intermountain West region – wind generation**

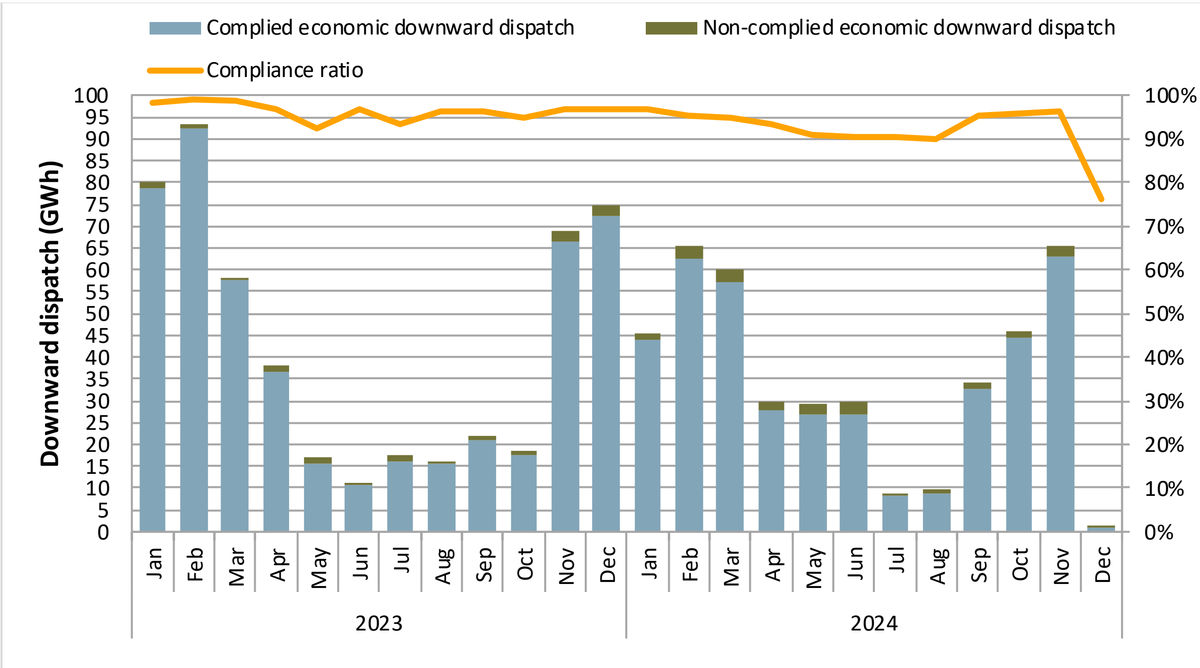



**Figure 1.40 Compliance with dispatch instructions in the Pacific Northwest region – solar generation**

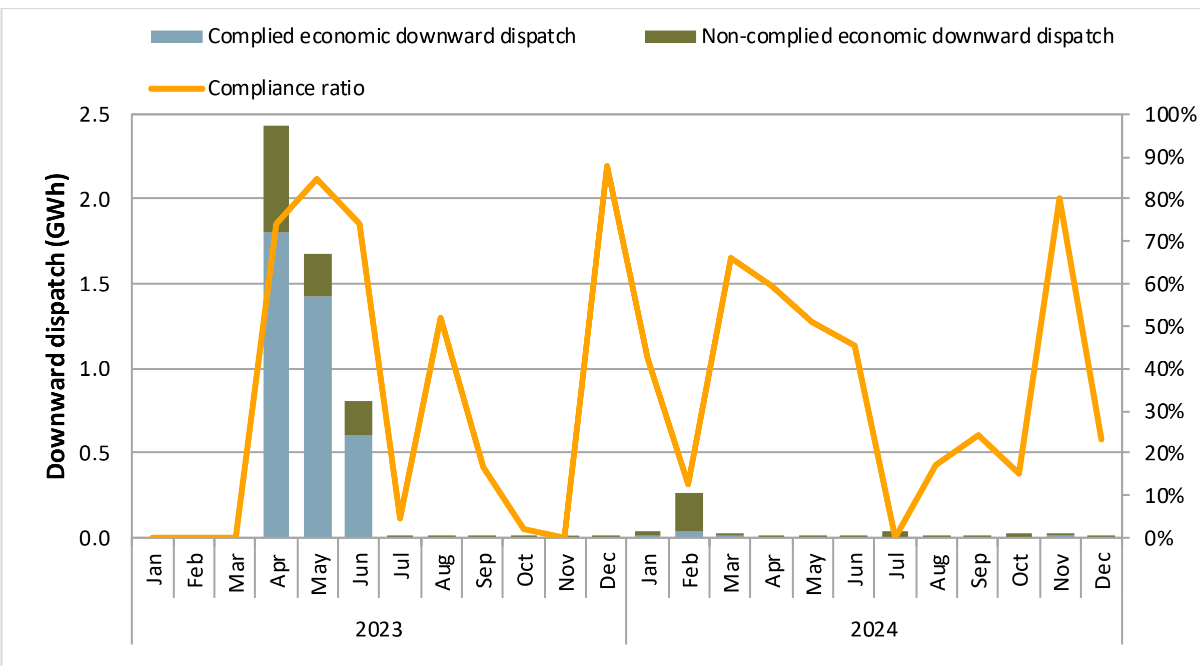
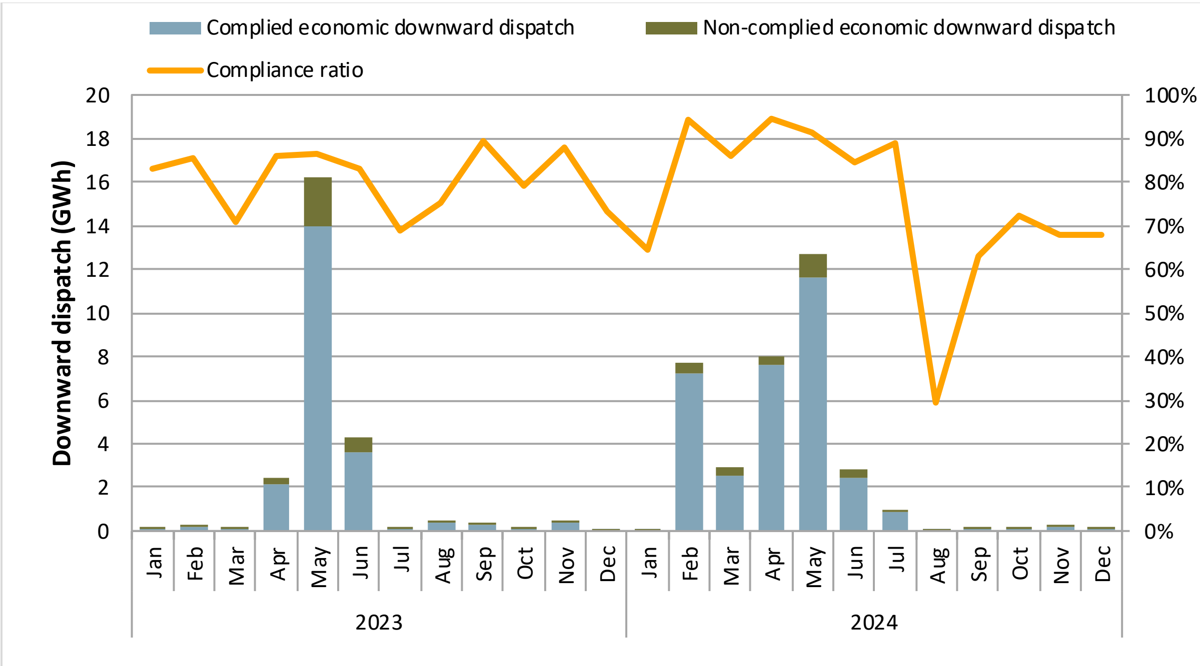


**Figure 1.41 Compliance with dispatch instructions in the Pacific Northwest region – wind generation**




### Hydroelectric supplies

In 2024, total WEIM hydroelectric production increased about 2 percent from 2023.[58] Much of this increase is from the Pacific Northwest and Intermountain West regions which saw a 4,600 GWh and 1,000 GWh increase in hydroelectric generation, respectively. Generation from hydro resources decreased in the California region by around 2,500 GWh.

Year-to-year variation in hydroelectric power supply in the WEIM 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.

Figure 1.42 shows total annual hydroelectric production in the California region alongside the April 1 snowpack level[59] and precipitation[60] in California from 2015 to 2024. Figure 1.43 through Figure 1.45 show the total annual hydroelectric production in the rest of the WEIM regions. Figure 1.46 compares monthly hydroelectric output from resources within the WEIM system for each month during the last

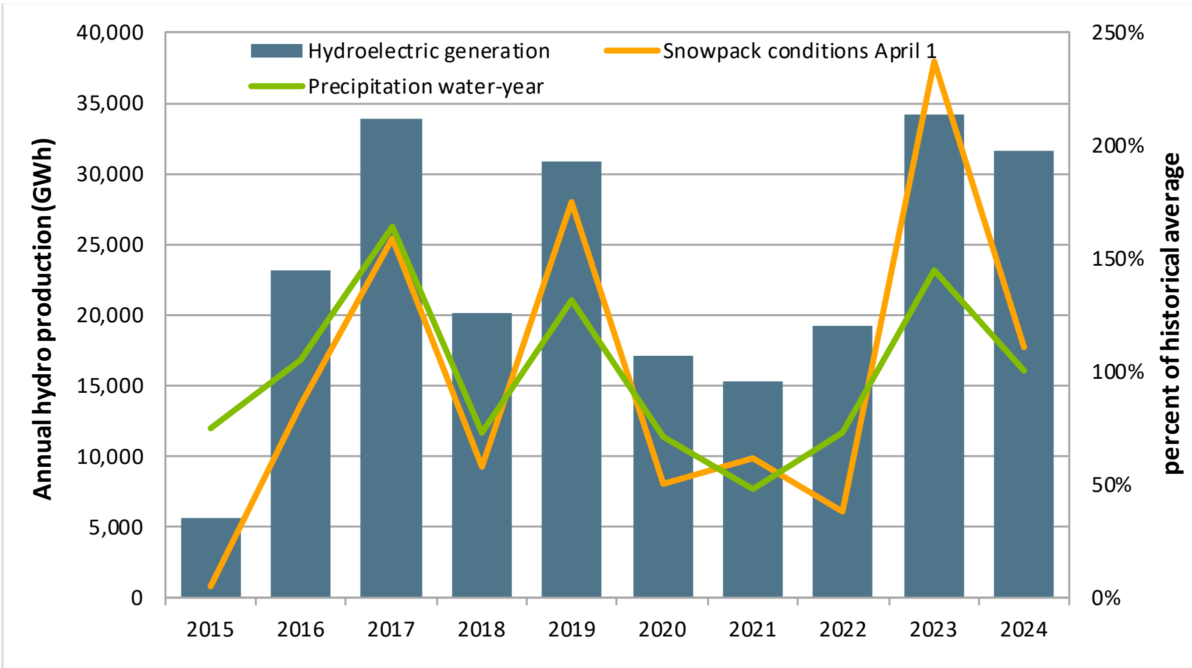
58 Annual hydroelectric production includes tie generators.

59 This table uses the April 1 measurement of snow water equivalent as a percent of long-term average. For more information, please see California Department of Water Resources, *California Data Exchange Center*: https://cdec.water.ca.gov/snowapp/sweq.action

60 For precipitation, this table uses the statewide weighted average precipitation as a percent of historic average for the October–September water year. For more information, please see: https://cdec.water.ca.gov/reportapp/javareports?name=PRECIPSUM

three years. Similarly to 2023, hydro generation followed a seasonal pattern with generation generally peaking in the summer throughout the WEIM. In the Pacific Northwest, hydro output peaked during the winter months with highs in the summer as well.

**Figure 1.42 California - Annual hydroelectric production (2015–2024)**[61]




[61] BANC joined the WEIM in two phases. The first was in April 2019 with SMUD, and the second phase was in 2021 with Modesto Irrigation District, the City of Redding, the City of Roseville, and the WAPA Sierra Nevada Region. TIDC and LADWP both joined the WEIM in 2021.

**Figure 1.43 Desert Southwest - Annual hydroelectric production (2015–2024)[62]**

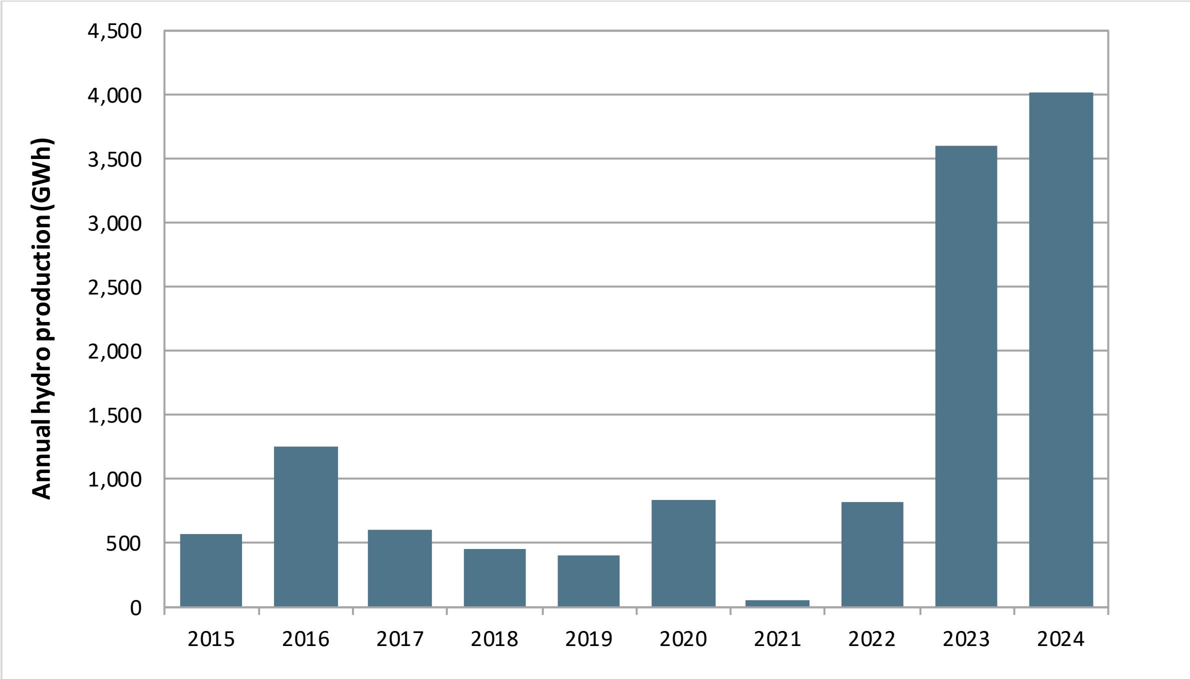
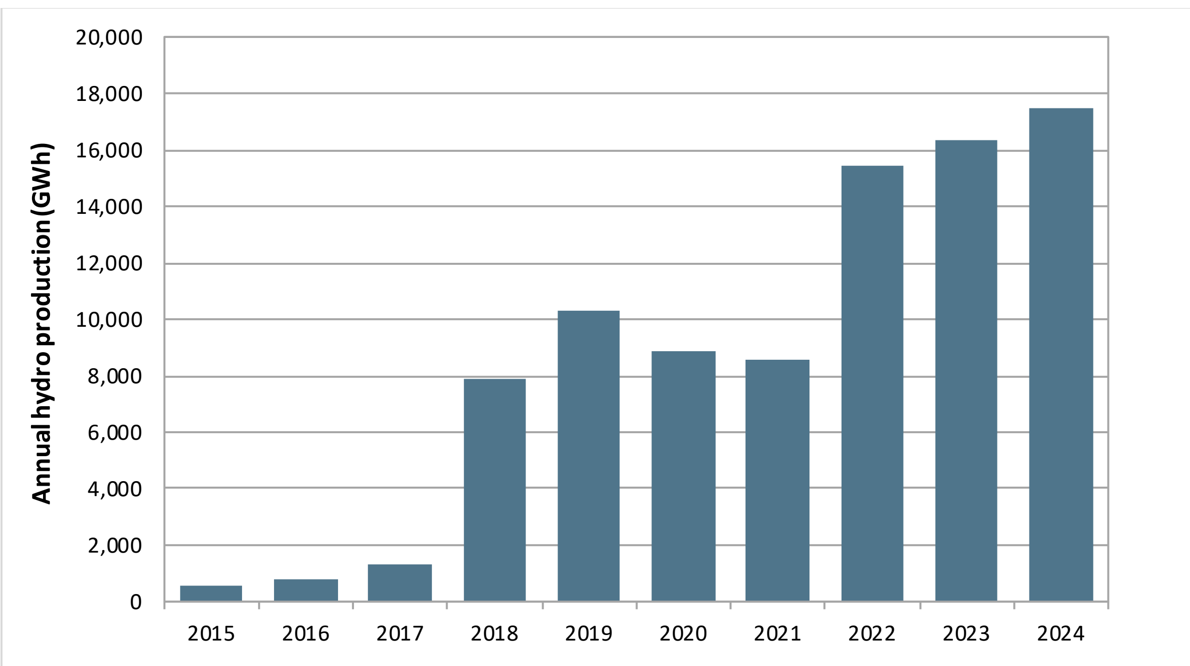



**Figure 1.44 Intermountain West - Annual hydroelectric production (2015–2024)[63]**




62 NEVP joined the WEIM in 2015. AZPS joined in 2016. SRP joined in 2020. PNM joined in 2021. TEPC joined in 2022. WALC and EPE joined in 2023.

63 IPCO joined the WEIM in 2018. NWMT and AVA joined in 2021 and 2022, respectively.

**Figure 1.45 Pacific Northwest - Annual hydroelectric production (2015–2024)[64]**

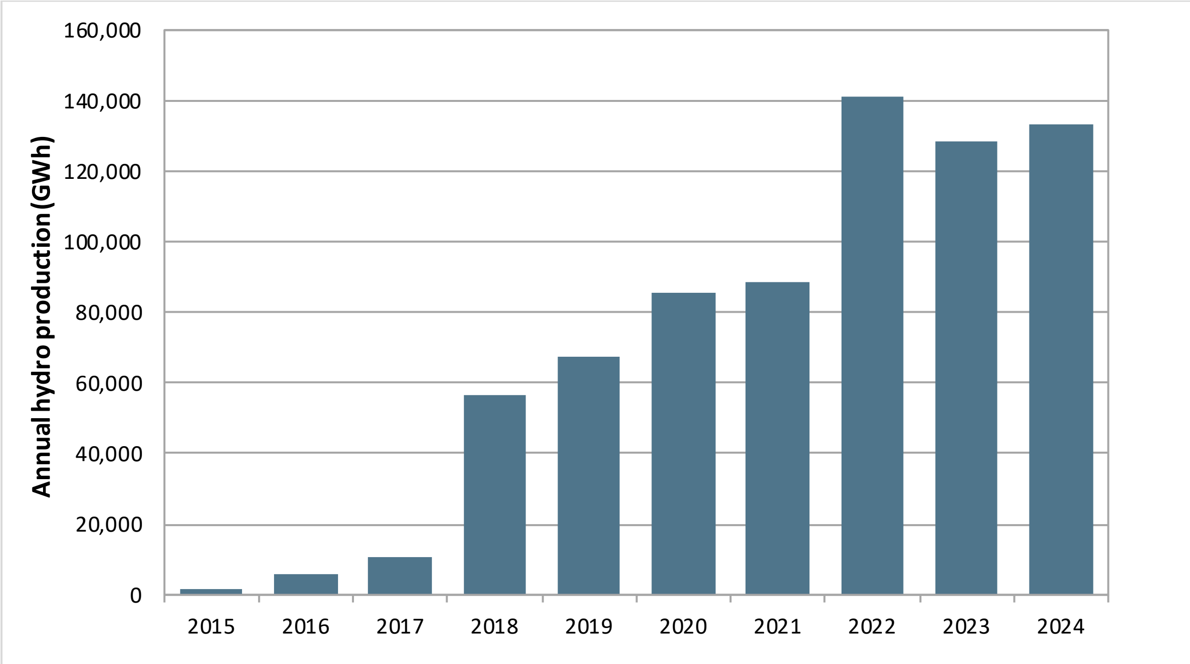
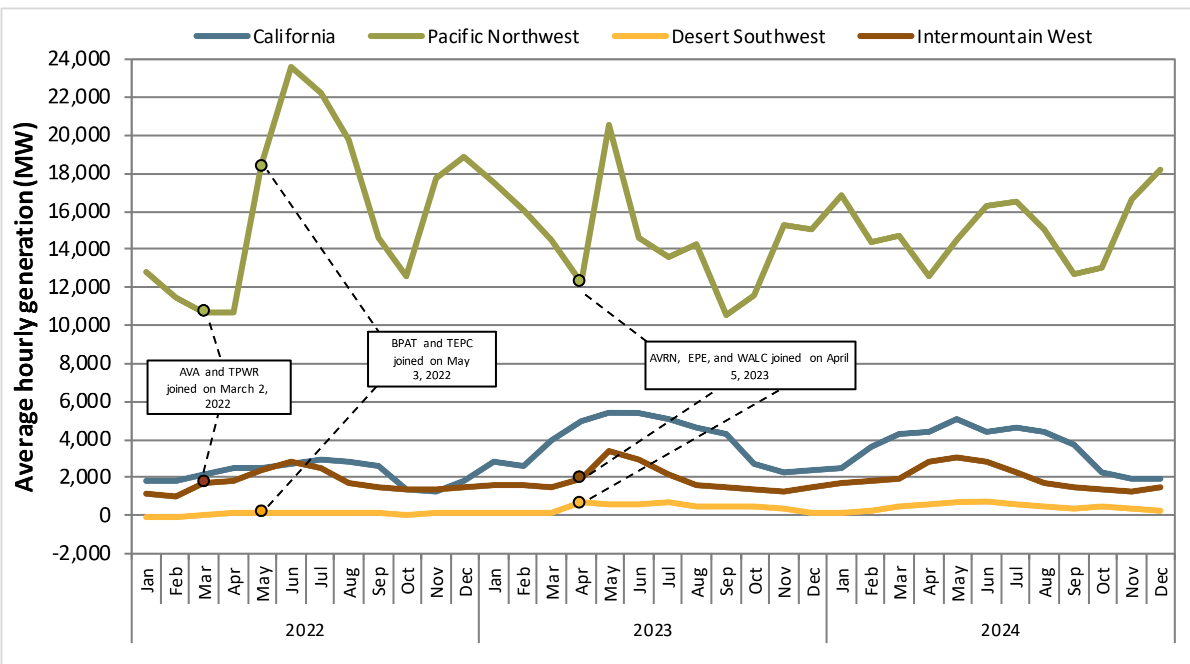



**Figure 1.46 Average hydroelectric production by month (2022–2024)**




64 PSEI joined the WEIM in 2016. PGE joined in 2017. BCHA joined in 2018. SCL joined in 2020. BPAT and TPWR joined in 2022. AVRN joined in 2023.

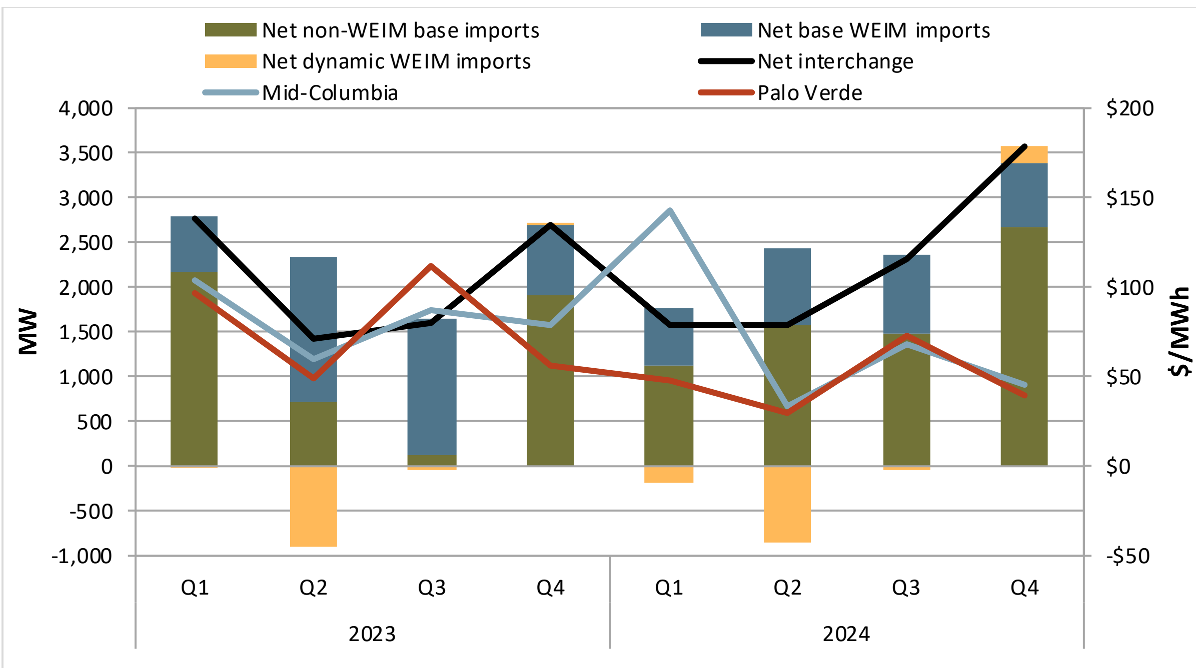
### 1.2.3 Net imports

#### Quarterly interchange and average prices

Figure 1.47 through Figure 1.50 show the hourly average generation from net imports and net WEIM dynamic transfers into each region in the WEIM. The power flowing into a balancing area in each region is represented as positive while power flowing out is shown as negative. The net interchange into the California region increased by 7 percent in 2024 compared to 2023.[65] The California and Intermountain West regions were net importers throughout 2024. Except for the third quarter, the Desert Southwest was a net exporter for 2024. The Pacific Northwest region was a net importer of WEIM transfers throughout 2024, and it was a net exporter of base schedules during all quarters except the first.

The figures in this section also show the quarterly average bilateral prices at Mid-Columbia (Mid-C) and Palo Verde. Bilateral prices peaked in the first quarter of 2024 at the Mid-C hub, and in the third quarter of 2023 at the Palo Verde hub.

**Figure 1.47 California - Net imports and average day-ahead price (2023–2024)**




[65] The net interchange is equal to scheduled imports minus scheduled exports in any period. This includes transfers between WEIM entities, and bilateral imports and exports between WEIM entities and non-WEIM entities.

**Figure 1.48 Desert Southwest - Net imports and average day-ahead price (peak hours, 2023–2024)**

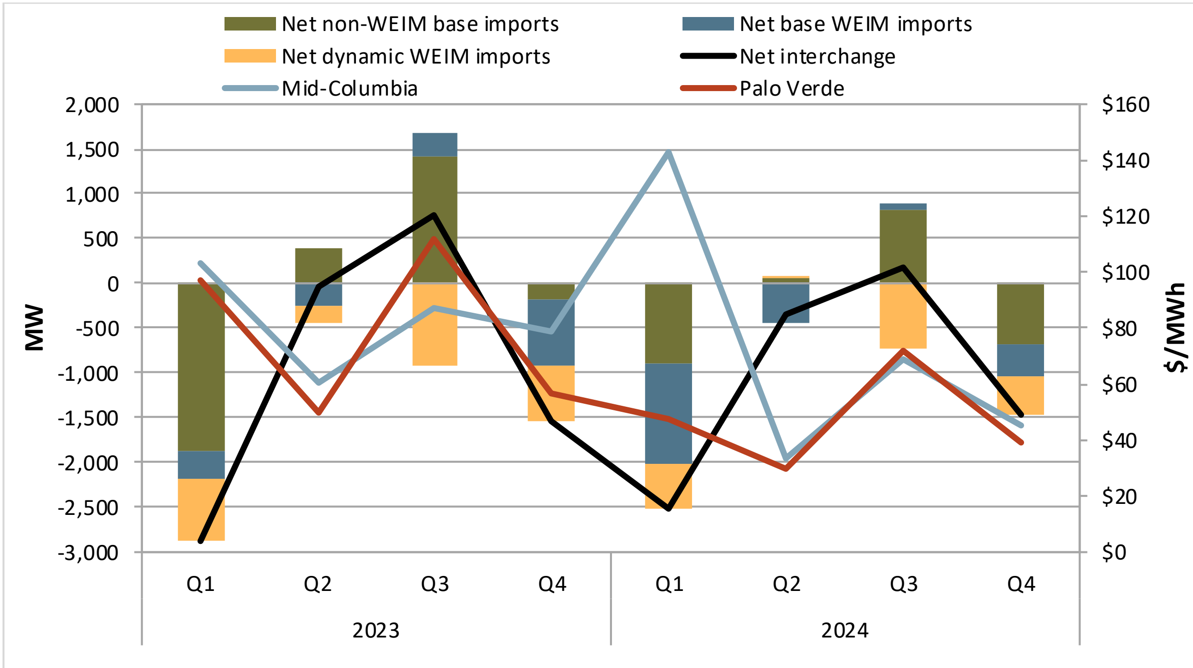



**Figure 1.49 Intermountain West - Net imports and average day-ahead price (peak hours, 2023–2024)**

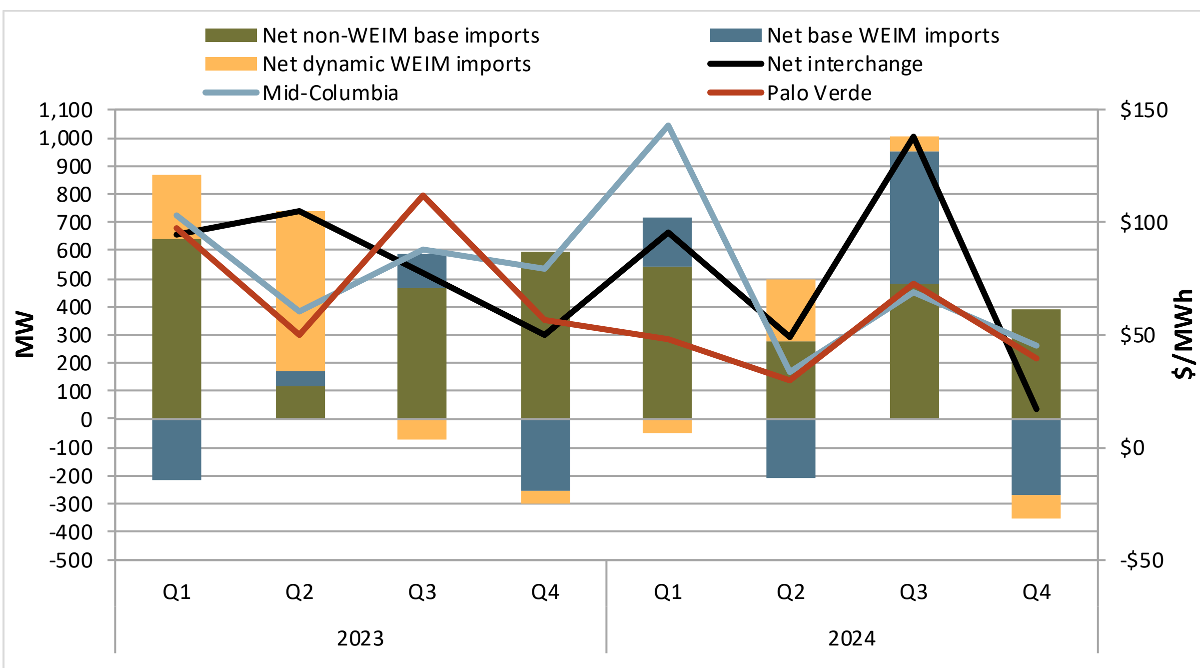
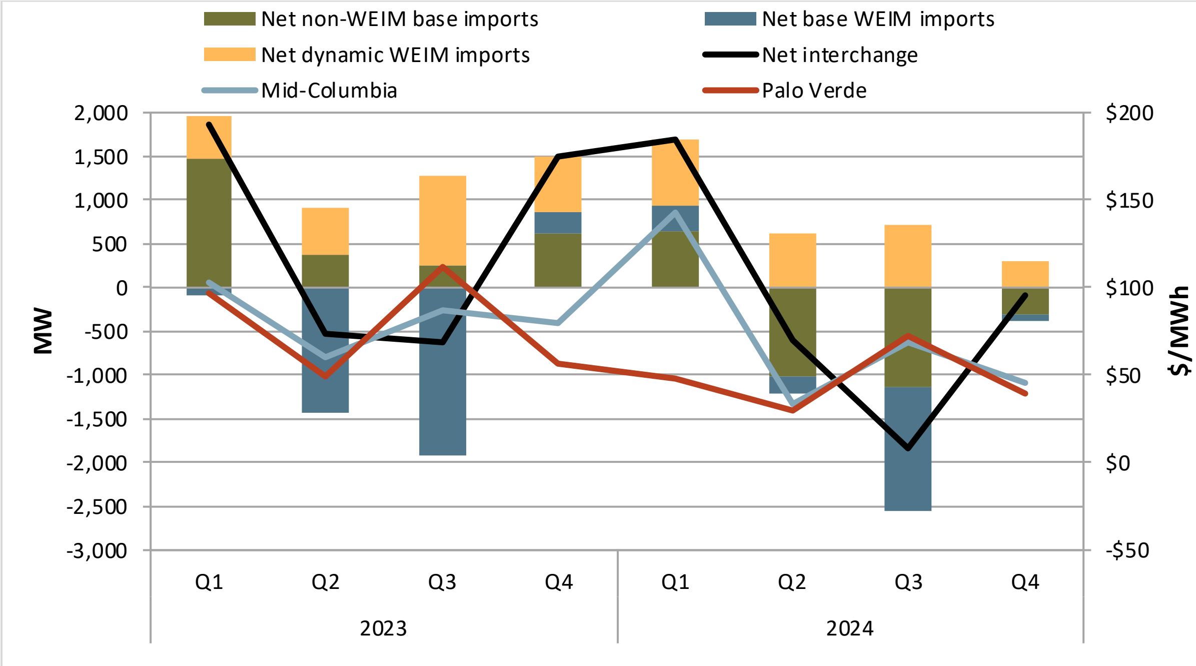


**Figure 1.50 Pacific Northwest - Net imports and average day-ahead price (peak hours, 2023–2024)**




### Hourly net interchange – imports, exports, and WEIM transfers

Figure 1.51 to Figure 1.54 show the average hourly net interchange of each WEIM region. The red line shows the net WEIM dynamic transfers into and out of all balancing areas optimized by the market software. This line also includes static transfers which are optimized in the 15-minute market but held fixed in the 5-minute market. The dotted black line nets all base non-WEIM and base WEIM exports and imports. The solid black line represents the final net interchange after adding the net dynamic transfers (red line) to the dotted black line.

In all quarters of 2024, the California region was a net importer both before and after the WEIM transfers. In all regions but California, most imports and exports were with WEIM balancing areas. The Pacific Northwest region's net interchange after accounting for WEIM transfers was in the import direction in the first quarter but in the export direction for the other three quarters. The Desert Southwest net interchange after WEIM transfers was mainly in the export direction in 2024, especially during the first and fourth quarters. The Intermountain West region was a net importer after WEIM transfers in the first three quarters of 2024.

**Figure 1.51 California - Average hourly net interchange by quarter**

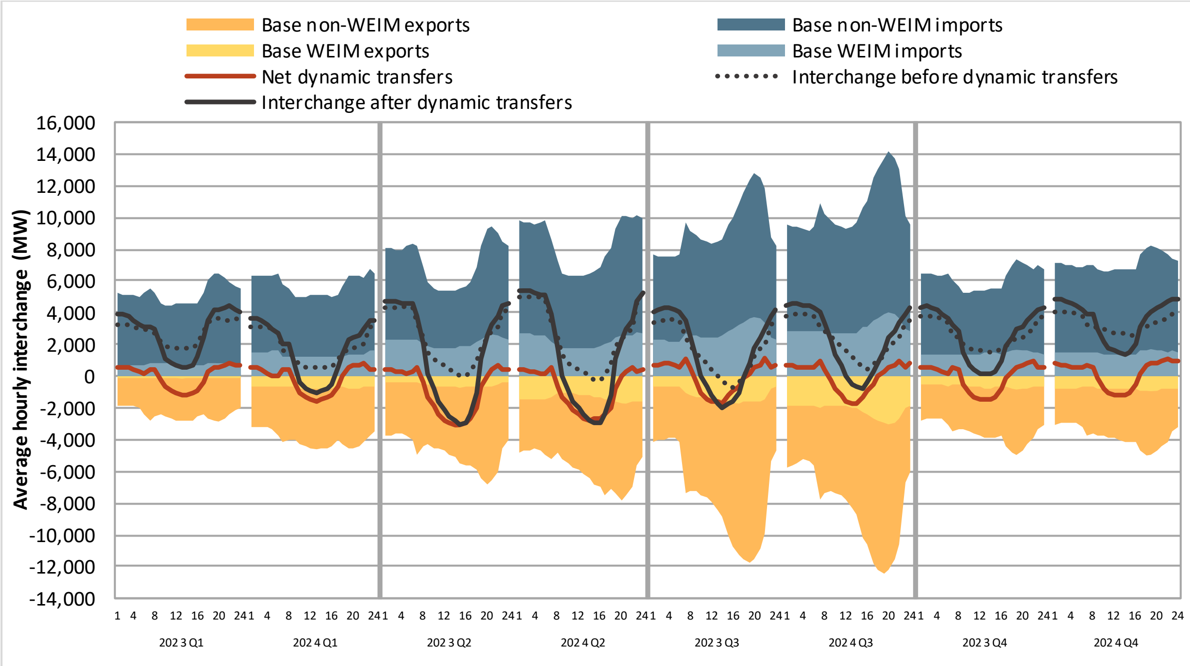



**Figure 1.52 Desert Southwest - Average hourly net interchange by quarter**

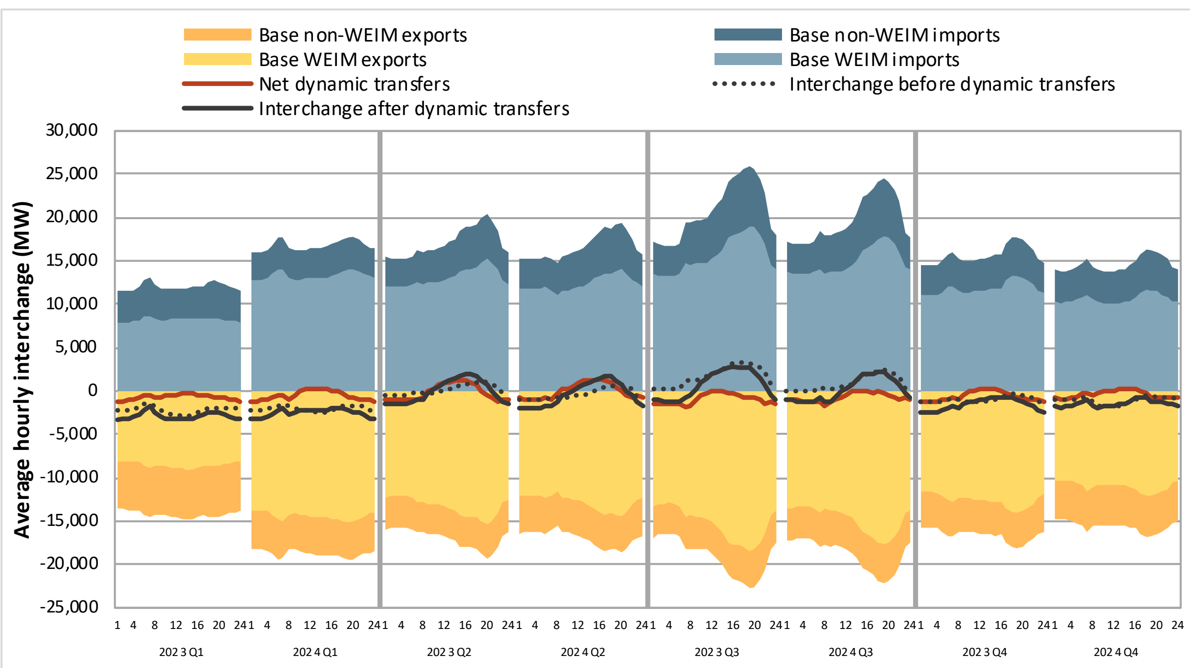


**Figure 1.53 Intermountain West - Average hourly net interchange by quarter**

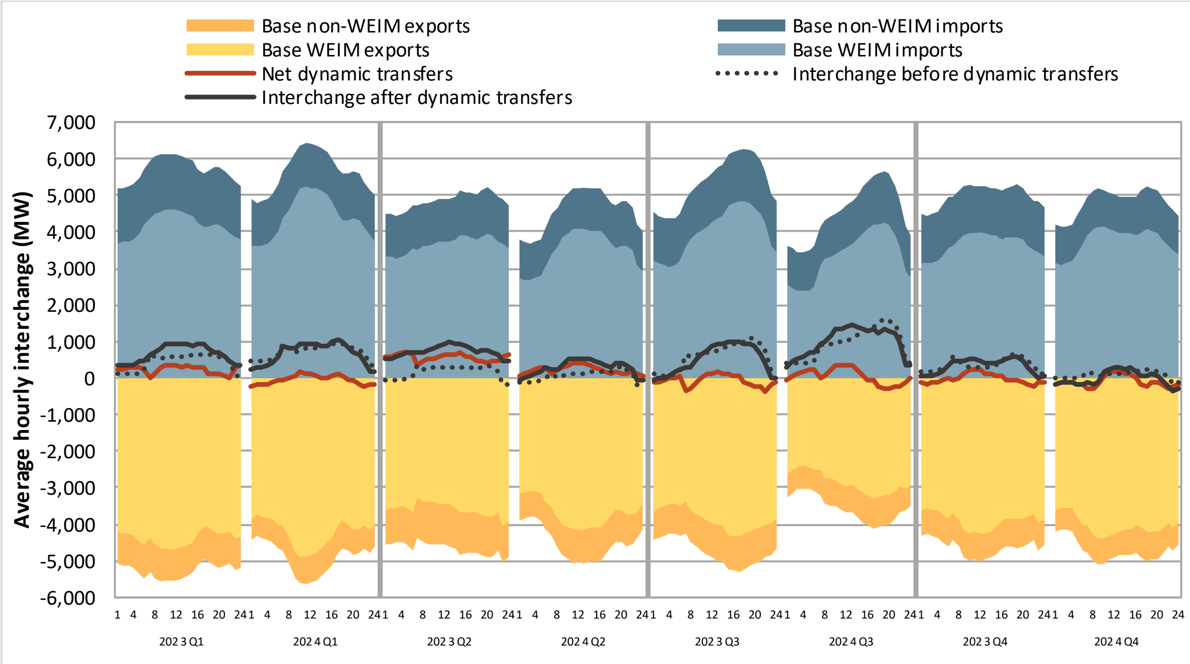
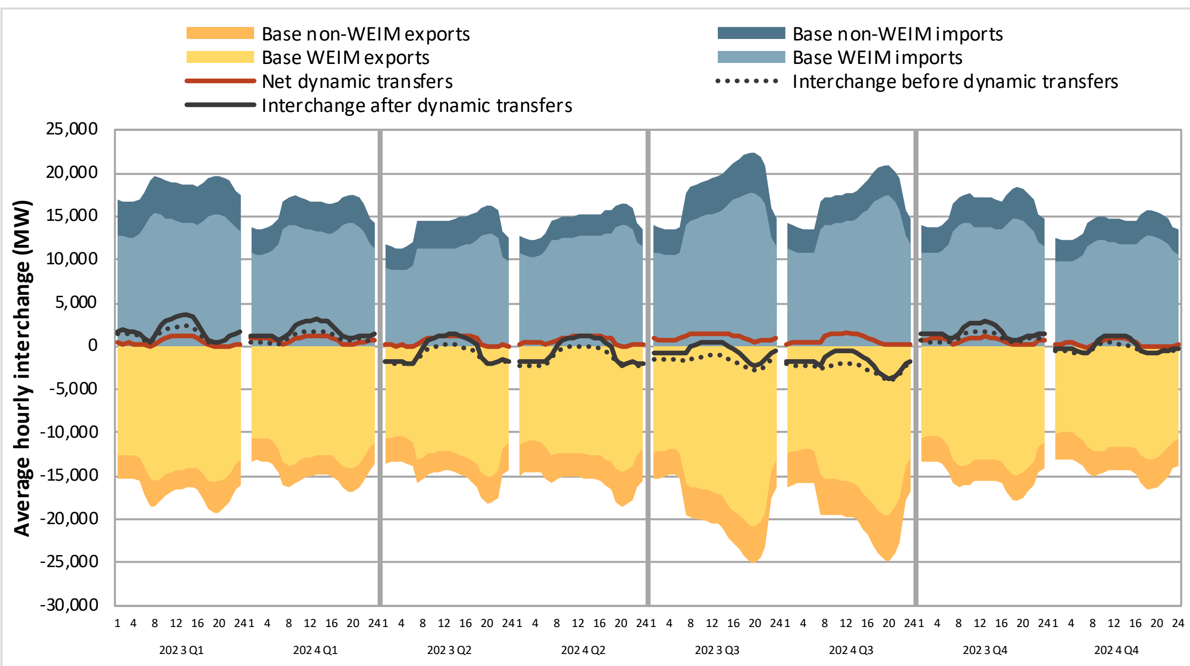



**Figure 1.54 Pacific Northwest - Average hourly net interchange by quarter**



### 1.2.4 Storage resources

Capacity from battery storage resources has increased significantly in recent years.[66] Storage resources typically participate under the non-generator resource model. Non-generator resources are resources that operate as generation, and bid into the market using a single supply curve with prices for negative capacity (charging) and positive capacity (discharging).

The California ISO has increasingly seen participation of hybrid resources, which typically pair renewable generation with battery storage components. Hybrids are modeled as a single resource, in that they have a single bid curve that applies to all their component parts and receive one dispatch instruction from the ISO. The hybrid resource operator self-optimizes the components of its resource to meet that dispatch instruction.

Co-located resources are those that share a point of interconnection with another resource. Similar to hybrids, co-located points of interconnection typically contain groupings of battery and intermittent renewable resources. Since they are modeled as separate resources, co-located facilities have separate metering arrangements, submit separate outages, receive separate dispatch instructions, and may be operated by different entities. Several market constraints only apply to co-located resources. For example, the aggregate capability constraint exists to ensure that dispatch instructions to co-located resources behind a common point of interconnection do not exceed interconnection limits. In addition, the ISO recently implemented an optional parameter that allows co-located batteries to restrict grid charging. This helps resources capture tax benefits meant to incentivize batteries to not charge beyond what their co-located solar component is producing. In 2024, the maximum observed hourly amount of co-located battery capacity that restricted grid charging was nearly 750 MW.

As of June 1, 2025, there are 169 co-located resources across 78 points of interconnection. Around 38 percent of installed co-located capacity consists of batteries, and all but three of these 78 points of interconnection have at least one battery resource.

Figure 1.55 shows the total capacity of CAISO BAA-participating battery storage as of December 31, 2024, represented in terms of maximum output (MW) and maximum duration (MWh).[67] Stand-alone batteries are defined as resources that consist solely of battery storage components and do not share a point of interconnection with other resources. In December 2024, active battery capacity totaled nearly 13,000 MW—5,800 MW from stand-alone projects, 5,700 MW from co-located projects, and about 1,500 MW from the storage components of hybrid resources and co-located hybrids. Most batteries in the ISO markets have a duration of four hours.

Figure 1.56 shows the number of actively participating batteries and their capacity for other balancing areas with active battery capacity. At the end of 2024, there were 50 actively participating resources with battery components in the Western Energy Imbalance Market (WEIM) outside of the CAISO balancing area, with a total of around 5,000 MW of discharge capacity and a 16,700 MWh maximum state-of-charge. In comparison, WEIM battery capacity totaled 2,600 MW in December 2023. Battery

[66] For more information, see DMM's special report: *2024 Special Report on Battery Storage*, Department of Market Monitoring, May 29, 2025: https://www.caiso.com/documents/2024-special-report-on-battery-storage-may-29-2025.pdf

[67] These values may differ from other battery capacity measures. This metric only includes capacity of participating batteries, defined as being scheduled at least once in the respective year. These data track co-located and hybrid status as of December 2021 and February 2023, respectively, though these types of capacity may have been participating sooner.

capacity in non-CAISO WEIM balancing areas is expected to grow faster than battery capacity in the CAISO balancing area in the coming years.[68]

**Figure 1.55 Battery capacity in the CAISO balancing area (2018–2024)**

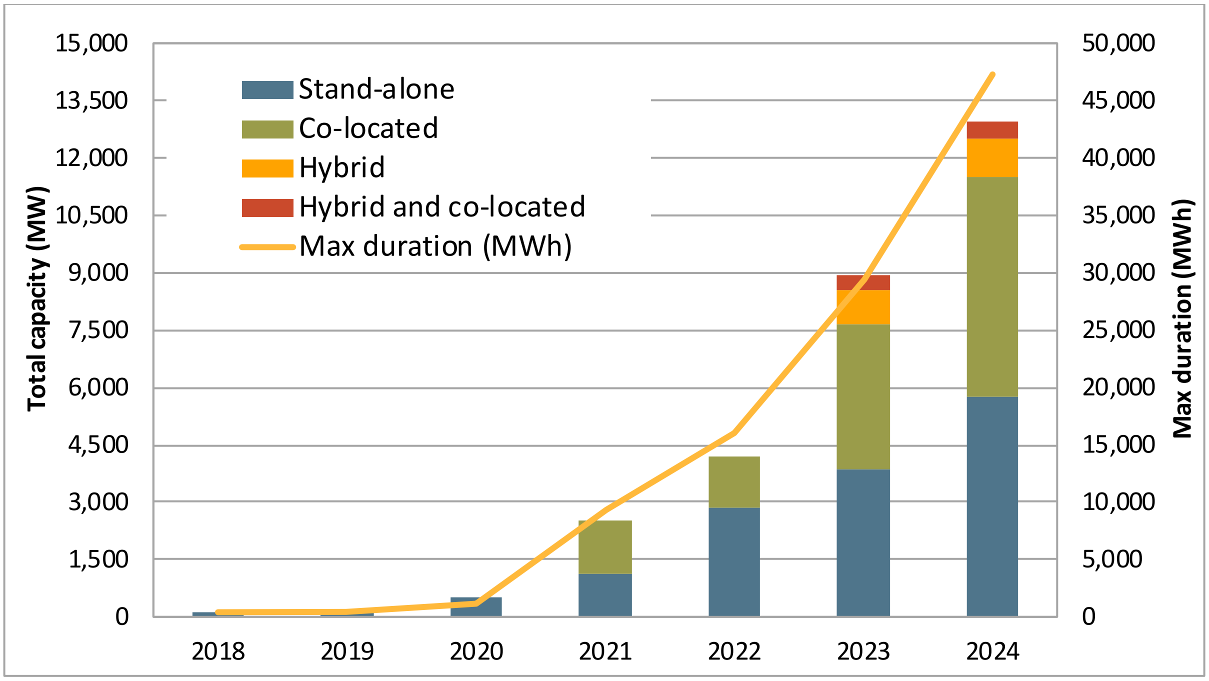
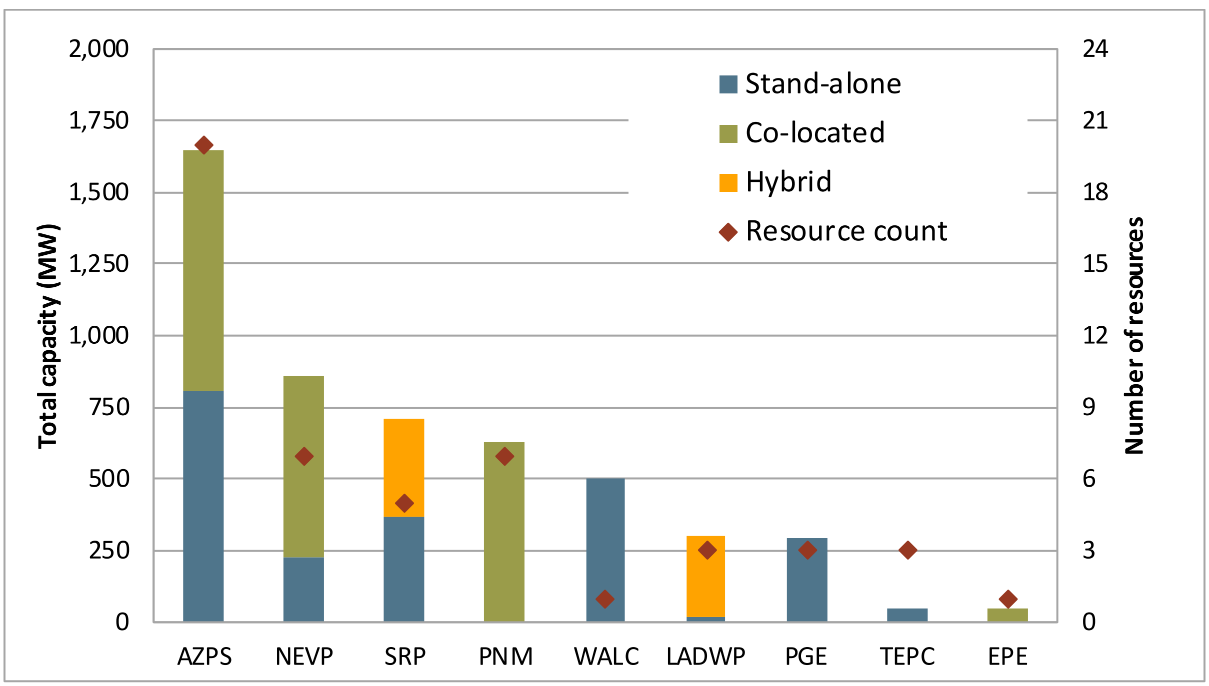



**Figure 1.56 Active battery capacity by WEIM balancing area (2024)**




[68] *2024 Special Report on Battery Storage*, Department of Market Monitoring, May 29, 2025, p 18: https://www.caiso.com/documents/2024-special-report-on-battery-storage-may-29-2025.pdf

Figure 1.57 shows average hourly real-time (15-minute market) schedules of limited energy storage resources (LESRs) in the CAISO balancing area. Historically, batteries have favored providing ancillary services—especially frequency regulation—over energy because it allows them to avoid deep charging and discharging cycles, which cause rapid cell degradation. Increasingly, energy schedules have replaced ancillary services in battery operations. The portion of total battery capacity scheduled for upward regulation, spin, and non-spin dropped from 12 percent in 2023 to 9 percent in 2024. Batteries tend to charge during the afternoon when solar energy is abundant, then discharge in the evening when power is in high demand, solar output is low, and prices are much higher. In peak demand hours, batteries contributed up to 60 percent of their scheduled output to discharging energy on average.

**Figure 1.57 Average hourly real-time battery schedules in 2024 (CAISO balancing area)**

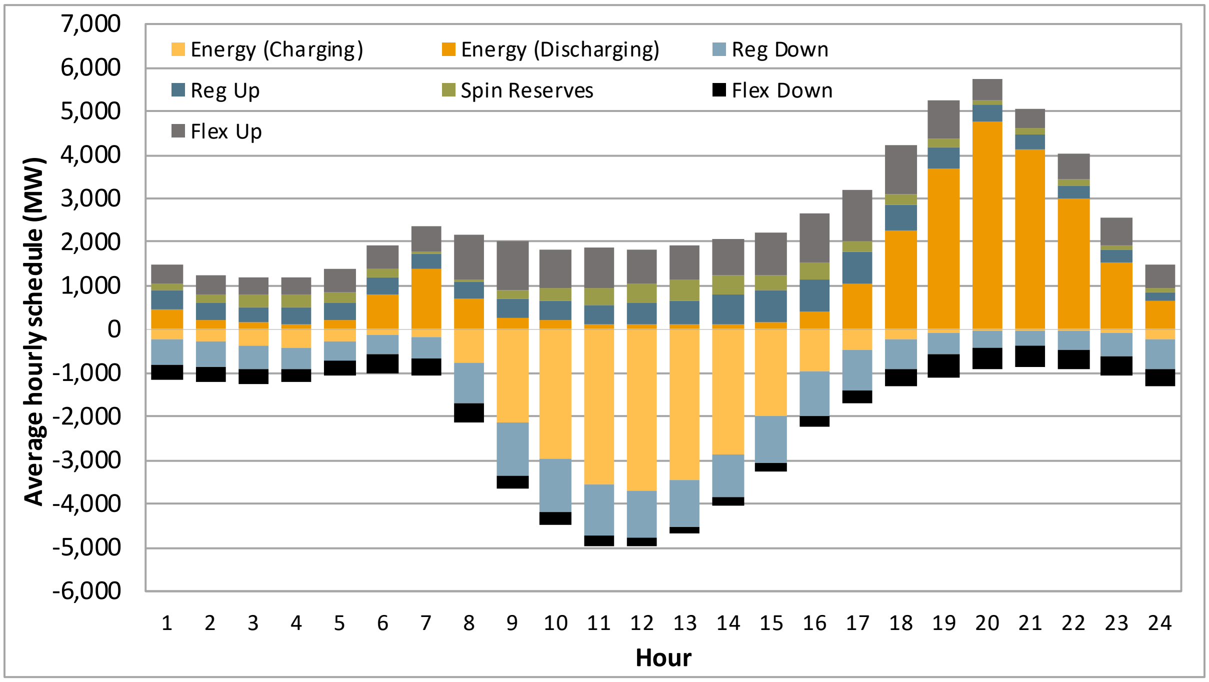
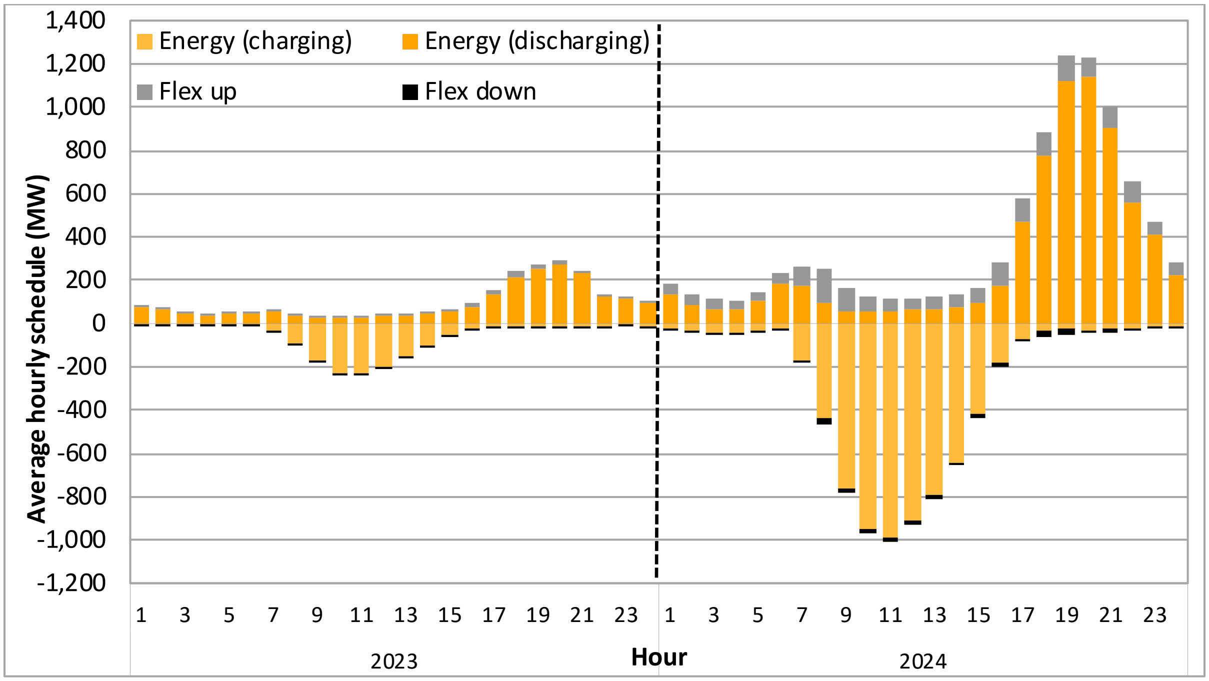


**Figure 1.58 WEIM (non-CAISO) average hourly battery schedules (2023–2024)**




As shown in Figure 1.58, batteries participating in the WEIM have similar schedules to batteries in the CAISO balancing area (i.e., primarily charging in the morning and early afternoon hours, then discharging in the evening). However, WEIM batteries do not have ancillary service schedules, since ancillary services are not procured through the market in WEIM balancing areas. WEIM batteries tend to be bid into the market such that they are not incremented or decremented significantly off base schedules.[69]

## 1.2.5 Generation outages

This section covers information on generation outages across the WEIM by region.[70]

The CAISO balancing area had 10 percent higher levels of outages in 2024 when compared to 2023. The average level of outages in the other California WEIM balancing areas and in the Desert Southwest region increased by less than 1 percent in 2024. The Intermountain West and Pacific Northwest regions saw more substantive increases in average outages of eight and seven percent, respectively.

Outage volumes in the CAISO, California (non-CAISO), Desert Southwest and Intermountain West regions followed a seasonal pattern of higher outage levels in non-summer months than in summer months. The Pacific Northwest had the most outages in Q2, second most outages in Q4, and the least amount of outages during the region's high load periods in Q1 and Q3.

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69 Ibid, p 20.

70 WEIM regions are as follows: California includes BANC, CISO, LADWP, and TIDC. Desert Southwest includes AZPS, EPE, NEVP, PNM, SRP, TEPC, and WALC. Intermountain West includes AVA, IPCO, NWMT, and PACE. Pacific Northwest includes AVRN, BCHA, BPAT, PACW, PGE, PSEI, SCL, and TPWR.

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.

### California ISO balancing area outages

Figure 1.59 and Figure 1.60 show the quarterly and monthly 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.

In 2024, average total generation outages for peak hours in the California ISO balancing area were about 14,800 MW, up from 13,700 MW in 2023. Outages for planned maintenance averaged about 3,100 MW during peak hours, while all other types of planned outages averaged about 1,200 MW. Some common types of outages in this category are ambient de-rates (both due to temperature and not due to temperature) and transmission-related outages. Forced outages for plant maintenance or trouble averaged about 4,500 MW, while all other types of forced outages averaged about 6,100 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.

**Figure 1.59 CAISO quarterly average of maximum daily generation outages by type – peak hours**

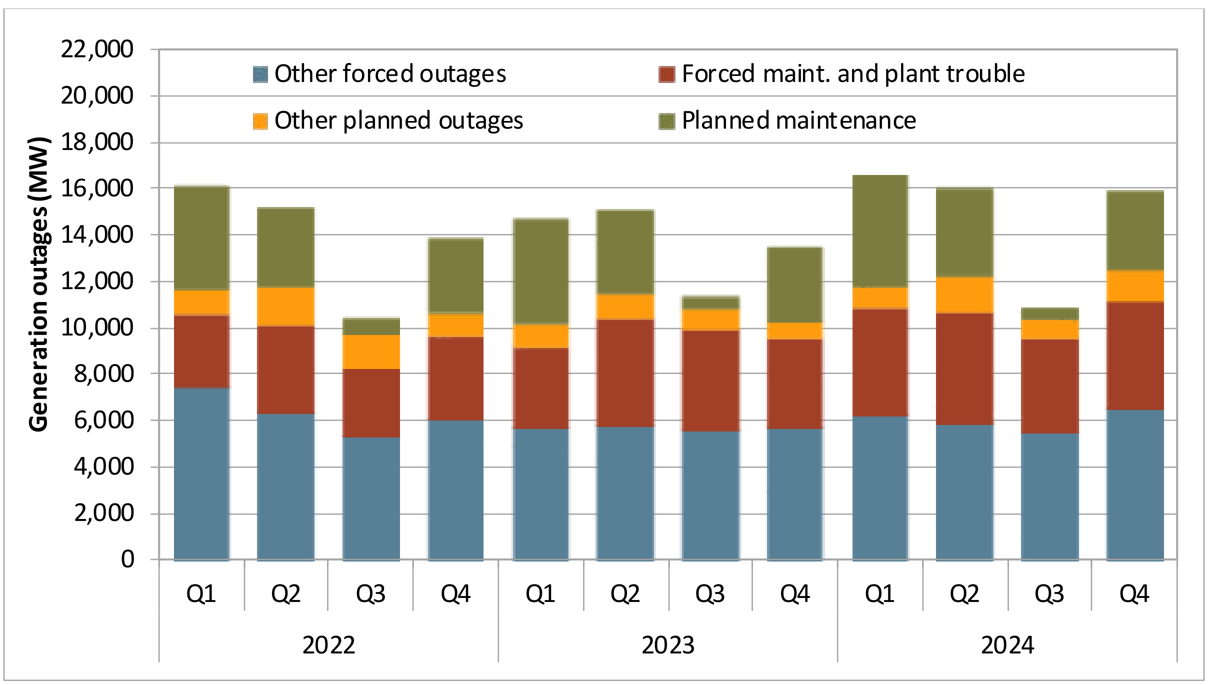
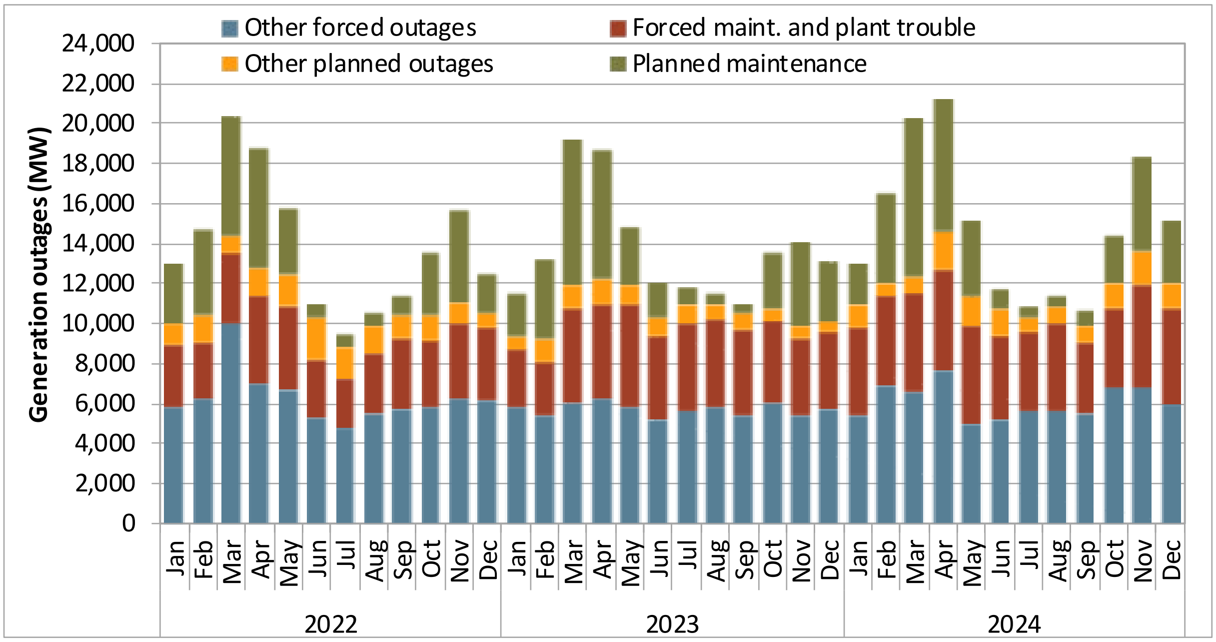


**Figure 1.60 CAISO monthly average of maximum daily generation outages by type – peak hours**

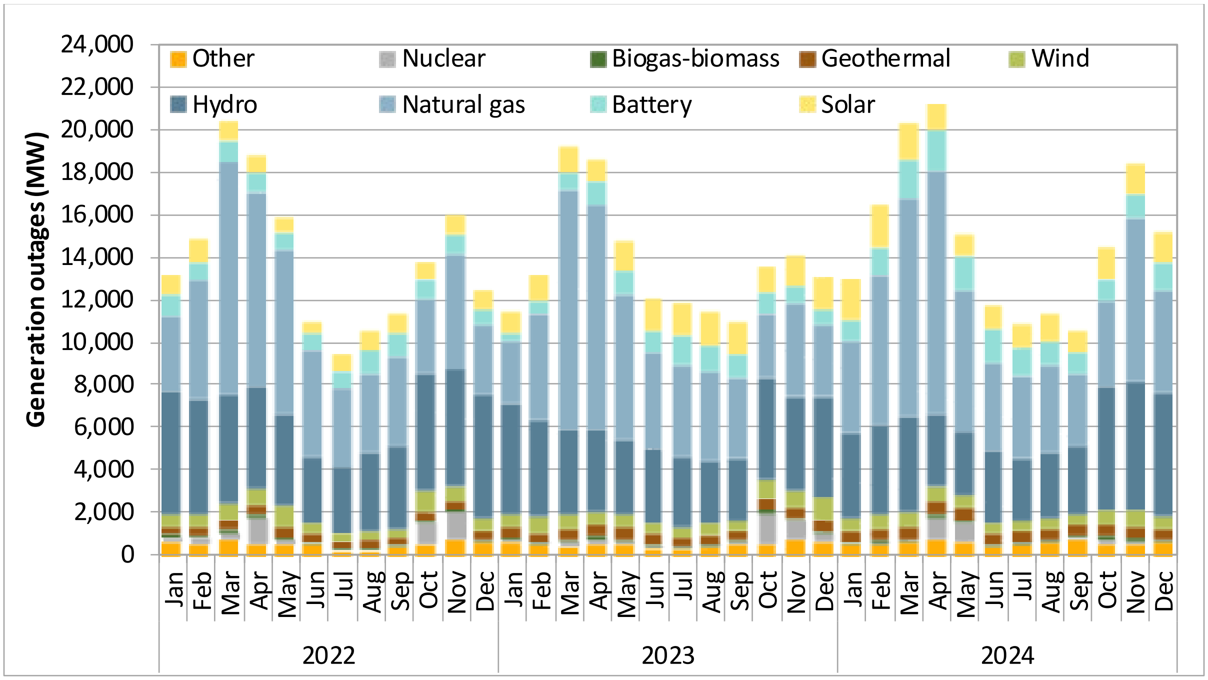



### Generation outages by fuel type

CAISO balancing area natural gas and hydroelectric generation averaged 6,000 MW and 4,100 MW on outage during 2024, respectively. Together, these two fuel types accounted for about 68 percent of the generation on outage for the year.

Figure 1.61 shows the monthly average generation on outage by fuel type during peak hours. Similar to 2023, the spring months experienced the highest monthly average generation on outage. This trend is driven by outages taken by gas resources for maintenance and other reasons in preparation for the high load summer months. It is also worth noting that battery outages increased from an average of approximately 970 MW in 2023 to 1,300 MW in 2024, a 37 percent increase. An increase in storage outages is expected given the rapidly growing size of the battery storage fleet.

**Figure 1.61 CAISO monthly average of maximum daily generation outages by fuel type – peak hours**




### California (non-CAISO) WEIM region

Figure 1.62 and Figure 1.63 show the quarterly averages of maximum daily outages during peak hours by outage type and fuel type, respectively, from the first quarter of 2023 through the fourth quarter of 2024 for entities in the California WEIM region, excluding the CAISO balancing area.[71] The typical seasonal outage pattern is primarily driven by planned outages for maintenance, which are generally performed outside of the high summer load period, and this trend continued in 2024. Average total outages for 2024 increased by less than 50 MW, an increase of less than one percent.

[71] The California region includes BANC, LADWP, and TIDC.

**Figure 1.62 California (non-CAISO) WEIM region quarterly average of maximum daily generation outages by type – peak hours**

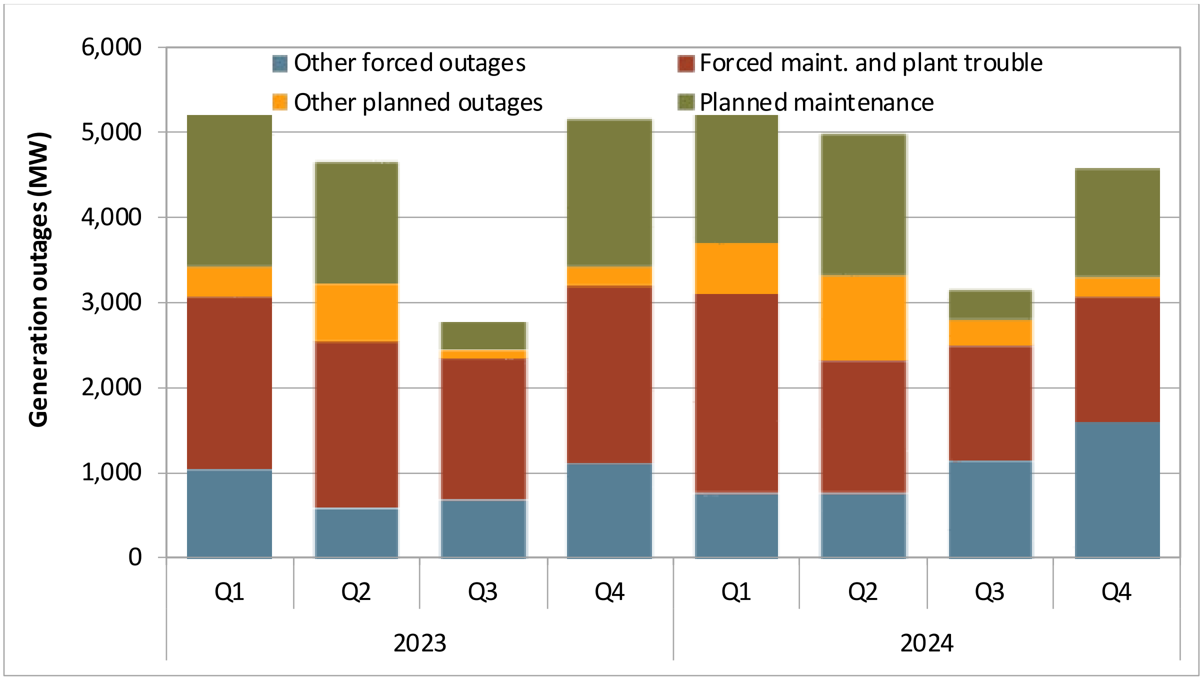
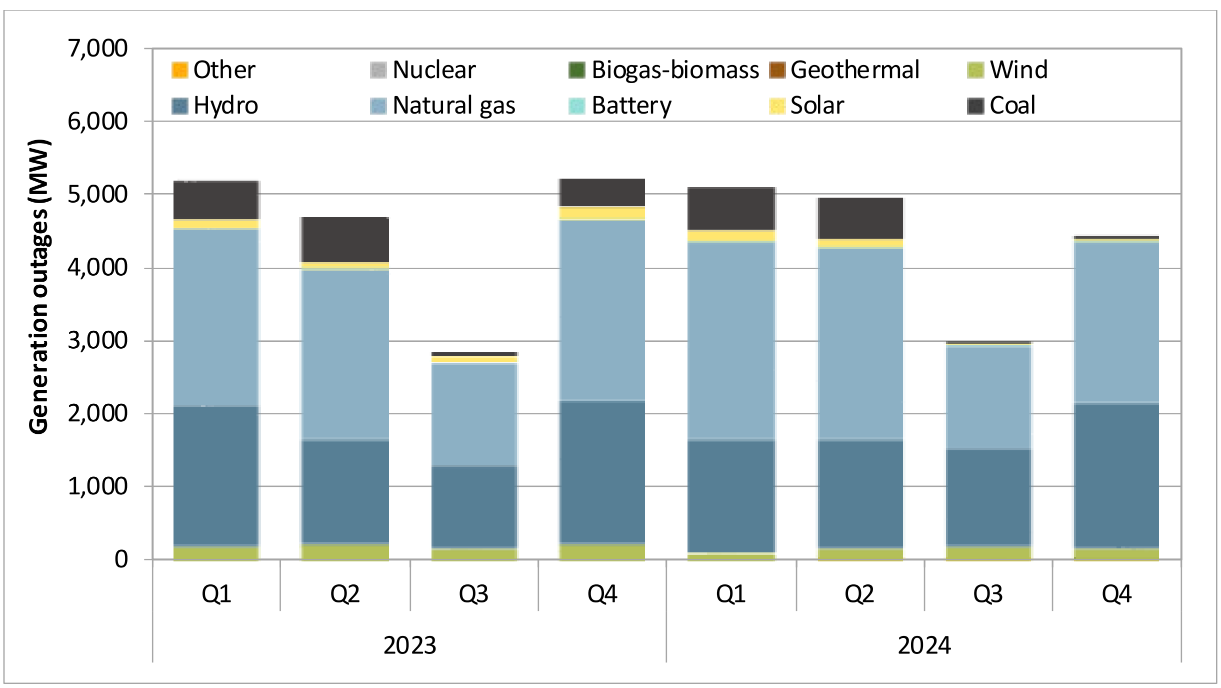


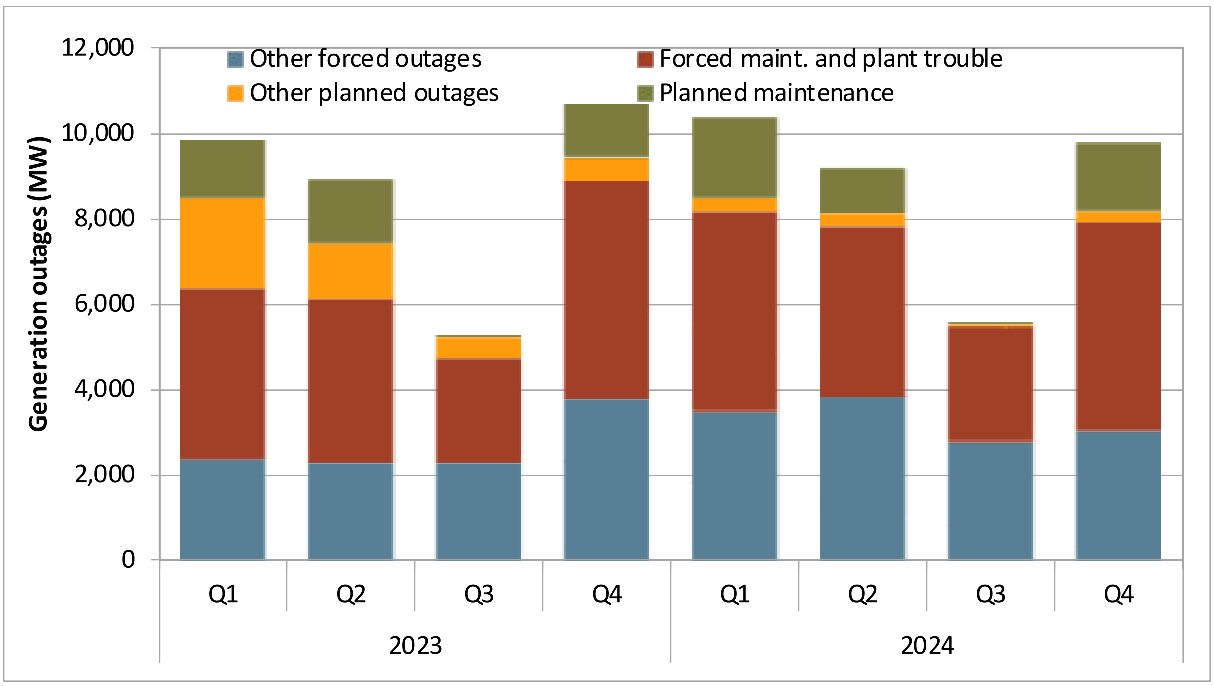

**Figure 1.63 California (non-CAISO) WEIM region quarterly average of maximum daily generation outages by fuel type – peak hours**



### Desert Southwest WEIM region

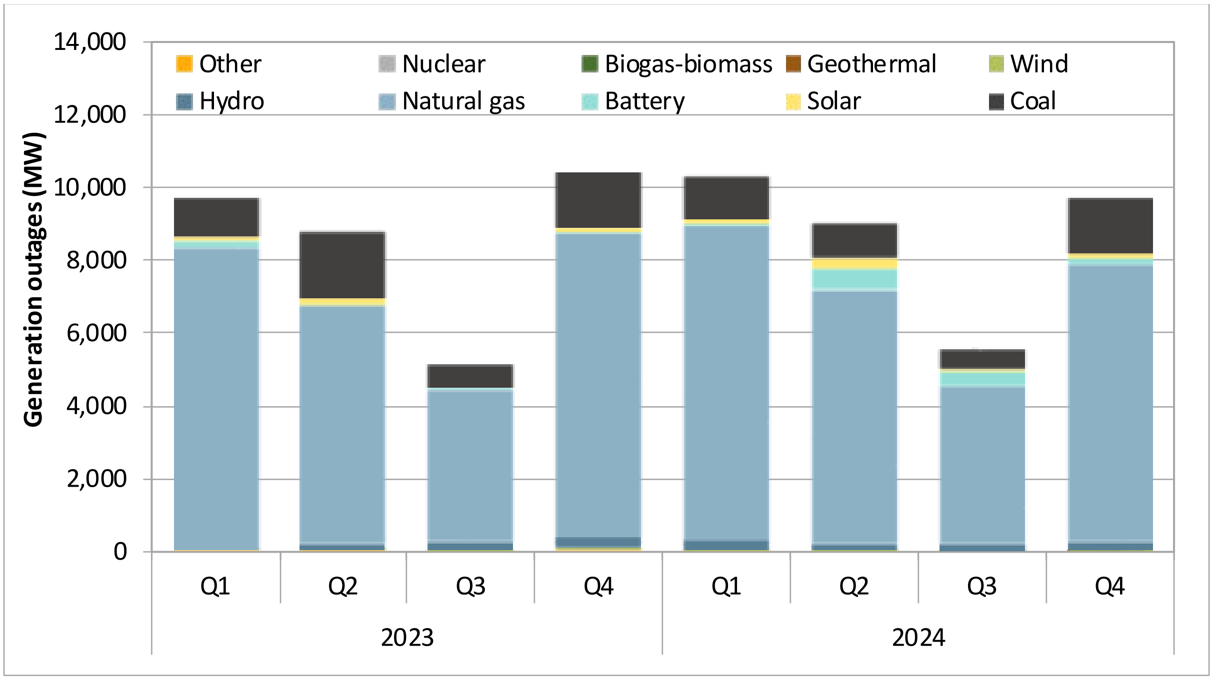
Figure 1.64 and Figure 1.65 show the quarterly averages of maximum daily outages during peak hours by outage type and fuel type, respectively, from the first quarter of 2023 through the fourth quarter of 2024 for entities in the Desert Southwest WEIM region.[72] The typical seasonal outage pattern is primarily driven by planned outages for maintenance, which are generally performed outside of the high summer load period, and this trend continued in 2024. Average total outages for the year increased by less than 50 MW, or less than one percent. While most fuel types saw minimal change in the volume of outages between 2023 and 2024, battery storage resources saw a significant increase from an average of 67 MW to 292 MW of reported outages. The increase in battery outages is likely driven by an increase in the number of participating battery resources in the Desert Southwest WEIM region.

**Figure 1.64 Desert Southwest WEIM region quarterly average of maximum daily generation outages by type – peak hours**




[72] The Desert Southwest region includes AZPS, EPE, NEVP, PNM, SRP, TEPC, and WALC.

**Figure 1.65 Desert Southwest WEIM region quarterly average of maximum daily generation outages by fuel type – peak hours**




### Intermountain West WEIM region

Figure 1.66 and Figure 1.67 show the quarterly averages of maximum daily outages during peak hours by outage type and fuel type, respectively, from the first quarter of 2023 through the fourth quarter of 2024 for entities in the Intermountain West WEIM region.[73] The typical seasonal outage pattern is primarily driven by planned outages for maintenance, which are generally performed outside of the high summer load period, and this trend continued in 2024. Average total outages in 2024 increased by approximately 175 MW or 8 percent. The increase in outages between 2023 and 2024 was primarily due to a 25 percent increase in the average amount of natural gas outages from 830 MW in 2023 to 1,040 MW in 2024.

[73] The Intermountain West region includes AVA, IPCO, NWMT, and PACE.

**Figure 1.66 Intermountain West WEIM region quarterly average of maximum daily generation outages by type – peak hours**

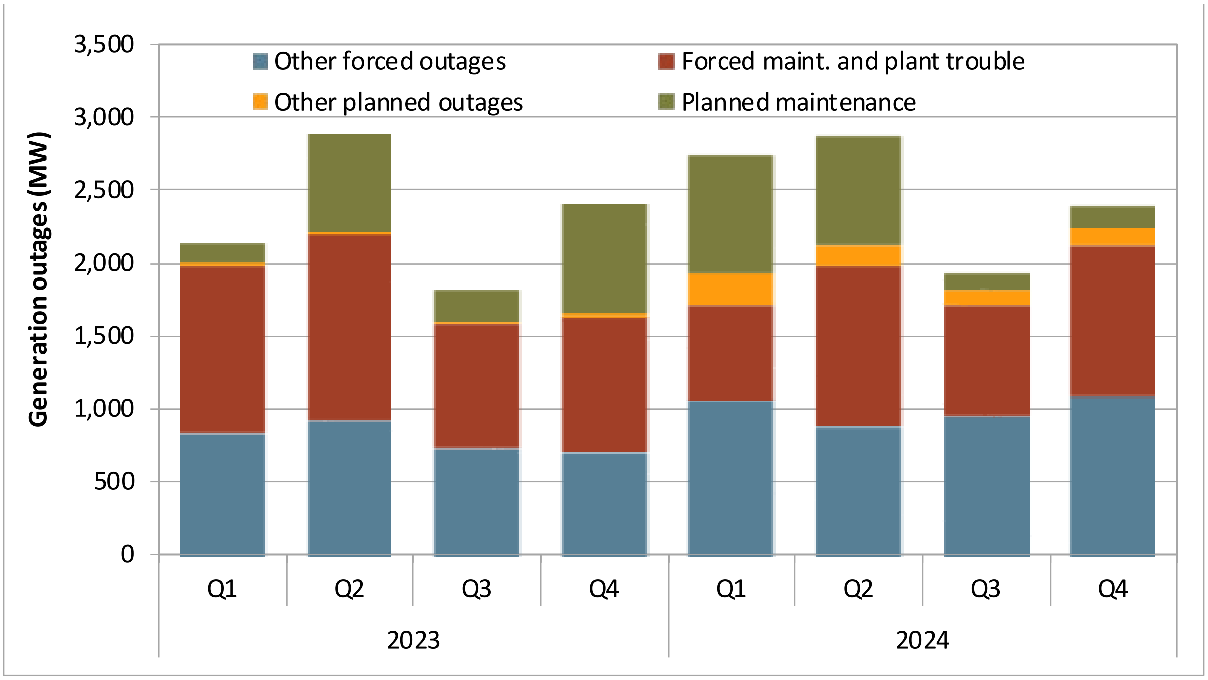
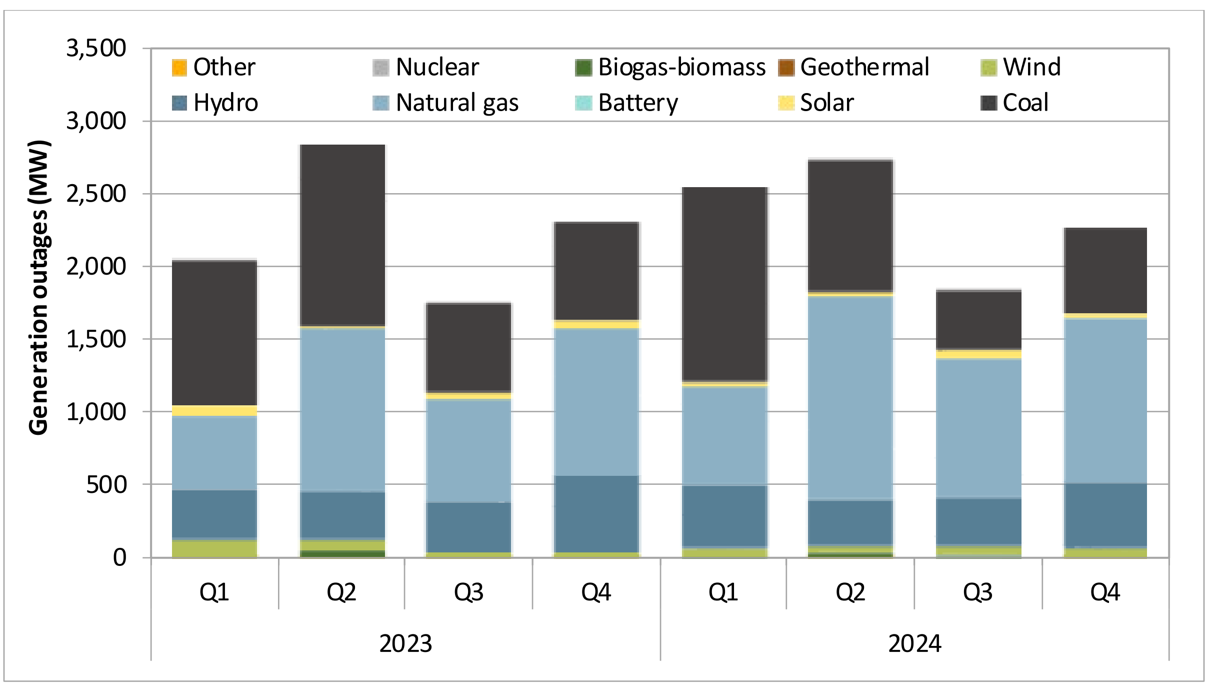


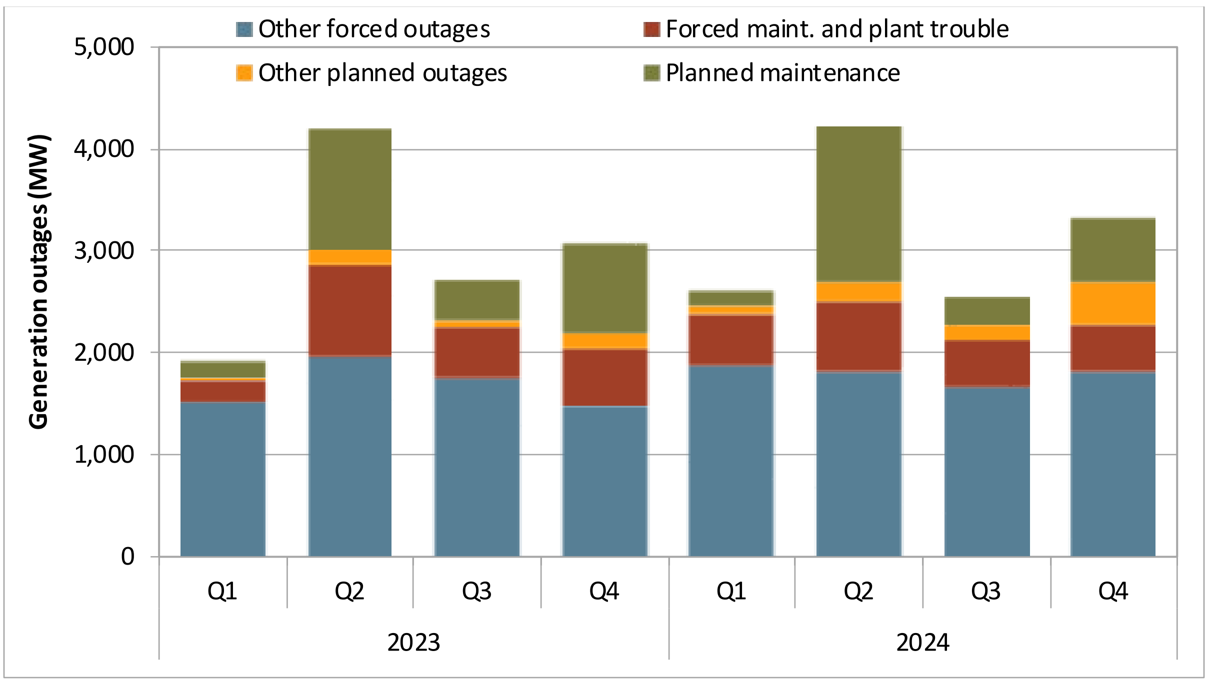

**Figure 1.67 Intermountain West WEIM region quarterly average of maximum daily generation outages by fuel type – peak hours**



### Pacific Northwest WEIM region

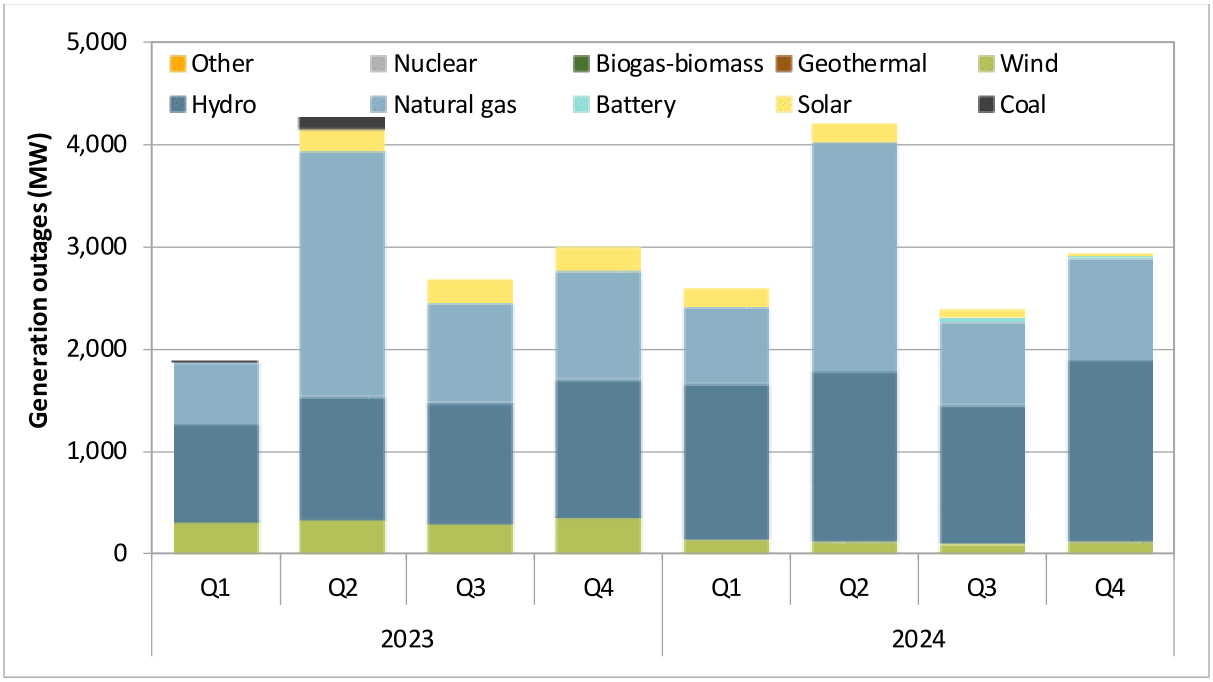
Figure 1.68 and Figure 1.69 show the quarterly averages of maximum daily outages during peak hours by outage type and fuel type, respectively, from the first quarter of 2023 through the fourth quarter of 2024 for entities in the Pacific Northwest WEIM region.[74] The typical seasonal outage pattern for the Pacific Northwest region diverges from the others, with outages typically peaking in the second quarter while outages in all other quarters remain low. The trend is still primarily driven by planned outages for maintenance, which are generally performed outside of the higher load periods. Average total outages in 2024 were approximately 3,200 MW, a 7 percent increase from 2023.

**Figure 1.68 Pacific Northwest WEIM region quarterly average of maximum daily generation outages by type – peak hours**




[74] The Pacific Northwest region includes AVRN, BCHA, BPAT, PACW, PGE, PSEI, SCL, and TPWR.

**Figure 1.69 Pacific Northwest WEIM region quarterly 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 ISO's markets and other regional markets. Average natural gas prices at major Western hubs were down 50 percent or more in 2024 compared to 2023. This was the major driver of significantly lower electricity prices across the WEIM.

Figure 1.70 shows monthly average natural gas prices at PG&E Citygate, SoCal Citygate, Northwest Sumas, Opal, 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.

As shown in Figure 1.70, gas prices at western gas hubs were lower in 2024 compared to 2023. There was a spike in natural gas prices in January 2024 due to extreme cold weather in the Pacific Northwest over the Martin Luther King Jr. Day weekend. However, even these high average January 2024 gas prices were lower than average monthly prices during many months of 2023. The El Paso trading hub was consistently the lowest priced trading hub and experienced three months with negative average monthly prices[75] due to a combination of factors, including record-high Permian gas production and pipeline maintenance that limited flow capacity.

[75] *Negative Permian gas prices set record stretch as Matterhorn startup looms*, S&P Global, August 21, 2024: https://www.spglobal.com/commodity-insights/en/news-research/latest-news/natural-gas/082124-negative-permian-gas-prices-set-record-stretch-as-matterhorn-startup-looms#:~:text=21%20Aug%202024%20%7C%2021:31,for%20much%20of%20this%20summer

**Figure 1.70 Monthly average natural gas prices (2022–2024)**

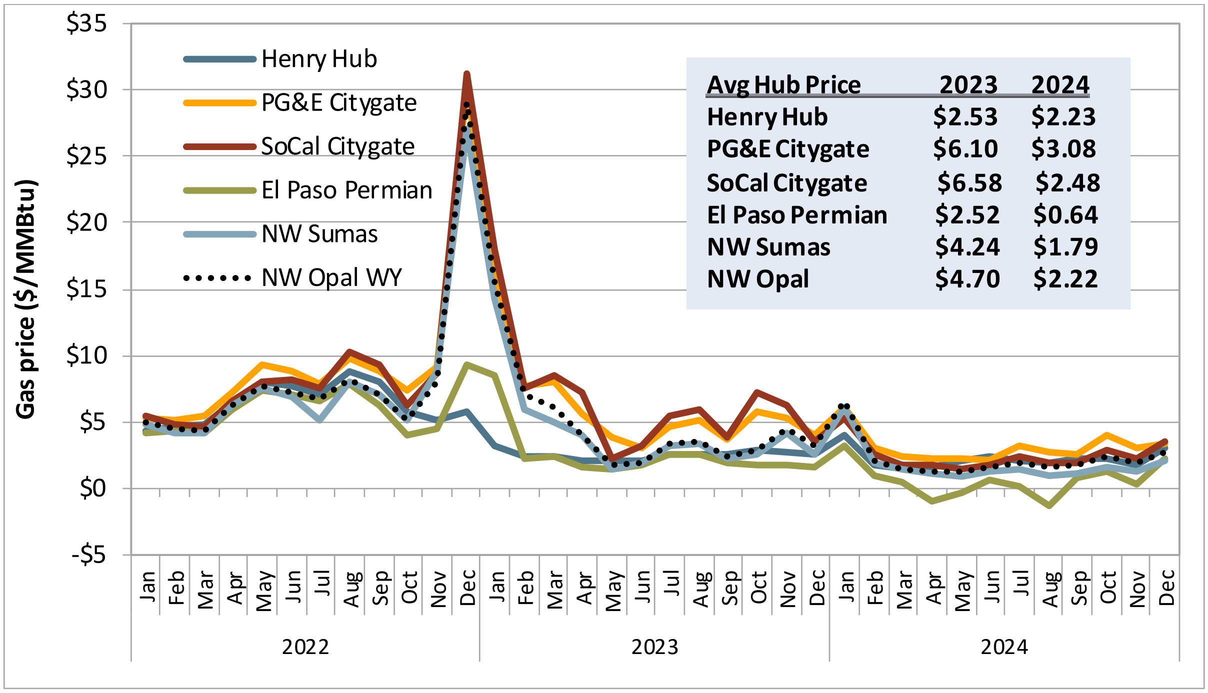
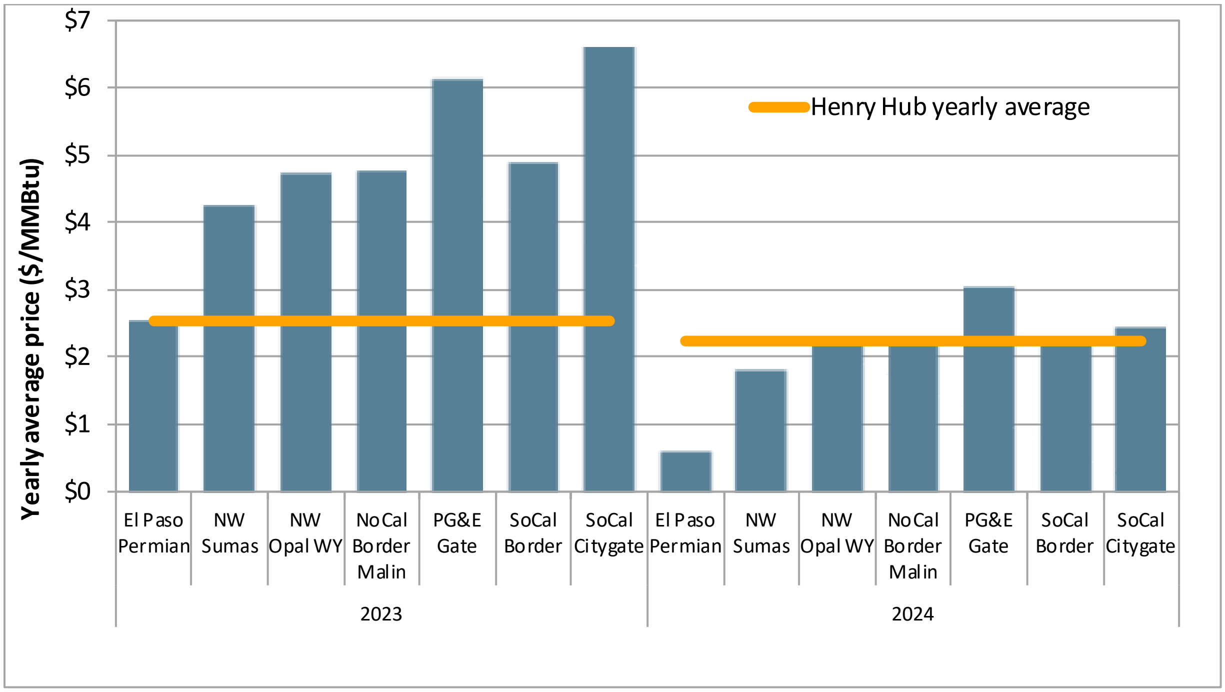



Figure 1.71 compares yearly average natural gas prices at six major western trading points to the Henry Hub average for 2023 and 2024. In 2024, prices at Henry Hub decreased by 12 percent compared to 2023. The decrease in natural gas prices at major Western trading hubs was much more significant. El Paso Permian prices were down 75 percent, while prices at NW Sumas, NW Opal WY, NorCal Border, and SoCal Border declined between 50 percent and 63 percent. These decreases in natural gas prices resulted in lower system marginal energy prices across the WEIM footprint in 2024.

**Figure 1.71 Yearly average natural gas prices compared to Henry Hub**




## 1.2.7 Greenhouse gas prices

This section provides background on California and Washington's greenhouse gas (GHG) allowance markets under the states' cap-and-trade and cap-and-invest programs, which were applied to the wholesale electric market in 2013 and 2023, respectively.[76] 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 California and Washington. This section also addresses greenhouse gas compliance costs that are attributed to resources that participate in the WEIM and serve load of WEIM balancing areas in California. 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 later in this section. It is important to note that the GHG attribution process as it is currently implemented only considers GHG costs for California and does not apply to Washington's GHG compliance.

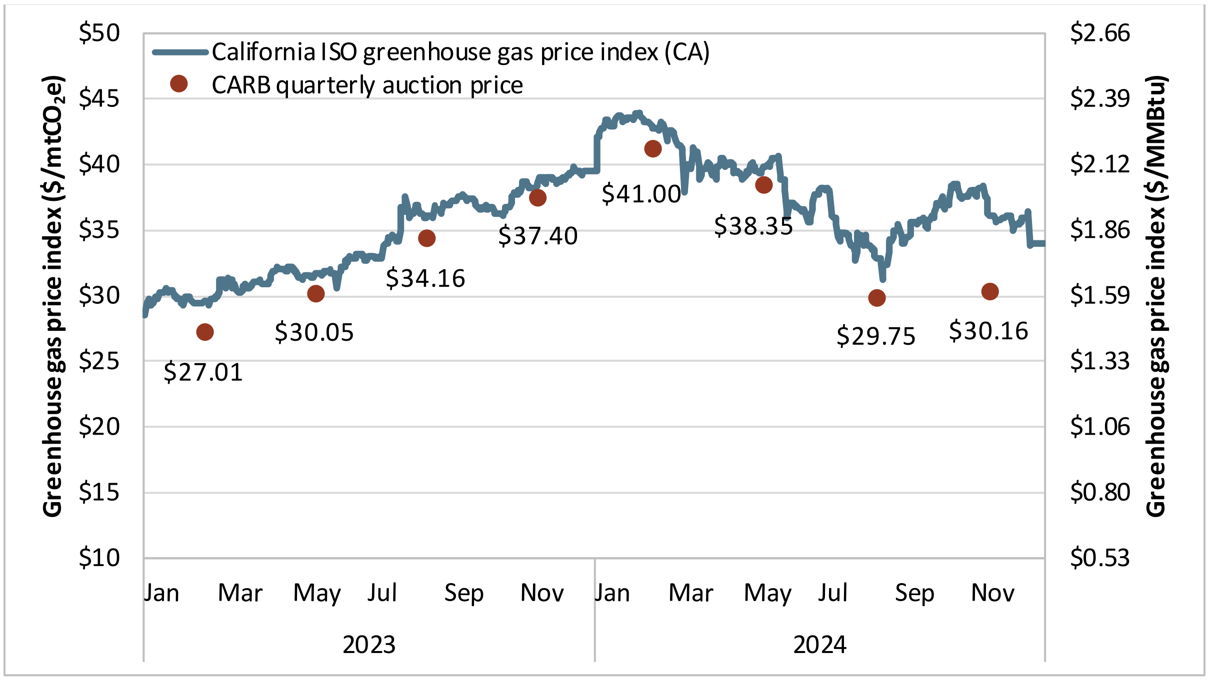
### Greenhouse gas allowance prices in California

When calculating various cost-based bids used in the market software for supply resources in California, a calculated greenhouse gas allowance index price is used as a daily measure for greenhouse gas

[76] A more detailed description of the cap-and-trade program and its impact on wholesale electricity prices was provided in DMM's 2015 annual report. *2015 Annual Report on Market Issues & Performance*, Department of Market Monitoring, May 2016, pp 45-48: http://www.caiso.com/Documents/2015AnnualReportonMarketIssuesandPerformance.pdf

allowance costs. The index price is calculated as the average of two market-based indices.[77] Daily values of this greenhouse gas allowance index are plotted in Figure 1.72. Also indicated in Figure 1.72 are market clearing prices in the California Air Resources Board's (CARB) quarterly auctions of emission allowances that can be used for the 2023 or 2024 compliance years. The values displayed on the right axis convert the greenhouse gas allowance price into an incremental gas price adder in 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.[78]

**Figure 1.72 California ISO greenhouse gas allowance price index for California and CARB auction prices**




As shown in Figure 1.72, the average cost of greenhouse gas allowances in bilateral markets increased 12 percent from a load-weighted average of \$34.06/mt$CO_2$e in 2023 to \$38.09/mt$CO_2$e in 2024. In 2024, the California Air Resources Board's quarterly allowance cleared at an average auction settlement price of \$34.81/mt$CO_2$e, compared to \$32.16/mt$CO_2$e last year, an eight percent increase.

77 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 tariff section 39.7.1.1.1.4: http://www.caiso.com/rules/Pages/Regulatory/Default.aspx

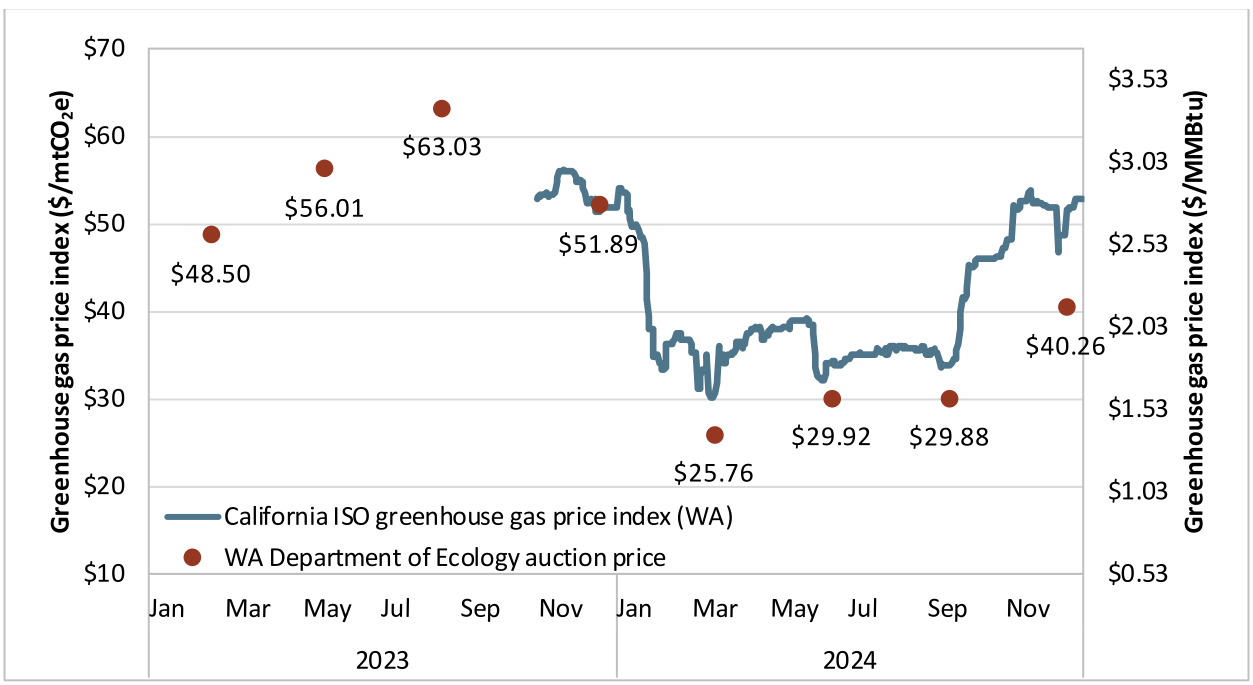
78 The emissions factor, 0.0531148 mt$CO_2$e/MMBtu, is the sum of the product of the global warming potential and emission factor for $CO_2$, $CH_4$, and $N_2O$ for natural gas. Values are reported in tables A-1, C-1, and C-2 of Code of Federal Regulations, *Title 40 – Protection of Environment, Chapter 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

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.[79] The greenhouse gas compliance cost expressed in dollars per MMBtu in 2024 ranged from about \$1.66/MMBtu to \$2.30/MMBtu. The \$38.09/mt$CO_2$e average compliance cost index in 2024 represents an additional cost of about \$16.19/MWh for a relatively efficient gas unit.[80] This is an increase from 2023 when the average price was \$34.06/mt$CO_2$e, or about \$14.47/MWh for the same relatively efficient gas resource.

### Greenhouse gas allowance prices in Washington

For supply resources in Washington, cost-based reference level compliance costs are incorporated using a similar method. However, because the Washington cap-and-invest program was new in 2023, the ISO used two bridging steps before the two indexes required for the California ISO's index were available. Prior to Washington's initial allowance auction, the California ISO would use \$41/mt$CO_2$e as the price. Following the initial allowance auction, the ISO would transition using the most recent settlement prices from the Washington Department of Ecology's allowance auction. In November of 2023, the ISO transitioned to using the calculated index. The daily index values for Washington and its allowance auction prices are shown in Figure 1.73. The values displayed on the right axis convert the greenhouse gas allowance price into an incremental gas price adder in dollars per MMBtu following the same method used in Figure 1.72.

**Figure 1.73 California ISO greenhouse gas price index for Washington and Washington Department of Ecology auction prices[81]**




[79] *2013 Annual Report on Market Issues & Performance*, Department of Market Monitoring, April 2014, pp 123-136: http://www.caiso.com/Documents/2013AnnualReport-MarketIssue-Performance.pdf

[80] 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 mt$CO_2$e/MMBtu, derived in footnote 97.

[81] The California ISO began calculating the index used for Washington greenhouse gas allowance costs in November 2023.

In 2024, the average cost of greenhouse gas allowances in bilateral markets for Washington was $40.18/ $mtCO_2e$. The Washington Department of Ecology quarterly allowance auction cleared at an average of $31.46/$mtCO_2e$ in 2024 compared to an average price of $54.86/$mtCO_2e$ in 2023, a 42 percent decrease in price. The greenhouse gas compliance cost expressed in dollars per MMBtu in 2024 ranged from about $1.60/MMBtu to $2.87/MMBtu. The $40.18/$mtCO_2e$ compliance cost index average in 2024 represents an additional cost of about $17.07/MWh for a relatively efficient gas resource. The drop in the California ISO index price for Washington and the Washington Department of Ecology auction prices correspond to the introduction of a ballot measure which would have repealed the law that established the cap-and-invest program. The ballot measure failed and the cap-and-invest program remains in effect.

### 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.[82] 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 into 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.[83]

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

82 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 the ARB's website here: https://ww2.arb.ca.gov/mrr-data

83 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

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 into California.

### Greenhouse gas prices

Figure 1.74 shows monthly average cleared WEIM greenhouse gas prices and hourly average quantities for energy delivered to California from 2022 to 2024. As the market is currently configured, California is the only GHG-regulation area where the marginal cost of greenhouse gas applies. Average 15-minute market greenhouse gas 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 15-minute and 5-minute delivered quantities are represented by the blue and green bars in the chart, respectively.

In 2024, weighted 15-minute greenhouse gas prices averaged $13.61/MWh, while 5-minute prices averaged $8.18/MWh. Prices were higher than 2023, when they averaged $10.99/MWh and $6.95/MWh in the 15-minute and 5-minute market, respectively. Weighted average greenhouse gas prices in the 5-minute market averaged 40 percent lower than 15-minute prices throughout 2024. In comparison, average 5-minute market greenhouse gas prices were 37 percent lower than 15-minute prices in 2023. Price differences between markets may occur if resources are procured in the 15-minute market and are then subsequently decrementally dispatched in the 5-minute market. This price separation is often correlated with operator imbalance conformance adjustments—described in Section 9 of this report—which are consistently higher in the CAISO balancing area in the 15-minute market than the 5-minute market during peak net load hours.

**Figure 1.74 WEIM greenhouse gas price and cleared quantity**

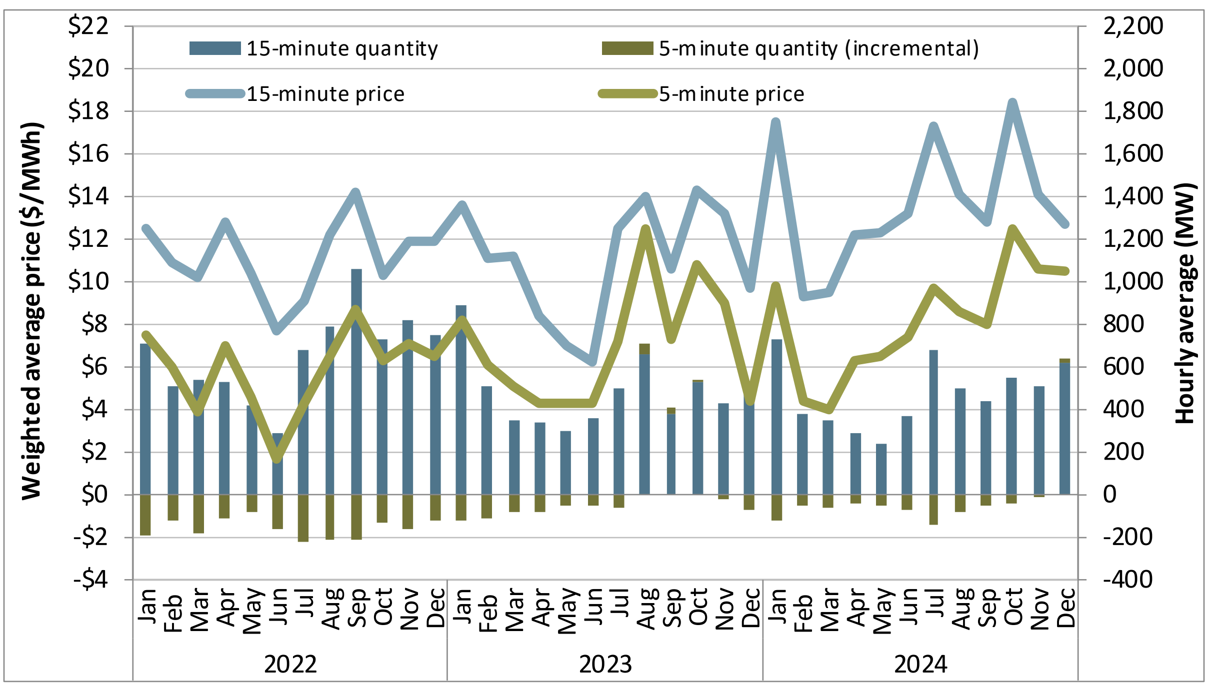


Figure 1.75 and Figure 1.76 illustrate the frequency of prices greater than $16/MWh for each market during each quarter of the last three years, as well as the maximum price by quarter. Figure 1.75 shows that the first through third quarters in 2024 had a greater percentage of intervals in the fifteen-minute market with prices above $16/MWh compared to 2022 and 2023, while the fourth quarter of 2024 was comparable but slightly lower than the same quarter in 2023. The fourth quarter of 2024 had the largest percent of intervals with greenhouse gas prices over $16/MWh, while the second quarter had the smallest, 16 and 7 percent, respectively. In 2024, the percentage of intervals with prices above $16/MWh was significantly lower in the 5-minute market than in the 15-minute market. The five-minute market in 2024 also had fewer intervals with GHG prices above $16/MWh than in 2023.

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. The highest 15-minute and 5-minute prices in 2024 were $175/MWh and $119/MWh, respectively.

**Figure 1.75 High 15-minute WEIM greenhouse gas prices**

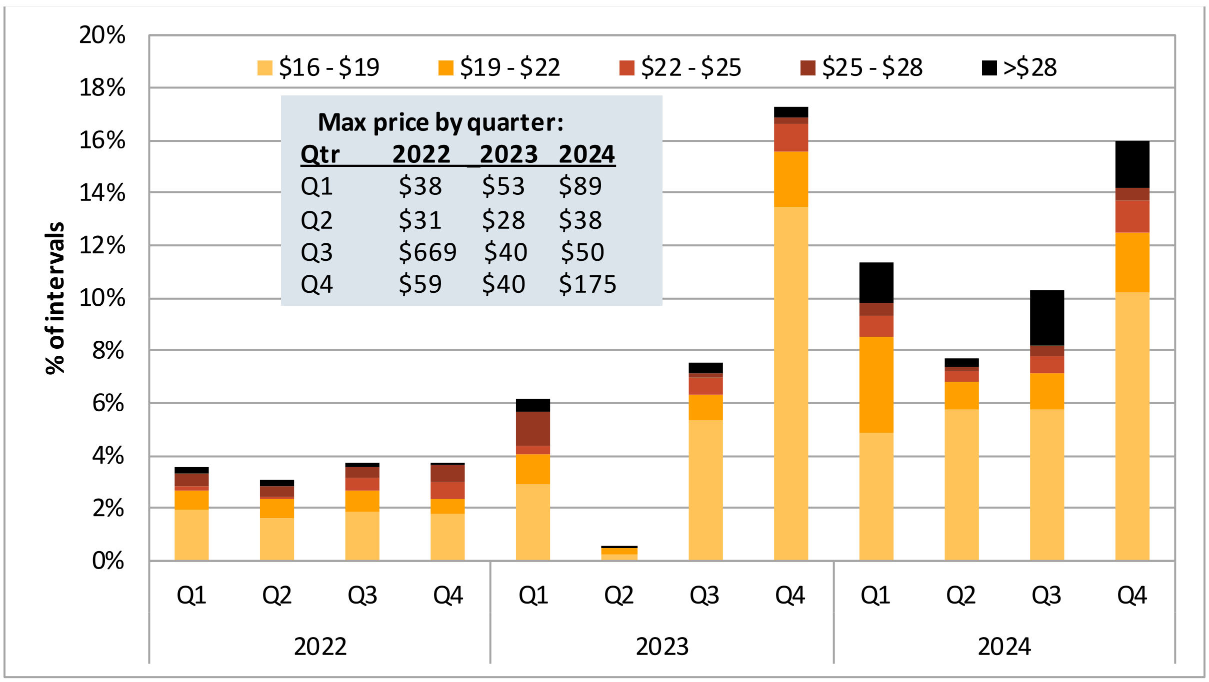
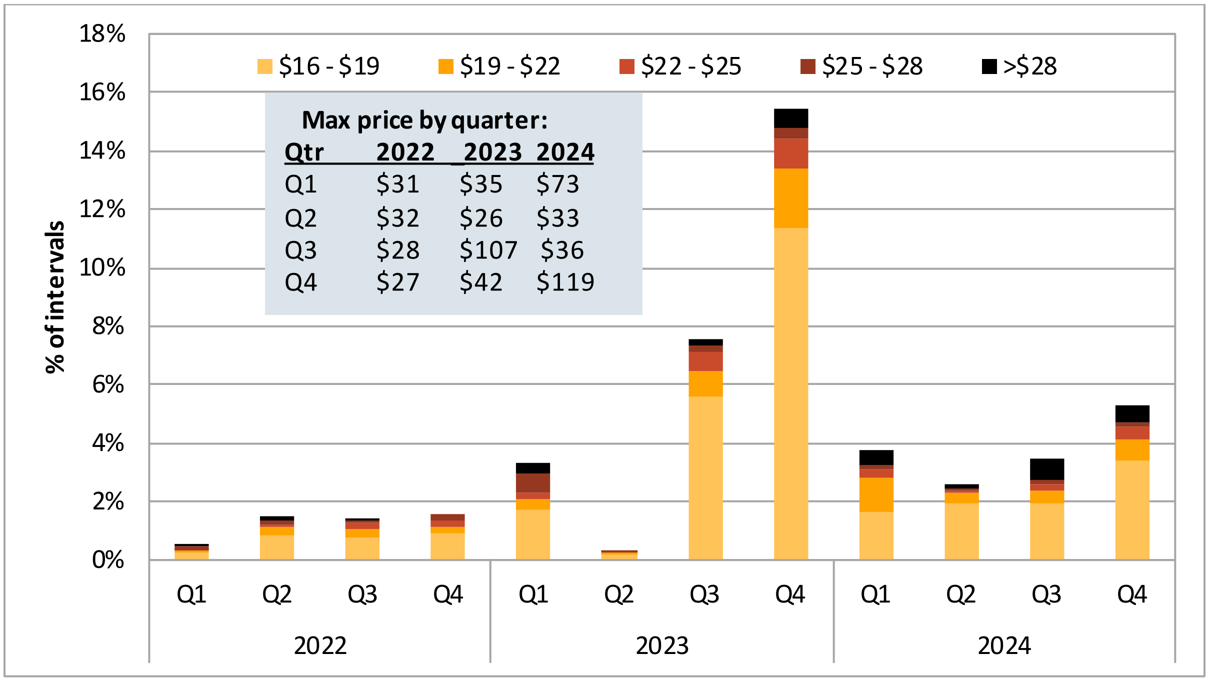


**Figure 1.76 High 5-minute WEIM greenhouse gas prices**




### Energy delivered to California by fuel type and balancing area

Figure 1.77 shows hourly average greenhouse gas energy by fuel type. In 2024, about 57 percent of WEIM greenhouse gas compliance obligations were assigned to hydro resources, lower than the approximately 64 percent in 2023. The next two fuel types most frequently assigned compliance obligations were natural gas with 31 percent and wind with 10 percent. The percentage of assigned compliance obligations for wind was consistent with the attributions from 2023, when Avangrid joined the WEIM.

**Figure 1.77 Percentage of greenhouse gas energy delivered to California by fuel type**

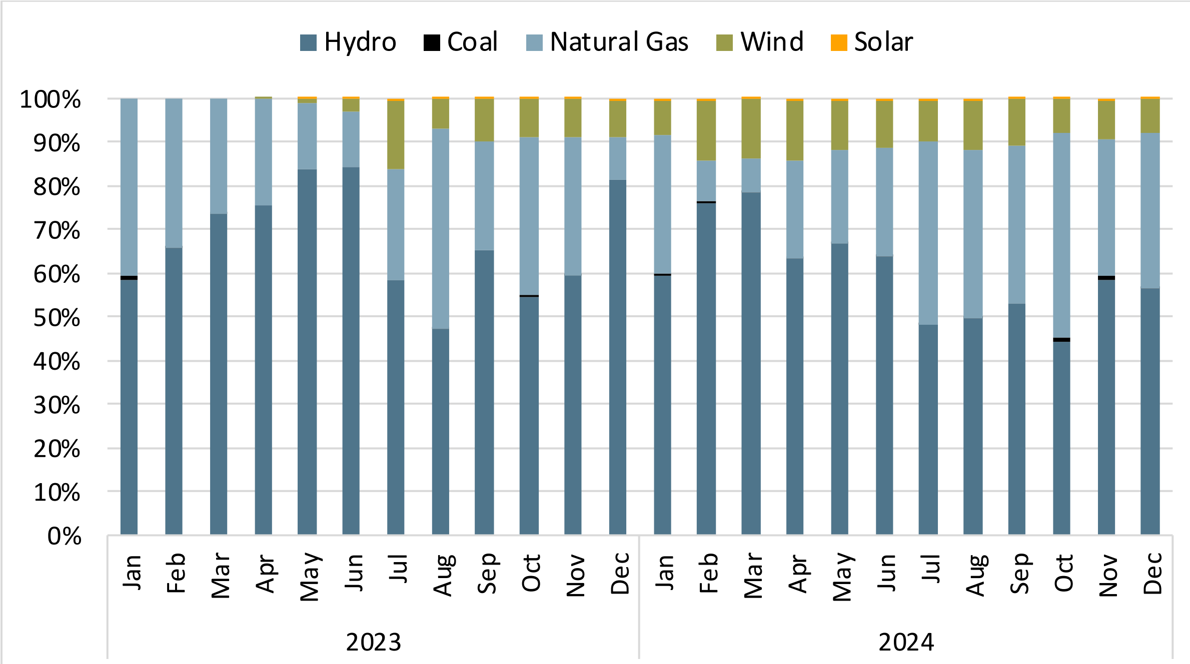
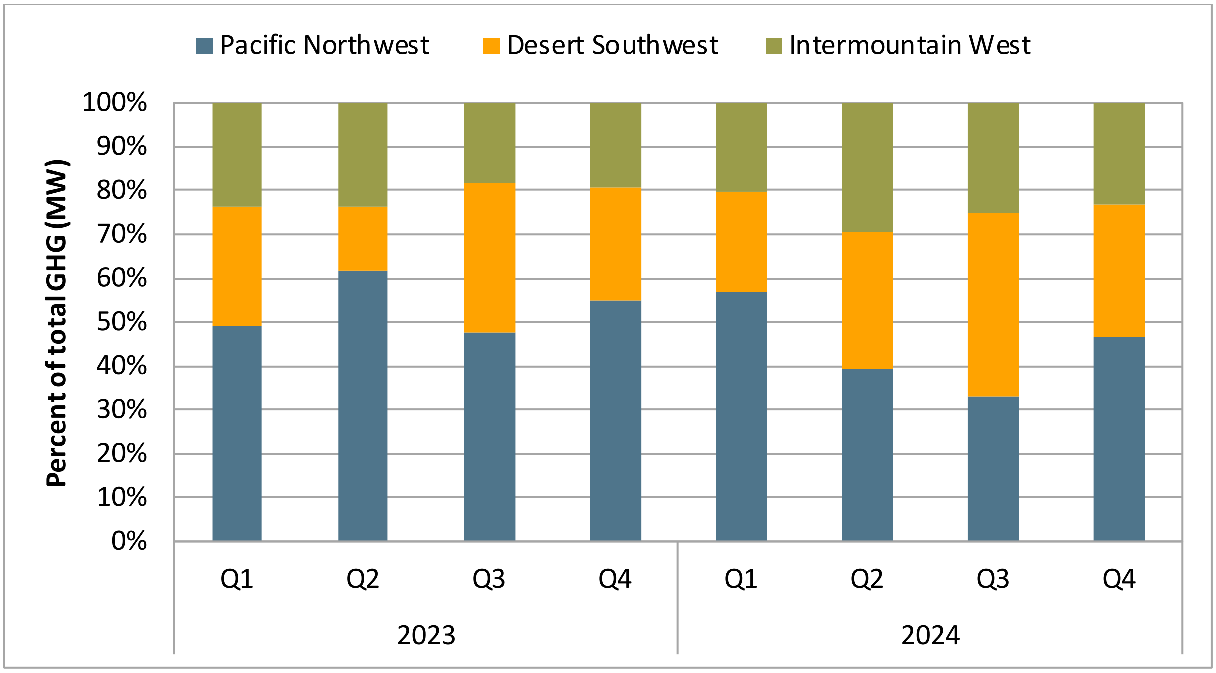



Figure 1.78 shows the percentage of total greenhouse gas energy cleared by region. In 2024, the percent of greenhouse gas attributed from entities in the Pacific Northwest and Intermountain West with large fleets of hydroelectric resources, decreased from 64 percent in 2023 to 57 percent. The increase in the percentage of greenhouse gas resource assignments to the Desert Southwest is driven by the increased share of natural gas resources. Table 1.2 provides details on the percentage of total greenhouse gas energy cleared by WEIM balancing area. In 2024, Idaho Power, Arizona Public Service, and Portland General Electric were the three balancing area authorities with the most GHG attribution and accounted for approximately 45 percent of the total greenhouse gas energy deemed delivered.

**Figure 1.78 Percentage of greenhouse gas energy delivered to California by region[84]**




[84] The Desert Southwest region includes Arizona Public Service, NV Energy, PNM, Salt River Project, El Paso Electric, Tucson Electric Power, and WAPA (DSW). Intermountain West includes Idaho Power, NorthWestern Energy, PacifiCorp East, and Avista. Pacific Northwest includes Avangrid, BPA, PacifiCorp West, Portland General Electric, Powerex, Puget Sound Energy, Seattle City Light, and Tacoma Power. These regions reflect a combination of general geographic location as well as common price-separated groupings that can exist when a balancing area is collectively import or export constrained along with one or more other balancing areas.

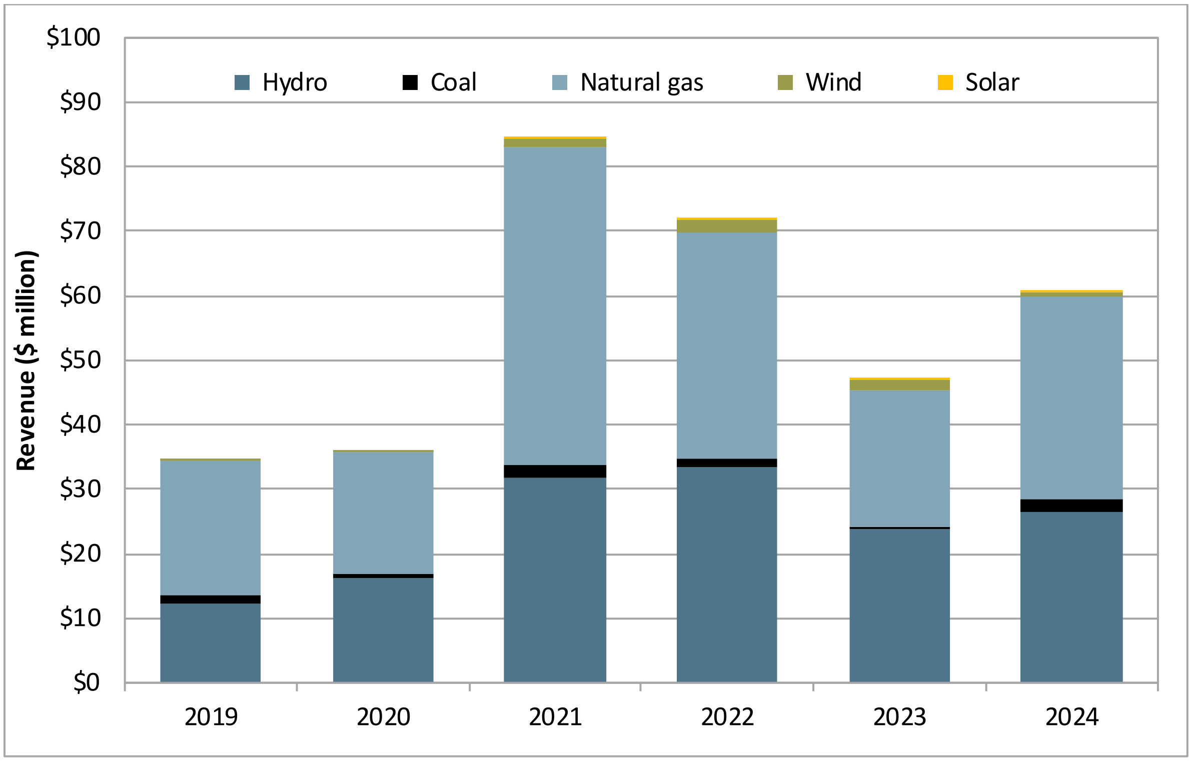
### Table 1.2 Percentage of greenhouse gas energy delivered to California by area

| | 2023 | | | | 2024 | | | |
|---|---|---|---|---|---|---|---|---|
| | Q1 | Q2 | Q3 | Q4 | Q1 | Q2 | Q3 | Q4 |
| ***Pacific Northwest*** | | | | | | | | |
| Avangrid | 0% | 1% | 8% | 3% | 3% | 2% | 1% | 1% |
| Bonneville Power Administration | 3% | 8% | 1% | 1% | 6% | 10% | 4% | 8% |
| PacifiCorp West | 16% | 16% | 1% | 1% | 1% | 1% | 4% | 5% |
| Portland General Electric | 9% | 9% | 8% | 10% | 10% | 10% | 12% | 10% |
| Puget Sound Energy | 7% | 16% | 21% | 26% | 23% | 0% | 0% | 7% |
| Seattle City Light | 9% | 6% | 5% | 7% | 6% | 7% | 5% | 7% |
| Tacoma Power | 6% | 6% | 4% | 7% | 7% | 9% | 6% | 8% |
| ***Desert Southwest*** | | | | | | | | |
| Arizona Public Service | 8% | 2% | 11% | 8% | 6% | 11% | 20% | 10% |
| NV Energy | 9% | 2% | 6% | 6% | 4% | 2% | 5% | 5% |
| Public Service New Mexico | 1% | 1% | 4% | 3% | 3% | 6% | 5% | 5% |
| Salt River Project | 8% | 9% | 12% | 7% | 7% | 11% | 9% | 7% |
| Tucson Electric Power | 2% | 0% | 1% | 2% | 2% | 1% | 3% | 3% |
| WAPA Desert Southwest | 0% | 0% | 0% | 0% | 1% | 0% | 0% | 0% |
| ***Intermountain West*** | | | | | | | | |
| Avista | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Idaho Power | 18% | 22% | 18% | 17% | 19% | 29% | 24% | 21% |
| PacifiCorp East | 6% | 2% | 1% | 2% | 1% | 0% | 1% | 3% |

### WEIM greenhouse gas revenues

Figure 1.79 shows revenues accruing to WEIM resources for energy delivered to California by fuel type. In 2024, revenues totaled roughly $60.6 million, a 29 percent increase from 2023 when revenues were $47.1 million. In 2024, natural gas revenues comprised 51 percent of revenues, while hydroelectric revenues comprised 44 percent. Coal and wind revenues comprised 3 and 1 percent, respectively. 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 1.79 Annual greenhouse gas revenues**




## 1.2.8 Capacity changes

Figure 1.80 through Figure 1.83 show the total nameplate capacity by fuel type for each WEIM region from June 2020 through June 2025. These amounts include capacity from WEIM participating resources as well as non-participating resources, which are neither bid nor optimized in the market.[85] Since 2020, roughly 130 GW of capacity has been added to the WEIM, 35 percent of which was hydroelectric and about 17 percent solar.

Since June 2024, battery capacity has increased significantly in all regions in the WEIM. Nameplate battery capacity increased 4.4 GW (43 percent) and 2 GW (57 percent) in the California and Desert Southwest regions, respectively. In the Intermountain West, battery capacity doubled to 457 MW, while the first 492 MW of batteries interconnected in the Pacific Northwest during 2024. Capacity from solar resources has also increased in every region as well.

85 Previous versions of this report only included participating capacity.

**Figure 1.80 California – Total capacity by fuel type and year (as of June 1, 2025)[86]**

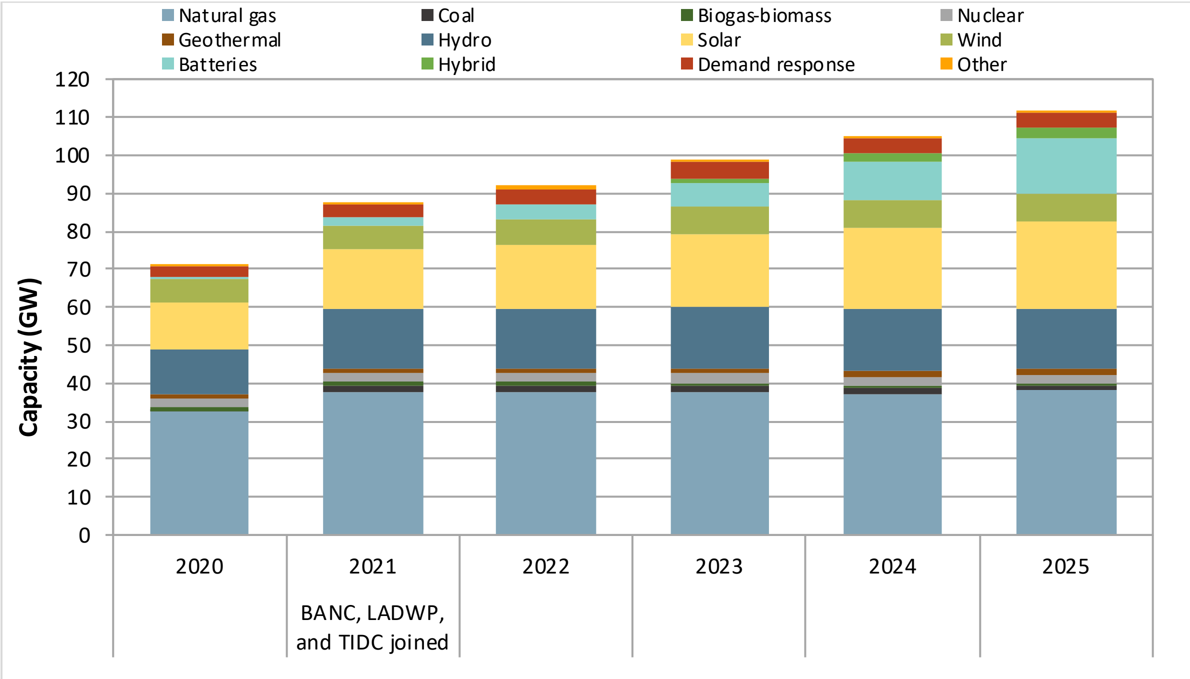
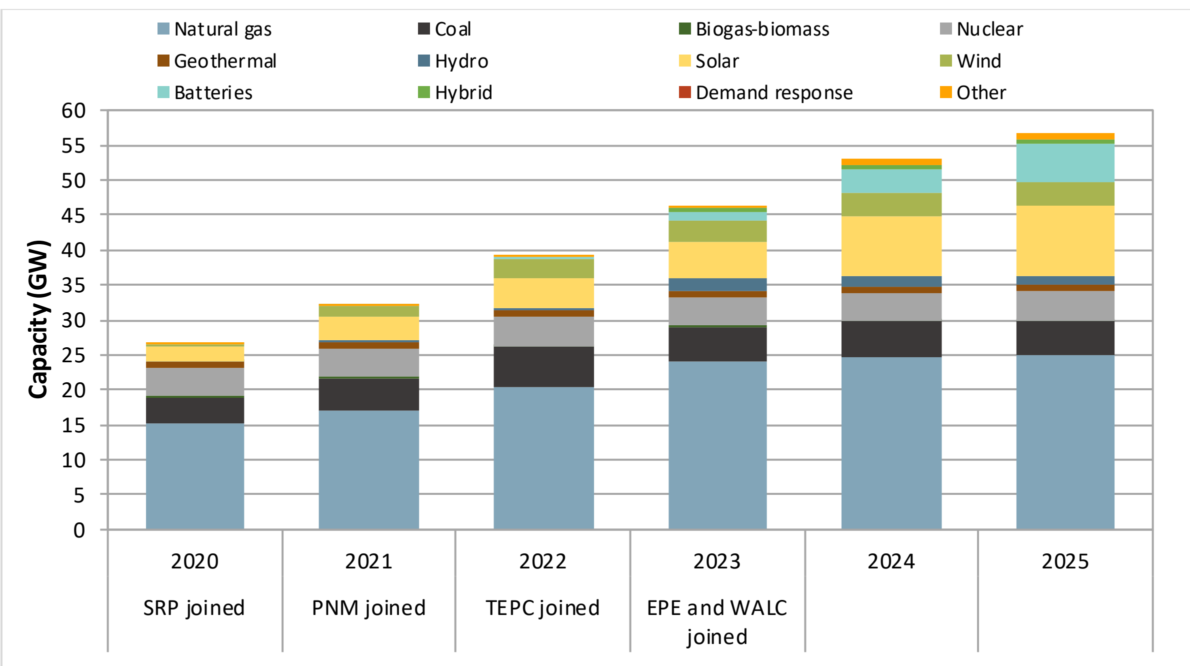



**Figure 1.81 Desert Southwest – Total capacity by fuel type and year (as of June 1, 2025)**




86 BANC joined in two phases. The first was in April 2019 with SMUD, and the second phase was in 2021 with Modesto Irrigation District, the City of Redding, the City of Roseville, and the WAPA Sierra Nevada Region.

**Figure 1.82 Intermountain West – Total capacity by fuel type and year (as of June 1, 2025)**

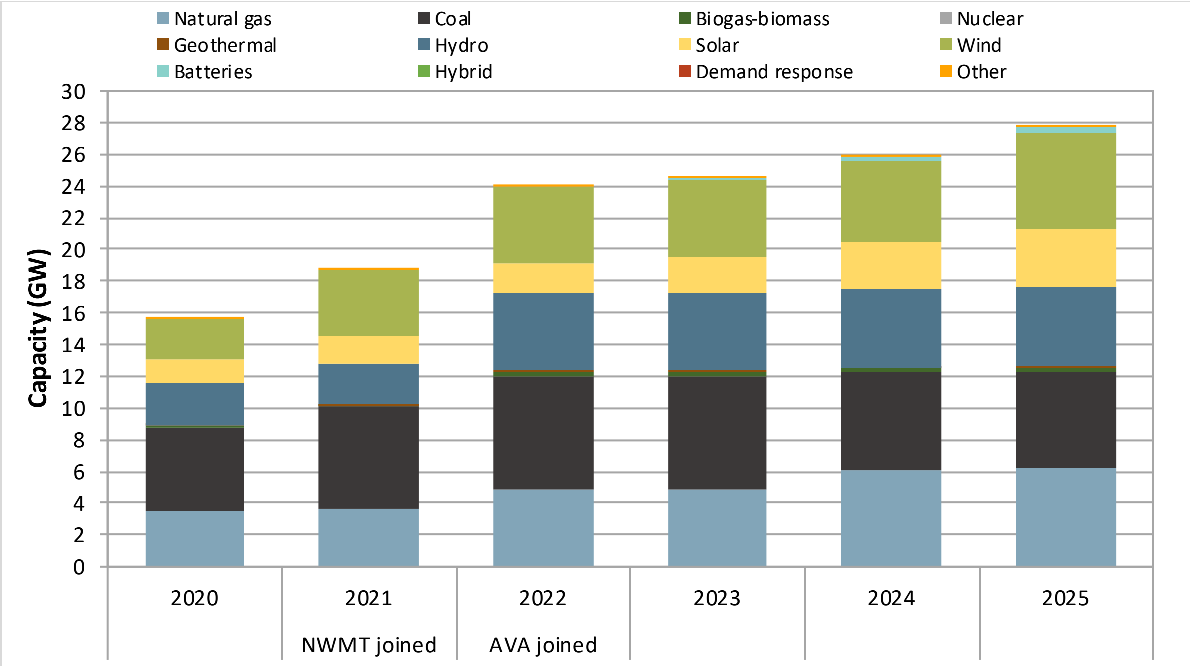



**Figure 1.83 Pacific Northwest – Total capacity by fuel type and year (as of June 1, 2025)**

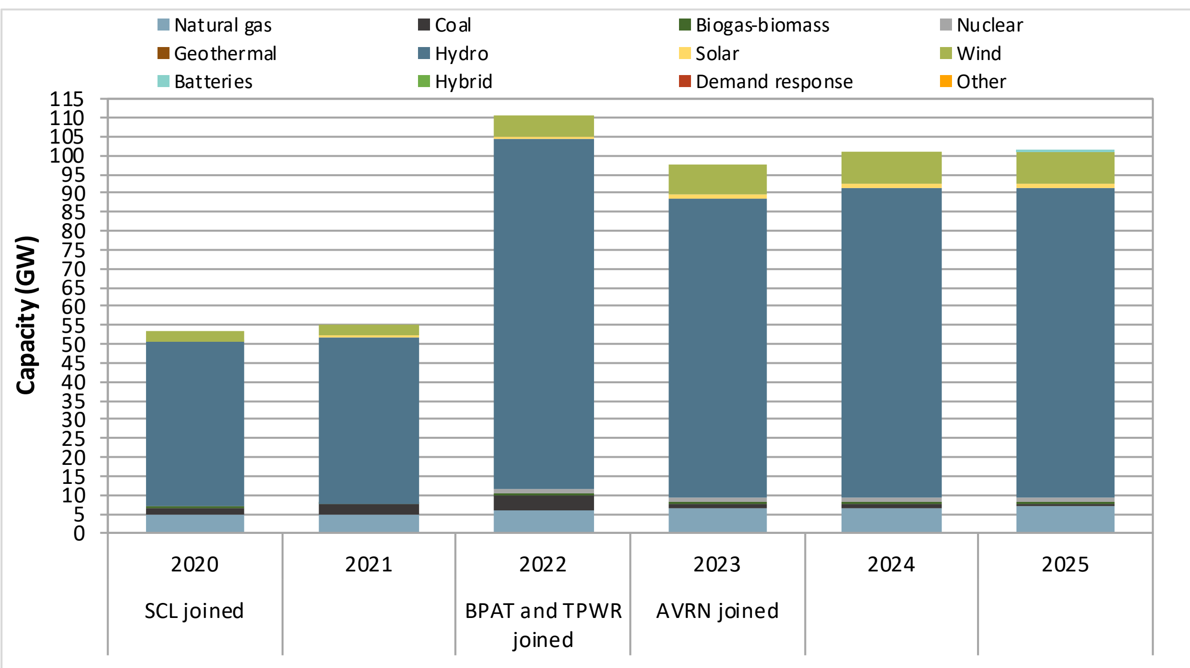


Figure 1.84 shows the fuel mix of all capacity for each balancing authority area in the WEIM as of June 1, 2025. The California ISO has the most capacity in the WEIM with 94.5 GW, with the next highest being Bonneville Power Administration at 40.5 GW. Figure 1.85 shows the change in capacity across the WEIM BAAs by fuel type from June 2024 to June 2025. In the chart, positive values represent increased capacity, while negative values represent a decrease in capacity from the previous summer. The total net change in capacity was around 12.7 GW. The California ISO and Arizona Public Service netted the biggest increase in capacity at 5.6 GW and 2.4 GW, respectively. Across all BAAs, battery capacity saw the most growth at 7.2 GW, followed by solar with 3.7 GW.

**Figure 1.84 Fuel mix of WEIM capacity by BAA (as of June 1, 2025)**

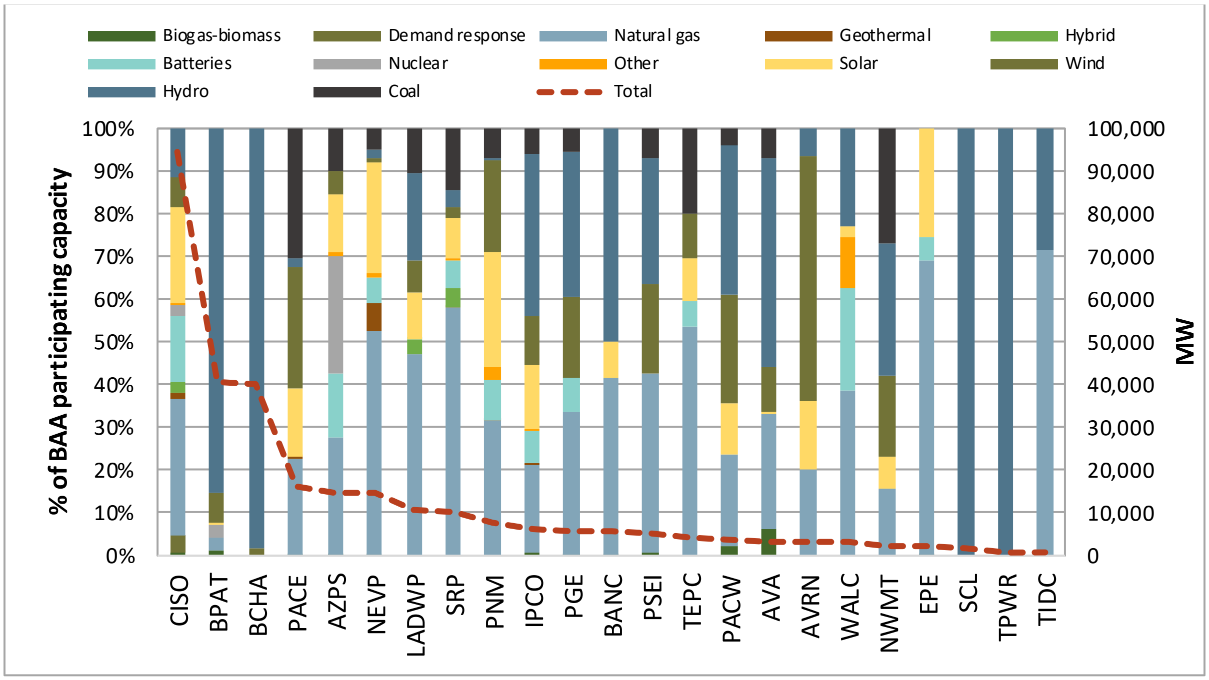
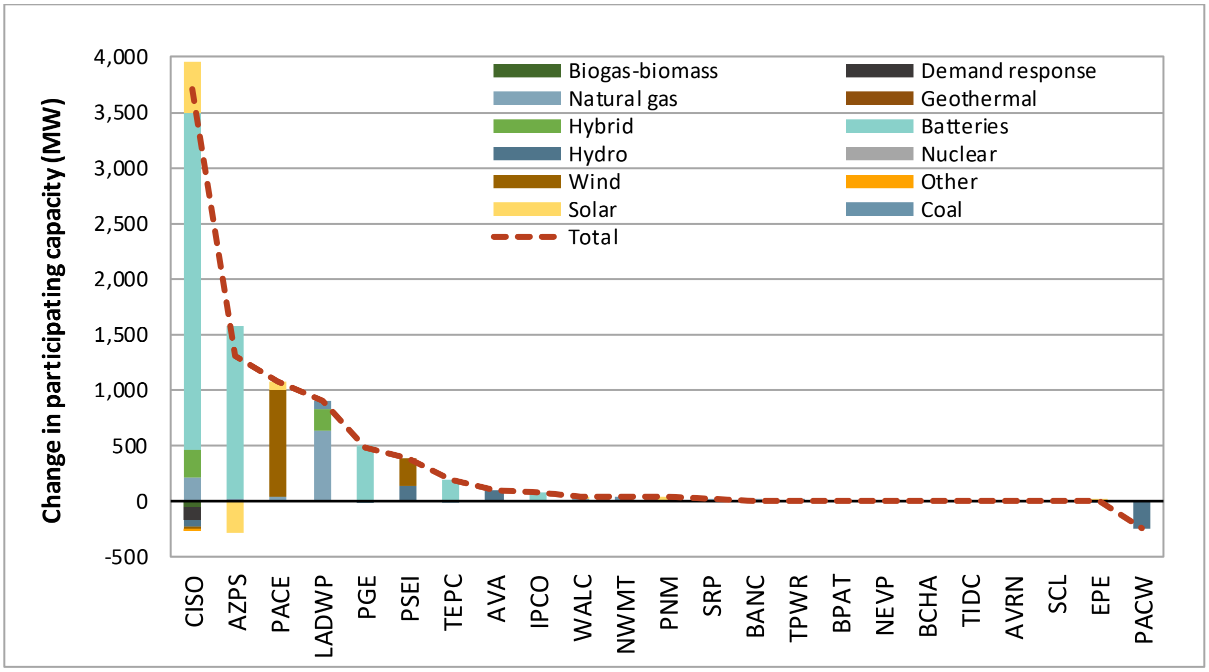


**Figure 1.85 Change in WEIM capacity by BAA (as of June 1, 2025)**




## 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.

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 2024, DMM estimates that net energy market revenues for a typical gas combined cycle unit ranged from $14 to $19/kW-yr compared to total annualized fixed costs of about $140/kW-yr. For a typical combustion turbine unit, DMM estimates net energy market revenues of about $10 to $16/kW-yr compared to total annualized fixed costs of about $172/kW-yr.

In addition, estimated net energy market revenues of gas units in 2024 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 $32 to $42/kW-yr, compared to net energy market revenues of $14 to $19/kW-yr. For a typical combustion turbine unit, DMM estimates net energy market revenues were about $10 to $16/kW-yr in 2024 compared to estimated annualized going-forward fixed costs of about $33 to $34/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, as of June 1, 2024, is set at $88/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 adequately justify its decision to allow a 20 percent adder for bids above the CPM soft offer cap.[87] On April 22, 2022, FERC issued an order reversing its original determination. In the April 22, 2022 order, FERC found that the California ISO had not demonstrated that the proposed 20 percent adder was just and reasonable.[88] On May 23, 2022, the California ISO submitted a compliance filing excluding the 20 percent adder from the compensation methodology.[89] After undergoing a stakeholder process for issues regarding the CPM, the California ISO Board of Governors approved an increase of the CPM soft offer cap to $88/kW-yr in 2023.[90]

### Gas optimization 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.[91] Incremental energy costs are calculated using default energy bids used in local market power

87 U.S. Court of Appeals, Order No. 20-1388 on *Petition for Review of Orders Regarding Bids Above CPM Soft Offer Cap*, December 17, 2021: https://media.cadc.uscourts.gov/opinions/docs/2021/12/20-1388-1927124.pdf

88 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

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

90 Capacity procurement mechanism enhancements initiative page: https://stakeholdercenter.caiso.com/StakeholderInitiatives/Capacity-procurement-mechanism-enhancements

91 Net revenues due to ancillary services and flexible ramping capacity are not modeled in the optimization model. For combined cycle units in the California ISO area, 2024 total average annual net revenues for regulation (up and down), spinning reserves, and flexible ramping capacity were around $0.07/kW-yr on average. Similarly, for combustion turbine units, 2024 average net revenues for operating reserves and flexible ramping capacity were $2.66/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.[92] Commitment costs are calculated using proxy start-up and minimum load cost methodology.[93]

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 1.4, 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*).[94] However, instead of fixed annual operating and maintenance (O&M) costs from the CEC report, DMM now uses estimates derived from its review of California-specific and nationwide sources.[95] 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 operating and maintenance costs of combined cycle gas units. In this report,

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92 Default energy bids are calculated using the variable cost option as described in: *Business Practice Manual Change Management, Market Instruments, Appendix F, Example of Variable Cost Option Bid Calculation*, California ISO: https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Market%20Instruments

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

94 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

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

FERC Docket No. ER18-240, *Metcalf RMR Agreement Filing Attachment A – Part 2, Schedule F, Article II Part B*, November 2, 2017, p 57: https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20171102-5246&optimized=false

FERC Docket No. ER18-230, *Gilroy RMR Agreement Filing Attachment A – Part 2, Schedule F, Article II Part B,* November 2, 2017, p 57: 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

DMM estimates that annual going-forward fixed costs range from $32 to $42/kW-yr for a typical combined cycle resource, and $33 to $34/kW-yr for a typical combustion turbine.[96]

### 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, which 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 Southern California (SP15), separately. These scenarios show how different assumptions would change net revenues for 2024.

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 2024, for a unit located in NP15 with the above assumptions, net revenues were $14/kW-yr with a 5 percent capacity factor.[97] Using the same assumptions for a hypothetical unit located in SP15, net revenues were $17/kW-yr with a 9 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.[98] Many resources do not include the full adder as part of their typical energy bid. Under this scenario, net revenues in 2024 for a hypothetical unit in the NP15 area were $16/kW-yr with a 6 percent capacity factor. In the SP15 area, net annual revenues were $19/kW-yr with an 11 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

[96] 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 combined cycle and $8.7/kW for combustion turbine) 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 combined cycle and $7.8/kW for combustion turbine) 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.

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

[98] See Section 3.3 for further discussion on price-cost markup.

market. Under this scenario, net revenues for a hypothetical unit located in the NP15 area were \$15/kW-yr with a 7 percent capacity factor. In the SP15 area, net annual revenues were \$18/kW-yr with an 11 percent capacity factor.

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

| Technical Parameters | Configuration 1 | Configuration 2 |
|---|---|---|
| Maximum capacity | 360 MW | 720 MW |
| Minimum operating level | 150 MW | 361 MW |
| Heat rates (Btu/kWh) | | |
| Maximum capacity | 7,500 Btu/kWh | 7,100 Btu/kWh |
| Minimum operating level | 7,700 Btu/kWh | 7,300 Btu/kWh |
| Variable O&M costs | \$2.40/MWh | \$2.40/MWh |
| GHG emission rate | 0.053165 $mtCO_2e$/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 auxiliary energy | 5 MWh | 5 MWh |
| Start-up major maintenance cost adder (2023) | \$7,008 | \$14,015 |
| Minimum load major maintenance cost adder (2023) | \$350 | \$701 |
| Minimum up time | 60 minutes | 60 minutes |
| Minimum down time | 60 minutes | 60 minutes |
| Ramp rate | 40 MW/minute | 40 MW/minute |
| **Financial Parameters (2024)** | | |
| Financing costs | | \$97 /kW-yr |
| Insurance | | \$8 /kW-yr |
| Ad Valorem | | \$10 /kW-yr |
| Fixed annual O&M | | \$14 /kW-yr |
| Taxes | | \$11 /kW-yr |
| **Total Fixed Cost Revenue Requirement** | | **\$140 /kW-yr** |

99 Start-up and minimum load major maintenance adders are derived based on Siemens SGT6-5000F5 gas turbine technology and costs reported in a NYISO study and adjusted each year for inflation. 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 resource operational characteristics of a typical combined cycle unit within the California ISO balancing area.

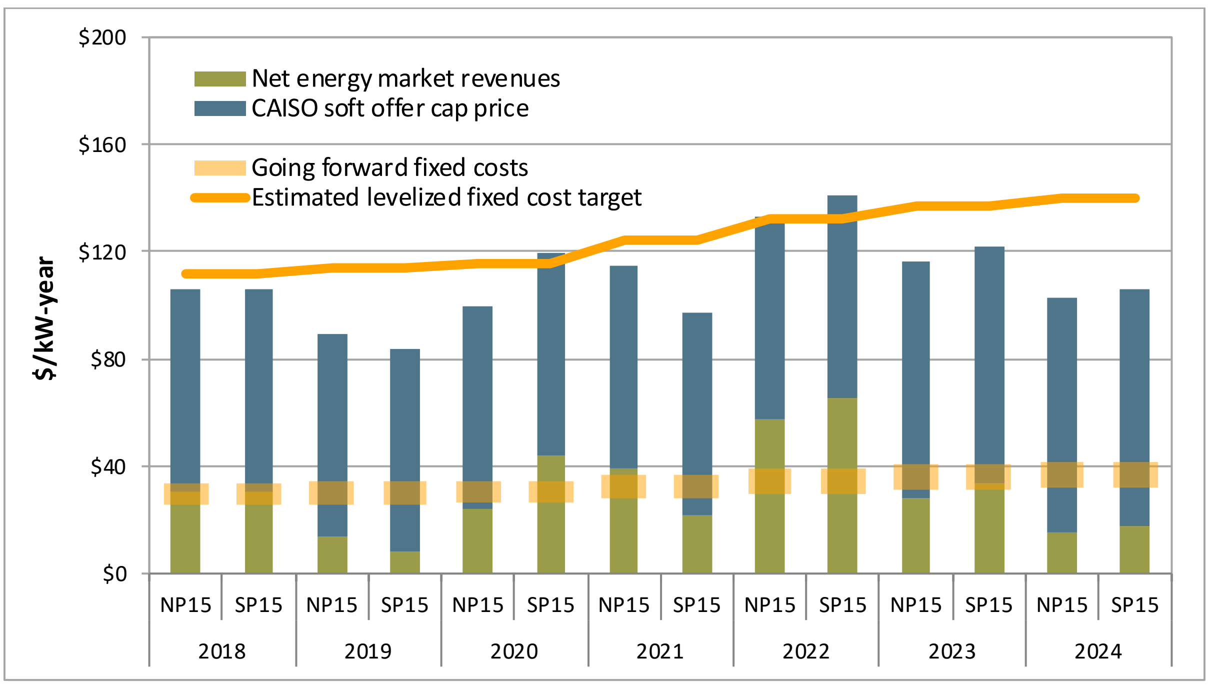
Maximum number of start-up and run-hours constraint has been relaxed in the annual optimization problem.

**Table 1.4 Financial analysis of new combined cycle unit (2024)**

| 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 | 5% | $56.17 | $41.81 | $14.37 |
| | Day-ahead prices and default energy bids without adder | 6% | $59.98 | $43.79 | $16.19 |
| | Day-ahead commitment with dispatch to day-ahead and 5-minute prices using default energy bids | 7% | $63.07 | $48.32 | $14.76 |
| SP15 | Day-ahead prices and default energy bids | 9% | $66.72 | $50.00 | $16.73 |
| | Day-ahead prices and default energy bids without adder | 11% | $78.36 | $59.40 | $18.96 |
| | Day-ahead commitment with dispatch to day-ahead and 5-minute prices using default energy bids | 11% | $75.79 | $58.27 | $17.52 |

Figure 1.86 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 seven 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 ($88.08/kW-yr).

**Figure 1.86 Estimated net revenue of hypothetical combined cycle unit**




As shown in Figure 1.86, compared to 2023, net revenues in 2024 for both NP15 and SP15 areas are significantly lower. This is primarily because of lower prices in 2024 resulting in decreased unit commitment and dispatch.

Figure 1.86 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 ($88.08/kW-yr), represent the potential additional contribution of a capacity payment up to the capacity procurement mechanism soft cap.

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 2024 ranged between 40 and 68 percent with an average of 53 percent capacity factor. In the SP15 area, actual capacity factors ranged between 3 and 44 percent, with an average capacity factor of 22 percent. Our estimates ranged from 5 to 11 percent, and were relatively low compared to the actual results.

These differences in hypothetical capacity factors compared to existing resource capacity factors stem from several conditions. 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 and longer minimum run times. The average minimum run time for comparable combined cycle units in the CAISO BAA is over six hours.

Additionally, 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.[100]

### 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 2024.

100 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[101]

| **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 auxiliary energy | 1.5 MWh |
| Start-up major maintenance cost adder (2023) | $0 |
| Minimum load major maintenance cost adder (2023) | $225 |
| Minimum up time | 60 minutes |
| Minimum down time | 60 minutes |
| Ramp rate | 50 MW/minute |
| **Financial Parameters (2024)** | |
| Financing costs | $127 /kW-yr |
| Insurance | $10 /kW-yr |
| Ad Valorem | $13 /kW-yr |
| Fixed annual O&M | $10 /kW-yr |
| Taxes | $12 /kW-yr |
| **Total Fixed Cost Revenue Requirement** | **$172 /kW-yr** |

### Table 1.6 Financial analysis of new combustion turbine (2023)

| Zone | Scenario | Capacity factor | Real-time energy revenues ($/kW-yr) | Operating costs ($/kW-yr) | Net revenue ($/kW-yr) |
|---|---|---|---|---|---|
| NP15 | 15-minute prices and default energy bids | 2.1% | $36.82 | $21.58 | $15.24 |
| | 15-minute prices and default energy bids without adder | 2.3% | $39.25 | $23.02 | $16.23 |
| | 15-minute commitment with dispatch to 15-minute and 5-minute prices using default energy bids | 2.1% | $38.17 | $22.40 | $15.76 |
| SP15 | 15-minute prices and default energy bids | 2.3% | $28.82 | $18.35 | $10.47 |
| | 15-minute prices and default energy bids without adder | 2.8% | $32.07 | $20.75 | $11.31 |
| | 15-minute commitment with dispatch to 15-minute and 5-minute prices using default energy bids | 2.5% | $30.30 | $19.76 | $10.54 |

[101] 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. *Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator*, NERA Economic Consulting, September 3, 2010: http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B25745D07-C958-42EA-AC1A-A1BB0D80FF52%7D

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 2024 prices, net annual revenues were approximately $15/kW-yr with a 2.1 percent capacity factor. Using SP15 prices for the same scenario, net revenues were approximately $10/kW-yr with a 2.3 percent capacity factor.

The second scenario assumes that 15-minute prices are used for commitment and dispatch instructions, but does not factor the 10 percent scalar into the default energy bids as a measure of incremental energy costs.[102] In this scenario, the hypothetical unit in NP15 earned net revenues of about $16/kW-yr with a 2.3 percent capacity factor. The hypothetical unit in SP15 earned net revenues of about $11/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 $16/kW-yr with a 2.1 percent capacity factor. In the SP15 area, net revenues were about $11/kW-yr with a 2.5 percent capacity factor.

Figure 1.87 shows how net revenue results from the optimization model compare to estimated annualized fixed costs of a hypothetical combustion turbine unit.[103] The green bars in this chart show estimated net revenues over the past seven years.

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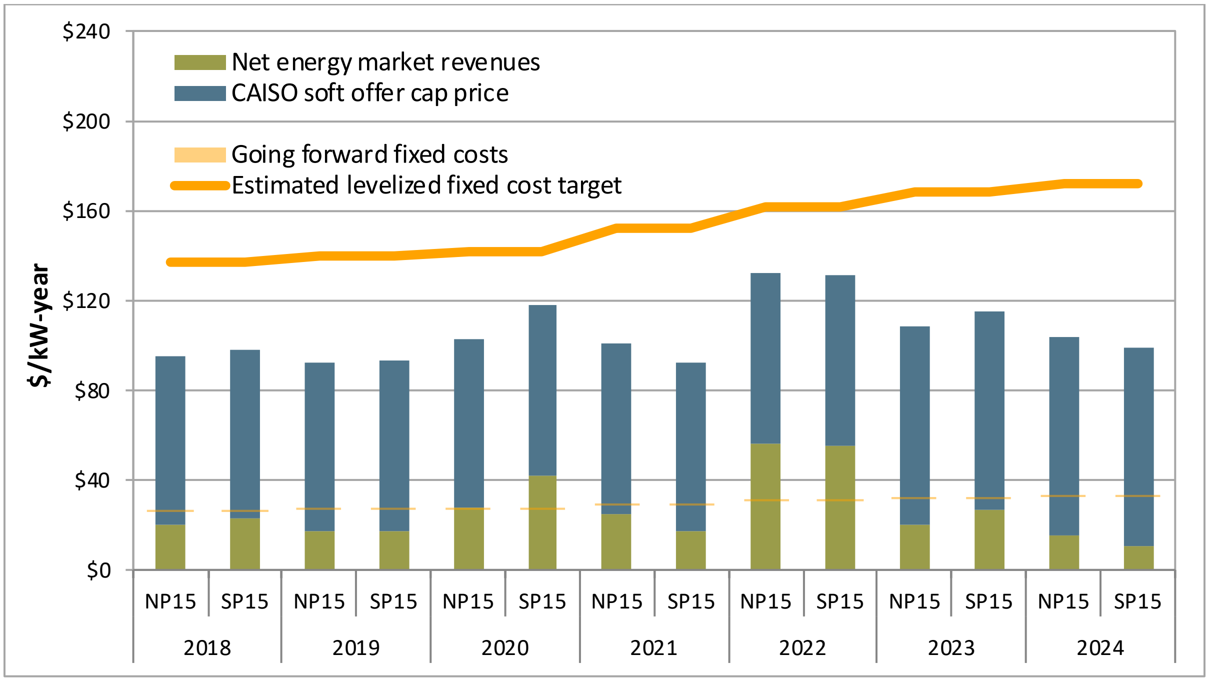
102 As noted above, we frequently find resources that bid in excluding the full 10 percent adder in their incremental energy bids.

103 More information on the capacity procurement mechanism can be found in Section 43A of the California ISO tariff: https://www.caiso.com/legal-regulatory/tariff

**Figure 1.87 Estimated net revenues of new combustion turbine**




As shown in Figure 1.87, net revenues for a hypothetical combustion turbine declined significantly in 2024. In both the NP15 and SP15 areas, simulated net market revenues were nearly half of what they were in 2023.

Figure 1.87 shows that, from 2018 through 2024, 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 1.6 with existing combustion turbines as a benchmark. Actual capacity factors in 2024 ranged between 0.08 and 11 percent, with an average capacity factor of 3.1 percent. DMM's estimates ranged from 2.1 to 2.8 percent.

### 1.3.3 Hypothetical battery energy storage system

For a battery energy storage system, potential market revenues are evaluated under two scenarios using a profit maximization model. The first scenario co-optimizes energy and ancillary services (AS) products (regulation up and down) to maximize profit in the day-ahead market across over 250 pricing nodes, independently. The second scenario maximizes profit from energy awards only in the fifteen-minute market using SP15 prices, NP15 prices, and EIM load aggregation point (ELAP) prices. Both scenarios use one year's worth of pricing data across those nodes with a monthly optimization horizon window. Both models optimize revenues using a mixed integer linear programming algorithm.

Charging costs and discharging revenues in the model scenarios are calculated based on price data and the energy award chosen by the optimization. For market revenues in the first scenario (energy and ancillary service co-optimization), regulation up and down ancillary service marginal prices (ASMPs) are used in addition to day-ahead market nodal prices to calculate market revenues.

Table 1.7 shows the key assumptions used in the profit maximization model for a new fast-ramping typical lithium-ion (Li-ion) battery energy storage system (BESS). Similar to the actual market model, DMM's model observes battery constraints related to state-of-charge and other operational characteristics. 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. The model excludes any variable operations and maintenance costs related to cycling the battery. The ISO market does allow battery operators to reflect variable operations costs as an adder in their default energy bid. However, as of June 2025, only 15 percent of registered batteries have these adders. In practice, most batteries likely reflect variable operations costs in their submitted bids.

**Table 1.7 Assumptions for typical 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 | $0 /MWh |
| Round-trip efficiency | 0.85 |

Revenues for regulation awards 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 day-ahead regulation up and regulation down awards are deployed in real-time according to hourly attenuation factors published by the ISO.[104] Hence, the model includes the costs and revenues associated with this fraction of regulation deployed in real-time in its profit maximization objective function.

Similar to the actual market model, DMM's model tracks two state-of-charge values. The conventional state-of-charge constraint only reflects the impact of energy awards. The "attenuated" state-of-charge additionally includes the impact of the regulation award multiplied by attenuation factors, as well as round-trip efficiency in the case of regulation down.[105] In the day-ahead market, batteries are subject to the ancillary service state-of-charge constraints, which limit regulation awards based on modeled state-

[104] Attenuation factors are multipliers which model the state-of-charge of a battery as being depleted or increased by a certain percentage of the regulation schedule. The ISO chooses multipliers based on historical usage of regulation and updates the multipliers on a quarterly basis to account for seasonality of regulation usage.

[105] Initially, the ISO had planned to model the impact of energy and regulation in a single state-of-charge parameter. However, this resulted in negative regulation down prices since regulation down deployment could support future energy awards, which the CAISO tariff prohibits. DMM's model takes prices as given and thus has no such issue.

of-charge. In DMM's optimization, the attenuated state-of-charge value controls for feasibility of regulation awards within the ancillary service state-of-charge constraints.

Table 1.8 shows quarterly average day-ahead energy and ancillary service revenues by local capacity area for hypothetical batteries at all utilized pricing nodes. On average, simulated revenues across all pricing nodes were $52/kW-yr for energy and $28/kW-year for ancillary services. Actual batteries in the CAISO balancing area with a full year of operation in 2024 had nearly $43/kW-yr in market revenues for energy and $7/kW-yr for regulation.

**Table 1.8 New battery net day-ahead market revenues by local capacity area**

| | | Net energy market revenues for energy and regulation ($/kW-yr) | | | | |
|---|---|---|---|---|---|---|
| Local capacity area | TAC Area | 2024 Q1 | 2024 Q2 | 2024 Q3 | 2024 Q4 | Total |
| Greater Bay Area | PG&E | 11.5 | 16.1 | 21.2 | 11.2 | 59.9 |
| Big Creek/Ventura | SCE | 21.3 | 21.6 | 21.6 | 14.9 | 79.5 |
| CAISO System | | 20.4 | 21.6 | 22.2 | 15.4 | 79.5 |
| Greater Fresno | PG&E | 20.2 | 29.4 | 31.6 | 20.3 | 101.5 |
| Humboldt | PG&E | 14.1 | 21.0 | 24.9 | 20.4 | 80.5 |
| Kern | PG&E | 21.8 | 25.1 | 25.8 | 19.1 | 91.9 |
| LA Basin | SCE | 20.8 | 21.1 | 21.6 | 14.4 | 77.9 |
| North Coast & North Bay | PG&E | 12.3 | 17.9 | 29.6 | 17.6 | 77.3 |
| San Diego/Imperial Valley | SDG&E | 20.6 | 20.8 | 22.6 | 14.7 | 78.7 |
| Sierra | PG&E | 12.2 | 19.4 | 30.0 | 11.6 | 73.2 |
| Stockton | PG&E | 12.1 | 19.7 | 25.3 | 12.0 | 69.1 |

Hourly average energy and regulation awards for the day-ahead optimization are shown in Figure 1.88. DMM's model likely overstates potential revenue from ancillary services for an actual battery resource. DMM's optimization does not limit the amount of regulation a battery can receive in an interval beyond the standard ancillary service constraints observed in the actual market optimization. While the high level of regulation procurement in DMM's model may theoretically be profit-maximizing, in practice there is a large amount of battery capacity competing to provide a relatively low amount of required regulation, making it unlikely that a single battery will procure the level of regulation shown in Figure 1.88.[106]

[106] *2023 Special Report on Battery Storage*, Department of Market Monitoring, July 16, 2024, p 25: https://www.caiso.com/documents/2023-special-report-on-battery-storage-jul-16-2024.pdf

**Figure 1.88 Average hourly hypothetical battery day-ahead market awards**

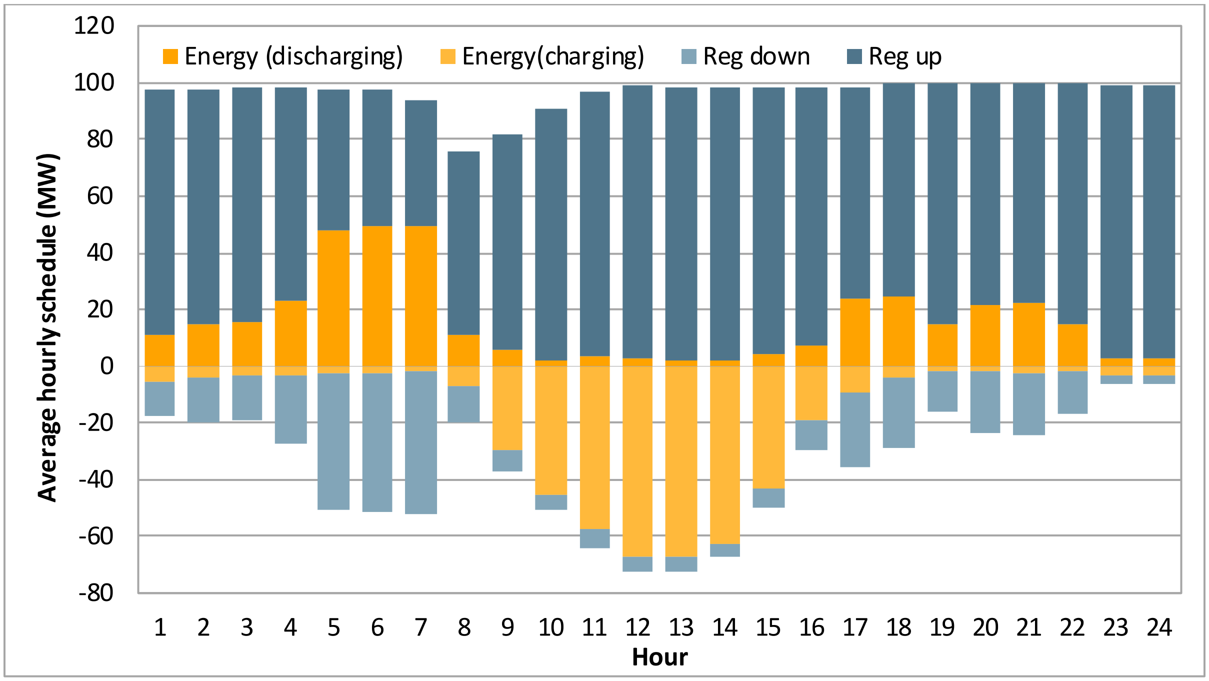



Table 1.9 shows quarterly average energy revenue for the real-time optimization scenario by area. Average simulated revenues were $40/kW-year across all areas. By region, the highest average simulated revenue figure was $51/kW-year in the Desert Southwest. Because revenue settlements outside of the CAISO BA are determined by energy imbalance, and actual EIM batteries mostly followed base schedules in 2024, the model's simulated revenues are not comparable to actual net market revenues paid to EIM-participating batteries.[107]

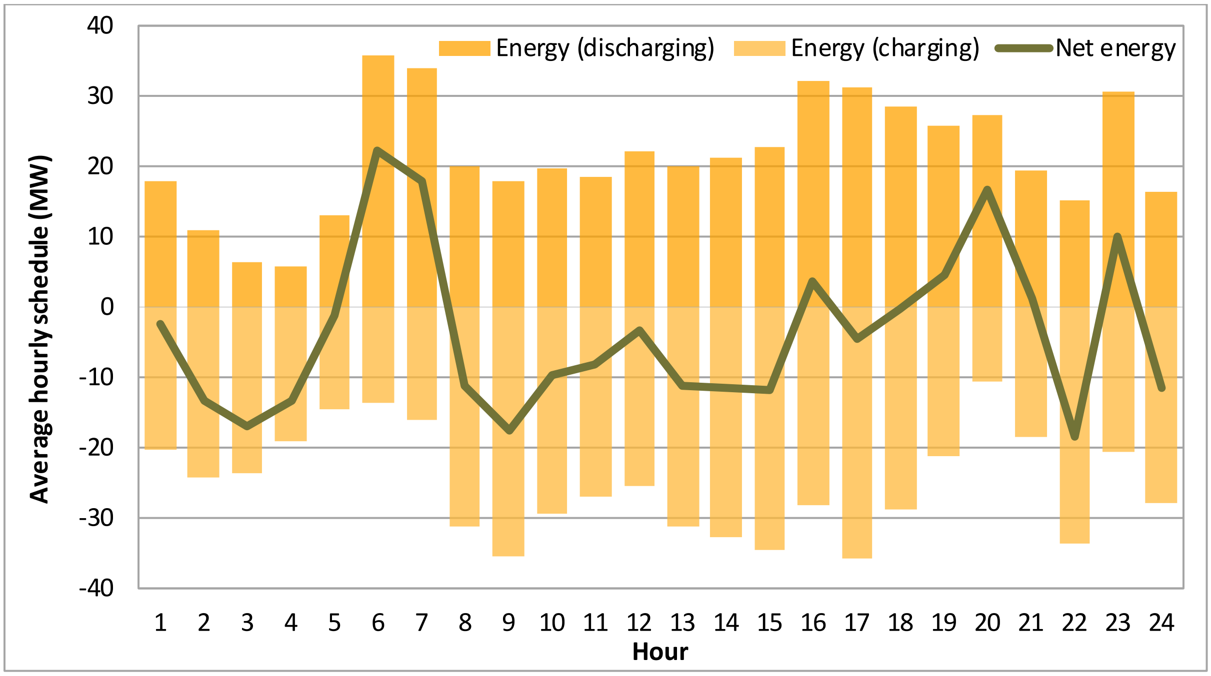
107 *2024 Special Report on Battery Storage*, Department of Market Monitoring, May 29, 2025, p 25: https://www.caiso.com/documents/2024-special-report-on-battery-storage-may-29-2025.pdf

### Table 1.9 New battery net 15-minute market revenues by area

| Region | Area | Net energy market revenues ($/kW-yr) | | | | |
|---|---|---|---|---|---|---|
| | | 2024Q1 | 2024Q2 | 2024Q3 | 2024Q4 | Total |
| Desert Southwest | Arizona Public Service | 14.1 | 9.7 | 11.5 | 6.7 | 41.9 |
| | El Paso Electric | 15.4 | 18.5 | 17.8 | 10.3 | 62.0 |
| | NV Energy | 9.6 | 9.4 | 9.9 | 5.3 | 34.2 |
| | PSC New Mexico | 22.4 | 17.5 | 12.3 | 35.7 | 87.9 |
| | Salt River Project | 13.0 | 12.9 | 12.9 | 7.0 | 45.8 |
| | Tucson Electric | 11.5 | 9.1 | 13.1 | 7.0 | 40.7 |
| | WAPA - Desert Southwest | 13.5 | 11.2 | 10.3 | 7.8 | 42.8 |
| Intermountain West | Avista Utilities | 17.6 | 5.9 | 7.3 | 4.9 | 35.6 |
| | Idaho Power | 18.6 | 8.1 | 8.5 | 4.9 | 40.2 |
| | NorthWestern Energy | 17.4 | 6.0 | 8.1 | 7.9 | 39.4 |
| | PacifiCorp East | 10.5 | 7.1 | 8.9 | 5.0 | 31.4 |
| Pacific Northwest | Avangrid | 15.5 | 6.1 | 6.3 | 4.6 | 32.6 |
| | Powerex | 5.1 | 3.2 | 3.6 | 3.3 | 15.2 |
| | Bonneville Power Admin. | 20.4 | 9.0 | 13.2 | 6.0 | 48.6 |
| | PacifiCorp West | 17.2 | 5.7 | 6.1 | 4.5 | 33.6 |
| | Portland General Electric | 15.9 | 6.6 | 5.9 | 4.4 | 32.9 |
| | Puget Sound Energy | 17.3 | 8.1 | 7.6 | 5.4 | 38.3 |
| | Seattle City Light | 17.4 | 7.4 | 7.0 | 6.7 | 38.6 |
| | Tacoma Power | 16.5 | 6.4 | 6.2 | 5.0 | 34.2 |
| California | BANC | 7.2 | 8.8 | 11.0 | 6.3 | 33.3 |
| | LADWP | 11.0 | 11.0 | 14.9 | 8.7 | 45.5 |
| | Turlock Irrigation District | 6.9 | 8.3 | 10.4 | 7.5 | 33.2 |
| CAISO | NP15 | 7.0 | 8.2 | 10.8 | 7.0 | 33.1 |
| | SP15 | 10.5 | 10.6 | 10.8 | 6.3 | 38.2 |

Figure 1.89 shows hourly average charging, discharging, and net energy schedules for a hypothetical battery located in the Public Service Company of New Mexico balancing area (PNM). Intra-hour differences in the 15-minute prices allow for arbitrage opportunities in more hours compared to the day-ahead price model shown in Figure 1.88.

**Figure 1.89 Average hourly hypothetical battery 15-minute market awards**



# 2 Energy market prices

ISO markets continued to perform efficiently and competitively in 2024.

- **Prices across the WEIM were about 35 percent lower in 2024 compared to 2023, primarily due to lower natural gas prices.** Prices in the 15-minute market averaged about $40/MWh, while prices in the 5-minute market averaged around $39/MWh. Day-ahead market prices averaged $41/MWh.
- **Prices were highest on average in the Pacific Northwest region, at $49/MWh, and prices were lowest in the Desert Southwest, at $31/MWh.** This price spread was caused by extreme cold weather in January in the Pacific Northwest and south-to-north congestion during solar hours throughout much of the year. 15-minute market prices in Powerex, California, and the Intermountain West were $42, $41, and $37/MWh, respectively.
- **During mid-day solar hours, prices were generally higher in the Pacific Northwest, Northern California, and the Intermountain West than in the Desert Southwest and Southern California.** This pattern was primarily driven by congestion on major transmission corridors in the south-to-north direction during solar production hours.
- **During non-solar hours, California balancing authority areas had higher prices compared to the rest of the WEIM** due mainly to California greenhouse gas pricing.
- **January had the highest monthly average 15-minute and 5-minute market prices for every balancing area.**
- **15-minute market prices were significantly higher than 5-minute market prices over the evening peak net load hours, particularly in California balancing areas.** This was caused largely by CAISO balancing area operators adjusting up the load forecast much more in the 15-minute market than in the 5-minute market over these hours.
- **For most of the year, day-ahead bilateral prices from the Intercontinental Exchange at Mid-Columbia and Palo Verde were higher than prices at comparable locations from the ISO's day-ahead and 15-minute markets.**
- **Only two balancing areas, Public Service Company of New Mexico and El Paso Electric, did not have enough available, bid-in energy supply to meet demand in more than 0.1 percent of 15-minute market intervals.** Across the whole WEIM, these undersupply infeasibilities decreased to 0.05 percent of intervals in 2024 from 0.07 percent of intervals in 2023.
- **DMM estimates the total wholesale cost of serving load for balancing areas in the day-ahead market. Total wholesale costs for the CAISO balancing area decreased by 38 percent to $9.1 billion due to substantially lower natural gas prices.** Controlling for both natural gas costs and greenhouse gas prices, wholesale electric costs increased by about 7 percent.

## 2.1 Real-time energy market prices by region

This section analyzes real-time market prices across the Western Energy Imbalance Market (WEIM). The analysis focuses on monthly and hourly load-weighted average prices at the regional level.[108] Prices are calculated based on the load schedules and corresponding prices at all Aggregated Pricing Nodes (APnodes).[109]

Figure 2.1 and Figure 2.2 display the weighted average monthly electricity prices in the 15-minute and 5-minute markets by region from January 2023 to December 2024. Prices in the 15-minute market across the WEIM averaged about $40/MWh, down 35 percent due mainly to lower natural gas prices. Prices in the 5-minute market were $39/MWh, a 33 percent decrease compared to 2023.

In 2024, the Pacific Northwest recorded the highest average price at $49/MWh, while other regions ranged between $31/MWh and $42/MWh. Severe cold weather and strained supply conditions in January 2024 contributed to elevated prices in the Pacific Northwest. The Desert Southwest region recorded the lowest average price at $31/MWh, notably below the $41/MWh–$49/MWh averages observed in Pacific Northwest, California, and Powerex. This price difference largely reflects the south-to-north congestion pattern during solar production hours, which decreased prices in the Desert Southwest and increased prices in the northern part of the WEIM.

Compared to 2023, prices across the WEIM were lower despite higher loads, primarily due to significantly reduced natural gas prices. Section 1.2.6 above on natural gas illustrates the substantial decline in natural gas prices across major Western U.S. trading hubs in 2024 compared to 2023. As gas-fired units frequently set electricity market prices, lower natural gas prices lead to lower real-time prices across the WEIM.

108 The California region includes CAISO, BANC, TIDC, and LADWP. The Desert Southwest region includes NEVP, AZPS, TEPC, SRP, PNM, WALC, and EPE. The Intermountain West region includes PACE, IPCO, NWMT, and AVA. The Pacific Northwest includes AVRN, BPA, TWPR, PGE, PSEI, and SCL. Powerex is categorized separately due to transmission limitations that frequently isolate it from the rest of the WEIM system.

109 The load-weighted average is calculated by weighting each interval's price by its corresponding load relative to the total over a specific time period. Monthly average prices for each real-time interval are weighted by their respective loads and divided by the total monthly load for the region. For hourly averages over the quarter, each interval's price is weighted by its load relative to the total load during that hour for the region.

**Figure 2.1 Weighted average monthly 15-minute market prices by region**

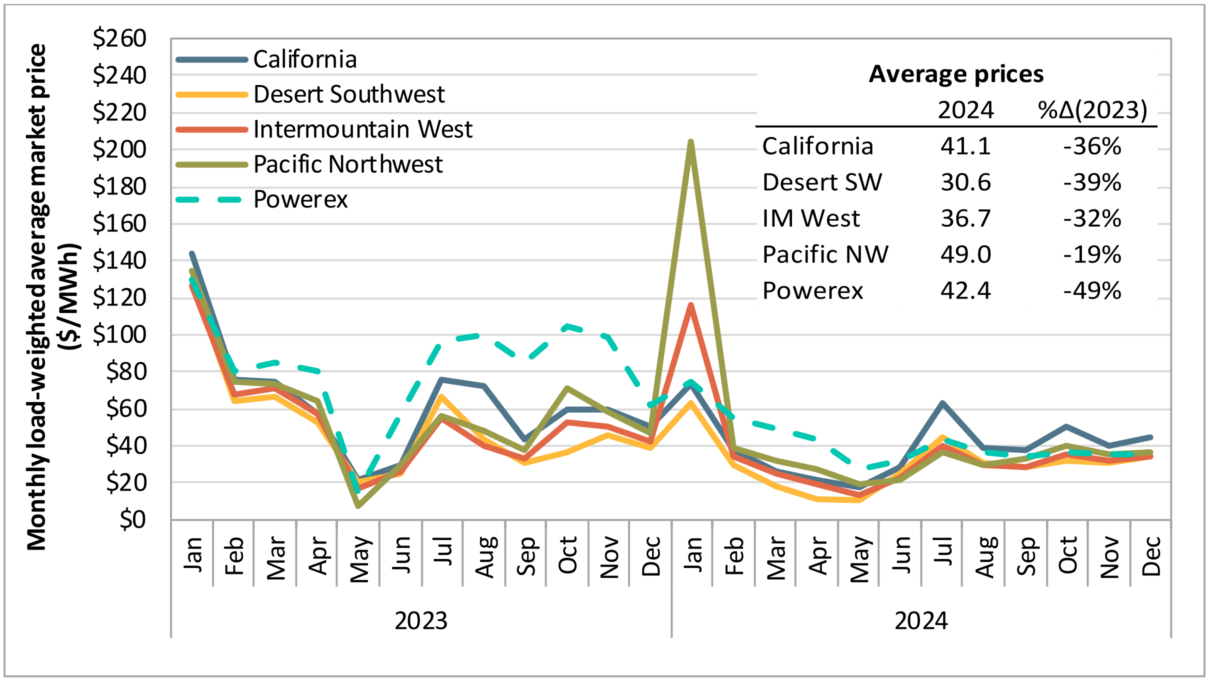



**Figure 2.2 Weighted average monthly 5-minute market prices by region**

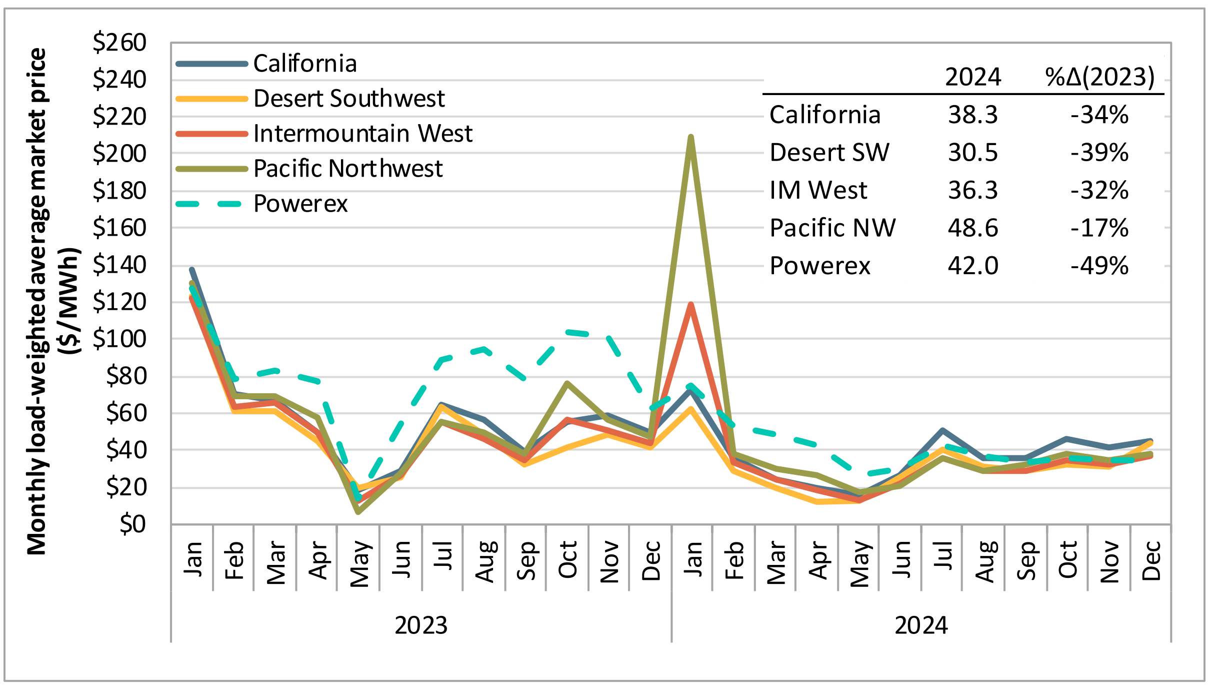



Figure 2.3 and Figure 2.4 illustrate the weighted average hourly prices for the 15-minute and 5-minute markets across regions, along with average system net-load schedules. The shape of hourly prices

tended to follow the net load pattern. This trend was most prominent for prices in the California and Desert Southwest regions, with relatively high prices during the morning and evening ramping hours, and lower prices during solar production hours.

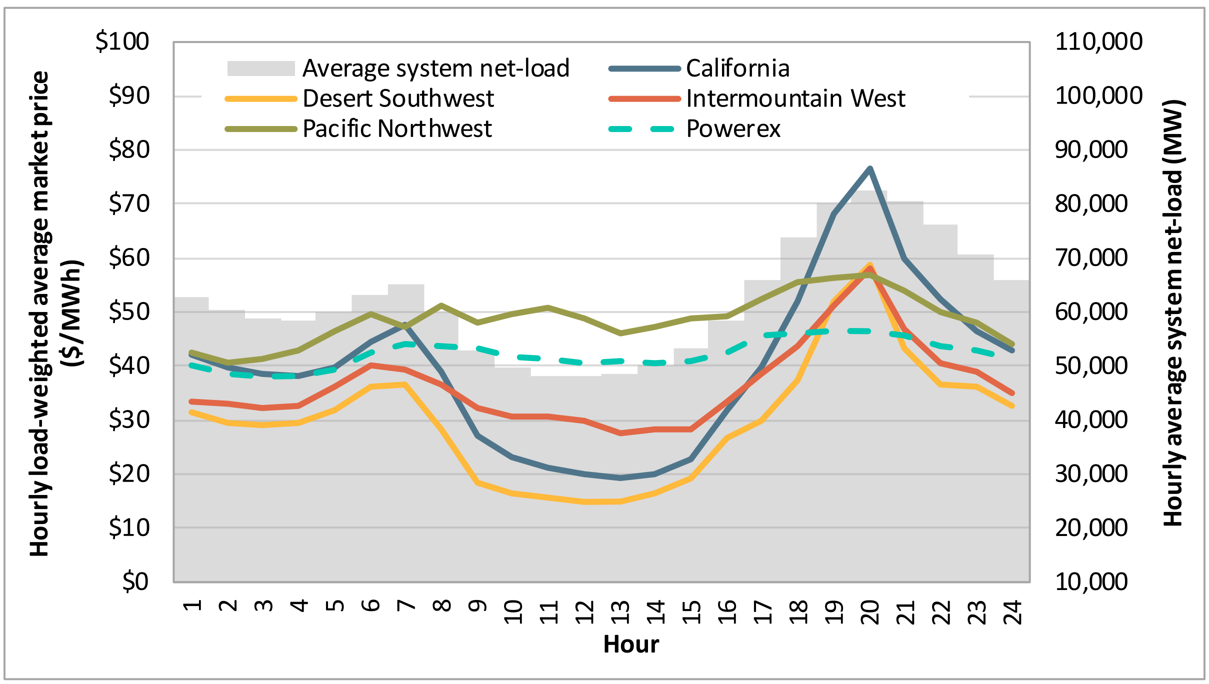
The system's peak net load occurred at hour-ending 20 in both the 15-minute and 5-minute markets, reaching around 83 GW and 81 GW, respectively. In both markets, all regions experienced peak average prices around the evening ramping hours.

Prices in the California region were higher than prices in other regions in both markets, especially during evening peak hours. The main contributor for higher prices in California is the greenhouse gas (GHG) cost, which tends to lower prices in the rest of the non-California regions.

A notable distinction occurred during mid-day solar hours when price separation was observed. The Desert Southwest experienced lower prices compared to other regions, while the Pacific Northwest saw relatively higher prices. This pattern aligned with congestion trends, where south-to-north congestion increased during high solar energy production.

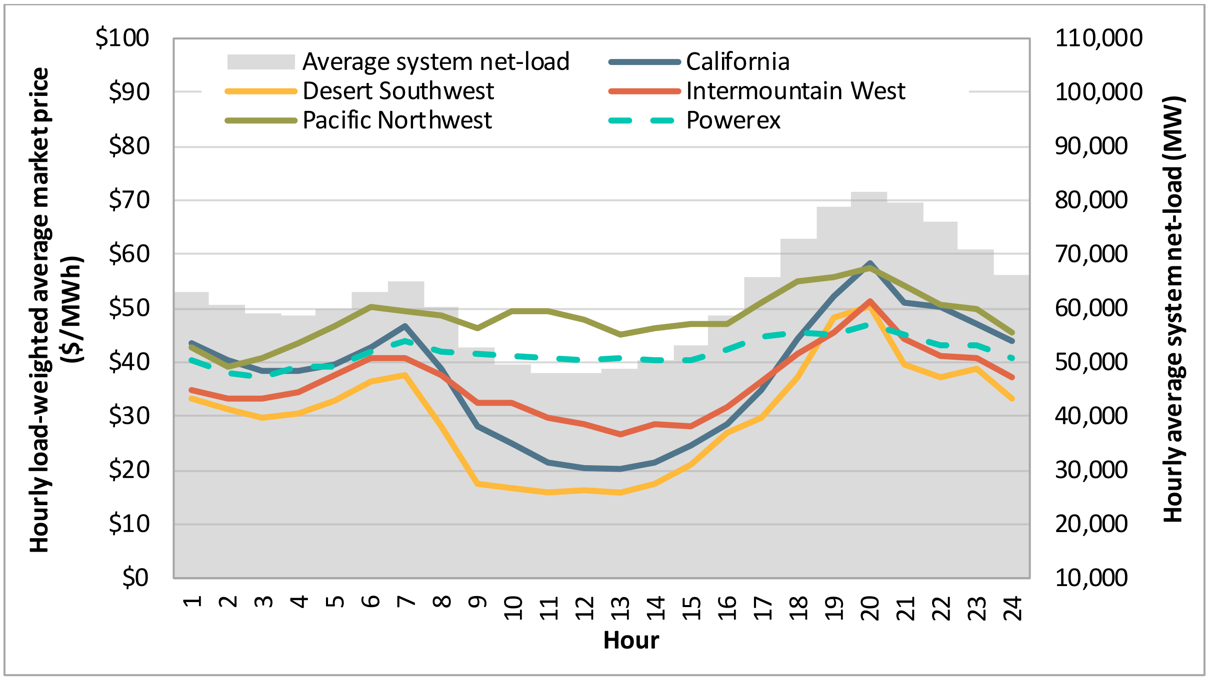
Comparing prices between the 15-minute and 5-minute markets, the 15-minute market had higher prices during peak net load hours, particularly in California. Around hour-ending 20, California's peak average price in the 15-minute market reached $77/MWh, compared to $58/MWh in the 5-minute market. One factor that contributed to this price difference was the CAISO balancing area using higher load conformance in the 15-minute market than in the 5-minute market during these hours.[110]

**Figure 2.3 Weighted average hourly 15-minute market prices by region (2024)**




110 For more information on load conformance, see Section 9.

**Figure 2.4 Weighted average hourly 5-minute market prices by region (2024)**




## 2.2 Real-time energy market prices by balancing area

This section summarizes prices in each Western Energy Imbalance Market (WEIM) balancing area during 2024. Figure 2.5 and Figure 2.6 show the average 15-minute and 5-minute market price by component for each balancing authority area in this year. These figures highlight how price differences between regions are determined by differences in transmission losses, greenhouse gas compliance costs, and congestion. These components are listed below.

- **System marginal energy price**, often referred to as SMEC, is the marginal clearing price for energy at a reference location. The SMEC is the same for all WEIM areas.
- **Transmission losses** are the price impact of energy lost on the path from source to sink.
- **GHG component** is the greenhouse gas price in each 15-minute or 5-minute interval 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 contributes to higher prices for WEIM areas in California.
- **Congestion within California ISO** is the price impact from transmission constraints within the California ISO area that are restricting the flow of energy. While these constraints are located within the California ISO balancing area, they can create price impacts across the WEIM.
- **Congestion within WEIM** is the price impact from transmission constraints within a WEIM area that are restricting the flow of energy. While these constraints are located within a single balancing area, they can create price impacts across the WEIM.

- **Other internal congestion.** DMM calculates the congestion impact from constraints within the California ISO or within WEIM by replicating the nodal congestion component of the price from individual constraints, shadow prices, and shift factors. In some cases, DMM could not replicate the congestion component from individual constraints such that the remainder is flagged as *Other internal congestion.*
- **Congestion on WEIM transfer constraints** is the price impact from any constraint that limits WEIM transfers between balancing areas. This includes congestion from (1) scheduling limits on individual WEIM transfers, (2) total scheduling limits, or (3) intertie constraints (ITC) and intertie scheduling limits (ISL).

Significant factors impacting the locational marginal price (LMP) differences between balancing areas included congestion on WEIM transfer constraints and internal congestion from flow-based constraints. GHG costs also contributed to lowering prices in non-California balancing areas relative to California areas. These compliance costs are embedded within system marginal energy costs, but are reflected as negative costs (or payments) that are received by other WEIM areas making transfers into California areas through the WEIM. This indicates resources with non-zero GHG costs were often sending the last increment of power to California in the real-time markets.

Figure 2.5 and Figure 2.6 show LMP separation across balancing authority areas (BAAs) and regions in both the 15-minute and 5-minute markets. The charts highlight that the GHG component (green bars) contributed to lower LMPs across most BAAs, except those located in the California region. LMP separation showed a south-to-north congestion pattern, with higher prices in the Intermountain West and Pacific Northwest compared to California and the Desert Southwest. The lower LMP in the Desert Southwest largely resulted from internal flow-based congestion within CAISO. In contrast, higher LMPs in the Intermountain West and Pacific Northwest reflected a combination of internal CAISO congestion and congestion on WEIM transfer constraints.

**Figure 2.5 Average 15-minute market prices by balancing area (2024)**

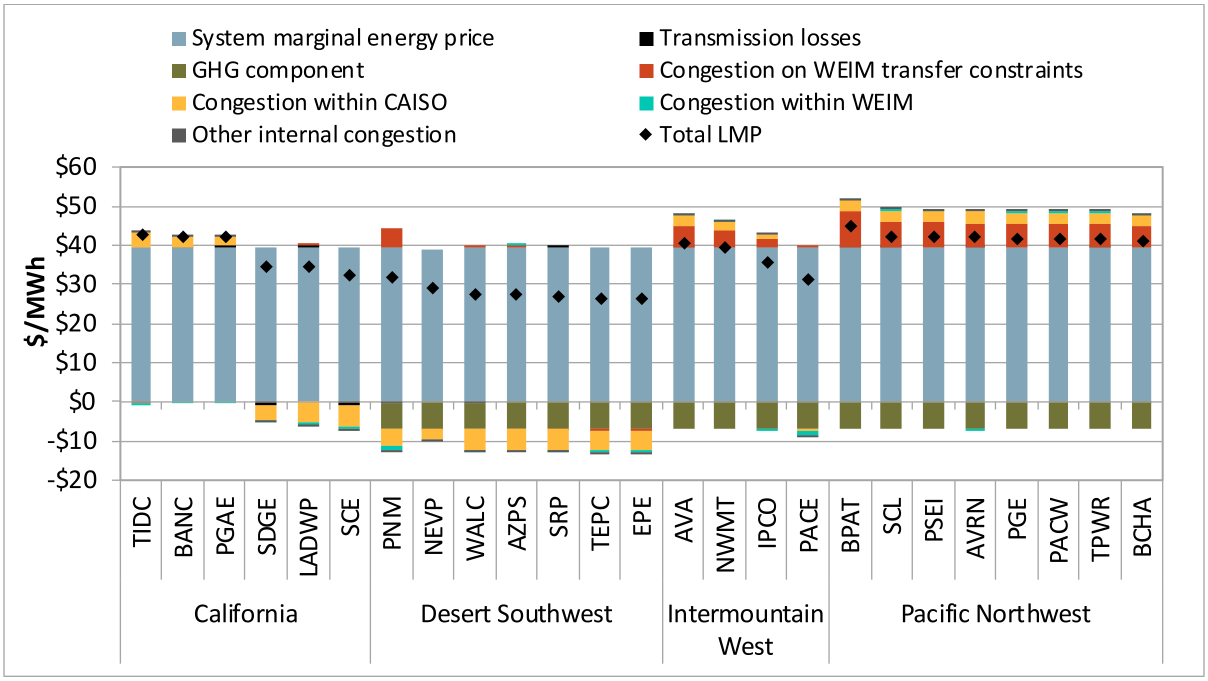



**Figure 2.6 Average 5-minute market prices by balancing area (2024)**

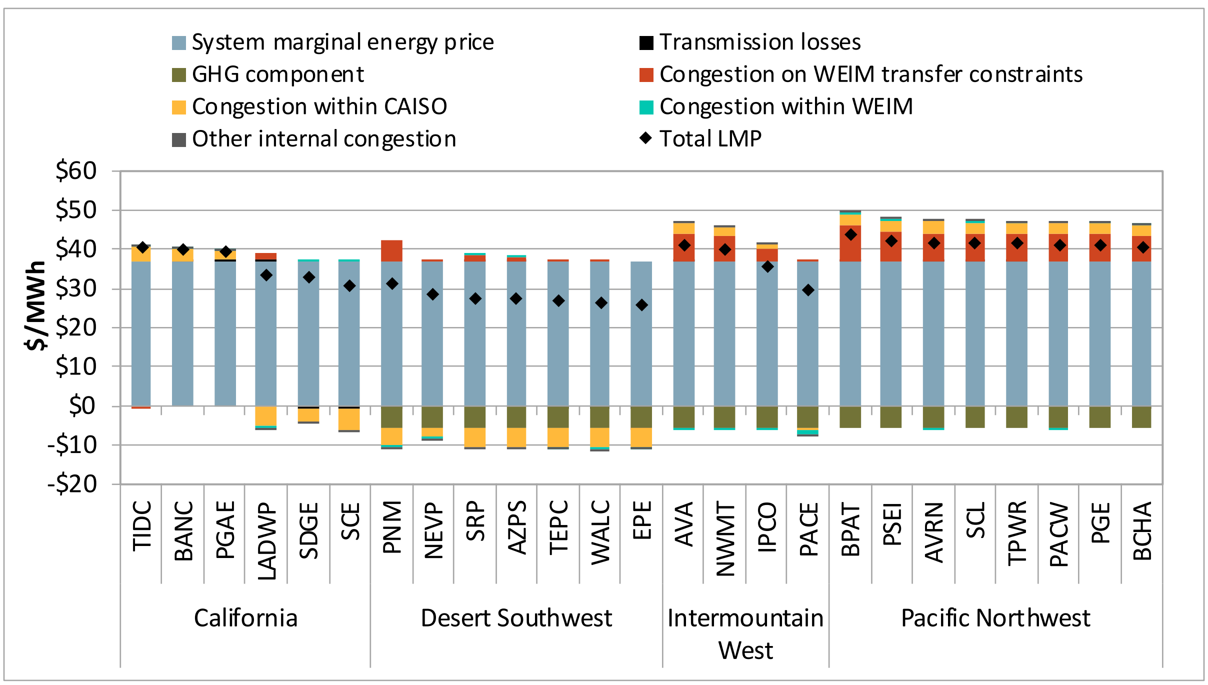



Table 2.1 and Table 2.2 show average 15-minute and 5-minute market prices by month for each balancing area. The color gradient highlights deviation from the average system marginal energy price

(SMEC), shown in the top row. Blue indicates prices below that month's average system price and orange indicates prices above. As shown in these tables, average prices in California balancing areas were generally higher than those in other regions in both the 15-minute and 5-minute markets over 2024. Greenhouse gas compliance costs contribute to higher prices in California relative to the rest of the system.

Table 2.3 and Table 2.4 show average hourly prices in the 15-minute and 5-minute markets in 2024. During mid-day solar hours, prices were generally higher in the Intermountain West, Pacific Northwest, and Northern California than in the Desert Southwest and Southern California. This pattern was primarily driven by south-to-north congestion on WEIM transfer and internal flow-based constraints. When internal or transfer constraints limit the amount of energy that can flow from areas with lower cost supply to areas with higher cost supply, prices will be higher on the side of the constraint with higher cost supply.

During non-solar hours, California balancing authority areas had higher prices compared to the rest of the WEIM due mainly to California greenhouse gas pricing.

**Table 2.1 Average monthly 15-minute market prices**

| | 2023 Jan | 2023 Feb | 2023 Mar | 2023 Apr | 2023 May | 2023 Jun | 2023 Jul | 2023 Aug | 2023 Sep | 2023 Oct | 2023 Nov | 2023 Dec | 2024 Jan | 2024 Feb | 2024 Mar | 2024 Apr | 2024 May | 2024 Jun | 2024 Jul | 2024 Aug | 2024 Sep | 2024 Oct | 2024 Nov | 2024 Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| SMEC | $140 | $73 | $73 | $55 | $19 | $28 | $66 | $67 | $42 | $57 | $58 | $50 | $89 | $38 | $28 | $22 | $16 | $26 | $51 | $36 | $35 | $46 | $41 | $42 |
| PG&E (CAISO) | $140 | $75 | $76 | $57 | $18 | $29 | $58 | $65 | $44 | $62 | $62 | $54 | $78 | $40 | $30 | $28 | $21 | $28 | $61 | $36 | $36 | $56 | $46 | $46 |
| SCE (CAISO) | $140 | $68 | $65 | $48 | $20 | $27 | $73 | $68 | $39 | $51 | $53 | $45 | $65 | $31 | $17 | $11 | $9 | $24 | $50 | $35 | $33 | $38 | $35 | $40 |
| BANC | $142 | $75 | $76 | $59 | $19 | $30 | $56 | $54 | $42 | $59 | $62 | $53 | $77 | $41 | $31 | $29 | $21 | $27 | $58 | $37 | $37 | $56 | $46 | $45 |
| Turlock ID | $142 | $76 | $77 | $61 | $19 | $30 | $56 | $54 | $43 | $60 | $63 | $54 | $78 | $41 | $33 | $31 | $21 | $25 | $54 | $37 | $39 | $61 | $47 | $45 |
| LADWP | $142 | $73 | $68 | $49 | $20 | $27 | $67 | $50 | $36 | $45 | $52 | $46 | $68 | $32 | $18 | $12 | $11 | $27 | $55 | $40 | $35 | $40 | $37 | $38 |
| NV Energy | $131 | $66 | $66 | $50 | $17 | $23 | $59 | $40 | $33 | $38 | $48 | $42 | $65 | $30 | $19 | $13 | $10 | $22 | $42 | $29 | $28 | $33 | $29 | $31 |
| Arizona PS | $130 | $66 | $65 | $50 | $17 | $24 | $63 | $41 | $30 | $34 | $45 | $38 | $59 | $28 | $18 | $8 | $8 | $21 | $45 | $30 | $27 | $30 | $26 | $31 |
| Tucson Electric | $129 | $63 | $60 | $47 | $21 | $26 | $58 | $38 | $30 | $33 | $45 | $39 | $59 | $27 | $15 | $9 | $11 | $21 | $39 | $26 | $26 | $28 | $27 | $31 |
| Salt River Project | $119 | $52 | $60 | $50 | $22 | $24 | $62 | $46 | $28 | $34 | $44 | $38 | $54 | $25 | $14 | $9 | $10 | $25 | $38 | $31 | $28 | $30 | $26 | $30 |
| PSC New Mexico | $127 | $64 | $65 | $67 | $17 | $24 | $59 | $40 | $30 | $40 | $50 | $40 | $69 | $35 | $18 | $14 | $10 | $24 | $43 | $29 | $28 | $27 | $57 | $29 |
| WAPA - Desert SW | | | | $57 | $20 | $24 | $62 | $41 | $30 | $34 | $45 | $40 | $60 | $29 | $14 | $7 | $10 | $21 | $42 | $29 | $27 | $32 | $26 | $32 |
| El Paso Electric | | | | $33 | $18 | $23 | $48 | $37 | $29 | $30 | $20 | $20 | $53 | $24 | $15 | $9 | $13 | $27 | $38 | $25 | $26 | $27 | $27 | $30 |
| PacifiCorp East | $120 | $63 | $67 | $52 | $18 | $26 | $53 | $38 | $31 | $40 | $46 | $40 | $76 | $31 | $22 | $16 | $12 | $21 | $39 | $28 | $27 | $35 | $31 | $33 |
| Idaho Power | $132 | $71 | $73 | $59 | $16 | $27 | $52 | $39 | $33 | $56 | $53 | $45 | $112 | $35 | $27 | $20 | $13 | $22 | $37 | $28 | $28 | $37 | $34 | $35 |
| NorthWestern | $133 | $72 | $75 | $61 | $13 | $27 | $53 | $39 | $34 | $62 | $54 | $46 | $151 | $38 | $29 | $24 | $18 | $21 | $36 | $28 | $29 | $30 | $33 | $33 |
| Avista Utilities | $133 | $72 | $74 | $64 | $12 | $27 | $49 | $39 | $34 | $63 | $55 | $46 | $155 | $38 | $30 | $26 | $18 | $21 | $33 | $28 | $29 | $39 | $36 | $35 |
| Avangrid | | | | $61 | $7 | $28 | $49 | $40 | $37 | $63 | $56 | $48 | $164 | $38 | $31 | $25 | $18 | $21 | $32 | $28 | $33 | $40 | $37 | $36 |
| BPA | $133 | $73 | $73 | $62 | $5 | $29 | $55 | $49 | $38 | $65 | $57 | $47 | $182 | $39 | $30 | $27 | $20 | $23 | $40 | $31 | $33 | $40 | $37 | $35 |
| Tacoma Power | $134 | $72 | $73 | $62 | $6 | $29 | $50 | $43 | $37 | $64 | $55 | $47 | $165 | $39 | $31 | $26 | $18 | $20 | $32 | $27 | $32 | $38 | $36 | $36 |
| PacifiCorp West | $132 | $71 | $72 | $61 | $6 | $28 | $48 | $39 | $35 | $64 | $55 | $47 | $170 | $38 | $30 | $25 | $17 | $20 | $31 | $27 | $32 | $39 | $36 | $36 |
| Portland GE | $132 | $71 | $72 | $62 | $9 | $29 | $50 | $43 | $37 | $65 | $55 | $47 | $165 | $38 | $32 | $27 | $17 | $21 | $32 | $27 | $32 | $39 | $36 | $35 |
| Puget Sound Energy | $133 | $73 | $74 | $62 | $8 | $29 | $59 | $44 | $37 | $69 | $58 | $48 | $167 | $39 | $31 | $27 | $18 | $21 | $33 | $28 | $32 | $38 | $35 | $36 |
| Seattle City Light | $133 | $75 | $72 | $61 | $6 | $28 | $50 | $45 | $37 | $64 | $55 | $47 | $167 | $40 | $30 | $28 | $18 | $20 | $31 | $27 | $32 | $40 | $36 | $37 |
| Powerex | $129 | $79 | $84 | $79 | $14 | $55 | $94 | $99 | $83 | $102 | $98 | $62 | $72 | $54 | $49 | $43 | $27 | $32 | $42 | $36 | $33 | $36 | $35 | $34 |

## Table 2.2 Average monthly 5-minute market prices (2024)

| | Jan 2023 | Feb 2023 | Mar 2023 | Apr 2023 | May 2023 | Jun 2023 | Jul 2023 | Aug 2023 | Sep 2023 | Oct 2023 | Nov 2023 | Dec 2023 | Jan 2024 | Feb 2024 | Mar 2024 | Apr 2024 | May 2024 | Jun 2024 | Jul 2024 | Aug 2024 | Sep 2024 | Oct 2024 | Nov 2024 | Dec 2024 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| SMEC | $135 | $68 | $66 | $47 | $16 | $27 | $58 | $53 | $39 | $53 | $57 | $49 | $85 | $35 | $26 | $20 | $14 | $24 | $43 | $34 | $34 | $44 | $40 | $43 |
| PG&E (CAISO) | $136 | $70 | $68 | $49 | $16 | $28 | $52 | $52 | $42 | $58 | $62 | $53 | $79 | $38 | $28 | $26 | $19 | $26 | $49 | $34 | $35 | $51 | $45 | $46 |
| SCE (CAISO) | $133 | $63 | $58 | $41 | $16 | $26 | $62 | $53 | $35 | $48 | $52 | $44 | $63 | $29 | $16 | $9 | $8 | $22 | $42 | $33 | $32 | $37 | $35 | $41 |
| BANC | $138 | $71 | $68 | $49 | $16 | $29 | $54 | $53 | $42 | $57 | $62 | $53 | $79 | $39 | $30 | $27 | $20 | $25 | $48 | $34 | $36 | $52 | $45 | $45 |
| Turlock ID | $139 | $72 | $69 | $52 | $16 | $30 | $54 | $53 | $42 | $58 | $63 | $54 | $79 | $40 | $31 | $29 | $19 | $24 | $45 | $35 | $38 | $57 | $46 | $46 |
| LADWP | $134 | $67 | $59 | $42 | $16 | $26 | $62 | $55 | $37 | $51 | $53 | $45 | $66 | $30 | $17 | $10 | $10 | $27 | $50 | $45 | $35 | $39 | $37 | $38 |
| NV Energy | $126 | $62 | $60 | $42 | $14 | $22 | $56 | $45 | $34 | $44 | $50 | $43 | $65 | $29 | $19 | $12 | $9 | $21 | $37 | $29 | $28 | $33 | $30 | $32 |
| Arizona PS | $123 | $66 | $61 | $42 | $15 | $24 | $59 | $45 | $32 | $40 | $46 | $40 | $59 | $26 | $17 | $8 | $8 | $21 | $40 | $32 | $27 | $30 | $27 | $33 |
| Tucson Electric | $123 | $60 | $54 | $40 | $20 | $26 | $58 | $44 | $31 | $38 | $46 | $40 | $58 | $28 | $16 | $10 | $14 | $24 | $34 | $26 | $27 | $27 | $28 | $32 |
| Salt River Project | $109 | $49 | $54 | $45 | $23 | $26 | $61 | $48 | $27 | $38 | $49 | $39 | $53 | $24 | $17 | $10 | $13 | $29 | $37 | $31 | $29 | $30 | $27 | $32 |
| PSC New Mexico | $122 | $60 | $58 | $53 | $14 | $24 | $56 | $44 | $33 | $46 | $51 | $42 | $70 | $34 | $18 | $16 | $12 | $25 | $37 | $28 | $28 | $27 | $50 | $30 |
| WAPA - Desert SW | | | | $40 | $19 | $26 | $58 | $44 | $33 | $38 | $47 | $40 | $59 | $28 | $14 | $6 | $9 | $21 | $37 | $29 | $27 | $32 | $27 | $32 |
| El Paso Electric | | | | $28 | $16 | $23 | $47 | $40 | $30 | $33 | $23 | $23 | $52 | $24 | $15 | $8 | $18 | $25 | $36 | $24 | $26 | $27 | $27 | $32 |
| PacifiCorp East | $116 | $59 | $62 | $45 | $14 | $25 | $52 | $43 | $34 | $44 | $47 | $40 | $73 | $30 | $21 | $15 | $11 | $20 | $35 | $27 | $27 | $34 | $31 | $34 |
| Idaho Power | $127 | $66 | $68 | $51 | $13 | $26 | $52 | $44 | $35 | $61 | $54 | $46 | $119 | $34 | $25 | $19 | $13 | $21 | $34 | $28 | $28 | $36 | $34 | $35 |
| NorthWestern | $128 | $67 | $69 | $56 | $9 | $27 | $55 | $46 | $37 | $67 | $55 | $48 | $161 | $37 | $28 | $26 | $18 | $20 | $33 | $28 | $30 | $31 | $34 | $34 |
| Avista Utilities | $129 | $67 | $69 | $56 | $10 | $27 | $51 | $44 | $37 | $68 | $55 | $48 | $164 | $37 | $29 | $27 | $18 | $20 | $32 | $28 | $29 | $37 | $36 | $36 |
| Avangrid | | | | $56 | $6 | $27 | $51 | $44 | $38 | $68 | $55 | $48 | $168 | $37 | $29 | $24 | $16 | $20 | $33 | $28 | $31 | $39 | $37 | $37 |
| BPA | $130 | $68 | $68 | $57 | $4 | $28 | $53 | $48 | $37 | $69 | $56 | $47 | $184 | $37 | $28 | $26 | $17 | $22 | $38 | $29 | $32 | $38 | $35 | $36 |
| Tacoma Power | $130 | $67 | $69 | $56 | $5 | $28 | $50 | $45 | $37 | $69 | $54 | $47 | $170 | $37 | $29 | $26 | $17 | $20 | $32 | $27 | $31 | $37 | $35 | $36 |
| PacifiCorp West | $129 | $66 | $68 | $56 | $6 | $26 | $50 | $42 | $37 | $68 | $54 | $47 | $171 | $37 | $28 | $24 | $16 | $20 | $32 | $27 | $31 | $38 | $36 | $36 |
| Portland GE | $129 | $66 | $68 | $56 | $9 | $27 | $50 | $45 | $37 | $69 | $54 | $47 | $169 | $37 | $29 | $26 | $16 | $20 | $32 | $27 | $31 | $38 | $35 | $36 |
| Puget Sound Energy | $131 | $68 | $69 | $56 | $7 | $28 | $61 | $47 | $38 | $74 | $56 | $47 | $175 | $37 | $29 | $27 | $16 | $20 | $33 | $27 | $31 | $37 | $34 | $36 |
| Seattle City Light | $130 | $69 | $68 | $56 | $5 | $27 | $50 | $46 | $37 | $68 | $55 | $47 | $171 | $37 | $28 | $26 | $16 | $20 | $31 | $27 | $31 | $38 | $35 | $36 |
| Powerex | $127 | $77 | $83 | $77 | $14 | $52 | $87 | $94 | $77 | $102 | $101 | $61 | $72 | $53 | $48 | $43 | $27 | $30 | $42 | $36 | $33 | $36 | $35 | $34 |

## Table 2.3 Average hourly 15-minute market prices (2024)

| 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 | $42 | $40 | $39 | $38 | $39 | $44 | $47 | $37 | $28 | $26 | $25 | $24 | $22 | $22 | $24 | $31 | $39 | $49 | $61 | $68 | $57 | $51 | $45 | $43 |
| PG&E (CAISO) | $42 | $40 | $39 | $39 | $40 | $45 | $48 | $42 | $34 | $32 | $29 | $27 | $25 | $26 | $28 | $35 | $43 | $55 | $68 | $72 | $60 | $52 | $46 | $43 |
| SCE (CAISO) | $41 | $39 | $38 | $38 | $39 | $44 | $46 | $33 | $17 | $11 | $9 | $7 | $6 | $6 | $8 | $17 | $28 | $41 | $56 | $65 | $54 | $49 | $45 | $42 |
| BANC | $42 | $40 | $39 | $39 | $40 | $44 | $47 | $41 | $35 | $33 | $32 | $30 | $28 | $29 | $32 | $38 | $43 | $51 | $63 | $70 | $58 | $51 | $46 | $43 |
| Turlock ID | $42 | $40 | $39 | $38 | $40 | $44 | $47 | $41 | $36 | $36 | $35 | $33 | $32 | $32 | $35 | $40 | $44 | $51 | $61 | $68 | $57 | $50 | $45 | $42 |
| LADWP | $44 | $40 | $38 | $38 | $39 | $44 | $46 | $35 | $19 | $13 | $11 | $9 | $8 | $9 | $12 | $22 | $30 | $43 | $60 | $70 | $56 | $51 | $48 | $43 |
| NV Energy | $32 | $31 | $30 | $30 | $32 | $36 | $35 | $28 | $19 | $17 | $16 | $15 | $14 | $14 | $16 | $23 | $28 | $36 | $48 | $54 | $43 | $37 | $36 | $33 |
| Arizona PS | $32 | $30 | $30 | $30 | $32 | $36 | $37 | $27 | $16 | $12 | $10 | $9 | $9 | $8 | $13 | $19 | $26 | $36 | $47 | $56 | $44 | $37 | $36 | $33 |
| Tucson Electric | $30 | $27 | $27 | $27 | $29 | $33 | $31 | $22 | $13 | $11 | $10 | $10 | $10 | $12 | $13 | $21 | $31 | $36 | $46 | $53 | $42 | $36 | $35 | $31 |
| Salt River Project | $31 | $29 | $28 | $29 | $31 | $35 | $34 | $24 | $14 | $13 | $11 | $12 | $10 | $11 | $12 | $20 | $26 | $33 | $51 | $49 | $38 | $34 | $36 | $32 |
| PSC New Mexico | $34 | $31 | $32 | $33 | $35 | $39 | $45 | $39 | $22 | $18 | $22 | $10 | $6 | $6 | $22 | $36 | $28 | $40 | $51 | $60 | $47 | $39 | $37 | $37 |
| WAPA - Desert SW | $35 | $33 | $30 | $30 | $32 | $36 | $36 | $26 | $17 | $12 | $10 | $9 | $8 | $8 | $9 | $17 | $25 | $35 | $50 | $54 | $43 | $37 | $38 | $32 |
| El Paso Electric | $31 | $25 | $24 | $24 | $27 | $31 | $30 | $21 | $14 | $12 | $10 | $11 | $14 | $13 | $12 | $27 | $32 | $44 | $48 | $50 | $40 | $34 | $32 | $27 |
| PacifiCorp East | $31 | $30 | $29 | $29 | $31 | $35 | $35 | $29 | $24 | $23 | $23 | $22 | $21 | $20 | $21 | $27 | $33 | $39 | $47 | $53 | $42 | $37 | $35 | $32 |
| Idaho Power | $33 | $33 | $32 | $33 | $37 | $40 | $40 | $38 | $35 | $32 | $31 | $30 | $26 | $26 | $27 | $31 | $37 | $40 | $48 | $53 | $46 | $39 | $40 | $34 |
| NorthWestern | $34 | $33 | $34 | $34 | $37 | $41 | $40 | $41 | $37 | $36 | $36 | $36 | $34 | $35 | $34 | $37 | $41 | $46 | $50 | $56 | $48 | $43 | $40 | $36 |
| Avista Utilities | $35 | $34 | $35 | $35 | $38 | $42 | $41 | $42 | $39 | $39 | $39 | $39 | $37 | $39 | $37 | $39 | $44 | $49 | $51 | $54 | $48 | $43 | $41 | $38 |
| Avangrid | $37 | $36 | $36 | $37 | $40 | $43 | $40 | $41 | $40 | $41 | $42 | $42 | $39 | $40 | $43 | $44 | $45 | $48 | $50 | $51 | $48 | $44 | $42 | $39 |
| BPA | $40 | $36 | $37 | $38 | $40 | $44 | $45 | $48 | $44 | $46 | $47 | $44 | $43 | $44 | $44 | $45 | $48 | $53 | $53 | $53 | $51 | $49 | $46 | $40 |
| Tacoma Power | $37 | $36 | $36 | $37 | $40 | $42 | $39 | $41 | $40 | $42 | $42 | $42 | $41 | $40 | $42 | $43 | $44 | $46 | $49 | $50 | $47 | $43 | $43 | $39 |
| PacifiCorp West | $38 | $36 | $36 | $37 | $40 | $44 | $39 | $41 | $39 | $40 | $42 | $42 | $39 | $41 | $44 | $43 | $46 | $47 | $49 | $49 | $47 | $43 | $42 | $39 |
| Portland GE | $37 | $36 | $36 | $37 | $40 | $43 | $39 | $41 | $40 | $40 | $42 | $42 | $40 | $41 | $43 | $44 | $44 | $47 | $50 | $50 | $47 | $43 | $42 | $39 |
| Puget Sound Energy | $38 | $36 | $36 | $37 | $39 | $42 | $40 | $43 | $40 | $41 | $42 | $42 | $40 | $40 | $42 | $43 | $45 | $48 | $50 | $52 | $48 | $44 | $44 | $40 |
| Seattle City Light | $37 | $36 | $36 | $37 | $39 | $42 | $41 | $41 | $40 | $43 | $46 | $43 | $40 | $40 | $43 | $43 | $45 | $49 | $49 | $50 | $47 | $44 | $43 | $41 |
| Powerex | $39 | $37 | $36 | $36 | $38 | $41 | $43 | $42 | $42 | $41 | $40 | $40 | $40 | $40 | $40 | $42 | $44 | $45 | $46 | $46 | $45 | $43 | $42 | $40 |

**Table 2.4 Average hourly 5-minute market prices (2024)**

| 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 | $40 | $39 | $38 | $39 | $42 | $45 | $38 | $29 | $28 | $24 | $23 | $21 | $22 | $22 | $26 | $33 | $40 | $48 | $54 | $50 | $50 | $46 | $44 |
| PG&E (CAISO) | $43 | $41 | $39 | $39 | $40 | $43 | $46 | $41 | $37 | $35 | $30 | $27 | $25 | $26 | $27 | $31 | $37 | $45 | $51 | $57 | $51 | $50 | $47 | $44 |
| SCE (CAISO) | $42 | $40 | $38 | $38 | $39 | $42 | $45 | $32 | $16 | $11 | $8 | $7 | $7 | $7 | $7 | $14 | $24 | $36 | $46 | $51 | $48 | $48 | $46 | $43 |
| BANC | $43 | $40 | $39 | $39 | $39 | $42 | $46 | $40 | $37 | $37 | $33 | $31 | $30 | $29 | $31 | $34 | $38 | $43 | $49 | $56 | $50 | $49 | $46 | $43 |
| Turlock ID | $43 | $40 | $38 | $38 | $39 | $42 | $46 | $40 | $39 | $40 | $36 | $33 | $31 | $32 | $34 | $36 | $39 | $43 | $47 | $54 | $49 | $49 | $46 | $43 |
| LADWP | $45 | $40 | $38 | $38 | $39 | $42 | $46 | $33 | $18 | $14 | $10 | $9 | $11 | $13 | $23 | $21 | $28 | $39 | $51 | $58 | $49 | $50 | $50 | $45 |
| NV Energy | $33 | $31 | $31 | $31 | $33 | $36 | $36 | $26 | $19 | $18 | $15 | $16 | $14 | $14 | $15 | $21 | $26 | $34 | $43 | $46 | $40 | $38 | $38 | $34 |
| Arizona PS | $34 | $33 | $30 | $31 | $34 | $36 | $37 | $29 | $14 | $12 | $10 | $8 | $10 | $8 | $12 | $18 | $25 | $35 | $45 | $47 | $40 | $38 | $38 | $34 |
| Tucson Electric | $30 | $29 | $28 | $28 | $30 | $34 | $31 | $22 | $12 | $11 | $10 | $11 | $12 | $13 | $19 | $24 | $34 | $39 | $42 | $46 | $39 | $36 | $36 | $32 |
| Salt River Project | $33 | $30 | $29 | $30 | $32 | $35 | $34 | $22 | $12 | $14 | $15 | $16 | $12 | $13 | $15 | $21 | $27 | $35 | $50 | $49 | $37 | $35 | $38 | $32 |
| PSC New Mexico | $34 | $34 | $31 | $33 | $37 | $40 | $50 | $37 | $24 | $18 | $15 | $11 | $7 | $8 | $15 | $30 | $29 | $38 | $49 | $49 | $45 | $40 | $40 | $36 |
| WAPA - Desert SW | $36 | $33 | $31 | $31 | $33 | $36 | $36 | $25 | $15 | $12 | $9 | $9 | $8 | $8 | $8 | $15 | $23 | $33 | $46 | $45 | $39 | $37 | $39 | $33 |
| El Paso Electric | $30 | $26 | $24 | $25 | $28 | $32 | $31 | $20 | $12 | $12 | $9 | $10 | $10 | $12 | $17 | $27 | $35 | $43 | $44 | $44 | $38 | $33 | $34 | $29 |
| PacifiCorp East | $32 | $30 | $30 | $30 | $32 | $35 | $35 | $29 | $24 | $24 | $21 | $20 | $19 | $20 | $20 | $23 | $29 | $35 | $40 | $46 | $39 | $37 | $37 | $33 |
| Idaho Power | $35 | $33 | $34 | $35 | $39 | $41 | $40 | $39 | $34 | $33 | $30 | $28 | $25 | $26 | $26 | $30 | $34 | $38 | $42 | $50 | $44 | $41 | $41 | $37 |
| NorthWestern | $36 | $34 | $34 | $36 | $38 | $43 | $44 | $43 | $37 | $40 | $37 | $36 | $33 | $37 | $35 | $38 | $41 | $48 | $50 | $53 | $47 | $44 | $42 | $39 |
| Avista Utilities | $37 | $35 | $35 | $36 | $40 | $43 | $44 | $41 | $39 | $41 | $39 | $39 | $37 | $39 | $37 | $40 | $43 | $48 | $49 | $53 | $48 | $44 | $44 | $40 |
| Avangrid | $38 | $35 | $36 | $38 | $40 | $43 | $42 | $40 | $39 | $40 | $41 | $41 | $38 | $40 | $41 | $41 | $43 | $48 | $49 | $52 | $48 | $44 | $44 | $40 |
| BPA | $40 | $36 | $36 | $38 | $41 | $45 | $45 | $42 | $40 | $45 | $44 | $44 | $43 | $42 | $42 | $42 | $47 | $50 | $52 | $51 | $50 | $49 | $47 | $40 |
| Tacoma Power | $38 | $35 | $36 | $38 | $40 | $43 | $42 | $40 | $38 | $41 | $42 | $40 | $38 | $40 | $41 | $41 | $43 | $47 | $48 | $51 | $47 | $44 | $45 | $40 |
| PacifiCorp West | $38 | $35 | $36 | $38 | $41 | $44 | $42 | $40 | $38 | $40 | $40 | $40 | $37 | $39 | $41 | $41 | $43 | $47 | $48 | $51 | $47 | $44 | $44 | $42 |
| Portland GE | $37 | $35 | $36 | $38 | $40 | $43 | $42 | $40 | $38 | $40 | $41 | $40 | $38 | $40 | $41 | $41 | $43 | $47 | $48 | $52 | $47 | $44 | $44 | $40 |
| Puget Sound Energy | $38 | $35 | $36 | $38 | $40 | $43 | $42 | $40 | $40 | $41 | $41 | $41 | $38 | $40 | $41 | $41 | $44 | $48 | $48 | $55 | $50 | $45 | $46 | $42 |
| Seattle City Light | $38 | $36 | $36 | $38 | $39 | $42 | $43 | $40 | $38 | $43 | $42 | $40 | $38 | $40 | $41 | $41 | $43 | $47 | $48 | $51 | $47 | $44 | $44 | $40 |
| Powerex | $39 | $37 | $36 | $37 | $38 | $41 | $42 | $41 | $40 | $40 | $40 | $40 | $40 | $40 | $40 | $42 | $43 | $44 | $44 | $46 | $44 | $43 | $42 | $40 |

## 2.3 Day-ahead market price comparison

This section analyzes day-ahead and real-time market prices for balancing areas in the day-ahead market. Currently, this is just the California ISO balancing area.

In 2024, prices in the CAISO balancing area's day-ahead, 15-minute, and 5-minute markets dropped by about 35 percent compared to the previous year. The simple average price of the three markets this year decreased to $40/MWh from $62/MWh in 2023.

Figure 2.7 shows load-weighted average monthly energy prices during all hours across all Aggregated Pricing Nodes (APnodes). Prices are calculated based on the load schedules and corresponding prices at these pricing nodes.[111] Average prices are shown for the day-ahead (blue line), 15-minute (gold line), and 5-minute (green line) markets from January 2023 to December 2024.

In 2024, day-ahead prices averaged $41/MWh, 15-minute prices averaged $40/MWh, and 5-minute prices averaged $39/MWh. January had the highest prices, with an average over the three markets of about $74/MWh.

Figure 2.7 also shows monthly average natural gas prices at PG&E Citygate from January 2023 to December 2024. The chart shows that the monthly variation of the energy prices is highly correlated with gas prices. Over the past 24 months, both gas and energy prices exhibited similar fluctuations. The

[111] The load-weighted average is calculated by weighting each interval's price by its corresponding load relative to the total over a specific time period. For monthly average, prices for each real-time interval are weighted by their respective loads and divided by the total monthly load for the region. For hourly averages over the quarter, each interval's price is weighted by its load relative to the total load during that hour for the region.

PG&E Citygate gas price has remained down after declining from January 2023, averaging about $3.08/MMBtu in 2024.

This strong correlation between energy and gas prices can be attributed to gas-fired units often serving as the price-setting units within the market. A high gas price increases the marginal cost of generation for gas-fired units and non-gas-fired resources with opportunity costs indexed to gas prices. Market bids reflect these higher marginal costs.

**Figure 2.7 Monthly average PG&E Citygate gas price and load-weighted average electricity prices for balancing areas in day-ahead market (CAISO)**

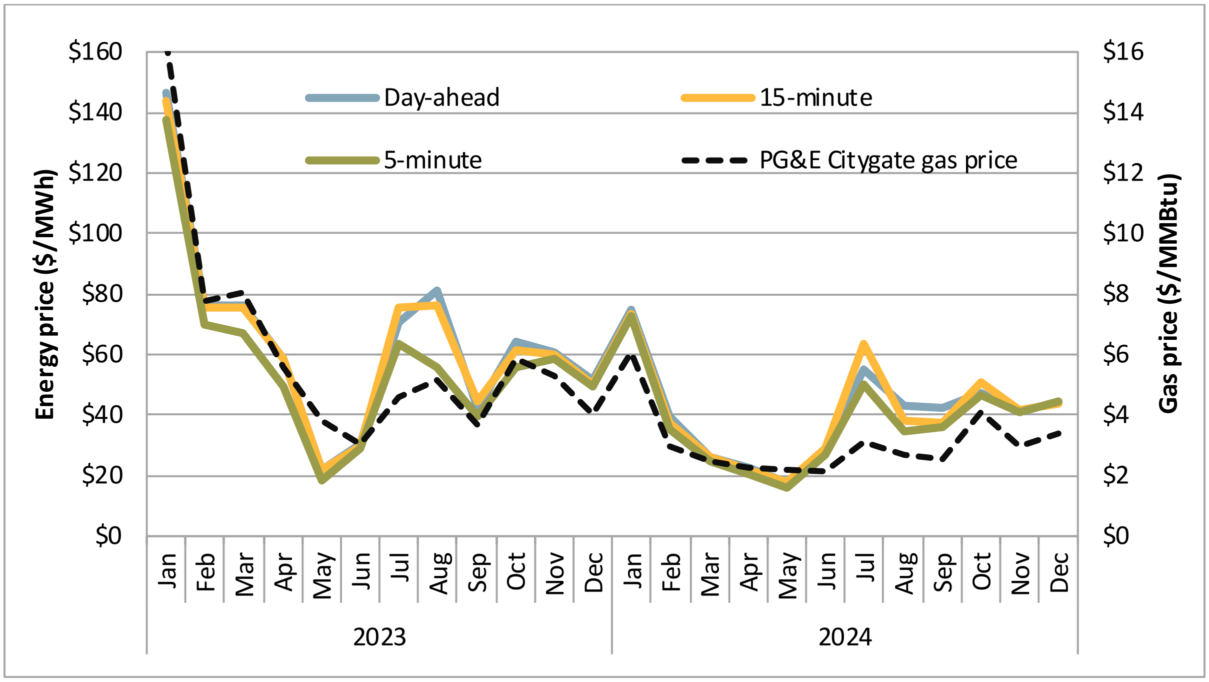



Figure 2.8 illustrates the hourly load-weighted average energy prices for 2024 compared to the average hourly net load.[112] Average hourly prices shown for the day-ahead (blue line), 15-minute (gold line), and 5-minute (green line) markets are measured by the left axis, while the average hourly net load (red dashed line) is measured by the right axis.

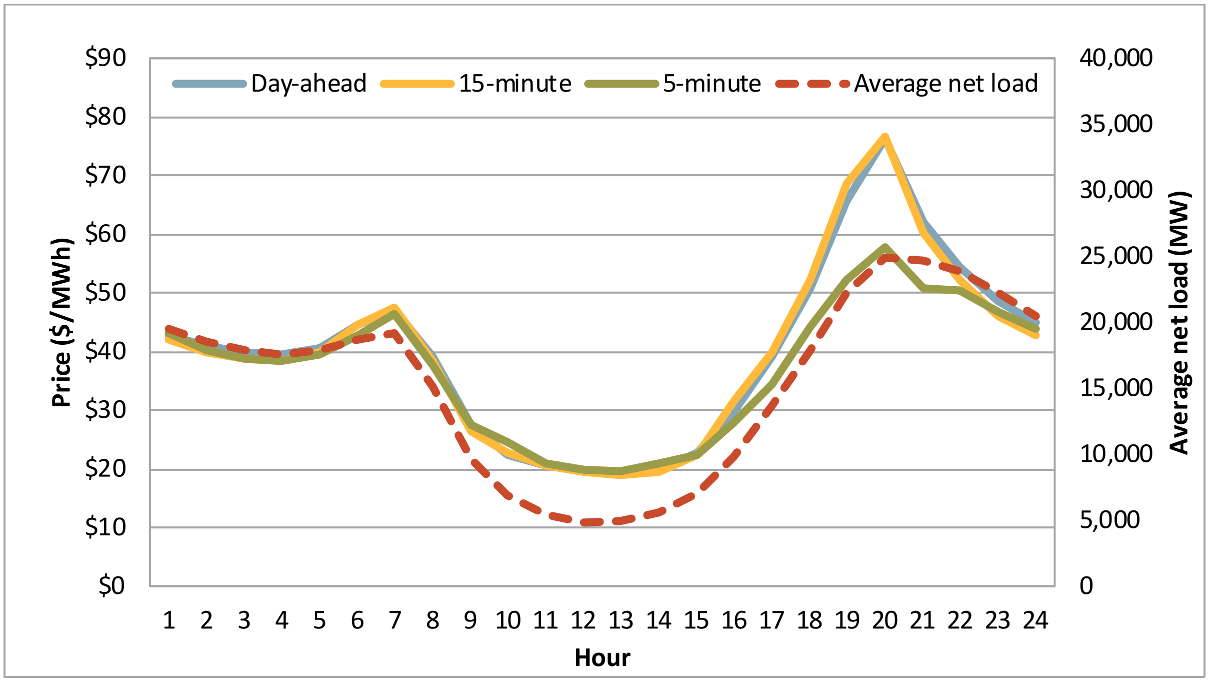
Average hourly prices continue to follow the net load pattern, with the highest energy prices during the morning and evening peak net load hours. Energy prices and net load both increased sharply during the early evening. Prices peaked at hour-ending 20 in all three markets, when demand was still high but solar generation was substantially below its peak. The average net load in this year reached 24,890 MW at hour-ending 20.

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

During hour-ending 20, the day-ahead load-weighted average energy price was $76/MWh, the 15-minute price was $77/MWh, and the 5-minute price was $58/MWh. Day-ahead and 15-minute market prices typically tend to converge on average due to convergence (virtual) bidding.

One major cause of price separation between the 15-minute and 5-minute markets this year was load conformance during evening peak net load hours. California ISO operators typically adjust the load forecast up significantly more in the 15-minute market than in the 5-minute market over these hours.[113]

**Figure 2.8 Hourly load-weighted average energy prices for balancing areas in day-ahead market (CAISO 2024)**




## 2.4 Bilateral price comparison

Figure 2.9 and Figure 2.10 compare 15-minute prices in different regions of the WEIM during peak hours (hours-ending 7 through 22) to day-ahead prices for comparable markets. These figures show the monthly average day-ahead peak energy prices from the Intercontinental Exchange (ICE) at the Mid-Columbia and Palo Verde hubs outside of the California ISO market. These prices were calculated during peak hours (hours-ending 7 through 22) for all days, excluding Sundays and holidays.

For the first three quarters of the year, day-ahead bilateral prices in the Intercontinental Exchange for the Mid-Columbia trading hub were substantially higher than ISO 15-minute market prices in the Pacific Northwest and ISO 15-minute and day-ahead market prices at Pacific Gas and Electric. Similarly, aside from November and December, bilateral prices in the Intercontinental Exchange for the Palo Verde hub

113 Please see Section 9 for a detailed discussion on load conformance.

were higher than ISO 15-minute market prices in the Desert Southwest and ISO 15-minute and day-ahead market prices at Southern California Edison.

**Figure 2.9 Mid-C bilateral ICE vs. Pacific Northwest 15-minute market prices (peak hours)**

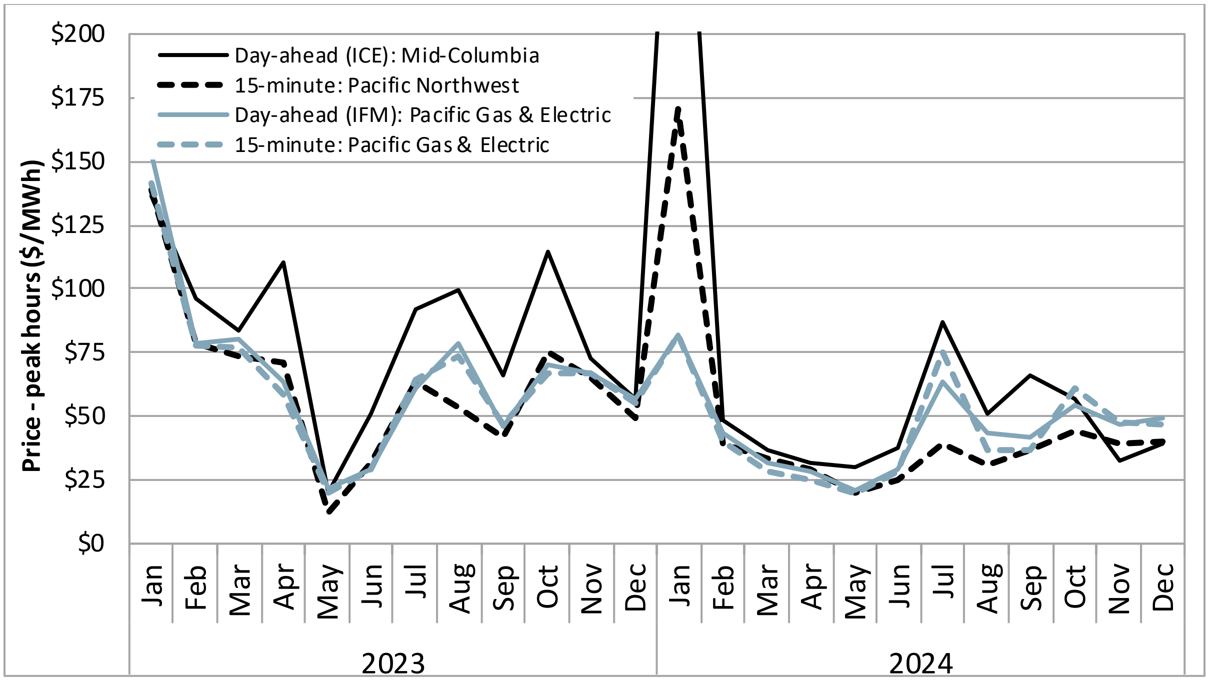



**Figure 2.10 Palo Verde bilateral ICE vs. Desert Southwest 15-minute market prices (peak hours)**

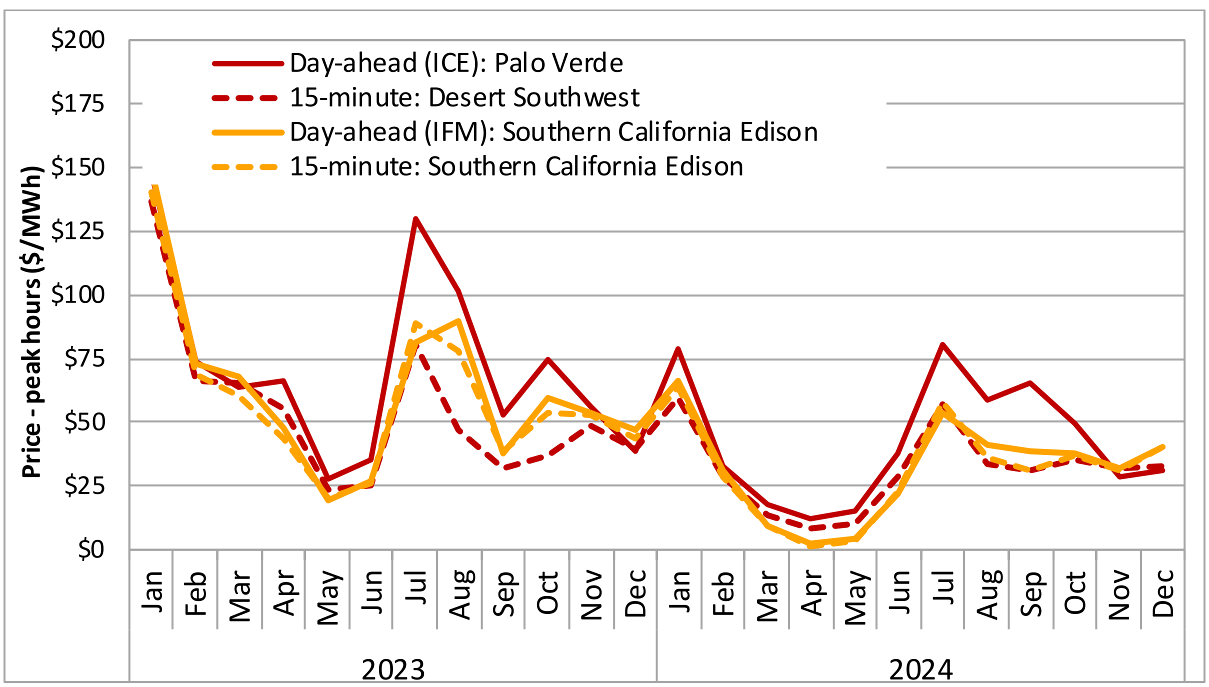


Figure 2.11 compares monthly average prices in the bilateral and ISO day-ahead market for 2023 and 2024. The California ISO market day-ahead prices are represented at the Southern California Edison and Pacific Gas and Electric default load aggregation points (DLAPs). Figure 2.12 shows daily California ISO market day-ahead load weighted average peak prices across the three largest load aggregation points (Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric), as well as averages for the bilateral day-ahead peak energy prices from the Intercontinental Exchange (ICE) at the Mid-Columbia and Palo Verde hubs outside of the ISO markets. These prices were calculated during peak hours (hours-ending 7 through 22) for all days, excluding Sundays and holidays.

**Figure 2.11 Monthly average day-ahead and bilateral market prices**

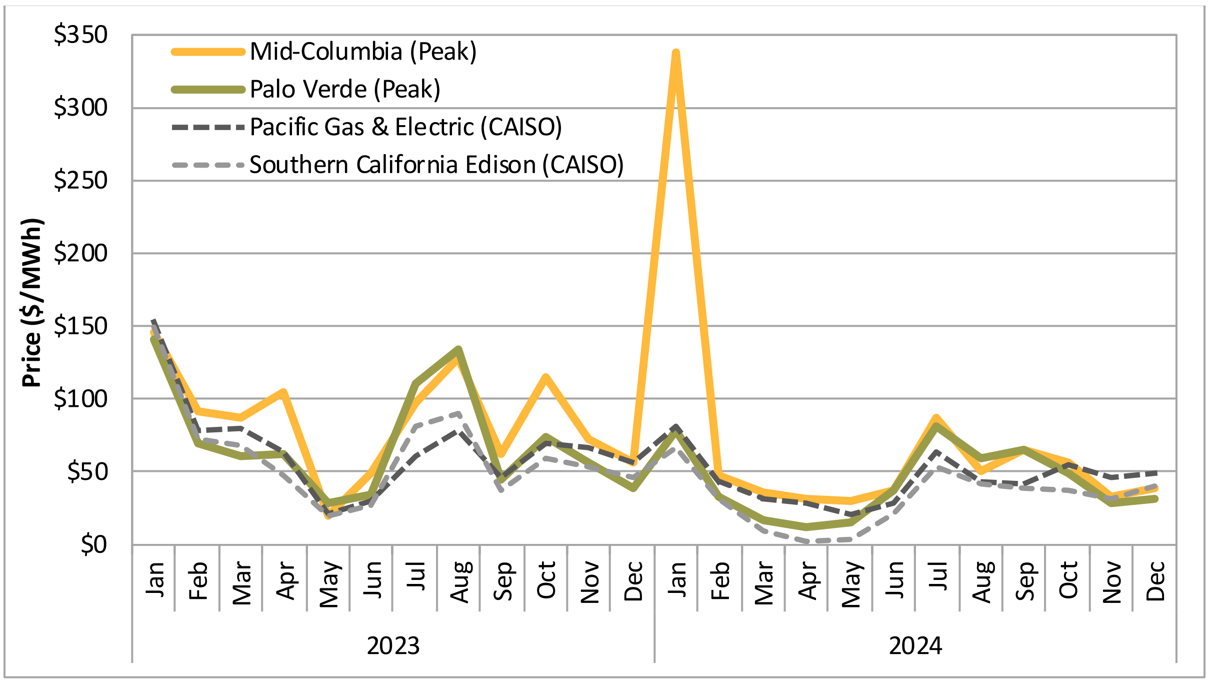
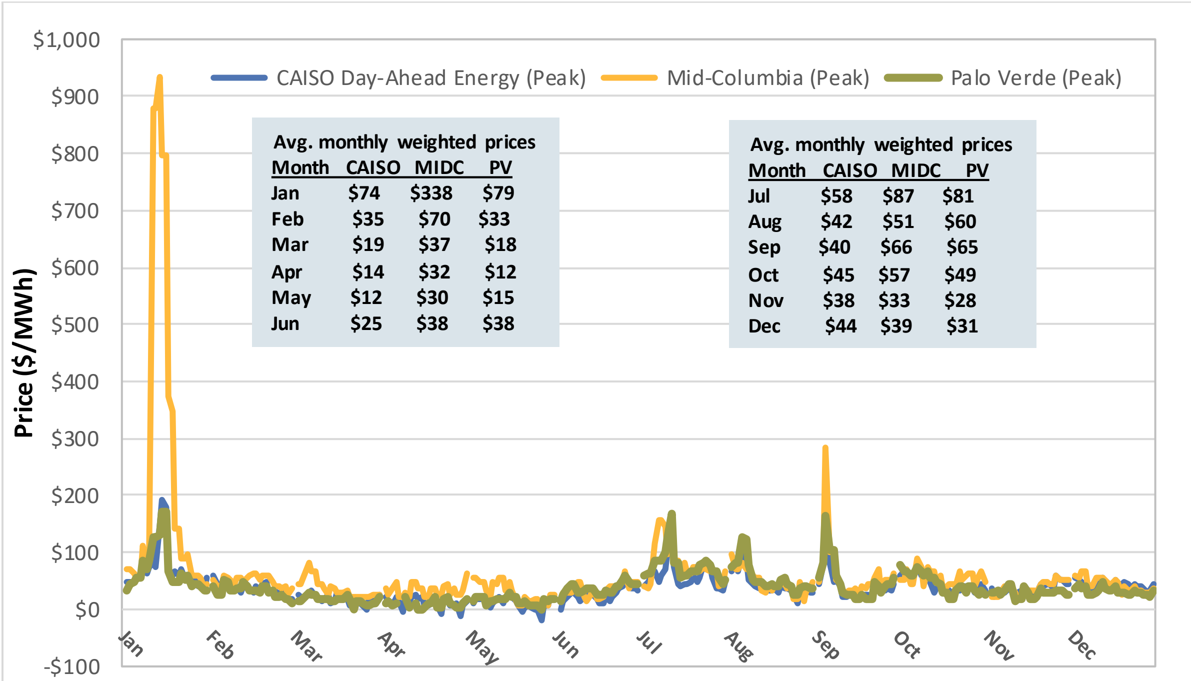


**Figure 2.12 Daily average day-ahead California ISO & bilateral market prices (January–December)**




Average day-ahead bilateral prices from the Intercontinental Exchange (ICE) at these bilateral hubs were also compared to real-time hourly energy prices traded at the Mid-Columbia and Palo Verde hubs for all hours of the year using data published by Powerdex. The average day-ahead ICE prices at Mid-Columbia were greater than the average real-time Powerdex Mid-Columbia prices by about $9/MWh. Average day-ahead ICE prices at Palo Verde were lower than real-time Powerdex Palo Verde prices by about $1.20/MWh.

## 2.5 Price variability

This section analyzes the frequency of prices exceeding $250/MWh and the occurrence of negative prices. Two groups of balancing authority areas (BAAs) were included: the first group consists of those participating in both the day-ahead and real-time markets, which as of this year includes only the California ISO balancing area.[114] The second group comprises balancing areas participating exclusively in the real-time market, which includes all WEIM entities aside from the California ISO balancing area.

[114] The frequency is calculated by counting the number of intervals with extreme prices at either the Default Load Aggregation Point (DLAP) for the CAISO balancing area, or EIM Load Aggregation Point (ELAP) for the WEIM areas not participating in the day-ahead market. The frequency is expressed as a ratio of these occurrences to the total number of intervals for each quarter, multiplied by the number of DLAPs and ELAPs within each group.

### High prices

Figure 2.13 shows the quarterly frequency of high prices across all three markets for the balancing area participating in both the day-ahead and real-time markets from Q1 2023 to Q4 2024.[115] Figure 2.14 illustrates the quarterly frequency of high prices for balancing areas participating only in the real-time market during the same period.[116]

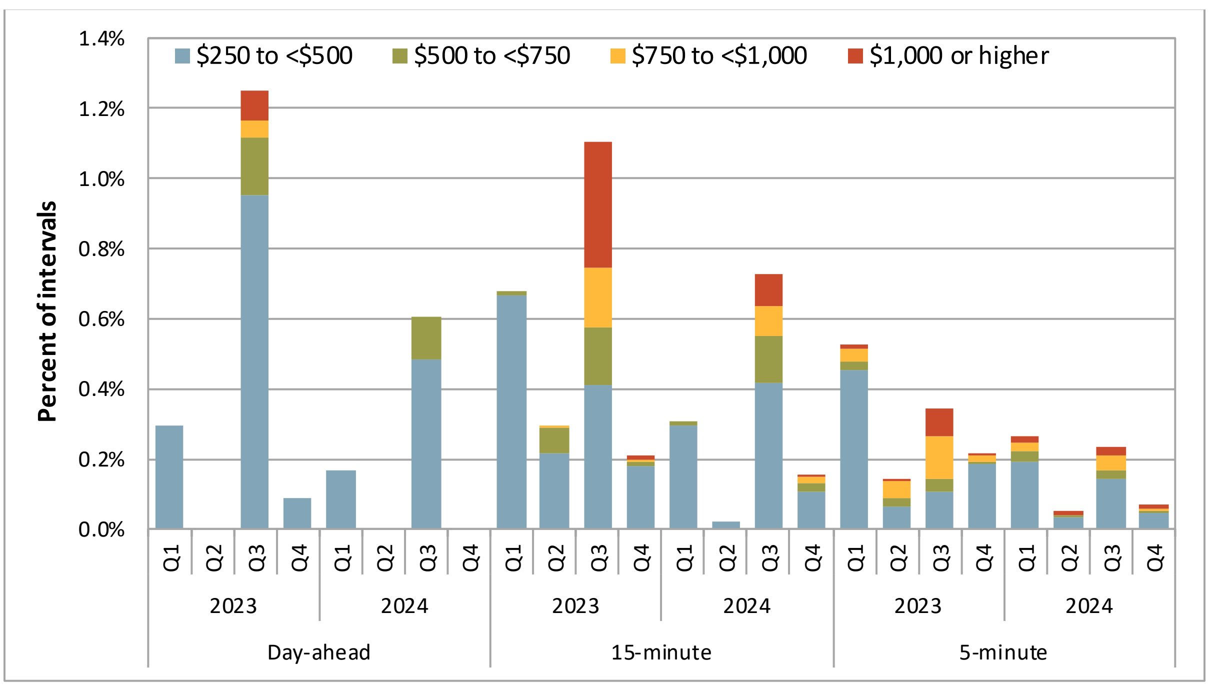
In the day-ahead market, the frequency of high prices over $250/MWh decreased compared to 2023. In 2024, the day-ahead market recorded 0.2 percent of intervals with an average price exceeding $250/MWh. In the previous year, 0.4 percent of intervals had prices above $250/MWh.

In the 15-minute market, the frequency of high prices for the balancing area participating in both the day-ahead and real-time markets decreased from 0.6 percent in 2023 to 0.3 percent in 2024. Conversely, for balancing areas participating exclusively in the real-time market, the frequency of high 15-minute market prices increased from 0.3 percent in 2023 to 0.8 percent in 2024.

In the 5-minute market, the frequency of high prices for the balancing area participating in the day-ahead and real-time markets decreased from 0.3 percent in 2023 to 0.2 percent in 2024. For balancing areas participating only in the real-time market, the frequency of high prices in the 5-minute market increased from 0.3 percent to 0.7 percent.

For the balancing areas participating only in the real-time market, a notable trend was the high frequency of extreme prices during Q1 2024, particularly during the cold weather event in January 2024.

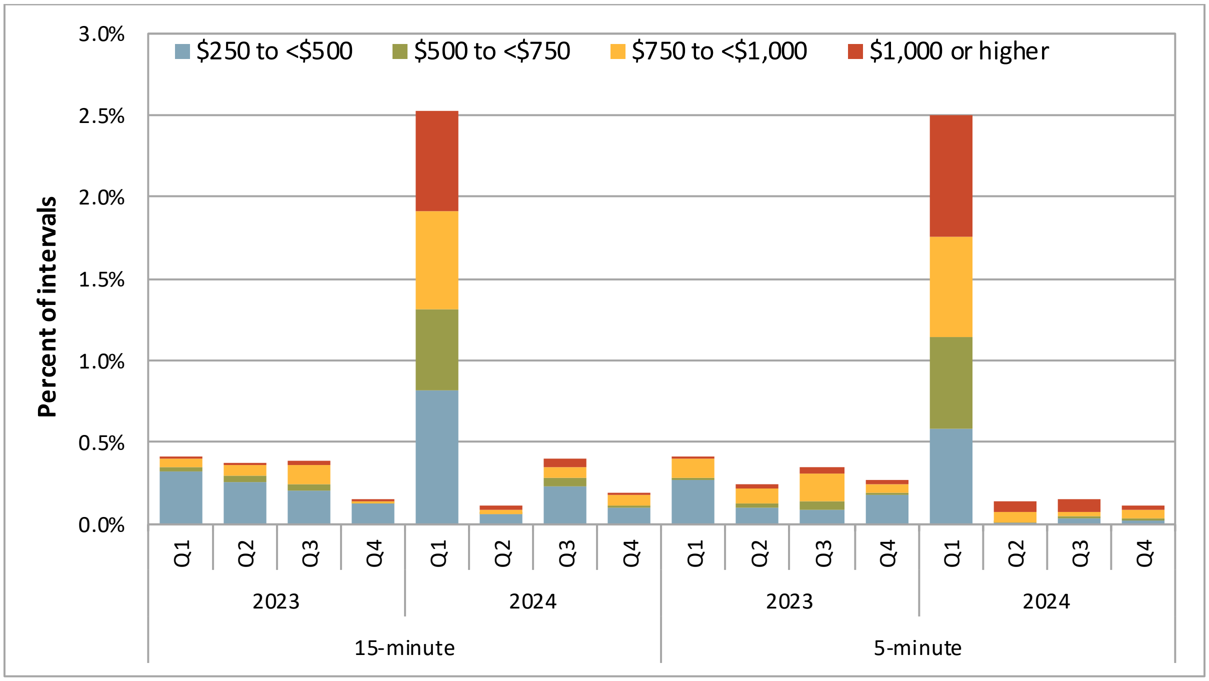
**Figure 2.13 Frequency of high prices in BAAs participating in the day-ahead market (CAISO)**




115 The frequency of high prices was measured at the three largest DLAPs within the California ISO balancing area: Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric.

116 The frequency of high prices was measured at EIM Load Aggregation Points (ELAPs).

**Figure 2.14 Frequency of high prices in BAAs participating only in the real-time markets**




### Negative prices

Figure 2.15 and Figure 2.16 show the frequency of negative prices across two groups of balancing areas: those participating in the day-ahead market and those participating only in the real-time markets, spanning the period from Q1 2023 to Q4 2024 for each market. Overall, the frequency of negative prices continued to increase for both the day-ahead and real-time market participating groups.

Negative prices tend to be most common when renewable production is high and demand is low. This is because in these scenarios, renewable resources are more likely to be the marginal energy source, and low-cost renewable resources often bid at or below zero dollars.

For balancing areas participating in the day-ahead and real-time market—currently just the CAISO balancing area—the frequency of negative prices significantly increased, with an average rise of 136 percent compared to the previous year. In the day-ahead market, the frequency increased from 2.6 percent to 8.8 percent compared to the previous year. In the 15-minute market, it increased from 4.7 percent to 10 percent, and in the 5-minute market, it increased from 6.5 percent to 10.7 percent.

For the BAAs participating exclusively in the real-time markets—all balancing areas in WEIM besides CAISO—the frequency of negative prices showed an increase across the 15-minute and 5-minute markets, with an average rise of 67 percent compared to the previous year. For instance, in the 15-minute market, the frequency increased from 3 percent to 5.4 percent, while in the 5-minute market, it rose from 4.1 percent to 6.4 percent in 2024.

**Figure 2.15 Frequency of negative prices in BAAs participating in the day-ahead market (CAISO)**

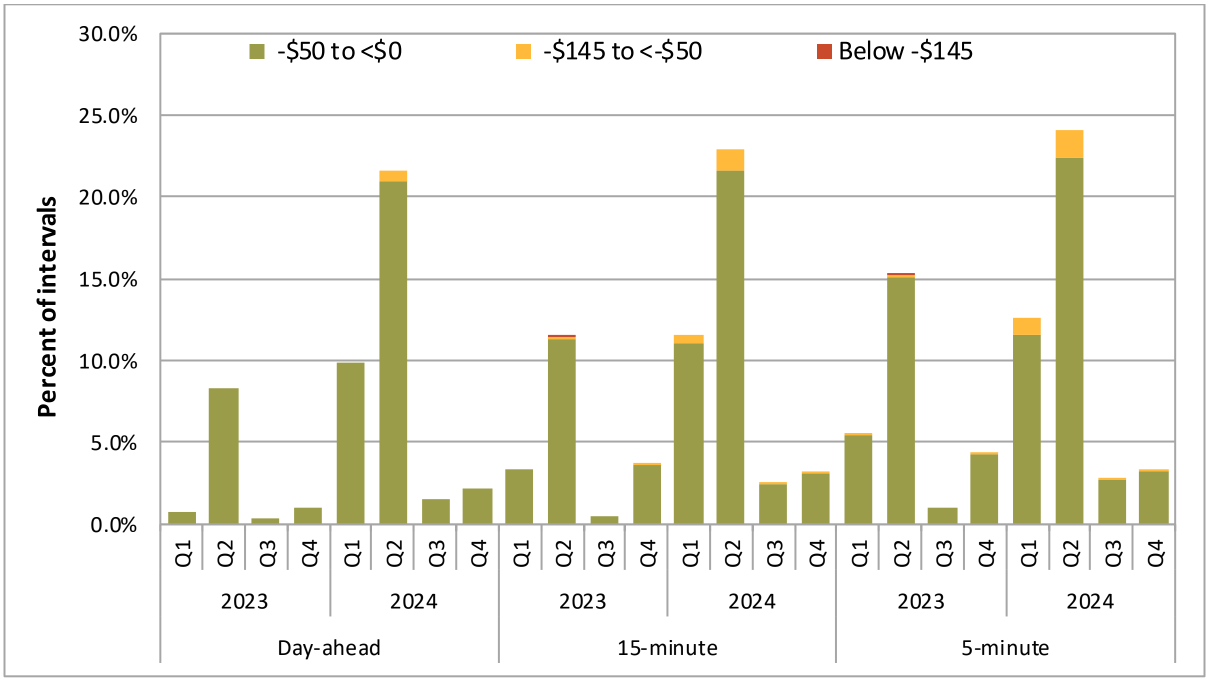
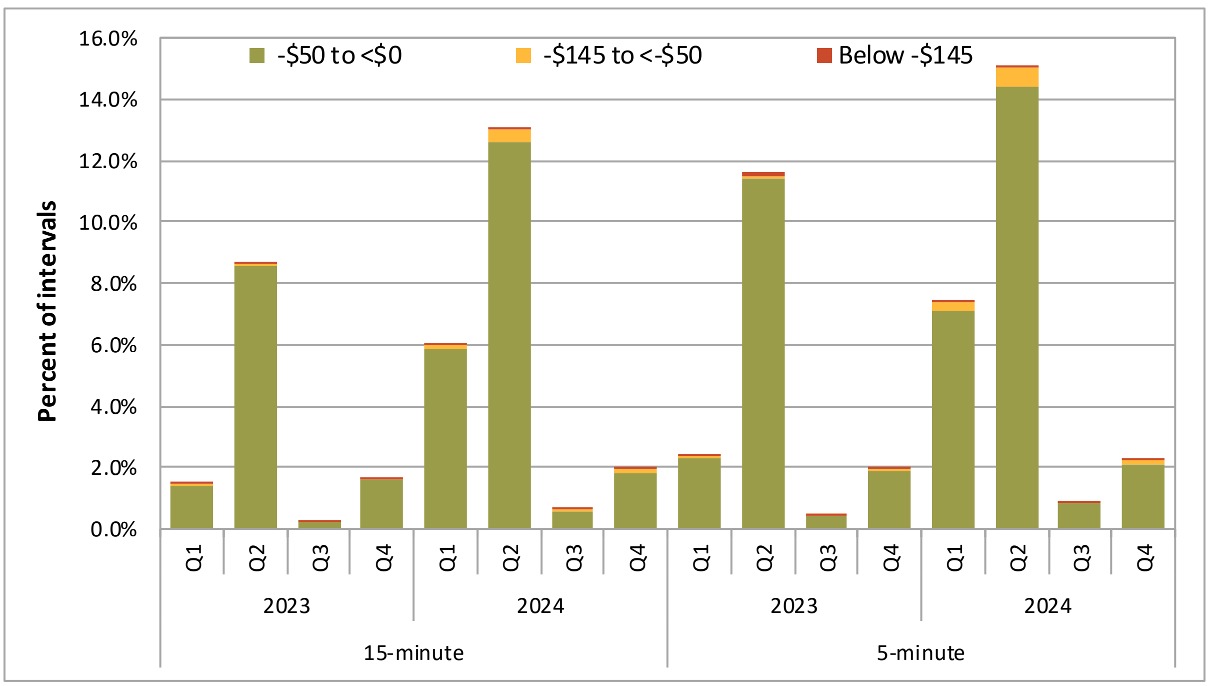



**Figure 2.16 Frequency of negative prices in BAAs participating only in the real-time markets**



### 2.5.1 FERC Order No. 831

The California ISO FERC Order 831 policy will increase the ISO market energy bid cap to $2,000/MWh if either of two conditions are met. The bid cap will rise to $2,000/MWh if a 16-hour block peak bilateral price, scaled and shaped into hourly prices according to the shape of ISO market hourly prices, exceeds $1,000/MWh. The bid cap will also rise to $2,000/MWh if a cost-verified energy bid from a resource-specific resource is greater than the $1,000/MWh bid cap. The California ISO raised its energy bid cap and penalty prices to $2,000/MWh for many hours in both the day-ahead and real-time markets in January on four days[117]—January 13 through 16, 2024—during an extreme cold temperature period, as well as hours-ending 19 and 20 in both the day-ahead and real-time markets on September 5, 2024.[118] The ISO did not raise the energy bid cap and penalty prices to $2,000/MWh in any other time period in 2024.

## 2.6 Power balance constraint

WEIM area prices can be significantly impacted by the frequency with which the power balance constraint (PBC) 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.[119] During the initial six months of 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.

Table 2.5 shows the frequency of power balance constraint relaxations in the 15-minute and 5-minute markets by balancing area for undersupply (shortage) and oversupply (excess) conditions throughout 2024. The color shading indicates frequency: darker colors represent relatively higher frequency, lighter colors indicate lower frequency, and white areas signify near-zero frequency.

Balancing authority areas in the Southwest region, including Public Service Company of New Mexico, Salt River Project, and El Paso Electric had a relatively high frequency of PBC relaxations. Public Service Company of New Mexico had high frequencies of undersupply infeasibilities. Salt River Project and El Paso Electric had relatively high frequencies of both oversupply and undersupply infeasibilities.

Most infeasibilities occurred following a resource sufficiency evaluation failure. 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. As a result, there is often a strong correlation

117 *Winter Conditions Report for January 2024*, California ISO, March 6, 2024, Figure 59: Maximum Import Bid Price and bid ceiling, DAM and RTM, p 64: https://www.caiso.com/documents/wintermarketperformancereportforjan2024.pdf

Day-ahead market days and hours: January 14 hours-ending 1 to 8 and hours-ending 17 to 24. January 15, hour-ending 7 and 17 through 22, and January 16 hours-ending 7 and 17 to 22.

Real-time market days and hours: January 13, hours-ending 16 to 24. January 14, hours-ending 1 to 8 and 17 to 24. January 14, hours-ending 1 to 8 and 17 to 24. January 15, hours-ending 7 and 17 to 22. January 16, hours-ending 7 to 8 and 17 to 22.

118 *Summer Market Performance Report for September 2024*, California ISO, October 31, 2024, p 80: https://www.caiso.com/documents/summer-market-performance-report-september-2024.pdf

119 The penalty parameter while relaxing the constraint for power shortages may rise from $1,000/MWh to $2,000/MWh depending on system conditions, per phase 2 implementation of FERC Order 831.

between WEIM areas failing a resource sufficiency evaluation test and having a power balance constraint relaxation.

**Table 2.5 Frequency of power balance constraint relaxations by market**

| Balancing area | Oversupply infeasibility | | Undersupply infeasibility | |
|---|---|---|---|---|
| | 15-minute | 5-minute | 15-minute | 5-minute |
| PSC New Mexico | .01% | .05% | .53% | .55% |
| Salt River Project | .13% | .15% | .06% | .22% |
| El Paso Electric | .11% | .09% | .17% | .2% |
| LADWP | .00% | .00% | .06% | .19% |
| Arizona PS | .00% | .04% | .06% | .13% |
| Tucson Electric | .00% | .00% | .02% | .13% |
| Idaho Power | .05% | .05% | .02% | .04% |
| Seattle City Light | .03% | .06% | .05% | .02% |
| Puget Sound Energy | .00% | .00% | .04% | .08% |
| NorthWestern | .00% | .00% | .01% | .07% |
| WAPA - Desert SW | .00% | .00% | .06% | .06% |
| PacifiCorp West | .00% | .00% | .05% | .04% |
| Powerex | .03% | .04% | .00% | .00% |
| NV Energy | .02% | .02% | .00% | .02% |
| Tacoma Power | .00% | .00% | .02% | .02% |
| Avista Utilities | .00% | .00% | .01% | .02% |
| CAISO | .00% | .00% | .02% | .01% |
| Avangrid | .00% | .00% | .00% | .01% |
| PacifiCorp East | .00% | .00% | .00% | .01% |
| Turlock ID | .01% | .01% | .00% | .00% |
| BANC | .00% | .00% | .00% | .01% |
| BPA | .00% | .00% | .00% | .01% |
| Portland GE | .00% | .00% | .00% | .00% |
| **Average** | **.02%** | **.02%** | **.05%** | **.08%** |

Figure 2.17 shows the frequency of system-wide power balance constraint infeasibilities identified by the market from Q1 2022 through Q4 2024. These percentages reflect how often any PBC was violated across all BAAs, based on the total number of possible BAA-interval combinations.[120] The yellow bars indicate the frequency of undersupply infeasibilities (shortage), while the green bars represent the frequency of oversupply infeasibilities (excess) for each quarter.

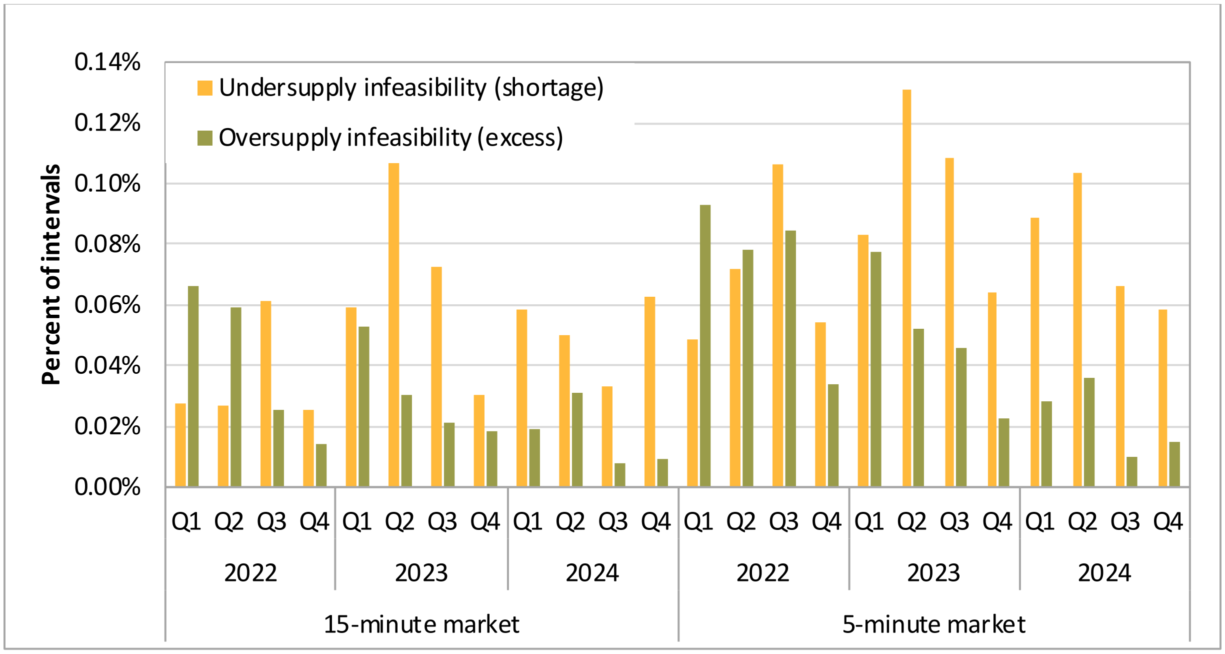
In 2024, average infeasibility frequency for undersupply was 0.05 percent in the 15-minute market and 0.08 percent in the 5-minute market. For oversupply, the rates were lower: 0.02 percent in both 15-minute and 5-minute markets. Undersupply infeasibilities declined compared to 2023, when undersupply occurred at rates of 0.07 percent and 0.1 percent in the 15-minute and 5-minute markets,

120 The frequency is based on the formula: PBC frequency = (Total PBC occurrences in the quarter) / (Number of BAAs × Number of intervals in the quarter).

respectively. Oversupply infeasibilities also decreased, from 0.03 percent to 0.02 percent in the 15-minute market and from 0.05 percent to 0.03 percent in the 5-minute market.

Overall, there were more power balance constraint relaxations due to undersupply (shortage) than oversupply. WEIM areas had more infeasibilities in the 5-minute market than in the 15-minute market.

**Figure 2.17 Frequency of system-wide power balance constraint infeasibilities by market**




## 2.7 Total wholesale market costs

DMM estimates the total wholesale cost of serving load for balancing areas in the day-ahead market. The total estimated wholesale cost for the California ISO balancing authority area in 2024 was about $9.1 billion, or about $44/MWh. This represents a 38 percent decrease from about $71/MWh or $14.5 billion in 2023.[121] After normalizing for natural gas prices and greenhouse gas compliance costs, using 2020 as a reference year, DMM estimates that total normalized wholesale energy costs increased by about 7 percent from about $34/MWh in 2023 to just over $36/MWh in 2024.

Decreased natural gas prices were the main driver of lower nominal wholesale electricity costs. Overall for 2024, average gas prices at NW Sumas, PG&E Citygate and SoCal Citygate decreased by 58 percent, 50 percent and 62 percent, respectively, compared to 2023 (Section 1.2.6).

Slightly higher loads in 2024 contributed to the small increase in normalized wholesale energy costs (Section 1).

[121] The nominal $/MWh values reported in this section have been updated for the 2021 through 2023 reporting years, after identifying and adjusting for an error in the reported load values. Although the $/MWh values for these years are slightly higher than previously reported, the overall trend of changes in the wholesale costs year over year from the last few years has not been impacted after these updates.

Figure 2.18 shows total estimated wholesale costs per megawatt-hour of system load for the previous five years. Wholesale costs are provided in nominal terms (blue bar), and normalized for changes in natural gas prices and greenhouse gas compliance costs (gold bar). The greenhouse gas compliance cost is included to account for the estimated cost of compliance with California's greenhouse gas cap-and-trade program. The green line represents the annual average daily natural gas price including greenhouse gas compliance.[122]

**Figure 2.18 Total annual wholesale costs per MWh of load (2020–2024)**

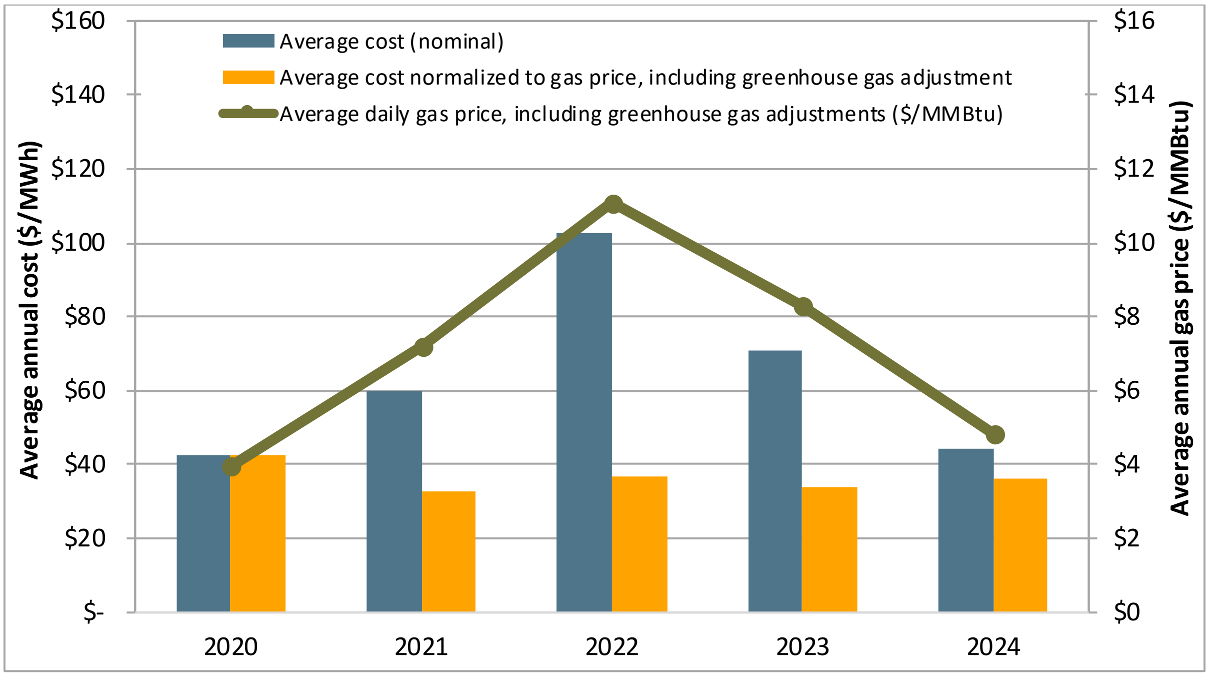



Table 2.6 provides annual summaries of nominal total wholesale costs by category for the previous five years.[123] The total wholesale energy cost also includes costs associated with ancillary services,

[122] 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. A gas cost factor of 0.8 (80 percent) has historically been incorporated into the normalization calculations to account for this relation between electricity costs and gas prices. In recent annual reports, we have adjusted this factor to one. This allows for a more straightforward interpretation of the normalized wholesale cost: increases or decreases relative to the reference year indicate significant factors other than gas and greenhouse gas compliance costs driving changes in wholesale electricity costs.

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

convergence bidding, residual unit commitment, bid cost recovery, reliability must-run contracts, the capacity procurement mechanism, the flexible ramping product, and grid management charges.[124]

As shown in Table 2.6, the 38 percent decrease in total nominal cost in 2024 reflected an overall trend in lower costs over nearly all categories. Day-ahead energy costs decreased by nearly $25/MWh or roughly 38 percent. Real-time energy costs decreased about 37 percent, from $2.42/MWh down to $1.52/MWh, as discussed in more detail in Section 2. Reserve costs and bid cost recovery decreased by 31 percent and 50 percent, respectively, while backstop capacity costs decreased to zero. Grid management charge costs saw a slight increase of about 2 percent. Combined natural gas and greenhouse gas costs decreased about 42 percent.

Day-ahead energy costs remain the largest proportion of wholesale costs at about 93 percent, similar to 2023. The remaining components continue to represent a relatively small portion of the total. Real-time energy costs remained about 3.4 percent of overall costs, similar to 2023. Overall reliability costs decreased to zero in 2024—when resources with existing reliability must-run (RMR) contracts transitioned into resource adequacy contracts, and no new capacity procurement mechanism designations were made for 2024—down from 0.1 percent of total costs in 2023. Bid cost recovery totals decreased as a percent of total cost to about 1.6 percent in 2024 from nearly two percent in 2023. Reserve costs decreased over 30 percent in 2024, but increased as a percent of total cost to nearly 1.3 percent from just over 1.1 percent in 2023.[125]

**Table 2.6 Estimated average wholesale energy costs per MWh (2020–2024)**

| | 2020 | 2021 | 2022 | 2023 | 2024 | Change '23-'24 |
|---|---|---|---|---|---|---|
| Day-ahead energy costs | $ 38.61 | $ 56.37 | $ 96.06 | $ 65.92 | $ 40.94 | $ (24.97) |
| Real-time energy costs (incl. flex ramp) | $ 1.65 | $ 1.28 | $ 3.51 | $ 2.42 | $ 1.52 | $ (.90) |
| Grid management charge | $ .46 | $ .45 | $ .45 | $ .50 | $ .51 | $ .01 |
| Bid cost recovery costs | $ .59 | $ .74 | $ 1.18 | $ 1.36 | $ .68 | $ (.67) |
| Reliability costs (RMR and CPM) | $ .07 | $ .19 | $ .23 | $ .07 | $ 0.00 | $ (.07) |
| **Average total energy costs** | **$ 41.39** | **$ 59.03** | **$ 101.43** | **$ 70.26** | **$ 43.66** | **$ (26.60)** |
| | | | | | | |
| Reserve costs (AS and RUC) | $ 1.02 | $ .84 | $ 1.20 | $ .81 | $ .56 | $ (.25) |
| **Average total costs of energy and reserve** | **$ 42.41** | **$ 59.87** | **$ 102.63** | **$ 71.08** | **$ 44.22** | **$ (26.86)** |

124 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 & 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. *2009 Annual Report on Market Issues & Performance,* Department of Market Monitoring, April 2010: http://www.caiso.com/Documents/2009AnnualReportonMarketIssuesandPerformance.pdf

125 Additional information on reliability costs, bid cost recovery, and ancillary service costs is included in Sections 15, 8, and 12, respectively.

# 3 Energy market competitiveness and mitigation

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

- **Overall prices in the day-ahead market were competitive,** averaging close to what DMM estimates would result under highly efficient and competitive conditions, with most supply being offered at or near marginal operating cost.
- **The number of structurally uncompetitive hours in the day-ahead market in 2024 was slightly higher than 2023 but significantly lower than 2021.** Uncompetitive hours decreased significantly from 2021 to 2023.
- **The amount of energy downstream of non-competitive constraints—and therefore subject to potential mitigation—increased overall in the day-ahead and 15-minute markets.** A large increase in the frequency of binding transmission constraints within the CAISO balancing area in the day-ahead and real-time markets caused a significant rise in bids subject to mitigation in this balancing area. Bids subject to mitigation in all WEIM regions outside of California decreased compared to 2023.
- **Most resources subject to mitigation submitted competitive offer prices, so a low portion of bids were lowered as a result of the bid mitigation process.** Roughly 22 percent (1,060 MW) of the day-ahead bids and 15 percent (956 MW) of 15-minute market bids that were subject to mitigation were changed.
- **The potential increase in dispatch from bids lowered by mitigation remained very low**. In the day-ahead market, the average potential increase in dispatch averaged 48 MW. In the 15-minute market, system-wide potential increase in dispatch from mitigation averaged 108 MW.

## 3.1 Background on 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 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 supplier 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.[126] 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

[126] 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.

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.

## 3.2 Day-ahead market structural measures of system competitiveness

The day-ahead residual supply index analysis considers balancing areas participating in the day-ahead market.[127] This analysis includes the following elements to account for supply and demand:

- Day-ahead bids for physical generating resources (adjusted for outages and de-rates).
- Maximum availability of non-pivotal imports offered relative to import transmission constraint limits.
- Demand includes the day-ahead load forecast, non-dispatchable pump load, self-scheduled exports, and upward ancillary service requirements.[128]
- Ancillary services bids in excess of energy bids are included to account for additional supply available to meet ancillary service requirements in the day-ahead market.
- CPUC jurisdictional investor-owned utilities are excluded as potentially pivotal suppliers.
- Virtual bids are excluded.

During 2024, the number of hours with a day-ahead residual supply index less than one was higher compared to the previous year (i.e., less competitive). Table 3.1 shows the number of hours each year with a residual supply index ratio less than one since 2021, based on the assumptions listed above. Figure 3.1 shows the same information graphically by quarter. For 2024, the residual supply index with the three largest suppliers removed ($RSI_3$) was less than one during 176 hours, compared to 129 hours in 2023. The index was less than one during 97 hours with the two largest suppliers removed ($RSI_2$) and less than one during 24 hours with the largest single supplier removed ($RSI_1$).

Figure 3.2 shows the lowest 500 $RSI_3$ values for each year. During these hours, structural competitiveness in 2024 was very similar to that of 2023 and 2022. However, in comparison to 2021, structural competitiveness was greater in 2024. During 2024, with the three largest suppliers removed, the $RSI_3$ was less than 0.9 in 53 hours, and less than 0.8 in three hours. At its lowest, the $RSI_3$ was around 0.78 in 2024.

Figure 3.3 summarizes non-pivotal supply with the three largest suppliers excluded in the same 500 hours with the lowest $RSI_3$ values. In particular, continued additions of battery (and hybrid) capacity offset decreases in gas capacity and helped reduce the number of potentially non-competitive hours.

[127] CAISO is currently the only balancing area participating in the day-ahead market.

[128] The day-ahead load forecast factors in losses.

**Table 3.1 Hours with day-ahead residual supply index less than one by year (balancing areas in the day-ahead market)**

| Year | $RSI_1$ | $RSI_2$ | $RSI_3$ |
|---|---|---|---|
| 2021 | 84 | 189 | 316 |
| 2022 | 44 | 79 | 130 |
| 2023 | 26 | 75 | 129 |
| 2024 | 24 | 97 | 176 |

**Figure 3.1 Hours with day-ahead residual supply index less than one by quarter (balancing areas in the day-ahead market)**

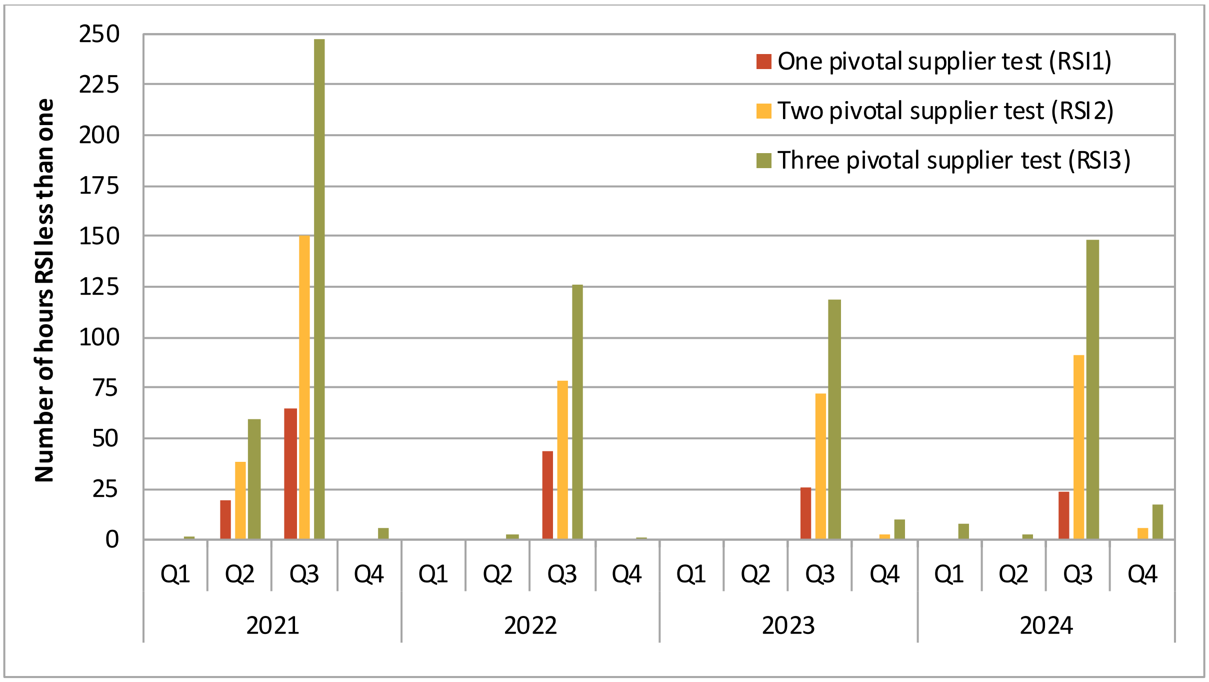


**Figure 3.2 Day-ahead residual supply index with largest three suppliers excluded (balancing areas in the day-ahead market, lowest 500 hours)**

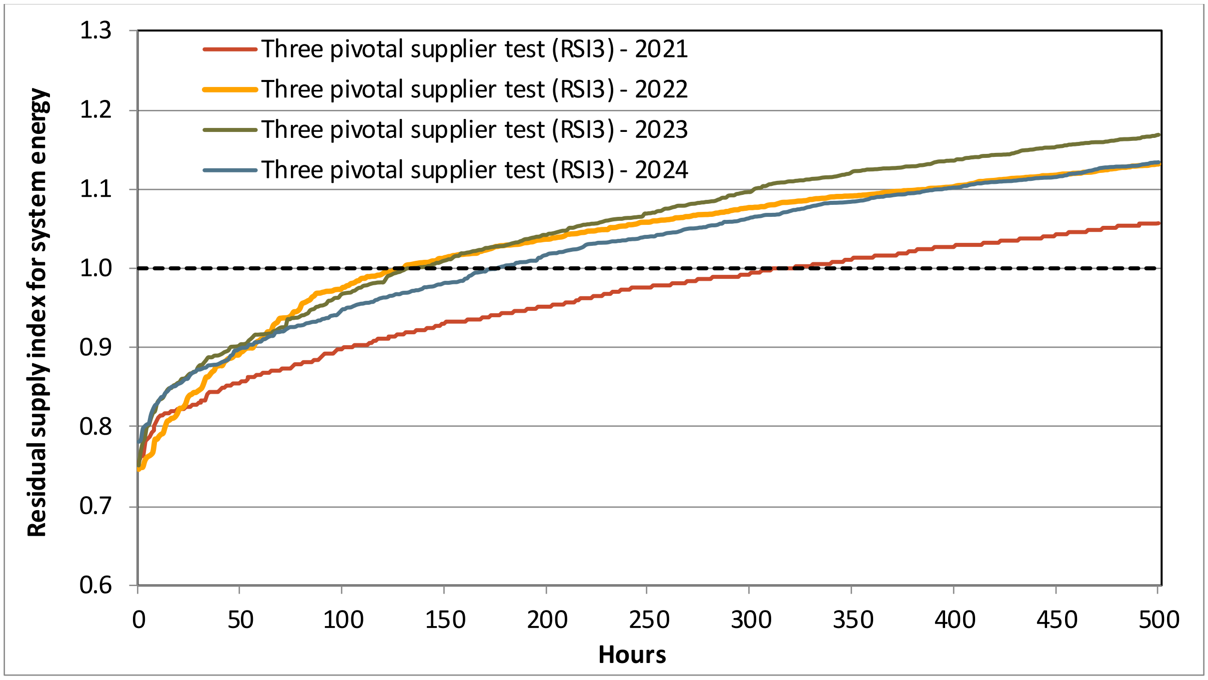
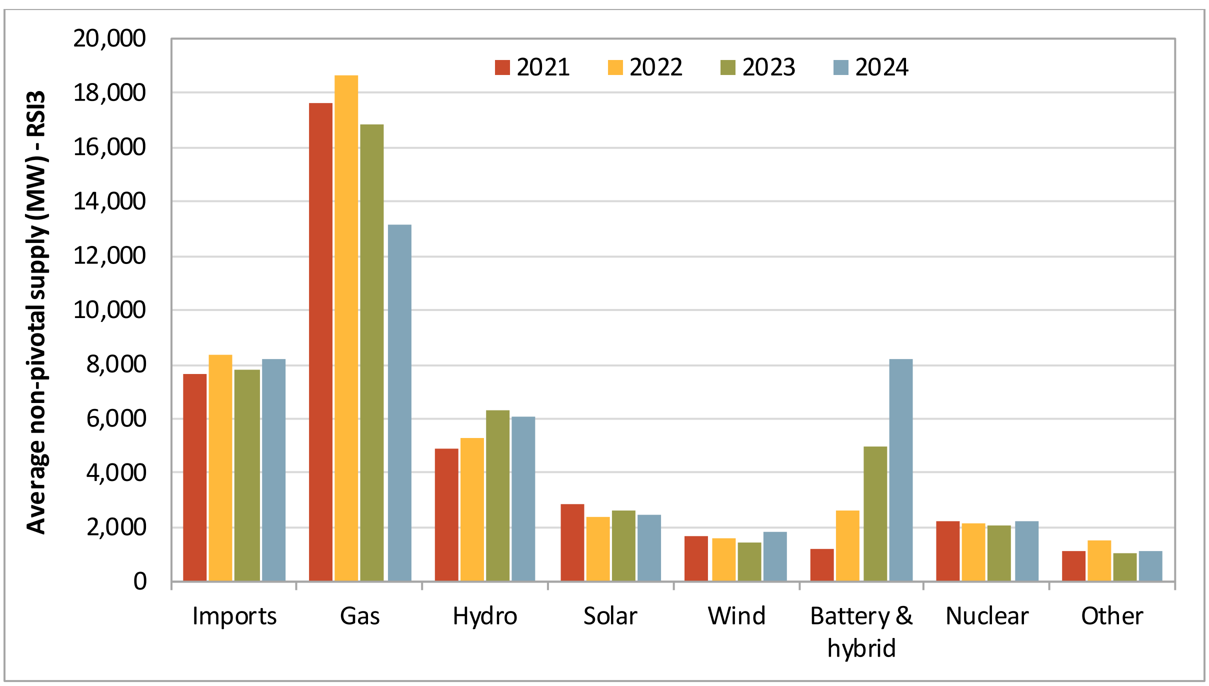



**Figure 3.3 Non-pivotal supply with the largest three suppliers excluded (balancing areas in the day-ahead market, lowest 500 hours)**



## 3.3 Day-ahead market price-cost markup

This section reviews the competitiveness of the ISO's day-ahead wholesale energy market. Currently, the day-ahead market consists only of the CAISO balancing area. The performance of the day-ahead market remained competitive, with prices during most hours near the marginal cost of generation. Price-cost markup for the comprehensive competitive scenario averaged around $4.08/MWh or 9.6 percent, compared to $2.38/MWh or 3.6 percent the previous year. This uptick in markup was largely the result of adjusting commitment costs in the competitive scenario. There was generally less online gas generation in 2024. This was due to increases in storage and renewable generation. As a result, the competitive scenario was more likely to commit additional generation, shifting the supply stack and decreasing prices.

DMM assesses the competitiveness of overall market prices based on the *price-cost markup*. This is a comparison between actual market prices and an estimate of prices that would result from a highly competitive market in which all suppliers bid at or near their marginal costs.

DMM calculates these estimated competitive prices by using a version of the day-ahead market software to simulate a competitive day-ahead market after replacing bids or other market inputs. First, DMM performs a base case re-run where no changes are made to the inputs from the original day-ahead market run.[129] DMM then compares these results to those simulated under a number of different competitive scenarios.[130] The day-ahead price-cost markup is calculated by comparing prices from each competitive scenario to prices from the base case re-run, using load-weighted average prices for all energy transactions in the day-ahead market.[131] When the price-cost markup is positive, this indicates that using competitive inputs (such as replacing high-priced energy bids with cost-based bids) lowered the price.

The analysis below highlights the results of *two* of the competitive scenarios that DMM performs:

**Gas cost-based scenario:** Replace market bids of gas-fired units with the lower of the submitted bids or their default energy bids (DEBs) to capture the effect of competitive bidding of energy by gas resources.

**Comprehensive scenario:** This is the most comprehensive scenario. It replaces market bids of all generation and imports with the lower of their submitted bids or their default energy bids *and* adjusts commitment costs to competitive levels to capture the effect of competitive bidding for

129 Trade dates that were unable to successfully complete the re-simulation of the market or were unable to replicate original market prices during this base case re-run were excluded from this analysis. In 2024, a total of 30 trade dates were excluded.

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

131 DMM calculates the price-cost markup as the percent difference from cost-based competitive scenario prices to base case market prices. For example, if the competitive price averaged $50/MWh and the base case price was $55/MWh, this would represent a price-cost markup of 10 percent.

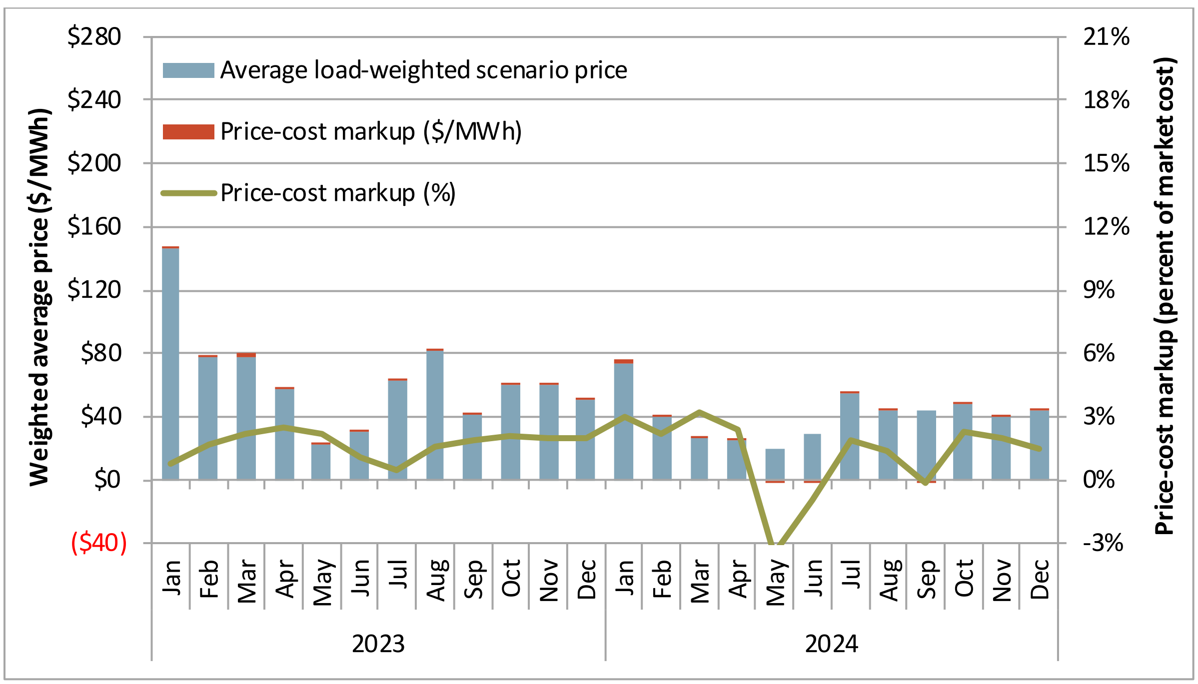
energy and commitment costs.[132] DMM uses this scenario as the primary observation to assess the competitiveness of the market.

Figure 3.4 shows results for the first scenario that caps energy bids for gas resources at the lower of their submitted bid or default energy bid. The red bars show the difference between the competitive scenario price and the base case price (price-cost markup). Actual market prices were very close to these estimated scenario prices, indicating that replacing only high-priced energy bids from gas resources with cost-based bids did not significantly lower prices. During high-priced hours, gas-fired resources were generally not setting prices. Price-cost markup values for this scenario were slightly lower in 2024, at about $0.66/MWh compared to $1.03/MWh in 2023. However, when comparing the markup as a percent of market cost, the value remained about the same at 1.6 percent in 2024, similar to the previous year.

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 to cap 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.
- 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.

**Figure 3.4 Day-ahead market price-cost markup (gas cost-based scenario)**

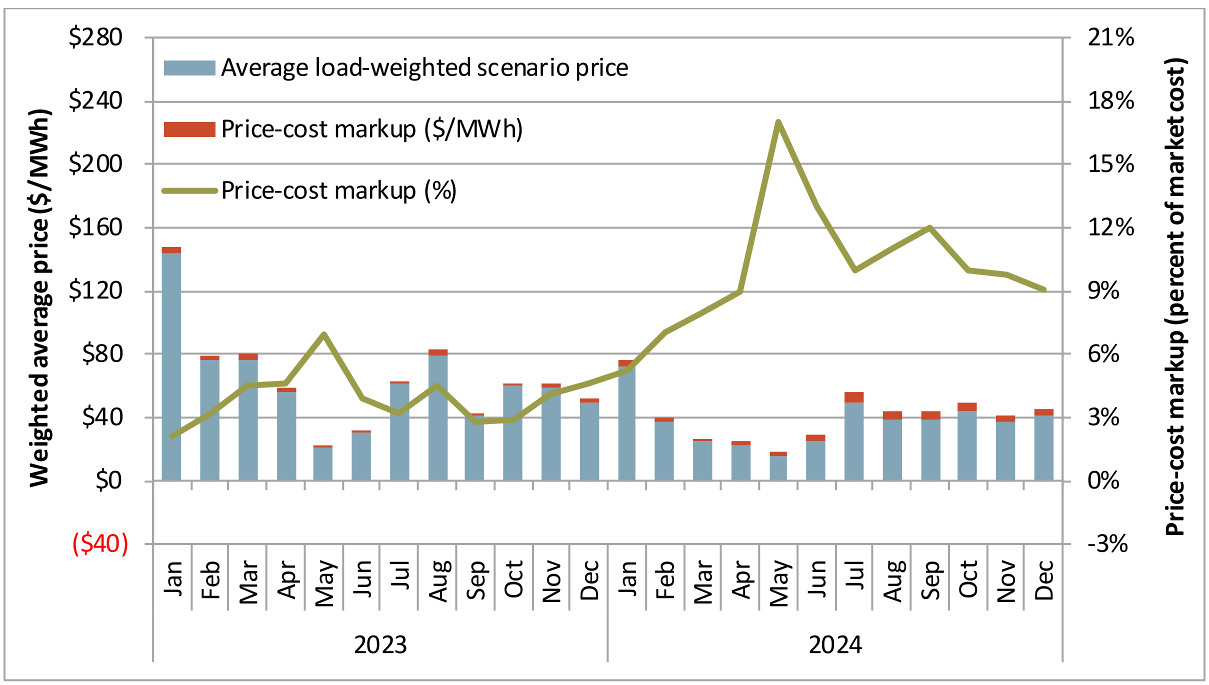



132 Bids for all generating resources subject to mitigation were set to the minimum of their submitted bid or default energy bid. Bids for import resources were set to the minimum of their bid or an estimated default energy bid (based on an opportunity cost default energy bid option offered by the ISO for hydro resources). Commitment costs were set to the minimum of their bid or 110 percent of the proxy price.

Figure 3.5 instead shows results for the comprehensive competitive scenario, which represents competitive bidding of energy and commitment costs for all resources, including imports. Overall, price-cost markup was low, indicating that prices were competitive for the year. However, compared to the scenario summarized in Figure 3.4, monthly average day-ahead market prices (base case prices) were higher above estimated competitive prices from this scenario. The average price-cost markup from this scenario was also higher compared to 2023. The average price-cost markup was about $4.08/MWh (or 9.6 percent), compared to $2.38/MWh (or 3.6 percent) the previous year.

The increased markup in this scenario compared to the scenario summarized above is largely from the adjustment of commitment costs. In particular, there continued to be more storage and renewable generation, resulting in less gas generation on-line in 2024 compared to 2023. As a result, the competitive scenario which caps the commitment costs had a bigger impact in 2024. Here, the scenario was more likely to commit additional generation (that was otherwise off-line with high commitment costs), shifting the supply stack and decreasing scenario prices. In addition, storage and renewable generation also contributed to lower prices in 2024 compared to 2023. So, since the *percent* markup is calculated as a percent of the market price, the percent markup will tend to increase as the market price decreases.

**Figure 3.5 Day-ahead market price-cost markup (comprehensive scenario)**



## 3.4 Local market power mitigation – frequency and impact of automated bid mitigation

This section provides an assessment of the frequency and impact of the automated local market power mitigation procedures across all balancing areas in the ISO's day-ahead and real-time markets.

Average incremental energy subject to mitigation increased in 2024 relative to 2023. Average incremental energy with bids lowered, and potential increase in dispatch because of mitigation, increased as well. The overall increase in mitigation was driven by increases in the CAISO balancing area. Bid mitigation in the CAISO balancing area increased due to a significant increase in the frequency of internal transmission constraints in the day-ahead and real-time markets. Bids subject to mitigation decreased in all WEIM regions outside of California in 2024. The potential increase in dispatch from bid mitigation remained very low in day-ahead and real-time markets.

### 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 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 procedures trigger when congestion occurs on a constraint that is determined to be uncompetitive. When this occurs, bids are mitigated to the higher of the system 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 bid changes.[133]

The following sections provide analysis on the frequency and impact of bid mitigation in the day-ahead and real-time markets.[134]

### Day-ahead market

As shown in Figure 3.6, in 2024, the average incremental energy subject to mitigation increased by 40 percent relative to 2023.

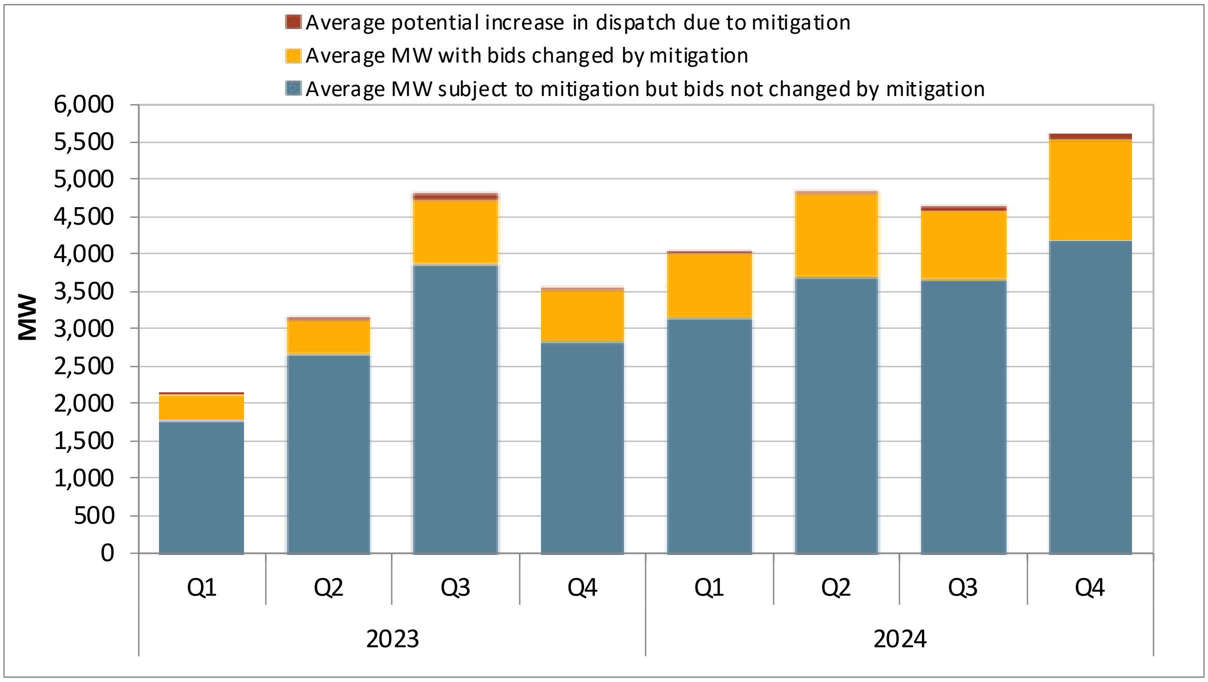
- Bids for an average of 4,730 MW per hour were subject to mitigation in 2024, an increase from 3,380 MW in 2023. Out of these bids subject to mitigation, 35 percent were gas resources, 37 percent were battery resources, and 12 percent were hydro resources.

[133] Since 2019, the methodology has been updated to show incremental energy instead of units that have been subject to automated bid mitigation. The potential increase in the unit's dispatch due to bid mitigation can be measured by the difference between the unit's actual market dispatch and its estimated dispatch level if its bid had not been mitigated.

[134] CAISO is the only balancing area currently participating in the day-ahead market.

- The amount of bids lowered due to mitigation averaged 1,060 MW in 2024, compared to 595 MW in 2023. About 22 percent of bids subject to mitigation had their bids lowered in 2024, which is an increase from 18 percent in 2023.
- Potential increase in dispatch from bid mitigation averaged about 48 MW per hour in 2024, compared to 38 MW per hour in 2023.
- On average, about 1,770 MW of bids from battery resources were subject to mitigation per hour in 2024, while only about 360 MW were lowered.[135]

**Figure 3.6 Average incremental energy considered for mitigation in day-ahead market**




### Real-time market

Figure 3.7 through Figure 3.16 highlight the frequency and volume of 15-minute and 5-minute market mitigation across the WEIM footprint. Average incremental energy subject to mitigation in 2024 increased by 13 percent in the 15-minute market across the overall WEIM, and decreased 4 percent in the 5-minute market. Average incremental energy with bids changed by mitigation increased by 48 percent in the 15-minute market and 41 percent in the 5-minute market. Average potential increase in dispatch due to mitigation increased by 8 percent in both the 15-minute and 5-minute markets. These overall increases were caused by increases in the CAISO balancing area, which had a significant increase in the frequency of binding internal transmission constraints in 2024 compared to 2023.

- In the CAISO balancing area, an average of 2,910 MW of incremental energy bids were subject to mitigation in the 15-minute market, which was an increase from 2,030 MW in 2023. Average

135 For battery energy storage units, both charge and discharge bid curves are subject to mitigation if local market power mitigation measures are triggered. Previous versions of this report only accounted for the discharge portion, but the analysis in this year's report accounts for the full charging range.

incremental energy with bids changed by mitigation was 615 MW, which was more than double from 2023. Average potential increase in 15-minute dispatch from bid mitigation was around 65 MW.

- In the California region, an average of only 26 MW of incremental energy bids were subject to mitigation in the 15-minute market, which was an increase from 5 MW in 2023. Average incremental energy with bids changed by mitigation was 4 MW. Average potential increase in 15-minute dispatch from bid mitigation was less than 1 MW.
- In the Desert Southwest region, an average of 150 MW of incremental energy bids were subject to mitigation in the 15-minute market, which was a 17 percent decrease from 2023. Out of these bids, about 16 MW on average were lowered in 2024. Average potential increase in 15-minute dispatch from bid mitigation was around 5 MW.
- In the Intermountain West region, an average of 590 MW of incremental energy bids were subject to mitigation in the 15-minute market, which was a 16 percent decrease from 2023. Average incremental energy with bids changed by mitigation was around 167 MW in 2024. Average potential increase in 15-minute dispatch from bid mitigation was around 30 MW.
- In the Pacific Northwest region, an average of 2,440 MW of incremental energy bids were subject to mitigation in the 15-minute market which was a 2 percent decrease from 2023. Average incremental energy with bids changed by mitigation was around 154 MW in 2024. Average potential increase in 15-minute dispatch from bid mitigation was around 7 MW.

**Figure 3.7 Average incremental energy considered for mitigation in 15-minute market (CAISO)**

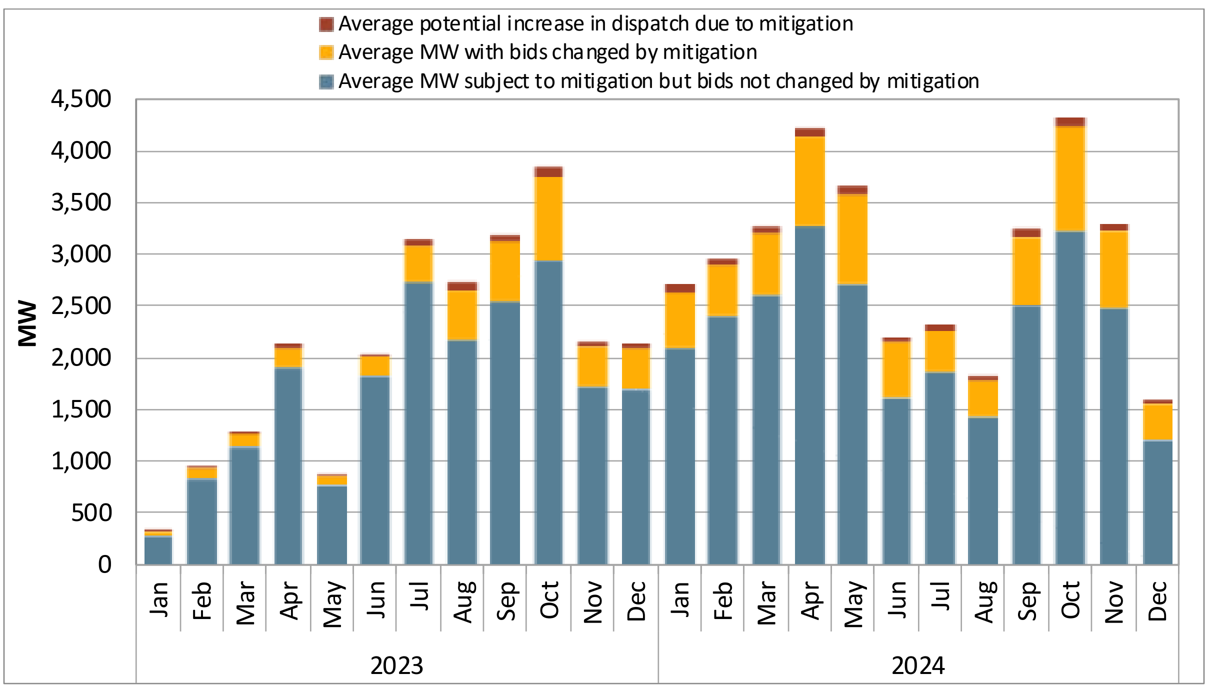


**Figure 3.8 Average incremental energy considered for mitigation in 15-minute market (California non-CAISO)**

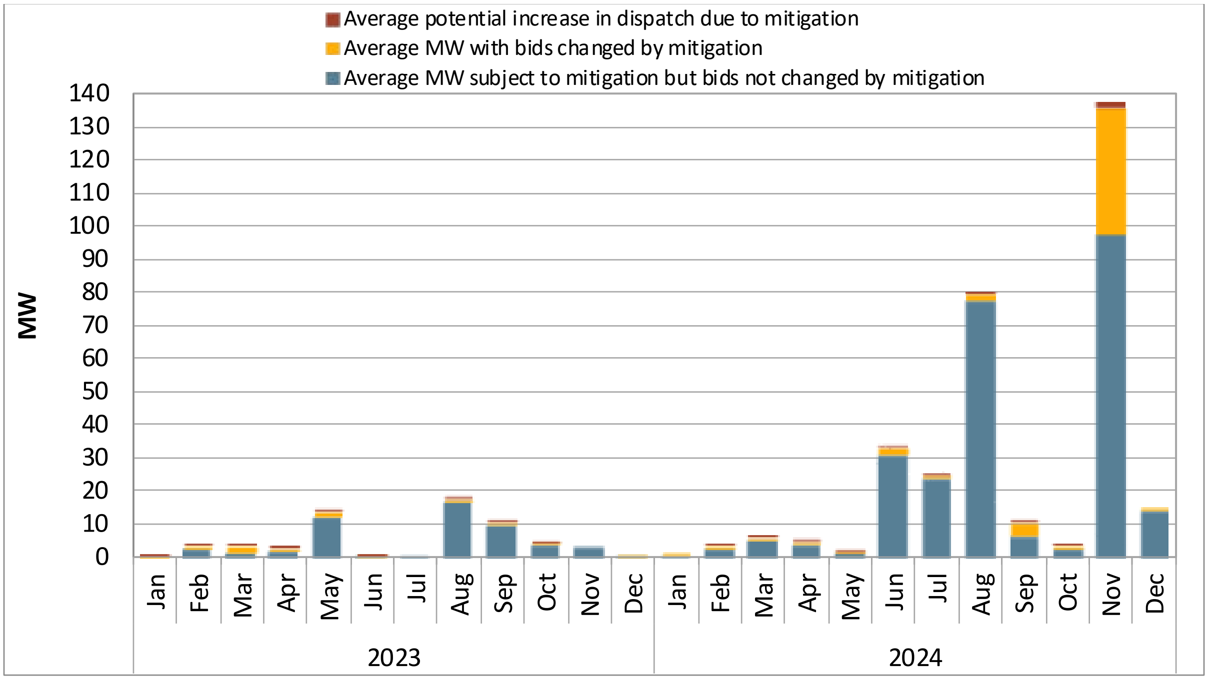



**Figure 3.9 Average incremental energy considered for mitigation in 15-minute market (Desert Southwest)**

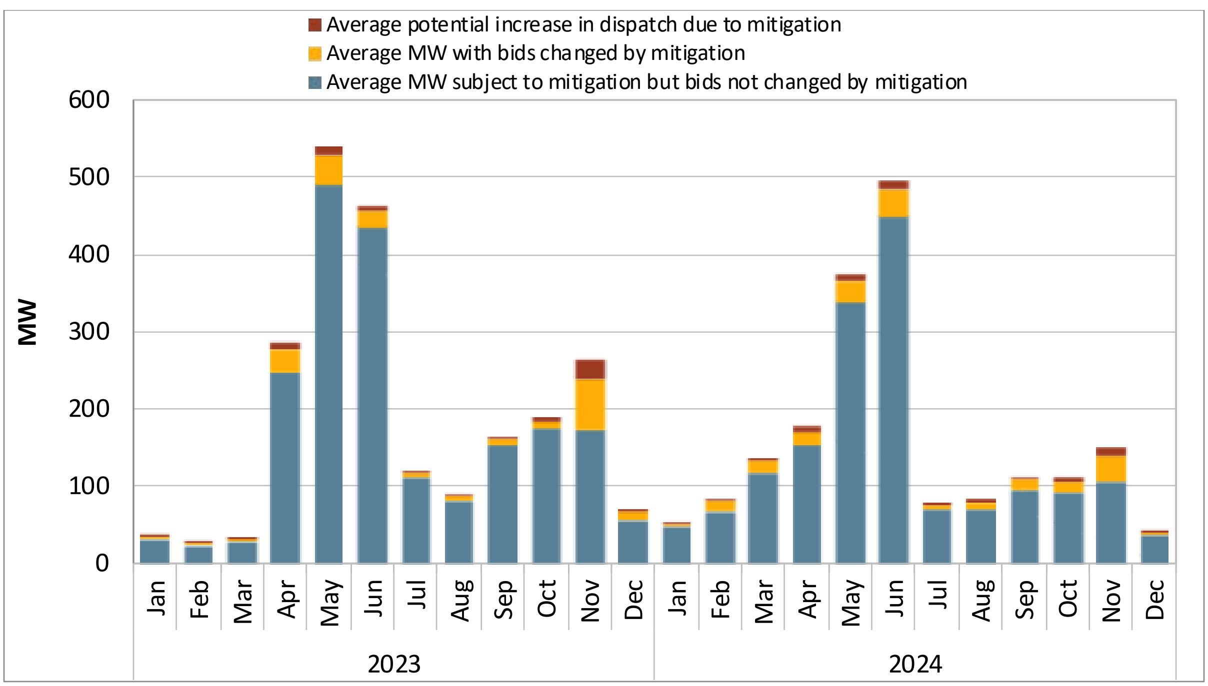


**Figure 3.10 Average incremental energy considered for mitigation in 15-minute market (Intermountain West)**

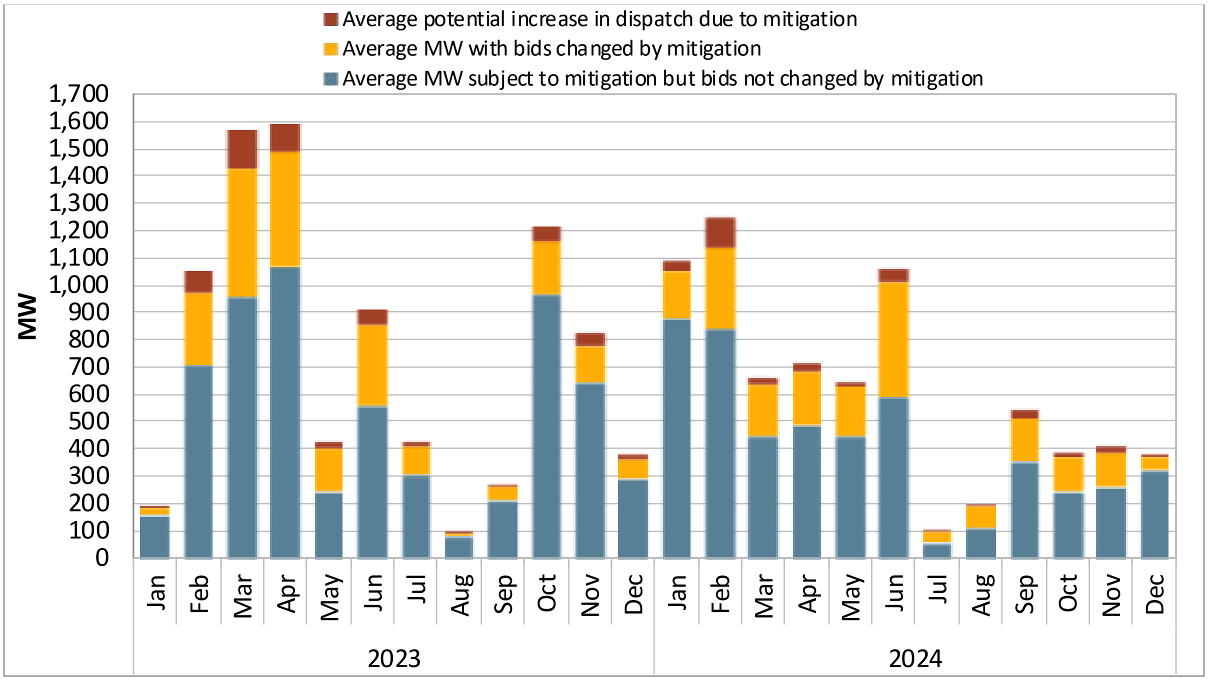



**Figure 3.11 Average incremental energy considered for mitigation in 15-minute market (Pacific Northwest)**

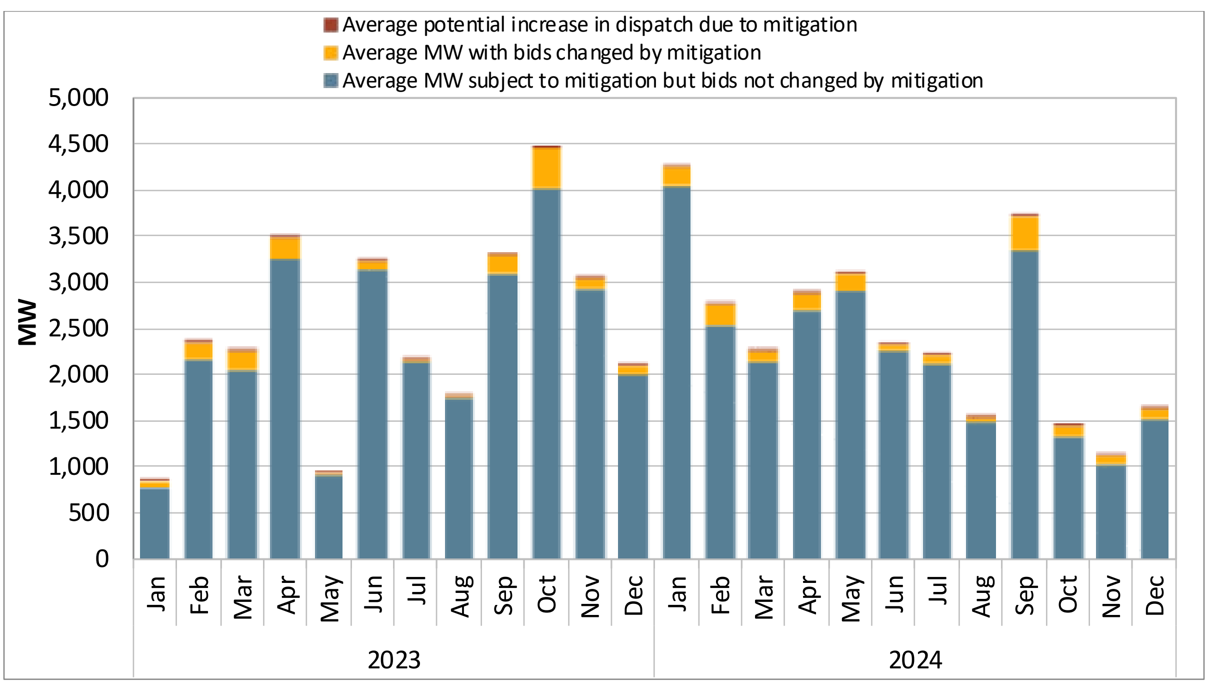


**Figure 3.12 Average incremental energy considered for mitigation in 5-minute market (CAISO)**

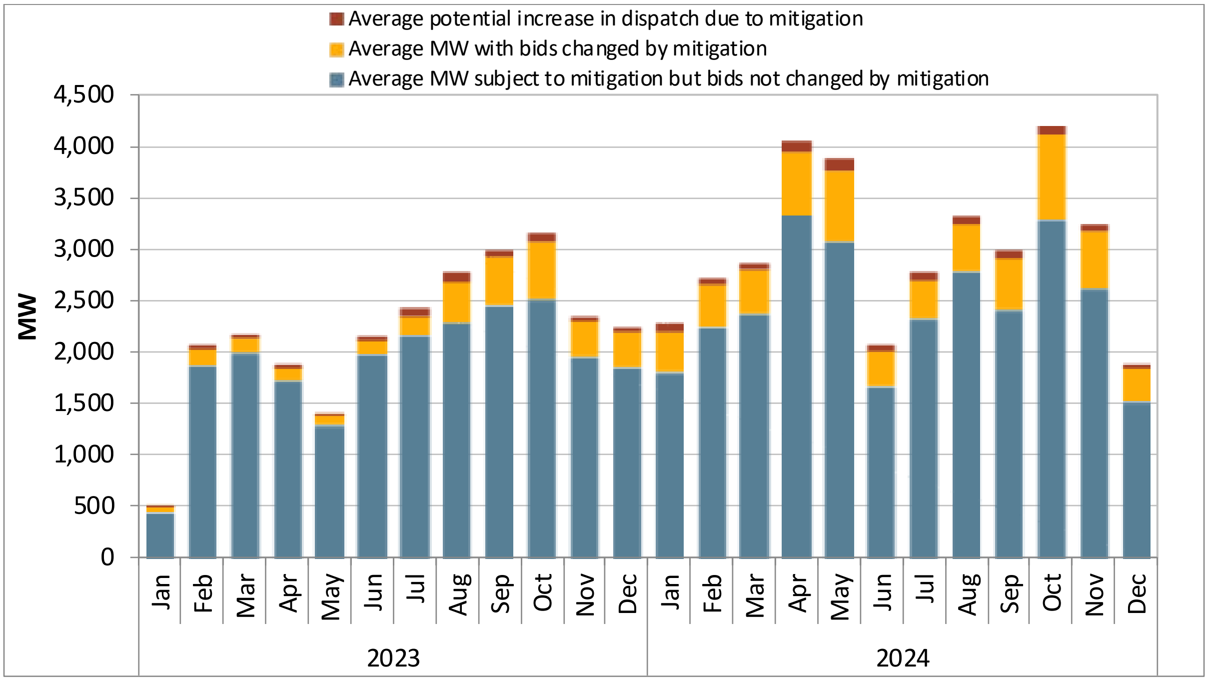



**Figure 3.13 Average incremental energy considered for mitigation in 5-minute market (California non-CAISO)**

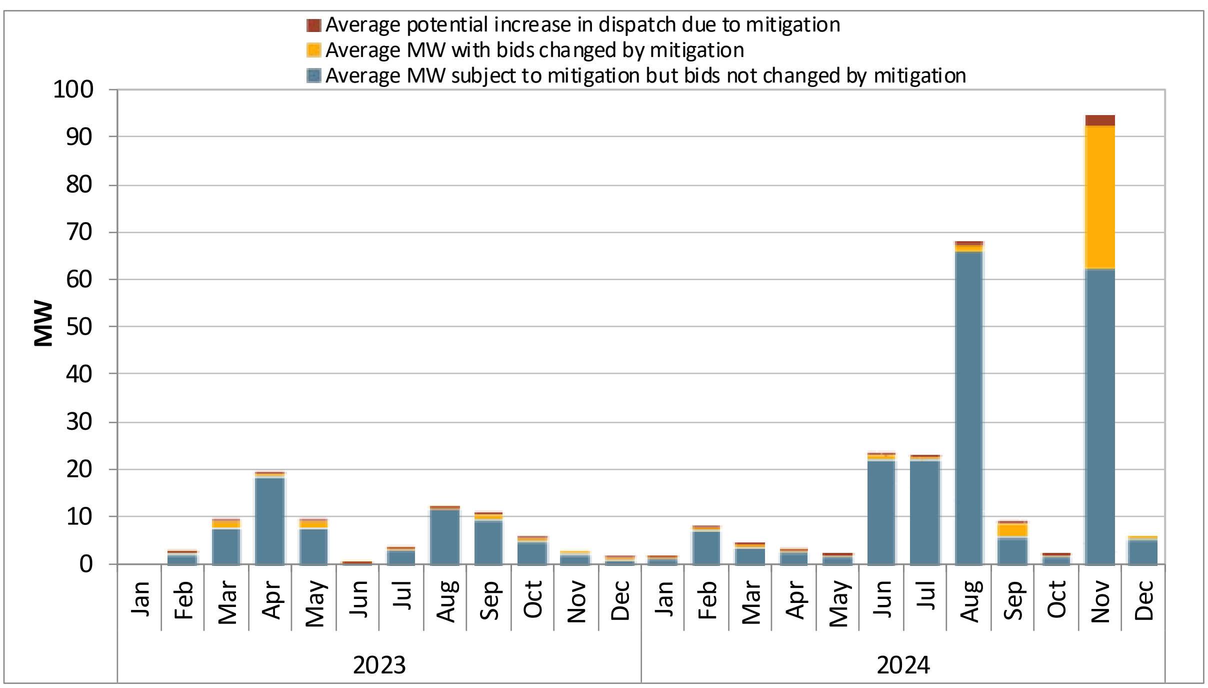


**Figure 3.14 Average incremental energy considered for mitigation in 5-minute market (Desert Southwest)**

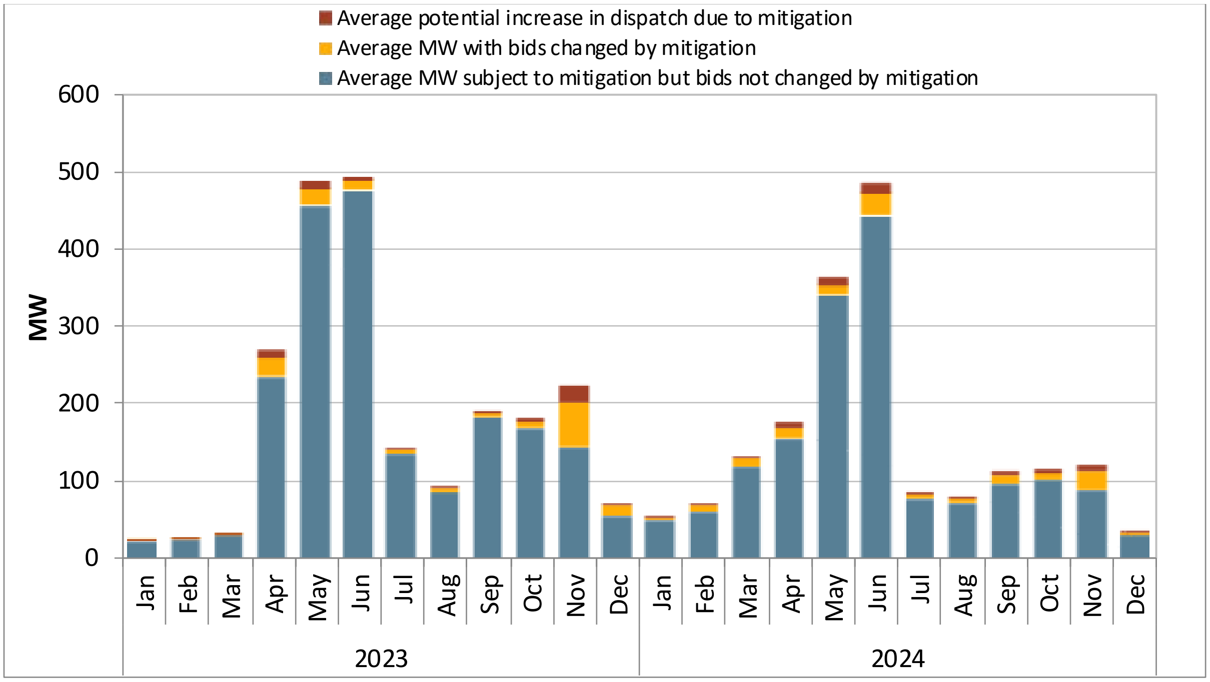



**Figure 3.15 Average incremental energy considered for mitigation in 5-minute market (Intermountain West)**

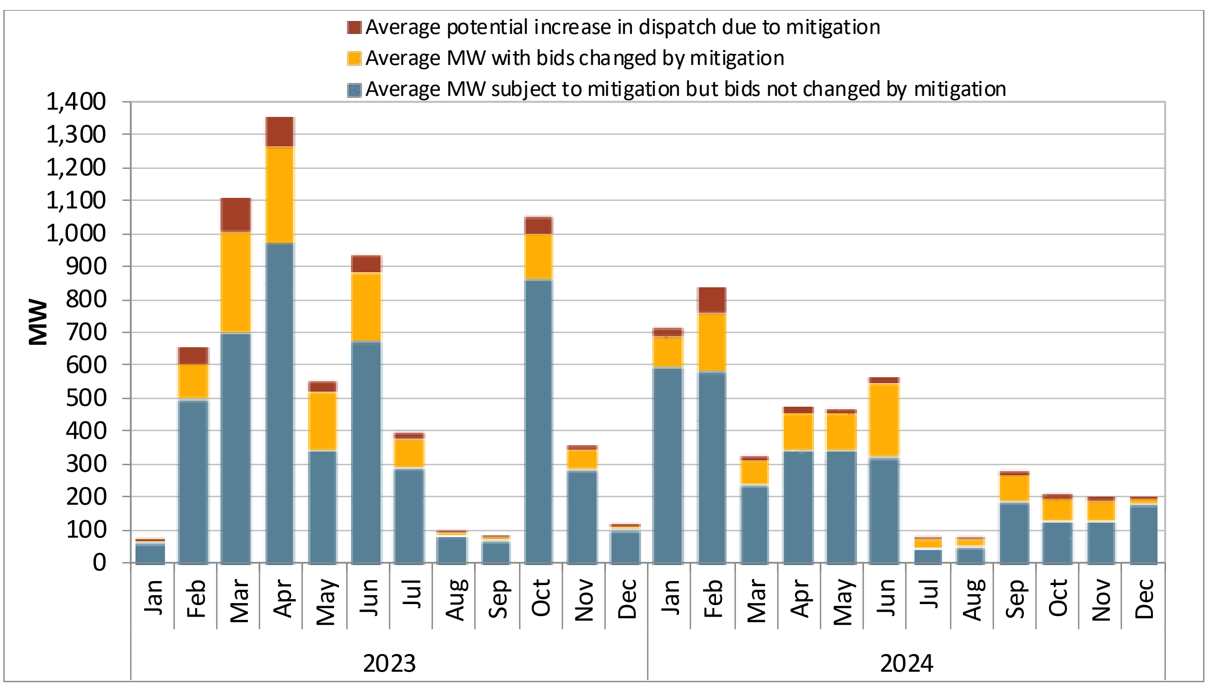
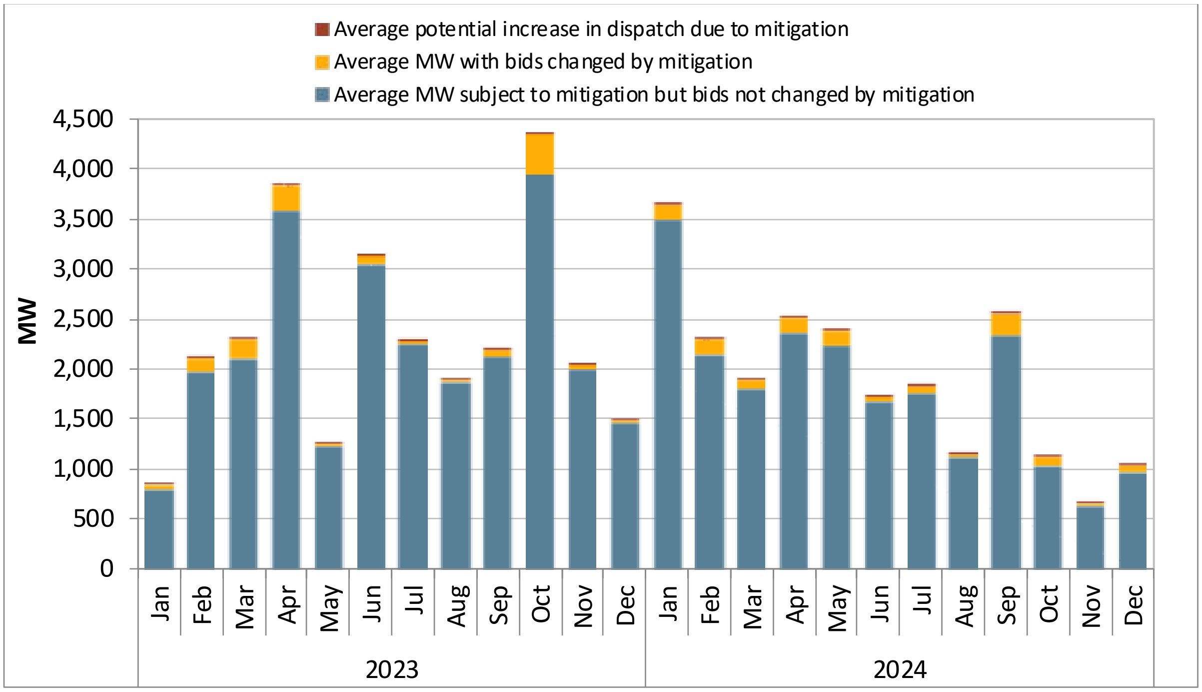


**Figure 3.16 Average incremental energy considered for mitigation in 5-minute market (Pacific Northwest)**




## 3.5 Start-up and minimum load bids

This section analyzes commitment cost bid behavior for gas capacity—excluding use-limited resources—under the proxy cost option.[136] For 2024, DMM estimates that about 41 percent of the total bid cost recovery payments paid to CAISO balancing area resources, approximately $65 million, were paid to resources that bid their commitment costs above 110 percent of their reference commitment costs. In 2023, 59 percent of the CAISO balancing area's total bid cost recovery payments were paid to resources that bid their commitment costs above 110 percent of their reference levels. Commitment cost bids are capped at 125 percent of reference proxy costs. About 91 percent of the $65 million is for resources bidding at or near the 125 percent bid cap for proxy commitment costs.

[136] Background on start-up and minimum load bidding rules can be found in the *Q1 2021 Report on Market Issues and Performance,* Department of Market Monitoring, July 27, 2022, p 195: http://www.caiso.com/Documents/2021-Annual-Report-on-Market-Issues-Performance.pdf

Figure 3.17 and Figure 3.18 highlight how proxy commitment costs were bid into the day-ahead and real-time markets by CAISO balancing area resources in 2024 compared to 2023.[137,138]

As shown in Figure 3.17, about 41 percent of the capacity in the day-ahead market submitted start-up bids at or near the proxy cost cap in 2024, similar to that in 2023. About 39 percent of capacity submitted start-up bids at or below the proxy cost in the day-ahead market in 2024, compared to 37 percent in 2023. The real-time market can only make start-up and shutdown decisions for short-start units. About 43 percent of this capacity submitted bids at or near the proxy cost cap in the real-time market in 2024, down from 44 percent in 2023.

As shown in Figure 3.18, about 29 percent of the capacity in the day-ahead market submitted minimum load bids at or near the proxy cost cap in 2024, compared to 32 percent in 2023 and 34 percent in 2022. About 37 percent of capacity submitted minimum load bids at or below the proxy cost in the day-ahead market in 2024, similar to that in 2023. About 32 percent of real-time minimum load bids in the CAISO balancing area were submitted at or near the proxy cost cap in 2024, compared to 33 percent in 2023.

Figure 3.19 and Figure 3.20 show start-up and minimum load bids as a percentage of proxy costs for resources in all other WEIM balancing areas. In 2024, about 20 percent of startup capacity and 2 percent of minimum load capacity for these resources was bid in at or near the proxy cost cap.

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137 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.

138 The analysis excludes days with commitment cost and default energy bid enhancements (CCDEBE) automated and manual reference level adjustment requests. This is because automated requests are evaluated against resource-specific reasonableness thresholds and manual requests are evaluated on a case-by-case basis with supporting documentation.

**Figure 3.17 Day-ahead and real-time gas-fired CAISO BA capacity under the proxy cost option for start-up cost bids (percentage)**

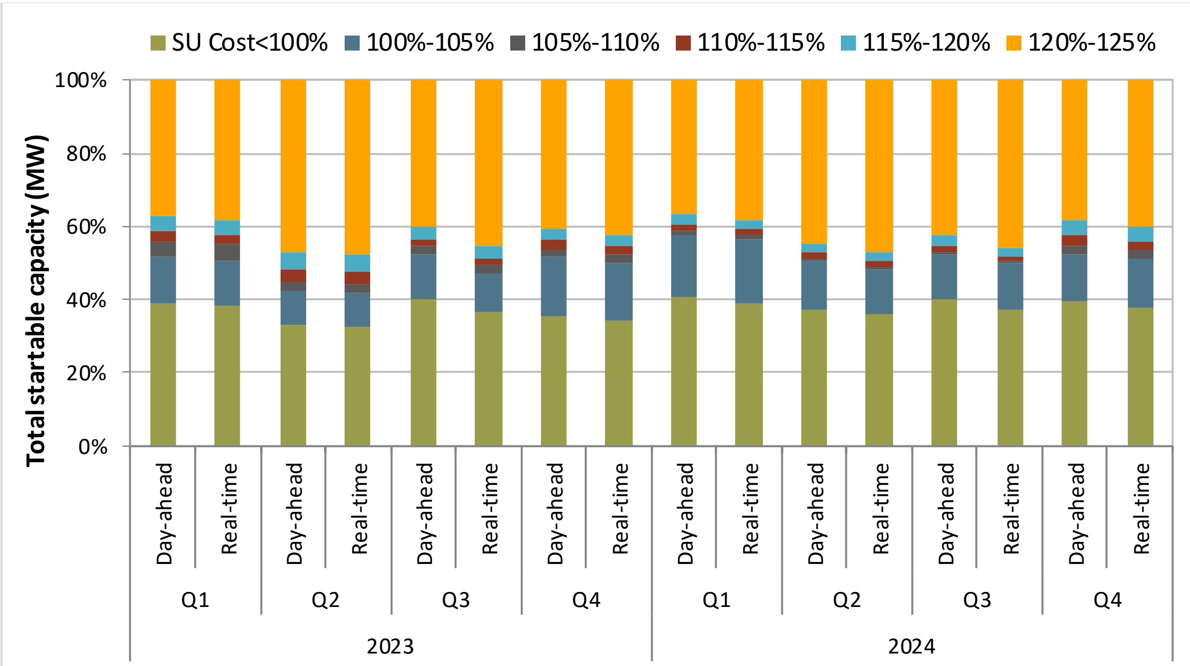



**Figure 3.18 Day-ahead and real-time gas-fired CAISO BA capacity under the proxy cost option for minimum load cost bids (percentage)**

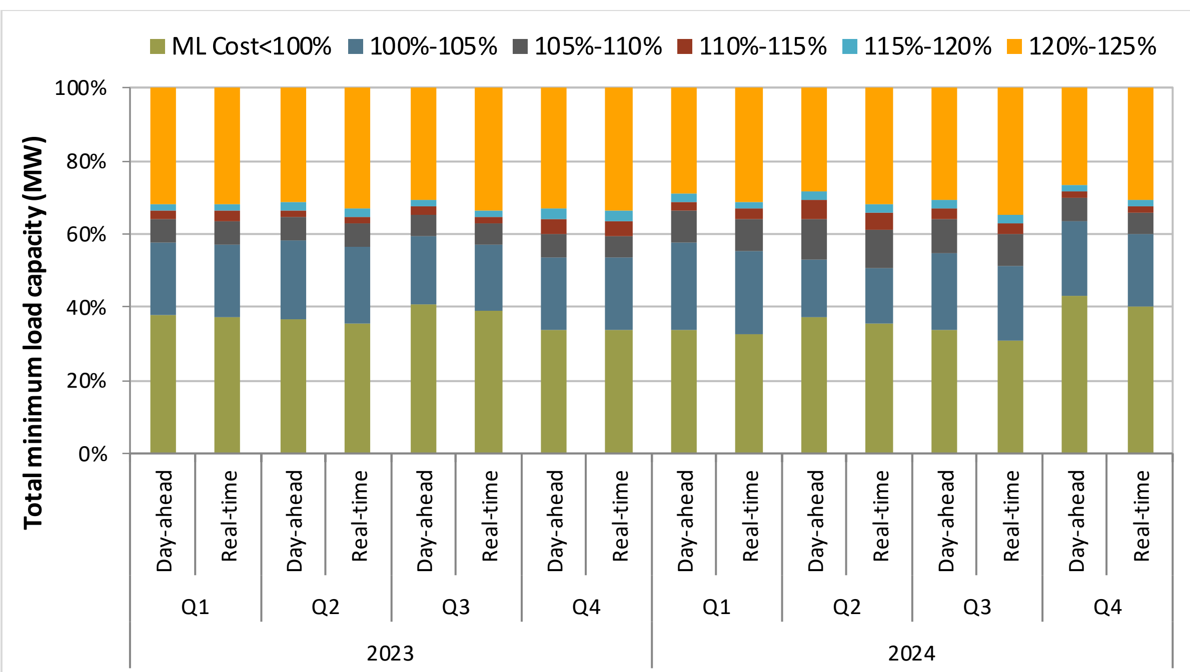


**Figure 3.19 Real-time gas-fired WEIM capacity under the proxy cost option for start-up cost bids (percentage)**

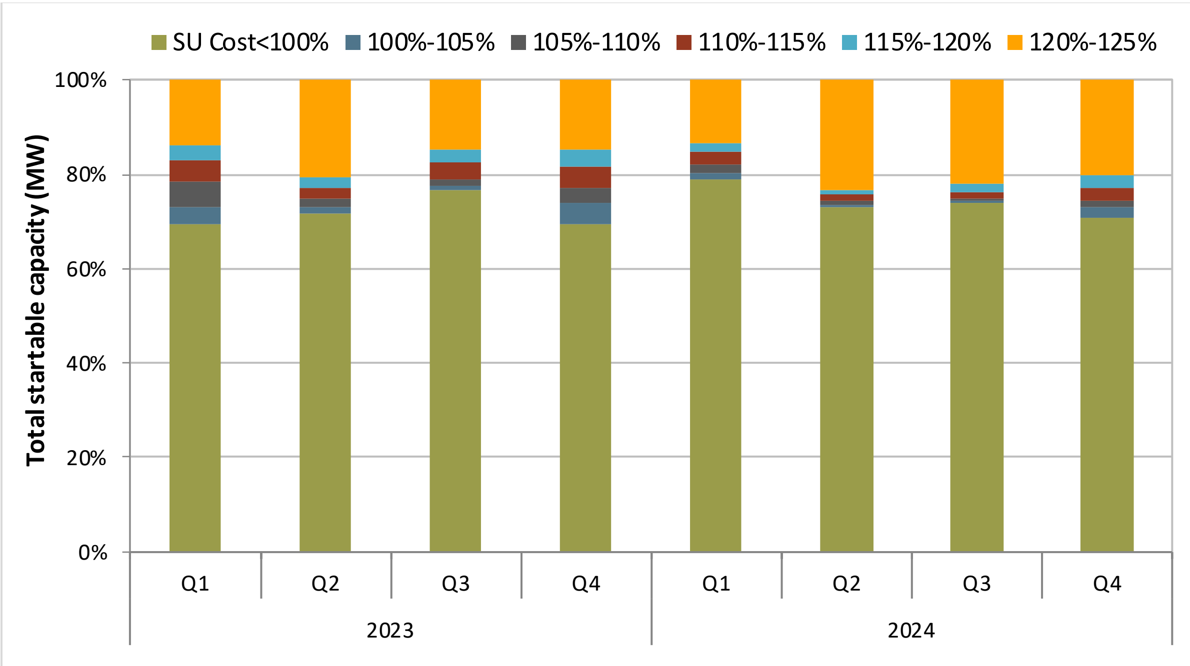
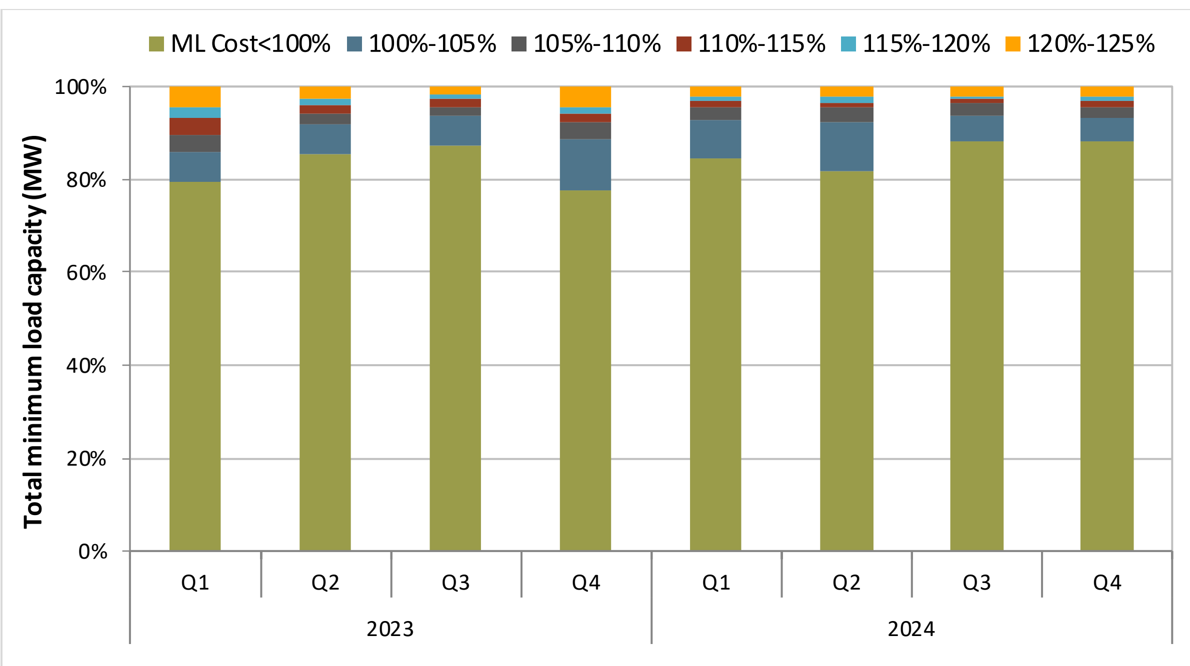



**Figure 3.20 Real-time gas-fired WEIM capacity under the proxy cost option for minimum load cost bids (percentage)**



### 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.[139,140] This process can be automated or manual, depending on the resource's bid and reasonableness threshold. The reasonableness threshold is a measure that includes an additional multiplier meant to reflect variability in fuel or fuel-equivalent costs.[141] 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.

There were no manual reference level change requests in 2024, and automated requests were limited to a few resources on a single trade date. When the policy was first implemented in February 2021, 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.

139 *Commitment Cost and Default Energy Bid Enhancements Phase 1: Deployment Effective for Trade Date 2/16/21*, California ISO Market Notice, February 14, 2021: http://www.caiso.com/Documents/CommitmentCost-DefaultEnergyBidEnhancementsPhase1-DeploymentEffective-TradeDate21621.html#search=market%20notice%202%2F16%2F21

140 For additional DMM analysis, see the *Q1 2021 Report on Market Issues and Performance,* Department of Market Monitoring, June 9, 2021, pp 90-93: http://www.caiso.com/Documents/2021-First-Quarter-Report-on-Market-Issues-and-Performance-Jun-9-2021.pdf

141 *Tariff Amendment to Enable Updates to Default Commitment Cost and Default Energy Bids*, California ISO, filed with FERC on July 9, 2020, pp 33-37: http://www.caiso.com/Documents/Jul9-2020-TariffAmendment-CommitmentCostsandDefaultEnergyBidEnhancementsCCDEBE-ER20-2360.pdf

# 4 WEIM transfers and transfer limits

This chapter analyzes transfers between WEIM balancing areas, including the transfer limits that constrain the amount of power that can flow between areas. Key findings include:

- **The average volume of WEIM transfers across the system was 4,380 MW during 2024**, similar to 2023.
- **WEIM transfers between regions continued to be significantly different during mid-day solar hours than during evening and early morning hours.** During solar hours, transfers were largely from the CAISO balancing area to other WEIM regions. During non-solar hours, transfers were lower and largely from the Desert Southwest and Intermountain West regions to California and the Pacific Northwest.
- **The Pacific Northwest and Intermountain West continued to have significantly lower transfer capacity into and out of their regions than the Desert Southwest and California.** This contributed to balancing areas in these regions being more frequently separated by congestion from the larger WEIM system.

### Energy transfers

One of the key benefits of the WEIM is the ability to transfer energy between balancing 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.

Figure 4.1 summarizes the average volume of dynamic WEIM transfers in the 5-minute market by hour during the last two years.[142] The average volume of transfers across the system was 4,380 MW during 2024, similar to the previous year.

Figure 4.2 summarizes average inter-regional transfers during the year. The bars show *net* WEIM transfers for each region by hour.[143] These regions reflect a combination of general geographic location as well as common price-separated groupings that can exist when a balancing area is collectively import or export constrained along with one or more other balancing areas relative to the greater WEIM system. Net WEIM exports for a region are shown as negative and net WEIM imports for a region are shown as positive. The figure also highlights two key periods: mid-day and peak. During the mid-day hours, regional WEIM transfers are typically highest with significant levels of exports from the CAISO balancing area. During the peak hours—when net load in the WEIM system is highest—regional WEIM transfers were lower. Overall, balancing areas in the Desert Southwest and Intermountain West regions were exporting out to balancing areas in California during this peak period.

Figure 4.3 and Figure 4.4 show average WEIM transfers in the 5-minute market by balancing area in the mid-day and peak periods during the quarter.[144] The curves show the path and size of exports where the

[142] WEIM transfers in this section exclude the fixed bilateral transactions between WEIM entities (base WEIM transfer schedules) and therefore reflect only *dynamic* WEIM transfer schedules optimized in the market.

[143] See Appendices of DMM's quarterly reports for figures on the average hourly transfers by quarter for each WEIM balancing area.

[144] In Figure 4.3 and Figure 4.4, each small tick is 50 MW, each large tick is 250 MW, and average WEIM transfer paths less than 25 MW are excluded.

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.

As shown in Figure 4.3, the CAISO balancing area exported on average over 1,900 MW out to neighboring balancing areas during the mid-day hours. These hours typically contain the highest levels of exports out of the CAISO balancing area because of significant solar production. During the peak period (Figure 4.4), balancing areas in the Desert Southwest region exported on average around 600 MW to balancing areas outside the region (and 390 MW to balancing areas within the region).

**Figure 4.1 Average dynamic WEIM transfer volume by hour and quarter (5-minute market)**

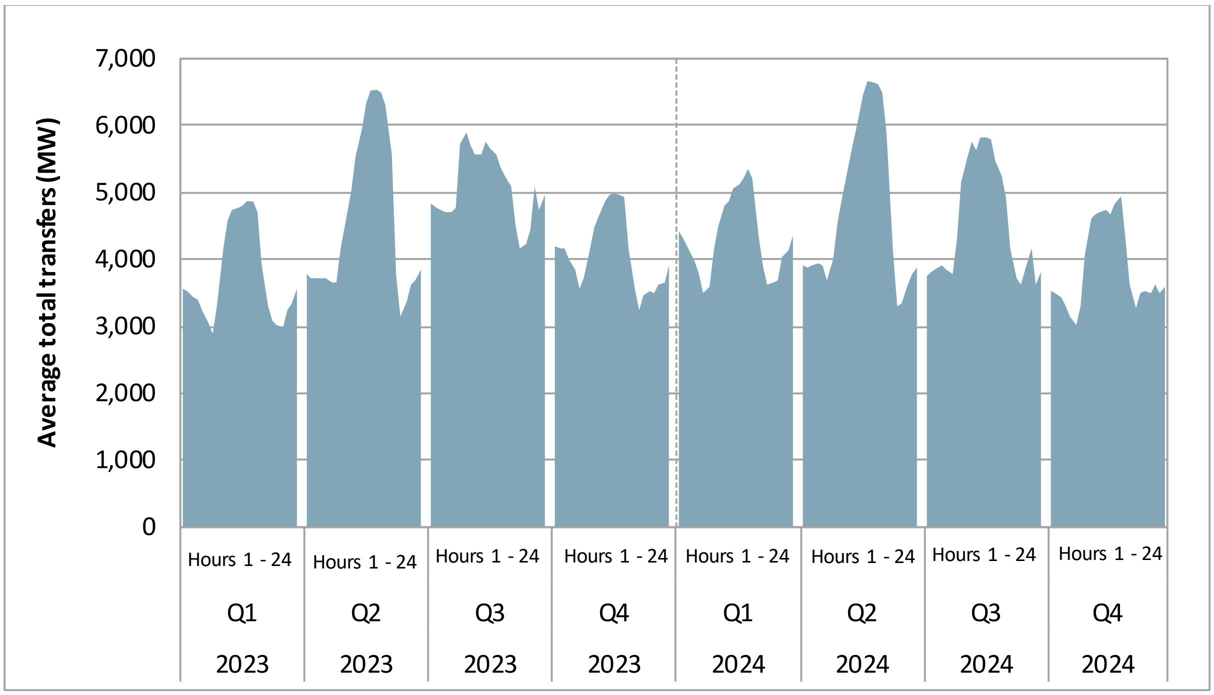


**Figure 4.2 Average dynamic inter-regional WEIM transfers by hour (5-minute market, 2024)**

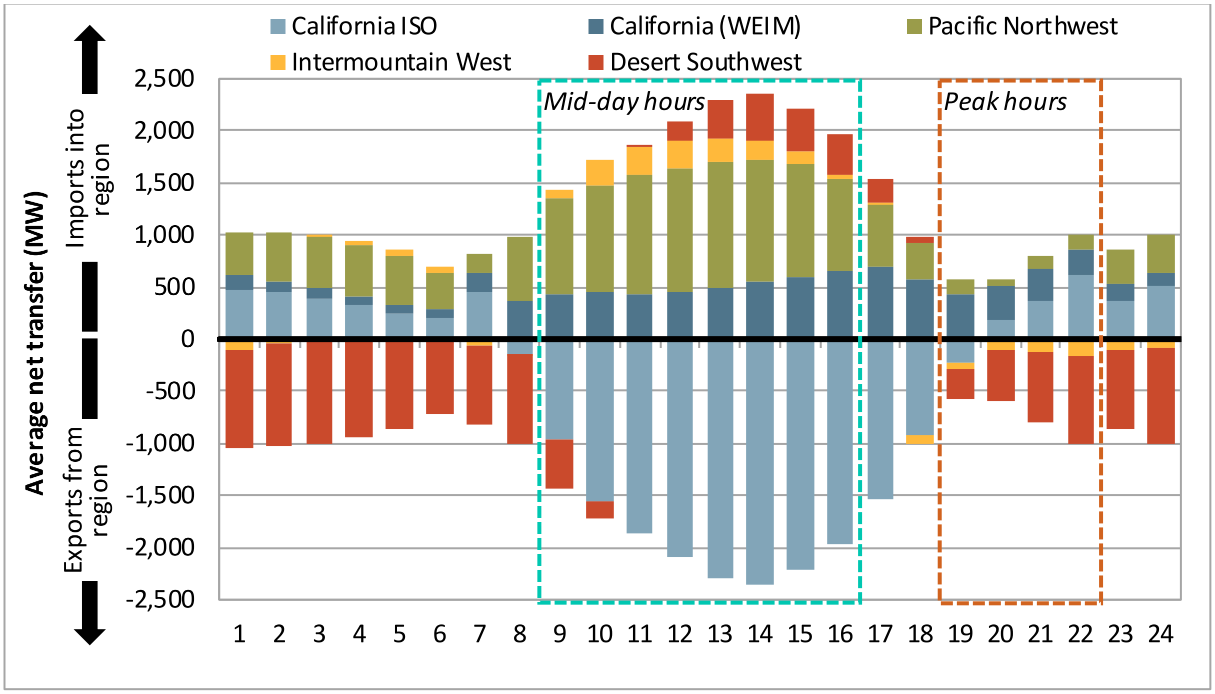



**Figure 4.3 Average 5-minute market WEIM exports (mid-day hours, 2024)**

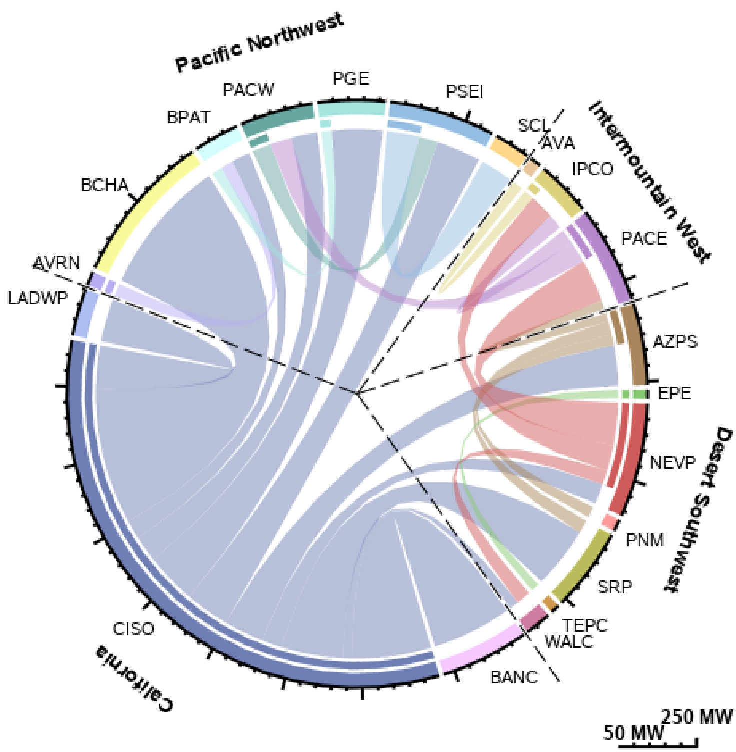
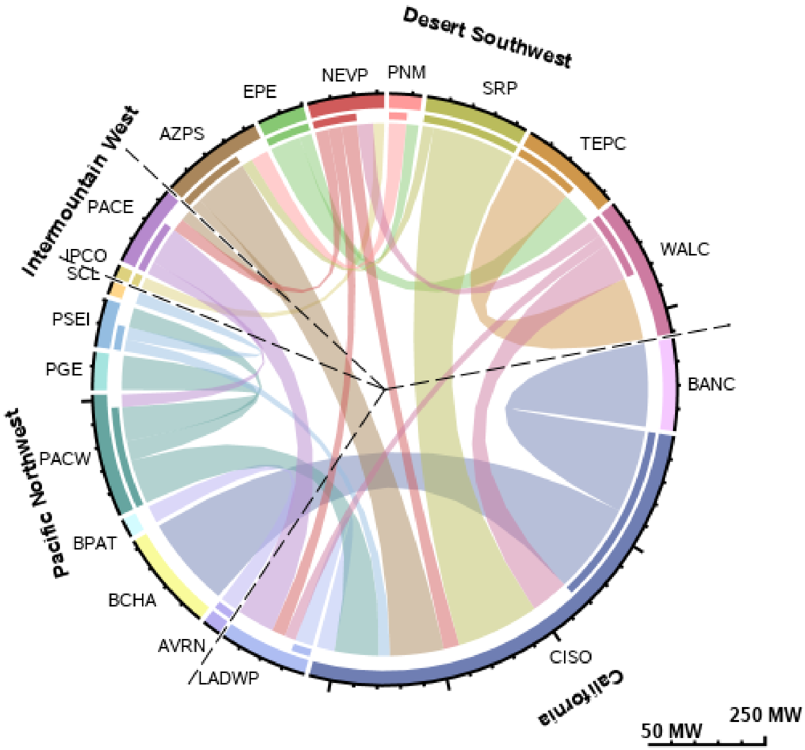


**Figure 4.4 Average 5-minute market WEIM exports (peak load hours, 2024)**




### Transfer limits

WEIM transfers between areas are constrained by transfer limits. These limits largely reflect transmission and interchange rights made available to the market by participating WEIM entities.

Table 4.1 summarizes all import or export scheduling limits from individual WEIM transfer points for each balancing area in the 5-minute market.[145] These amounts exclude base WEIM transfer schedules and therefore reflect transfer capability which is made available by WEIM entities to optimally transfer energy between areas. The last two columns in Table 4.1 show WEIM transfer limits between regions (out-of-region import and export limits).

Average transfer capacity into or out of the Desert Southwest region is relatively high, at around 32,200 MW for imports and 28,400 MW for exports during 2024. Transfer capacity for the Intermountain West and Pacific Northwest regions are lower. On average for the year, the Intermountain West region had around 2,100 MW of import transfer capacity and 2,900 MW of export transfer capacity into or out of the region. For the Pacific Northwest region, there was an average of around 1,600 MW of import transfer capacity and 750 MW of export transfer capacity into or out of the region. The lack of transfer

[145] These amounts only reflect scheduling limits on individual WEIM Energy Transfer System Resources (ETSRs) and therefore do not account for either (1) total scheduling limits that can be the result of a resource sufficiency evaluation failure or (2) intertie constraints that can limit WEIM transfers.

capability out of the Pacific Northwest often leads to price separation between the region and the rest of the WEIM.

**Table 4.1 Average 5-minute market WEIM limits (2024)**

| Region/ balancing area | Total import limit | Total export limit | Out-of-region import limit | Out-of-region export limit |
|---|---|---|---|---|
| **California** | | | **27,410** | **31,319** |
| California ISO | 35,813 | 34,958 | 24,241 | 26,713 |
| BANC | 4,101 | 3,933 | 0 | 0 |
| LADWP | 7,141 | 11,917 | 3,168 | 4,606 |
| Turlock Irrig. District | 1,470 | 1,628 | 0 | 0 |
| **Desert Southwest** | | | **32,208** | **28,369** |
| Arizona Public Service | 36,044 | 29,660 | 24,079 | 19,660 |
| El Paso Electric | 631 | 462 | 0 | 0 |
| NV Energy | 4,416 | 3,588 | 3,749 | 2,805 |
| PSC New Mexico | 990 | 1,177 | 0 | 0 |
| Salt River Project | 10,415 | 12,320 | 1,619 | 2,801 |
| Tucson Electric | 4,542 | 5,804 | 683 | 933 |
| WAPA - Desert SW | 5,147 | 5,336 | 2,077 | 2,169 |
| **Intermountain West** | | | **2,136** | **2,904** |
| Avista Utilities | 651 | 999 | 108 | 101 |
| Idaho Power | 2,150 | 2,846 | 555 | 826 |
| NorthWestern Energy | 667 | 736 | 26 | 17 |
| PacifiCorp East | 3,233 | 2,888 | 1,446 | 1,961 |
| **Pacific Northwest** | | | **1,589** | **751** |
| Avangrid | 782 | 748 | 18 | 20 |
| Powerex | 430 | 48 | 383 | 0 |
| BPA | 646 | 734 | 165 | 166 |
| PacifiCorp West | 1,829 | 1,797 | 596 | 470 |
| Portland General Electric | 737 | 572 | 210 | 24 |
| Puget Sound Energy | 1,262 | 1,052 | 202 | 55 |
| Seattle City Light | 432 | 424 | 16 | 16 |
| Tacoma Power | 345 | 249 | 0 | 0 |

### WEIM intertie constraints

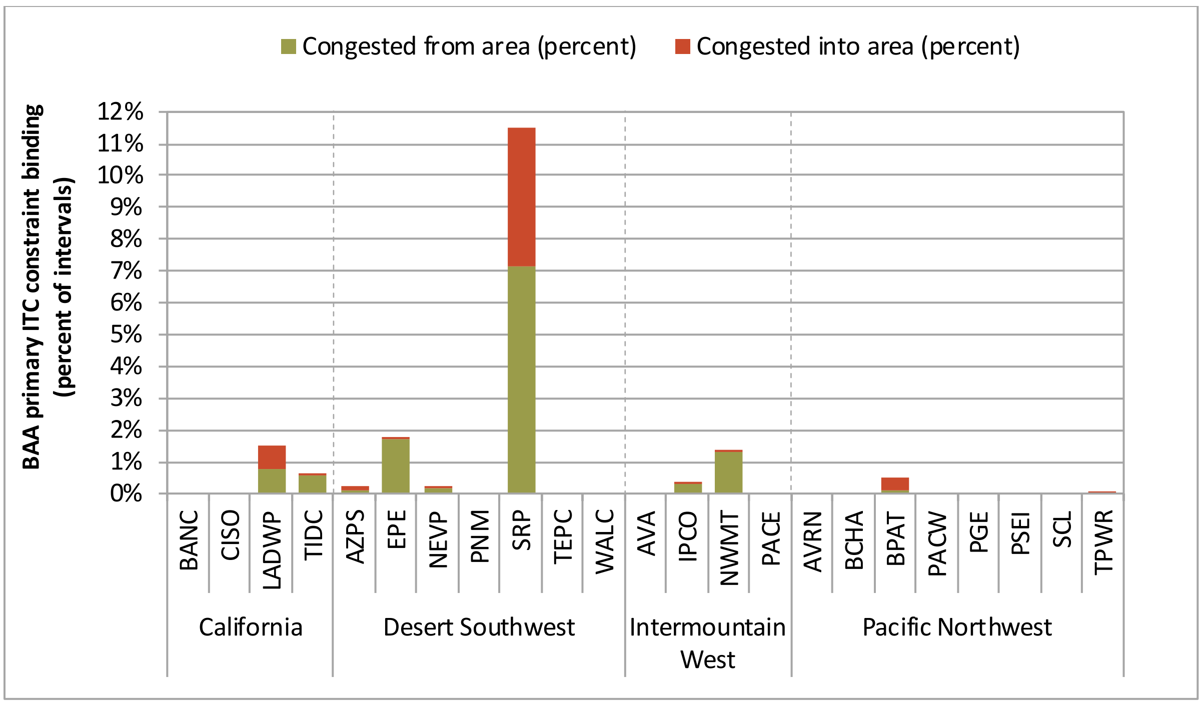
An intertie constraint (ITC) is a scheduling limit applied to a specified set of scheduling points or intertie resources. This ensures that net transfers of the imports or exports (considering counterflow) do not violate the physical or contractual limits. In the WEIM, these can also be used to manage WEIM transfers in a balancing area. Here, a *primary* intertie constraint is modeled for each balancing area that is mapped to all of their dynamic WEIM transfers. A WEIM entity can use this constraint to effectively manage all dynamic WEIM transfers into or out of their system, on net, without needing to adjust individual transfer limits.

Figure 4.5 shows the percent of intervals in the 5-minute market in which the primary intertie constraint—that limits all dynamic WEIM transfers on net for a balancing area—was binding in either the import or export direction, resulting in congestion. Of note, the primary intertie constraint for Salt River Project was binding for net imports in around 4 percent of intervals and for net exports in around

7 percent of intervals. When this constraint was binding in the import direction, net transfers were limited to around 390 MW on average. When this constraint was binding in the export direction, net transfers were limited to around 640 MW on average.

A WEIM entity can also set up intertie constraints that are mapped to a subset of their WEIM transfers (non-primary). For example, the entity can set up an intertie constraint that is mapped to only WEIM transfers at a specific intertie. A WEIM entity can also create an intertie constraint that is mapped to either only WEIM imports or only WEIM exports, which will limit total imports or total exports rather than net WEIM transfers. During the year, Tucson Electric enforced an intertie constraint that was binding for total WEIM imports in around 4 percent of intervals and for total WEIM exports in around 10 percent of intervals. The limit was around 500 MW on average in both directions when these constraints were binding.

**Figure 4.5 Frequency of primary ITC constraint binding for net WEIM transfers (5-minute market, 2024)**



# 5 Congestion

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

Section 5.1 addresses congestion on the constraints limiting WEIM transfers between balancing areas in the real-time market. Section 5.2 addresses real-time market internal congestion.[146] Section 5.3 analyzes day-ahead market congestion rent and loss surpluses. Section 5.4 addresses intertie constraint congestion in the day-ahead market. Section 5.5 addresses the impact of internal congestion on the day-ahead market. Lastly, Section 5.6 addresses congestion revenue rights.

Key findings in this chapter include:

- **Most balancing areas in the Pacific Northwest, plus Avista and Northwestern in the Intermountain West, were import transfer constrained relative to the CAISO balancing area in more than 10 percent of 15-minute market intervals.** Limited transfer capacity into these regions contributed to their relatively high rate of WEIM transfer congestion.
- **El Paso Electric, Tucson Electric Power, and Salt River Project were frequently export transfer constrained during the year.** These balancing areas were frequently transfer constrained because of intertie constraints that these balancing areas use to manage WEIM transfers into or out of their system
- **WEIM balancing area price separation driven by congestion on internal transmission constraints was less pronounced in 2024** than 2023. However, this price separation in the day-ahead market was more pronounced in 2024.
- **Congestion rent in 2024 was $537 million, down 6 percent** from 2023. While congestion rent on internal constraints was down, intertie congestion rent in the export direction rose to $134 million in 2024 from $13 million in 2023. This rent was mainly over the Malin intertie during the extreme cold weather event in the Pacific Northwest in January 2024.
- **Payouts to congestion revenue rights (CRRs) sold in the California ISO auction exceeded auction revenues received for these rights by about $66 million in 2024,** up from $59 million in 2023. These losses are borne by transmission ratepayers who pay for the full cost of the transmission system through the transmission access charge. Changes to the auction implemented in 2019 have reduced, but not eliminated, losses to transmission ratepayers from the auction. The Department of Market Monitoring (DMM) continues to recommend further changes to eliminate or further reduce these losses.

[146] This report defines internal congestion as congestion on any constraint within a balancing authority area. Therefore, the effect of internal congestion on the CAISO balancing area may include effects of congestion from transmission elements within WEIM balancing areas. Analysis of internal congestion excludes transfer constraints and intertie constraint congestion.

## 5.1 WEIM transfer constraint congestion

When limits on constraints impacting WEIM transfers between balancing areas are reached, this can create congestion—resulting in higher or lower prices in the area relative to prevailing system prices. Figure 5.1 and Figure 5.2 show the percent of intervals and price impact of 15-minute and 5-minute market transfer constraint congestion in each WEIM area during the year.[147] The congestion on the WEIM transfer constraints are measured relative to a reference price in the CAISO balancing area. *Congested from area* reflects that prices are lower in the balancing area because of limited export capability out of the area or region, relative to the CAISO (and connected WEIM system). *Congestion into area* reflects that prices are higher within an area or region, because of limited import capability into the area or region.[148]

Powerex was frequently constrained relative to the CAISO balancing area because of WEIM transfer congestion during the year. In the 5-minute market, Powerex was import constrained during around 60 percent of intervals and export constrained during around 16 percent of intervals. On average for the year, Powerex prices were roughly $6/MWh higher because of WEIM transfer congestion in the 15-minute and 5-minute markets.

The rest of the Pacific Northwest region was also frequently transfer constrained relative to the rest of the WEIM system. In the 5-minute market, these balancing areas were *import* constrained in around 12 percent of intervals and *export* constrained in around 5 percent of intervals. Avista and NorthWestern Energy were also import constrained relatively frequently during the year, in around 10 percent of intervals.

El Paso Electric, Tucson Electric Power, and Salt River Project were also frequently export constrained during the year. In the 5-minute market, El Paso Electric was export constrained in around 11 percent of intervals. Tucson Electric Power was export constrained in around 10 percent of intervals. Salt River Project was export constrained in around 7 percent of intervals. These balancing areas were frequently transfer constrained because of intertie constraints that these balancing areas use to manage WEIM transfers into or out of their system.

147 The frequency is calculated as the number of intervals where the shadow price on an area's transfer constraint was positive or negative, indicating higher or lower prices in an area relative to prevailing system prices. This accounts for any constraint that can limit WEIM transfers between balancing areas, including (1) scheduling limits on individual WEIM transfers, (2) total scheduling limits, or (3) intertie constraint and intertie scheduling limits.

148 When a balancing area has net WEIM transfer import congestion into the area, the market software triggers local market power mitigation procedures for resources in that area. If bid in supply after removing the three largest suppliers is less than the generation dispatched in the area in the market power mitigation run, bids in excess of the higher of default energy bids and the competitive locational marginal price (LMP) will be replaced by the higher of default energy bids and the competitive LMP.

**Figure 5.1 Frequency and impact of WEIM transfer congestion in the 15-minute market (2024)**

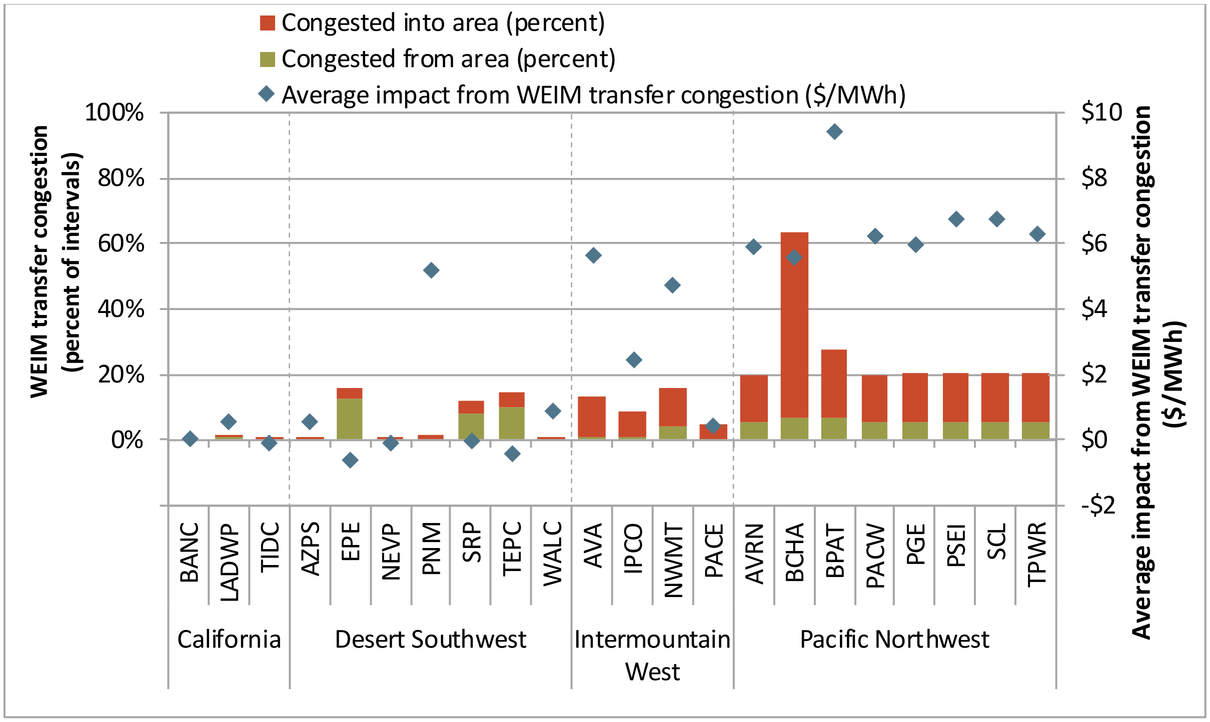
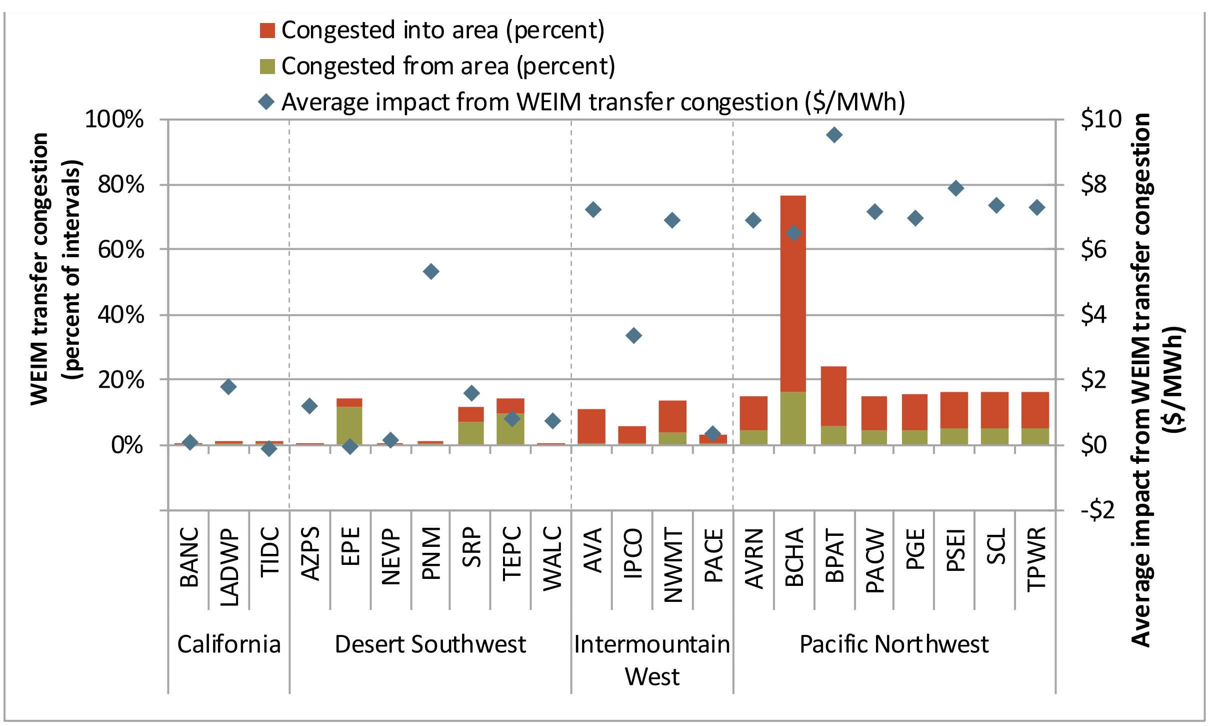



**Figure 5.2 Frequency and impact of WEIM transfer congestion in the 5-minute market (2024)**



## 5.2 Internal congestion in the real-time market

This section presents analysis of the effect of internal congestion on real-time markets across the WEIM.[149] This section focuses on individual flow-based constraints that are internal to balancing authority areas, rather than schedule-based constraints between areas. The impact from transfer constraints is discussed above in Section 5.1.

The impact of congestion on each pricing node in the system is calculated as the product of the shadow price of that constraint and the shift factor for that node relative to the congested constraint. This calculation works for individual nodes, as well as for groups of nodes that represent different load aggregation points or local capacity areas.[150]

In 2024, internal congestion in the real-time market was on average in the south-to-north direction. Most south-to-north congestion occurred during mid-day solar production hours. This congestion contributed to increasing prices in the Northern California and Pacific Northwest regions relative to balancing areas in Southern California and the Desert Southwest.[151]

Figure 5.3 illustrates the overall impact of internal congestion on prices at the default load aggregation points (DLAPs) and EIM load aggregation points (ELAPs) in 2024. The blue bars represent the 15-minute market price impact, and the yellow bars indicate the 5-minute market price impact from internal constraints.

[149] This report defines internal congestion as congestion on any constraint within a balancing authority area. Therefore, the effect of internal congestion on the CAISO balancing area may include effects of congestion from transmission elements within other WEIM balancing areas. Analysis of internal congestion excludes transfer constraints and intertie constraint congestion.

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

[151] Language in the report describing congestion as “increasing" or “decreasing” a price is describing the change relative to the particular reference bus used in that market. The ISO uses a particular reference bus—distributed amongst load nodes according to the load at each node’s percentage of total load. However, in theory, any node could be used as the reference bus, and changing the reference bus would change the value of how much congestion “increased” or “decreased” prices at a node relative to the reference bus. While the specific value of an increase or decrease in congestion price is relative to the reference bus, the *difference* between the impact of congestion on one node and another node is not dependent on the reference bus. Therefore, in assessing the impacts of congestion on prices, DMM suggests the reader focus on the difference of the price impacts between nodes or areas, and not on the specific value of an increase or decrease to one node or area.

**Figure 5.3 Overall impact of internal congestion on price separation in the 15-minute and 5-minute markets (2024)**

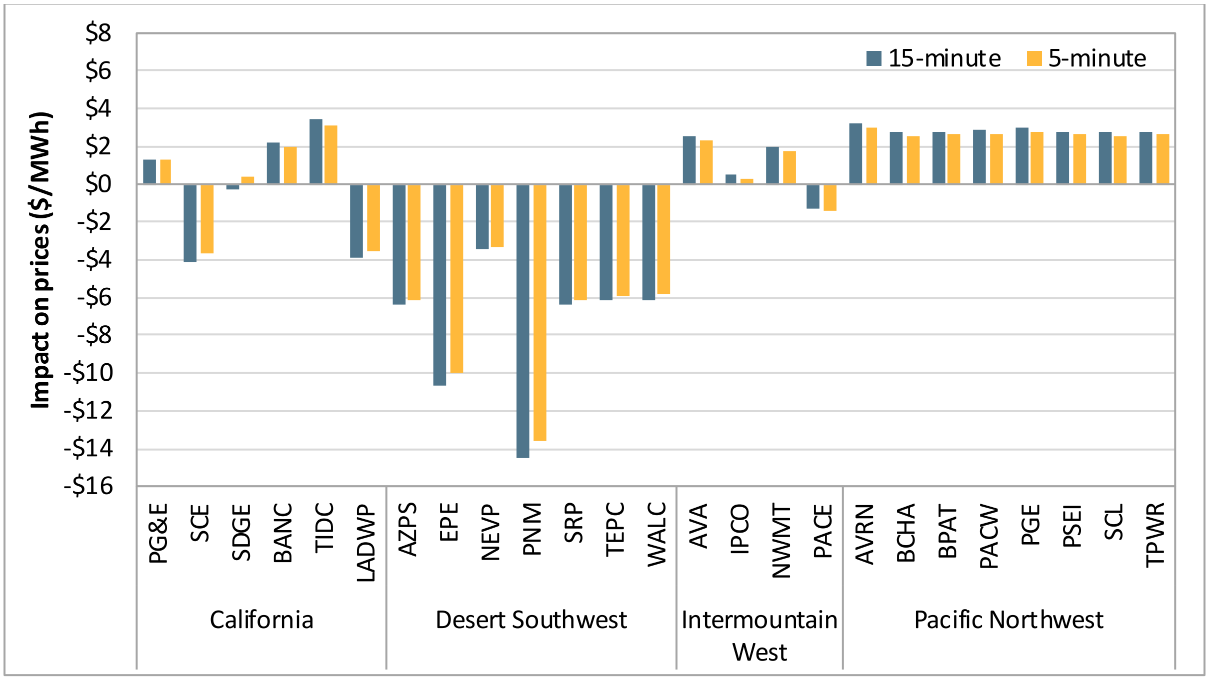



Figure 5.4 displays the average impact of internal congestion on prices in 2023 and 2024. The blue bars represent the impact for 2023, and the red bars show the impact for 2024. This impact was calculated as the average of the 15-minute and 5-minute market price impacts of internal constraints for all intervals.

In both 2023 and 2024, internal congestion generally led to increased prices in the Pacific Northwest and the Intermountain West, while prices decreased in Southern California and the Desert Southwest. Internal congestion increased prices in Northern California in 2024, whereas it slightly lowered prices in 2023. Overall, price separation driven by internal congestion was less pronounced in 2024 compared to 2023.

**Figure 5.4 Average impact of internal congestion on real-time market price (2023–2024)**

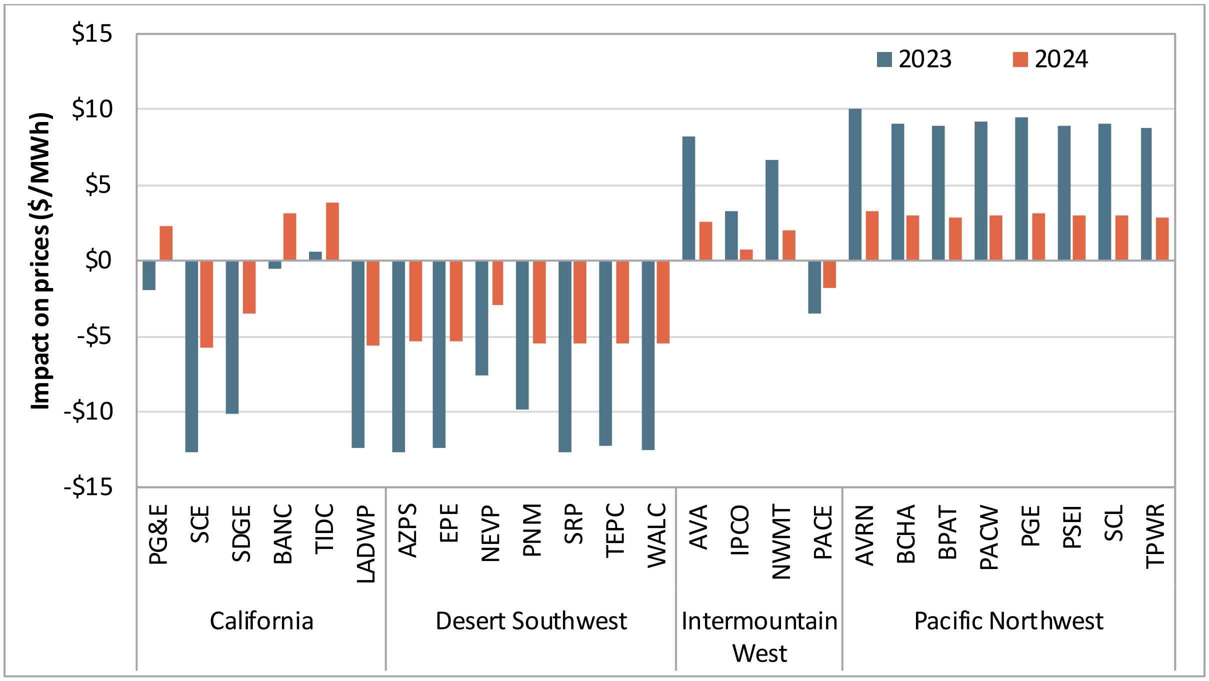



Figure 5.5 and Figure 5.6 display the hourly impact of internal congestion on the 15-minute market prices of DLAPs and ELAPs for 2024 and 2023, respectively. The mid-day congestion patterns were similar in 2023 and 2024. Pronounced mid-day congestion resulted in south-to-north congestion that increased prices in Northern California, the Pacific Northwest, and much of the Intermountain West. A key distinction in 2024 compared to 2023 was the shift in evening peak-hour congestion patterns. In 2024, congestion during peak hours had a relatively smaller impact and tended to increase prices in CAISO DLAPs. In contrast, 2023 saw a stronger congestion impact, increasing prices in Southern California and the Desert Southwest and decreasing prices in the Pacific Northwest, Intermountain West, and Northern California.

## Figure 5.5 Overall impact of internal congestion on price separation in the 15-minute market by hour (2024)

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| PG&E | .3 | -.2 | .3 | .7 | .6 | .6 | .8 | 3.5 | 5.1 | 5.6 | 3.1 | 2.5 | 2.6 | 2.9 | 3.7 | 3 | 2.8 | 4.9 | 5.4 | 3.4 | 2.3 | .4 | .9 | 0 |
| BANC | .1 | -.1 | .3 | .7 | .6 | .6 | .7 | 3.2 | 6.2 | 7.8 | 6.8 | 6.1 | 5.8 | 6.5 | 8 | 6.5 | 3.7 | 2.3 | 1.9 | 2.4 | 1.5 | .1 | .8 | -.1 |
| Turlock ID | .1 | -.3 | .1 | .5 | .4 | .5 | .6 | 3.6 | 8.1 | 10.8 | 10.3 | 9.5 | 9.4 | 10.4 | 11.7 | 9.5 | 5 | 1.7 | .2 | -.1 | -.2 | -.7 | .3 | -.4 |
| SCE | 0 | -.4 | -.1 | .2 | .2 | .3 | .2 | -3.4 | -10.9 | -13.9 | -15.7 | -16 | -15.3 | -15.8 | -15.4 | -13.2 | -10.8 | -7.2 | -3.8 | -2.1 | -1.7 | -1 | .3 | -.2 |
| SDG&E | 1.4 | .7 | .6 | .9 | 1 | .9 | .9 | -1.2 | -6.8 | -10.1 | -12.4 | -13.4 | -13.2 | -13.7 | -12.5 | -10.2 | -7.7 | -3.2 | -.4 | .5 | 1.5 | 2.4 | 2 | .8 |
| LADWP | -.1 | -.8 | -.4 | -.1 | -.4 | -.7 | -1.3 | -4.9 | -9.8 | -12.5 | -14.9 | -14.9 | -14.4 | -14 | -13.3 | -11 | -10.3 | -7 | -3.5 | -2.2 | -2 | -1.3 | -.9 | -.5 |
| NV Energy | -.2 | -.4 | -.2 | 0 | -.1 | -.1 | -.3 | -2.3 | -5.4 | -6.3 | -7.9 | -7.8 | -7.3 | -6.9 | -6.3 | -5.7 | -5.3 | -3.9 | -1.9 | -1.6 | -1.7 | -1.1 | -.2 | -.3 |
| Arizona PS | -.6 | -.9 | -.5 | -.2 | -.3 | -.2 | -.2 | -4.4 | -10.3 | -12.3 | -14.3 | -14.1 | -13.5 | -12.7 | -11.7 | -9.9 | -8.2 | -5.8 | -3.6 | -2.5 | -2.4 | -1.8 | -.5 | -.6 |
| Tucson Electric | -.6 | -.9 | -.5 | -.3 | -.4 | -.3 | -.6 | -4.2 | -9.9 | -11.9 | -13.8 | -13.7 | -13.2 | -13.2 | -12.9 | -11.1 | -8.7 | -6.1 | -3.5 | -2.5 | -2.3 | -1.8 | -.5 | -.6 |
| Salt River Project | -.6 | -.9 | -.5 | -.2 | -.3 | -.3 | -.5 | -4.4 | -10.4 | -12.4 | -14.3 | -14.2 | -13.6 | -13 | -12.2 | -10.6 | -8.7 | -6.2 | -3.6 | -2.6 | -2.4 | -1.8 | -.6 | -.6 |
| PSC New Mexico | -.2 | -.6 | -.5 | -.2 | 0 | .3 | -.3 | -4.8 | -10.6 | -13.1 | -14.1 | -14.5 | -14.8 | -14.5 | -13.3 | -11.3 | -8 | -5.8 | -3.4 | -2.4 | -2.3 | -1.7 | -.2 | -.3 |
| WAPA - Desert SW | -.6 | -.9 | -.5 | -.2 | -.3 | -.3 | -.6 | -4.3 | -10.2 | -12.2 | -14.2 | -14 | -13.4 | -13.6 | -13.3 | -11.4 | -9 | -6.3 | -3.6 | -3 | -2.4 | -1.8 | -.6 | -.6 |
| El Paso Electric | -2.2 | -2.3 | -2.2 | -2 | -2.2 | -2.2 | -2.1 | -4.9 | -9.8 | -11.7 | -13.1 | -13.1 | -12.1 | -11.8 | -11.5 | -8.4 | -7 | -4.4 | -2.3 | -1 | -1.7 | -1.8 | -1.4 | -1.8 |
| PacifiCorp East | -1.2 | -1.2 | -1.1 | -1.1 | -1 | -1.1 | -1.2 | -1.6 | -2.1 | -2.2 | -2.4 | -2.4 | -2.4 | -2.4 | -2.3 | -2.1 | -1.9 | -1.7 | -2.2 | -2.7 | -2 | -1.5 | -1.2 | -1.1 |
| Idaho Power | 0 | .1 | 0 | -.1 | -.1 | -.1 | -.1 | .4 | 1.4 | 1.9 | 2.3 | 2.3 | 2.1 | 2.2 | 2.3 | 2.2 | 2.2 | 1.5 | -.4 | -.8 | -.2 | 0 | -.1 | .1 |
| NorthWestern | 0 | .2 | -.1 | -.3 | -.2 | -.3 | -.2 | 1.2 | 3.6 | 4.7 | 5.9 | 5.9 | 5.5 | 5.6 | 5.6 | 5.3 | 4.8 | 3 | -.2 | -1 | -.5 | -.1 | -.3 | .1 |
| Avista Utilities | -.1 | .2 | -.2 | -.4 | -.3 | -.4 | -.3 | 1.7 | 5 | 6.3 | 7.7 | 7.7 | 7.2 | 7.4 | 7.3 | 6.8 | 6.2 | 3.8 | -.3 | -1.2 | -.6 | -.2 | -.5 | .1 |
| Avangrid | -.1 | .3 | -.2 | -.5 | -.4 | -.4 | -.2 | 2.3 | 6.5 | 8.1 | 9.5 | 9.2 | 8.2 | 9.2 | 9.3 | 8.4 | 7.6 | 4.9 | 0 | -1 | -.2 | .1 | -.5 | .1 |
| BPA | -.1 | .3 | -.2 | -.5 | -.4 | -.4 | -.3 | 1.9 | 5.7 | 7 | 8.7 | 8.7 | 8.2 | 8.4 | 8.2 | 7.7 | 6.9 | 4.2 | -.2 | -1.1 | -.4 | -.1 | -.5 | .1 |
| Tacoma Power | -.1 | .3 | -.2 | -.5 | -.3 | -.4 | -.3 | 1.9 | 5.6 | 6.9 | 8.8 | 8.6 | 8 | 8.3 | 8.2 | 7.6 | 7 | 4.2 | -.2 | -1.2 | -.5 | -.2 | -.5 | .1 |
| PacifiCorp West | -.1 | .3 | -.2 | -.5 | -.3 | -.4 | -.2 | 2 | 5.7 | 7.3 | 8.7 | 8.6 | 8 | 8.3 | 8.3 | 7.6 | 6.9 | 4.4 | -.2 | -1.1 | -.4 | .2 | -.5 | .1 |
| Portland GE | -.1 | .3 | -.2 | -.5 | -.3 | -.4 | -.3 | 2 | 5.9 | 7.2 | 9.4 | 9.6 | 9.2 | 9.4 | 9.2 | 8.8 | 7.5 | 4.5 | -.2 | -1.1 | -.4 | -.1 | -.5 | .1 |
| Puget Sound Energy | -.1 | .3 | -.2 | -.5 | -.3 | -.4 | -.3 | 1.9 | 5.8 | 7 | 8.9 | 8.9 | 8.5 | 8.7 | 8.4 | 7.9 | 7.1 | 4.3 | -.2 | -1.1 | -.5 | -.2 | -.5 | .1 |
| Seattle City Light | -.1 | .3 | -.2 | -.5 | -.3 | -.4 | -.3 | 1.9 | 6.1 | 7 | 8.9 | 9.1 | 8.7 | 8.8 | 8.5 | 8 | 7.2 | 4.3 | -.1 | -1 | -.5 | -.2 | -.5 | .1 |
| Powerex | -.1 | .2 | -.2 | -.4 | -.3 | -.4 | -.2 | 1.8 | 6.1 | 6.9 | 8.8 | 9.1 | 8.8 | 8.8 | 8.5 | 8 | 7.1 | 4.2 | -.1 | -1 | -.5 | -.2 | -.5 | .1 |

Hour

## Figure 5.6 Overall impact of internal congestion on price separation in the 15-minute market by hour (2023)

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| PG&E | -.2 | -.3 | -.3 | -.3 | -.3 | -.4 | -.8 | 2.2 | 4.8 | 5.2 | 4.8 | 5.1 | 4.5 | 4.1 | 3.6 | 2.0 | 1.7 | -.5 | -2.2 | -5.2 | -3.4 | -2.6 | -.8 | -.4 |
| BANC | -.6 | -.6 | -.6 | -.7 | -.6 | -.9 | -1.0 | 2.0 | 6.1 | 7.4 | 7.2 | 7.5 | 7.1 | 6.6 | 6.1 | 3.6 | 2.1 | -.4 | -2.3 | -5.7 | -3.8 | -2.8 | -1.2 | -.7 |
| Turlock ID | -.5 | -.5 | -.5 | -.4 | -.5 | -.8 | -1.0 | 2.6 | 7.8 | 10.3 | 10.2 | 10.5 | 9.7 | 9.2 | 8.6 | 5.8 | 3.8 | .6 | -2.3 | -5.8 | -3.8 | -2.8 | -1.2 | -.7 |
| SCE | .7 | .7 | .7 | .7 | .7 | 1.1 | 1.3 | -2.0 | -7.3 | -9.7 | -9.9 | -10.3 | -10.0 | -9.1 | -8.2 | -5.1 | -2.6 | .6 | 3.8 | 7.7 | 4.7 | 3.4 | 1.7 | 1. |
| SDG&E | 2.5 | 2.5 | 2.4 | 2.2 | 2.4 | 3.0 | 3.2 | 1.3 | -2.3 | -5.6 | -5.5 | -6.3 | -7.1 | -6.7 | -5.2 | -2.0 | .3 | 3.2 | 6.1 | 10.0 | 7.5 | 6. | 4.5 | 3.2 |
| LADWP | .4 | .4 | .3 | .1 | .2 | .8 | 1.1 | -2.2 | -7.2 | -9.8 | -9.9 | -10.3 | -10.0 | -8.4 | -7.8 | -4.7 | -2.5 | .4 | 3.4 | 7.0 | 4.4 | 2.9 | 1.1 | .7 |
| NV Energy | -.2 | -.3 | -.2 | -.1 | .1 | .2 | .4 | -2.7 | -4.9 | -5.1 | -4.9 | -4.9 | -4.8 | -4.6 | -4.0 | -2.0 | -1.1 | .4 | 2.1 | 3.7 | 2.1 | 1.1 | -.5 | -.4 |
| Arizona PS | -.1 | -.1 | -.2 | -.1 | 0 | .2 | .4 | -3.7 | -9.7 | -11.8 | -11.8 | -12.1 | -11.5 | -10.4 | -8.5 | -4.5 | -2.6 | -.2 | 2.3 | 5.2 | 3.0 | 1.8 | .3 | 0 |
| Tucson Electric | -.1 | -.1 | -.2 | -.1 | 0 | .3 | .4 | -3.5 | -9.4 | -11.3 | -11.3 | -11.6 | -11.4 | -10.8 | -9.9 | -6.2 | -3.8 | -.9 | 2.0 | 4.8 | 2.8 | 1.6 | .2 | -.1 |
| Salt River Project | -.1 | -.1 | -.1 | -.1 | 0 | .3 | .4 | -3.8 | -9.9 | -11.9 | -11.9 | -12.3 | -12.0 | -11.5 | -10.6 | -6.7 | -4.1 | -1.1 | 2.1 | 5.1 | 3.0 | 1.8 | .3 | 0 |
| PSC New Mexico | -.1 | -.2 | -.1 | 0 | .1 | .3 | .4 | -2.9 | -7.4 | -8.8 | -9.1 | -9.4 | -9.3 | -8.6 | -7.9 | -4.9 | -2.9 | -.4 | 2.1 | 4.3 | 2.5 | 1.4 | -.1 | -.5 |
| WAPA - Desert SW | 0 | 0 | -.1 | -.1 | -.1 | -.2 | -.5 | -3.7 | -9.1 | -10.3 | -9.6 | -9.5 | -8.8 | -8.2 | -7.1 | -3.9 | -2.8 | 0 | 3.6 | 7.1 | 4.0 | 2.3 | .6 | .1 |
| El Paso Electric | -4.1 | -4.0 | -3.9 | -4.0 | -3.8 | -3.3 | -3.9 | -5.6 | -9.3 | -9.8 | -9.1 | -8.8 | -7.8 | -7.2 | -6.5 | -4.4 | -4.2 | -2.3 | .9 | 3.7 | .8 | -1.0 | -3.0 | -3.9 |
| PacifiCorp East | -2.9 | -2.9 | -2.8 | -3.0 | -3.1 | -3.2 | -3.5 | -3.5 | -3.5 | -3.5 | -3.4 | -3.3 | -3.4 | -3.5 | -3.4 | -3.4 | -3.3 | -3.3 | -3.6 | -4.0 | -3.7 | -3.3 | -3.3 | -3.0 |
| Idaho Power | 0 | 0 | 0 | 0 | 0 | .1 | -.2 | .5 | 1.6 | 1.8 | 1.8 | 1.8 | 1.6 | 1.3 | 1.1 | .5 | .4 | -.5 | -2.2 | -4.2 | -2.5 | -1.6 | -.6 | -.2 |
| NorthWestern | -.3 | -.3 | -.2 | -.2 | -.2 | -.4 | -.5 | .8 | 2.8 | 3.3 | 3.1 | 3.2 | 3.1 | 2.7 | 2.3 | 1.3 | .6 | -.9 | -3.2 | -5.8 | -3.4 | -2.1 | -.8 | -.4 |
| Avista Utilities | -.4 | -.4 | -.3 | -.3 | -.4 | -.7 | -.6 | 1.0 | 3.6 | 4.3 | 4.1 | 4.3 | 4.3 | 3.9 | 3.2 | 1.7 | .8 | -1.1 | -3.8 | -6.9 | -4.1 | -2.5 | -1. | -.6 |
| Avangrid | -.7 | -.6 | -.6 | -.5 | -.6 | -.7 | -.2 | 1.6 | 5.4 | 6.0 | 5.5 | 5.5 | 5.1 | 4.7 | 3.7 | 1.8 | 1.0 | -1.7 | -5.6 | -10.3 | -6.1 | -3.7 | -1.5 | -.8 |
| BPA | -.4 | -.4 | -.3 | -.3 | -.4 | -.7 | -.7 | 1.1 | 3.9 | 4.7 | 4.6 | 4.8 | 4.7 | 4.2 | 3.7 | 1.9 | 1.0 | -1.1 | -3.7 | -6.7 | -4.0 | -2.6 | -1.1 | -.6 |
| Tacoma Power | -.4 | -.4 | -.3 | -.3 | -.4 | -.7 | -.7 | 1.1 | 3.8 | 4.6 | 4.4 | 4.6 | 4.5 | 4.0 | 3.5 | 1.8 | .9 | -1.2 | -3.9 | -7.2 | -4.3 | -2.7 | -1.1 | -.6 |
| PacifiCorp West | -.5 | -.4 | -.3 | -.3 | -.4 | -.7 | -.7 | 1.1 | 4.1 | 4.9 | 4.7 | 4.9 | 4.6 | 4.1 | 3.5 | 1.8 | 1.0 | -1.2 | -4.0 | -7.4 | -4.5 | -2.8 | -1.1 | -.6 |
| Portland GE | -.4 | -.4 | -.3 | -.3 | -.4 | -.7 | -.7 | 1.1 | 4.1 | 4.7 | 4.6 | 4.8 | 5.1 | 3.9 | 3.9 | 2.3 | 1.4 | -.8 | -3.9 | -7.3 | -4.5 | -2.8 | -1.1 | -.6 |
| Puget Sound Energy | -.4 | -.4 | -.3 | -.3 | -.4 | -.7 | -.7 | 1.2 | 4.0 | 4.8 | 4.7 | 4.9 | 5.2 | 4.9 | 4.3 | 2.5 | 1.0 | -1.1 | -3.9 | -7.1 | -4.3 | -2.6 | -1.1 | -.6 |
| Seattle City Light | -.4 | -.4 | -.3 | -.3 | -.4 | -.7 | -.7 | 1.2 | 4.0 | 4.9 | 4.8 | 5.0 | 5.7 | 5.6 | 4.9 | 2.9 | 1.1 | -1.0 | -3.9 | -7.1 | -4.3 | -2.6 | -1.1 | -.6 |
| Powerex | -.4 | -.4 | -.3 | -.3 | -.4 | -.7 | -.7 | 1.3 | 4.0 | 5.1 | 4.9 | 5.1 | 6.1 | 6.1 | 5.2 | 3.3 | 1.2 | -.9 | -3.8 | -7.0 | -4.2 | -2.5 | -1.1 | -.6 |

Hour

### Congestion in the 15-minute market from internal, flow-based constraints

Table 5.1 shows the annual impact of congestion from individual constraints on prices across the WEIM for the 15-minute market. The table reports the top 50 constraints based on their aggregate impact and price separation across DLAPs and ELAPs. Constraints with minimal impact are consolidated under the “other” category, which appears in the second-to-last row of the second column.

The three constraints that had the greatest impact on price separation in the 15-minute market were the California-Oregon Intertie (COI) nomogram, Gates-Midway #1 500 kV line, and Tesla-Los Banos #1 500 kV line.

#### California-Oregon Intertie (COI) nomogram

The California-Oregon Intertie nomogram (6110_COI_S-N) decreased prices in California and the Desert Southwest, while it increased prices in the Intermountain West and Pacific Northwest. This line was primarily binding in the first quarter as well as in April of 2024, with most occurrences during the mid-day solar hours, typically from hour-ending 11 to hour-ending 15.

#### Gates-Midway #1 500 kV line

The Gates-Midway #1 500 kV line (30055_GATES1_500_30060_MIDWAY_500_BR_1_1) increased prices in Northern California, the Pacific Northwest, and the Intermountain West, while it decreased prices in Southern California and the Desert Southwest. This line bound throughout the year but showed higher concentration in the first quarter as well as in April. This line experienced congestion during solar production hours, most frequently from hour-ending 9 to 15.

#### Tesla-Los Banos #1 500 kV line

The Tesla-Los Banos #1 500 kV line (30040_TESLA_500_30050_LOSBANOS_500_BR_1_1) increased prices in Northern California, the Pacific Northwest, and the Intermountain West, while it decreased prices in Southern California and the Desert Southwest. This line experienced congestion during the winter months, particularly in the first quarter of 2024. Congestion occurred during solar production hours, with the highest frequency between hour-ending 10 and hour-ending 16.

## Table 5.1 Impact of internal transmission constraint congestion on 15-minute market prices during all hours – top 50 primary constraints (WEIM, 2024)[152]

| BAA | Constraint | Average quarter impact ($/MWh) – California | | | | | | Desert Southwest | | | | | | | Intermountain West | | | | Pacific Northwest | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | PG&E | BANC | TIDC | SCE | SDG&E | LADWP | AZPS | EPE | NEVP | PNM | SRP | TEPC | WALC | AVA | IPCO | NWMT | PACE | AVRN | BCHA | BPAT | PACW | PGE | PSEI | SCL | TPWR |
| BANC | XFMR2500.TRY | .03 | .06 | .08 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | -.02 | -.01 | -.01 | -.01 | -.02 | -.02 | -.02 | -.02 | -.02 | -.02 | -.02 | -.02 |
| BPAT | NWACI_SN | -.15 | -.16 | -.16 | -.12 | -.11 | -.12 | -.1 | -.08 | -.09 | -.08 | -.1 | -.09 | -.1 | .13 | .06 | .11 | .01 | .16 | .13 | .14 | .14 | .14 | .13 | .13 | .13 |
| | INTNEL | -.05 | -.05 | -.05 | -.05 | -.05 | -.05 | -.05 | -.05 | -.05 | -.05 | -.05 | -.05 | -.05 | -.01 | -.05 | 0 | -.04 | -.06 | .24 | 0 | -.06 | -.06 | .09 | .18 | -.01 |
| | NOPE | -.05 | -.05 | -.05 | -.05 | -.05 | -.05 | -.04 | -.04 | -.04 | -.04 | -.04 | -.04 | -.04 | .03 | -.03 | .01 | -.03 | -.06 | .08 | .06 | . | .19 | .11 | .09 | .11 |
| | NWACI_NS | .02 | .03 | .02 | .01 | .01 | .01 | .01 | .01 | .01 | .01 | .01 | .01 | .01 | -.04 | -.02 | -.03 | -.01 | -.05 | -.04 | -.04 | -.04 | -.04 | -.04 | -.04 | -.04 |
| CISO | 6110_COI_S-N | -1.47 | -1.54 | -1.52 | -1.14 | -1.08 | -1.12 | -.97 | -.84 | -.83 | -.78 | -.96 | -.92 | -.96 | 1.12 | .54 | .93 | .01 | 1.34 | 1.17 | 1.2 | 1.23 | 1.23 | 1.19 | 1.18 | 1.19 |
| | 30055_GATES1_500_30060_MIDWAY_500_BR_1_1 | .94 | 1.12 | 1.16 | -1.45 | -1.38 | -1.43 | -1.24 | -1.13 | -.79 | -1.07 | -1.24 | -1.2 | -1.24 | .71 | .24 | .55 | -.23 | .9 | .75 | .78 | .82 | .8 | .77 | .77 | .77 |
| | 30040_TESLA_500_30050_LOSBANOS_500_BR_1_1 | .21 | .61 | .61 | -.84 | -.8 | -.82 | -.71 | -.65 | -.45 | -.61 | -.71 | -.69 | -.71 | .46 | .17 | .37 | -.1 | .58 | .49 | .5 | .53 | .52 | .5 | .5 | .5 |
| | 30750_MOSSLD_230_30797_LASAGUIL_230_BR_1_1 | .53 | .14 | .4 | -.93 | -.88 | -.53 | -.42 | -.29 | -.09 | -.22 | -.42 | -.38 | -.42 | .09 | . | .05 | . | .12 | .09 | .1 | .1 | .1 | .09 | .09 | .09 |
| | 30790_PANOCHE_230_30900_GATES_230_BR_2_1 | .28 | .37 | .48 | -.37 | -.36 | -.33 | -.28 | -.25 | 0 | -.21 | -.28 | -.27 | -.28 | .15 | . | .04 | . | .22 | .17 | .17 | .19 | .18 | .17 | .17 | .17 |
| | 30050_LOSBANOS_500_30055_GATES1_500_BR_1_2 | .19 | .29 | .29 | -.29 | -.28 | -.29 | -.25 | -.23 | -.15 | -.22 | -.25 | -.25 | -.25 | .2 | .06 | .15 | -.04 | .25 | .22 | .22 | .23 | .23 | .22 | .22 | .22 |
| | 30050_LOSBANOS_500_30055_GATES1_500_BR_1_3 | .14 | .23 | .24 | -.29 | -.28 | -.27 | -.26 | -.24 | -.18 | -.22 | -.25 | -.25 | -.26 | .17 | .06 | .13 | -.03 | .2 | .17 | .17 | .19 | .18 | .18 | .18 | .18 |
| | 30105_COTTNWD_230_30245_ROUNDMT_230_BR_3_1 | .23 | .4 | .1 | .13 | .12 | .05 | .02 | 0 | . | . | .02 | 0 | .02 | -.31 | -.04 | -.22 | . | -.34 | -.32 | -.32 | -.33 | -.33 | -.32 | -.32 | -.32 |
| | 6110_COI_N-S | .16 | .17 | .16 | .1 | .09 | .09 | .07 | .05 | .03 | .04 | .07 | .06 | .07 | -.25 | -.16 | -.21 | -.08 | -.28 | -.25 | -.26 | -.26 | -.26 | -.26 | -.26 | -.26 |
| | 30900_GATES_230_30970_MIDWAY_230_BR_1_1 | .19 | .23 | .25 | -.2 | -.19 | -.19 | -.15 | -.14 | -.11 | -.13 | -.15 | -.14 | -.15 | .12 | 0 | .09 | . | .15 | .12 | .13 | .13 | .13 | .13 | .13 | .13 |
| | 6410_CP10_NG | .17 | .16 | .16 | -.18 | -.17 | -.17 | -.15 | -.14 | -.09 | -.14 | -.15 | -.15 | -.15 | .1 | .03 | .08 | -.03 | .13 | .11 | .11 | .12 | .11 | .11 | .11 | .11 |
| | 30765_LOSBANOS_230_30790_PANOCHE_230_BR_2_1 | .05 | .56 | 1.31 | -.28 | -.26 | -.12 | -.06 | -.04 | 0 | -.02 | -.05 | -.05 | -.06 | 0 | . | . | . | .08 | .01 | .01 | .02 | .02 | .01 | .01 | .01 |
| | 30056_GATES2_500_30060_MIDWAY_500_BR_2_1 | .1 | .12 | .12 | -.1 | -.1 | -.1 | -.09 | -.08 | -.07 | -.08 | -.09 | -.09 | -.09 | .08 | .02 | .06 | -.02 | .09 | .08 | .08 | .09 | .09 | .08 | .08 | .08 |
| | 30060_MIDWAY_500_24156_VINCENT_500_BR_2_3 | -.13 | -.12 | -.12 | .1 | .09 | .1 | .08 | .08 | .07 | .07 | .08 | .08 | .08 | -.08 | -.04 | -.07 | 0 | -.1 | -.08 | -.09 | -.09 | -.09 | -.09 | -.08 | -.09 |
| | 30005_ROUNDMT_500_30245_ROUNDMT_230_XF_1_P | -.1 | -.18 | -.1 | -.06 | -.06 | -.06 | -.05 | -.04 | -.02 | -.03 | -.05 | -.04 | -.05 | .09 | .06 | .08 | 0 | .1 | .09 | .09 | .09 | .1 | .09 | .09 | .09 |
| | MIGUEL_BKs_MXFLW_NG | .02 | . | . | .07 | .57 | . | -.16 | -.15 | . | -.13 | -.17 | -.16 | -.16 | . | . | . | . | . | . | . | . | . | . | . | . |
| | 7820_TL230S_OVERLOAD_NG | .01 | 0 | 0 | .04 | .61 | 0 | -.12 | -.11 | -.03 | -.08 | -.13 | -.12 | -.12 | . | 0 | . | -.03 | 0 | . | . | . | . | . | . | . |
| | OMS_16244394_COI_DLO | .05 | .06 | .05 | .03 | .03 | .03 | .02 | .02 | .01 | .02 | .02 | .02 | .02 | -.09 | -.05 | -.07 | -.03 | -.1 | -.09 | -.09 | -.09 | -.09 | -.09 | -.09 | -.09 |
| | 24801_DEVERS_500_24804_DEVERS_230_XF_2_P | .04 | .03 | .03 | .01 | 0 | .04 | -.13 | -.12 | -.02 | -.1 | -.14 | -.12 | -.11 | . | . | . | -.03 | 0 | . | . | 0 | . | . | . | . |
| | 30114_DELEVAN_230_30450_CORTINA_230_BR_1_1 | .07 | . | 0 | .03 | .02 | . | . | . | . | . | . | . | . | -.07 | -.02 | -.06 | . | -.08 | -.07 | -.07 | -.08 | -.07 | -.07 | -.07 | -.07 |
| | 30797_LASAGUIL_230_30790_PANOCHE_230_BR_1_1 | .04 | .03 | .03 | -.07 | -.07 | -.06 | -.06 | -.06 | -.04 | -.05 | -.06 | -.06 | -.06 | .01 | . | . | . | .03 | .01 | .01 | .02 | .02 | .01 | .01 | .01 |
| | 30055_GATES1_500_30057_DIABLO_500_BR_1_1 | .03 | .03 | .04 | -.04 | -.04 | -.04 | -.04 | -.03 | -.02 | -.03 | -.04 | -.03 | -.04 | .02 | .01 | .02 | -.01 | .03 | .02 | .02 | .02 | .02 | .02 | .02 | .02 |
| | 99002_MOE-ELD_500_24042_ELDORDO_500_BR_1_2 | .02 | .02 | .02 | .03 | .01 | .03 | -.06 | -.1 | .02 | -.11 | -.06 | -.07 | -.05 | 0 | -.01 | 0 | -.03 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 24801_DEVERS_500_24804_DEVERS_230_XF_1_P | .02 | .02 | .02 | .01 | 0 | .02 | -.07 | -.06 | -.02 | -.05 | -.07 | -.06 | -.06 | . | . | . | -.02 | .01 | . | . | . | . | . | . | . |
| | COI_600N-S | .02 | .02 | .02 | .01 | .01 | .01 | .01 | .01 | 0 | .01 | .01 | .01 | .01 | -.03 | -.02 | -.03 | -.01 | -.03 | -.03 | -.03 | -.03 | -.03 | -.03 | -.03 | -.03 |
| | 30055_GATES1_500_30900_GATES_230_XF_11_P | -.1 | -.01 | 0 | -.02 | -.02 | -.02 | -.02 | -.02 | -.01 | -.02 | -.02 | -.02 | -.02 | .02 | 0 | .02 | 0 | .02 | .02 | .02 | .02 | .02 | .02 | .02 | .02 |
| | 7820_CP3_NG | 0 | . | 0 | .01 | .21 | 0 | -.04 | -.04 | -.01 | -.03 | -.04 | -.04 | -.04 | . | 0 | . | -.01 | . | . | . | . | . | . | . | . |
| | OMS14513059LOSBNS_BUS_OUTAGE | .01 | .02 | .02 | -.04 | -.04 | -.04 | -.02 | -.02 | -.01 | -.02 | -.02 | -.02 | -.02 | .01 | 0 | .01 | 0 | .02 | .01 | .01 | .01 | .01 | .01 | .01 | .01 |
| | 7430_CP6_NG | .06 | .24 | . | -.07 | -.07 | . | . | . | . | . | . | . | . | . | . | . | . | . | . | . | . | . | . | . | . |
| | 39536_FINKSS_230_38402_WSTLYTID_230_BR_1_1 | .01 | .03 | .06 | -.02 | -.02 | -.02 | -.02 | -.02 | -.01 | -.02 | -.02 | -.02 | -.02 | .01 | 0 | .01 | . | .02 | .01 | .01 | .01 | .01 | .01 | .01 | .01 |
| | 22886_SUNCREST_230_22885_SUNCREST_500_XF_2_P | .01 | . | . | .01 | .12 | . | -.04 | -.03 | -.01 | -.03 | -.04 | -.04 | -.04 | . | . | . | -.01 | . | . | . | . | . | . | . | . |
| | 24801_DEVERS_500_99014_CALCAPS2_500_BR_2_1 | .01 | .01 | .01 | .02 | .02 | .01 | -.04 | -.03 | -.01 | -.03 | -.04 | -.04 | -.03 | 0 | 0 | . | -.01 | .01 | 0 | 0 | .01 | 0 | 0 | 0 | 0 |
| | 99013_CALCAPS_500_24801_DEVERS_500_BR_1_1 | .01 | .01 | .01 | .02 | 0 | .01 | -.04 | -.03 | -.01 | -.03 | -.04 | -.03 | -.03 | . | . | . | -.01 | 0 | . | . | 0 | 0 | . | . | . |
| | 6410_CP1_NG | -.02 | -.01 | -.02 | .01 | .01 | .01 | .01 | .01 | .01 | .01 | .01 | .01 | .01 | -.01 | 0 | -.01 | 0 | -.01 | -.01 | -.01 | -.01 | -.01 | -.01 | -.01 | -.01 |
| | 30055_GATES1_500_30060_MIDWAY_500_BR_1_3 | .01 | .01 | .01 | -.02 | -.01 | -.02 | -.01 | -.01 | -.01 | -.01 | -.01 | -.01 | -.01 | .01 | 0 | .01 | 0 | .01 | .01 | .01 | .01 | .01 | .01 | .01 | .01 |
| | 30015_TABLEMT_500_30030_VACA-DIX_500_BR_1_3 | . | 0 | .01 | . | . | .01 | .01 | 0 | 0 | 0 | .01 | 0 | .01 | -.02 | -.01 | -.02 | 0 | -.02 | -.02 | -.02 | -.02 | -.02 | -.02 | -.02 | -.02 |
| | 24091_MESACAL_230_24076_LAGUBELL_230_BR_2_1 | -.02 | -.02 | -.02 | .04 | .03 | 0 | . | . | . | . | . | . | . | -.01 | . | 0 | . | -.02 | -.01 | -.01 | -.01 | -.01 | -.01 | -.01 | -.01 |
| | 32214_RIOOSO_115_30330_RIOOSO_230_XF_1 | .21 | . | . | -.02 | 0 | . | . | . | . | . | . | . | . | . | . | . | . | . | . | . | . | . | . | . | . |
| LADWP | WECC_Path_41 | .03 | .03 | .03 | .06 | 0 | -.37 | -.05 | -.05 | -.06 | -.05 | -.05 | -.05 | -.05 | . | . | . | -.02 | .02 | . | 0 | .01 | .01 | 0 | 0 | 0 |
| PACE | WINDSTAREXPORTTCOR | .04 | . | . | .04 | .04 | . | . | 0 | . | 0 | . | . | . | . | 0 | .01 | -.47 | . | . | . | . | . | . | . | . |
| | TOTAL_WYOMING_EXPORT | .02 | . | . | .02 | .02 | . | . | . | . | . | . | . | . | . | . | . | -.26 | . | . | . | . | . | . | . | . |
| PGE | MCL_PE_SHW_V682 | -.02 | -.02 | -.02 | -.01 | -.01 | -.01 | -.01 | -.01 | -.01 | -.01 | -.01 | -.01 | -.01 | . | . | . | . | -.02 | . | .02 | . | .14 | .01 | . | .01 |
| PNM | CZ345kV | .02 | . | . | .01 | .01 | . | . | -.25 | . | -.77 | . | . | . | . | . | . | . | . | . | . | . | . | . | . | . |
| | 115kvLK | . | . | . | . | . | . | . | -.38 | . | . | . | . | . | . | . | . | . | . | . | . | . | . | . | . | . |
| | 115kvWE_So_El | . | . | . | . | . | . | . | .23 | . | -.13 | . | . | . | . | . | . | . | . | . | . | . | . | . | . | . |
| | Other | .41 | .12 | .1 | -.21 | .51 | -.07 | .04 | -.19 | .16 | -.24 | -.1 | -.24 | -.26 | .04 | .01 | .01 | -.2 | .05 | .04 | .08 | .07 | .05 | .07 | .05 | .06 |
| | Total | 2.3 | 3.01 | 3.78 | -6.06 | -3.8 | -5.88 | -5.48 | -5.54 | -3.05 | -5.68 | -5.62 | -5.56 | -5.71 | 2.63 | .8 | 2.01 | -1.75 | 3.35 | 3.1 | 2.98 | 3.02 | 3.28 | 3.07 | 3.11 | 2.96 |

152 For visualization purposes, numbers are rounded to two decimal points. As a result, values below 0.005 appear as zero, even if they are non-zero. Blank cells with dots indicate that no shift factor exists for the pricing node within the DLAP or ELAP, signifying either no impact from the constraint or their shift factors were too small.

## 5.3 Congestion rent and loss surpluses

Figure 5.7 shows that in 2024, annual congestion rent and loss surpluses were $537 million and $134 million, respectively.[153,154] These amounts represent a decrease of 6 percent and a decrease of 43 percent relative to 2023. The reduction in the congestion component can be attributed to decreased congestion rent from internal constraints. The reduction in the loss component was due to lower energy prices in 2024 compared to 2023.

Congestion rent consists of rents from internal constraints and interties. Internal congestion rent decreased from $526 million to $373 million this year compared to 2023. Intertie congestion rent increased from $47 million to $164 million this year compared to 2023. The primary driver of the increased intertie congestion rent in 2024 was severe cold weather and constrained supply conditions in the Pacific Northwest in Q1 2024, which increased congestion during that period.

In the day-ahead market, hourly congestion rent collected on a constraint is roughly 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 43 percent decrease in the loss surplus compared to 2023 can largely be attributed to lower system energy costs, which declined by 37 percent. The loss surplus represents the difference between what load pays for the loss component of the locational marginal price (LMP) and what generation gets paid from the loss component of LMP in the day-ahead market. The magnitude of the loss component of LMP is directly proportional to the energy component of LMP, so the loss surplus values should correlate with electricity prices and load quantities over time. In settlements, the loss surplus is computed as the difference between daily net energy charge and daily congestion rent. The loss surplus is allocated to measured demand.[155]

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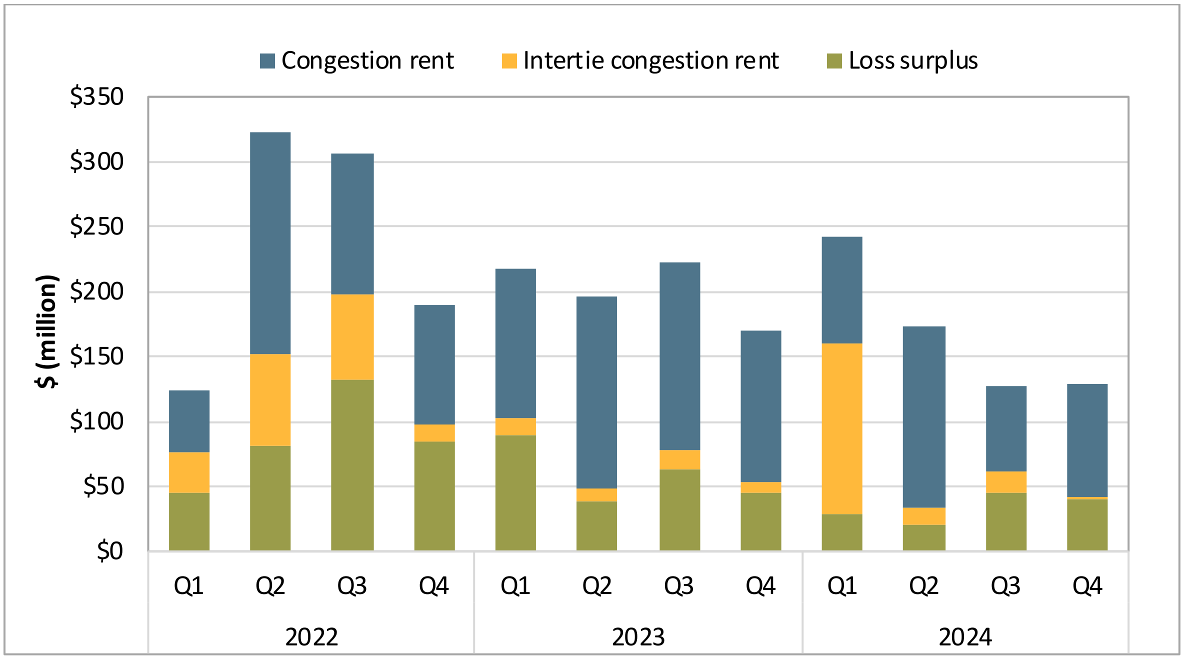
153 Information in this section is based on settlement values available at the time of drafting and will be updated in future reports. Updates can occur regularly within the settlements timeline, starting with T+9B (trade date plus nine business days) and T+70B, as well as others up to 36 months after the trade date.

154 DMM adjusted the source data by removing day-ahead congestion rent calculated through the Nodal Pricing Model (NPM). The ISO provides the Nodal Pricing Model day-ahead service for PacifiCorp, which is used solely for internal Net Power Cost allocation within PACW and PACE balancing areas. As a result, updated congestion rent values no longer include NPM-based congestion rent in any of DMM's quarterly or annual reports published after July 2025.

155 For more information on marginal loss surplus allocation, refer to: *Business Practice Manual Change Management – Settlements and Billing,* CG CC6947 IFM Marginal Losses Surplus Credit Allocation, California ISO: https://bpmcm.caiso.com/Pages/SnBBPMDetails.aspx?BPM=Settlements%20and%20Billing

**Figure 5.7 Day-ahead congestion rent and loss surplus by quarter (2022–2024)**[156]




## 5.4 Congestion on interties

In 2024, total intertie congestion rent in the day-ahead market was $164 million, a significant increase from $47 million in 2023. The major driver was $126 million in export congestion on Malin, resulting from the severe cold weather event in the Pacific Northwest during Q1 2024.

The total intertie congestion charges reported by DMM represent the products of the shadow prices multiplied by the binding limits for the intertie constraints. For a supplier or load serving entity trying to import power over an intertie congested in the import direction, assuming a radial line, the congestion price represents the difference between the higher price of generation on the California ISO side of the intertie and the lower price of import bids outside of the California ISO area. This congestion charge also represents the amount paid to owners of congestion revenue rights that are sourced outside the California ISO area at points corresponding to these interties.

Figure 5.8 shows total intertie congestion charges in the day-ahead market from 2020 to 2024. This figure categorizes total congestion charges by interties and flow direction, distinguishing between imports and exports. Figure 5.9 shows the frequency of congestion on five major interties, categorized by import and export congestion. Table 5.2 provides a detailed summary of congestion rent and frequency over a broader set of interties distinguished by imports and exports. As highlighted in these charts and table:

156 DMM adjusted the source data by removing day-ahead congestion rent calculated through the Nodal Pricing Model (NPM). CAISO provides the NPM day-ahead service for PacifiCorp, which is used solely for internal Net Power Cost allocation within PACW and PACE balancing areas. As a result, updated congestion rent values no longer include NPM-based congestion rent in any of DMM quarterly or annual reports published after July 2025.

Compared to 2023, the total intertie congestion rent increased from $47 million to $164 million. While import congestion rent declined by $4.1 million, export congestion rent rose sharply from $13 million in 2023 to $134 million in 2024. This significant increase was driven by Q1 congestion on Malin, which accounted for 94 percent of total export congestion rent in 2024.

Total intertie congestion rent has fluctuated over the past five years, ranging from a low of $47 million in 2023 to a high of $182 million in 2020. A notable trend is the steady increase in export congestion rent, with an exceptional spike observed in 2024.

Malin and NOB interties accounted for 94 percent of total congestion rent in 2024. Over the past five years, these two interties represented the majority of congestion rent. From 2020 to 2024, Malin and NOB together averaged 81 percent of total annual congestion rent.

**Figure 5.8 Day-ahead congestion charges on major interties**

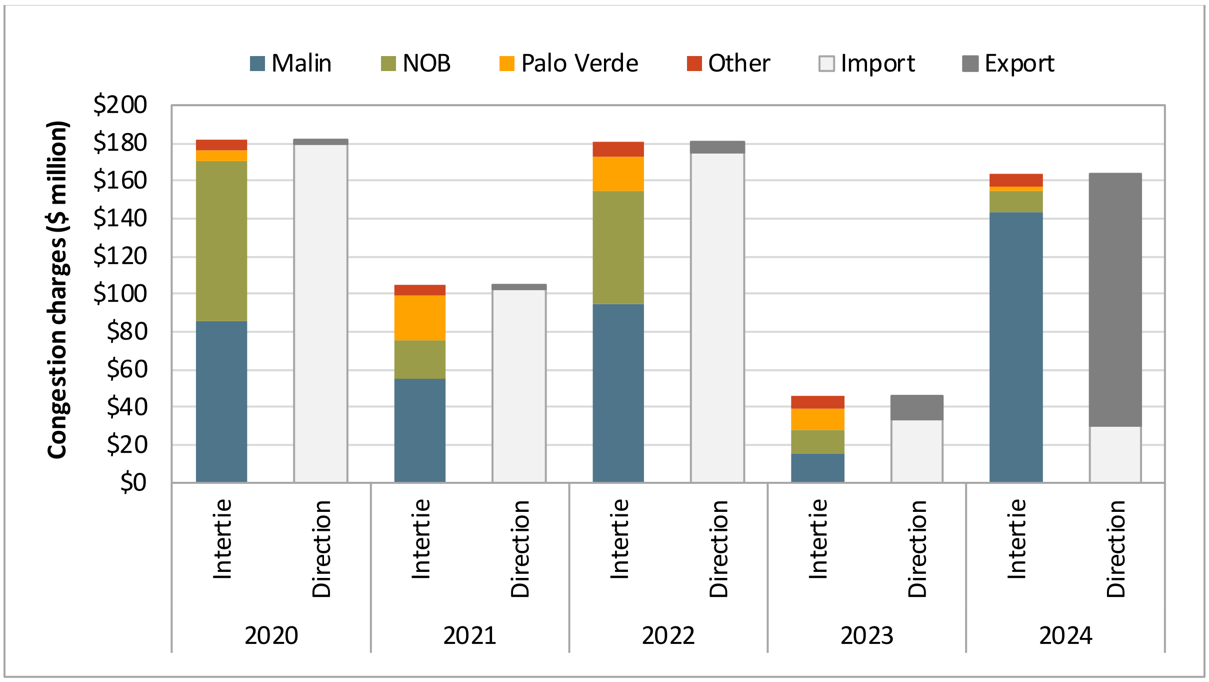
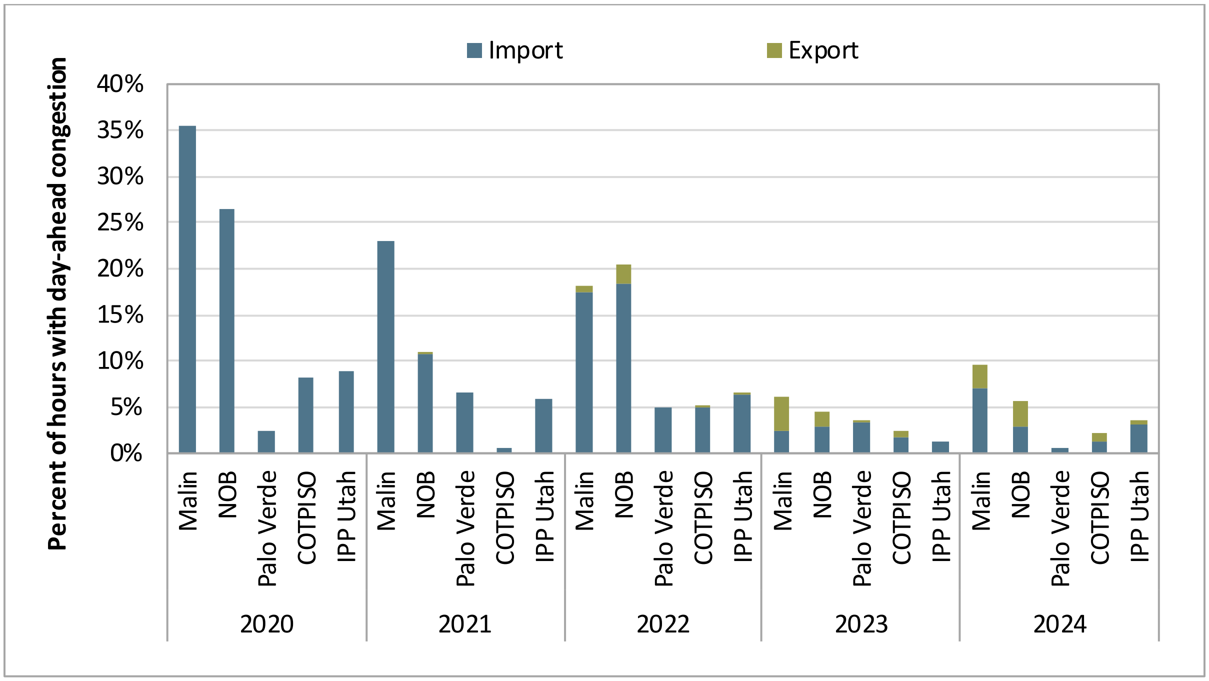


**Figure 5.9 Frequency of congestion on major interties in the day-ahead market**



### Table 5.2 Summary of intertie congestion in day-ahead market (2020–2024)

| Intertie | Direction* | Congestion charges ($ thousand) | | | | | Frequency of congestion | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2020 | 2021 | 2022 | 2023 | 2024 | 2020 | 2021 | 2022 | 2023 | 2024 |
| ***Northwest*** | | | | | | | | | | | |
| Malin | I | $85,929 | $54,927 | $90,385 | $6,367 | $17,429 | 35.4% | 23.% | 17.4% | 2.4% | 7.1% |
| | E | | | $4,826 | $8,658 | $125,863 | | | .8% | 3.8% | 2.5% |
| NOB | I | $84,372 | $20,429 | $58,510 | $11,832 | $8,631 | 26.4% | 10.7% | 18.4% | 2.9% | 2.9% |
| | E | | $267 | $1,398 | $1,170 | $2,341 | | .3% | 2% | 1.5% | 2.8% |
| COTPISO | I | $424 | $31 | $813 | $232 | $140 | 8.3% | .5% | 5% | 1.7% | 1.3% |
| | E | | | $1 | $89 | $1,367 | | | .1% | .8% | .9% |
| Cascade | I | $54 | | $72 | | | .1% | | .7% | | |
| | E | | | | $0 | $2,147 | | | | 0% | 2% |
| Summit | I | $6 | | $20 | $57 | $14 | .1% | | .4% | .5% | .2% |
| | E | | | $0 | | | | | 0% | | |
| ***Southwest*** | | | | | | | | | | | |
| Palo Verde | I | $6,092 | $24,128 | $18,000 | $10,582 | $2,382 | 2.5% | 6.6% | 4.9% | 3.3% | .7% |
| | E | | | | $243 | | | | | .% | |
| IPP Utah | I | $2,259 | $1,625 | $5,636 | $264 | $1,038 | 9% | 5.8% | 6.4% | 1.2% | 3.2% |
| | E | | | $20 | | $401 | | | .2% | | .4% |
| IPP DC Adelanto | I | $108 | $40 | $685 | $2,996 | | .1% | .2% | 1.6% | 1.7% | |
| | E | | | | | $1,071 | | | | | 1% |
| Mona | I | | | | | $23 | | | | | .1% |
| | E | | $1,060 | $83 | $220 | $968 | | .1% | .1% | .3% | 1% |
| Mead | I | $512 | $84 | $182 | $75 | $24 | .5% | .1% | .2% | .1% | .1% |
| | E | $835 | $665 | $308 | $2,370 | | .3% | .1% | .1% | .4% | |
| Merchant | I | | $150 | $101 | | | | .1% | 0% | | |
| | E | | | | | | | | | | |
| Silver Peak | I | | | | | | | | | | |
| | E | | | $34 | $16 | | | | .6% | .7% | |
| Mercury | I | | | $10 | | | | | 0% | | |
| | E | | | | | | | | | | |
| Other | I | $54 | $1,511 | $0 | $1,357 | $8 | | | | | |
| | E | $985 | $72 | $0 | $0 | $129 | | | | | |
| ***Import total (I)*** | | $179,811 | $102,925 | $174,414 | $33,762 | $29,689 | | | | | |
| ***Export total (E)*** | | $1,820 | $2,065 | $6,669 | $12,765 | $134,285 | | | | | |
| ***Total*** | | $181,631 | $104,990 | $181,084 | $46,527 | $163,974 | | | | | |

* I: import, E: export

## 5.5 Internal congestion in the day-ahead market

Figure 5.10 shows the overall impact of congestion on day-ahead market prices in each load area from Q1 2022 to Q4 2024. Figure 5.11 shows the frequency of congestion. Highlights for this year include:

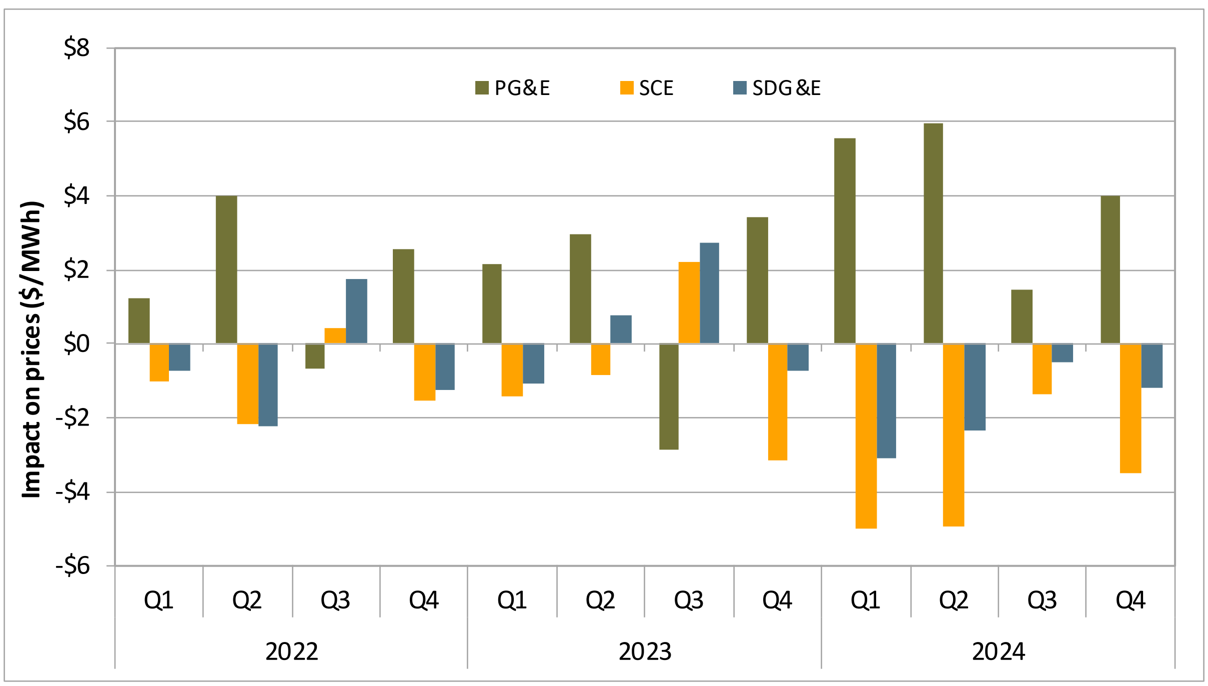
The overall impact of day-ahead congestion on price separation in 2024 was higher compared to 2023, with a general trend of south-to-north congestion.

Day-ahead congestion increased annual average prices in PG&E by $4.3/MWh, while it decreased average SCE and SDG&E prices by $3.7/MWh and $1.8/MWh, respectively.[157]

The percentage of hours in which congestion impacted DLAP prices increased each year from 2022 to 2024. Overall, in 2024, PG&E experienced congestion in 75 percent of hours—an increase from 60 percent in 2023. Across all CAISO balancing area DLAPs, congestion frequency ranged between 70 percent and 75 percent during 2024.

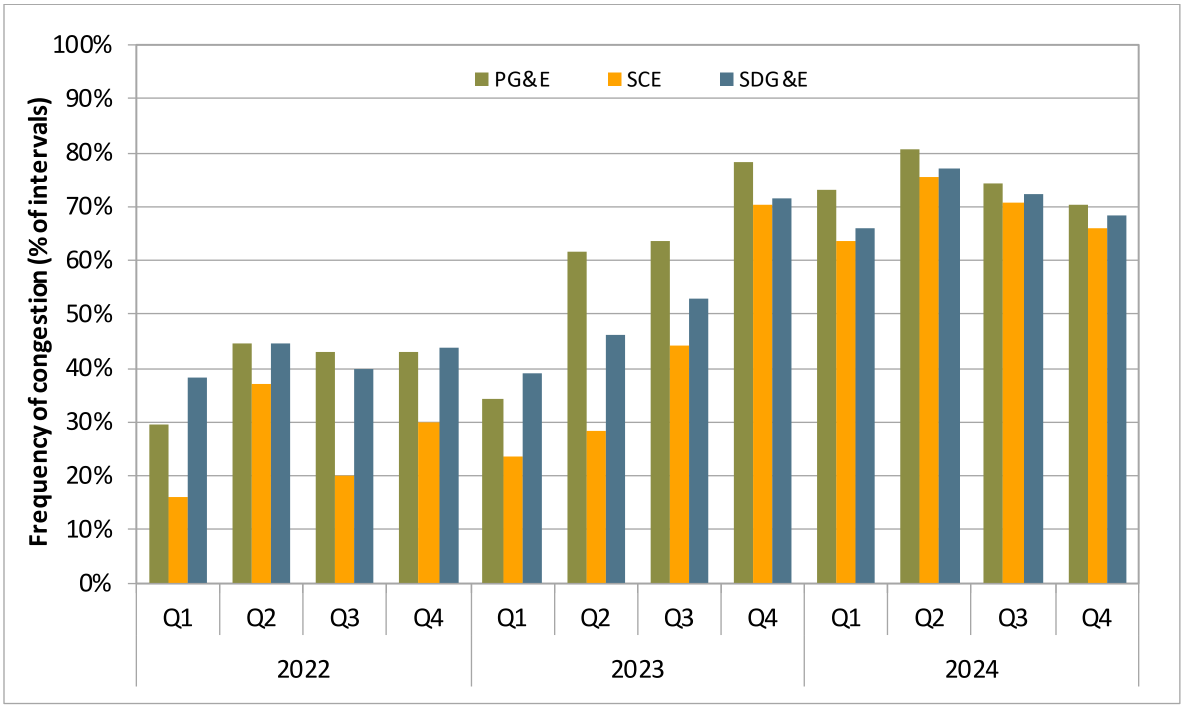
The primary constraints affecting day-ahead market prices were the Gates-Midway #1 500 kV, Moss Landing-Las Aguilas #1 230 kV, and Tesla-Los Banos #1 500 kV lines.

**Figure 5.10 Overall impact of congestion on price separation in the day-ahead market**




[157] Language in the report describing congestion as "increasing" or "decreasing" a price is describing the change relative to the particular reference bus used in that market. The ISO uses a particular reference bus—distributed amongst load nodes according to the load at each node's percentage of total load. However, in theory, any node could be used as the reference bus, and changing the reference bus would change the value of how much congestion "increased" or "decreased" prices at a node relative to the reference bus. While the specific value of an increase or decrease in congestion price is relative to the reference bus, the *difference* between the impact of congestion on one node and another node is not dependent on the reference bus. Therefore, in assessing the impacts of congestion on prices, DMM suggests the reader focus on the difference of the price impacts between nodes or areas, and not on the specific value of an increase or decrease to one node or area.

**Figure 5.11 Hours with congestion impacting day-ahead prices by load area (>$0.05/MWh)**




### Impact of congestion from individual constraints

Table 5.3 breaks down the congestion effect on price separation during 2024 by constraint.[158] The table presents the top 25 most congested lines, ranked by their impact, while the "Other" category shows the average impact of the remaining constraints. Color shading is used in the tables to help distinguish patterns in the impacts of constraints. Orange indicates a positive impact on prices, while blue represents a negative impact—the stronger the shading, the greater the impact in either the positive or the negative direction.

The constraints with the greatest impact on day-ahead price separation for this year were the Gates-Midway #1 500 kV, Moss Landing-Las Aguilas #1 230 kV, and Tesla-Los Banos #1 500 kV lines.

**Gates-Midway #1 500 kV line**

The Gates-Midway #1 500 kV line (30055_GATES1_500_30060_MIDWAY_500_BR_1_1) bound in 9 percent of hours over the year. Congestion on the constraint increased average PG&E prices by $1.01/MWh and decreased average SCE and SDG&E prices by $0.77/MWh and $0.72/MWh, respectively. This transmission line was most frequently binding during solar generation hours, from hour-ending 9 through hour-ending 15.

[158] DMM calculates the congestion impact from constraints by replicating the nodal congestion component of the price from individual constraints, shadow prices, and shift factors. In some cases, DMM could not replicate the congestion component from individual constraints such that the remainder is flagged as *"Other"*. In addition, constraints with price impact of less than $0.01/MWh for all load aggregation points (LAPs) in the region are grouped in "*Other*".

**Moss Landing-Las Aguilas #1 230 kV line**

The Moss Landing-Las Aguilas #1 230 kV line (30750_MOSSLD_230_30797_LASAGUIL_230_BR_1_1) bound in about 24 percent of hours. In 2024, the constraint increased average PG&E prices by about $1.01/MWh, and decreased average SCE and SDG&E prices by $0.77/MWh and $0.72/MWh, respectively. This line was frequently binding during solar production hours, from hour-ending 9 through hour-ending 16.

**Tesla-Los Banos #1 500 kV line**

The Tesla-Los Banos #1 500 kV line (30040_TESLA_500_30050_LOSBANOS_500_BR_1_1) bound in 6.5 percent of hours over this year. Congestion on the constraint increased average PG&E prices by $0.64/MWh and decreased average SCE and SDG&E prices by $0.54/MWh and $0.5/MWh, respectively. This line was frequently binding during solar production hours, from hour-ending 10 through hour-ending 16.

Other notable constraints include transmission lines through the Imperial Valley to the San Diego metropolitan area. These constraints frequently experienced congestion, which specifically drove up prices for SDG&E.

**Table 5.3 Impact of congestion on day-ahead prices – top 25 primary congestion constraints**

| Constraint | Frequency | Average quarter impact ($/MWh) | | |
|---|---|---|---|---|
| | | PG&E | SCE | SDG&E |
| 30055_GATES1_500_30060_MIDWAY_500_BR_1_1 | 9.0% | 1.01 | -.85 | -.8 |
| 30750_MOSSLD_230_30797_LASAGUIL_230_BR_1_1 | 24.2% | 1.01 | -.77 | -.72 |
| 30040_TESLA_500_30050_LOSBANOS_500_BR_1_1 | 6.5% | .64 | -.54 | -.5 |
| 30790_PANOCHE_230_30900_GATES_230_BR_2_1 | 11.2% | .35 | -.27 | -.26 |
| 30050_LOSBANOS_500_30055_GATES1_500_BR_1_3 | 1.8% | .22 | -.18 | -.17 |
| 30050_LOSBANOS_500_30055_GATES1_500_BR_1_2 | 3.7% | .23 | -.17 | -.16 |
| 30060_MIDWAY_500_24156_VINCENT_500_BR_2_3 | 2.2% | -.22 | .15 | .15 |
| 7820_TL23040_IV_SPS_NG | 6.5% | -.05 | -.01 | .38 |
| 30765_LOSBANOS_230_30790_PANOCHE_230_BR_2_1 | 9.1% | .17 | -.13 | -.12 |
| 6410_CP10_NG | 1.8% | .16 | -.13 | -.12 |
| MIGUEL_BKs_MXFLW_NG | 1.8% | -.04 | -.01 | .3 |
| 32214_RIOOSO_115_30330_RIOOSO_230_XF_1 | 13.0% | .14 | -.09 | -.09 |
| 7820_TL230S_OVERLOAD_NG | 5.5% | -.03 | -.01 | .25 |
| 7820_TL50002_IV-NG-OUT_TDM | 1.5% | -.02 | -.01 | .18 |
| 30900_GATES_230_30970_MIDWAY_230_BR_1_1 | 1.9% | .08 | -.06 | -.06 |
| 32056_CORTINA_60.0_30451_CRTNAM_1.0_XF_1 | 8.0% | .07 | -.07 | -.07 |
| 30056_GATES2_500_30060_MIDWAY_500_BR_2_1 | 1.1% | .07 | -.05 | -.05 |
| 22208_ELCAJON_69.0_22408_LOSCOCHS_69.0_BR_1_1 | 5.8% | 0 | 0 | .13 |
| 7430_CP6_NG | 4.2% | .05 | -.04 | -.03 |
| 30733_VASONA_230_30735_METCALF_230_BR_1_1 | .7% | .04 | -.04 | -.03 |
| 22886_SUNCREST_230_22885_SUNCREST_500_XF_2_P | 1.0% | -.01 | 0 | .09 |
| 30797_LASAGUIL_230_30790_PANOCHE_230_BR_1_1 | 2.2% | .04 | -.03 | -.03 |
| 35621_IBM-HRJ_115_35642_METCALF_115_BR_1_1 | 1.0% | .03 | -.03 | -.03 |
| 30440_TULUCAY_230_30460_VACA-DIX_230_BR_1_1 | .5% | .03 | -.03 | -.03 |
| 24021_CENTERS_230_24091_MESACAL_230_BR_1_1 | .3% | -.02 | .02 | .02 |
| Other | | .3 | -.33 | -.01 |
| Total | | 4.25 | -3.68 | -1.78 |

## 5.6 Congestion revenue rights

### Background

Congestion revenue rights (CRRs) 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.

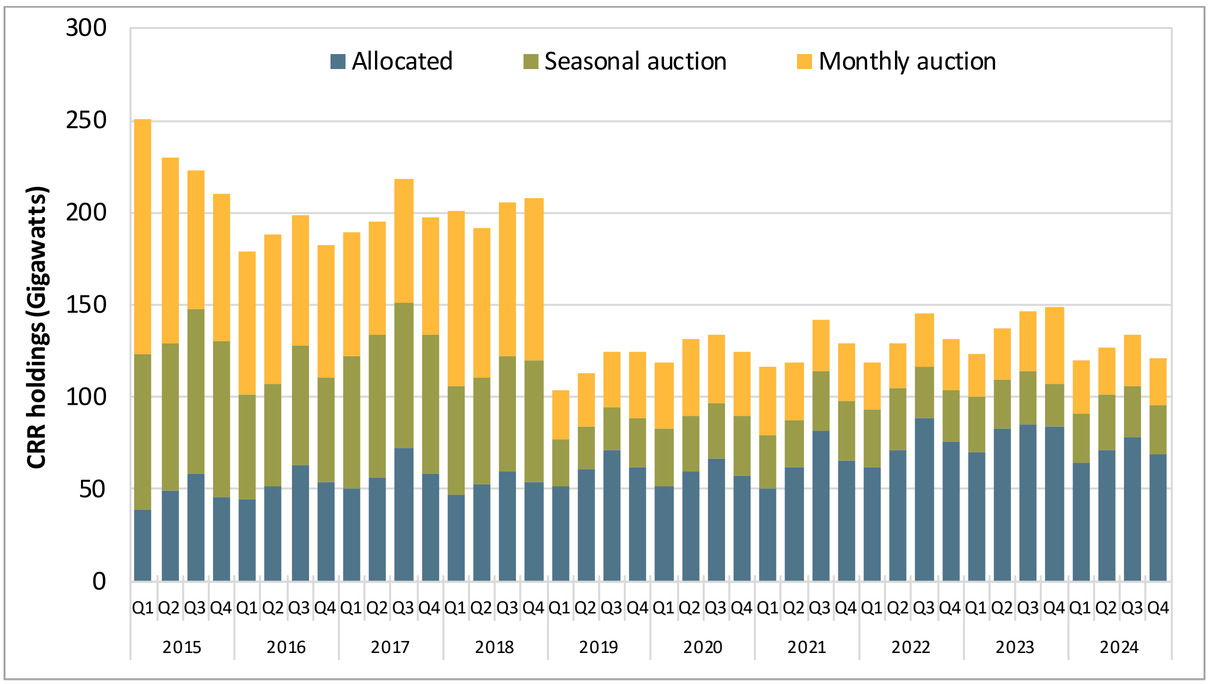
Congestion revenue rights are either allocated or auctioned to market participants. Participants serving load are allocated rights monthly, annually (with seasonal terms), or for 10 years (for the same seasonal term each year). All participants can procure congestion revenue rights in the auctions. Annual 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.[159]

Ratepayers own the day-ahead transmission rights not held by merchant transmission or long-term rights holders. Allocating congestion revenue rights is a means of distributing the congestion rent to entities serving load, to then be passed on to ratepayers. Any congestion rent 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

Figure 5.12 shows the congestion revenue right megawatts by allocated, seasonally auctioned, and monthly auctioned rights; this figure includes all peak and off-peak rights. In 2024, the share of allocated congestion revenue rights was about 57 percent of the total megawatts held. Auctioned rights were about 43 percent of total CRRs. As shown in the figure, in 2019, the quantity of auctioned CRRs reduced significantly compared to prior years. This was because of the Track 1A changes implemented for the 2019 auction. These Track 1A changes limited allowable source and sink pairs to "delivery path" combinations.

**Figure 5.12 Congestion revenue rights held by procurement type (2015–2024)[160]**



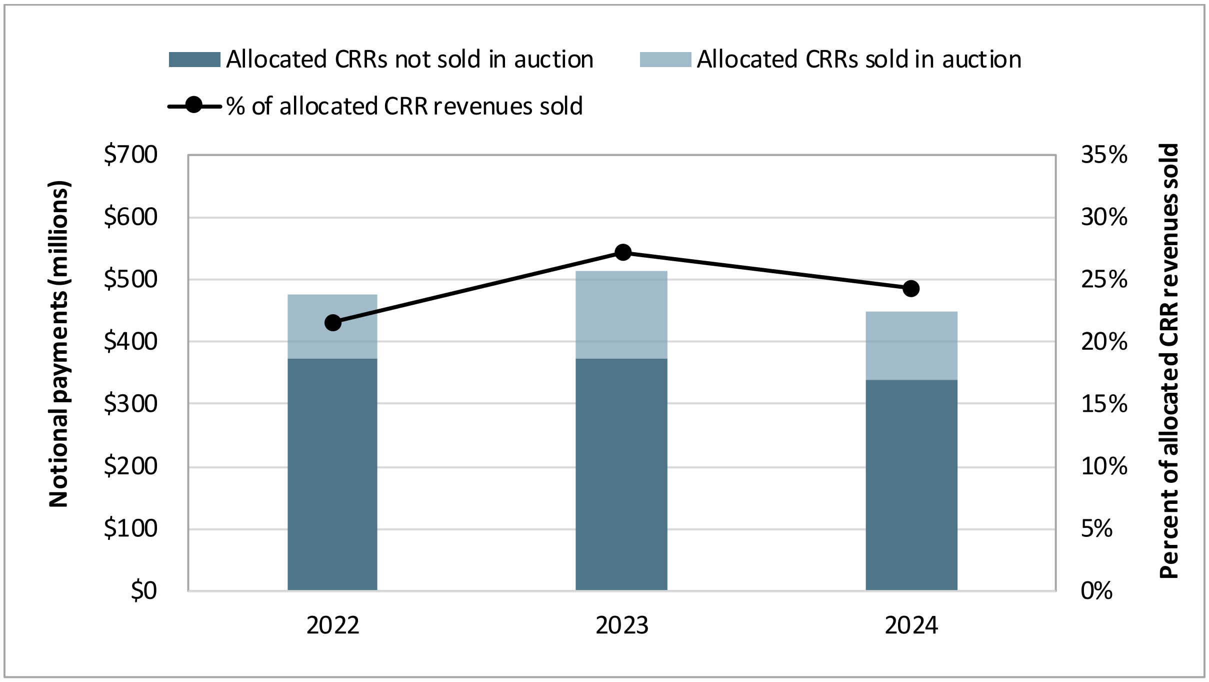

159 For a more detailed explanation of the congestion revenue right processes, see *Business Practice Manual Change Management, Congestion Revenue Rights*, California ISO: https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Congestion%20Revenue%20Rights

160 Allocated CRR holdings also include existing transmission rights (ETCs) and transmission ownership rights (TORs).

### Congestion revenue right sales

Figure 5.13 shows the total allocated CRRs and the portion of those allocated CRRs sold by load serving entities each year, evaluated by notional dollar payment. In 2024, the total payouts to allocated CRRs amounted to $450 million, with load serving entities selling $110 million—representing 25 percent of the total allocated CRR revenue. Over the past three years, load serving entities sold an average of 24 percent of their allocated CRRs—27 percent in 2023 and 22 percent in 2022.

**Figure 5.13 Annual summary of allocated CRRs and sales by load serving entities**




### Congestion revenue right auction returns

The CRR auction returns compare 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, the California ISO instituted significant changes to the auction starting in the 2019 settlement year.[161] 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.[162]

[161] For further information, see *Shortcomings in the congestion revenue right auction design*, DMM whitepaper, November 28, 2016: http://www.caiso.com/Documents/DMM-WhitePaper-Shortcomings-Congestion RevenueRightAuctionDesign.pdf.

[162] *Congestion Revenue Rights Auction Efficiency Track 1B Straw Proposal*, California ISO, April 19, 2018: http://www.caiso.com/InitiativeDocuments/StrawProposal-CongestionRevenueRightsAuctionEfficiencyTrack1B.pdf

**Track 1A** – Limiting allowable source and sink pairs to "delivery path" combinations.[163]

**Track 1B** – Limiting congestion revenue right payments to not exceed congestion rents actually collected from the underlying transmission constraints.[164]

DMM believes the current auction is unnecessary and could be eliminated.[165] 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.

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 5.14 compares the following for each of the last several years:

Auction revenues received by ratepayers from congestion revenue rights sold in auction (blue bars).[166]

Net payments made to the non-load serving entities purchasing congestion revenue rights in auction (green bars).

Deficiency offsets are the amount that reduce payments to CRR holders when congestion rents are not enough to cover those payments, as implemented under Track 1B reforms (transparent portion of green bars and yellow line).

Total ratepayer losses are the difference between auction revenues received and payments made to non-load serving entities (yellow line).

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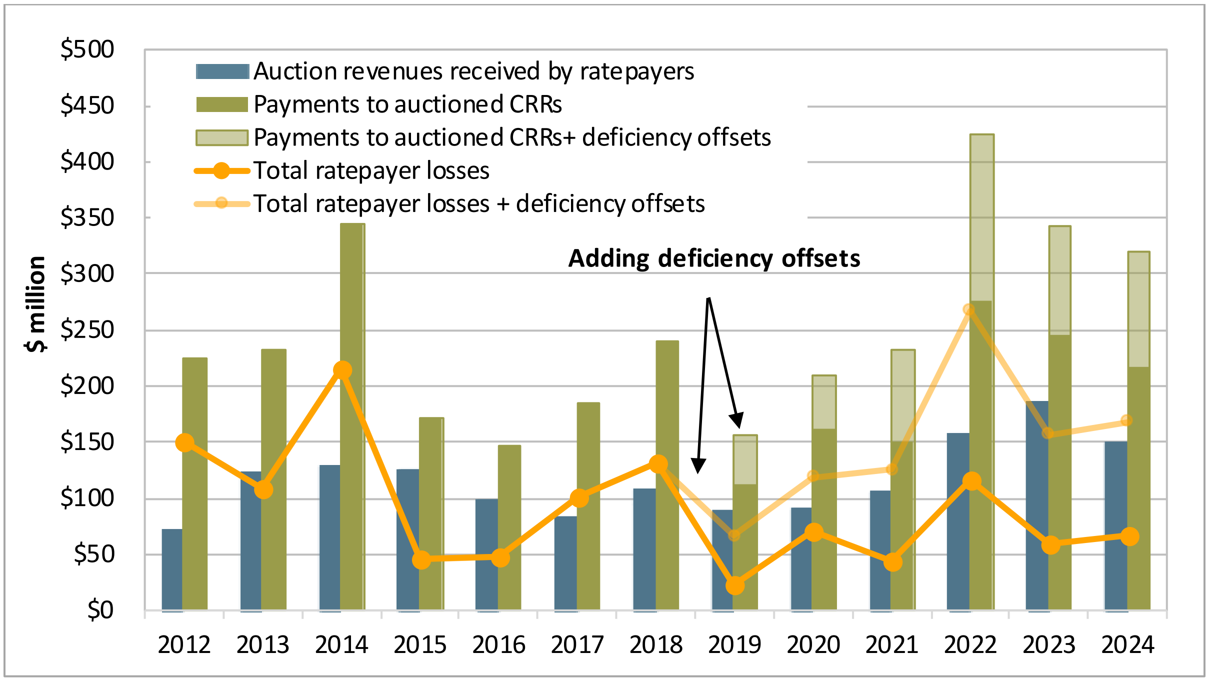
163 *Congestion Revenue Rights Auction Efficiency Track 1A Draft Final Proposal Addendum*, California ISO, March 8, 2018: http://www.caiso.com/InitiativeDocuments/DraftFinalProposalAddendum-CongestionRevenueRightsAuctionEfficiency-Track1.pdf

164 *Congestion Revenue Rights Auction Efficiency Track 1B Draft Final Proposal Second Addendum*, California ISO, June 11, 2018: http://www.caiso.com/InitiativeDocuments/DraftFinalProposalSecondAddendum-CongestionRevenueRightsAuctionEfficiencyTrack1B.pdf

165 *Problems in the performance and design of the congestion revenue right auction,* DMM whitepaper, November 27, 2017: http://www.caiso.com/Documents/DMMWhitePaper-Problems_Performance_Design_CongestionRevenueRightAuction-Nov27_2017.pdf

166 The auction revenues received by ratepayers are the auction revenues from congestion revenue rights paying into the auction less the revenues paid to "counter-flow" rights. Similarly, day-ahead payments made by ratepayers are net of payments by "counter-flow" rights.

**Figure 5.14 Auction revenues and payments to non-load serving entities**




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.

In 2024, ratepayer auction losses were around $66 million, or about 12 percent of day-ahead market congestion rent. Ratepayers received an average of 69 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 $102 million.

In 2023, losses were around $59 million, or about 7 percent of day-ahead market congestion rent. Ratepayers received an average of 76 cents in auction revenue per dollar paid out. Track 1B revenue deficiency offsets reduced payments to auctioned rights by about $97 million.

Figure 5.14 also illustrates revenues, payments, and losses in the absence of Track 1B reforms (transparent green bars and yellow line). Without the implementation of the revenue deficiency offset, payments to auctioned CRRs would have totaled $319 million in 2024, resulting in $168 million in losses to ratepayers.

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 ratepayer losses are from the ISO sales (through the auction transmission model) versus load serving entity trades. This is because it is not possible to directly tie the offsets actually paid by congestion revenue rights purchasers to the sales of specific congestion revenue rights. DMM created a simplified estimate of these offsets by estimating the notional revenue that would have been paid to the sold rights had they been kept, and applying the average ratio of offsets to notional revenues.

Figure 5.15 shows the estimated breakout of ratepayer auction losses by CAISO sales (the blue bars) and load serving entity trades (the green bars). The losses are mostly from CAISO sales. On net, DMM estimates that trades made by load serving entities (LSEs) decreased ratepayer losses by $20 million in 2024 compared to increasing losses by $13 million in 2023.

**Figure 5.15 Estimated CRR auction loss breakout by CAISO and load serving entity**

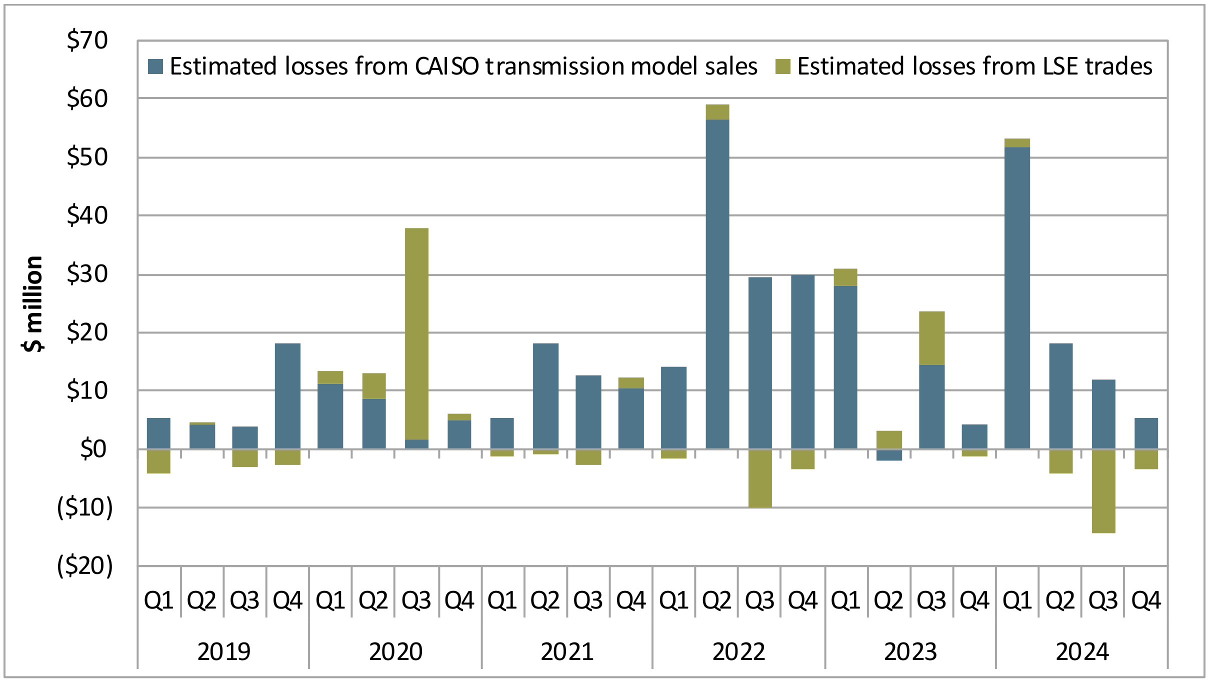



Figure 5.16 through Figure 5.18 compare the auction revenues paid and day-ahead market payments received from congestion revenue rights traded in the auction by market participant type.[167] The difference between auction revenues paid and the payments to congestion revenue rights are the profits for the entities holding the auctioned rights. These profits are losses to ratepayers.

Financial entities received net revenues of about $38 million in 2024, down from $43 million in 2023. Total revenue deficit offsets were about $69 million.

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

Marketers received net revenues of about $10 million from auctioned rights in 2024, down from $11 million in 2023. Total revenue deficit offsets were nearly $27 million.

Physical generation entities received about $18 million in net revenue from auctioned rights in 2024, a significant increase from about $5 million in 2023. Total revenue deficit offsets were about $6 million.

One of the benefits of auctioning congestion revenue rights is to allow day-ahead market participants to hedge congestion costs. However, in 2024, physical generators as a group continued to account for a relatively small portion of congestion revenue rights held. Financial entities received the highest 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.

DMM believes the current auction is unnecessary and could be eliminated.[168,169] If the ISO believes it is beneficial to the market to facilitate hedging, DMM believes the current auction format could be changed to a market for congestion revenue rights or locational price swaps, based on bids submitted by entities willing to buy or sell congestion revenue rights.

168 *Problems in the performance and design of the congestion revenue right auction,* DMM whitepaper, November 27, 2017: http://www.caiso.com/Documents/DMMWhitePaper-Problems_Performance_Design_CongestionRevenueRightAuction-Nov27_2017.pdf

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

**Figure 5.16 Auction revenues and payments (financial entities)**

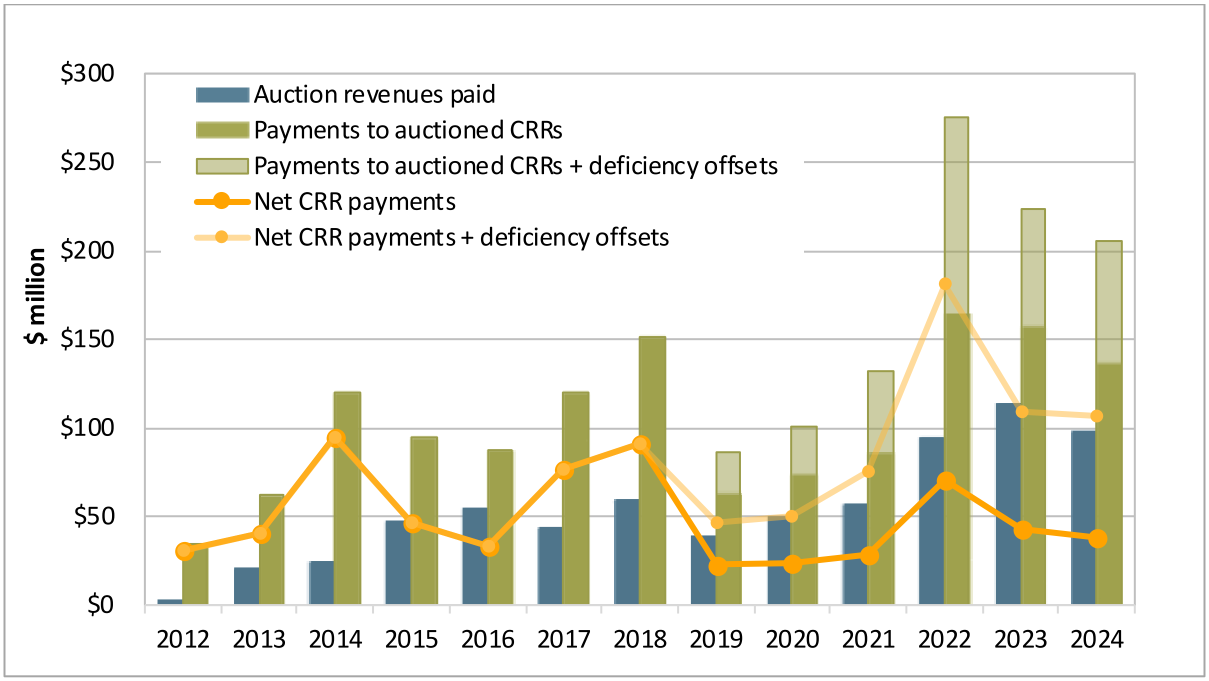



**Figure 5.17 Auction revenues and payments (marketers)**

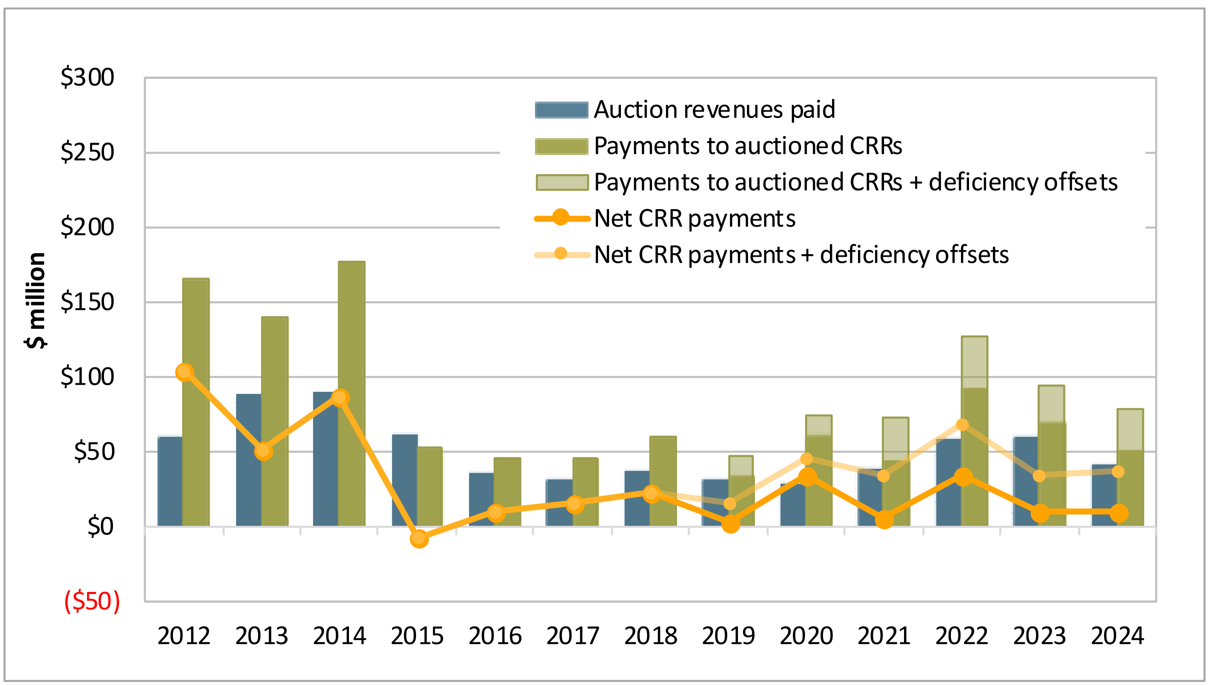
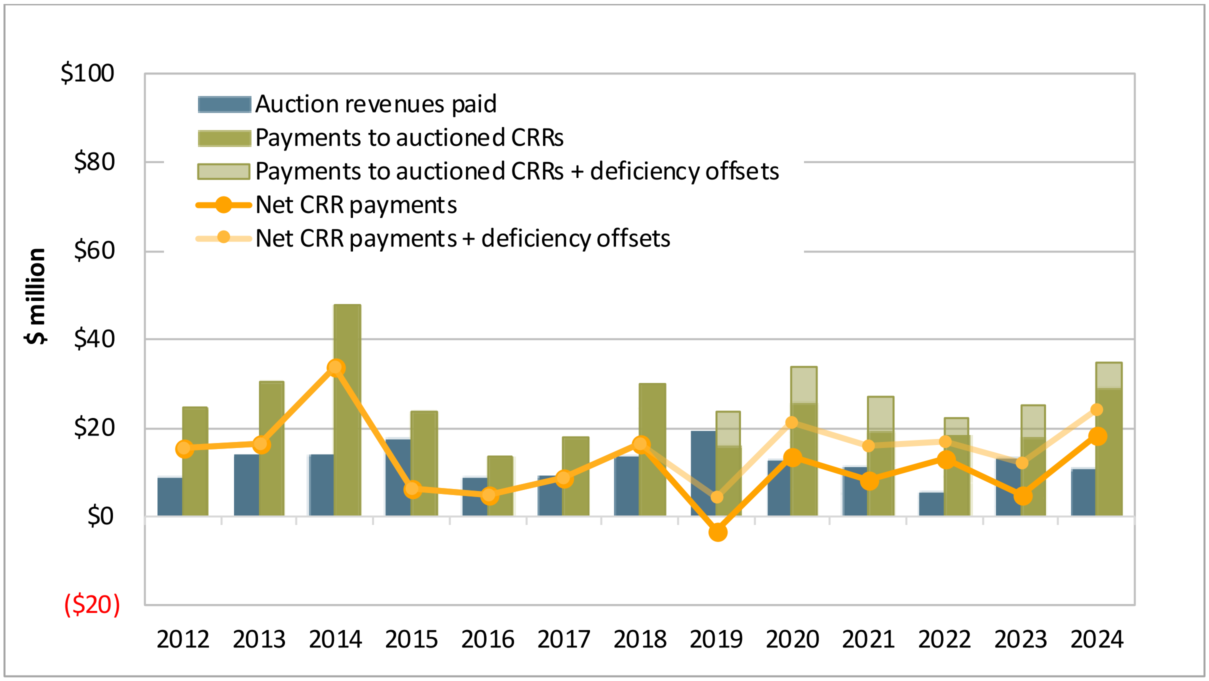


**Figure 5.18 Auction revenues and payments (generators)**



# 6 Resource sufficiency evaluation

As part of the WEIM design, each area, including the California ISO balancing area, is subject to a resource sufficiency evaluation. The resource sufficiency evaluation allows the market to optimize transfers between participating WEIM entities while deterring WEIM balancing areas from relying on other WEIM areas for capacity.

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 can 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 has enough ramping flexibility over an hour to meet the forecasted change in demand as well as uncertainty.

If an area that has not opted in to assistance energy transfers fails either the bid range capacity test or flexible ramping sufficiency test in the *upward* direction, WEIM transfers *into* that area cannot be increased.[170] If an area fails either test in the *downward* direction, transfers *out of* that area cannot be increased.

Key findings from this chapter include:

- **Most balancing areas failed each test in less than 0.5 percent of intervals.** Exceptions were Public Service Company of New Mexico (PNM), WAPA Desert Southwest, and El Paso Electric, who failed the upward flexibility test in about 1.6 percent, 0.7 percent, and 0.6 percent of intervals, respectively. PNM also failed the downward flexibility test in about 0.5 percent of intervals.
- **Ten balancing areas opted in to the assistance energy transfer program on at least one day during the year.** Eight of these balancing areas received additional WEIM transfers during a resource sufficiency evaluation failure as a result of the program. Additional WEIM transfers received by each balancing area over the year ranged from 45 MWh to 973 MWh.
- **DMM is providing additional metrics, data, and analysis on the resource sufficiency tests in separate quarterly reports** as part of the *WEIM resource sufficiency evaluation* stakeholder initiative. These reports include many metrics and analyses not included in this report, such as the impact of several changes proposed or adopted through the stakeholder process.[171]

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[170] Normally, 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. The assistance energy transfers (AET) option gives balancing areas access to excess WEIM supply that may not have been available otherwise following an upward resource sufficiency evaluation failure. Balancing areas can opt in to AET to prevent their WEIM transfers from being limited during a test failure but will be subject to an ex-post surcharge. For more on AETs, see Section 6.2.

[171] Department of Market Monitoring Reports and Presentations, *WEIM resource sufficiency evaluation reports*: https://www.caiso.com/market-operations/market-monitoring/reports-and-presentations#weim-resource

## 6.1 Frequency of resource sufficiency evaluation failures

Figure 6.1 and Figure 6.2 show the percent of intervals in which each WEIM area failed the upward capacity and flexibility tests, while Figure 6.3 and Figure 6.4 provide the same information for the downward direction.[172] The dash indicates the area did not fail the test during the month.

During 2024:

- Public Service Company of New Mexico (PNM) failed the upward flexibility test relatively frequently, in around 1.6 percent of intervals. This was most common during November (around 7 percent of intervals). PNM also failed the downward flexibility test in around 0.5 percent of intervals.
- WAPA Desert Southwest failed the upward flexibility test in 0.7 percent of intervals while El Paso Electric failed the upward flexibility test in 0.6 percent of intervals.
- All other balancing areas failed each test type in less than 0.5 percent of intervals.

**Figure 6.1 Frequency of upward capacity test failures by month and area (percent of intervals)**

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Arizona Publ. Serv. | — | — | — | — | — | — | — | — | — | — | — | .1 |
| Avangrid | — | — | — | — | — | — | .1 | — | — | — | — | — |
| Avista | .3 | .1 | — | — | — | — | .1 | — | — | .1 | — | — |
| BANC | — | — | — | — | — | — | — | — | — | — | — | — |
| BPA | .3 | — | — | — | — | — | — | — | — | — | — | — |
| California ISO | — | — | — | — | — | — | — | — | — | — | — | — |
| El Paso Electric | — | — | .1 | .2 | .6 | .1 | .3 | .1 | .0 | — | .1 | .0 |
| Idaho Power | .0 | — | — | — | — | — | — | — | — | — | — | — |
| LADWP | .1 | .0 | — | .0 | .0 | — | .1 | .3 | — | — | — | — |
| NorthWestern En. | — | .1 | — | — | — | — | — | — | .3 | — | — | .3 |
| NV Energy | — | — | — | — | .1 | .0 | .1 | .0 | — | — | — | — |
| PacifiCorp East | — | — | — | — | — | — | — | — | — | — | — | — |
| PacifiCorp West | .8 | .0 | — | .1 | .0 | — | — | — | — | .1 | .3 | .0 |
| Portland Gen. Elec. | — | — | — | — | .0 | .1 | .0 | — | — | — | — | — |
| Powerex | — | — | — | — | — | — | — | — | — | — | — | — |
| PSC of New Mexico | — | — | — | .1 | .1 | .1 | .3 | .1 | — | .4 | 3.1 | — |
| Puget Sound En. | .8 | .1 | .2 | .3 | .2 | — | .2 | .1 | — | .1 | — | .1 |
| Salt River Proj. | .1 | .1 | .2 | .1 | — | .2 | .1 | .1 | .2 | .1 | — | — |
| Seattle City Light | .5 | — | — | .4 | — | .0 | .4 | .1 | .1 | .3 | .0 | .1 |
| Tacoma Power | — | — | .3 | — | .0 | — | — | — | — | .0 | .1 | — |
| Tucson Elec. Pow. | — | — | — | — | — | — | .0 | — | .0 | — | — | — |
| Turlock Irrig. Dist. | — | — | — | — | — | — | — | — | — | — | — | — |
| WAPA DSW | — | — | .1 | — | .5 | .3 | .2 | .2 | — | .1 | — | — |

2024

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

### Figure 6.2 Frequency of upward flexibility test failures by month and area (percent of intervals)

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2024 | | | | | | | | | | | |
| Arizona Publ. Serv. | .2 | .1 | .5 | .1 | .3 | — | .0 | .0 | — | — | — | .1 |
| Avangrid | .2 | .1 | .1 | .0 | .2 | .5 | .2 | — | .1 | .5 | .1 | .4 |
| Avista | .1 | — | .1 | — | — | — | .1 | — | — | .0 | — | — |
| BANC | — | — | — | — | — | — | — | — | — | — | — | — |
| BPA | .4 | .0 | — | .1 | .1 | .1 | .3 | .3 | .0 | — | .1 | .1 |
| California ISO | — | — | — | — | — | — | .0 | — | — | — | — | — |
| El Paso Electric | .3 | .0 | 1.0 | .9 | 1.0 | .9 | .6 | .8 | .3 | .2 | .3 | .4 |
| Idaho Power | 1.1 | — | .1 | .6 | .6 | .1 | .1 | — | — | .0 | — | — |
| LADWP | .1 | — | .1 | .4 | .1 | .0 | .3 | .3 | .0 | — | .1 | — |
| NorthWestern En. | .5 | .1 | .0 | .0 | .1 | .3 | .2 | — | .4 | .1 | .2 | .2 |
| NV Energy | — | .1 | .0 | — | .1 | — | — | — | — | — | — | — |
| PacifiCorp East | — | — | — | .0 | .0 | — | — | .1 | — | .1 | .0 | — |
| PacifiCorp West | 1.0 | — | .1 | — | — | .1 | — | — | — | — | .3 | .1 |
| Portland Gen. Elec. | — | — | .0 | — | .2 | .2 | — | — | .0 | .1 | — | — |
| Powerex | .2 | — | — | — | — | — | .6 | — | — | — | — | — |
| PSC of New Mexico | 2.0 | 2.3 | .4 | 1.8 | 1.1 | 1.2 | 1.0 | 1.0 | .9 | .3 | 7.1 | .2 |
| Puget Sound En. | .8 | .1 | .2 | .4 | .5 | .5 | .7 | .3 | — | .4 | — | .5 |
| Salt River Proj. | .2 | .1 | .7 | .4 | .1 | .3 | .3 | .4 | .5 | .2 | — | — |
| Seattle City Light | .3 | — | .1 | .1 | .1 | — | — | — | .0 | .1 | .1 | — |
| Tacoma Power | .1 | .0 | .4 | .0 | .0 | — | — | — | — | — | .1 | .0 |
| Tucson Elec. Pow. | .0 | .2 | — | .1 | .1 | — | .1 | .3 | .7 | .2 | .1 | .1 |
| Turlock Irrig. Dist. | — | — | — | — | — | — | — | — | — | — | — | — |
| WAPA DSW | 1.1 | 2.5 | 3.5 | .3 | .8 | .2 | — | — | — | .2 | — | .1 |

### Figure 6.3 Frequency of downward capacity test failures by month and area (percent of intervals)

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2024 | | | | | | | | | | | |
| Arizona Publ. Serv. | .1 | .0 | .1 | .2 | — | — | — | — | .4 | — | — | — |
| Avangrid | — | — | — | — | — | — | — | — | — | — | — | — |
| Avista | — | — | .1 | — | — | — | — | — | — | .0 | — | — |
| BANC | — | — | — | — | — | — | — | — | — | — | — | — |
| BPA | — | — | — | — | — | — | — | — | — | — | — | .1 |
| California ISO | — | — | — | — | — | — | — | — | — | — | — | — |
| El Paso Electric | .2 | — | .4 | .2 | .4 | .3 | .1 | .1 | .0 | .1 | .0 | — |
| Idaho Power | — | — | — | .5 | — | — | — | — | — | — | — | — |
| LADWP | — | — | — | — | — | — | — | — | .0 | — | — | — |
| NorthWestern En. | — | — | — | — | — | — | — | — | .1 | — | .0 | — |
| NV Energy | — | — | — | — | — | — | — | — | — | — | — | — |
| PacifiCorp East | — | — | — | — | — | — | — | — | — | — | — | — |
| PacifiCorp West | — | — | — | — | — | — | — | — | — | — | — | — |
| Portland Gen. Elec. | — | — | — | — | — | — | — | — | — | — | — | — |
| Powerex | — | — | — | .0 | — | — | — | — | — | — | .1 | — |
| PSC of New Mexico | — | — | — | — | — | — | .1 | — | — | — | .2 | — |
| Puget Sound En. | — | — | — | — | — | — | — | — | — | — | — | — |
| Salt River Proj. | — | .1 | .1 | .4 | .7 | — | — | .2 | — | — | — | .3 |
| Seattle City Light | .0 | — | — | — | — | — | .3 | — | — | — | .1 | .0 |
| Tacoma Power | — | — | — | — | — | .0 | .1 | .0 | — | — | — | — |
| Tucson Elec. Pow. | — | — | — | — | — | — | — | — | — | — | — | — |
| Turlock Irrig. Dist. | — | — | — | — | — | — | — | — | — | — | — | — |
| WAPA DSW | — | — | — | — | — | — | .1 | — | — | — | — | — |

**Figure 6.4 Frequency of downward flexibility test failures by month and area (percent of intervals)**

| | Jan 2024 | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Arizona Publ. Serv. | .1 | .1 | .2 | .1 | — | — | — | — | — | — | .3 | .2 |
| Avangrid | .1 | — | — | — | — | — | — | — | — | — | — | — |
| Avista | — | .0 | — | — | — | — | .1 | — | .0 | .6 | — | — |
| BANC | — | — | — | — | — | — | — | — | — | — | — | — |
| BPA | .4 | .1 | — | .0 | .1 | .1 | — | — | — | — | — | .8 |
| California ISO | — | — | — | — | — | — | — | — | — | — | — | — |
| El Paso Electric | .3 | .2 | .4 | .8 | .7 | .1 | — | .1 | — | .0 | — | .2 |
| Idaho Power | — | — | .0 | 1.0 | — | — | — | — | — | — | — | — |
| LADWP | — | — | — | — | — | — | — | — | .1 | — | — | — |
| NorthWestern En. | .2 | — | .1 | — | .3 | .2 | .2 | .1 | .0 | 2.2 | .2 | .1 |
| NV Energy | — | — | .1 | .0 | — | .1 | — | — | — | — | — | — |
| PacifiCorp East | — | .2 | .0 | .5 | .2 | .0 | .0 | — | .1 | — | — | — |
| PacifiCorp West | — | — | .2 | — | — | — | — | — | — | .0 | .0 | — |
| Portland Gen. Elec. | — | — | — | — | — | — | — | — | — | — | — | — |
| Powerex | — | .1 | .4 | .0 | — | — | 1.1 | .2 | — | — | .1 | — |
| PSC of New Mexico | .9 | .9 | .4 | .0 | .6 | .1 | .1 | .0 | .9 | .3 | 2.0 | .1 |
| Puget Sound En. | — | — | — | — | — | — | .1 | — | — | — | — | — |
| Salt River Proj. | .1 | .1 | .7 | .7 | .7 | .0 | — | — | — | .1 | — | .5 |
| Seattle City Light | .2 | .1 | .1 | .2 | — | .1 | .5 | .1 | — | .0 | .2 | .1 |
| Tacoma Power | — | .0 | — | — | — | — | — | — | — | — | — | — |
| Tucson Elec. Pow. | — | .1 | — | — | — | — | — | — | — | — | — | — |
| Turlock Irrig. Dist. | — | .0 | — | — | .2 | .0 | — | .0 | — | .1 | .1 | — |
| WAPA DSW | .3 | .1 | .0 | .0 | — | — | .1 | .0 | .1 | — | .0 | — |

## 6.2 Assistance energy transfers

The assistance energy transfer (AET) option gives balancing areas access to excess WEIM supply that may not have been available otherwise following an upward resource sufficiency evaluation failure. Without AET, a balancing area failing either the upward flexibility or upward capacity test would have net WEIM imports limited to the greater of either the base transfer or the optimal transfer from the last 15-minute market interval. Balancing areas can voluntarily opt in to the AET program to prevent their WEIM transfers from being limited during an upward resource sufficiency evaluation failure, but will be subject to an ex-post surcharge. Balancing areas must opt in or opt out of the program in advance of the trade date.[173]

The assistance energy transfer surcharge is applied during any interval in which an opt-in balancing area fails the upward flexibility or capacity test. The surcharge is calculated as the *applicable real-time assistance energy transfer* times the real-time bid cap.[174] The applicable AET quantity is based on the lesser of either (1) the tagged dynamic WEIM transfers or (2) the amount by which the balancing area

173 Assistance energy transfer designation requests are submitted to Master File as *opt-in* or *opt-out* and include both a start and end date. The standard timeline to implement an opt-in or opt-out request is at least five business days in advance of the start date. An *emergency* opt-in request is also available, should reliability necessitate this, for two business days in advance of the start date. For more information, see: https://bpmcm.caiso.com/Pages/ViewPRR.aspx?PRRID=1525&IsDlg=0

174 The soft bid cap is $1,000/MWh and can increase to the hard bid cap of $2,000/MWh under certain conditions.

failed the resource sufficiency evaluation. If the tagged dynamic WEIM transfers are less than the amount by which the balancing area failed the resource sufficiency evaluation, then the applicable AET quantity is also reduced by a credit. The credit is either upward available balancing capacity for WEIM entities or cleared regulation up for the ISO balancing area.

Opting in to the assistance energy transfer program does not guarantee that the balancing area will achieve additional WEIM supply following a resource sufficiency evaluation failure (compared to opting out of the program). It only removes the import limit that would have been in place following a test failure, allowing the market to freely and optimally schedule WEIM transfers based on supply and demand conditions in the system. If the import limit following a test failure was set high such that it is not restricting the optimal solution, then opting in or opting out of the program will have no effect on WEIM import supply in that interval.

Table 6.1 shows the days in which a balancing area was opted in to receiving assistance energy transfers during 2024. Ten balancing areas were opted in to the program on at least one day during this period: Avangrid, CAISO, Idaho Power, NorthWestern Energy, NV Energy, PacifiCorp East, PacifiCorp West, Portland General Electric, PNM, and WAPA Desert Southwest.[175] Avangrid, NorthWestern Energy, and NV Energy were opted in to AET during most days during the year. Idaho Power, PacifiCorp East, and PacifiCorp West were opted in to AET during more than half of the year.

**Table 6.1 Assistance energy transfer opt-in designations by balancing area (2024)**

| Balancing area | Period opted in to receiving assistance energy transfers | Days opted in to AET |
|---|---|---|
| Avangrid | Jan. 1 - Dec. 31 | 366 |
| California ISO | Mar. 4 - Mar. 5, Mar. 18 - Mar. 19, Mar. 25, Mar. 27, Apr. 8, Jul. 3, Jul. 8 - Jul. 11, Jul. 22 - Jul. 24, Aug. 5 - Aug. 7, Sep. 4 - Sep. 6, Sep. 9 - Sep. 10, Oct. 1 - Oct. 8, Nov. 7 | 32 |
| Idaho Power | Jan. 14 - Jan. 17, Apr. 8, Jun. 1 - Oct. 31, Nov. 6 - Dec. 31 | 214 |
| NV Energy | Jan. 1 - Dec. 31 | 366 |
| NorthWestern Energy | Jan. 1 - Mar. 31, Apr. 10 - Dec. 31 | 357 |
| PacifiCorp East | Jan. 15 - Jan. 16, May. 31 - Sep. 30, Oct. 24 - Dec. 31 | 194 |
| PacifiCorp West | Jan. 15 - Jan. 16, May. 31 - Sep. 30, Oct. 24 - Dec. 31 | 194 |
| Portland General Electric | Jul. 4 - Jul. 10, Aug. 5 - Aug. 7 | 10 |
| PSC of New Mexico | Jul. 8 - Sep. 23 | 78 |
| WAPA Desert Southwest | Jul. 8 - Oct. 15 | 100 |

Table 6.2 summarizes all balancing areas that were opted in to assistance energy transfers on at least one day during the year and its impact following a resource sufficiency evaluation failure. First, the table shows the number of 15-minute intervals in which a balancing area failed the upward resource sufficiency evaluation after opting in to AET. These are the intervals in which the WEIM import limit following the test failure was removed—giving the WEIM entity access to WEIM supply that may not

175 The CAISO balancing area can opt in to assistance energy transfers based on upcoming system conditions and operator experience. For more information, see the *Business Practice Manual for the Western Energy Imbalance Market*, section 11.3.2: https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Energy%20Imbalance%20Market

have been available otherwise. With the exception of Portland General Electric, all of these balancing areas failed the resource sufficiency evaluation during at least one interval while opted in to the program.

Table 6.2 also shows the percent of failure intervals in the 5-minute market in which the balancing area achieved additional WEIM imports due to opting in to AET. The table also shows the average and maximum WEIM imports added in the 5-minute market because of AET. During the year, PNM added the most WEIM imports as a result of opting in to receiving assistance energy transfers (973 MWh). PNM failed the resource sufficiency evaluation during 79 intervals while opted in and achieved an additional 49 MW on average during these intervals (and a maximum of 434 MW).

**Table 6.2 Resource sufficiency evaluation failures during assistance energy transfer opt-in (2024)**

| Balancing area | Days opted in to AET | RSE failures under AET (15-min. intervals) | Percent of failure intervals with additional WEIM imports due to AET | Average WEIM imports added (MW) | Max WEIM imports added (MW) | Total WEIM imports added (MWh) |
|---|---|---|---|---|---|---|
| Avangrid | 366 | 72 | 26% | 22 | 221 | 404 |
| California ISO | 32 | 1 | 0% | 0 | 0 | 0 |
| Idaho Power | 214 | 32 | 38% | 27 | 278 | 220 |
| NorthWestern Energy | 357 | 75 | 28% | 13 | 158 | 247 |
| NV Energy | 366 | 13 | 56% | 159 | 626 | 515 |
| PacifiCorp East | 194 | 4 | 25% | 45 | 203 | 45 |
| PacifiCorp West | 194 | 23 | 41% | 30 | 235 | 171 |
| Portland General Electric | 10 | 0 | N/A | N/A | N/A | N/A |
| PSC of New Mexico | 78 | 79 | 41% | 49 | 434 | 973 |
| WAPA Desert Southwest | 100 | 9 | 56% | 99 | 277 | 223 |

Table 6.3 summarizes the total cost from assistance energy transfers. AET is settled during any interval in which the balancing area both opted in to receiving assistance energy transfers and failed the resource sufficiency evaluation. The applicable quantity that is settled for AET is based on the lower of either the resource sufficiency evaluation insufficiency or the WEIM imports.[176] The price is the real-time bid cap, typically $1,000/MWh. Table 6.3 also shows the total cost per *WEIM imports added*. WEIM imports added are measured as net WEIM imports in the 5-minute market above what the limit would have been following the resource sufficiency evaluation failure without opting in to AET.

[176] If the dynamic WEIM transfers are less than the amount by which the balancing area failed the resource sufficiency evaluation, then the applicable AET quantity is also reduced by a credit. The credit is either upward available balancing capacity for WEIM entities or cleared regulation up for the ISO balancing area.

**Table 6.3 Cost of assistance energy transfers (2024)**

| Balancing area | RSE failures under AET (15-min. intervals) | Total WEIM imports added (MWh) | Total cost of assistance energy transfers ($) | Total cost per added WEIM imports ($/MWh) |
|---|---|---|---|---|
| Avangrid | 72 | 404 | $81,883 | $203 |
| California ISO | 1 | 0 | $97,020 | N/A |
| Idaho Power | 32 | 220 | $77,282 | $352 |
| NorthWestern Energy | 75 | 247 | $359,321 | $1,455 |
| NV Energy | 13 | 515 | $161,273 | $313 |
| PacifiCorp East | 4 | 45 | $21,618 | $476 |
| PacifiCorp West | 23 | 171 | $71,701 | $418 |
| Portland General Electric | 0 | N/A | N/A | N/A |
| PSC of New Mexico | 79 | 973 | $870,527 | $895 |
| WAPA Desert Southwest | 9 | 223 | $22,913 | $103 |

### Resource sufficiency evaluation reports

DMM is providing additional transparency surrounding test accuracy and performance in regular reports specific to this topic.[177] These reports include many metrics and analyses not included in this report, such as the impact of several changes proposed or adopted through the stakeholder process.

[177] *WEIM resource sufficiency evaluation reports*, Department of Market Monitoring Reports and Presentations: https://www.caiso.com/library/western-energy-imbalance-market-resource-sufficiency-evaluation-reports

# 7 Real-time imbalance offset costs

Real-time imbalance offset costs for balancing areas participating in the day-ahead market were $234 million in 2024.[178,179] This was a decrease from $358 million in 2023. During 2024, real-time *congestion* imbalance offset costs made up the majority of these costs ($197 million).

Real-time imbalance offset costs for balancing areas participating only in the WEIM real-time markets were a $157 million credit to WEIM entities in 2024, compared to a $237 million credit in 2023. The congestion portion of the offset, which is largely congestion rent from WEIM transfer constraints, was a $173 million credit. The energy portions of the offset were a $15 million charge.

The real-time imbalance offset cost is the difference between the total money *paid out* and the total money *collected* by the California ISO settlement process for energy in the real-time markets. This charge is calculated separately for each balancing area. Any revenue surplus or revenue shortfall within this charge is allocated to measured demand (for the California ISO balancing area) or the WEIM entity scheduling coordinator (for the WEIM balancing areas).[180]

The real-time imbalance offset charge consists of three components. Any revenue imbalance from the congestion components of real-time energy settlement prices is collected through the *real-time congestion imbalance offset charge* (RTCIO). Similarly, any revenue imbalance from the *loss* component of real-time energy settlement prices is collected through the *real-time loss imbalance offset charge,* while any remaining revenue imbalance is recovered through the *real-time imbalance energy offset charge* (RTIEO). Figure 7.1 shows monthly imbalance offset costs for balancing areas participating in the day-ahead market by component since 2023.

178 Information in this section is based on settlement values available at the time of drafting and will be updated in future reports. Updates can occur regularly within the settlements timeline, starting with T+9B (trade date plus nine business days) and T+70B, as well as others up to 36 months after the trade date.

179 CAISO is currently the only balancing area participating in the day-ahead market.

180 Measured demand is physical load plus exports.

**Figure 7.1 Monthly real-time imbalance offset costs (balancing areas in day-ahead market)**

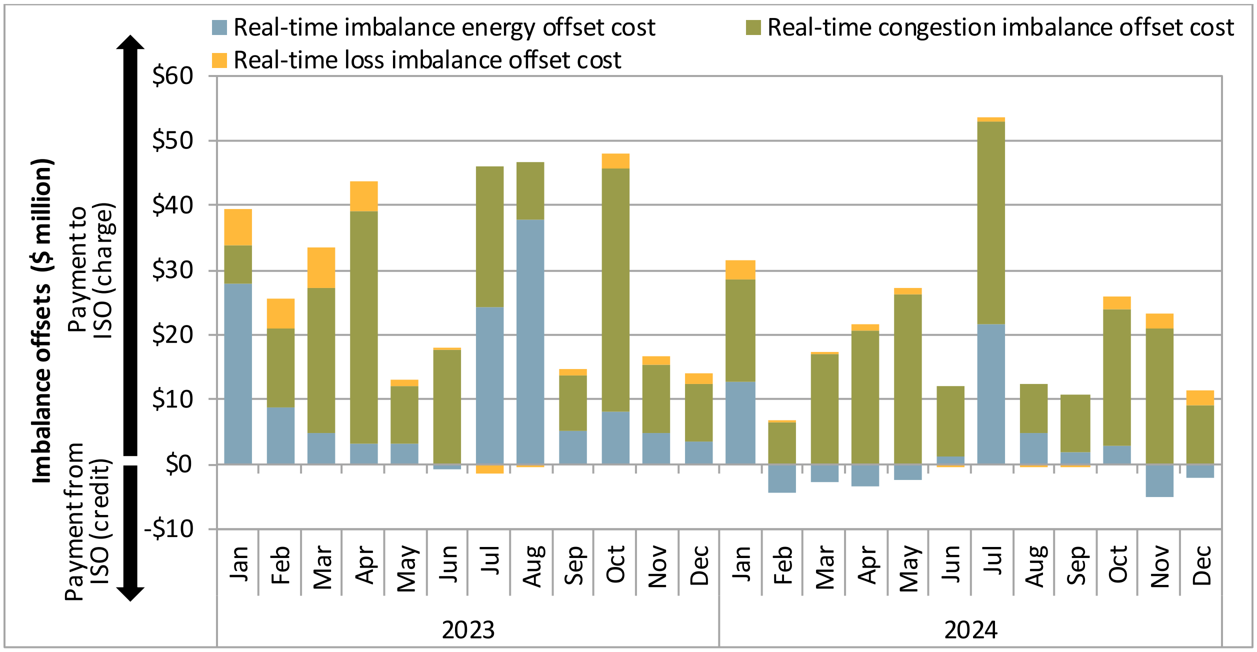


Figure 7.2 shows monthly imbalance offset costs for balancing areas only participating in the WEIM real-time markets. Offset amounts for each balancing area and charge type (energy, congestion, or losses) were assessed as positive or negative over the month, and shown collectively in the corresponding bars. The lighter-colored bars reflect positive amounts (or charges for revenue shortfall), while the darker bars reflect negative amounts (or credits for revenue surplus).

Figure 7.3 through Figure 7.5 show the quarterly real-time energy, congestion, or loss imbalance offsets for each balancing area participating only in the WEIM. Figure 7.6 shows the *total* real-time imbalance offset charges for each quarter and balancing area. Charges for revenue shortfall are shown in red, while credits for revenue surplus are shown in black. The color gradient highlights balancing areas with either greater revenue shortfall (orange) or revenue surplus (blue) over the period. Of note in 2024:

- Revenue *shortfall* from imbalance energy offsets for both Arizona Public Service and NorthWestern Energy were $14 million (charge), compared to around $25 million in the previous year.
- Revenue *surplus* from imbalance energy offsets for PacifiCorp West was $23 million (credit), compared to $35 million the previous year.
- Revenue *shortfall* from congestion imbalance offsets for LADWP was $5 million (charge) in the fourth quarter. This was mostly from $7 million in revenue shortfall on one day, December 18, associated with congestion on constraint *WECC_Path_4.* Here, outages and limited capacity on the Pacific DC Intertie created significant congestion on this constraint, restricting energy flow out of the Los Angeles region.
- Revenue *surplus* from congestion imbalance offsets for PacifiCorp East was $48 million (credit), doubled from $24 million in the previous year.
- Revenue *surplus* from congestion imbalance offsets for Powerex was also $48 million (credit), though down significantly from $166 million in the previous year.

**Figure 7.2 Monthly real-time imbalance offset costs (balancing areas participating only in WEIM)**

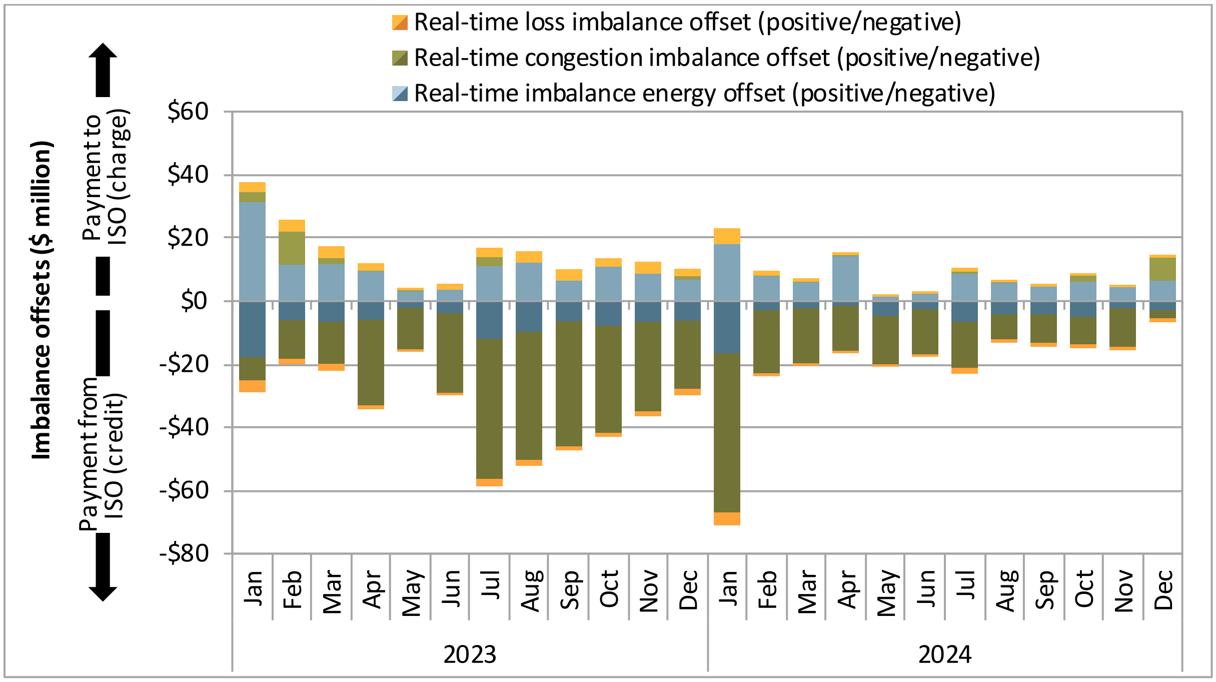


**Figure 7.3 Real-time imbalance energy offsets by quarter and balancing area ($ millions)**

| | 2023 Q1 | 2023 Q2 | 2023 Q3 | 2023 Q4 | 2024 Q1 | 2024 Q2 | 2024 Q3 | 2024 Q4 | Total 2023 | Total 2024 |
|---|---|---|---|---|---|---|---|---|---|---|
| Arizona Public Service | 13 | 2 | 5 | 4 | 7 | 1 | 4 | 3 | 24 | 14 |
| Avangrid | | .1 | 3 | .1 | 2 | 3 | .3 | .5 | 3 | .2 |
| Avista | .2 | .2 | .2 | .1 | .1 | .1 | .1 | .1 | .7 | .5 |
| BANC | 0 | .1 | .1 | .3 | .4 | .1 | 1 | .2 | .4 | .7 |
| Bonneville Power Administration | 1 | 0 | .8 | .2 | .6 | .3 | .5 | .6 | 2 | .8 |
| El Paso Electric | | .5 | .6 | .2 | 0 | 0 | .3 | 0 | 1 | .3 |
| Idaho Power | 2 | 2 | 1 | .6 | 3 | .1 | 1 | .3 | 3 | 2 |
| LADWP | .4 | .4 | .4 | .2 | .2 | .2 | 2 | .2 | .2 | 2 |
| NorthWestern Energy | 12 | 3 | 4 | 6 | 5 | 1 | 3 | 4 | 25 | 14 |
| NV Energy | 2 | .4 | .5 | 2 | .9 | .2 | .6 | 1 | 4 | 2 |
| PacifiCorp East | 12 | 3 | 9 | 7 | 3 | .7 | 5 | 4 | 31 | 13 |
| PacifiCorp West | 11 | 3 | 13 | 8 | 10 | 1 | 6 | 5 | 35 | 23 |
| Portland General Electric | .2 | .2 | .6 | .2 | .1 | 0 | .4 | .1 | 1 | .7 |
| Powerex | .3 | 1 | .5 | .7 | .7 | .2 | .4 | .1 | .9 | 1 |
| Public Service Company of NM | 9 | 4 | 3 | 4 | 6 | 1 | .9 | 3 | 20 | 11 |
| Puget Sound Energy | 12 | 3 | 6 | 6 | 7 | 2 | 4 | 4 | 27 | 16 |
| Salt River Project | 6 | 3 | 7 | 5 | 4 | 1 | 3 | 2 | 21 | 10 |
| Seattle City Light | .3 | 0 | 0 | .1 | .4 | .1 | .1 | .5 | .4 | .4 |
| Tacoma Power | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | .1 | .1 |
| Tucson Electric Power | 1 | .6 | .3 | .5 | .4 | .1 | 0 | 0 | 3 | .5 |
| Turlock Irrigation District | 1 | .6 | 1 | .5 | .3 | .4 | .9 | .4 | 4 | 2 |
| WAPA Desert Southwest | | .3 | .4 | .1 | 0 | .1 | .3 | 0 | .9 | .4 |

## Figure 7.4 Real-time congestion imbalance offsets by quarter and balancing area ($ millions)

| | Q1 2023 | Q2 2023 | Q3 2023 | Q4 2023 | Q1 2024 | Q2 2024 | Q3 2024 | Q4 2024 | Total 2023 | Total 2024 |
|---|---|---|---|---|---|---|---|---|---|---|
| Arizona Public Service | 2 | 2 | .3 | .3 | .1 | .1 | .7 | .2 | 4 | .8 |
| Avangrid | | .3 | .3 | .1 | .8 | .3 | .3 | .1 | .7 | 1 |
| Avista | .2 | .5 | .2 | .4 | 1 | .3 | .4 | .1 | 1 | 2 |
| BANC | 0 | .2 | 0 | .1 | 0 | .2 | 0 | 0 | .2 | .2 |
| Bonneville Power Administration | .9 | 2 | 1 | 1 | .7 | 0 | 2 | 0 | 5 | 2 |
| El Paso Electric | | .8 | 2 | 1 | .3 | .7 | .8 | .1 | 3 | 2 |
| Idaho Power | .9 | 2 | 1 | 2 | 5 | 1 | 1 | .1 | 6 | 7 |
| LADWP | .7 | 1 | 4 | 1 | 2 | 1 | 4 | 5 | 7 | 2 |
| NorthWestern Energy | .2 | .3 | .1 | .3 | 1 | .2 | .1 | .7 | .9 | 2 |
| NV Energy | 1 | 2 | .3 | 1 | 2 | 1 | .2 | .3 | 4 | 3 |
| PacifiCorp East | 16 | 7 | 9 | 23 | 22 | 7 | 7 | 12 | 24 | 48 |
| PacifiCorp West | 2 | 3 | 3 | 2 | 9 | 1 | 1 | .9 | 10 | 12 |
| Portland General Electric | 2 | 2 | 5 | 3 | 6 | 2 | 1 | 1 | 11 | 11 |
| Powerex | 16 | 29 | 85 | 36 | 25 | 16 | 6 | 1 | 166 | 48 |
| Public Service Company of NM | .3 | 1 | 2 | 0 | 1 | 1 | .5 | 2 | .4 | .8 |
| Puget Sound Energy | 1 | 2 | 5 | 4 | 5 | 2 | 2 | 1 | 12 | 10 |
| Salt River Project | 5 | 6 | 5 | 5 | 4 | 5 | 1 | .7 | 20 | 10 |
| Seattle City Light | .2 | .2 | .3 | .3 | .3 | .1 | .2 | .2 | 1 | .8 |
| Tacoma Power | .1 | .1 | .1 | .1 | .2 | .1 | .1 | 0 | .4 | .5 |
| Tucson Electric Power | 1 | 3 | 4 | 2 | 2 | 3 | 4 | 2 | 10 | 11 |
| Turlock Irrigation District | .2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | .2 | 0 |
| WAPA Desert Southwest | | .2 | .3 | 0 | .1 | 0 | 0 | 0 | .6 | .1 |

## Figure 7.5 Real-time loss imbalance offsets by quarter and balancing area ($ millions)

| | Q1 2023 | Q2 2023 | Q3 2023 | Q4 2023 | Q1 2024 | Q2 2024 | Q3 2024 | Q4 2024 | Total 2023 | Total 2024 |
|---|---|---|---|---|---|---|---|---|---|---|
| Arizona Public Service | 3 | .4 | 1 | .4 | .4 | .2 | .8 | .2 | 5 | 2 |
| Avangrid | | .1 | .1 | .0 | .3 | .0 | .2 | .2 | .0 | .7 |
| Avista | .1 | .0 | .0 | .0 | .0 | .0 | .1 | .0 | .0 | .1 |
| BANC | .2 | .0 | .1 | .0 | .1 | .0 | .0 | .0 | .3 | .1 |
| Bonneville Power Administration | .6 | .2 | .3 | .1 | .9 | .0 | .1 | .1 | .9 | 1 |
| El Paso Electric | | .0 | .1 | .1 | .1 | .0 | .2 | .1 | .2 | .4 |
| Idaho Power | .6 | .3 | 1 | .8 | .4 | .2 | .3 | .6 | 3 | .2 |
| LADWP | .0 | .0 | .1 | .0 | .5 | .0 | .0 | .2 | .1 | .3 |
| NorthWestern Energy | .2 | .0 | .0 | .1 | .1 | .0 | .1 | .1 | .0 | .3 |
| NV Energy | .5 | .1 | .3 | .3 | .4 | .0 | .3 | .1 | 1 | .7 |
| PacifiCorp East | .8 | .3 | 2 | 2 | 2 | .1 | 1 | 2 | 3 | 5 |
| PacifiCorp West | .5 | .2 | .1 | .4 | .0 | .3 | .3 | .4 | 1 | .9 |
| Portland General Electric | .4 | .2 | .2 | .1 | 2 | .0 | .4 | .1 | .9 | 2 |
| Powerex | 4 | 2 | 8 | 7 | 3 | 1 | 1 | .6 | 21 | 7 |
| Public Service Company of NM | 3 | .7 | .3 | .1 | .0 | .1 | .0 | .1 | 4 | .3 |
| Puget Sound Energy | .1 | .0 | .1 | .1 | .5 | .0 | .2 | .0 | .3 | .7 |
| Salt River Project | 1 | .5 | .7 | .7 | .7 | .1 | .4 | .2 | 3 | 1 |
| Seattle City Light | .4 | .2 | .2 | .2 | .4 | .2 | .5 | .3 | 1 | 1 |
| Tacoma Power | .2 | .0 | .0 | .0 | .3 | .0 | .0 | .0 | .2 | .3 |
| Tucson Electric Power | .4 | .0 | .6 | .4 | .3 | .1 | .4 | .3 | 1 | 1 |
| Turlock Irrigation District | .1 | .0 | .0 | .0 | .0 | .0 | .0 | .0 | .2 | .1 |
| WAPA Desert Southwest | | .0 | .0 | .0 | .2 | .0 | .0 | .0 | .0 | .1 |

**Figure 7.6 Total real-time imbalance offsets by quarter and balancing area ($ millions)**

| | 2023 Q1 | 2023 Q2 | 2023 Q3 | 2023 Q4 | 2024 Q1 | 2024 Q2 | 2024 Q3 | 2024 Q4 | Total 2023 | Total 2024 |
|---|---|---|---|---|---|---|---|---|---|---|
| Arizona Public Service | 9 | .7 | 4 | 3 | 6 | 1 | 4 | 3 | 15 | 14 |
| Avangrid | | .5 | 3 | .1 | 1 | 3 | .2 | .2 | 2 | 2 |
| Avista | .0 | .3 | .1 | .3 | 1 | .2 | .1 | .1 | .5 | 1 |
| BANC | .2 | .1 | .1 | .3 | .5 | .0 | 1 | .2 | .1 | .7 |
| Bonneville Power Administration | .3 | 2 | .8 | .6 | .4 | .3 | .9 | .7 | 3 | .4 |
| El Paso Electric | | 1 | 2 | 1 | .4 | .7 | .7 | .1 | 5 | 2 |
| Idaho Power | 2 | .4 | .9 | .2 | 2 | 1 | 3 | .8 | .5 | 6 |
| LADWP | 1 | 2 | 4 | 1 | 3 | 1 | 2 | 6 | 7 | .0 |
| NorthWestern Energy | 12 | 3 | 4 | 6 | 4 | 1 | 3 | 4 | 24 | 12 |
| NV Energy | .0 | 1 | .2 | .5 | 1 | 1 | .1 | .6 | 1 | 2 |
| PacifiCorp East | 28 | 4 | 2 | 18 | 21 | 6 | 3 | 9 | 3 | 39 |
| PacifiCorp West | 13 | 6 | 16 | 11 | 19 | 3 | 7 | 6 | 46 | 36 |
| Portland General Electric | 1 | 1 | 4 | 3 | 4 | 2 | .3 | .8 | 9 | 8 |
| Powerex | 11 | 28 | 76 | 30 | 20 | 15 | 4 | .5 | 146 | 40 |
| Public Service Company of NM | 11 | 3 | 6 | 4 | 4 | .1 | .4 | 6 | 24 | 11 |
| Puget Sound Energy | 13 | 5 | 10 | 10 | 11 | 4 | 6 | 5 | 39 | 26 |
| Salt River Project | 12 | 9 | 13 | 10 | 8 | 6 | 4 | 3 | 45 | 22 |
| Seattle City Light | .5 | .0 | .2 | .0 | .4 | .0 | .2 | .5 | .4 | .1 |
| Tacoma Power | .3 | .0 | .1 | .1 | .5 | .1 | .0 | .1 | .5 | .7 |
| Tucson Electric Power | .2 | 3 | 4 | 1 | 2 | 3 | 4 | 2 | 8 | 11 |
| Turlock Irrigation District | .9 | .6 | 1 | .4 | .3 | .4 | .8 | .4 | 3 | 2 |
| WAPA Desert Southwest | | .2 | .1 | .0 | .1 | .1 | .4 | .0 | .3 | .3 |

# 8 Bid cost recovery payments

This chapter analyzes bid cost recovery for balancing areas participating in the ISO's day-ahead and real-time markets. 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 or dispatch.

Key findings in this chapter include:

- **Bid cost recovery payments totaled $157 million for all balancing areas in 2024, down 49 percent** from 2023. Most of these payments ($141 million) came from the one balancing area (CAISO) participating in the day-ahead market.
- **Of the $16 million in bid cost recovery paid to generation in balancing areas only participating in the WEIM, $10.6 million went to the Desert Southwest region.**
- **Bid cost recovery payments associated with residual unit commitment during 2024 totaled about $27.5 million, or about $107.6 million (80 percent) lower than in 2023.**
- **The majority of bid cost recovery payments in every region went to gas resources.** The share of total bid cost recovery payments going to batteries in the CAISO balancing area increased to 13 percent in 2024 from 7 percent in 2023.

### Bid cost recovery

Bid cost recovery payments totaled $157 million in 2024 across the Western Energy Imbalance Market (WEIM), which is a little over half of the $307 million in total payments for 2023. Estimated bid cost recovery payments for units in balancing areas participating in the day-ahead market (CAISO) totaled about $141 million.[181] This was a 48 percent decrease from the $275 million in bid cost recovery in 2023. Bid cost recovery for units in areas participating only in the WEIM totaled about $16 million. WEIM area bid cost recovery payments decreased about 50 percent from $31.8 million in 2023.[182]

Figure 8.1 shows monthly bid cost recovery payments in 2024 for areas participating in the day-ahead market. Bid cost recovery payments associated with the day-ahead integrated forward market totaled about $37.9 million, up from $28.4 million in 2023. Bid cost recovery payments associated with residual unit commitment during 2024 totaled about $27.5 million, or about $107.6 million (80 percent) lower than in 2023. Bid cost recovery associated with the real-time market (green bars) for areas that participate in the day-ahead market totaled about $75.9 million, which was about $36.1 million lower than in 2023.

Figure 8.2 shows monthly bid cost recovery payments paid to units in areas participating only in the WEIM. Bid cost recovery payments to these units in 2024 were greatest in the Desert Southwest and California[183] regions at $10.6 million and $3.6 million, respectively. Bid cost recovery payments to the

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181 CAISO is the only balancing area currently participating in the day-ahead market.

182 The bid cost recovery payment amounts for 2022 and 2023 in this report are different than what is reported in the 2023 report due to resettlements.

183 Figure 8.2 includes only non-CAISO balancing authority areas.

Intermountain West and Pacific Northwest regions totaled around $470,000 and $1.3 million, respectively.

**Figure 8.1 Monthly bid cost recovery payments for day-ahead market area (CAISO)**

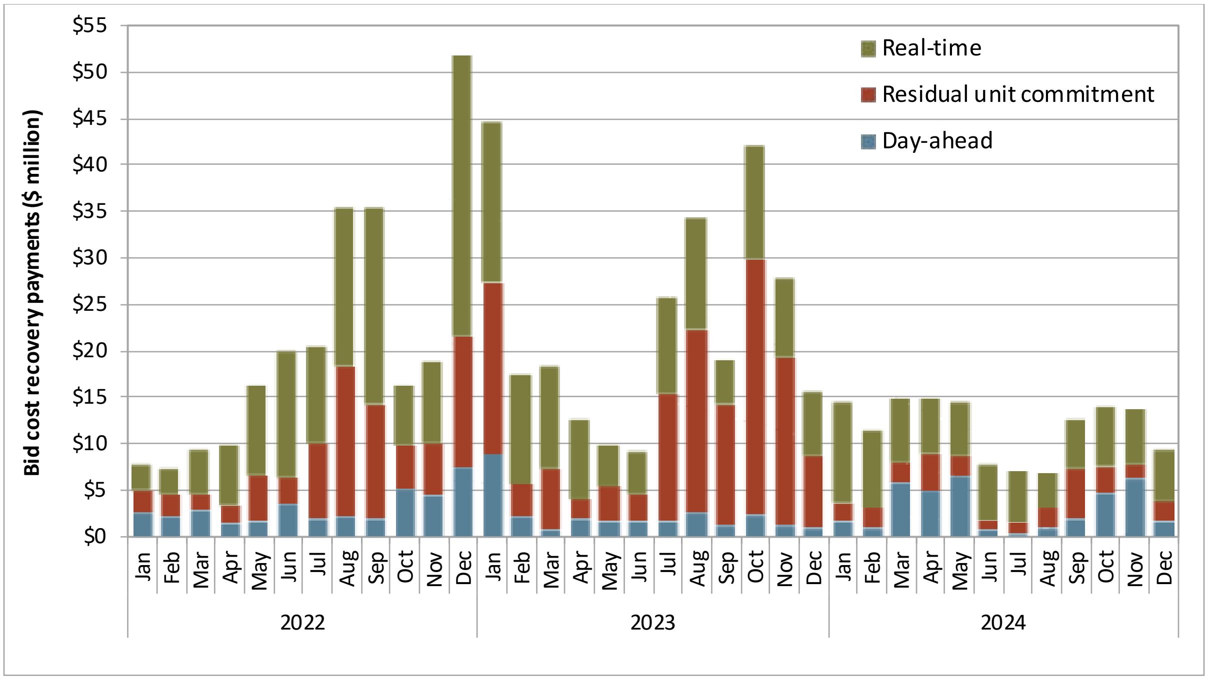



**Figure 8.2 Monthly bid cost recovery payments for the WEIM (non-CAISO)**

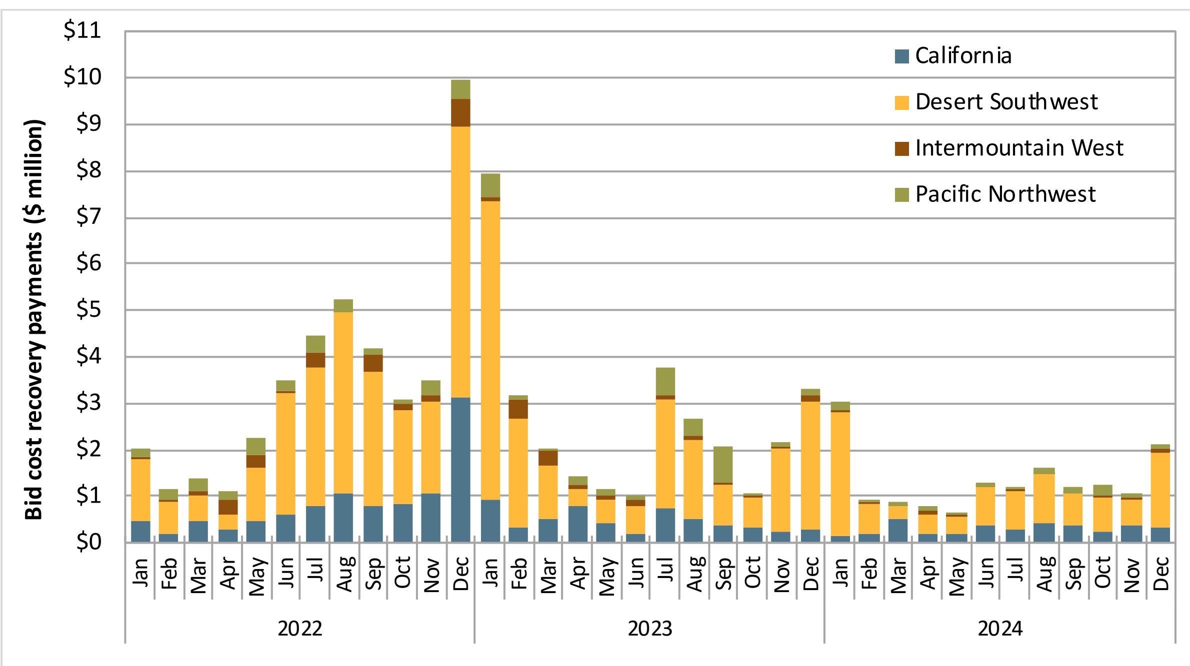


Table 8.1 through Table 8.5 show bid cost recovery payments in the CAISO and WEIM balancing areas by fuel type. In the CAISO balancing area, gas resources made up 77 percent of the total bid cost recovery payments, a decrease from 86 percent in 2023. Batteries' share of total bid cost recovery payments increased to 13 percent in 2024 from 7 percent in 2023. Gas resources made up the majority of payments in all regions, and hydro resources represented the next largest share in the California, Intermountain West, and Pacific Northwest regions. In the Desert Southwest region, payments to gas and coal resources decreased while increasing in nearly all other fuel types.

**Table 8.1 Total bid cost recovery payments in the day-ahead market area (CAISO) by fuel type (2022–2024)**

| Region | Fuel type | Bid cost recovery payments ($) | | | Percent of total bid cost recovery payments (%) | | |
|---|---|---|---|---|---|---|---|
| | | 2022 | 2023 | 2024 | 2022 | 2023 | 2024 |
| CISO | Gas | $200,708,062 | $238,149,217 | $109,017,185 | 81% | 86% | 77% |
| CISO | Batteries | $23,705,703 | $20,657,089 | $18,155,285 | 10% | 7% | 13% |
| CISO | Solar | $4,855,655 | $2,550,003 | $5,688,524 | 2% | 1% | 4% |
| CISO | Hydro | $17,021,976 | $12,684,843 | $4,797,253 | 7% | 5% | 3% |
| CISO | Hybrid | $0 | $311,479 | $1,583,097 | 0% | < 1% | 1% |
| CISO | Other | $740,941 | $265,423 | $1,318,782 | < 1% | < 1% | 1% |
| CISO | Wind | $702,841 | $598,904 | $477,719 | < 1% | < 1% | < 1% |
| CISO | Geothermal | $111,925 | $193,591 | $169,421 | < 1% | < 1% | < 1% |
| CISO | Coal | $16,574 | $11,239 | $9,456 | < 1% | < 1% | < 1% |
| CISO | Biogas-biomass | $19,433 | $6,786 | $5,829 | < 1% | < 1% | < 1% |
| | **Total:** | **$247,883,109** | **$275,428,572** | **$141,222,551** | | | |

**Table 8.2 Total bid cost recovery payments in the California (non-CAISO) region by fuel type (2022–2024)**

| Region | Fuel type | Bid cost recovery payments ($) | | | Percent of total bid cost recovery payments (%) | | |
|---|---|---|---|---|---|---|---|
| | | 2022 | 2023 | 2024 | 2022 | 2023 | 2024 |
| California | Gas | $9,582,611 | $4,481,993 | $2,957,932 | 95% | 79% | 81% |
| California | Hydro | $519,869 | $1,147,170 | $553,229 | 5% | 20% | 15% |
| California | Coal | $62 | $4,927 | $112,468 | < 1% | < 1% | 3% |
| California | Hybrid | $0 | $0 | $6,343 | 0% | 0% | < 1% |
| California | Batteries | $15,475 | $4,900 | $2,542 | < 1% | < 1% | < 1% |
| California | Wind | $210 | $2,182 | $1,361 | < 1% | < 1% | < 1% |
| California | Solar | $71 | $162 | $104 | < 1% | < 1% | < 1% |
| California | Demand response | $1 | $0 | $0 | < 1% | < 1% | 0% |
| | **Total:** | **$10,118,298** | **$5,641,335** | **$3,633,978** | | | |

### Table 8.3 Total bid cost recovery payments in the Desert Southwest region by fuel type (2022–2024)

| Region | Fuel type | Bid cost recovery payments ($) | | | Percent of total bid cost recovery payments (%) | | |
|---|---|---|---|---|---|---|---|
| | | 2022 | 2023 | 2024 | 2022 | 2023 | 2024 |
| Desert Southwest | Gas | $19,398,497 | $15,729,156 | $6,781,697 | 74% | 73% | 64% |
| Desert Southwest | Coal | $6,842,669 | $5,399,301 | $2,582,783 | 26% | 25% | 24% |
| Desert Southwest | Solar | $3,539 | $72,037 | $410,738 | < 1% | < 1% | 4% |
| Desert Southwest | Wind | $1,354 | $167,419 | $331,502 | < 1% | 1% | 3% |
| Desert Southwest | Batteries | $3,288 | $17,008 | $257,510 | < 1% | < 1% | 2% |
| Desert Southwest | Other | $3,017 | $59,105 | $219,833 | < 1% | < 1% | 2% |
| Desert Southwest | Hybrid | $0 | $8,834 | $8,342 | 0% | < 1% | < 1% |
| Desert Southwest | Hydro | $0 | $0 | $193 | 0% | < 1% | < 1% |
| Desert Southwest | Biogas-biomass | $0 | $17 | $145 | < 1% | < 1% | < 1% |
| Desert Southwest | Demand response | $0 | $0 | $14 | 0% | 0% | < 1% |
| Desert Southwest | Geothermal | $0 | $0 | $6 | 0% | < 1% | < 1% |
| | **Total:** | **$26,252,365** | **$21,452,878** | **$10,592,761** | | | |

### Table 8.4 Total bid cost recovery payments in the Intermountain West region by fuel type (2022–2024)

| Region | Fuel type | Bid cost recovery payments ($) | | | Percent of total bid cost recovery payments (%) | | |
|---|---|---|---|---|---|---|---|
| | | 2022 | 2023 | 2024 | 2022 | 2023 | 2024 |
| Intermountain West | Gas | $1,490,137 | $763,989 | $294,435 | 62% | 47% | 63% |
| Intermountain West | Hydro | $161,485 | $121,859 | $97,198 | 7% | 8% | 21% |
| Intermountain West | Coal | $727,461 | $660,884 | $67,966 | 30% | 41% | 14% |
| Intermountain West | Wind | $6,451 | $56,293 | $9,458 | < 1% | 3% | 2% |
| Intermountain West | Demand response | $3,127 | $8,257 | $553 | < 1% | 1% | < 1% |
| Intermountain West | Biogas-biomass | $56 | $269 | $216 | < 1% | < 1% | < 1% |
| Intermountain West | Solar | $18 | $3 | $4 | < 1% | < 1% | < 1% |
| | **Total:** | **$2,388,734** | **$1,611,553** | **$469,829** | | | |

### Table 8.5 Total bid cost recovery payments in the Pacific Northwest region by fuel type (2022–2024)

| Region | Fuel type | Bid cost recovery payments ($) | | | Percent of total bid cost recovery payments (%) | | |
|---|---|---|---|---|---|---|---|
| | | 2022 | 2023 | 2024 | 2022 | 2023 | 2024 |
| Pacific Northwest | Gas | $2,771,794 | $1,287,425 | $957,864 | 89% | 42% | 74% |
| Pacific Northwest | Hydro | $328,227 | $1,744,328 | $284,994 | 11% | 57% | 22% |
| Pacific Northwest | Wind | $1,177 | $30,378 | $49,295 | < 1% | 1% | 4% |
| Pacific Northwest | Solar | $0 | $274 | $64 | < 1% | < 1% | < 1% |
| Pacific Northwest | Coal | $11,261 | $0 | $0 | < 1% | 0% | 0% |
| Pacific Northwest | Other | $0 | $2 | $0 | 0% | < 1% | 0% |
| | **Total:** | **$3,112,460** | **$3,062,406** | **$1,292,217** | | | |

# 9 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 in the real-time market. Over the last few years, the California ISO has placed a priority on reducing its market adjustments.

Findings from this chapter include the following:

- **Adjustments to load forecasts were generally much higher in the 5-minute market than the 15-minute market,** with exceptions being the CAISO balancing area and Bonneville Power Administration (BPA).
- **The CAISO balancing area's adjustments to load forecasts during the evening peak net load hours continued to be significantly larger in the hour-ahead and 15-minute markets than in the 5-minute market.** For hour-ending 19, average hourly adjustments in the 15-minute market were 1,770 MW, compared to 430 MW in the 5-minute market. This contributes to higher prices in the 15-minute market than in the 5-minute market over these hours.
- **CAISO balancing area operator adjustments to the residual unit commitment load forecast were significantly lower in 2024.** These adjustments, to account for load and resource uncertainty, averaged 656 MW per hour in 2024, down 56 percent from 1,485 MW per hour in 2023.
- **Combined incremental and decremental manual dispatch energy** increased from 2023 to 2024 in the Desert Southwest and Intermountain West regions by 14 percent and 8 percent, respectively. Total manual dispatch energy decreased in the California (non-CAISO) and Pacific Northwest regions by 9 percent and 5 percent, respectively.
- **Total energy from exceptional dispatches in the CAISO balancing area averaged 0.34 percent of system loads in 2024**, up from 0.26 percent of system loads in 2023.

## 9.1 Imbalance conformance

Operators in WEIM balancing areas can manually adjust the load forecasts used in the real-time markets in order to help maintain system reliability. The ISO refers to this as *imbalance conformance*. These adjustments are to account for potential modeling inconsistencies and inaccuracies, and to create additional unloaded ramping capacity in the real-time market.

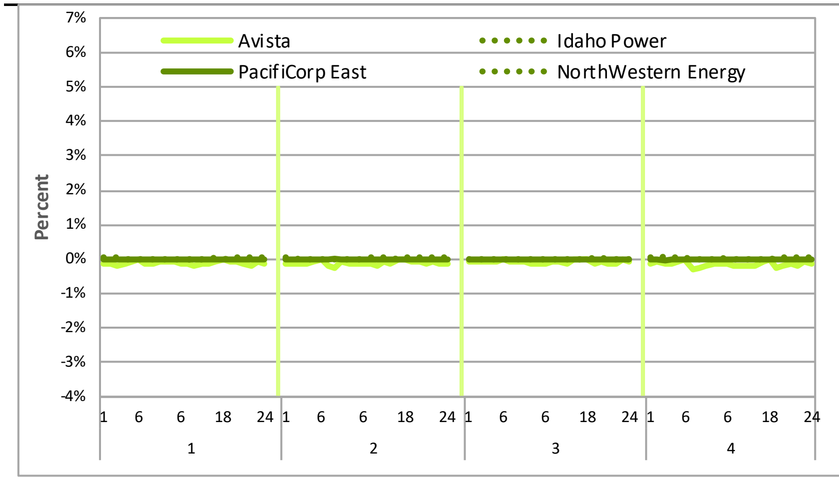
### 9.1.1 Imbalance conformance by balancing area

The figures below show the 2024 15-minute market and 5-minute market average hourly imbalance conformance by quarter for each balancing area as a percentage of the average load of the balancing area.[184] Generally, imbalance conformance levels were much higher in the 5-minute market than the 15-minute market, with exceptions being the CAISO balancing area and Bonneville Power Administration (BPA).

[184] Avangrid and Powerex are not shown in this figure. Avangrid is a generation-only entity and therefore load conformance cannot be measured as a percent of load. Powerex is not a balancing authority area like other participating WEIM entities and instead uses residual capability of the BC Hydro system to participate in the WEIM. Powerex therefore does not have the ability to enter load bias in the market.

**Figure 9.1 Intermountain West: Average hourly imbalance conformance as a percent of average load in the 15-minute and 5-minute markets by balancing area (Q1–Q4 2024)**

*15-minute market*




*5-minute market*

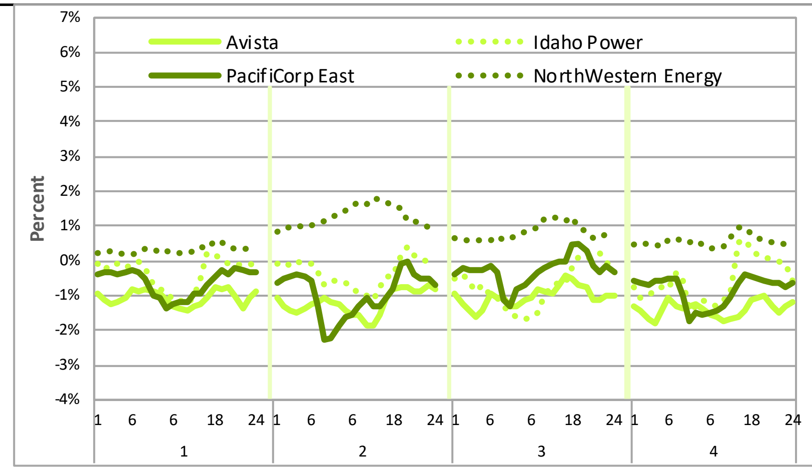
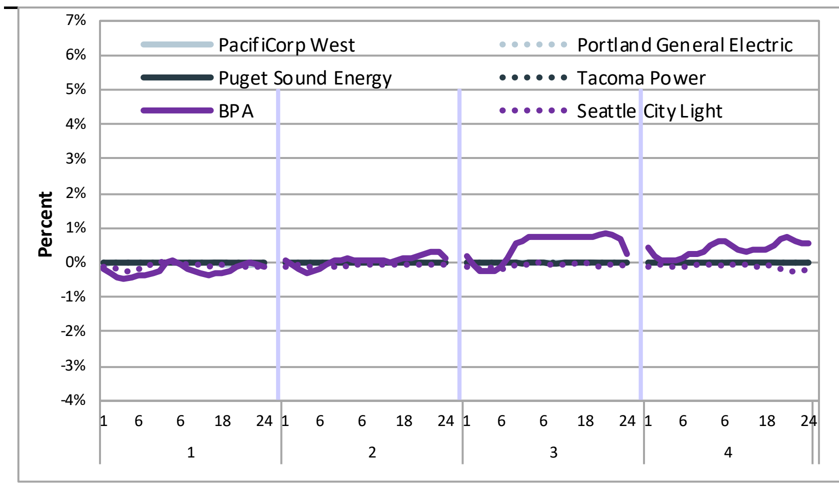



**Figure 9.2 Pacific Northwest: Average hourly imbalance conformance as a percent of average load in the 15-minute and 5-minute markets by balancing area (Q1–Q4 2024)**

*15-minute market*




*5-minute market*

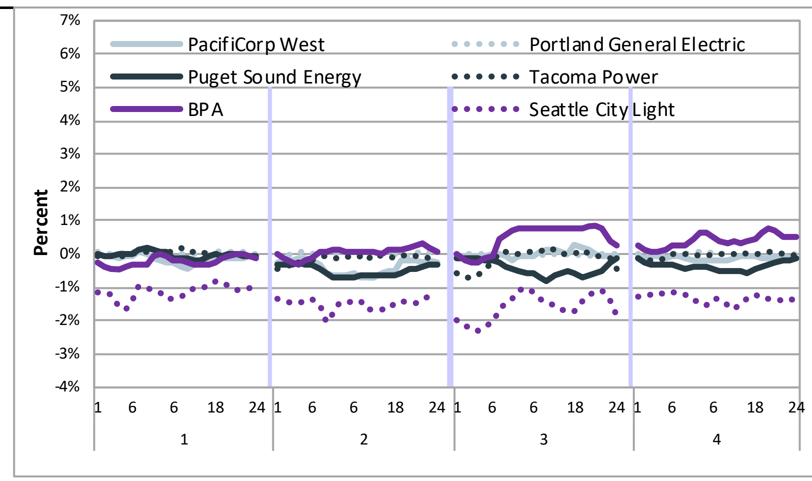


**Figure 9.3 Desert Southwest: Average hourly imbalance conformance as a percent of average load in the 15-minute and 5-minute markets by balancing area (Q1–Q4 2024)**

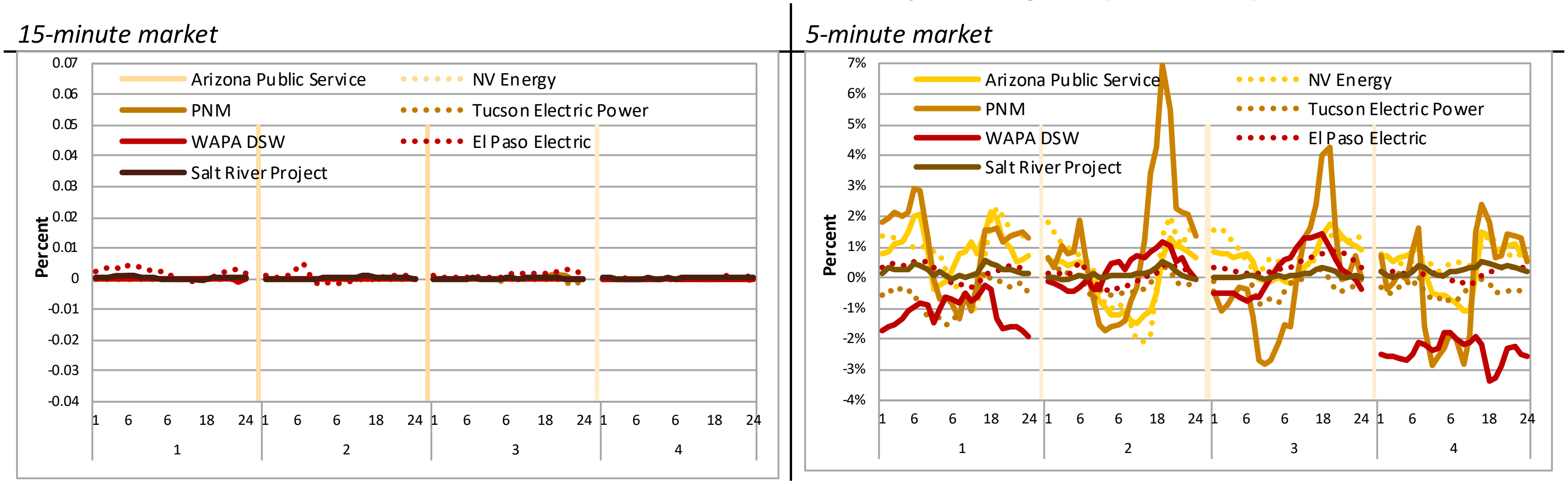
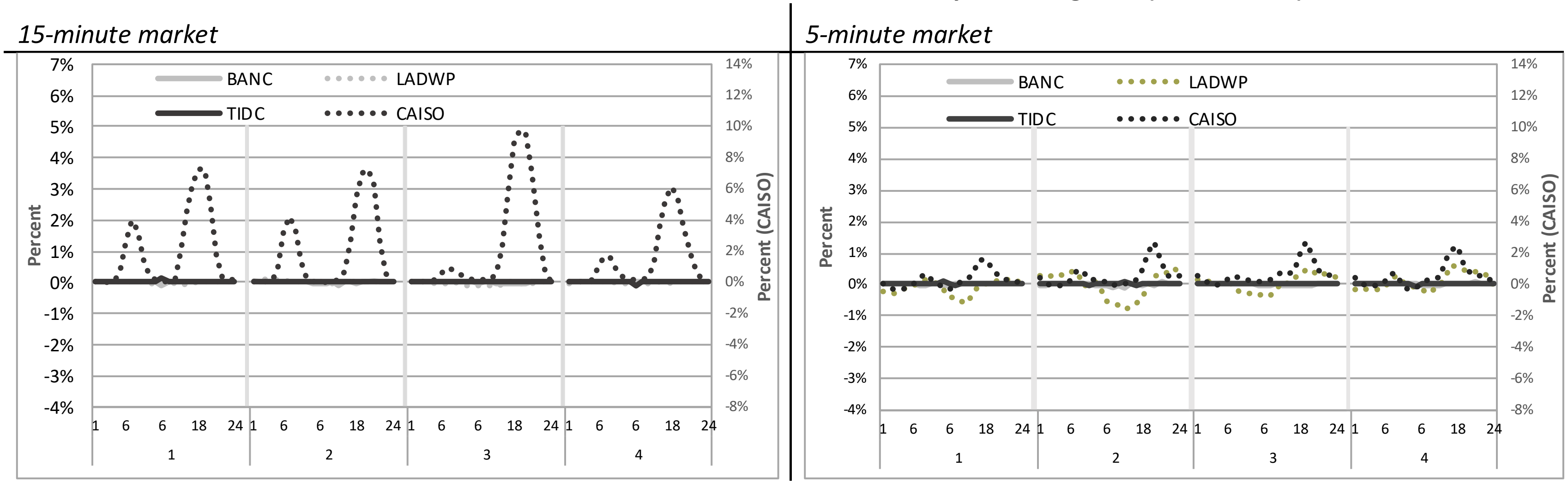



**Figure 9.4 California: Average hourly imbalance conformance as a percent of average load in the 15-minute and 5-minute markets by balancing area (Q1–Q4 2024)**



### 9.1.2 Imbalance conformance — special report on CAISO balancing area

In 2024, the use of imbalance conformance in the 15-minute market by operators in the CAISO balancing area, in both size and frequency, is an outlier amongst WEIM areas. This section analyzes the use of imbalance conformance by CAISO balancing area operators.

Beginning in 2017, there was a large increase in imbalance conformance adjustments during the steep morning and evening net load ramp periods in the California ISO balancing area hour-ahead and 15-minute markets. Figure 9.5 shows CAISO area imbalance conformance adjustments in real-time markets for 2022 to 2024. Imbalance conformance over the evening peak net load hours continued to be significantly larger in the hour-ahead and 15-minute markets than in the 5-minute market. This contributes to higher prices in the 15-minute market than in the 5-minute market over these hours.

Average hourly imbalance conformance adjustments in the hour-ahead and 15-minute markets increased in the morning ramp in 2024 compared to 2023, while the 2022 levels were the highest of the reporting period. During the morning hours, the highest average hourly adjustments were around 560 MW. This was an increase from a maximum of about 330 MW over the morning hours in 2023. The evening ramp in 2024 was very similar to 2023 levels and lower than 2022 levels. Imbalance conformance over the evening peak hours reached about 1,770 MW, or about 50 MW lower than the largest average hourly evening adjustments in 2023.

The 5-minute market adjustments in 2024 were similar to both 2023 and 2022. These adjustments peaked in hour-ending 19 at about 430 MW.

**Figure 9.5 Average CAISO balancing area hourly imbalance conformance adjustment (2022–2024)**

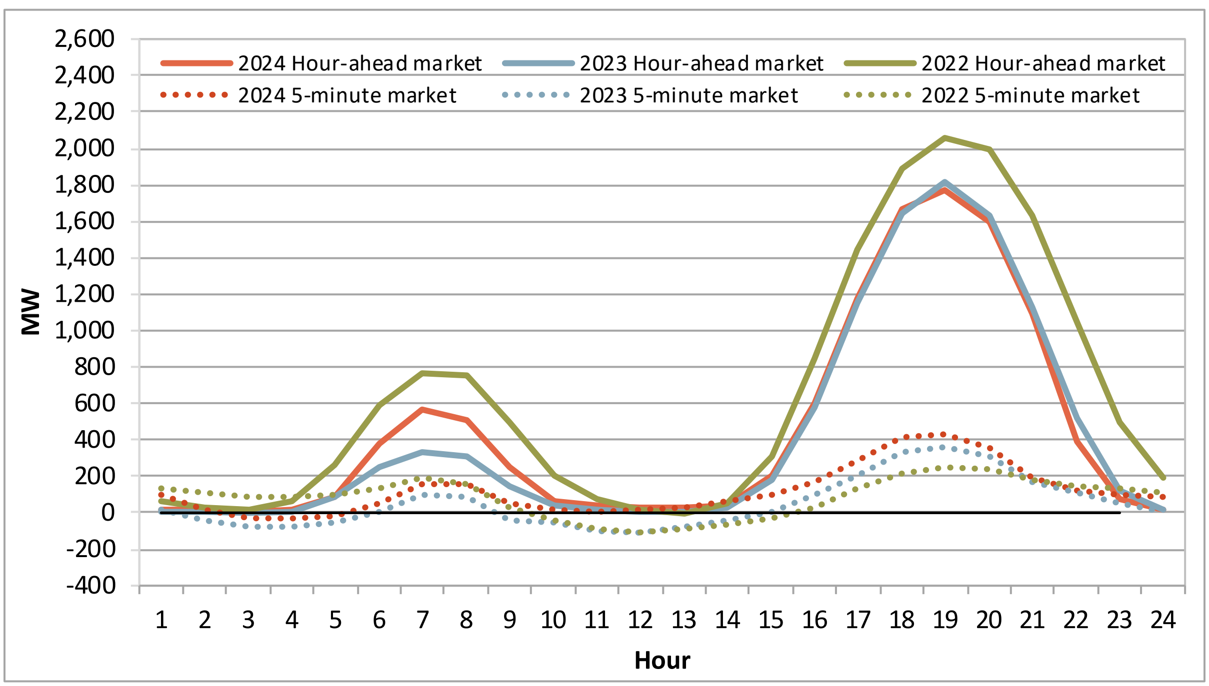
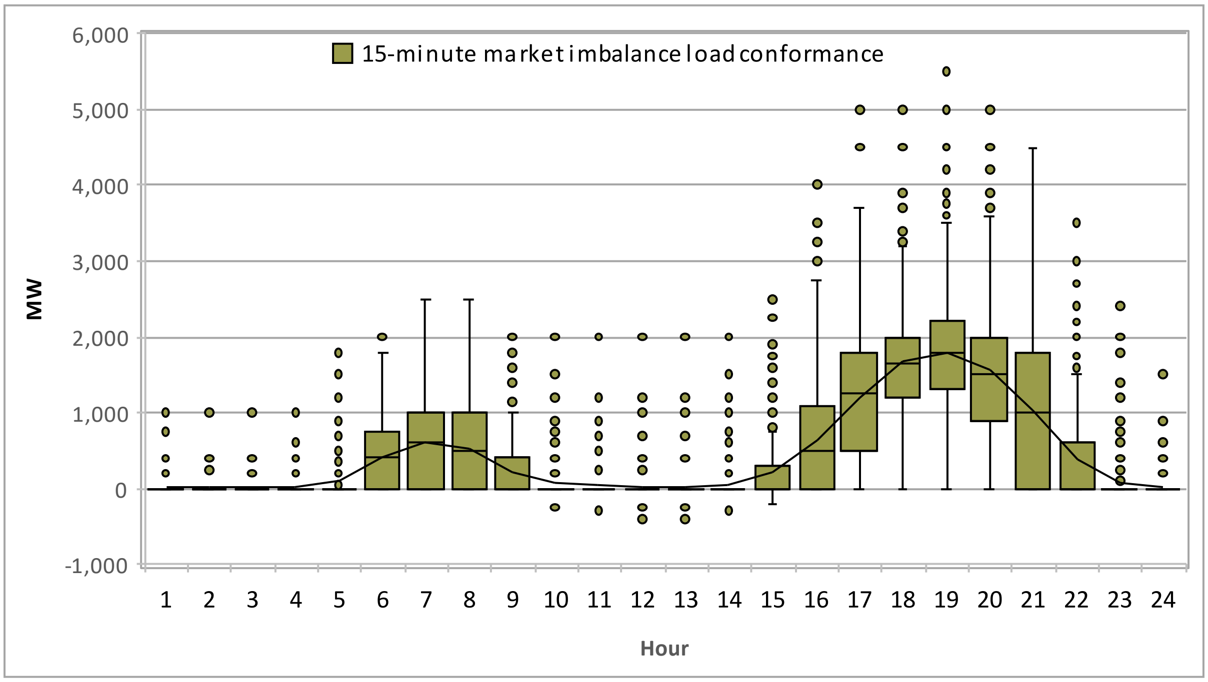


Figure 9.6 shows an hourly distribution of the 15-minute market load adjustments for 2024. This box and whisker graph highlights extreme outliers[185] (positive and negative), minimum excluding outliers, lower quartile, median, upper quartile, and maximum excluding outliers, as well as the mean (line). The extreme outliers are represented by the filled "dots". The outside whiskers do not include these outliers. For the year, the maximums and major outliers in hours-ending 17 to 22, e.g., greater than 5,000 MW, primarily occurred on July 24 and August 28, associated with rapid solar ramp down. The mid-day negative minimum outliers occurred on two days, October 27 and November 27, while the 2,000 MW outliers occurred on October 8.

**Figure 9.6 CAISO BA 15-minute market hourly distribution of operator load adjustments (2024)**




## 9.2 Residual unit commitment requirement adjustments

Figure 9.7 shows the average hourly determinants of capacity requirements used in the residual unit commitment process by quarter in 2023 and 2024.

The residual unit commitment process includes an automated adjustment to account for the need to replace net virtual supply clearing in the integrated forward market (IFM) run of the day-ahead market, which can offset physical supply in that run. In 2024, this automated adjustment, shown in the green bars in Figure 9.7, was the primary driver of positive residual unit commitment requirement. Average

185 A data point is an outlier if it is more than 1.5 * Interquartile Range (IQR) above the third quartile or below the first quartile. The upper outliers are greater than the 3rd quartile + 1.5 x Interquartile Range (IQR), while lower outliers are values less than the 1st quartile less 1.5 x Interquartile Range (IQR).

residual unit commitment requirements due to net virtual supply decreased to 427 MW in 2024 from 696 MW in 2023.

California ISO operators can also make adjustments to increase the amount of residual unit commitment requirements above the day-ahead load forecast. These are made to address uncertainty in load and supply between the day-ahead market and real-time markets. These adjustments, shown in the red bars in Figure 9.7, contributed an average of 656 MW per hour to the requirements in 2024, a decrease of about 56 percent from 1,485 MW per hour in 2023. These adjustments were largest during the first and third quarters.

The blue bars in Figure 9.7 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 IFM run of the day-ahead market and the CAISO day-ahead load forecast. This represents the difference between the CAISO day-ahead load forecast and the physical load that cleared the IFM. This difference increased residual unit commitment requirements by about 240 MW on a yearly average basis in 2024, down from about 340 MW in 2023.

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 bars in Figure 9.7.

**Figure 9.7 Determinants of residual unit commitment procurement**

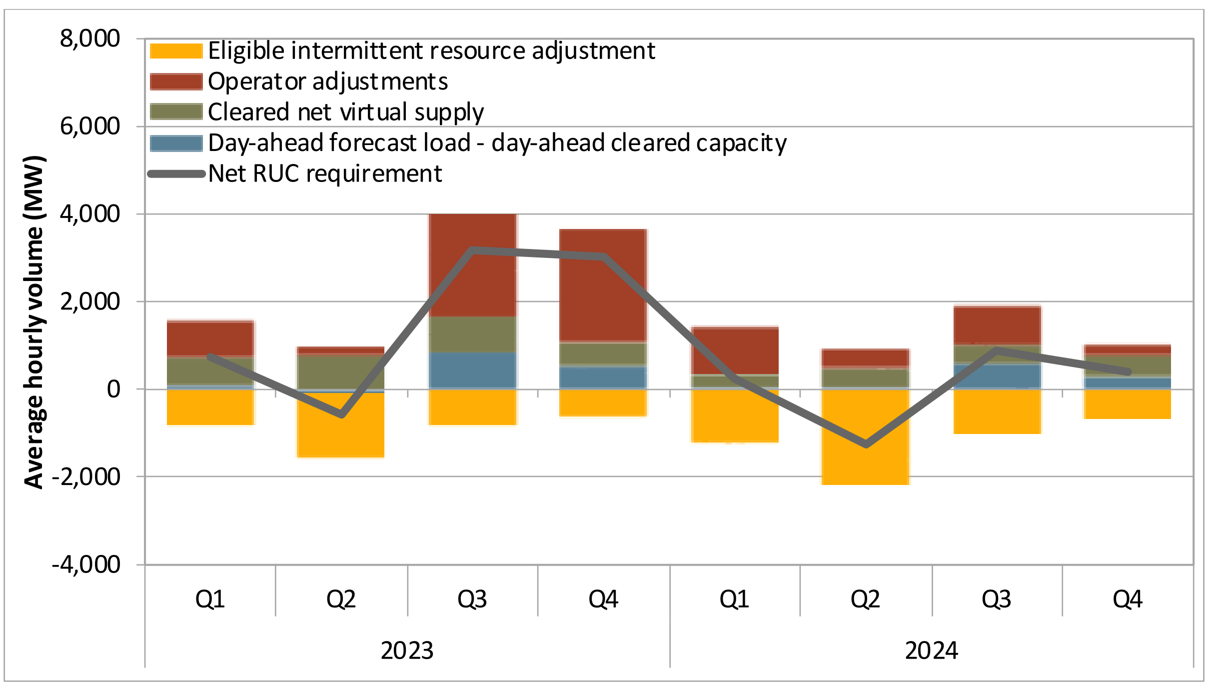



Figure 9.8 shows these same four determinants of the residual unit commitment requirements for 2024 by hour. As shown by the red bars, adjustments to the requirement by grid operators generally occur throughout the day but tend to be greatest in the morning and evening solar ramp periods. During the

first four months of the year, as well as in July and August, operators increased the residual unit commitment requirement on average by more than 999 MW. The month with the largest average hourly operator adjustment was March, at about 1,200 MW.

While operator adjustments were generally lower 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 (i.e., cleared IFM load) during all hours except 10 through 16 in 2024. Similar to 2023, the bulk of the intermittent resource adjustments occurred in hours-ending 8 to 19.

Figure 9.9 shows the hourly distribution of operator adjustments during the *third quarter of 2024*. The black line shows the average adjustment quantity in each hour and the red markers highlight outliers in each hour. The average adjustment in the third quarter was about 845 MW per hour, compared to about 2,360 MW in the same quarter of 2023. These adjustments were primarily used to address reliability concerns and to account for net load forecast errors.

**Figure 9.8 Average hourly determinants of residual unit commitment procurement (2024)**

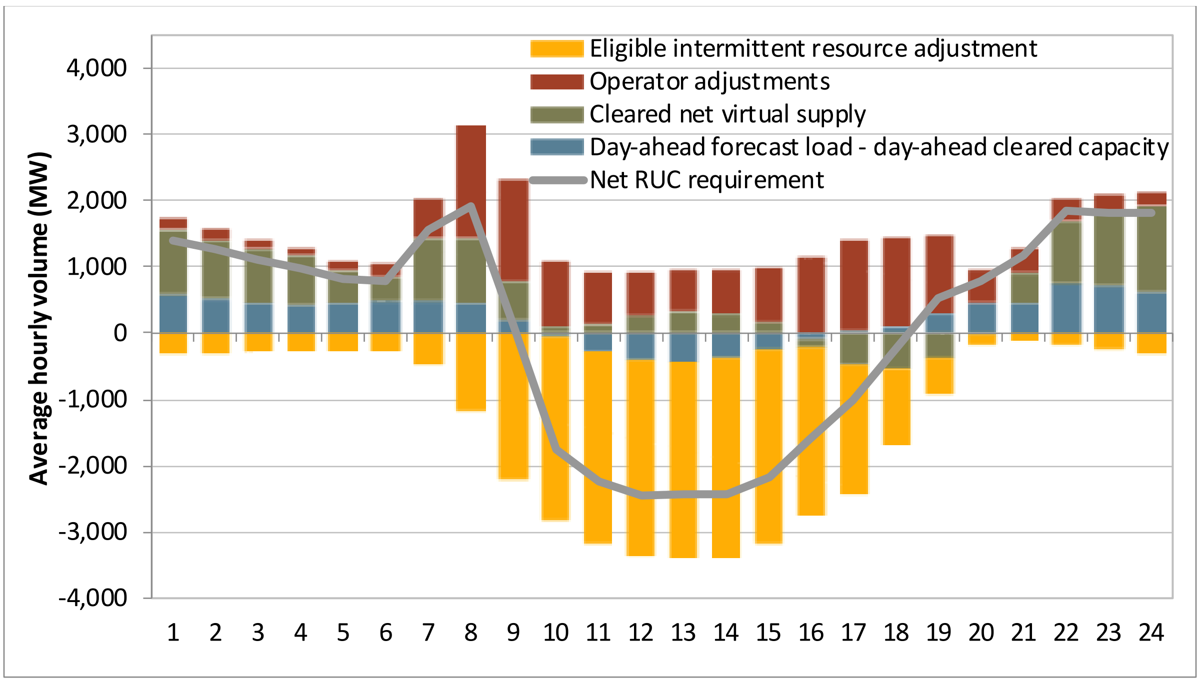
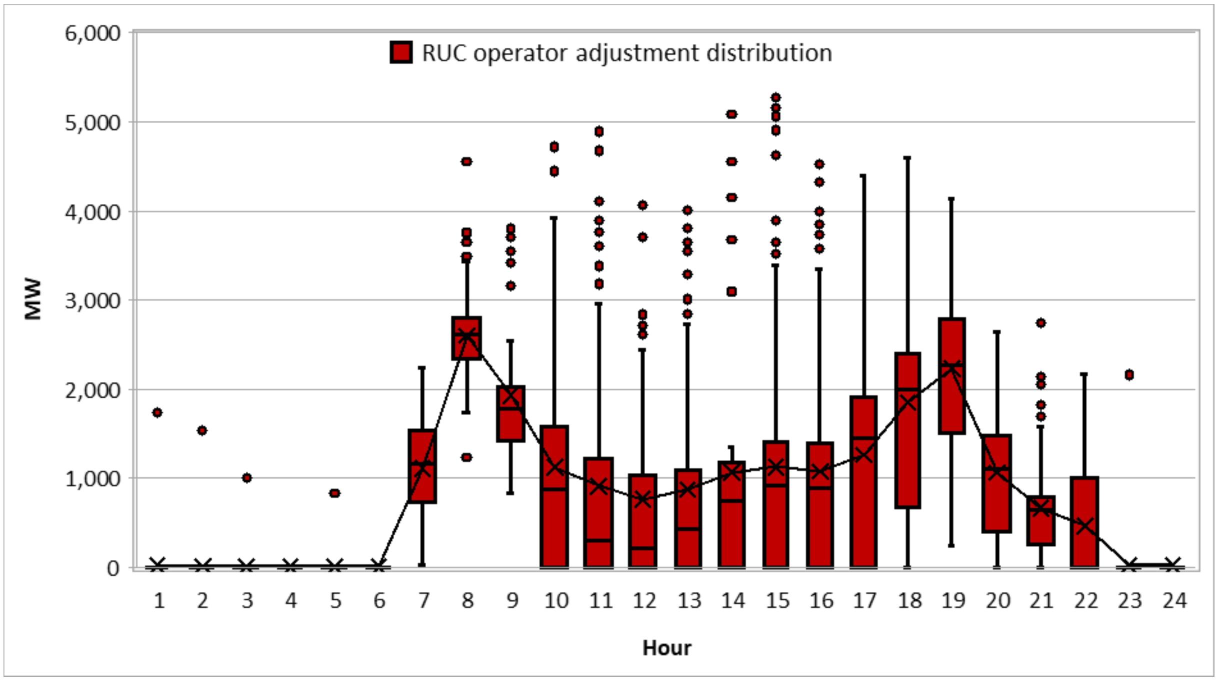


**Figure 9.9 Hourly distribution of residual unit commitment operator adjustments (July–September 2024)**




## 9.3 Manual dispatch

This section analyzes manual dispatches for the California ISO balancing area, known as exceptional dispatches, as well as manual dispatches in balancing areas across the WEIM. CAISO balancing area exceptional dispatches are covered in a separate subsection from the rest of the WEIM because of significant differences in how manual dispatches are settled in the CAISO balancing area relative to other balancing areas in the WEIM.

### 9.3.1 California ISO exceptional dispatch

This section analyzes exceptional dispatches for the California ISO balancing area. 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 because out-of-market payments to the resources may exceed market prices. Manual dispatch compensation may also 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 have likely 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.

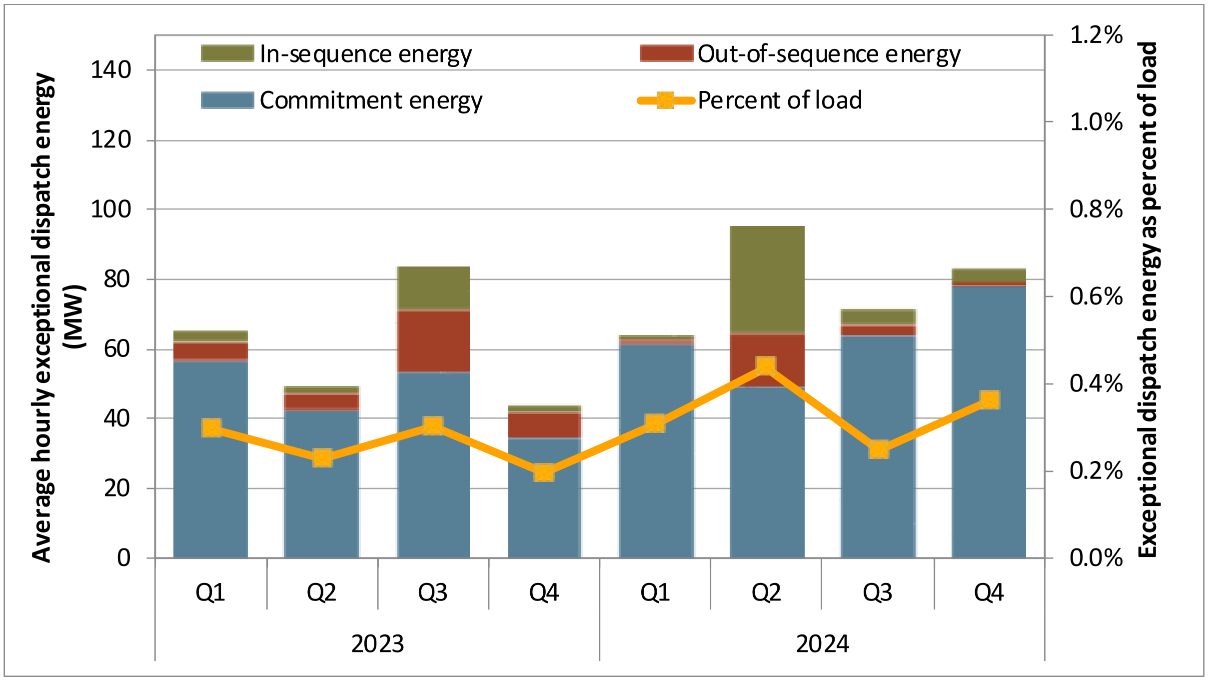
### Energy from exceptional dispatch

Energy from exceptional dispatches continued to account for under 1 percent of total load in 2024 in the California ISO balancing area, represented by the yellow line in Figure 9.10. Total energy from exceptional dispatches, including minimum load energy from unit commitments, increased by 30 percent in 2024 compared to 2023. Total energy from exceptional dispatches averaged 0.34 percent of system loads in 2024, compared to 0.26 percent of system loads in 2023.

Exceptional dispatch energy above minimum load increased by approximately 12 percent in 2024 from 2023, while minimum load energy from unit commitments increased by about 35 percent. As shown in Figure 9.10, minimum load energy from units committed via exceptional dispatch (blue) accounted for 81 percent of all exceptional dispatch energy in 2024. About 7 percent of energy from exceptional dispatches was from out-of-sequence energy above minimum load (red), and the remaining 12 percent was from in-sequence energy above minimum load (green).

The in-sequence energy portion of the exceptional dispatches above minimum load increased by 107 percent in 2024 compared to 2023. Out-of-sequence energy from exceptional dispatch decreased 38 percent year over year between 2023 and 2024.

**Figure 9.10 Average hourly energy from exceptional dispatch**

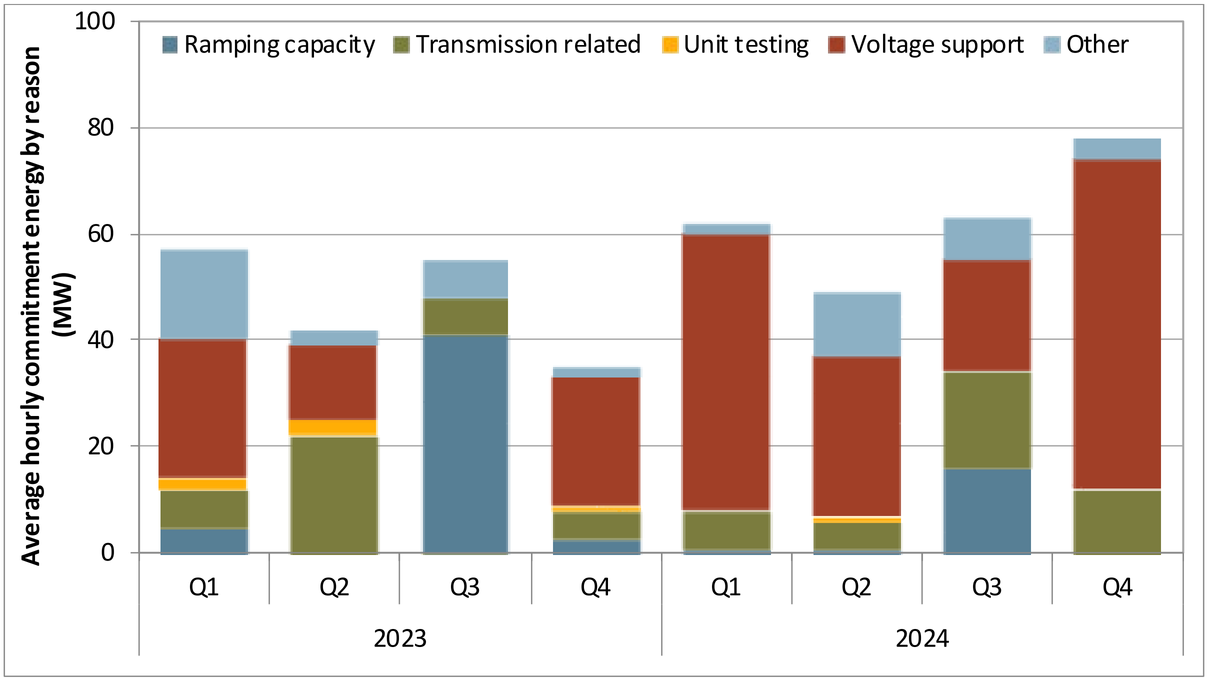



### Exceptional dispatches for unit commitment

The California ISO balancing area operators occasionally 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 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.

Figure 9.11 shows the reasons for minimum load energy exceptional dispatches—ramping capacity (blue), transmission related (green), unit testing (yellow), and voltage support (red). Minimum load energy from exceptional dispatch unit commitments increased in 2024 compared to 2023, with most occurring in the third and fourth quarters of 2024. Exceptional dispatch unit commitments in all four quarters of 2024 were predominately issued to provide voltage support. Voltage support exceptional dispatches are issued to ensure that proper voltage is maintained on the grid via the generation or absorption of reactive power by the exceptionally dispatched resources. Exceptional dispatch unit commitments for voltage support increased in all quarters of 2024 compared to their respective quarters in 2023.

**Figure 9.11 Average minimum load energy from exceptional dispatch unit commitments**




### Exceptional dispatches for energy

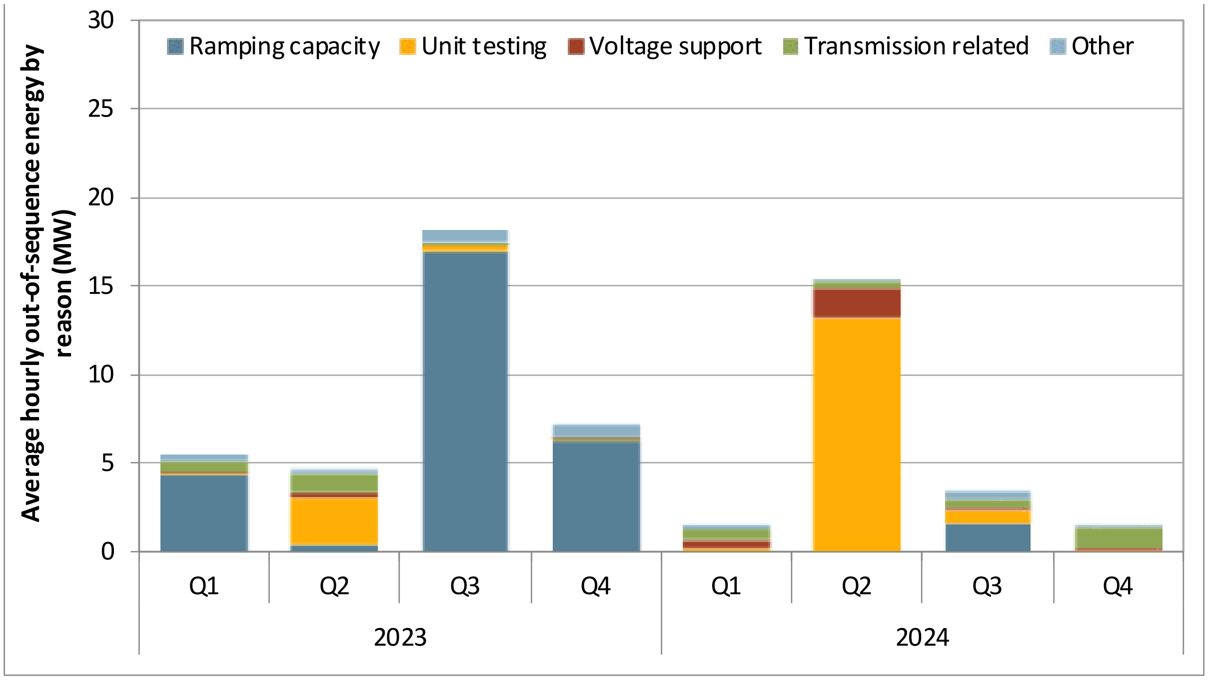
Figure 9.12 shows the out-of-sequence exceptional dispatch energy by quarter for 2023 and 2024. Overall, out-of-sequence exceptional dispatch energy decreased by 63 percent in 2024 when compared to 2023. Out-of-sequence exceptional dispatch energy in 2024 decreased in every quarter other than the second quarter, when compared to 2023. The primary reason logged for out-of-sequence energy exceptional dispatches in the second quarter was for unit testing. Out-of-sequence exceptional dispatch energy due to unit testing (yellow bars) increased by 390 percent in the second quarter of 2024 when compared to the second quarter of 2023. This increase is largely due to pre-commercial unit testing for a new resource that came on-line in June 2024. Because this resource was pre-commercial during unit testing, it did not submit any bids to the market. Therefore, the identified out-of-sequence energy is due to the resource's default energy bid being out-of-sequence. Exceptional dispatches for unit testing are settled at the locational marginal price, so there is no settlement impact associated with this energy, despite being out-of-sequence.

Out-of-sequence exceptional dispatch energy due to ramping capacity (blue bars) decreased by 90 percent in the third quarter of 2024 when compared to the third quarter of 2023. This decrease is largely due to the implementation of specific exceptional dispatch instructions for Long Start Strategic Reliability Reserve (LS-SRR) resources in 2024.[186] In the third quarter of 2023, a majority of out-of-sequence exceptional dispatch energy due to ramping capacity came from long-start gas units in response to load forecast uncertainty and system capacity needs. However, with the use of specific LS-SRR dispatch instructions in 2024, these long-start gas units were only exceptionally dispatched during extreme conditions and system emergencies, rather than for non-transmission related ramping capacity.

[186] California ISO Operating Procedure No. 4420, Section 3.2.3. Long Start Strategic Reliability Reserve Resources (LS-SRR)

This not only reduced the frequency of dispatch for these resources, but also significantly reduced the amount of out-of-sequence exceptional dispatch energy due to ramping capacity in the third quarter of 2024.

**Figure 9.12 Out-of-sequence exceptional dispatch energy by reason**



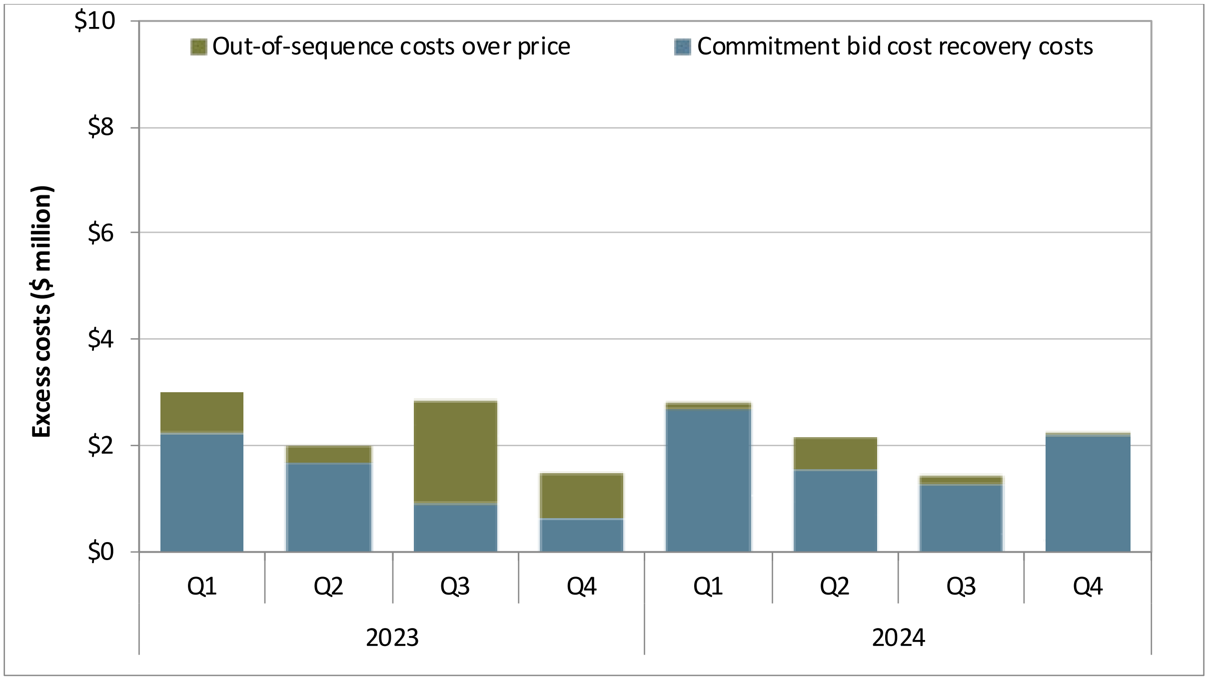

### Exceptional dispatch costs

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

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

Figure 9.13 shows the estimated costs for unit commitment and out-of-sequence energy. Commitment and additional energy costs for exceptional dispatch paid through bid cost recovery increased from $5.5 million in 2023 to $7.7 million in 2024, while out-of-sequence energy costs decreased from $3.8 million in 2023 to $0.94 million in 2024. Total excess costs for exceptional dispatches decreased by about 7 percent—to about $8.7 million in 2024 from $9.3 million in 2023.

**Figure 9.13 Excess exceptional dispatch cost by type**




## 9.3.2 Mitigation of exceptional dispatches

### Overview

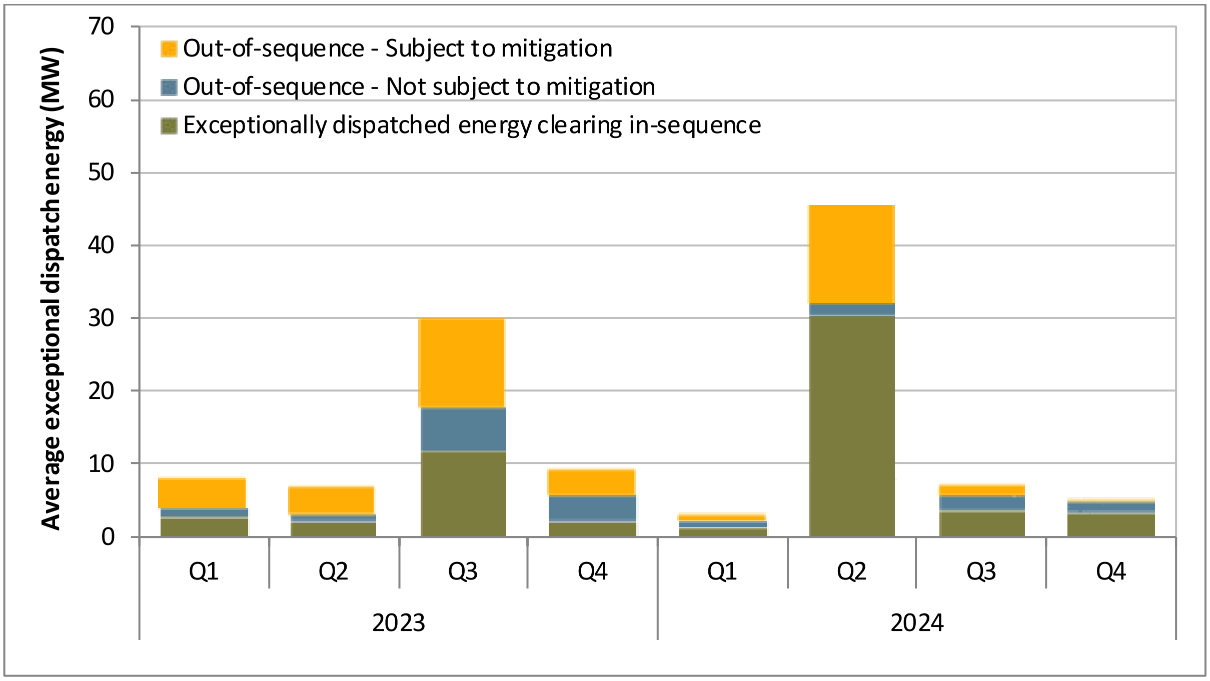
Commitment cost bids for units that are committed via exceptional dispatch are not subject to any additional mitigation beyond the commitment cost bid caps, which include 25 percent headroom above estimated start-up and minimum load costs. Exceptional dispatches for energy above minimum load are subject to mitigation if a grid operator indicates the dispatch is made for any of the following reasons:

- Address reliability requirements related to non-competitive transmission constraints;
- Ramp resources with ancillary services awards or residual unit commitment capacity to a dispatch level that ensures their availability in real-time;
- Ramp resources to their minimum dispatch level in real-time, allowing the resource to be more quickly ramped up if needed to manage congestion or meet another reliability requirement; or
- Address unit-specific environmental constraints not incorporated into the model or the market software that affect the dispatch of units in the Sacramento Delta, commonly known as *Delta Dispatch*.

### Volume and percent of exceptional dispatches subject to mitigation

As shown in Figure 9.14, the overall volume of exceptional dispatch energy above minimum load increased by about 12 percent in 2024 when compared to 2023. As previously discussed in Section 9.3.1, 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 53 percent in 2024 compared to 2023. Out-of-sequence exceptional dispatches subject to mitigation decreased by about 31 percent in 2024 compared to 2023.

**Figure 9.14 Exceptional dispatches subject to bid mitigation**




## 9.3.3 Western Energy Imbalance Market manual dispatch

Western Energy Imbalance Market (WEIM) areas sometimes need to dispatch resources out-of-market for reliability, to manage transmission constraints, or for other reasons. These 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 balancing area, 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 balancing area. 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 9.15 through Figure 9.18 summarize average hourly incremental and decremental manual dispatch activity of participating and non-participating resources for each WEIM region. The California region, however, has no manual dispatch energy from non-participating resources.

When comparing 2024 to 2023, incremental manual dispatch energy from participating resources (yellow bars) increased in the Desert Southwest and Pacific Northwest regions by 4 percent and 2 percent, respectively, but decreased in the California and Intermountain West regions by 6 percent and 13 percent, respectively. Similarly, when comparing 2024 to 2023, incremental manual dispatch energy from non-participating resources (red bars) increased for the Desert Southwest and Intermountain West regions by 88 percent and 21 percent, respectively, but decreased by 6 percent for the Pacific Northwest region.

Decremental manual dispatch energy from participating resources (green bars) increased between 2023 and 2024 in all WEIM regions, except for California with a 12 percent decrease. Meanwhile, when comparing 2024 to 2023, decremental manual dispatch energy from non-participating resources (blue bars) increased in the Desert Southwest and Intermountain West regions by 192 percent and 83 percent, respectively, but decreased in the Pacific Northwest by 6 percent.

Overall, combined incremental and decremental manual dispatch energy increased from 2023 to 2024 in the Desert Southwest and Intermountain West regions by 14 percent and 8 percent, respectively. Meanwhile, total manual dispatch energy decreased in the California (non-CAISO) and Pacific Northwest regions by 9 percent and 5 percent, respectively.

**Figure 9.15 WEIM manual dispatches – California**

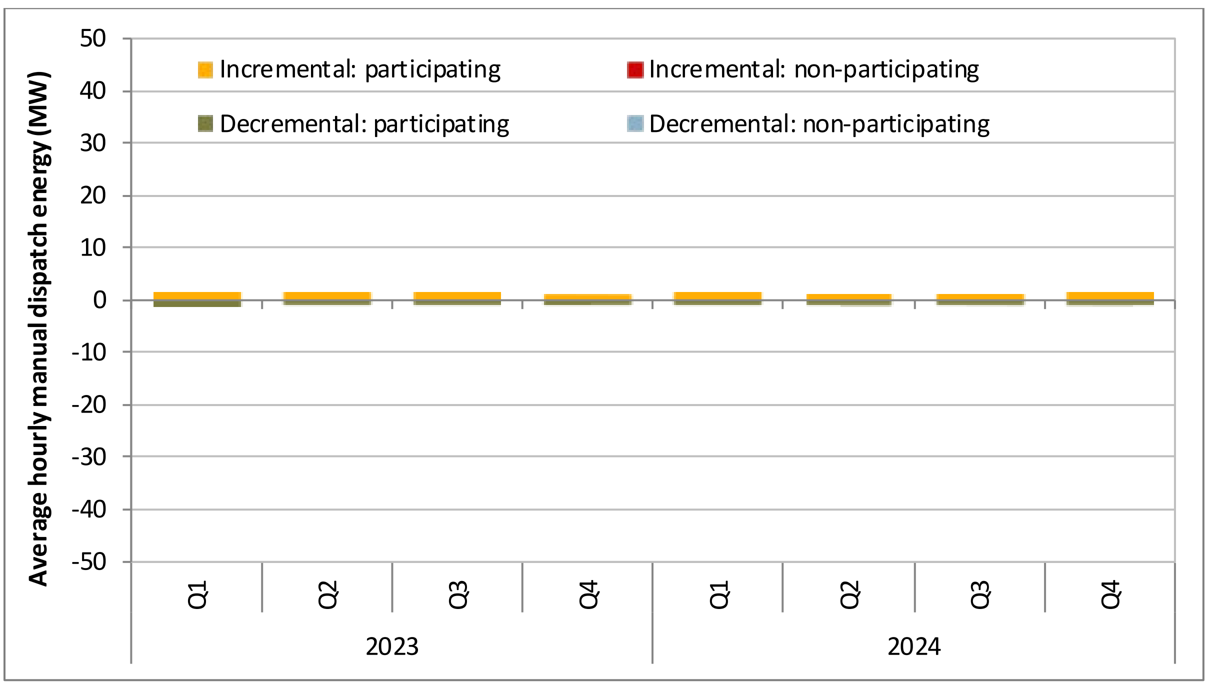


**Figure 9.16 WEIM manual dispatches – Desert Southwest**

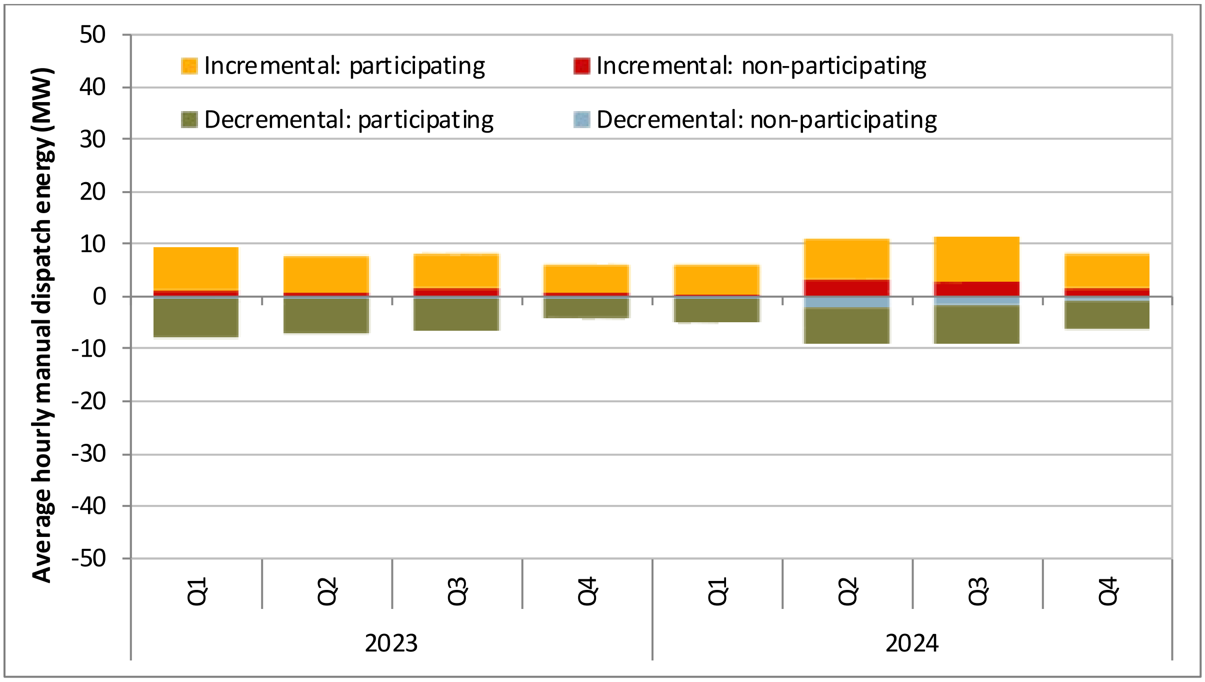



**Figure 9.17 WEIM manual dispatches – Intermountain West**

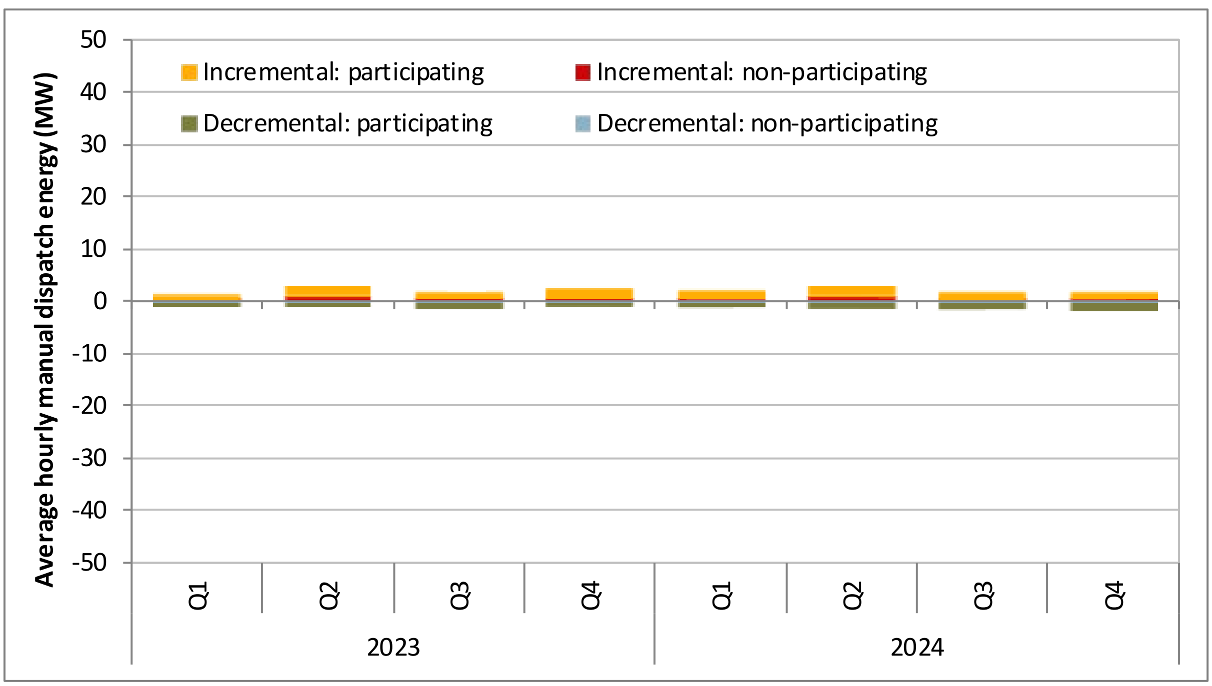
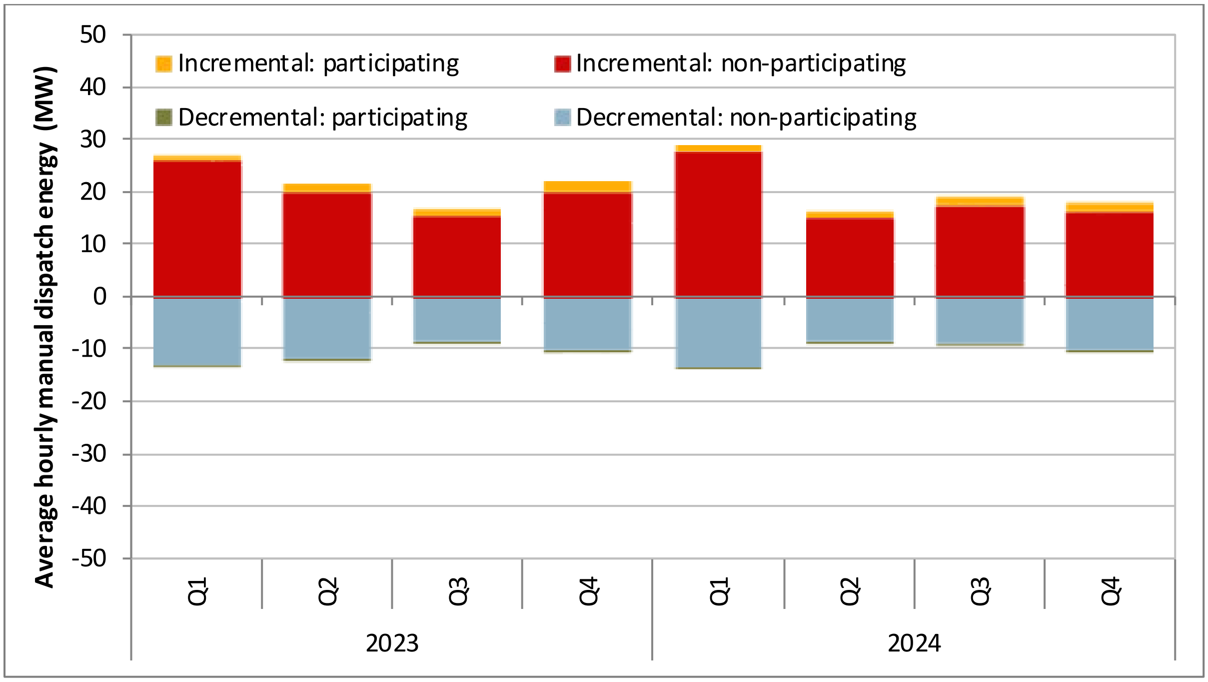


**Figure 9.18 WEIM manual dispatches – Pacific Northwest**



## 9.4 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.[187] 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 their operational characteristics.
- **Information systems and processes.** In some cases, problems occur in the complex combination of information systems and processes needed to operate the real-time market on a timely and accurate basis. In such cases, operators may need to block commitment or dispatch instructions generated by the real-time market model.

Figure 9.19 through Figure 9.23 show the frequency of blocked real-time commitment instructions for both the CAISO balancing area and other WEIM regions.

Within the CAISO area, blocked commitment instructions decreased by 33 percent from 2023 to 2024. Blocked shut-down instructions continued to be the most common reason for blocked instructions at about 52 percent in 2024. This was a decrease from about 82 percent of all blocked commitment instructions in 2023.

Within the California (non-CAISO) WEIM region, blocked commitment instructions decreased by 14 percent from 2023 to 2024. Blocked shut-down instructions continued to be the most common reason for blocked instructions at about 37 percent in 2024. This was a decrease from about 41 percent of all blocked commitment instructions in 2023.

Within the Desert Southwest region, blocked commitment instructions decreased by 33 percent from 2023 to 2024. Blocked transition instructions continued to be the most common reason for blocked instructions at about 56 percent in 2024. This is a decrease from 61 percent of all blocked commitment instructions in 2023.

Within the Intermountain West region, blocked commitment instructions decreased by 17 percent from 2023 to 2024. Blocked shut-down instructions continued to be the most common reason for blocked

[187] *Market performance metric catalog 2020*, California ISO. Blocked instruction information can be found in the later sections of the catalog reports: https://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=AF1E04BD-C7CE-4DCB-90D2-F2ED2EE8F6E9

instructions at about 46 percent in 2024. This is a decrease from 51 percent of all blocked commitment instructions in 2023.

Within the Pacific Northwest region, blocked commitment instructions decreased by 60 percent from 2023 to 2024. Blocked transition instructions became the most common reason for blocked instructions in 2024, as compared to blocked shut-down instructions being the most common in 2023. Blocked transition instructions made up 38 percent of all blocked commitment instructions in 2024, while blocked shut-down instructions made up 68 percent in 2023.

**Figure 9.19 Frequency of blocked real-time commitment instructions in CAISO**

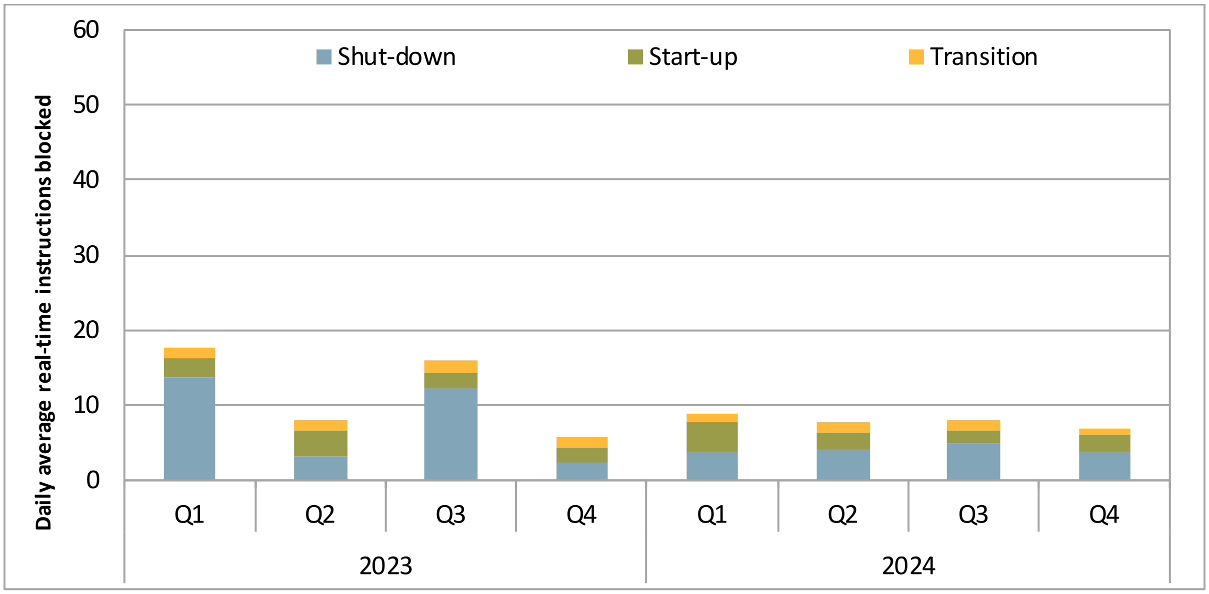



**Figure 9.20 Frequency of blocked real-time commitment instructions in California (non-CAISO) WEIM**

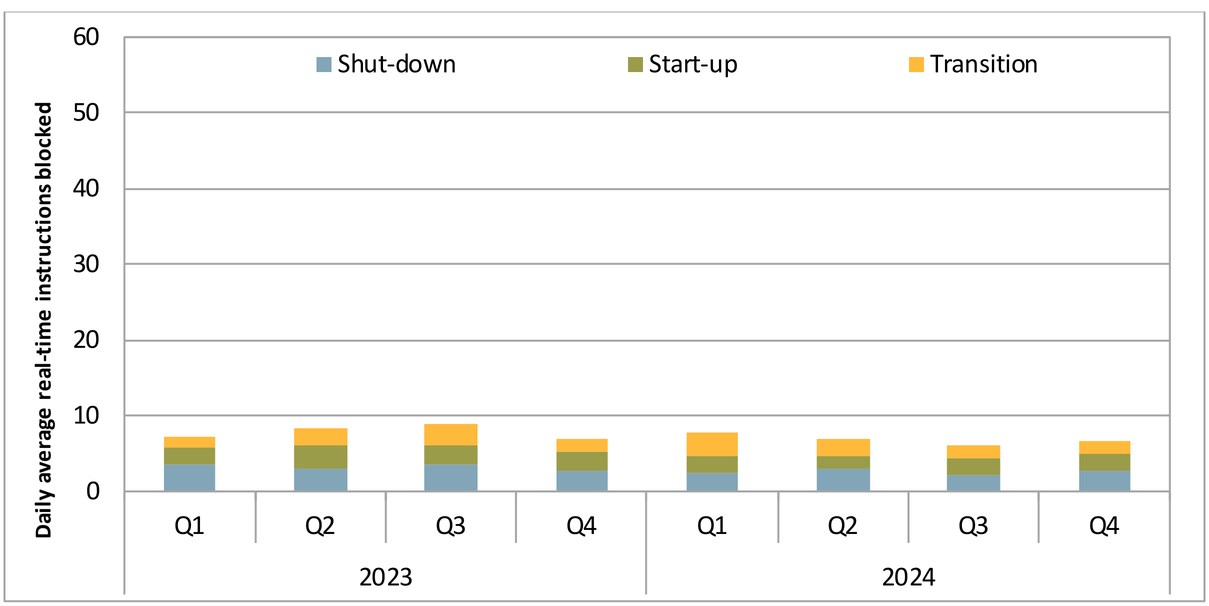


**Figure 9.21 Frequency of blocked real-time commitment instructions in Desert Southwest**

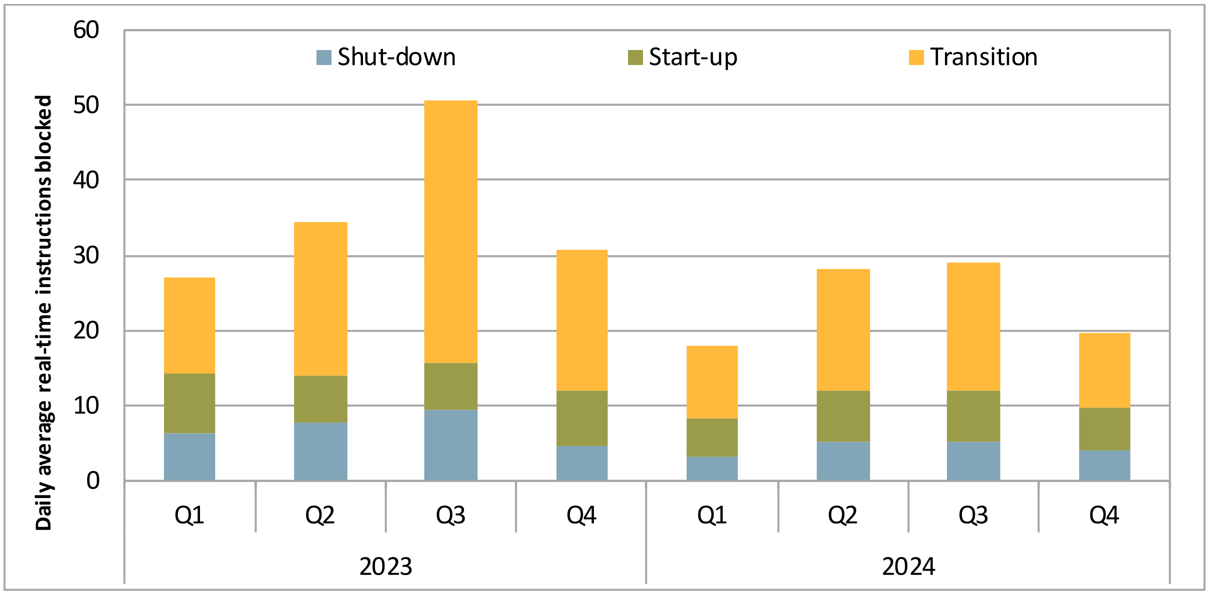



**Figure 9.22 Frequency of blocked real-time commitment instructions in the Intermountain West**

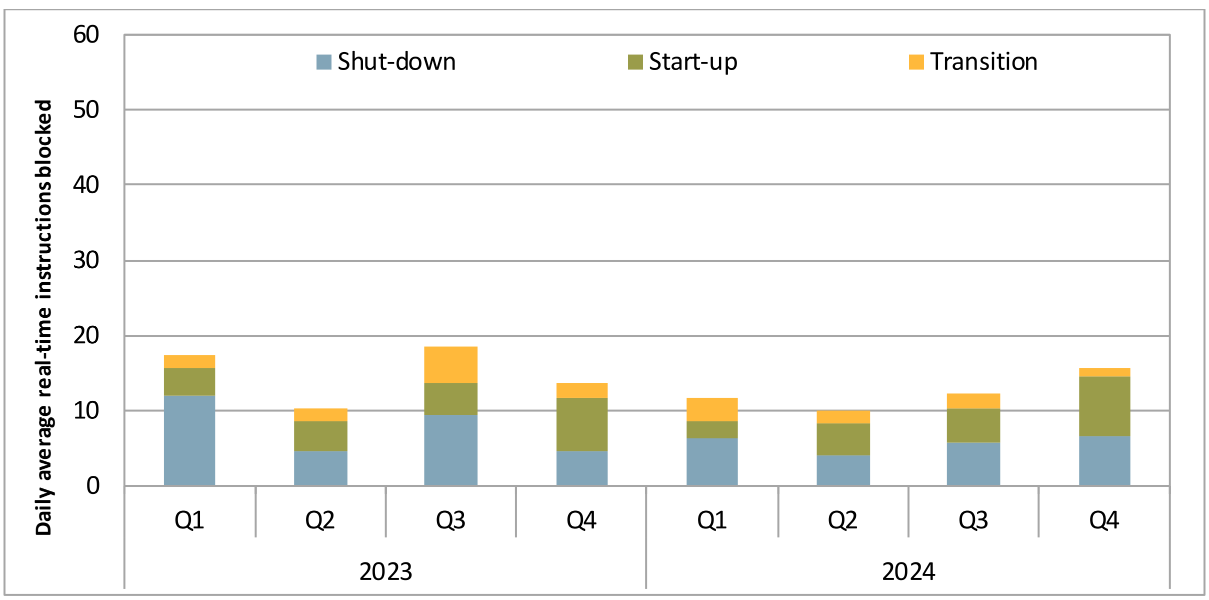
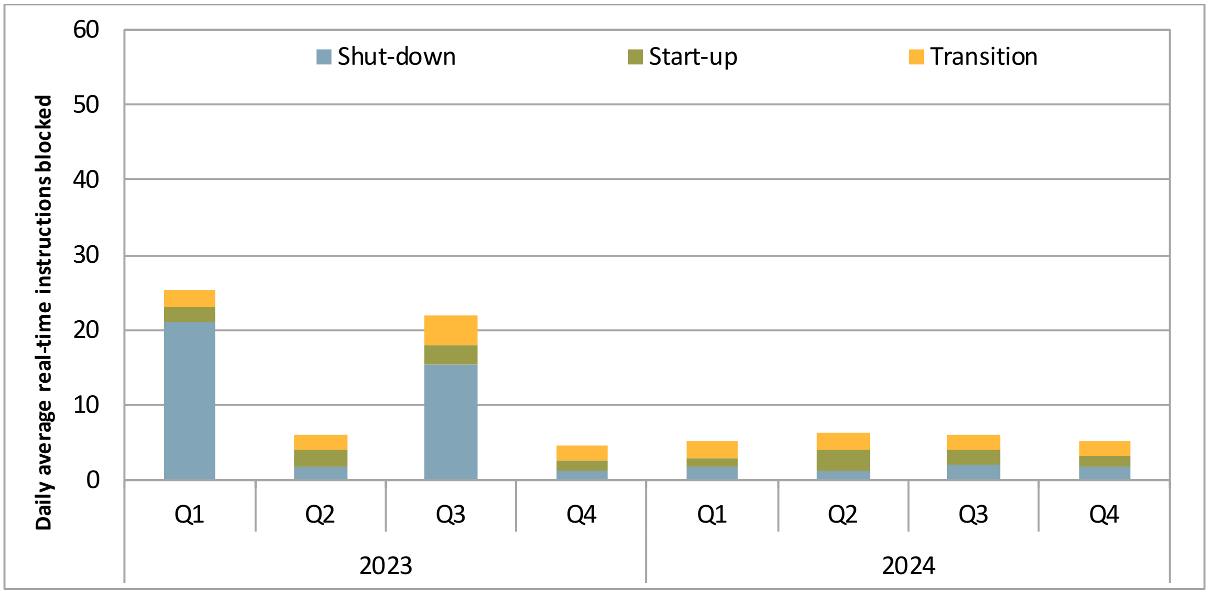


**Figure 9.23 Frequency of blocked real-time commitment instructions in the Pacific Northwest**




### 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 real-time dispatch instructions and prices from reaching the market.

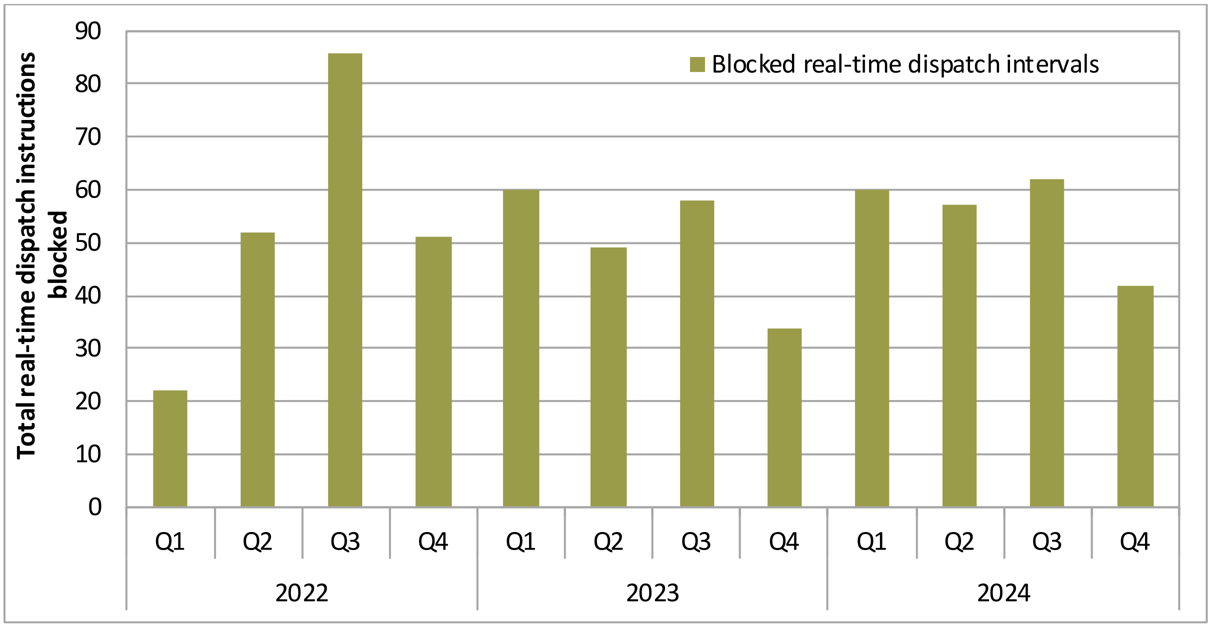
The California ISO began blocking dispatches in 2011, as both market participants and California ISO staff were concerned that inappropriate price signals were being sent to the market even when they were known to be problematic. These inappropriate dispatches would often have caused participants to 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.[188]

Figure 9.24 shows the frequency that operators blocked price results in the real-time dispatch from the first quarter of 2022 through 2024. The total number of blocked intervals in 2024 increased by about 10 percent from the previous year.

188 For example, if the load were to drop by 50 percent in one interval, the software can automatically block results.

**Figure 9.24 Frequency of blocked real-time dispatch intervals**



# 10 Flexible ramping product

This chapter analyzes flexible ramping product prices and procurement. Key findings in this chapter include:

- **For balancing areas that passed the resource sufficiency evaluation, upward flexible ramping product prices in the 15-minute market were greater than zero for one or more balancing areas in this system during 0.5 percent of intervals in 2024.** At the balancing area level, the Public Service Company of New Mexico (PNM) had prices for flexible capacity following a failure of the resource sufficiency evaluation during around 3 percent of intervals.
- **Battery and hydro resources made up 55 percent and 32 percent of upward flexible ramping product, respectively.** Wind and solar combined to provide 38 percent of downward flexible capacity, and batteries provided 31 percent of downward flexible capacity.
- **The CAISO balancing area continued to make up the majority of upward and downward flexible ramping product awards, at around 61 percent of each**. Balancing areas in the Pacific Northwest made up 27 percent of upward flexible capacity and 17 percent of downward flexible capacity.

### Background

The flexible ramping product is designed to enhance reliability and market performance by procuring upward and downward flexible ramping capacity in the real-time market, to help manage volatility and uncertainty surrounding net load forecasts.[189] 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. Flexible capacity is procured and priced at a nodal level to better ensure that sufficient transmission is available for the capacity to be utilized.

The flexible ramping product demand curves are implemented in the 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 in each direction that might materialize.[190] Therefore, it is sometimes referred to as the *flex ramp requirement* or *uncertainty requirement*.

The real-time market enforces an area-specific uncertainty requirement for balancing areas that fail the resource sufficiency evaluation. This requirement can only be met by flexible capacity within that area. Flexible capacity for the group of balancing areas that instead pass the resource sufficiency evaluation are pooled together to meet the uncertainty requirement for the rest of the system. Both the requirement for the pass-group and the requirement for balancing areas that fail the resource sufficiency evaluation are calculated using a method called *mosaic quantile regression*. This method applies regression techniques on historical data to produce a series of coefficients that define the

189 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.

190 Based on a 95 percent confidence interval.

relationship between forecast information (load, solar, or wind) and the extreme percentile of uncertainty that might materialize (95 percent confidence interval). These coefficients are then combined with current forecast information for each interval to determine the uncertainty requirement.

Flexible capacity awards are produced through two deployment scenarios that adjust the expected net load forecast in the following interval by the lower and upper ends of uncertainty that might materialize. The uncertainty requirement is distributed at a nodal level to load, solar, and wind resources based on allocation factors that reflect the estimated contribution of these resources to potential uncertainty. The result is more deliverable upward and downward flexible capacity awards that do not violate transmission or transfer constraints.

## 10.1 Flexible ramping product prices

Flexible ramping product prices are determined locationally at each node. This nodal price can be made up of multiple components.[191] The first component is the shadow price associated with meeting the flexible ramp requirement either for the group of balancing areas that pass the resource sufficiency evaluation or the individual balancing areas that fail the tests.

The nodal price also includes components to reflect any congestion based on the dispatch of flexible capacity in the deployment scenarios. This accounts for any congestion on WEIM transfer constraints between balancing areas as well as congestion on transmission constraints.[192] These components can create price differences across nodes in the WEIM based on the demand for flexibility in the system and the feasibility for flexible capacity at a node to meet that demand. For the transmission constraints, only base-case flow-based constraints and nomogram constraints were modeled in the deployment scenarios for most of 2024. Contingency flowgate constraints were activated on June 4, 2024, and de-activated on June 12 due to performance issues with the solution run-times.[193] Using the same constraints for both the real-time market and flexible ramping product deployment scenarios is important in order to prevent conditions in which procured flexible capacity is actually stranded behind transmission constraint congestion, and therefore not able to address materialized uncertainty.

The pass-group constraint maintains that the sum of flexible capacity in the group of balancing areas that pass the resource sufficiency evaluation equals the group's uncertainty requirement (minus any relaxation). The ability to relax the requirement is allowed by *slack variables*. This allows flexible capacity to be forgone when the cost of procuring flexible capacity is higher than the benefit it provides (or when flexible capacity is not available).

The slack variables are implemented for each balancing area.[194] The cost associated with the slack variable (cost of relaxing the requirement) is reflected by a demand curve. The demand curves are based

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[191] For details on the deployment scenario constraints and how the ISO derives flexible ramping prices from them, see *Business Requirements Specification – Flexible Ramp Product: Deliverability*, California ISO, August 19, 2022, pp 89-90: https://www.caiso.com/documents/businessrequirementsspecifications12-flexiblerampingproduct-deliverability.pdf

[192] Congestion on WEIM transfer constraints is reflected through the individual balancing area power balance constraint in the deployment scenarios. This constraint considers both flexible ramping awards and flexible ramping requirements in addition to WEIM supply, load, and WEIM transfers between the areas.

[193] *Market Performance and Planning Forum*, Q2, California ISO, June 27, 2024, slides 170-171: https://www.caiso.com/documents/presentation-market-performance-planning-forum-jun-27-2024.pdf

[194] Or for each surplus zone in the case of the CAISO balancing area (by TAC area) and BANC (by custom load aggregation point).

on each balancing area's expected cost of a power balance constraint violation for the level of flexible capacity forgone.[195] The more flexibility forgone, the greater the likelihood of a power balance constraint violation and therefore greater expected cost. For a balancing area in the pass-group, the slack variable (or end of the demand curve) is limited by its distributed share of the pass-group uncertainty requirement.

The shadow price on the constraint for procuring flexible capacity in the pass-group has frequently been zero. When the shadow price on this constraint is zero, this generally reflects that flexible capacity within the wider footprint of balancing areas that passed the resource sufficiency evaluation is readily available.[196] Here, the flexible capacity requirement for the group of balancing areas that passed the resource sufficiency evaluation can be met by resources with zero opportunity cost for providing that flexibility.

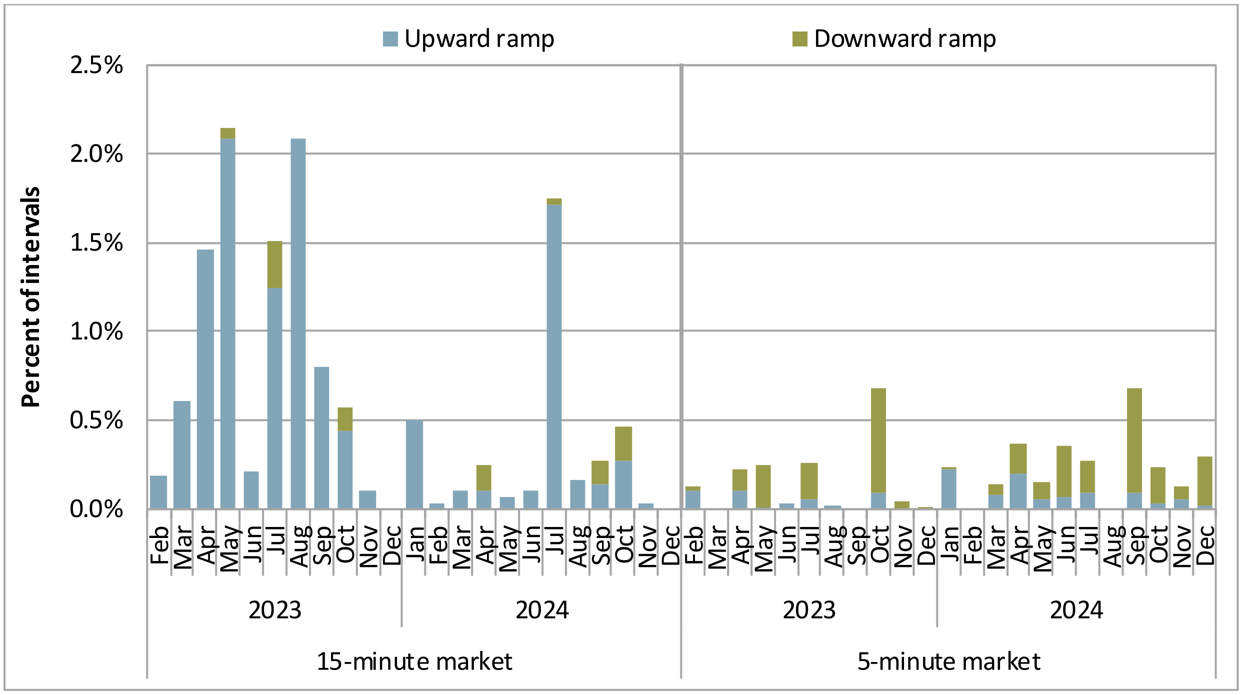
Figure 10.1 shows the percent of intervals in which the shadow price on the pass-group constraint was non-zero (constraint binding) for upward and downward flexible capacity. This reflects more widespread prices for flexible capacity within the group of balancing areas that passed the resource sufficiency evaluation, but does not account for any congestion that may affect the price of flexible capacity at the nodal level.[197] The pass-group constraint for procuring *upward* flexible capacity in the 15-minute market was binding in 1.7 percent of intervals during July. In all other months of 2024, the constraint for procuring flexible capacity within the pass-group was binding very infrequently.

195 For upward flexible capacity, the demand curves are capped at $247/MWh.

196 This pass-group constraint is intended to limit the sum of all flexible ramp capacity in the passing group. The limit is the group's total flexible ramp requirement. The formulation of the deployment scenario also includes an individual power balance constraint for each balancing area in the pass-group, which considers the balancing area's energy load and supply, flexible ramping product requirement and supply, and transfers of energy and flexible ramping product. Given this individual power balance constraint for each balancing area, the pass-group flexible ramping capacity constraint may be redundant. This complicates the interpretation of the meaning of the shadow price of this pass-group constraint, and other constraints, in the deployment scenario in some cases. The potential redundancy of the constraint may also result in abnormal flexible ramping prices in some situations.

197 This figure does not account for congestion on WEIM transfer constraints between the areas in the pass-group. It also does not account for any congestion on flow-based constraints.

**Figure 10.1 Frequency of flexible ramping product prices from pass-group constraint**




The price of flexible capacity for a node in a balancing area that passed the resource sufficiency evaluation can still be positive even when the shadow price on the constraint for procuring pass-group-level flexible capacity is zero (e.g., not binding). This can occur because of congestion on WEIM transfer constraints that might separate a balancing area from the rest of the system. Here, outside flexible capacity may not be feasible to meet the isolated balancing area's share of pass-group uncertainty and this requirement may be relaxed, resulting in a localized price for flexible capacity. Congestion on binding transmission constraints in the deployment scenario can also create a localized price for flexible capacity.

Figure 10.2 summarizes the frequency of flexible ramping product prices in either the wider pass-group or transfer-constrained balancing areas within the pass-group. The blue bars are identical to the 15-minute market upward ramping capacity information shown in Figure 10.1, summarizing the frequency in which the constraint for meeting pass-group flexible capacity requirements was binding. The figure adds the percent of intervals in which the constraint that reflects WEIM transfer congestion in the deployment scenario was binding for one or more balancing areas in the pass-group—*and the pass-group constraint was not also binding*. This reflects additional flexible ramping product prices within at least one balancing area. In most cases, these prices were within one isolated balancing area in the pass-group that was not able to meet its share of pass-group uncertainty. For balancing areas that passed the resource sufficiency evaluation, upward flexible ramping product prices in the 15-minute market were greater than zero for one or more balancing areas in this system during 0.5 percent of intervals in 2024, compared to 1.4 percent of intervals during 2023.[198] Localized flexible ramping product prices within the

[198] Average for 2023 is from February to December (since implementation of the enhancements).

pass-group that are entirely driven by congestion on transmission constraints are not reflected in this figure.

**Figure 10.2 Frequency of upward flexible ramping product prices from pass-group or WEIM transfer constraints (15-minute market)**

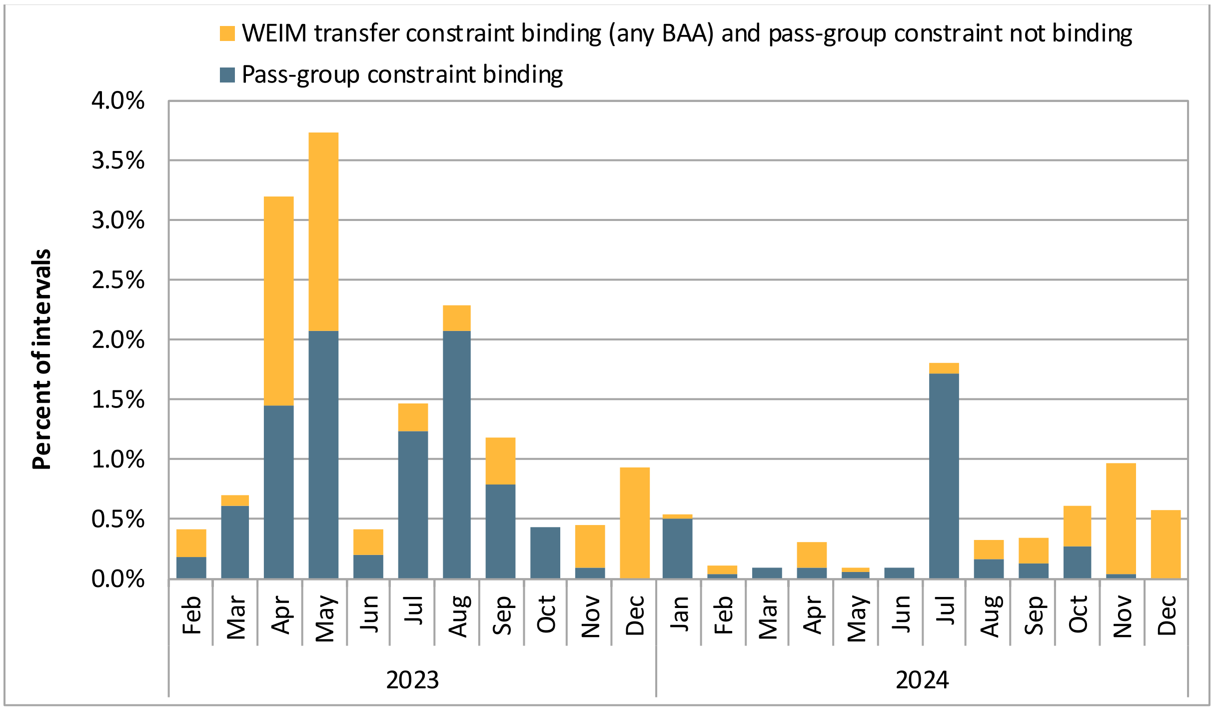


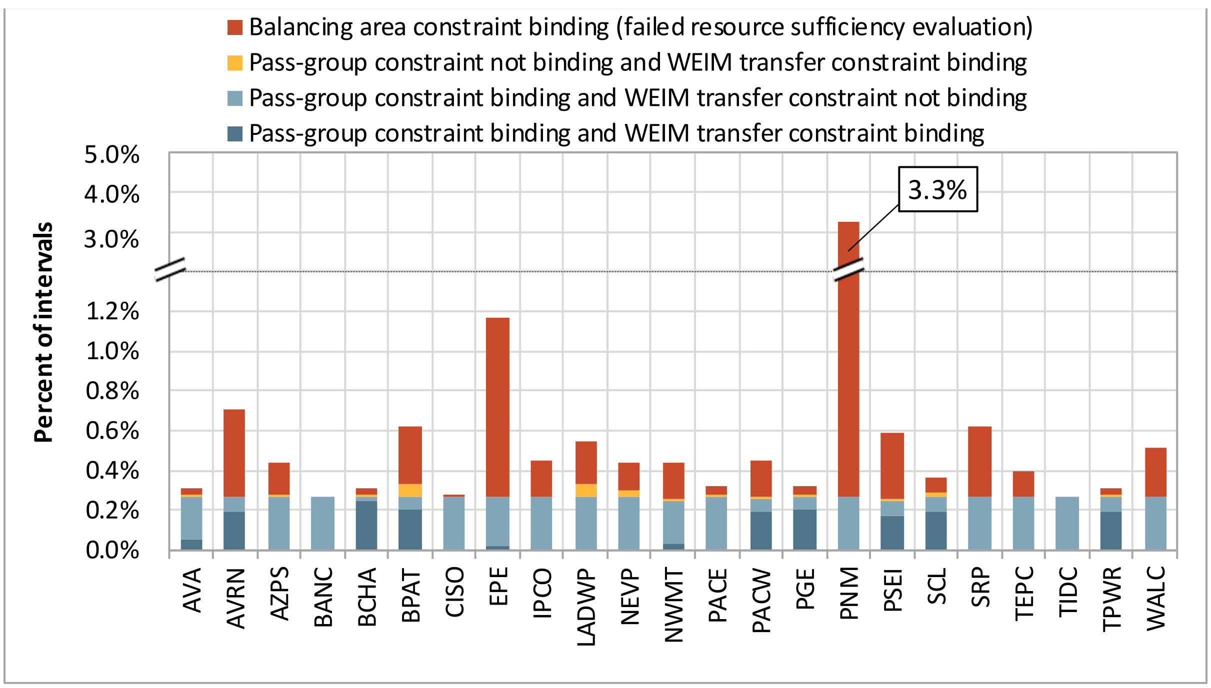

Figure 10.3 summarizes the frequency of upward flexible ramping product prices in the 15-minute market by balancing area during 2024. These results are shown separately by the constraint contributing to that price:

- **Pass-group constraint binding and WEIM transfer constraint not binding** indicates that the balancing area passed the resource sufficiency evaluation, and there is a price for upward flexible capacity within the wider pass-group.
- **Pass-group constraint binding and WEIM transfer constraint binding** indicates that the balancing area passed the resource sufficiency evaluation, and there is a price for upward flexible capacity within the wider pass-group; but because of WEIM transfer congestion out of the balancing area, there is typically no price for upward flexible capacity within the balancing area.
- **Pass-group constraint not binding and WEIM transfer constraint binding** indicates that the balancing area passed the resource sufficiency evaluation, and there is no price for upward flexible capacity within the wider pass-group; but because of WEIM transfer congestion into the balancing area, there is a price for upward flexible capacity within the balancing area.
- **Balancing area constraint binding (failed resource sufficiency evaluation)** indicates that the balancing area failed the resource sufficiency evaluation and there is a price for upward flexible capacity within the balancing area.

During 2024, the pass-group constraint was binding very infrequently for upward flexible capacity in the 15-minute market, during around 0.3 percent of intervals. In some of these intervals, balancing areas in the Pacific Northwest region had sufficient flexible capacity, but because of congestion on WEIM transfer constraints out of the balancing area in the deployment scenario, flex ramp prices here were typically zero.

Figure 10.3 also summarizes flexible capacity prices that can exist following a resource sufficiency evaluation failure (red bars). When a balancing area fails the resource sufficiency evaluation, the area will not have access to any diversity benefit of reduced uncertainty over a larger footprint and will instead need to meet its uncertainty needs from flexible capacity within its area only. The Public Service Company of New Mexico (PNM) had prices for flexible capacity following a failure of the resource sufficiency evaluation during around 3 percent of intervals. Most of these were associated with failure of the second run of the resource sufficiency evaluation at 55 minutes prior to the hour, which impacts the first interval of each hour.[199]

**Figure 10.3 Frequency of upward flexible ramping product prices by balancing area and constraint (15-minute market, 2024)**




199 There are three runs of the resource sufficiency evaluation, at 75 minutes (first run), 55 minutes (second run), and 40 minutes (final run) prior to each evaluation. The first and second runs are sometimes considered the advisory runs, with the final evaluation occurring at 40 minutes prior to the hour. For procuring and pricing flexible capacity in the first 15-minute market interval of each hour, the market uses the results from the second run of the resource sufficiency evaluation. This is based on the latest information available at the time of this market run.

## 10.2 Flexible ramping product procurement

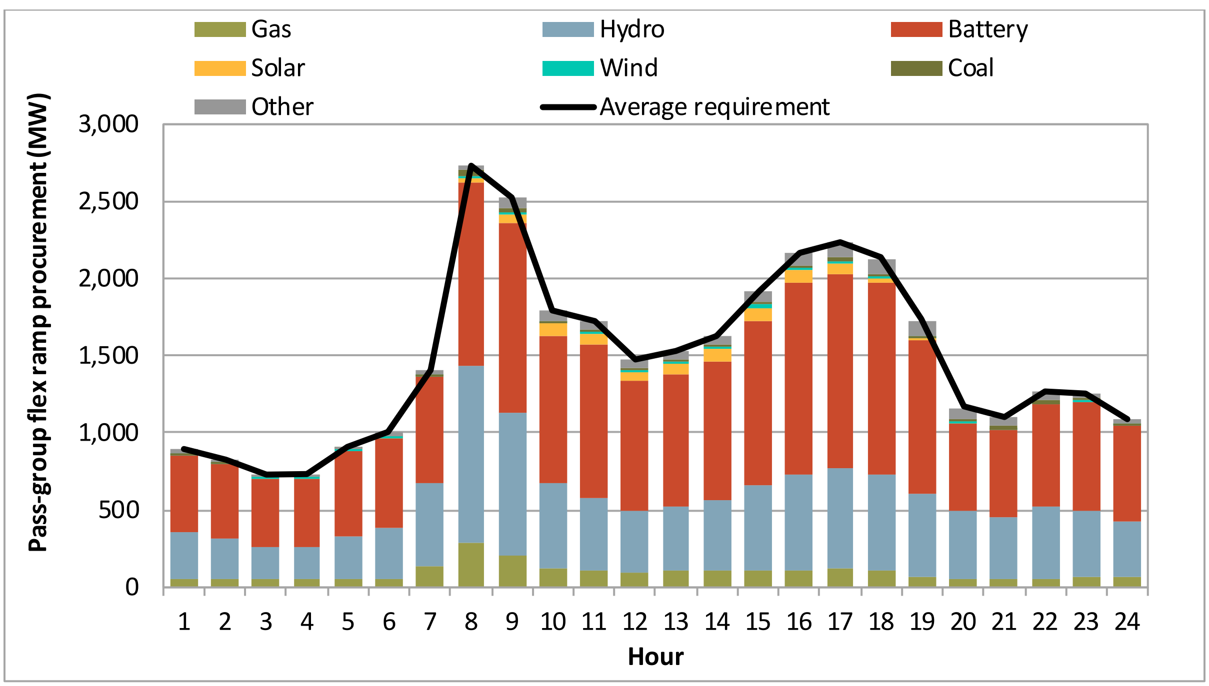
This section summarizes flexible capacity procured to meet the uncertainty needs of the group of WEIM balancing areas that pass the resource sufficiency evaluation. Figure 10.4 and Figure 10.5 show the average upward or downward flexible capacity that was procured from various fuel types.

During the year, battery resources continued contributing to much of the upward and downward flexible capacity. Battery resources made up around 55 percent of upward flexible capacity and 31 percent of downward flexible capacity. Hydro resources continued to supply a large portion of upward flexible capacity (32 percent). Wind and solar resources combined made up around 38 percent of downward flexible capacity.

Figure 10.6 and Figure 10.7 show average upward or downward flexible capacity that was procured in various regions.[200] These regions reflect a combination of general geographic location as well as common price-separated groupings that can exist when a balancing area is collectively import or export constrained, along with one or more other balancing areas relative to the greater WEIM system.

During the year, the California ISO balancing area continued to make up the majority of upward and downward flexible capacity awards, at around 61 percent for both directions. Balancing areas in the Pacific Northwest made up 27 percent of upward flexible capacity and 17 percent of downward flexible capacity.

**Figure 10.4 Average upward pass-group flexible ramp procurement by fuel type (15-minute market, 2024)**




[200] California (WEIM) includes BANC, LADWP, and Turlock Irrigation District. Desert Southwest includes Arizona Public Service, NV Energy, PNM, Salt River Project, El Paso Electric, Tucson Electric Power, and WAPA (DSW). Intermountain West includes Idaho Power, NorthWestern Energy, PacifiCorp East, and Avista. Pacific Northwest includes Avangrid, BPA, PacifiCorp West, Portland General Electric, Powerex, Puget Sound Energy, Seattle City Light, and Tacoma Power.

**Figure 10.5 Average downward pass-group flexible ramp procurement by fuel type (15-minute market, 2024)**

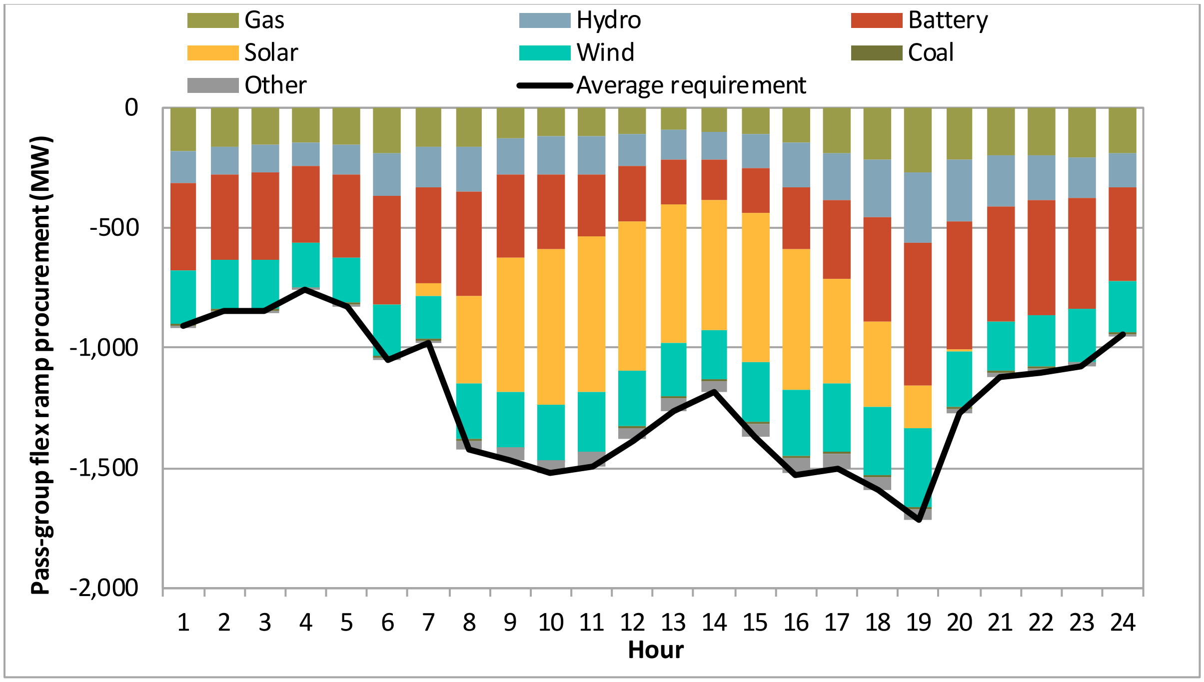



**Figure 10.6 Average upward pass-group flexible ramp procurement by region (15-minute market, 2024)**

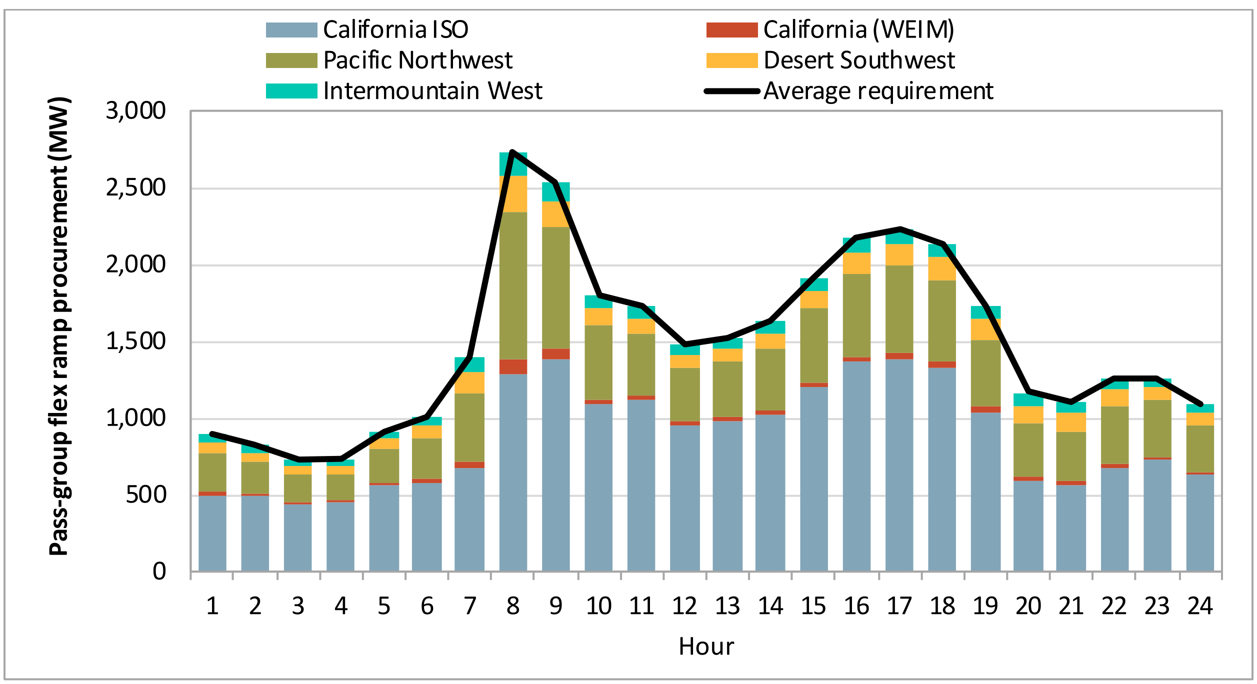
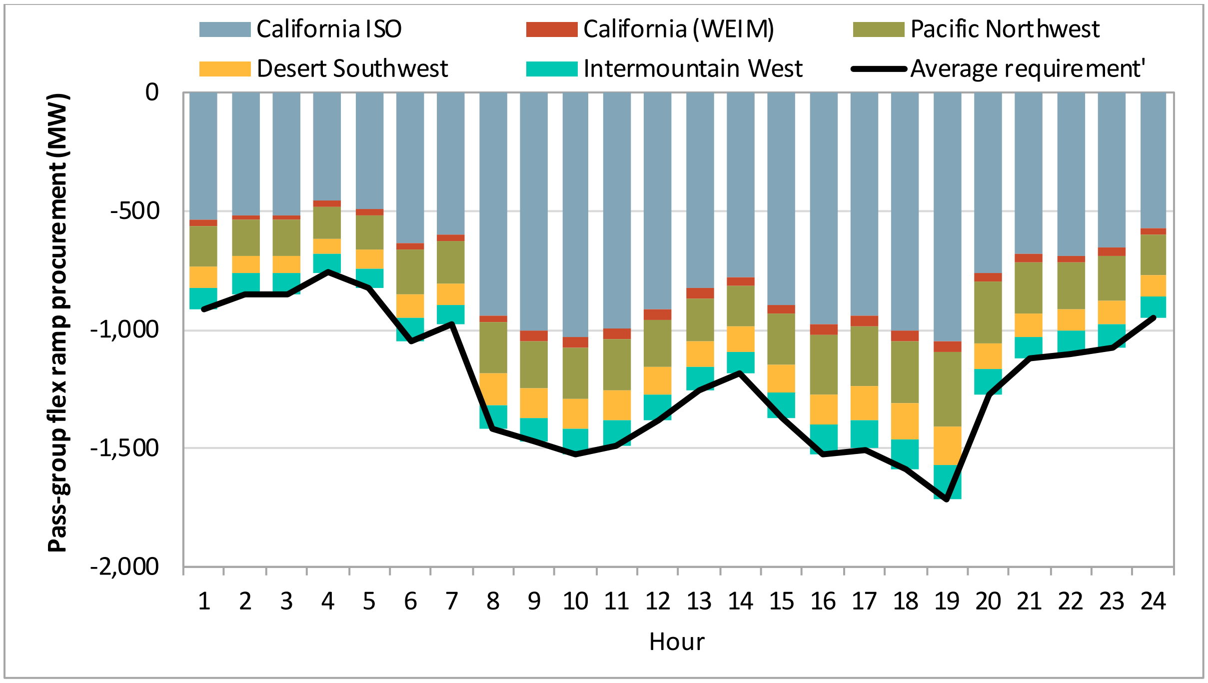


**Figure 10.7 Average downward pass-group flexible ramp procurement by region (15-minute market, 2024)**



# 11 Uncertainty

This section discusses uncertainty considered in different applications of the market, including the flexible ramping product (FRP), resource sufficiency evaluation (RSE), and the residual unit commitment (RUC) adjustment. Each of these market processes use a method called *mosaic quantile regression* to calculate and account for uncertainty that may materialize. This chapter reviews the results of the uncertainty calculation and assesses the regression method.

Key findings in this chapter include:

- **Mosaic quantile regression uncertainty requirements for the flexible ramping product and resource sufficiency evaluation were on average lower than requirements would have been using the previous histogram method.**
- **For the flexible ramping product, the rate at which the regression method uncertainty requirements covered realized uncertainty was below the target coverage rate of 97.5 percent for each direction and market.** The regression coefficients were statistically different from zero in only 30 percent of intervals.
- **For the resource sufficiency evaluation, the coverage rate varied between 87 percent and 90 percent across balancing areas**. The target coverage rate is 95 percent. 37 percent of regression coefficients were statistically significant.
- **The regression model's predicted uncertainty for the resource sufficiency evaluation covered the realized uncertainty much less for intervals at the end of the hour than for intervals at the beginning of the hour.** This is because the model is designed to predict uncertainty in forecasts that are produced only 45 to 55 minutes before real-time. However, the time horizon of the resource sufficiency evaluation includes four intervals, produced between 47.5 and 102.5 minutes before real-time.
- **The ISO set the uncertainty adjustment to the residual unit commitment load forecast to cover the 97.5$^{th}$ percentile of net load uncertainty on only 5 percent of days in the year.** The 75$^{th}$ percentile target was applied on 37 percent of days. The 50$^{th}$ percentile target was applied on 33 percent of days. No adjustment was applied on 26 percent of days. The imbalance reserve product for the extended day-ahead market is intended to procure capacity to address this same uncertainty, but the requirement will be set to cover the 97.5$^{th}$ percentile of uncertainty in all hours of all days. The low number of hours in which the ISO used the 97.5$^{th}$ percentile target in the residual unit commitment indicates that the imbalance reserve product demand curve may be much too high during most hours.

### Background defining the uncertainty analyzed in this chapter

The California ISO introduced a regression method to calculate uncertainty on February 1, 2023.[201] This methodology is a forecasting approach to manage uncertainty. Uncertainty in the market is defined as a forecasting error. For example, the 15-minute and 5-minute markets utilize available forecasts for load,

[201] Before the February 2023 changes, uncertainty was calculated by selecting the 2.5$^{th}$ and 97.5$^{th}$ percentile of observations from a distribution of historical net load errors. This is known as the *histogram method*. For the 15-minute market product and the resource sufficiency evaluation, the historical net load error observations in the distribution are defined as the difference between binding 5-minute market net load forecasts and corresponding advisory 15-minute market net load forecasts.

wind, and solar at the time when the market runs. If the target is hour-ending 18, both markets run for the same target hour, but calculations are made at different times. The 15-minute market runs earlier than the 5-minute markets, leading to differences in forecast data due to updates in weather and other variables in the interim period. This difference in forecast data is the uncertainty.

Uncertainty in the market can take many forms. When discussing uncertainty in this section, we are specifically referring to net load uncertainty. This is the net load forecasting error between different market runs for the same ultimate interval of power flow. This section focuses on uncertainty across two different markets. One is the forecasting error from the day-ahead market to the 15-minute market, which is the uncertainty considered in the residual unit commitment adjustment. The other is the forecast difference from the 15-minute market to the 5-minute market that is used for the flexible ramping product and the resource sufficiency evaluation.

Uncertainty for an upcoming interval cannot be known in advance. For example, for the 15-minute market flexible ramping product, uncertainty is defined as the difference between the first advisory 15-minute forecast and the binding 5-minute forecasts.[202] At the start time of the advisory 15-minute market run, the 15-minute market uses a forecast of what net load is expected to be. However, at that time, the net load that the corresponding 5-minute markets will use when those market runs start 45-55 minutes later is not known. The uncertainty calculation uses historical data to forecast what the uncertainty might be. This allows for better preparation and adjustment in the market operations.

### Background on calculating net load uncertainty

In calculating uncertainty, the ISO has employed two different methods. The first method involved estimating future uncertainty by analyzing the historical distribution of uncertainty. By examining past data, the method identified lower and upper extremes of uncertainty and used these to predict future uncertainty. This approach assumes that future uncertainty will fall within the historical range, with uncertainty fluctuating between the observed high and low extremes. This histogram method was used in the market until February 1, 2023.

On February 1, 2023, the ISO began using a second method to calculate uncertainty. This was the mosaic quantile regression method. The regression approach adds another layer to the uncertainty calculation by incorporating the mosaic variable—a predictor constructed by the ISO. Unlike the first method that only considers historical uncertainty, this approach looks for patterns between uncertainty and the mosaic variable, and uses it for forecasting. For example, if uncertainty was high when the mosaic variable was high in the past, it suggests that high uncertainty might occur in future periods when the mosaic variable is also high. The regression method quantifies the patterns observed in the past, providing exact numbers rather than just indicating high or low. Once the pattern is known, it can be applied to future scenarios. The variable is derived from a combination of load, solar, and wind forecasts.[203]

202 In comparing the 15-minute observation to the three corresponding 5-minute observations for the 15-minute market product, the minimum and maximum net load errors were each used as a separate observation in the distribution. The 5-minute market product instead used the difference between a binding 5-minute market net load forecast and advisory 5-minute market net load forecast.

203 For a more detailed description of the mosaic quantile regression method, see the DMM special report, *Review of mosaic quantile regression for estimating net load uncertainty*, Department of Market Monitoring, November 20, 2023: https://www.caiso.com/documents/review-of-the-mosaic-quantile-regression-nov-20-2023.pdf

For a regression methodology to produce better forecasting results than a histogram methodology, there must be a strong pattern between the uncertainty and the mosaic variable. Also, this pattern should persist in the future period being forecasted. If the pattern does not persist over time, it may suggest the pattern is driven by noise in the past data, providing incorrect information for forecasting uncertainty. This could result in less accurate and potentially erroneous forecasts. If the pattern is weak or nonexistent, the regression method essentially reverts to the histogram method, which relies solely on past uncertainty distributions without the added insight from the mosaic variable.[204]

Patterns in regression are essentially a formula. This formula shows the historical level of uncertainty for any given mosaic variable value. In simple terms, regression answers the question: if the mosaic variable was, for example, 1,000 MW, what was the level of uncertainty in the past? Plugging mosaic variable values for upcoming intervals into the historical pattern can forecast uncertainty.

Quantile regression focuses on specific parts of the data pattern. Instead of analyzing the overall pattern between uncertainty and the mosaic variable, it targets specific percentiles. For example, if the target percentile is 97.5, the regression mainly focuses on the top 2.5$^{th}$ percent of uncertainty. It puts the most weight on finding patterns between this extreme uncertainty and the mosaic variable.

The ISO uses quantile regression with target percentiles of 97.5 and 2.5. Therefore, the regression method aims to find patterns at the extreme ends of historical data samples. The regression method produces a forecast as its output. This forecast is interpreted as a prediction range. The realized net load uncertainty between a current and upcoming market run is expected to fall within the upper and lower bounds of the prediction range with 95 percent probability.

### Background on assessing performance of the mosaic quantile regression forecast

One important criterion for assessing the performance of the quantile regression forecast method is its *accuracy*. A useful metric for evaluating the accuracy of the forecast is called the coverage rate. The coverage rate indicates the percentage of realized uncertainty that falls within the forecasted prediction range described above. For the flexible ramping product and resource sufficiency evaluation, the target coverage rate is 95 percent. This means that for an accurate regression model, we would expect that 95 percent of the realized uncertainty will be within the model's predicted range.

Another important criterion for assessing the regression model is *efficiency*. An efficient model would produce a narrow prediction range while maintaining this 95 percent coverage rate. The efficiency is often measured by the average upward and downward requirement. These requirements represent the prediction range for uncertainty, with the upward requirement corresponding to the 97.5$^{th}$ percentile and the downward requirement corresponding to the 2.5$^{th}$ percentile of uncertainty.

Accuracy and efficiency are critical metrics for evaluating the performance of a forecasting model, but assessing them can be more complex. Accuracy has an absolute benchmark, such as achieving 95 percent coverage. In contrast, efficiency lacks a clear standard. A model might achieve 95 percent accuracy, but this could come at the expense of very high upward and very low downward requirements. Efficiency can be meaningful when compared to other models. Since the current forecast method relies on a single regression model, evaluating the performance can be less insightful.

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204 For further information on the weak pattern and its implication, details can be found in the DMM special report, *Review of mosaic quantile regression for estimating net load uncertainty*, November 20, 2023: https://www.caiso.com/documents/review-of-the-mosaic-quantile-regression-nov-20-2023.pdf

In addition to accuracy and efficiency, this section evaluates the model's validity by examining the statistical significance of its coefficients. These coefficients reflect patterns in historical data, and their statistical significance confirms whether these patterns are strong enough for forecasting. For example, in load forecasting, if temperature and load have a significant historical relationship, this can be useful for future prediction, assuming the pattern holds. However, if the relationship is non-significant, the forecast is likely based on unreliable patterns, making the prediction questionable.

In uncertainty forecasting, the relationships between variables are not always as intuitive as those between load and temperature, making actual testing crucial. Statistical significance alone does not guarantee good forecasts, especially when historical and future conditions are different. However, it can serve as a reliable indicator for forecasting, particularly when only a single predictor is used to estimate uncertainty.

Statistical testing determines whether the historical patterns represented by regression coefficients are actually different from zero. Simply comparing the size of the coefficient to zero is not always helpful, as coefficients can be very small yet still meaningfully different from zero. This section uses tests on these coefficients to determine their significance. If the coefficient is significantly different from zero, it indicates a pattern in the historical data. While this does not guarantee that the pattern will be useful for forecasting, it at least suggests some relationship exists. However, if the coefficient is not significantly different from zero, it may imply either no pattern at all or that the quantified pattern is unreliable or irrelevant, potentially leading to erroneous forecasts.

If in a larger percentage of intervals, the regression method produces statistically significant coefficients, the regression forecast results should have greater divergence from the histogram method results. This is because the regression incorporates the histogram method. When the pattern detected by regression is not statistically significant, one possibility is that the coefficient may be zero, causing the regression results to resemble the histogram.[205] Another possibility is that the coefficient is non-zero but unreliable, potentially leading to erroneous forecasts. In practice, mosaic regression often encounters a combination of these two issues.

In the following subsections, this report presents performance metrics for the mosaic quantile regression performed for the flexible ramping product, resource sufficiency evaluation, and the residual unit commitment market adjustment. Measurements of the uncertainty requirements and coverage in this section are based on actual market results. The statistical significance metrics are based on DMM's replication of the ISO's mosaic quantile regression method.[206]

## 11.1 Flexible ramping product uncertainty

The flexible ramping product procures flexible capacity to cover uncertainty that may materialize in the real-time market. By design, the *uncertainty requirement* captures the extreme ends of net load uncertainty and it can be optimally relaxed based on the trade-off between the cost of procuring additional flexible ramping capacity and the expected cost of a power balance relaxation. For the 15-minute market flexible ramping product, uncertainty is defined as the difference between the advisory

205 For further information about the statistical significance test and its implementation, details can be found in the DMM special report, *Review of mosaic quantile regression for estimating net load uncertainty*, November 20, 2023, p 5, section 3: https://www.caiso.com/documents/review-of-the-mosaic-quantile-regression-nov-20-2023.pdf

206 This choice is made because there are no statistical significance tests available based on the ISO's estimations.

15-minute market net load forecast and the binding 5-minute market forecasts. For the 5-minute market flexible ramping product, uncertainty is defined as the difference between the advisory 5-minute market forecast and the binding 5-minute market forecast.

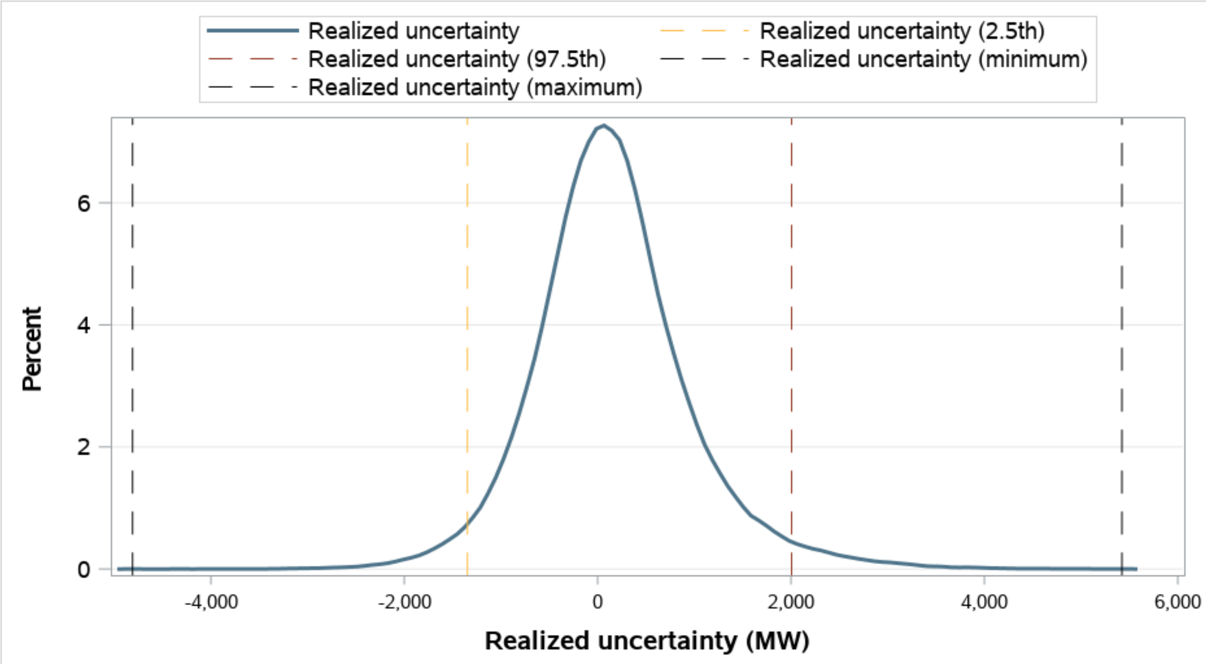
The flexible ramping product uses an area-specific uncertainty requirement for balancing areas that fail the resource sufficiency evaluation. This requirement can only be met by flexible capacity within that area. Flexible capacity for instead the group of balancing areas that pass the resource sufficiency evaluation (known as the pass-group) are pooled together to meet the uncertainty requirement for the rest of the system.

Figure 11.1 illustrates the distribution of realized uncertainty in the flexible ramping product (FRP) for the group of balancing areas that passed the resource sufficiency evaluation (RSE) for 2024. The distribution is depicted as a blue line, with the extreme percentiles highlighted: the lowest 2.5$^{th}$ percentile in yellow, the 97.5$^{th}$ percentile in red, and the black dashed lines indicating the minimum and maximum values.

The range from the upper 2.5 percent of uncertainty to its maximum spans from 2,000 MW to over 5,400 MW, reflecting a long tail distribution. These long tails in the distribution could indicate that the uncertainty is influenced by rare, extreme events rather than typical fluctuations. The distribution was skewed upward, resulting in a longer tail on the upper end. This may indicate the influence of systematic patterns, rather than purely random variations. These factors may provide valuable information for forecasting uncertainty.

The extreme long tail in the distribution of realized uncertainty is potentially influenced by several factors. One key factor is the variability in the number of balancing authority areas within the RSE pass-group; the composition is not always constant. Sometimes all balancing areas in the WEIM pass the RSE, while other times only a subset does. This variability affects the scale of aggregated uncertainty for the pass-groups. Additionally, extreme weather events and rapid changes in demand further contribute to this long tail.

**Figure 11.1 Distribution of realized uncertainty in FRP (pass-group, 2024)**




## 11.1.1 Results of flexible ramping product uncertainty calculation

Figure 11.2 compares 15-minute market uncertainty for the group of balancing areas that passed the resource sufficiency evaluation (RSE), both with the histogram method (pulled from the 2.5th and 97.5th percentile of observations in the hour from the historical 180-day period) and with the mosaic quantile regression method. The green and blue lines show the average upward and downward uncertainty from each method while the areas around the lines show the minimum and maximum amount over the year. The dashed red and yellow lines show the average histogram and seasonal thresholds, respectively, during the period.[207]

Figure 11.3 shows the same information for 5-minute market uncertainty, which reflects the difference between the binding and advisory net load forecasts in the 5-minute market.

Overall, pass-group uncertainty calculated from the quantile regression approach was typically lower or comparable to uncertainty calculated with the histogram approach. Of note, between 16:00 and 18:00, the regression-based uncertainty was much lower on average, in comparison to the histogram-based uncertainty. However, results of the regression-based approach vary more widely, including periods with much lower (or zero) uncertainty.

[207] Two ceiling thresholds are applied to help prevent extreme outlier results from impacting the final uncertainty.

**Figure 11.2 15-minute market pass-group uncertainty requirements (2024)**

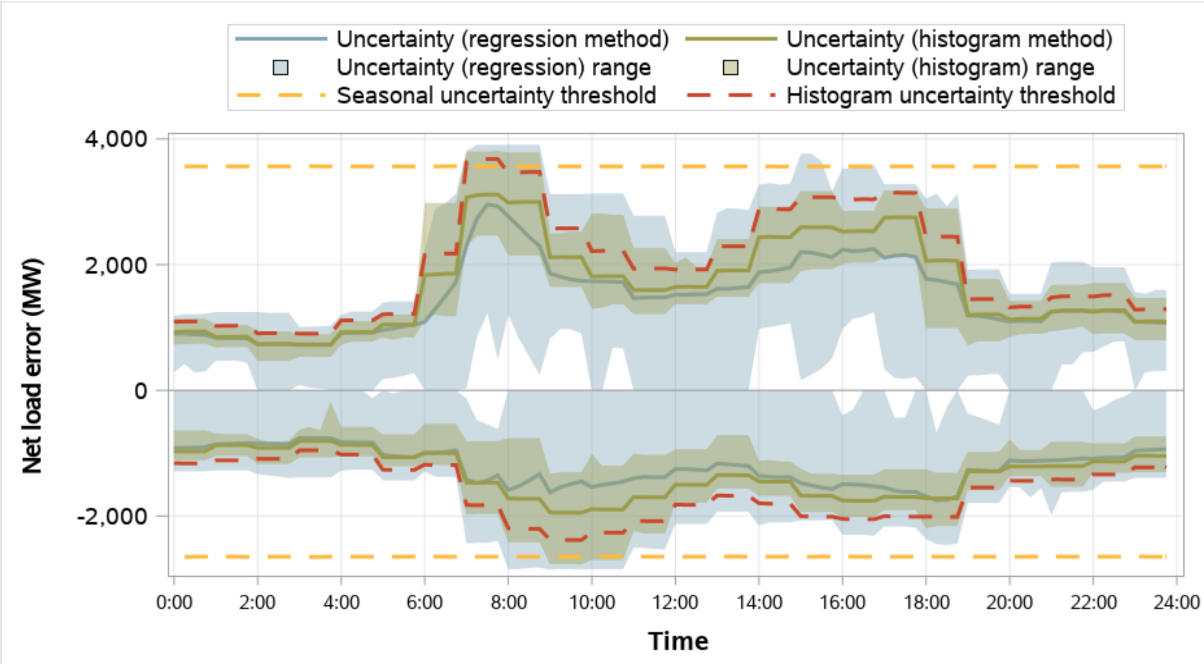



**Figure 11.3 5-minute market pass-group uncertainty requirements (2024)**

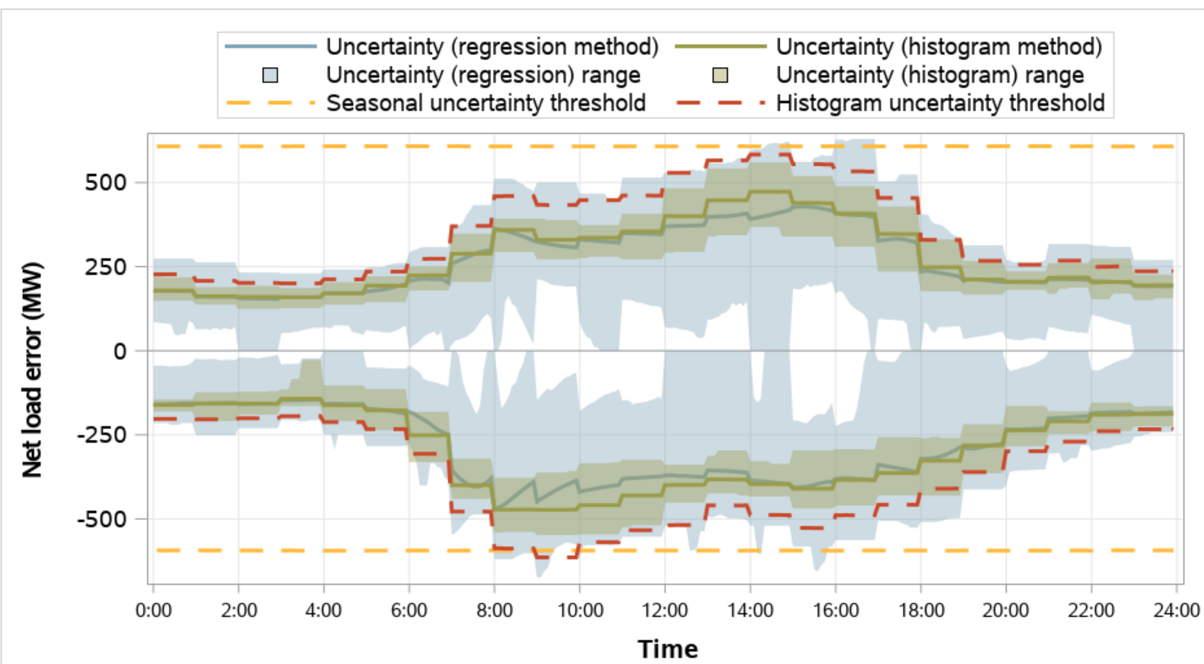


Table 11.1 summarizes the average uncertainty requirement and coverage for the group of balancing areas that passed the resource sufficiency evaluation, using both the histogram and mosaic quantile regression methods. The *requirement* shows the average target for procuring flexible capacity within the pass-group (based on a 95 percent confidence interval). The *coverage* shows how often the realized uncertainty fell within the requirement for the same interval.[208]

In flexible ramping product (FRP), due to the different composition of the upward and downward RSE pass-group, each direction is evaluated with a target coverage of 97.5 percent.[209] In the 15-minute market, uncertainty forecasted by mosaic regression generally had slightly lower coverage and requirements, whereas the histogram method showed slightly higher coverage and requirements. The rate at which the regression method uncertainty requirements covered realized uncertainty was below the target coverage for each direction and market.

**Table 11.1 Average pass-group uncertainty requirements (2024)**

| | | Requirement | | | Coverage | | |
|---|---|---|---|---|---|---|---|
| **Market** | **Direction** | **Histogram** | **Mosaic** | ***Difference*** | **Histogram** | **Mosaic** | ***Difference*** |
| 15-minute market | Up | 1,688 | 1,500 | -187 | 97.2% | 96.4% | -0.8% |
| | Down | 1,342 | 1,216 | -127 | 97.4% | 96.3% | -1.1% |
| 5-minute market | Up | 280 | 268 | -12 | 97.3% | 97.0% | -0.2% |
| | Down | 300 | 284 | -16 | 97.4% | 96.9% | -0.4% |

Table 11.2 presents the percentage of statistically significant coefficients across various quantile regressions for the 15-minute market calculation of pass-group uncertainty. The results are based on DMM's replication.

The mosaic regression is primarily designed to forecast net load uncertainty, with the mosaic variable serving as the main predictor in this regression. The three additional quantile regressions—load, solar, and wind—function as intermediate regressions used to construct the mosaic variable.[210]

The percentages in the table indicate the proportion of estimated coefficients that were statistically different from zero among all regression estimation in this year. Each regression includes two primary

208 Realized 15-minute market uncertainty is measured as the difference between binding 5-minute market net load forecasts and the advisory 15-minute market net load forecast. Realized 5-minute market net load error is measured as the difference between the binding 5-minute market net load forecast and the advisory 5-minute market net load forecast.

209 The composition of the RSE pass-group differs for each direction. For instance, at a given interval, the RSE pass-group for upward uncertainty might include all 23 BAAs, while for the same interval the pass-group for downward uncertainty could include only 20. These disparities mean that the actual uncertainty for the pass-group are different in each direction. Since the regression employs the 97.5$^{th}$ percentile for upward uncertainty and the 2.5$^{th}$ percentile for downward uncertainty, the target coverage for each direction is set at 97.5 percent.

210 For a more detailed description of how the three other quantile regressions are used to construct the mosaic variable, see the DMM special report, *Review of mosaic quantile regression for estimating net load uncertainty*, Department of Market Monitoring, November 20, 2023, pp 6-10: https://www.caiso.com/documents/review-of-the-mosaic-quantile-regression-nov-20-2023.pdf

coefficients: a quadratic term and a linear term.[211] The percentages represent the proportion of regression where at least one of these coefficients was statistically significant. The significance level was set at 10 percent.

**Table 11.2 Test for statistical significance of mosaic quantile regression in FRP (2024)**

| Regression type | All hours | Peak hours(1) |
|---|---|---|
| Mosaic | 30% | 34% |
| Load | 22% | 32% |
| Solar | 63% | 73% |
| Wind | 48% | 54% |

(1): Peak hours include hour-ending (HE) from 7 to 9 and HE from 17 to 21.

The coefficient for the mosaic variable was statistically significant during only 30 percent of intervals. This means that in 70 percent of cases, the mosaic variable does not show a strong pattern with historical uncertainty.[212] Whether the mosaic variable is high or low, the uncertainty does not consistently respond with similarly high or low levels of uncertainty. Consequently, when looking at future data, even if the mosaic variable is high, it is unclear whether the uncertainty will be high or low.

Low statistical significance suggests that the regression often fails to identify a meaningful relationship. This failure could stem from either no relationship or inconsistent relationship. While it is difficult to quantify the proportion of cases due to no relationship versus inconsistency, mathematically, if no relationship exists, the quantile regression outcomes will converge to the histogram results.[213] Intuitively, this occurs because a no relationship implies that the mosaic variable provides no additional information for forecasting. As a result, the forecast relies solely on the historical net load uncertainty data, which is the histogram method.

In Figure 11.2 and Table 11.1, the average hourly requirement and performance metrics show a high degree of similarity between the histogram and mosaic regression method. This resemblance can be explained by the low percentage of statistically significant coefficients.

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211 The mosaic quantile regression includes three coefficients: an intercept, a quadratic term for the mosaic variable, and a linear term for the mosaic variable. The percentage of significant coefficients is determined by whether either the quadratic term or the linear term is statistically different from zero at the 0.1 significance level. This significance is calculated for both upward and downward uncertainty estimations, and then averaged.

212 Quantile regression assesses patterns that may exist at a specific percentile of the sample. For the flexible ramping product, the 97.5$^{th}$ and 2.5$^{th}$ percentiles reflect the extreme upper or lower 2.5 percent of uncertainty relative to the mosaic variable. If the pattern is strong, it indicates a clear relationship at these extremes. Conversely, a weak pattern suggests that the relationship is less pronounced or not robust.

213 For a detailed discussion on the theoretical background and empirical findings regarding the resemblance between the mosaic quantile regression and the histogram method, see the DMM special report, *Review of mosaic quantile regression for estimating net load uncertainty*, Department of Market Monitoring, November 20, 2023, p 5 and pp 31-33: https://www.caiso.com/documents/review-of-the-mosaic-quantile-regression-nov-20-2023.pdf

### 11.1.2 Threshold for capping flexible ramping product uncertainty

Flexible ramping product and resource sufficiency evaluation uncertainty calculated from the quantile regressions is capped by the lesser of two ceiling thresholds. The thresholds are designed to help prevent extreme outlier results from impacting the final uncertainty. The *histogram* threshold is pulled for each hour from the 1st and 99th percentile of net load error observations from a 180-day period.[214] The seasonal threshold is updated each quarter and is calculated based on the 1st and 99th percentile using observations over the previous 90 days. For the upward seasonal threshold, the 99th percentile is calculated separately for each of the 24 hours in a day. The maximum value out of these 24 hours is used as the threshold for all hours.[215]

During the year, the ceiling thresholds capped *upward* uncertainty for the group of balancing areas that passed the resource sufficiency evaluation in around 13 percent of intervals in the 15-minute market and 8 percent of intervals in the 5-minute market. *Downward uncertainty* was capped by the ceiling thresholds in around 9 percent of intervals in the 15-minute market and 7 percent of intervals in the 5-minute market. The histogram threshold capped calculated uncertainty much more frequently compared to the seasonal threshold.

The ceiling threshold implies that the requirement is set at the highest 1 percent of uncertainty over the past 90 or 180 days. The expected frequency of reaching this threshold is around 1 percent of the time. However, the observed frequency of over 10 percent in the 15-minute market significantly exceeded this expectation.

A floor threshold is also in place that sets the floor for uncertainty at 0.1 MW in both directions. The upward and downward uncertainty is therefore set near zero when the uncertainty calculated from the quantile regression would be negative. During the year, uncertainty calculated for the group of balancing areas that passed the resource sufficiency evaluation was set near zero by this threshold in less than 1 percent of intervals in both directions and in both the 15-minute and 5-minute markets.

## 11.2 Resource sufficiency evaluation uncertainty

Uncertainty is included as an additional requirement in the flexible ramp sufficiency test (flexibility test) as part of the resource sufficiency evaluation (RSE). Here, balancing areas must show enough upward and downward ramping flexibility over an hour to meet both the forecasted change in demand *as well as uncertainty*.[216] This additional requirement in the flexibility test is also based on a 95 percent confidence interval for uncertainty that might materialize. This section analyzes the performance of the mosaic quantile regression in the resource sufficiency evaluation.

Figure 11.4 shows the distribution of realized 15-minute uncertainty in the RSE for each balancing authority area (BAA) for 2024. Here, realized uncertainty is defined as the net load forecast difference between the forecasts used in the resource sufficiency evaluation and those in the binding 5-minute

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[214] As of August 14, 2024, the histogram threshold uses symmetric sampling, from historical observations from the previous 90 days as well as the next 90 days minus one year.

[215] For the downward seasonal threshold, the 1st percentile is calculated separately for each of the 24 hours in a day. The minimum value out of these 24 is used as the threshold for all hours.

[216] The flexibility test also includes a discount to account for *diversity benefit*. System-level flexible ramping needs are smaller than the sum of the needs of individual balancing areas because of reduced uncertainty across a larger footprint. Balancing areas therefore receive a prorated diversity benefit discount in the test based on this proportion.

market runs. To facilitate comparison across different BAAs, the realized uncertainty has been standardized by its mean and standard deviation.[217] This eliminates scale issues and allows for a clear assessment of relative volatility in realized uncertainty among BAAs. Additionally, the figure displays the standardized average upward and downward requirement imposed in the market, enabling a comparison of each BAA's requirement relative to its own uncertainty, as well as in relation to other areas.

**Figure 11.4 Standardized realized uncertainty and requirement for RSE (2024)**

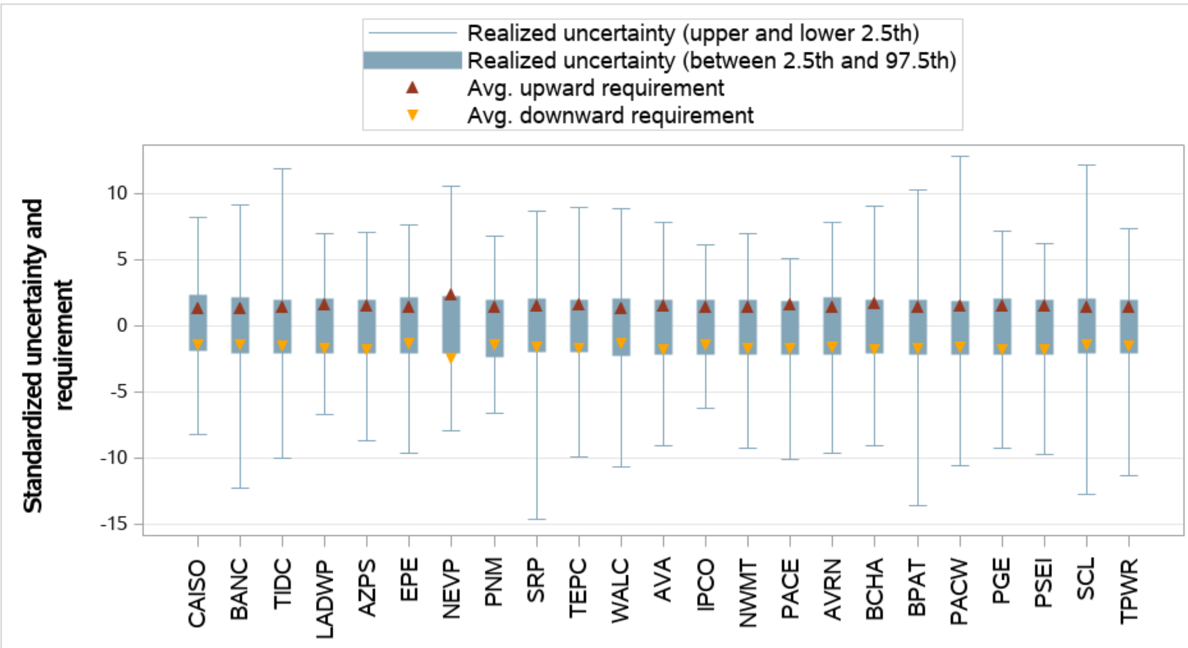



Figure 11.4 provides a comparison of the realized uncertainty across different BAAs for this year. The blue box represents the range of realized uncertainty between the 2.5th and 97.5th percentiles. The blue lines extend upward from the 97.5th percentile to the maximum value and downward from the 2.5th percentile to the minimum value of realized uncertainty. The triangle markers show the average upward and downward requirement applied in the market, based on the ISO estimates.

Key observations include:

- **Long tails**: Most BAAs exhibit a long tail distribution. The range of uncertainty beyond the 2.5th and 97.5th percentiles is wider than the main distribution of data.

[217] Standardizing involves calculating the z-score, which is done by subtracting the mean of uncertainty from each data point and then dividing the result by the standard deviation. This process transforms the data so that it has a mean of zero and a standard deviation of one. This is helpful for comparing uncertainty across different BAAs because it removes the scale difference between them. Each BAA has different absolute levels of uncertainty, but by standardizing, all areas are brought onto the same scale. This allows for a direct comparison of their relative volatility and makes it easier to see which BAA experiences more or less uncertainty.

- **Asymmetry in uncertainty:** Not all have symmetric uncertainty distributions. Some tend to have more positive uncertainty, while others skew more negative.
- **Requirement**: The requirements reflect the forecasted outcomes of the mosaic regression. Some BAAs exhibited a narrower range of requirements compared to others, which may indicate the regression model performed differently across BAAs.

### 11.2.1 Results of resource sufficiency evaluation uncertainty calculation

Table 11.3 summarizes the average requirements and coverage for uncertainty in the resource sufficiency evaluation using both the histogram and mosaic quantile regression methods. In this table, *requirement* shows the average uncertainty component considered in the upward and downward flexibility test requirements. *Coverage* measures how frequently realized uncertainty—as measured by the difference between binding 5-minute market net load forecasts and net load forecasts in the resource sufficiency evaluation (RSE)—fell within the calculated uncertainty requirements for the same interval.

In the RSE, both the histogram and mosaic regression showed overall coverage levels significantly below the 95 percent target. Of note, coverage using the regression method remained at or below 90 percent across all balancing areas. This is largely due to a disparity with the underlying data used to estimate resource sufficiency evaluation uncertainty, as discussed in the following section. On average across all hours, the uncertainty calculated from the regression method was less than the histogram method for all of the WEIM entities.

**Table 11.3 Average resource sufficiency evaluation uncertainty requirements and coverage (2024)**

| | Upward uncertainty | | | Downward uncertainty | | | Coverage | | |
|---|---|---|---|---|---|---|---|---|---|
| ***Balancing area*** | **Histogram** | **Mosaic** | **Difference** | **Histogram** | **Mosaic** | **Difference** | **Histogram** | **Mosaic** | **Difference** |
| Arizona Public Service | 231 | 212 | -18 | 228 | 210 | -18 | 92% | 90% | -2% |
| Avangrid | 213 | 173 | -39 | 184 | 145 | -39 | 92% | 89% | -3% |
| Avista | 56 | 49 | -7 | 65 | 59 | -6 | 92% | 90% | -2% |
| BANC | 44 | 40 | -4 | 43 | 38 | -6 | 91% | 89% | -2% |
| Bonneville Power Admin. | 229 | 202 | -27 | 254 | 218 | -36 | 92% | 90% | -2% |
| California ISO | 1,195 | 1,043 | -152 | 802 | 685 | -117 | 92% | 89% | -3% |
| El Paso Electric | 39 | 35 | -4 | 35 | 30 | -5 | 91% | 88% | -3% |
| Idaho Power | 121 | 114 | -7 | 140 | 125 | -15 | 90% | 88% | -2% |
| LADWP | 156 | 144 | -11 | 157 | 143 | -14 | 92% | 90% | -2% |
| NorthWestern Energy | 74 | 64 | -9 | 81 | 72 | -9 | 92% | 90% | -2% |
| NV Energy | 251 | 212 | -39 | 218 | 182 | -35 | 92% | 88% | -3% |
| PacifiCorp East | 353 | 330 | -23 | 490 | 455 | -35 | 92% | 90% | -2% |
| PacifiCorp West | 92 | 87 | -5 | 134 | 111 | -22 | 92% | 90% | -2% |
| Portland General Electric | 132 | 123 | -9 | 130 | 128 | -2 | 91% | 90% | -1% |
| Powerex | 144 | 136 | -7 | 149 | 141 | -7 | 92% | 90% | -2% |
| PNM | 144 | 130 | -14 | 150 | 140 | -10 | 90% | 88% | -3% |
| Puget Sound Energy | 142 | 129 | -13 | 135 | 128 | -7 | 92% | 90% | -2% |
| Salt River Project | 139 | 127 | -12 | 129 | 116 | -12 | 92% | 90% | -2% |
| Seattle City Light | 20 | 18 | -2 | 21 | 19 | -2 | 90% | 88% | -2% |
| Tacoma Power | 11 | 11 | -1 | 12 | 11 | -1 | 91% | 88% | -2% |
| Tucson Electric Power | 100 | 96 | -4 | 85 | 79 | -7 | 92% | 89% | -3% |
| Turlock Irrigation District | 8 | 7 | -1 | 8 | 7 | -1 | 92% | 88% | -3% |
| WAPA Desert Southwest | 24 | 23 | -2 | 24 | 23 | -2 | 90% | 87% | -3% |

Table 11.4 summarizes the percentage of statistically significant coefficients during all hours and peak hours, based on DMM's replication of the regression. The balancing areas are listed in descending order, starting with those with the highest percentage of significant coefficients. Overall, 37 percent of regression coefficients were significant in 2024, indicating that 63 percent of the regression estimations were based on either weak or inconsistent patterns.

**Table 11.4 Test for statistical significance of mosaic quantile regression in RSE (2024)**

| BAA | Percent of significant coefficients | |
|---|---|---|
| | All hours | Peak hours(1) |
| Avangrid | 90% | 94% |
| BPA | 68% | 69% |
| PacifiCorp West | 63% | 61% |
| Avista Utilities | 47% | 45% |
| Idaho Power | 45% | 58% |
| NorthWestern | 44% | 47% |
| CAISO | 43% | 51% |
| Portland GE | 42% | 41% |
| Arizona PS | 41% | 36% |
| NV Energy | 37% | 52% |
| LADWP | 36% | 41% |
| Salt River Project | 32% | 32% |
| PacifiCorp East | 32% | 35% |
| PSC New Mexico | 32% | 38% |
| El Paso Electric | 30% | 38% |
| Puget Sound Energy | 29% | 30% |
| Tucson Electric | 29% | 29% |
| BANC | 24% | 26% |
| Seattle City Light | 23% | 27% |
| WAPA - Desert SW | 21% | 26% |
| Powerex | 20% | 20% |
| Turlock ID | 17% | 20% |
| Tacoma Power | 15% | 18% |
| Average | 37% | 41% |

(1): Peak hours include hour-ending (HE) from 7 to 9 and HE from 17 to 21.

### 11.2.2 RSE uncertainty special issue — time horizon for predicting uncertainty

The regression model used for the resource sufficiency evaluation is currently designed to predict uncertainty in forecasts produced only 45 to 55 minutes before real-time. However, the time horizon of the resource sufficiency evaluation includes four intervals, typically produced between 47.5 and 102.5 minutes before real-time.

The resource sufficiency evaluation uses exactly the same underlying historical data to perform the regressions and calculate uncertainty as the flexible ramping product in the 15-minute market.[218] This data is based on the difference from advisory forecasts in the 15-minute market to the corresponding binding forecasts in the 5-minute market. The regressions use this data to produce hourly coefficients that define the relationship between the forecasts and uncertainty. This calculation reflects 45 to 55 minutes in which uncertainty may materialize between the applicable 15-minute and 5-minute market runs.

However, the resource sufficiency evaluation occurs over a different timeframe than what is considered for procuring 15-minute market flexible capacity. Figure 11.5 illustrates the timeframe of uncertainty considered for the flexible ramping product in the 15-minute market, and how it compares with the timeframe of the resource sufficiency evaluation.[219] For the flexible ramping product, the calculation is designed to capture uncertainty that may materialize around a single upcoming (advisory) interval. However, the resource sufficiency evaluation considers forecast information from *four* 15-minute intervals within an hour. When comparing the forecast values used in each interval of the resource sufficiency evaluation to corresponding 5-minute market intervals, there exists a larger gap of time for uncertainty to materialize.

In comparing the first 15-minute test interval of the RSE to corresponding 5-minute market intervals, the timeframe and potential for net load uncertainty to materialize is similar to the timeframe of the 15-minute market flexible ramping product uncertainty calculation. However, in the later test intervals, the gap between the predicted forecasts at the time of the resource sufficiency evaluation and the real-time forecasts widens, reaching above 100 minutes. The current determination of the regression coefficients for predicting net load uncertainty for the resource sufficiency evaluation (based on short-term historical data) does not capture the increased net load uncertainty associated with the longer-term horizon of this market process.[220]

This inconsistency results in lower performance in the rate of coverage provided by the uncertainty component in the resource sufficiency evaluation. Figure 11.6 shows the average coverage rate across all balancing areas by interval. Here, coverage is measured as the percent of intervals when realized

218 A balancing-area-specific flexible ramping product uncertainty requirement will be enforced for any balancing area that failed the resource sufficiency evaluation.

219 The figure shows the time horizon for the resource sufficiency evaluation ran 55 minutes prior to the hour (T-55 RSE). While the final test is run at 40 minutes prior to the hour, the load and renewable forecasts used in the final test are held fixed from the forecasts in the T-55 RSE. This is intended to reduce unexpected failures that would be caused by forecast variation between the T-55 and T-40 resource sufficiency evaluations.

220 The resource sufficiency evaluation and flexible ramping product uncertainty calculations for a single balancing area use the same hourly regression coefficients (produced from same short-term historical data) but are combined with the current forecast information at the time of each market process to determine the final uncertainty. Here, longer-term forecast information at the time of the resource sufficiency evaluation is combined with the short-term regression coefficients.

uncertainty from the forecasts considered in the resource sufficiency evaluation to the 5-minute market forecasts fell within the calculated uncertainty requirement for the same interval. The calculated uncertainty covered the realized uncertainty much less for intervals at the end of the hour compared to the beginning of the hour because the current calculation is not designed to capture uncertainty that can realize over a longer-term horizon.

**Figure 11.5 Comparison of timeframe considered for the flexible ramping product and resource sufficiency evaluation**

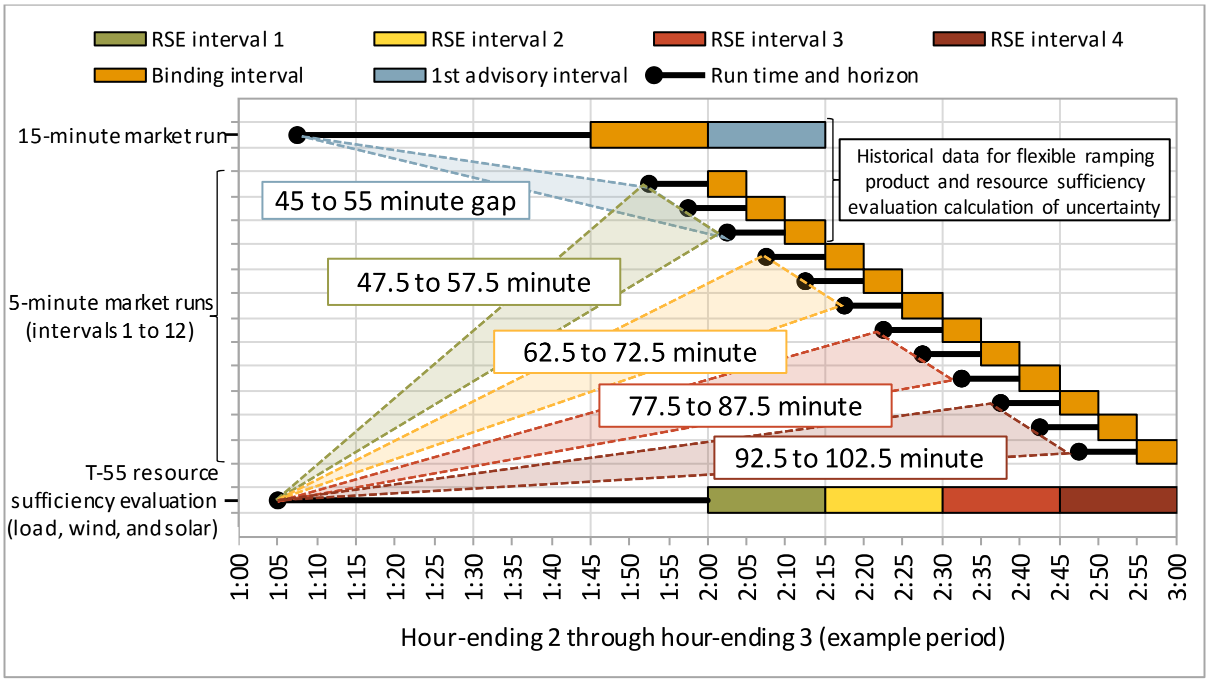
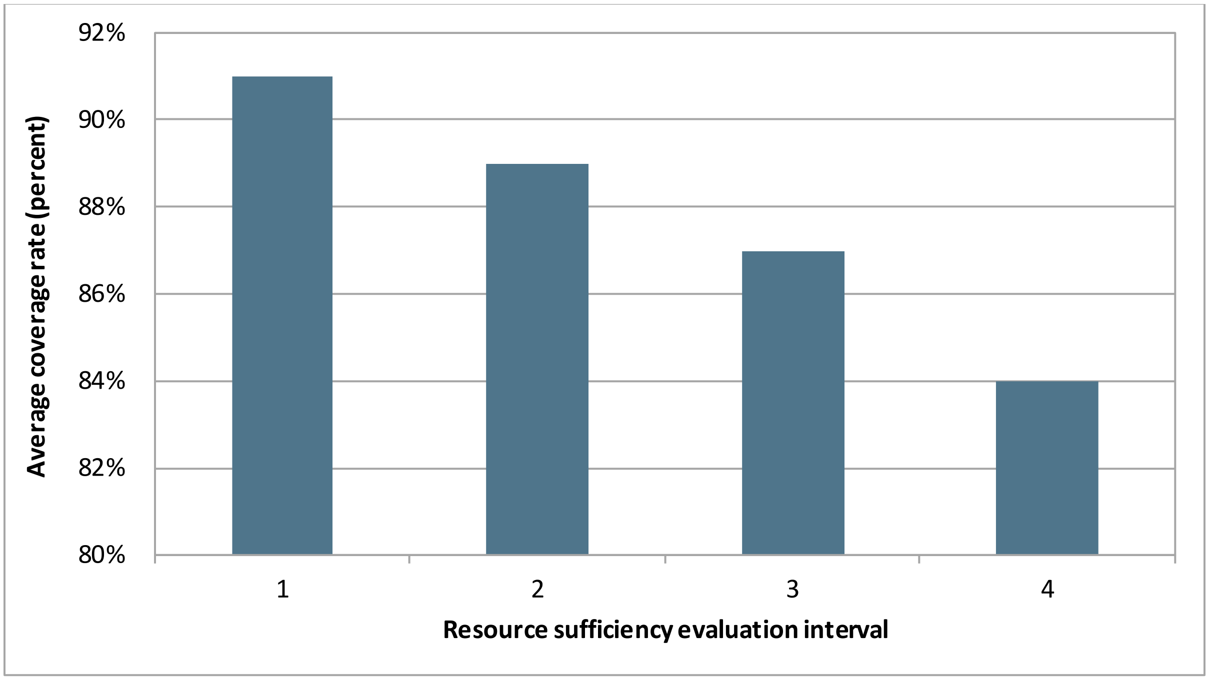


**Figure 11.6 Average coverage rate by resource sufficiency evaluation interval (2024)**




## 11.3 Residual unit commitment uncertainty

Uncertainty is often added to the residual unit commitment (RUC) target load requirement. This adjustment is used to ensure there is sufficient capacity to account for uncertainty that may materialize between the day-ahead and real-time markets. For the residual unit commitment market adjustment, uncertainty is defined as the difference between the day-ahead net load forecast and 15-minute market forecasts.

Figure 11.7 shows the average residual unit commitment adjustment on each day of 2023 (red) and 2024 (blue). The arrows highlight key changes that occurred in 2023 and 2024.

1. On June 30, 2023, the ISO began using the *mosaic quantile regression* method to calculate the RUC adjustments. Between June 30 and December 20, 2023, this calculation was applied to all hours based on the 97.5$^{th}$ percentile of net load uncertainty that might materialize in real-time.

2. On December 21, 2023, the ISO implemented a new operating procedure that changed the methodology for calculating the RUC adjustments, effectively lowering the amounts. The procedure calls for selecting the percentile target for calculating the adjustment based on conditions in the system. Under periods with moderate operational uncertainty, the operating procedure calls for using an adjustment that will procure enough capacity 50 percent of the time (i.e., the 50$^{th}$ percentile of upward uncertainty). The ISO can adjust the calculation on any day to instead use the 75$^{th}$ or 97.5$^{th}$ percentile during periods of higher forecast uncertainty or in extreme conditions.

3. On May 7, 2024, the ISO made changes to the operating procedure that allowed the uncertainty adjustment to be applied to only select hours.[221] During periods with moderate uncertainty, the adjustment is typically applied only to the peak morning and peak evening hours (around six hours). During periods with more operational uncertainty, the adjustment is generally applied to either mid-day hours (around 16 hours) or all hours. During periods with low operational uncertainty, *no adjustment* can also be applied.[222]

**Figure 11.7 Average residual unit commitment adjustment by day (2023 vs. 2024)**

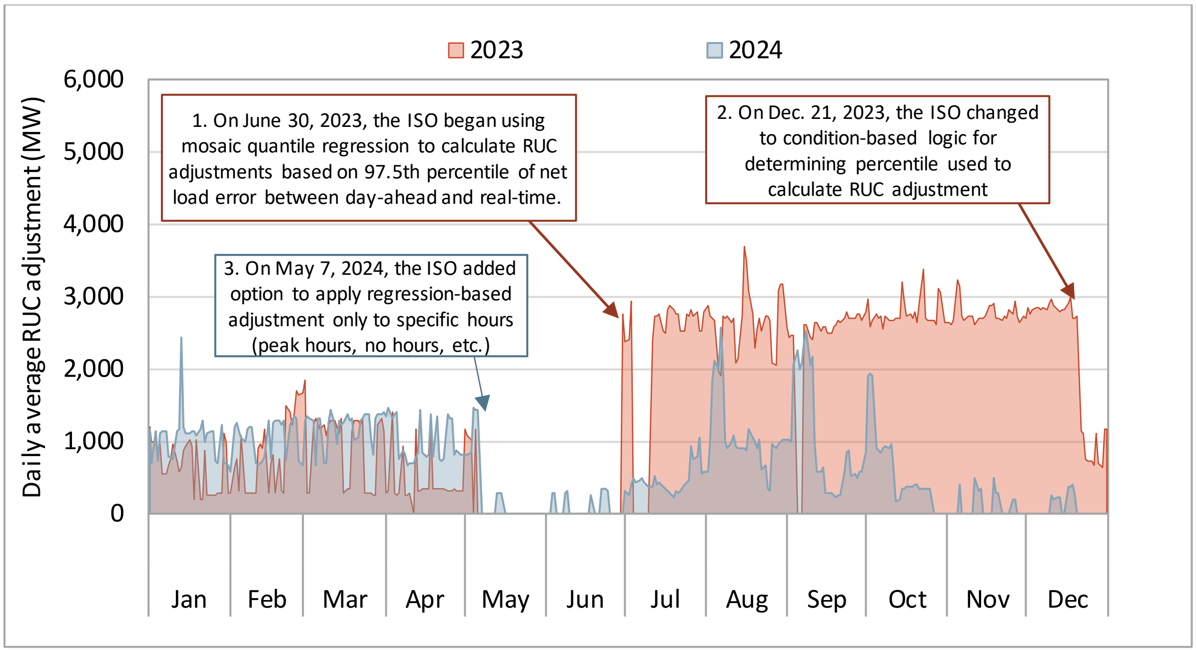
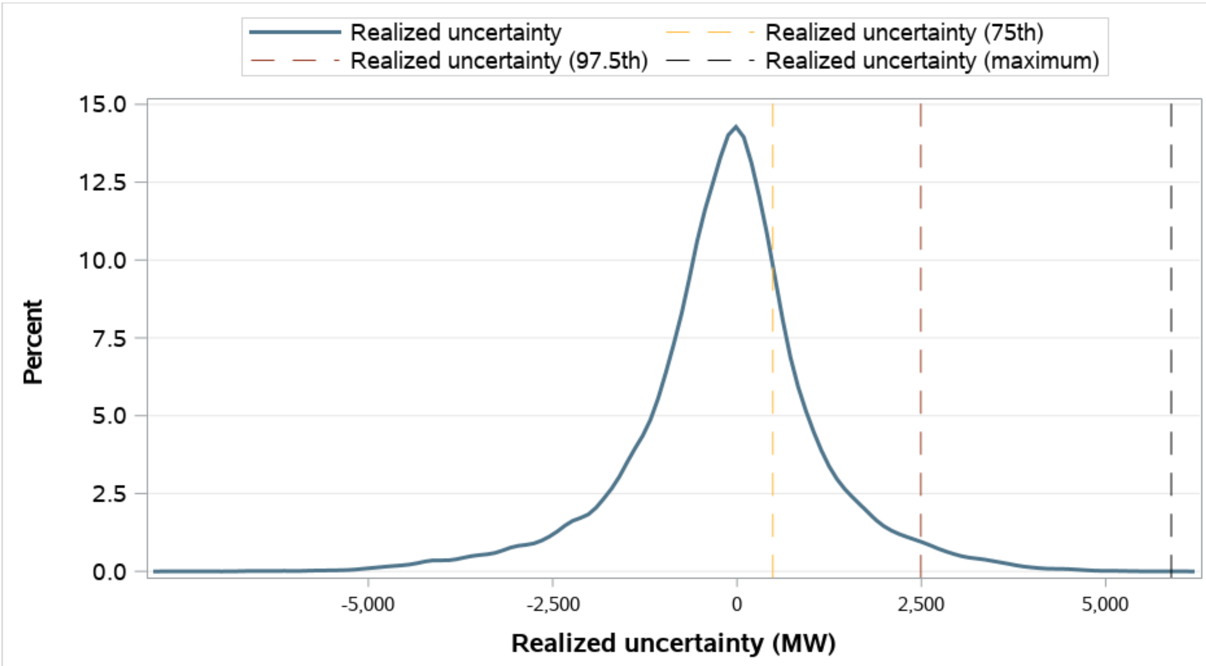



Figure 11.8 shows this year's distribution of realized uncertainty between the net load forecasts of the day-ahead market and the 15-minute market. This distribution represents all uncertainties observed in the 15-minute market intervals for 2024 and serves as the forecasting target. The first notable feature is that net load uncertainty in the day-ahead time horizon ranged from -7,600 MW to 5,900 MW. The distribution shows a long tail, with the area between the red dashed line and the black dashed line highlighting the range from the 97.5$^{th}$ percentile of uncertainty up to the maximum value. This area ranged from 2,500 MW to 5,900 MW. A long tail could indicate rare but impactful events, such as unexpected weather changes or some other cause of a sudden shift in demand or renewable resource output.

221 See CAISO Operating Procedure 1210, May 7, 2024, pp 12-13: https://www.caiso.com/Documents/1210.pdf

222 As noted in the day-ahead market operating procedure, dispatchable resources in the market, WEIM transfers, or regulating resources can instead manage uncertainty during periods with lower uncertainty.

**Figure 11.8 Distribution of realized uncertainty between RUC and 15-minute market net load forecasts (2024)**




## 11.3.1 Results of uncertainty calculation for residual unit commitment

Figure 11.9 shows the average RUC adjustment on each day since May 7, 2024, during the peak morning and evening hours (hours 7 to 9 and 19 to 21). The figure also shows the estimated percentile that was used to determine the additional requirements for the peak hours of each day.[223] During the year, the 97.5th percentile target was applied on 5 percent of days. The 75th percentile target was applied on 37 percent of days while the 50th percentile target was applied on 33 percent of days. During much of the year, no adjustment was applied (26 percent of days).

On May 7, the ISO added the option to apply the regression-based adjustment only to specific hours (or no hours). Prior to this date, the regression-based adjustment was applied to all hours each day. Figure 11.10 shows the average RUC adjustment for each day *across all hours* since May 7.[224] The dotted black line (right axis) shows the number of hours in which the adjustment was applied. Since May 7, the regression-based adjustment was applied to the mid-day hours in 27 percent of days and the peak hours

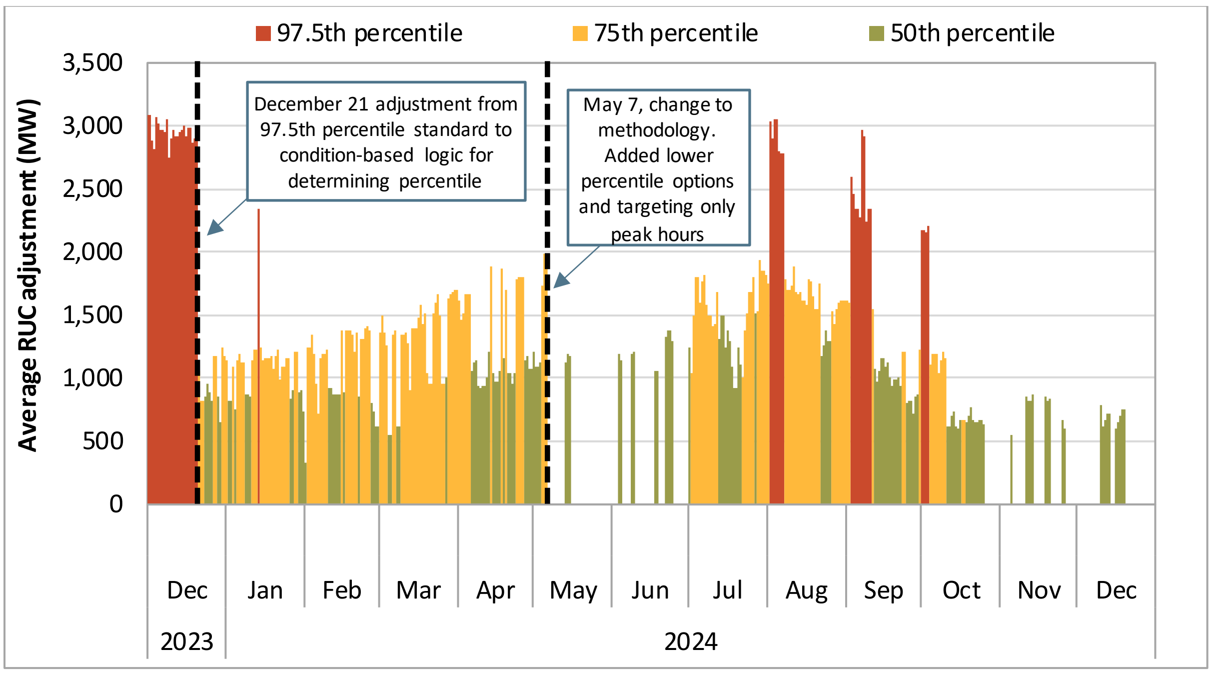
223 Data on the percentile used to calculate the RUC adjustments for each day was not available. The percentiles shown here were estimated from the magnitude of the adjustments and DMM recalculation of the uncertainty.

224 In the hours when no adjustment is applied, the residual unit commitment adjustment for uncertainty is 0 MW, resulting in a lower daily average.

in 33 percent of days.[225] The adjustment was applied during all 24 hours using the 97.5 percentile target on just one day since May 7 (August 6).

The imbalance reserve product for the extended day-ahead market is intended to procure capacity to address the same uncertainty as this RUC adjustment, but the imbalance reserve up requirement will be set to cover the 97.5th percentile of uncertainty in all hours of all days. The low number of hours in which the ISO used the 97.5th percentile target in RUC indicates that the imbalance reserve product demand curve may be much too high during most hours.

**Figure 11.9 Average residual unit commitment adjustment by day (peak morning and evening hours, 2024)**




225 Mid-day hours were typically between hours 7 and 22 (16 hours). Peak hours were only the peak morning and evening hours (typically 6 hours).

**Figure 11.10 Average residual unit commitment adjustment by day (all hours, May 7–December 31, 2024)**

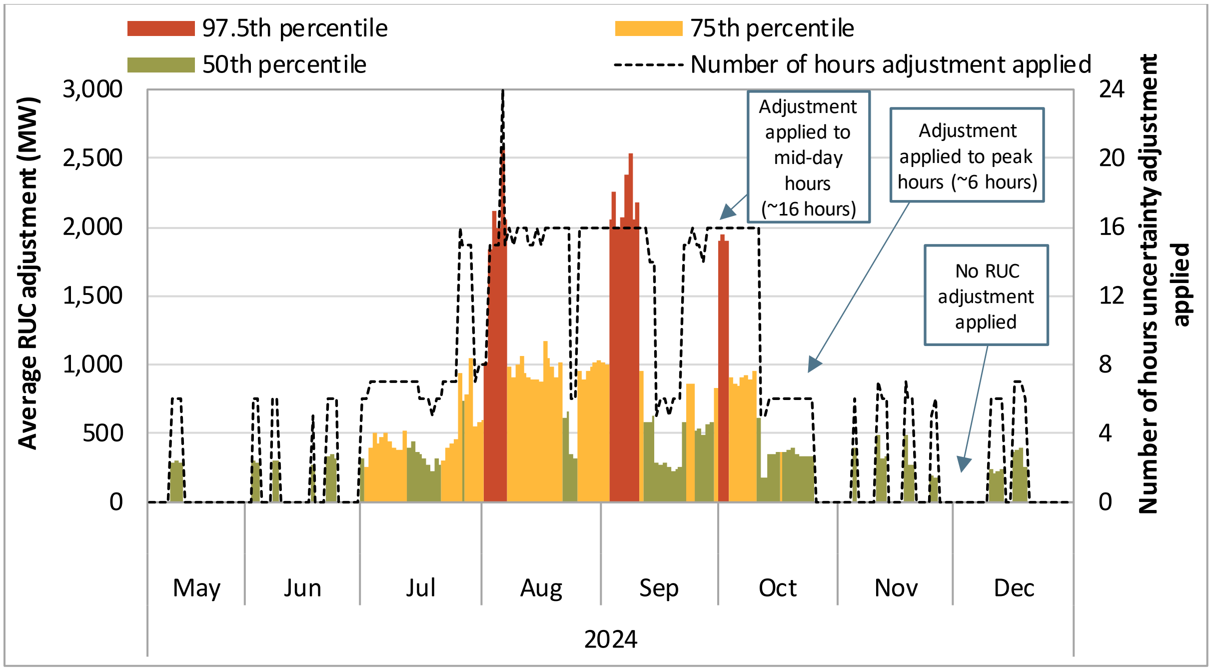



Table 11.5 summarizes the average requirement and coverage based on the percentile target that was selected and the hours it was applied (either mid-day hours or peak hours). Coverage shows the percent of 15-minute market intervals in which realized uncertainty from the day-ahead market to the real-time market was below the RUC adjustment quantity. The average requirement and coverage were assessed only in hours the uncertainty adjustment was applied. Average requirements using the 97.5$^{th}$ percentile target were roughly double those using the 75$^{th}$ percentile target while coverage was higher.

**Table 11.5 Average residual unit commitment uncertainty adjustment and coverage (2024)**

| Percentile target | Hours applied | Percent of days | Average requirement (MW) | Coverage |
|---|---|---|---|---|
| 97.5$^{th}$ percentile | All hours | 0.5% | 2,504 | 100% |
| | Mid-day hours | 4% | 3,183 | 100% |
| | Peak hours | 0.3% | 3,030 | 100% |
| 75$^{th}$ percentile | All hours | 21% | 1,248 | 82% |
| | Mid-day hours | 10% | 1,436 | 90% |
| | Peak hours | 5% | 1,507 | 89% |
| 50$^{th}$ percentile | All hours | 13% | 776 | 71% |
| | Mid-day hours | 4% | 933 | 84% |
| | Peak hours | 16% | 1,238 | 81% |

Table 11.6 represents DMM's simulation of the RUC adjustment using the mosaic quantile regression. It provides insight into the different percentiles used in the market and illustrates the likely outcomes if a specific percentile were applied to forecast the RUC adjustment.

The first section of the table shows the average requirement across different percentile values from the DMM replication. The middle section of the table shows the percentage of statistically significant coefficients, and the last section shows the coverage rate for each percentile regression.

The 97.5th percentile regression showed only one percent of statistical significance, likely due to sample size. This specific percentile regression focuses on only 4 to 5 observations.[226] While an underlying pattern may exist, the small sample size of 4 to 5 observations is insufficient to find such a pattern, resulting in only one percent of statistical significance.

The coverage rates for regression were notably inflated. For example, the 50th percentile regression, designed to capture 50 percent of realized uncertainty, showed coverage rates of 72 percent and 78 percent during peak hours.

This inflation arises from two key factors. First, while the realized uncertainty represents the difference between day-ahead and 15-minute net load forecasts, available as four uncertainty realizations per hour, the regression model forecasts the maximum uncertainty for each hour. This discrepancy inflated the result. As shown in Figure 11.8, the realized uncertainty distribution indicated the 50th percentile value was around -90 MW, meaning that a -90 MW requirement would effectively achieve 50 percent coverage. However, the 50th percentile regression averaged around 602 MW (as shown in Table 11.6). This means that the regression is producing about 700 MW more than ideal, due to the practice of forecasting the maximum uncertainty per hour. Second, the regression in RUC estimates only the upper bound of uncertainty, meaning any negative uncertainty is automatically covered, contributing to the inflated coverage rate.

**Table 11.6 DMM simulation for RUC adjustment using mosaic quantile regression (2024)**

| | Requirement (MW) | | Percent of significant coefficients | | Coverage | |
|---|---|---|---|---|---|---|
| | All hours | Peak hours(1) | All hours | Peak hours | All hours | Peak hours |
| Replication (97.5th) | 2,213 | 2,706 | 1% | 2% | 99% | 99% |
| Replication (75th) | 1,133 | 1,629 | 23% | 36% | 87% | 90% |
| Replication (50th) | 602 | 1,089 | 38% | 52% | 72% | 78% |
| Replication (25th) | 96 | 540 | 37% | 51% | 52% | 62% |

(1): Peak hours include hour-ending (HE) from 7 to 9 and HE from 17 to 21.

226 Quantile regression identifies patterns within a subset of data. A 97.5th percentile regression targets the upper 2.5 percent of uncertainty, requiring a large sample size. The sampling methodology in mosaic regression shares similarities between the RUC adjustment and other market applications, employing either symmetric or past 180-day sampling, ultimately selecting data from 180 days. The ISO further filters for the same hour as the forecasting hour. A key distinction for the RUC adjustment forecast lies in its day-ahead forecast data, resulting in only one observation per hour. In contrast, other real-time uncertainty calculations have mosaic variable and uncertainties available across 4 to 12 intervals per hour, leaving the RUC adjustment forecast's sampling size at 180 observations.

## 11.4 Enhancements and issues with uncertainty calculation

In 2024, two major updates were made to the mosaic regression models in the RSE and FRP uncertainty calculations. Since forecasting relies on historical data to predict future periods, the selection of past data is a critical component. Originally, the ISO sampled data from the prior 180 days and applied day-type filters—using only weekend days to forecast weekends and weekdays to forecast weekdays.

The first update, implemented on April 4, 2024, removed the use of day-type classification in the sample. The second update, implemented on August 14, introduced symmetric sampling, which selects data from 90 days before and 90 days after the forecast data in the prior year.[227]

This section evaluates the forecasting performance of the original sampling approach, the first update, and the symmetric sampling method. DMM conducted the assessment using internal replication simulations applied consistently across all intervals in 2024. The result focuses on 15-minute market uncertainty estimations in both the FRP and RSE.

Table 11.7 includes performance metrics such as statistical significance, coverage, and requirement. These metrics are based on DMM's replication result—not actual ISO market outcomes. The table columns correspond to the original methodology, the first update (removal of day-type filtering), and the second update (symmetric sampling), with all methods evaluated over all intervals in 2024.

Based on DMM's simulation, the second update—symmetric sampling—showed meaningful improvement in forecasting performance. The frequency of regression producing statistically significant coefficients increased from 30 percent under the original sampling method to 41 percent under the symmetric sampling (2$^{nd}$ update). While most of the regression (59 percent) still does not yield statistically meaningful relationships, the 11-percentage point gain represents a notable improvement in model validation. Coverage improved to 93 percent on average, a 2 percent gain over the original method, partially driven by an increase in the average requirement, which reached 5 MW higher under symmetric sampling.

[227] For more details on the sampling method updates, refer to DMM's *2024 Second Quarter Report on Market Issues and Performance*, Nov 22, 2024 (page 97), and DMM's *2024 Third Quarter Report on Market Issues and Performance*, Dec 23, 2024 (page 102): https://www.caiso.com/market-operations/market-monitoring/market-issues-and-performance-reports

### Table 11.7 Uncertainty forecast performance comparison of sampling methods in 2024

| | Statistical significance test | | | Coverage | | | Requirement[1] | | |
|---|---|---|---|---|---|---|---|---|---|
| | Original | 1st update | 2nd update | Original | 1st update | 2nd update | Original | 1st update | 2nd update |
| **FRP:** | | | | | | | | | |
| Pass-group | 20% | 33% | 37% | 94% | 95% | 96% | 1,415 | 1,444 | 1,463 |
| **RSE:** | | | | | | | | | |
| AVRN | 79% | 86% | 81% | 91% | 92% | 92% | 162 | 163 | 164 |
| PACW | 57% | 67% | 61% | 92% | 92% | 93% | 103 | 105 | 104 |
| BPAT | 56% | 66% | 69% | 92% | 93% | 94% | 223 | 225 | 231 |
| IPCO | 38% | 45% | 46% | 91% | 84% | 92% | 129 | 129 | 126 |
| AVA | 38% | 51% | 48% | 93% | 93% | 93% | 58.7 | 59.1 | 58.6 |
| CISO | 35% | 41% | 45% | 92% | 93% | 94% | 889 | 903 | 923 |
| PGE | 33% | 42% | 49% | 92% | 92% | 93% | 133 | 135 | 142 |
| AZPS | 31% | 41% | 43% | 92% | 93% | 93% | 225 | 232 | 230 |
| NEVP | 31% | 36% | 45% | 90% | 83% | 94% | 197 | 202 | 215 |
| NWMT | 31% | 45% | 51% | 92% | 92% | 93% | 73.0 | 72.9 | 76.4 |
| LADWP | 29% | 38% | 40% | 92% | 85% | 93% | 150 | 152 | 152 |
| PNM | 27% | 31% | 34% | 91% | 91% | 91% | 140 | 141 | 137 |
| EPE | 25% | 32% | 37% | 91% | 84% | 93% | 34.7 | 35.0 | 34.9 |
| BANC | 25% | 31% | 31% | 91% | 92% | 93% | 39.2 | 40.5 | 41.2 |
| PACE | 23% | 36% | 36% | 92% | 92% | 93% | 417 | 420 | 413 |
| SRP | 23% | 34% | 39% | 93% | 93% | 94% | 131 | 132 | 132 |
| PSEI | 22% | 31% | 38% | 92% | 92% | 93% | 137 | 138 | 140 |
| TEPC | 20% | 28% | 35% | 91% | 92% | 92% | 91.9 | 92.6 | 92.3 |
| WALC | 19% | 23% | 29% | 89% | 90% | 90% | 23.5 | 23.5 | 23.1 |
| TIDC | 15% | 20% | 26% | 91% | 91% | 94% | 7.8 | 7.7 | 8.0 |
| SCL | 13% | 17% | 29% | 89% | 91% | 91% | 19.1 | 19.5 | 19.0 |
| BCHA | 11% | 19% | 21% | 92% | 92% | 93% | 148 | 147 | 153 |
| TPWR | 10% | 11% | 21% | 90% | 91% | 92% | 11.4 | 11.5 | 11.5 |
| **Average** | **30%** | **38%** | **41%** | **91%** | **91%** | **93%** | **207** | **210** | **212** |

(1) The requirement is the average value without the extreme outliers that the regression generates, with the upper and lower 5 percent of extreme requirements removed from this calculation.

# 12 Ancillary services

This chapter analyzes ancillary services for balancing areas in the day-ahead market (CAISO) and available balancing capacity for balancing areas participating only in the WEIM. Key findings in this chapter include the following:

- **Ancillary service costs decreased to $107 million,** down from $151 million in 2023.
- **Regulation up and regulation down requirements increased, while operating reserve requirements remained similar to those in 2023**. Regulation down requirements increased 4 percent to 935 MW. Regulation up requirements increased 8 percent to 440 MW.
- **Provision of ancillary services from battery resources continued to increase, replacing procurement from natural gas resources.** Average hourly procurement of ancillary services from battery resources increased by 46 percent compared to 2023, and batteries now provide 84 percent of CAISO balancing area regulation requirements.
- **There were no ancillary service scarcity events in 2024.** There were two intervals with ancillary service scarcities in 2023, and 6 in 2022.
- **Twelve percent of resources failed** unannounced ancillary service performance audits and compliance tests, compared to 15 percent in 2023, and 22 percent in 2022.
- **Most EIM entities offered available balancing capacity into the market throughout 2024.** However, available balancing capacity was rarely dispatched to resolve capacity insufficiencies.

The California ISO ancillary service market design includes co-optimizing energy and ancillary service bids provided by each resource in the day-ahead market. 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.[228]

## 12.1 Ancillary service costs

Costs for ancillary services totaled about $107 million in 2024, a significant decrease from $151 million in 2023.

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. The CAISO rescinded about 6.5 percent of ancillary service payments in 2024.

Figure 12.1 shows ancillary service costs both as percentage of wholesale energy costs and per megawatt-hour of load from 2022 to 2024. The cost per megawatt-hour decreased from $0.75 in 2023

[228] *2010 Annual Report on Market Issues & Performance*, Department of Market Monitoring, April 2011, pp 139-142: http://www.caiso.com/Documents/2010AnnualReportonMarketIssuesandPerformance.pdf

to $0.52 in 2024. Ancillary service costs as a percentage of energy costs increased slightly from 1 percent in 2023 to 1.2 percent in 2024.

Figure 12.2 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 previous years, ancillary service costs were highest in the third quarter, corresponding with high loads during the summer months.

In 2024, payments for regulation down, regulation up, spinning reserves, and non-spinning reserves decreased by 24 percent, 42 percent, 29 percent, and 27 percent, respectively. Of all ancillary service products, regulation down costs had the largest decrease in absolute terms, at around $16 million less than what was paid in 2023.

**Figure 12.1 Ancillary service cost as a percentage of wholesale energy costs (2022–2024)**

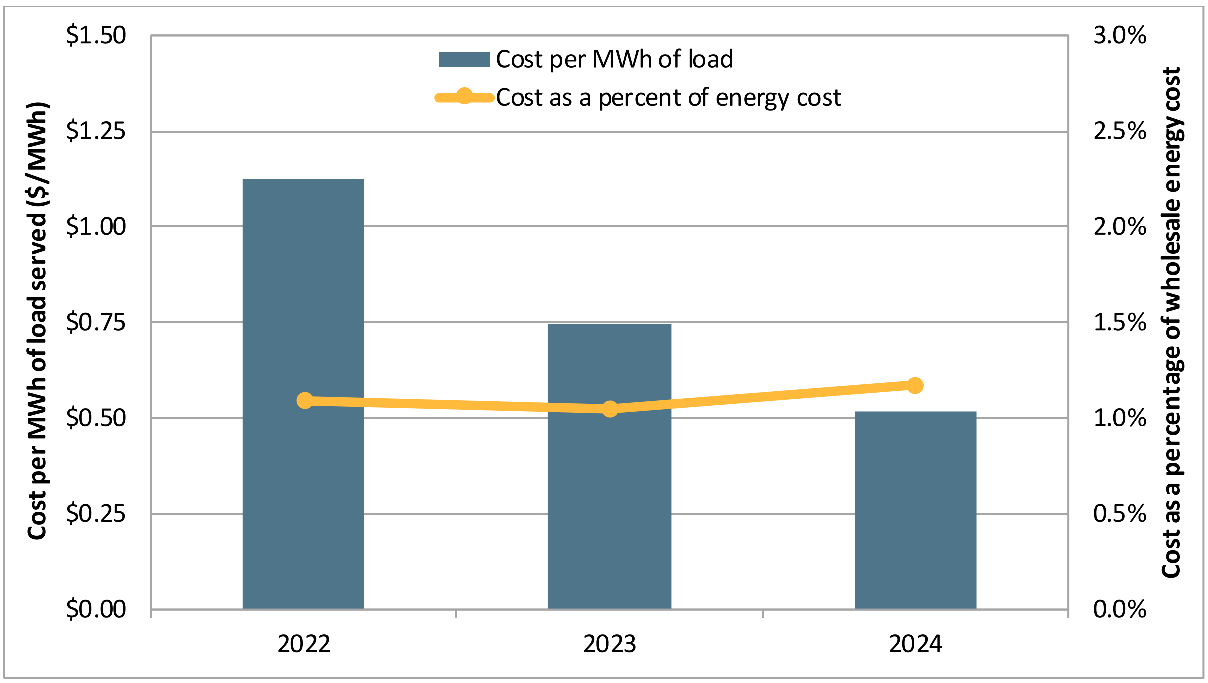
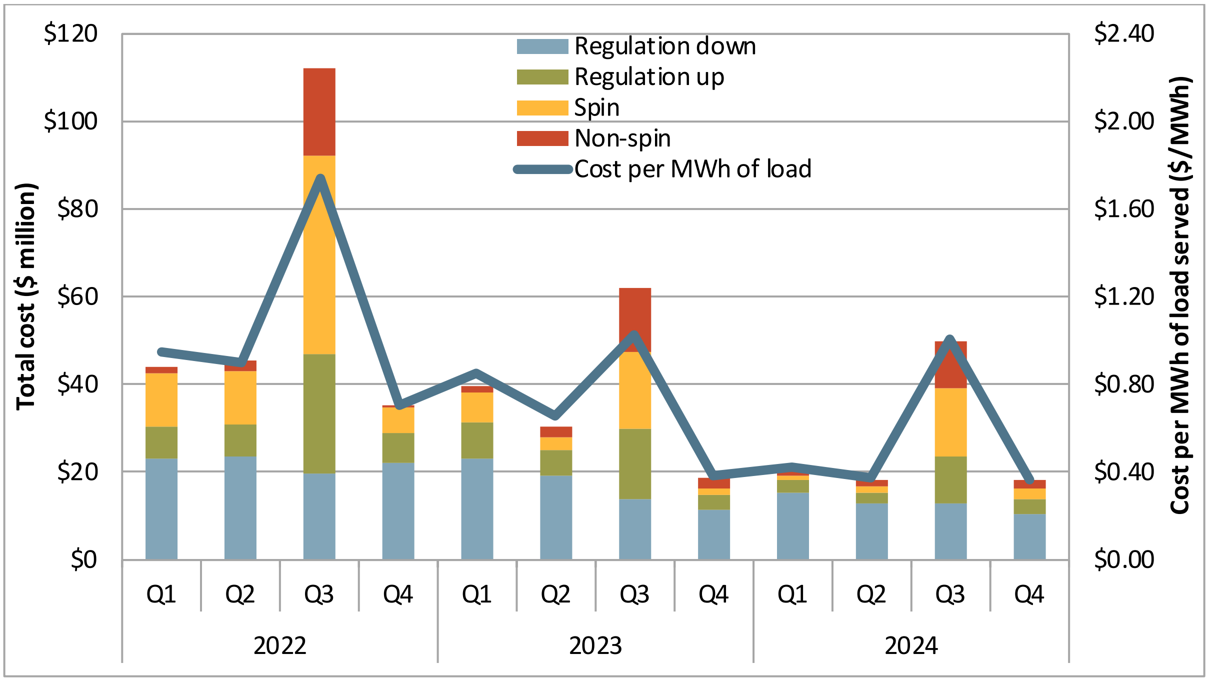


**Figure 12.2 Total ancillary service cost by quarter and type**




Similar to past years, the value of self-provided ancillary services was less than 1 percent of the total cost of ancillary services in 2024. 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 around $160,000 in 2024.

## 12.2 Ancillary service requirements and procurement

The California ISO procures four ancillary services for its balancing authority area in the day-ahead and real-time markets: regulation up, regulation down, spinning reserves, and non-spinning reserves.[229] Ancillary service procurement requirements are set for each ancillary service to meet or exceed Western Electricity Coordinating Council's (WECC) minimum operating reliability criteria, and North American Electric Reliability Corporation's (NERC) control performance standards. The 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

229 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.

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

Six of these regions are typically utilized: expanded system (or expanded 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) 10 percent of forecasted solar production.[230] 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.[231] As of April 2024, CAISO operators lowered the contribution of forecasted solar production in determining day-ahead operating reserve requirements from 15 percent to 10 percent. CAISO operators determined they could change the requirement because of the growing fleet of new solar resources that can respond quickly to voltage issues.

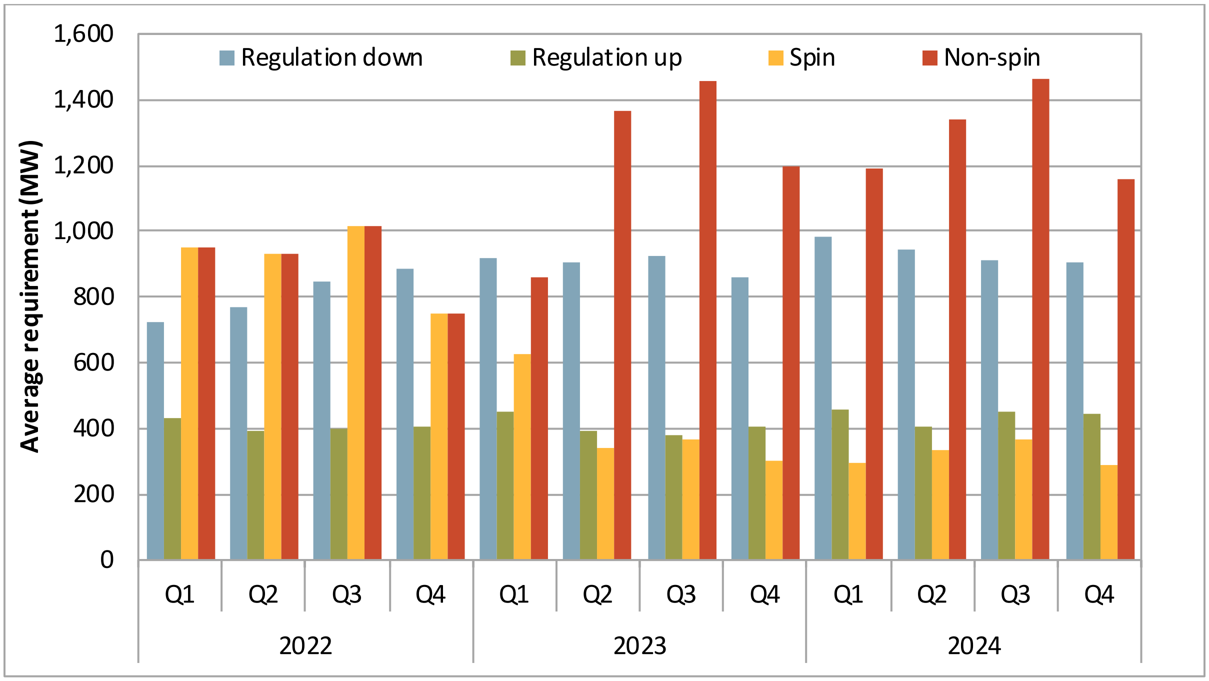
Historically, operating reserve requirements were split equally between spinning and non-spinning reserves. However, starting on March 1, 2023, CAISO operators changed the procurement target for operating reserves following changes in WECC and NERC reliability standards, which now allow spinning reserves to account for less than 50 percent of requirements. In all months after the procurement target changed, CAISO operators procured 20 percent of operating reserves as spinning reserves, and the rest as non-spinning reserves.

Figure 12.3 includes quarterly average day-ahead operating reserve requirements since 2022. Total operating reserve requirements in the day-ahead market averaged 1,608 MW in 2024, compared to 1,618 in 2023.

230 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.

231 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 12.3 Quarterly average day-ahead ancillary service requirements**



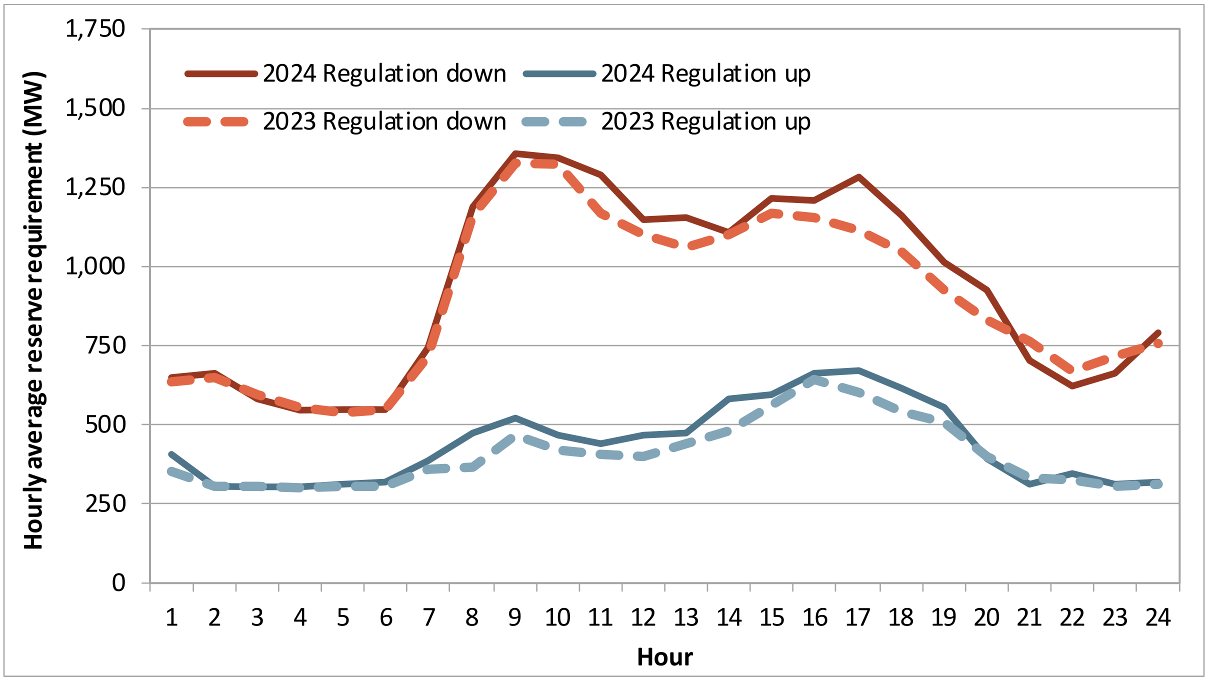

### Regulation requirements

The California ISO calculates regulation requirements based on observed regulation needs during the same time period in the prior year and in the previous month. Requirements are calculated for each hour of the day on a monthly basis. Furthermore, the California ISO can adjust requirements manually for periods when conditions indicate higher net load variability.

Figure 12.3 shows average regulation requirements by quarter. Regulation down requirements averaged 935 MW, a 4 percent increase from 2023. At 440 MW, average day-ahead regulation up requirements increased 8 percent from 2023.

Figure 12.4 summarizes the average hourly profile of the day-ahead regulation requirements in 2023 and 2024. Average hourly requirements for regulation up and down both peaked during ramping hours.

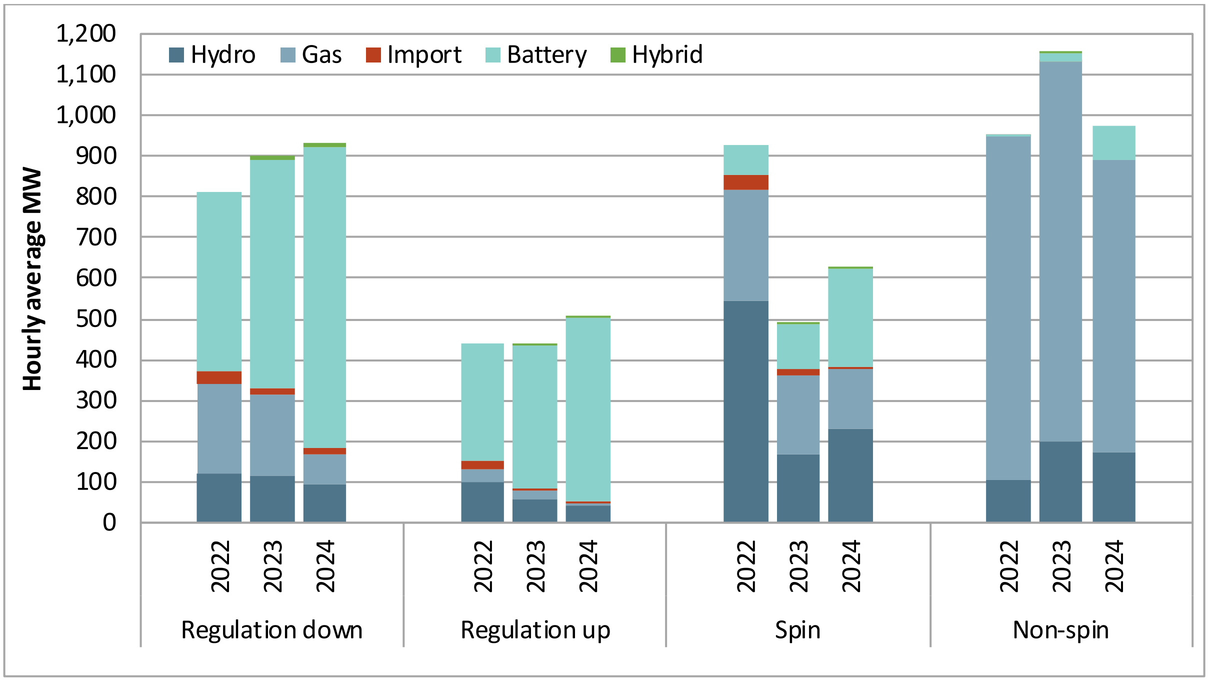
**Figure 12.4 Hourly average day-ahead regulation requirements**




### Ancillary service procurement by fuel

Figure 12.5 shows the portion of ancillary services procured by fuel type from 2022 through 2024. 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 California ISO resources.

**Figure 12.5 Ancillary service procurement by fuel type**




As in previous years, the vast majority of required ancillary service capacity came from a mix of CAISO gas, hydroelectric, and battery resources. Average ancillary service hourly procurement served by battery resources has been steadily increasing in recent years, growing from 800 MW in 2022 to 1,500 MW in 2024. In 2024, battery resources provided around 84 percent of the CAISO's regulation requirements, compared to 69 percent in 2023. Average ancillary service procurement from gas resources dropped 30 percent, while those procured by hydroelectric resources remained the same. Hourly average ancillary service procurement served by imports was 27 MW, a 23 percent decrease from 2023.

## 12.3 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 12.6 and Figure 12.7 show the weighted average market clearing prices for each ancillary service product by quarter in the day-ahead and real-time markets during 2023 and 2024, weighted by the quantity settled.

As shown in Figure 12.6, weighted average day-ahead prices for all upward ancillary service products (spinning reserve, non-spinning reserve, and regulation up) tended to decrease compared to 2023, despite increases in requirements. Both regulation up and regulation down prices decreased in 2024 despite increases in requirements, largely due to more participation from battery storage resources.

**Figure 12.6 Day-ahead ancillary service market clearing prices**

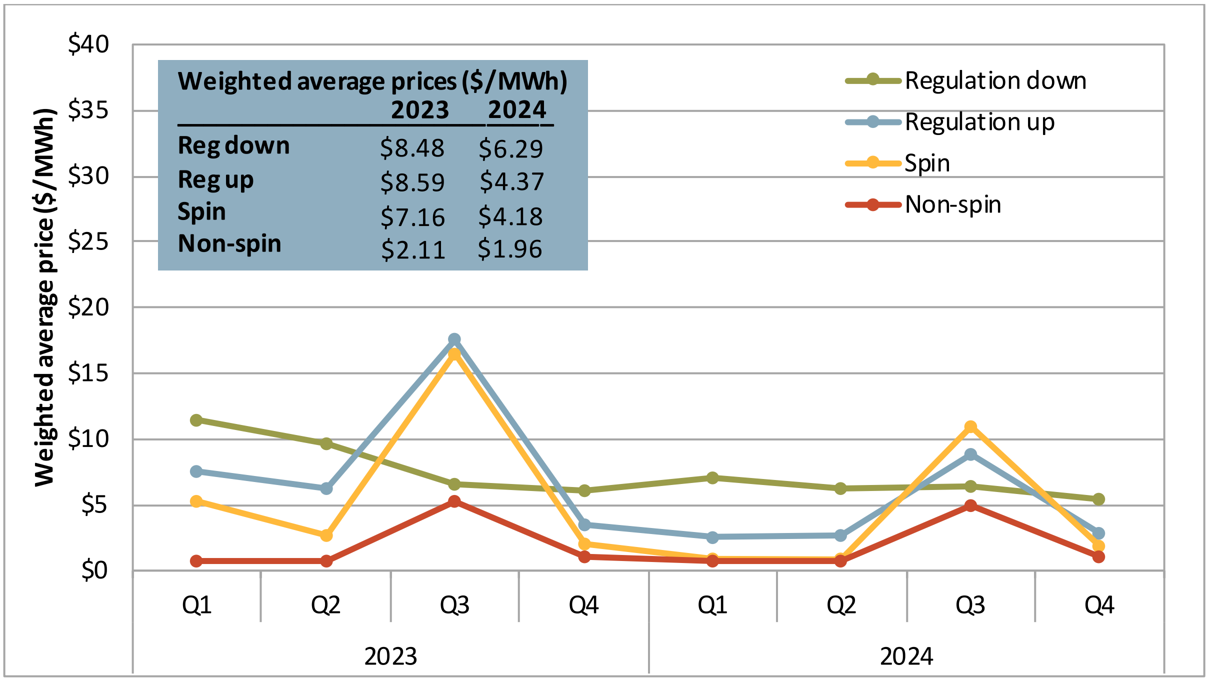
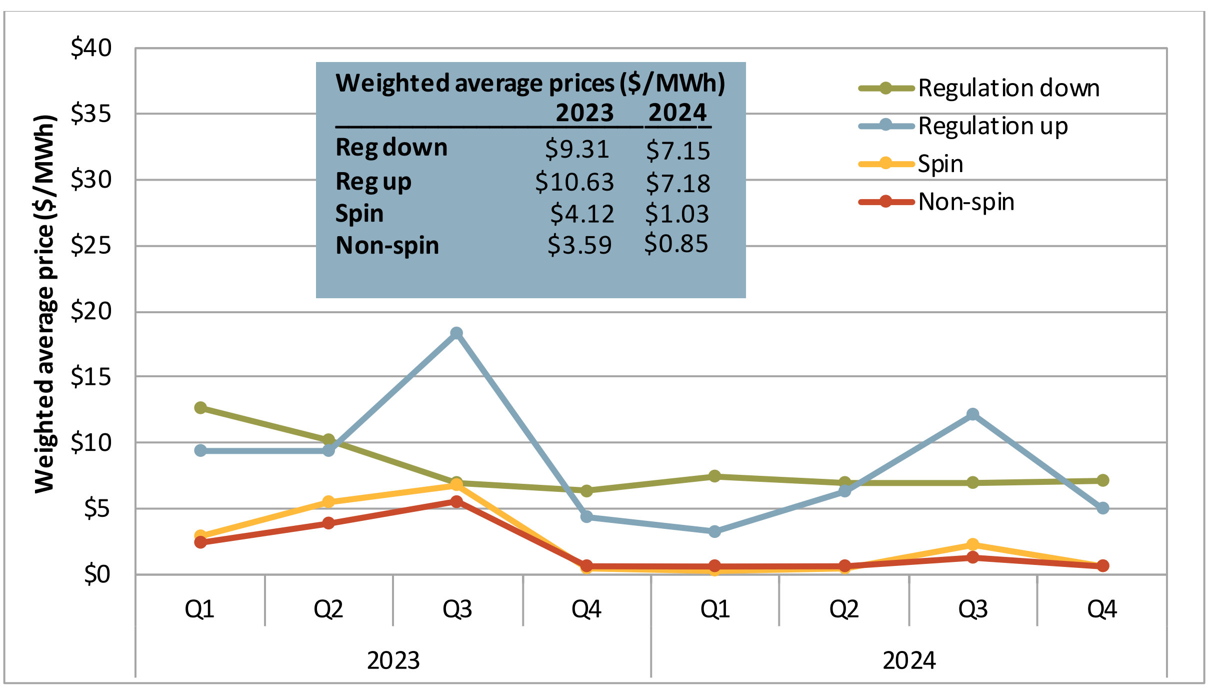



Figure 12.7 shows that the weighted average prices for ancillary services decreased for the most part in the real-time market. In general, ancillary service costs are largely determined by day-ahead market prices since most ancillary services are procured in the day-ahead market, with only 5 percent of ancillary service costs incurred in the real-time market in 2024.

**Figure 12.7 Real-time ancillary service market clearing prices**



## 12.4 Special issues

### 12.4.1 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 CAISO balancing authority area 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.

There were no ancillary service scarcity events in 2024. In comparison, there was only one scarcity event in 2023 and six in 2022. The frequency of ancillary service scarcities has decreased every year since 2019. This lack of scarcity events can be attributed in part to the rapidly increasing participation of battery storage resources, which now provide nearly a majority of the CAISO balancing area's ancillary services.

### 12.4.2 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.[232]

During 2024, the California ISO performed a combined total of 715 performance audits and unannounced compliance tests for resources holding ancillary services, which was an increase from the 335 tests performed in 2023. The failure rate was 12 percent for unannounced tests, an improvement over 15 percent in 2023. The failure rate for performance tests was 3 percent in 2024.

## 12.5 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.[233]

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

[233] 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 12.1 and Table 12.2 summarize the annual frequency of upward and downward available balancing capacity, both offered and scheduled, in each area during 2024.[234] Around half of the WEIM participants offered upward and downward available balancing capacity in at least 95 percent of hours or greater. However, Avangrid, El Paso Electric, LADWP, PSC New Mexico, Puget Sound Energy, Seattle City Light, Idaho Power, and Portland General Electric offered available balancing capacity in less than 10 percent of hours for one or both directions. The table also shows the average size of the available balancing capacity when offered in their hourly resource plan. Similar to previous years, Powerex offered an average of 1,147 and 597 MW of upward and downward available balancing capacity, respectively, during 2024. Overall, available balancing capacity was dispatched very infrequently for scarcity conditions during 2024.

**Table 12.1 Frequency of upward available balancing capacity offered and scheduled (2024)**

| | Offered | | Scheduled | |
|---|---|---|---|---|
| | Percent of hours | Average MW | Percent of intervals (15-minute market) | Percent of intervals (5-minute market) |
| BANC | 100% | 89 | 0.0% | 0.0% |
| Bonneville Power Admin. | 100% | 314 | 0.0% | 0.0% |
| Turlock Irrigation District | 100% | 15 | 0.0% | 0.0% |
| Avista Utilities | 100% | 13 | 0.0% | 0.0% |
| Powerex | 100% | 1,147 | 0.0% | 0.0% |
| Tucson Electric | 100% | 33 | 0.0% | 0.0% |
| Salt River Project | 100% | 98 | 0.0% | 0.0% |
| WAPA - Desert Southwest | 99% | 28 | 0.0% | 0.0% |
| NV Energy | 99% | 61 | 1.0% | 1.0% |
| Portland General Electric | 99% | 30 | 0.0% | 0.0% |
| Tacoma Power | 72% | 2 | 0.0% | 0.0% |
| NorthWestern Energy | 98% | 5 | 0.0% | 0.0% |
| Arizona Public Service | 97% | 30 | 0.0% | 0.0% |
| LADWP | 90% | 60 | 0.0% | 0.0% |
| PacifiCorp East | 37% | 72 | 0.0% | 0.0% |
| Seattle City Light | 1% | 47 | 0.0% | 0.0% |
| PacifiCorp West | 11% | 39 | 0.0% | 0.0% |
| PSC New Mexico | 0.0% | 70 | 0.0% | 0.0% |
| El Paso Electric | 13.0% | 21 | 0.0% | 0.0% |
| Puget Sound Energy | 0.0% | N/A | 0.0% | 0.0% |
| Avangrid | 56% | 45 | 0.0% | 0.0% |
| Idaho Power | 0% | N/A | 0.0% | 0.0% |

[234] 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 12.2 Frequency of downward available balancing capacity offered and scheduled (2024)**

| | Offered | | Scheduled | |
|---|---|---|---|---|
| | Percent of hours | Average MW | Percent of intervals (15-minute market) | Percent of intervals (5-minute market) |
| BANC | 100% | 106 | 0.0% | 0.0% |
| Powerex | 100% | 597 | 0.0% | 1.0% |
| Bonneville Power Admin. | 100% | 332 | 0.0% | 0.0% |
| Turlock Irrigation District | 100% | 5 | 0.0% | 0.0% |
| Avista Utilities | 100% | 13 | 0.0% | 0.0% |
| Tucson Electric | 100% | 35 | 0.0% | 0.0% |
| WAPA - Desert Southwest | 97% | 21 | 0.0% | 0.0% |
| NorthWestern Energy | 98% | 5 | 0.0% | 0.0% |
| Salt River Project | 98% | 49 | 0.0% | 0.0% |
| Tacoma Power | 96% | 3 | 0.0% | 0.0% |
| Arizona Public Service | 98% | 30 | 0.0% | 0.0% |
| NV Energy | 88% | 62 | 1.0% | 1.0% |
| PSC New Mexico | 52% | 77 | 0.0% | 0.0% |
| PacifiCorp East | 70% | 166 | 0.0% | 0.0% |
| PacifiCorp West | 15% | 62 | 0.0% | 0.0% |
| Seattle City Light | 0% | N/A | 0.0% | 0.0% |
| LADWP | 0.0% | 52 | 0.0% | 0.0% |
| Puget Sound Energy | 0.0% | N/A | 0.0% | 0.0% |
| Avangrid | 0.0% | N/A | 0.0% | 0.0% |
| El Paso Electric | 0% | N/A | 0.0% | 0.0% |
| Idaho Power | 0% | N/A | 0.0% | 0.0% |
| Portland General Electric | 0% | N/A | 0.0% | 0.0% |

# 13 Residual unit commitment

This chapter provides information on residual unit commitment (RUC) procurement volume, costs, and undersupply infeasibilities. Analysis of various adjustments to the RUC requirement is in Section 9 on Market Adjustments, and further analysis of the method used to determine adjustments to the RUC load forecast to address uncertainty between day-ahead and real-time net load is in Section 11 on Uncertainty.

Highlights of this chapter include:

- **The average volume of capacity procured through the residual unit commitment process was 385 MW, down 47 percent from 2023.** The volume of procured capacity had increased 81 percent in 2023 over 2022.
- **The total direct cost of non-resource adequacy capacity procured in the residual unit commitment process decreased to about $1.6 million in 2024**, from a direct cost of about $5.4 million in 2023.
- **There was not enough supply to meet the residual unit commitment requirement for a total of nine hours on five separate days in 2024**. Five of these hours occurred on September 6.

### Background

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 the IFM run and the day-ahead forecast load. Capacity procured through residual unit commitment must be bid into the real-time market.

### Residual unit commitment procurement and costs

Figure 13.1 shows average hourly volume of capacity procured in the residual unit commitment process by quarter for 2023 and 2024. The blue bars show RUC capacity procured from resource adequacy resources. The green bars show non-resource adequacy capacity procured in RUC, and the red bars show the amount of RUC procurement from resources' minimum load.

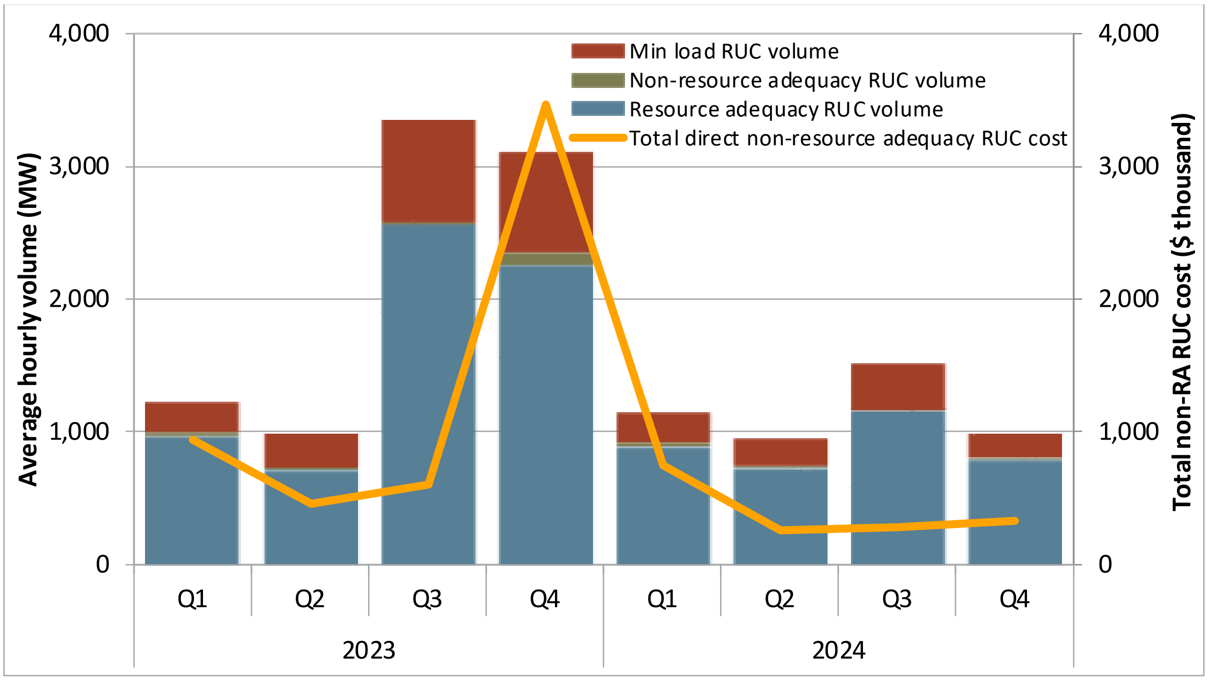
The total volume of capacity procured in the residual unit commitment process was down significantly in 2024 compared to 2023. The average hourly RUC procurement was 385 MW in 2024, down 47 percent from the 722 MW average hourly procurement in 2023. For comparison, RUC procurement volume increased 81 percent from 2022 to 2023.

The large increase in RUC procurement in 2023 and the large decrease in 2024 were due to significant changes the CAISO balancing area made in its procedures for determining adjustments to RUC load forecasts to address load and supply uncertainty. These changes are described in more detail in Section 11.

Some of the capacity procured by the residual unit commitment process in excess of integrated forward market schedules comes from resources' minimum load levels. This is represented by the blue bars in Figure 13.1. Minimum load capacity procured in RUC averaged about 240 MW in 2024, down from about 500 MW in 2023. Most of this capacity is from short-start units that do not need to receive a binding startup instruction from the RUC process. The real-time markets can issue them startup instructions if they are ultimately needed in real-time. Only long-start units without IFM schedules are actually committed to be on-line by the residual unit commitment process.[235] In 2024, about 4 percent of the 240 MW of minimum load capacity procured in RUC was from long-start units, down from 10 percent in 2023.

Most of the capacity procured in the residual unit commitment market does not incur any direct costs because only awards to non-resource adequacy capacity receive RUC capacity payments.[236] As shown by the small green segment of each bar in Figure 13.1, the non-resource adequacy volume averaged about 24 MW per hour in 2024, down from about 40 MW procured in 2023. The total direct cost of non-resource adequacy residual unit commitment, represented by the gold line in the same figure, decreased to about $1.6 million in 2024, from a direct cost of about $5.4 million in 2023.

**Figure 13.1 Residual unit commitment (RUC) costs and volume (2023–2024)**




### Residual unit commitment undersupply infeasibilities

If there is not sufficient supply in the residual unit commitment process (RUC) to meet the load requirement and self-scheduled exports, the power balance constraint can be relaxed. This results in RUC prices being set by a penalty price. The situation is called an undersupply infeasibility.

235 Long-start units are resources with a cycle time of more than 255 minutes (Start-Up Time plus Minimum Run Time is more than 255 minutes) and require between five and up to 18 hours to Start-Up and synchronize to the grid. The definition can be found in Appendix A of the ISO Fifth Replacement Electronic Tariff: https://www.caiso.com/documents/appendixa-masterdefinitionsupplement-asof-jan1-2024.pdf. 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.

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

In September 2020, the California ISO revised the residual unit commitment process 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 adjust procurement of 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.[237]

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.[238] High priority exports receive equal priority to CAISO balancing area load. All low-priority exports that clear the residual unit commitment process will be prioritized below internal load. In addition, the California ISO will prioritize low priority exports that bid into the day-ahead market and clear the residual unit commitment process over new low priority exports that self-schedule into the real-time market.

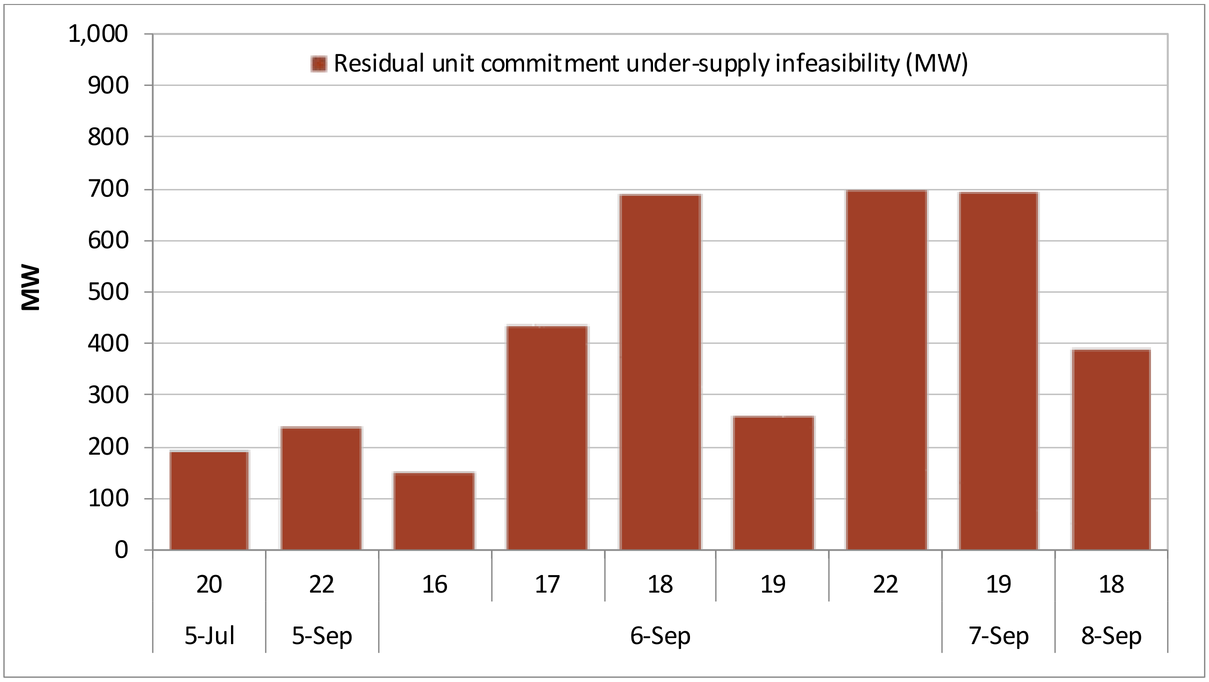
In 2024, the residual unit commitment undersupply power balance constraint was infeasible on a total of nine hours on five separate days. Five of these hours occurred on September 6. These infeasibilities resulted in prices being set around $250/MWh during those hours. In addition, significant volumes of economic exports and low-priority self-schedule exports were not procured in the residual unit commitment process prior to relaxing the power balance constraint.[239]

[237] 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

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

[239] More information on residual unit commitment export schedule reductions can be found in: *Summer Market Performance Report – September 2024*, California ISO, October 31, 2024, Chapter ‘Demand and supply cleared in the markets’, as well as ‘Figure 34: RUC export reduction for August - September 2024’: https://www.caiso.com/documents/summer-market-performance-report-september-2024.pdf

**Figure 13.2 Residual unit commitment undersupply infeasibilities (2024)**



# 14 Convergence bidding

Convergence bidding is designed to align day-ahead and real-time prices by allowing financial arbitrage between the two markets. Throughout 2024, 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.

Other key findings in this chapter include:

- **Annual profits paid to convergence bidders totaled around $50.8 million**, an increase of almost $18 million from 2023, after accounting for about $12 million in bid cost recovery charges allocated to virtual bids. Convergence bidders lost $10.1 million from virtual demand, and virtual supply earned $72.9 million, before accounting for bid cost recovery charges.
- **Virtual supply exceeded virtual demand by an average of about 430 MW per hour**, compared to 700 MW in 2023. The percent of bid-in virtual supply and demand clearing was around 50 percent, an increase from about 41 percent in 2023.
- **Financial entities and marketers continued to earn the most profits from virtual bidding**, receiving about 96 percent and 3 percent of positive net revenues, respectively. Load serving entities received nearly 1 percent of positive net revenues, and physical generators lost money from virtual positions overall.
- **Financial participants held the majority of cleared virtual positions (nearly 83 percent) throughout 2024**, continuing a multi-year trend. As with the previous years, financial participants bid more virtual supply than demand.

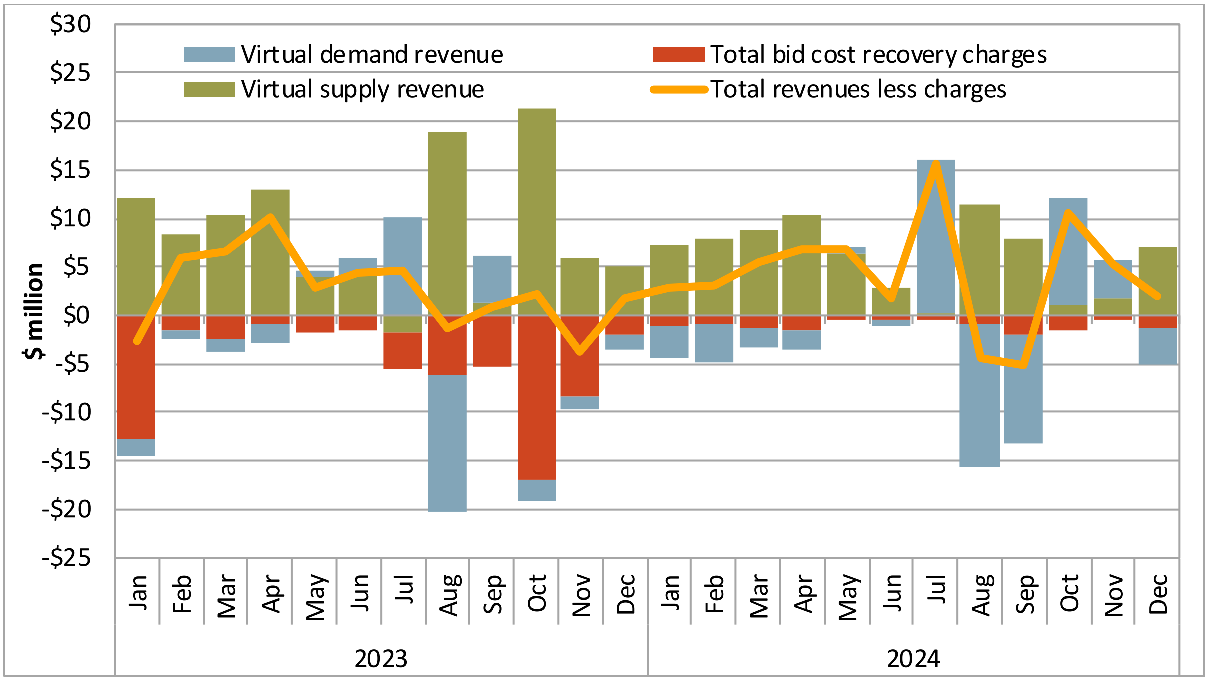
## 14.1 Convergence bidding revenues

Historically, net convergence bidding revenues have been positive for most months in a given year. In 2024, net convergence bidding revenues were negative for August and September. Net revenues for convergence bidders, before accounting for bid cost recovery charges, were about $62.8 million, compared to $95.4 million in 2023. Net revenues for virtual supply and demand increased to $50.8 million from about $32.4 million in 2023, after accounting for bid cost recovery charges associated with virtual supply.[240]

Figure 14.1 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).

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

**Figure 14.1 Convergence bidding revenues and bid cost recovery charges**




### Net revenues and volumes by participant type

Table 14.1 compares the distribution of convergence bidding cleared volumes and net revenues among different groups of convergence bidding participants.[241] For 2024, DMM updated the methodology for classifying participant type.

The quantity of virtual bids increased 26 percent from 2023 due to increased participation from financial entities. Following a trend from past years, most virtual bidding was conducted by entities engaging in purely financial trading that do not serve load or transact physical supply.

[241] 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 14.1 Convergence bidding volumes and revenues by participant type – 2023 to 2024

| 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 | |
| **2024** | | | | | | | | |
| Financial | 2,997 | 3,259 | 6,256 | -$3.43 | $62.62 | -$9.05 | $53.57 | $50.14 |
| Marketer | 420 | 460 | 880 | -$4.83 | $7.14 | -$.89 | $6.25 | $1.42 |
| Physical load | 44 | 93 | 137 | -$.18 | $1.61 | -$.90 | $.71 | $.53 |
| Physical generation | 100 | 176 | 275 | -$1.63 | $1.50 | -$1.17 | $0.33 | -$1.30 |
| **Total** | **3,561** | **3,988** | **7,548** | **-$10.07** | **$72.87** | **-$12.01** | **$60.86** | **$50.79** |
| **Trading entities** | **Average hourly megawatts** | | | **Revenues\Losses ($ million)** | | | | **Total revenue after BCR** |
| | **Virtual demand** | **Virtual supply** | **Total** | **Virtual demand** | **Virtual supply before BCR** | **Virtual bid cost recovery** | **Virtual supply after BCR** | |
| **2023** | | | | | | | | |
| Financial | 2,170 | 2,632 | 4,802 | -$4.02 | $83.10 | -$40.53 | $42.57 | $38.55 |
| Marketer | 442 | 586 | 1,028 | -$2.65 | $18.06 | -$12.53 | $5.53 | $2.88 |
| Physical load | 0 | 22 | 22 | $0 | $.59 | -$5.58 | -$4.99 | -$4.99 |
| Physical generation | 40 | 109 | 149 | -.73 | $1.08 | -$4.43 | -$3.35 | -$4.08 |
| **Total** | **2,652** | **3,349** | **6,001** | **-$7.40** | **$102.83** | **-$63.07** | **$39.76** | **$32.36** |

# 15 Resource adequacy

The purpose of the resource adequacy program is to ensure the California ISO balancing area has enough resources to operate the grid safely and reliably in real-time. Key findings in this chapter include:

- **The nameplate capacity of batteries and solar grew the most out of any resource type in the CAISO balancing area, adding 4.4 GW and 1.5 GW, respectively, since June 2024**. The CAISO fleet currently has 2.2 GW of capacity from resources with multiple generation technologies participating under the hybrid model, which is an increase of around 260 MW from last year. Overall, nameplate capacity has had a net increase of 5.6 GW since June 2024. In comparison, CAISO added 6.4 GW of nameplate capacity from June 2023 to June 2024.
- **Between June 2024 and June 2025, only 240 MW of capacity withdrew from CAISO**, including 80 MW of solar.
- **Four of the CAISO balancing area's 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.
- **Resource adequacy capacity provided sufficient coverage of annual instantaneous peak load.** The annual instantaneous peak load in 2024 reached 48,323 MW on September 5 during hour-ending 17. The total CAISO balancing area load requirement including operating reserve (2,854 MW) and regulation up (680 MW) requirements was 51,853 MW. Schedules from resource adequacy resources in the real-time market were over 53,000 MW. This included solar, wind, and other schedules in excess of a resource's resource adequacy capacity.
- **Average resource adequacy capacity exceeded average load during the emergency notification hours in 2024**. There were 332 total hours with RMO+ emergency notifications, and seven EEA Watch+ hours in 2024, all occurring in July, August, and September. Average hourly load was about 37 GW during these hours, while average resource adequacy capacity was 53 GW.
- **Capacity available after reported outages and de-rates was 95 percent in the day-ahead market and 94 percent in the real-time market for RMO+ availability assessment hours**. Average resource adequacy capacity was around 52,805 MW during the RMO+ hours that occurred over evening peak net load hours in 2024.
- **Resources that are not availability-limited accounted for just 32 percent of system capacity.** About 16,900 MW of system capacity was subject to California ISO bid insertion during all hours. Gas-fired generation in this category made up about 15,600 MW (30 percent) of total resource adequacy capacity. Other generators accounted for less than 3 percent.
- **The amount of resource adequacy procured from storage resources increased significantly in 2024.** Storage resources accounted for the second largest portion (15 percent) of total capacity behind gas resources in 2024.
- **Investor-owned utilities procured most of the system capacity.** Investor-owned utilities accounted for about 30,700 MW (58 percent) of system resource adequacy procurement, community choice aggregators contributed 25 percent, municipal utilities contributed 9 percent, and direct access services contributed 8 percent. The remaining is a combination of the capacity procurement mechanism and the Central Procurement Entity.
- **Both year-ahead and actual flexible resource adequacy requirements were sufficient to meet the actual maximum three-hour net load ramp for all months in 2024.** The effectiveness of flexible requirements and must-offer rules in addressing supply during maximum load ramps depends on

the ability to predict the size and timing of the maximum net load ramp. This analysis suggests the 2024 requirements and must-offer hours were sufficient in reflecting actual ramping needs in all cases.

- **Resource adequacy availability incentive mechanism penalties totaled $75.3 million in 2024, an increase of about $24.4 million from 2023.** Much of this is attributable to flexible resource adequacy charges increasing to $47.7 million in 2024 from about $29.7 million in 2023.

## 15.1 Background

The purpose of the resource adequacy program is to ensure the California ISO balancing area has enough capacity to operate the grid reliably. Along 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. 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 for reliability during system-level peak demand each month;
2. Local resource capacity for reliability in specific areas with limited import capability; and
3. Flexible resource capacity for reliability during ramping periods.

Load serving entities make filings with 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, supplying entities must make capacity available to the California ISO market according to rules that depend on requirement and resource type.

## 15.2 CAISO load conditions

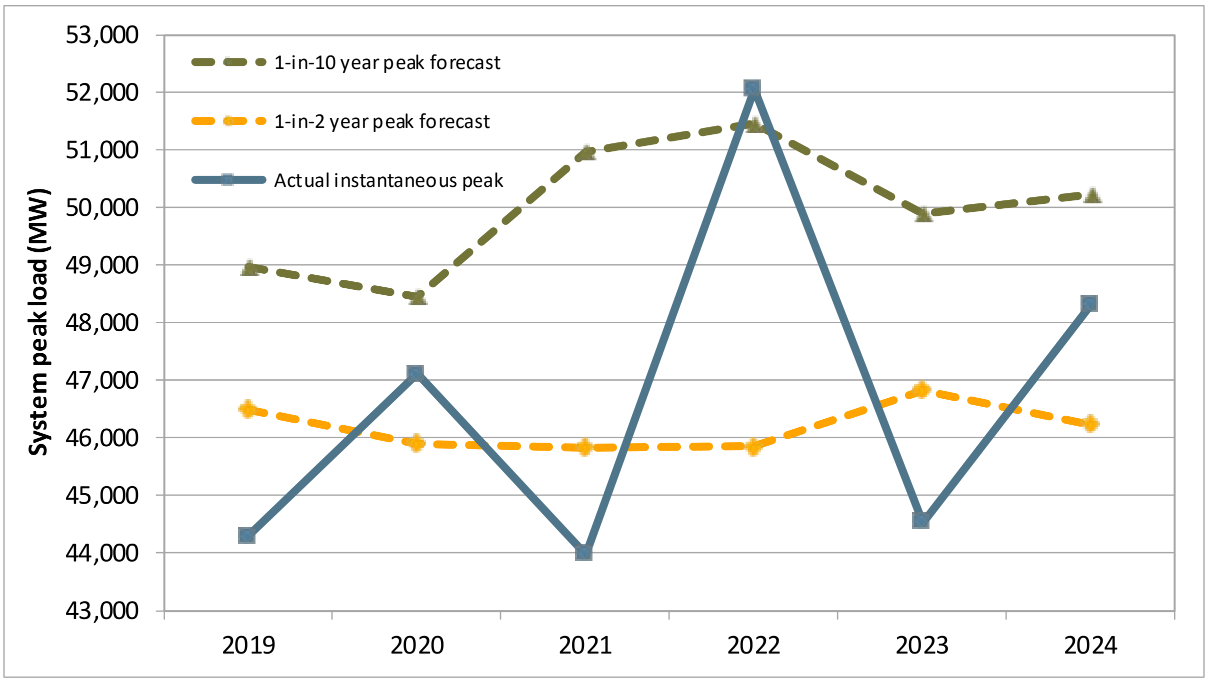
This section provides an overview of load conditions in the California ISO balancing authority area. In 2024, CAISO total annual energy load increased from 2023 to 2024 to 207,000 GWh, reversing a previously decreasing trend. The system peak load in 2024 increased from 2023 as well. Load conditions and forecasts are used in determining resource adequacy requirements.

### CAISO peak load

Instantaneous summer loads peaked at 48,323 MW on September 5, about 3,800 MW higher than the 2023 peak. This peak represents the third highest instantaneous load on record for the California ISO since 2010.[242]

The instantaneous peak load in 2024 was 4.5 percent higher than the CAISO *1-in-2 year* load forecast (46,244 MW) and 3.8 percent lower than the *1-in-10 year* forecast (50,220 MW) as shown in Figure 15.1. 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 plus a planning reserve margin. Resource adequacy requirements for local areas are based on the *1-in-10 year* (or 90th percentile year) peak forecast for each area.

**Figure 15.1 Actual instantaneous load compared to planning forecasts**




### CAISO 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. Section 15.4 of this report assesses the structural competitiveness of

242 California ISO Instantaneous Peak Load History, 1998-2024:
https://www.caiso.com/documents/californiaisopeakloadhistory.pdf

https://www.caiso.com/documents/2024-statistics.pdf the market for capacity in local areas. Section 3.4 assesses the frequency and impact of local energy market power mitigation procedures. This section provides a high-level perspective of supply and demand conditions in each local area.

Table 15.1 presents forecasted peak load, current dependable generation, and capacity requirements for these local capacity areas. Figure 15.2 shows the location of each local capacity area and the proportion of each area's load, relative to the total system peak load.[243] 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 15.1 Load and supply within local capacity areas in 2024[244]**

| 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 | PG&E | 11,081 | 23% | 7,948 | 7,329 | 92% |
| Greater Fresno | PG&E | 3,354 | 7% | 3,127 | 2,028 | 65% |
| Sierra | PG&E | 1,758 | 4% | 1,883 | 1,212 | 64% |
| North Coast/North Bay | PG&E | 1,495 | 3% | 989 | 983 | 99% |
| Stockton | PG&E | 1,080 | 2% | 750 | 750 | 100% |
| Kern | PG&E | 924 | 2% | 427 | 427 | 100% |
| Humboldt | PG&E | 173 | 0.4% | 176 | 133 | 76% |
| LA Basin | SCE | 19,637 | 40% | 8,353 | 4,413 | 53% |
| Big Creek/Ventura | SCE | 4,579 | 9% | 4,117 | 1,971 | 48% |
| San Diego/Imperial Valley | SDG&E | 4,908 | 10% | 5,388 | 2,834 | 53% |
| **Total** | | **48,989** | | **33,158** | **22,080** | |

*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.

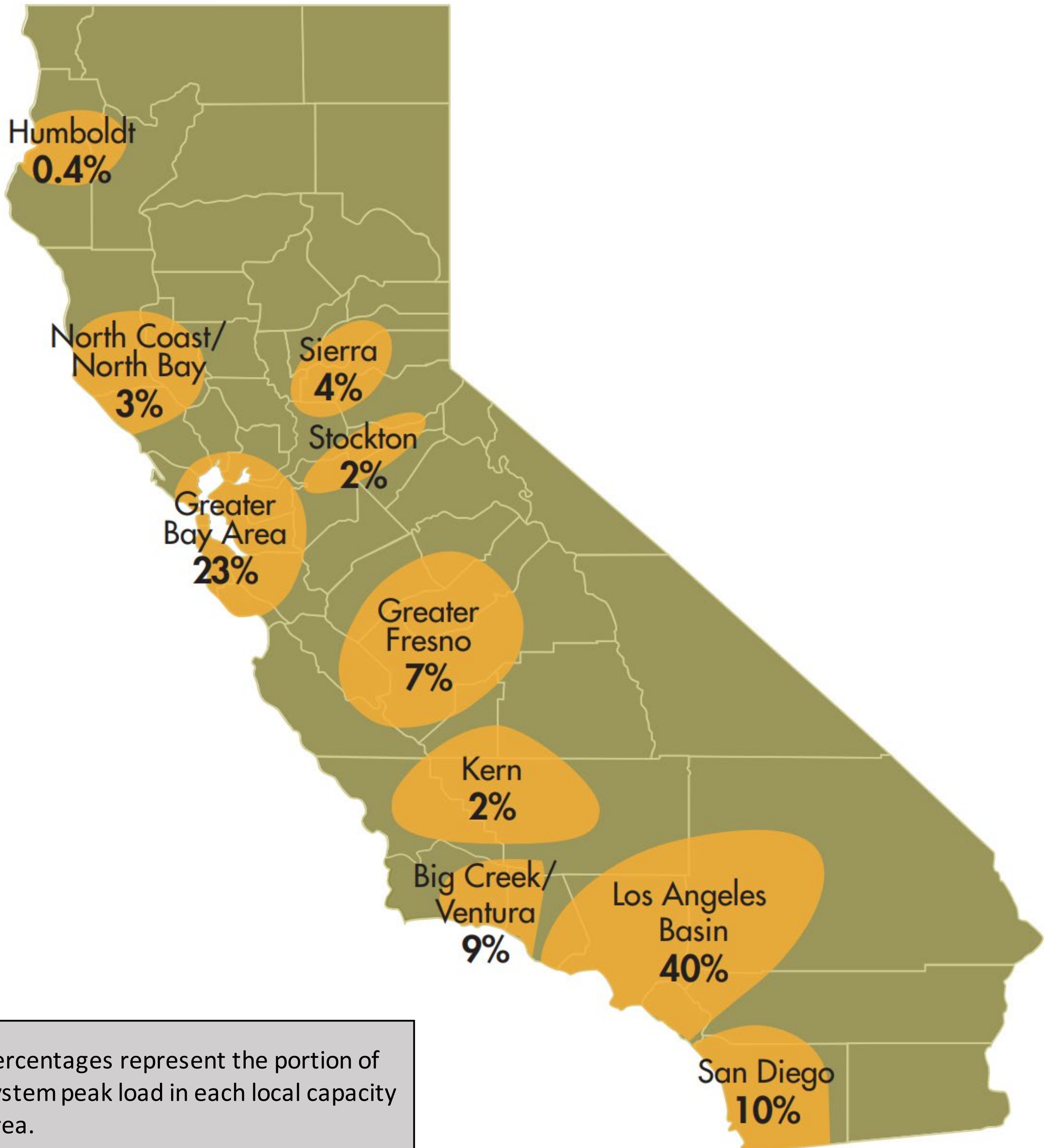
The California ISO performs annual studies to identify the minimum local resource capacity requirements in each local area to meet established reliability criteria. An updated criterion is used in the study to match the NERC transmission planning standards for resource adequacy in year 2024. As a result, local capacity requirements decreased to 22,080 MW for 2024 compared to 25,449 MW in 2023. Dependable generation decreased and peak load slightly increased overall in these areas. The final column in Table 15.1 shows the local reliability requirement as a percent of dependable generation in each local capacity area. 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. Requirements decreased in the LA Basin by 3,116 MW and increased in the Greater Bay Area by 17 MW. Requirements decreased in the San Diego/Imperial Valley area by 498 MW and increased in the Greater Fresno area by 158 MW. In 2024, the 1-in-10 year peak load increased in the LA Basin and San Diego/Imperial Valley

[243] Note that the total local area peak load figure, as well as a 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.

[244] *2024 Local Capacity Technical Study*, California ISO, April 28, 2023, p 27, Table 3.1-1: https://stakeholdercenter.caiso.com/InitiativeDocuments/Final-2024-Local-Capacity-Technical-Report.pdf

areas by 100 MW and 152 MW, respectively. The peak load decreased in the Greater Bay Area by 55 MW.

**Figure 15.2 Local capacity areas**




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

## 15.3 CAISO 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. Since summer 2024, the primary trend in capacity changes has been an increase in battery capacity.

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.

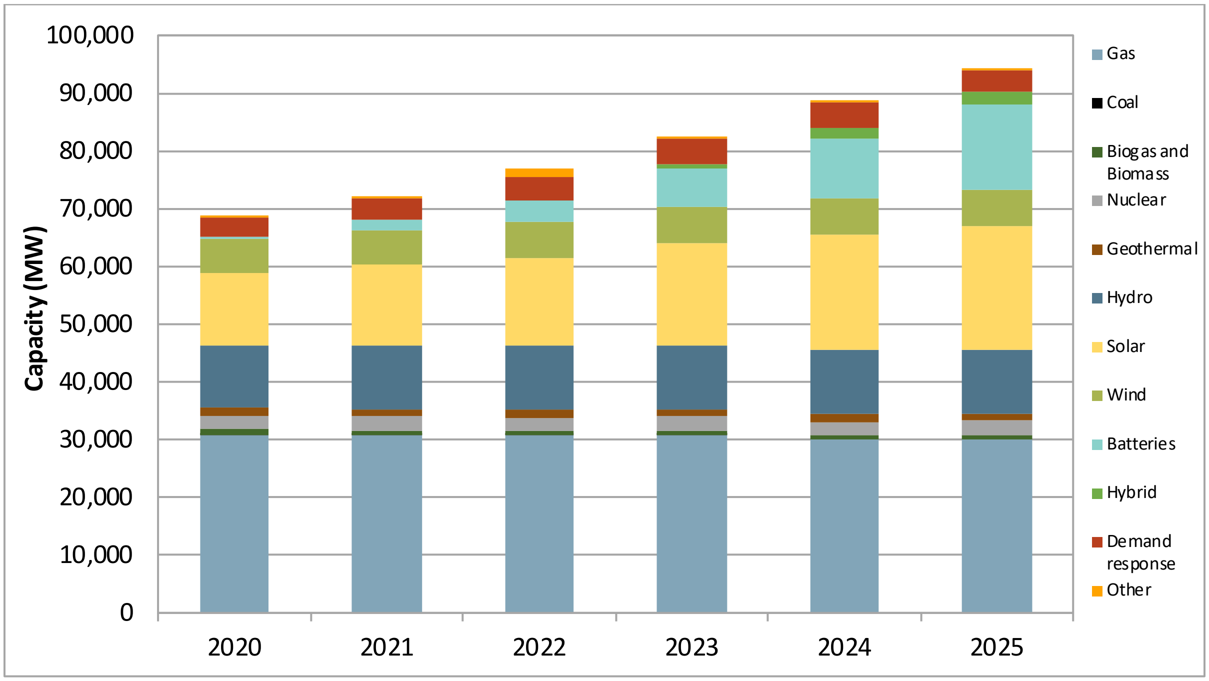
Graphs reflect nameplate capacity and changes between Junes of one year to the next to reflect changes to summer capacity.[245]

### Total California ISO registered and participating capacity

Figure 15.3 summarizes the trends in available nameplate capacity from June 2020 through June 2025 for the California ISO balancing area. At 30.2 GW, natural gas capacity slightly increased by around 120 MW since last year. Batteries and solar grew the most out of any resource type in CAISO, adding 4.4 GW and 1.5 GW, respectively, since June 2024. The CAISO fleet currently has 2.2 GW of capacity from resources with multiple generation technologies participating under the hybrid model, which is an increase of around 260 MW from last year. Overall, nameplate capacity has had a net increase of 5.6 GW since June 2024. In comparison, the CAISO added 6.4 GW of nameplate capacity from June 2023 to June 2024.

[245] 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.

**Figure 15.3 Total California ISO participating capacity by fuel type and year (as of June 1)**



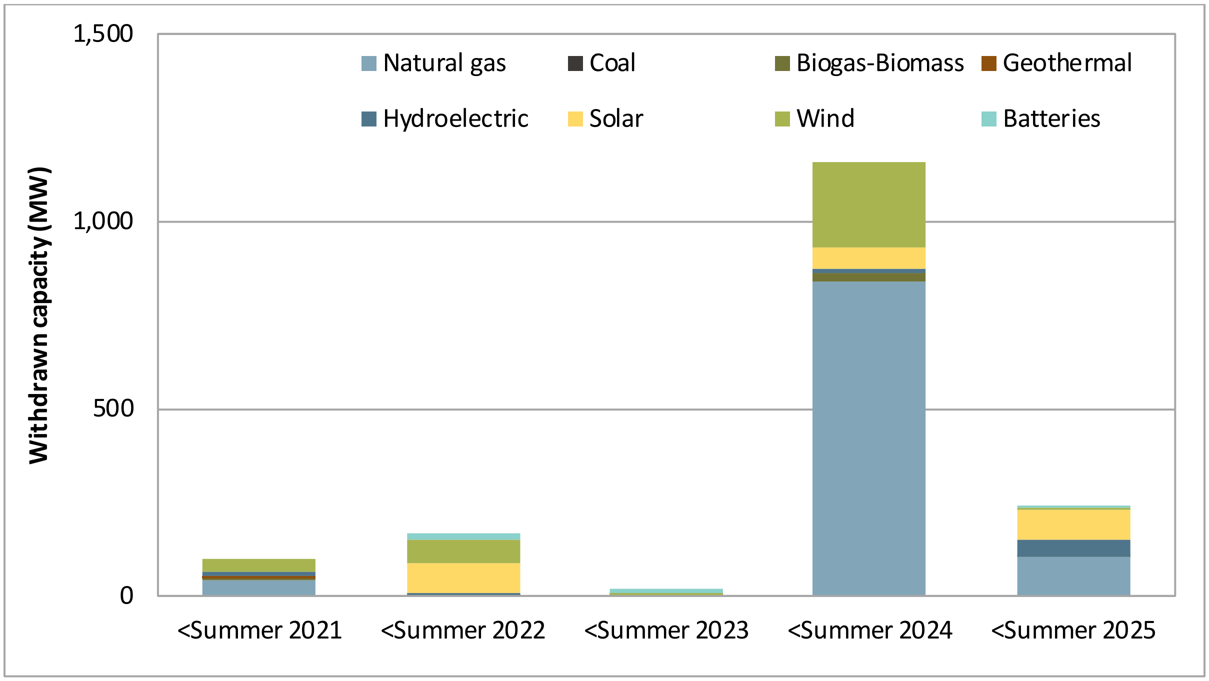

### Withdrawal and retirement of California ISO participating capacity

In recent years, the California ISO (ISO) and several California state agencies have taken steps to ensure there is enough capacity to meet peak summer load, resulting in a historically low number of resource retirements. In addition, the State Water Resources Control Board adopted a resolution amending its policy on once-through cooling (OTC) to delay the retirement of six natural gas generating units, with nearly 3,000 MW of capacity, from December 2023 until 2026.[246]

Figure 15.4 shows the withdrawal and retirement of capacity from June 2020 through 2025. Between June 2020 and June 2023, only around 290 MW of capacity withdrew from the market. Resources that didn't have their OTC policy compliance date extended drove a large amount of capacity retirement between June 2023 and 2024. Between June 2024 and June 2025, around 240 MW of capacity withdrew from the market, including 80 MW of solar.

[246] State Water Resources Control Board, Resolution No. 2023-0025, August 15, 2023, p 3-4: https://www.waterboards.ca.gov/board_decisions/adopted_orders/resolutions/2023/rs2023-0025.pdf

**Figure 15.4 Withdrawals from California ISO market participation by fuel type**




### Additions to participating capacity

Figure 15.5 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.[247]

From June 2019 to June 2025, around 10.8 GW of solar, 1.9 GW of natural gas, 1.1 GW of wind, 2.3 GW of hybrid[248], and 14.4 GW of battery capacity were added or returned to the market.[249] The majority of the increase in battery capacity happened within the last two years, with around 8 GW of capacity added since June 2023.

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

248 The growth in hybrid in this figure does not include resources that converted from solar capacity.

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

**Figure 15.5 Additions to California ISO market participation by fuel type[250]**

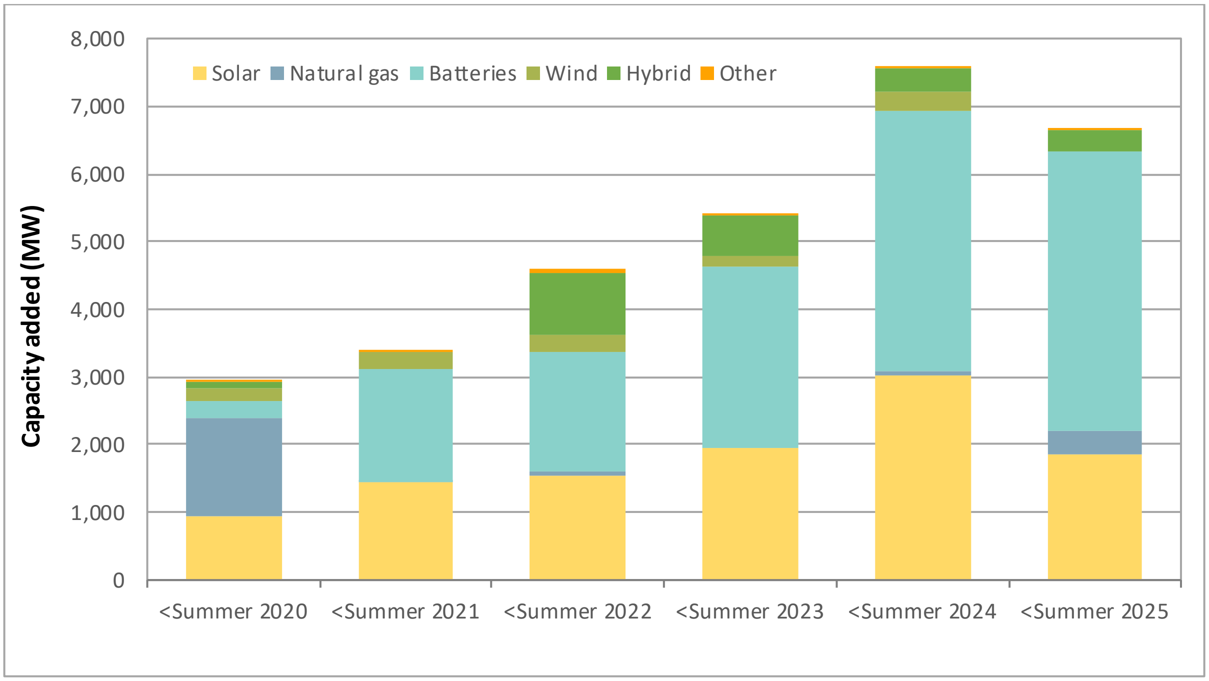
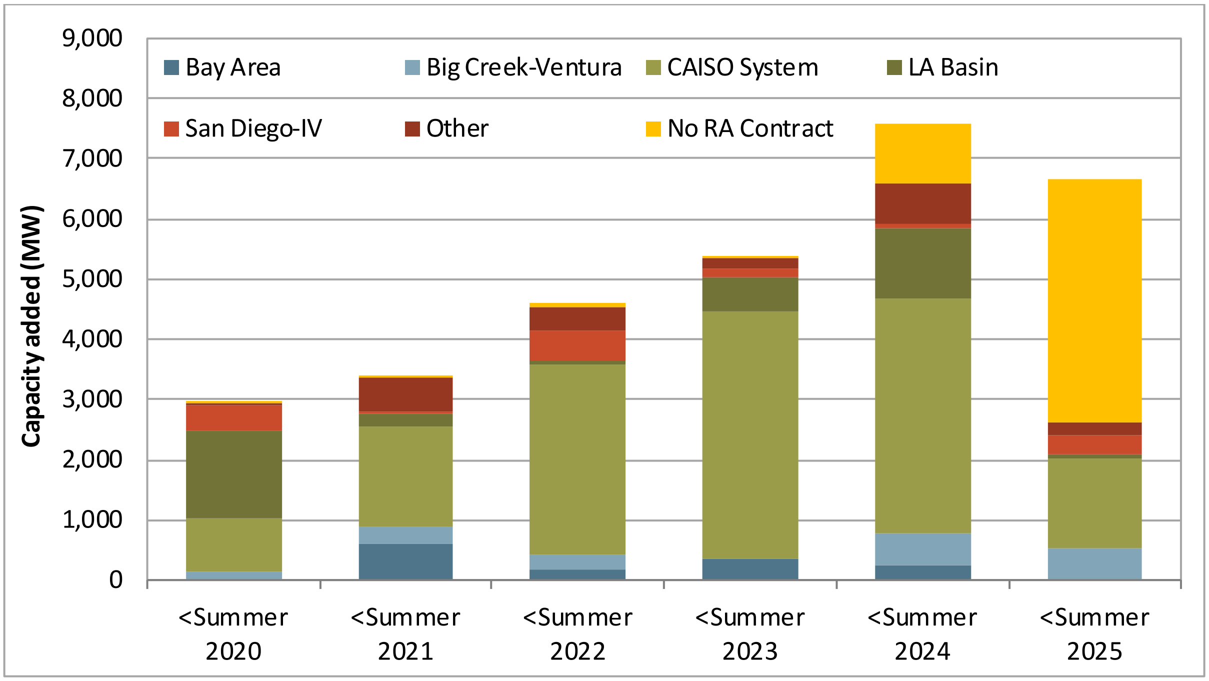



Figure 15.6 shows additions by local area according to local resource adequacy showings. Resources shown for system resource adequacy (RA) are labeled as CAISO System and are represented by the light olive bars.[251] In the last couple of years, a significant amount of the new capacity came in as system RA, with around 4.1 GW added from June 2022 to June 2023, and 3.9 GW added from June 2023 to June 2024. The majority of added capacity from June 2024 to June 2025 has no RA contract as of this report's drafting, though this is subject to change.

250 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.

251 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 15.6 Additions to California ISO market participation by local area**




The California ISO requires projects to undergo a series of impact studies before they can be connected to the grid. The list of projects in this process is known as the "interconnection queue". The interconnection queue currently includes about 104 GW of planned capacity, around 56 percent of which comes from mixed-fuel projects. All mixed-fuel projects currently in the interconnection queue contain a battery, with 96 percent of them being paired with a wind or solar resource. The most common project types in the interconnection queue are battery only and battery/solar combination projects, making up 41 GW and 49 GW of all planned capacity, respectively. Among non-battery projects, wind and solar projects are most common and make up 4 GW of all planned capacity.

The ISO's 20-year transmission outlook calls for 165.1 GW of capacity additions to meet its 2045 resource portfolio, including over 69 GW of solar, 35 GW of wind, and around 49 GW of battery storage resources.[252] Historically, the median wait time for completed projects has been around 2,150 days, while the median wait time for projects currently in the queue is around 3,520 days. About 3 GW of capacity has come on-line since June 2024. However, many projects drop out of the interconnection queue before their interconnection studies are finished. In 2024, 43 projects totaling 11 GW of planned capacity withdrew from the interconnection queue. The median wait time for projects that have dropped out of the CAISO interconnection queue historically has been 363 days from their queue start date until dropping out.

[252] *20 Year Transmission Outlook*, California ISO, May 4, 2022, p 2: http://www.caiso.com/InitiativeDocuments/20-YearTransmissionOutlook-May2022.pdf

## 15.4 CAISO local capacity requirements and structural measures of competitiveness

In 2024, four 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 15.2 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 through 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.[253]

Table 15.2 shows that the Greater Bay area is the only area—of areas in which the total local resource adequacy requirement exceeds capacity held by load serving entities—that has sufficient non-load serving entity capacity to meet its net non-load serving entity capacity requirement. In all of the local capacity areas in the table, at least one supplier is individually pivotal for meeting the remainder of the capacity requirement. In other words, some portion of a single supplier's capacity is needed to meet the portion of local requirements not covered by load serving entities' supply. In the case of Kern, North Coast/North Bay, and Stockton, there is not enough non-LSE capacity in their respective local capacity areas to meet the requirement.

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 in year 2024.[254] As a result, the total local capacity requirement decreased by 3,369 MW (13.2 percent) between 2023 and 2024, with a considerable decrease to the LA Basin and San Diego/Imperial Valley local capacity area requirements.

Key findings of this analysis include the following:

- The Greater Bay, Kern, North Coast/North Bay, and Stockton 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.

[253] 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 likely overestimates competitiveness in local areas.

[254] *2024 Local Capacity Technical Study*, California ISO, April 28, 2023: https://stakeholdercenter.caiso.com/InitiativeDocuments/Final-2024-Local-Capacity-Technical-Report.pdf

- In 2024, the LA Basin and San Diego/Imperial Valley local area capacity requirements decreased from 2023 due to new transmission projects.

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.[255]

**Table 15.2 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 | 5047 | 5782 | 1.15 | 0.47 | 0.10 | 0.05 | 2 |
| Kern | 313 | 304 | 0.97 | 0.00 | 0.00 | 0.00 | 3 |
| North Coast/North Bay | 836 | 826 | 0.99 | 0.00 | 0.00 | 0.00 | 3 |
| Stockton | 535 | 497 | 0.93 | 0.30 | 0.05 | 0.02 | 3 |

*Available capacity is insufficient to meet the LCA requirement; All supply is needed to contribute toward the LCA requirement

In the day-ahead and real-time energy markets, the potential for local market power is mitigated through bid mitigation procedures. These procedures require that each congested transmission constraint be designated as either competitive or non-competitive in each market run. This designation is based on established procedures for applying a pivotal supplier test in assessing the competitiveness of constraints. Section 3.4 examines the frequency and impact of these automated bid mitigation procedures.

255 For further information on the capacity procurement mechanism, see Section 15.8.

## 15.5 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 balancing area issued energy emergency alerts to operate the grid safely and reliably.[256]

### Regulatory requirements

The California ISO balancing area 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). The CPUC local regulatory authority planning reserve margin for 2024 was set at 17 percent, with an "effective" planning reserve margin procurement target of 1,700 to 3,200 MW which would translate to 21 to 23.5 percent.[257,258] 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.[259] For monthly supply plan showings, CPUC-jurisdictional entities must demonstrate they have procured 100 percent of their monthly system obligation. Table 15.3 shows recent CPUC decisions that affected the procurement, availability, or performance of resource adequacy resources in 2024:

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256 Previous annual reports analyzed resource adequacy availability during the top 210 load hours of the year.

257 The planning reserve margin reflects operating reserve requirements and additional capacity to cover potential forced outages and load forecast error.

258 For the summers of 2024 and 2025, CPUC decision D.23-06-029 determined an "effective" PRM target of 1,700 to 3,200 MW by requiring extra procurement from the three investor owned utilities (IOUs). See Table 15.3 for more details.

259 A showing is the list of resources and procured capacity that load serving entities and suppliers show to the California ISO in annual and monthly resource/supply plans.

### Table 15.3 Recent CPUC decisions relevant to 2024 resource adequacy year[260]

| Decision | Title | Description |
|---|---|---|
| D.21-06-029 | Decision Adopting Local Capacity Obligations for 2022-2024, Adopting Flexible Capacity Obligations for 2022, and Refinements to the Resource Adequacy Program | Starting in the 2022 compliance year, the Maximum Cumulative Capacity Buckets were adjusted to require availability Monday through Saturday and the availability of Category 1 resources increased to 100 hours per month.<br><br>For demand response resources, the 6% component of the planning reserve margin (PRM) adder associated with ancillary services and operating resources is removed for demand response resources and the distribution loss factor (DLF) adder is incorporated into DR qualifying capacity values starting in the 2022 compliance year.<br><br>A points-based penalty structure for RA deficiencies is added to the current penalty structure where LSEs are charged a multiple of the system RA penalty price based on how many points they accrue in a 24-month period for having month-ahead deficiencies. |
| D.22-06-050 | Decision Adopting Local Capacity Obligations for 2023 - 2025, Flexible Capacity Obligations for 2023, and Reform Track Framework | The Commission modified Resource Adequacy (RA) measurement hours to 5:00-10:00 PM for March and April, and 4:00–9:00 PM for all other months. The modified RA hours shall be effective beginning in the 2023 RA compliance year. A 16% PRM is adopted for 2023, and a minimum of a 17% PRM for 2024. ELCC values for solar and wind were updated, and the quarterly demand response testing must be for 4 hours. Slice-of-day is adopted with a test year in 2024 and program implementation in 2025. An exceedance methodology is adopted to calculate solar and wind profiles for RA accounting. Storage resource accounting must be accompanied by excess energy generation. |
| D.23-04-010 | Decision on Phase 2 of the Resource Adequacy Reform Track | The Commission adopted changes to the Maximum Cumulative Capacity buckets structure and the 2024 test year for the 24-hour slice-of-day framework. Standalone energy storage resources may be included in the MCC bucket 4 in the 2024 Resource Adequacy compliance year.<br><br>Starting with the 2024 test year in the slice-of-day framework, MCC buckets 1-4 won't be applicable to the Resource Adequacy program while retaining the demand response bucket. Non-resource speciifc imports will count towards the RA requirements for the 2024 test year under some conditions |
| D.23-06-029 | Decision on Phase 3 of the Resource Adequacy Implementation Track | Adopts the local and flexible RA requirements for 2024 - 2026. Adopts a PRM of 17% from 2024 and 2025, and further extends the Effective PRM to stay at approximately 22.5%.<br>Requires all import RA to procure available transmission capability (ATC).<br><br>Beginning with the 2024 RA compliance year, demand response resources except reliability demand response resources must be available for the duration of California ISO and Governor's Office emergency notifications. Reliablity Demand Response Resources (RDRR) are enabled to bid into periods in the day-ahead when the system is under EEA Watch conditions, or greater. Demand response cannot bid above RDRR, and a bid cap of $949/MWh has been adopted. |

### 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.[261] Day-ahead cleared schedules include total energy, spin reserves, non-spin reserves, and regulation up schedules; real-time market cleared schedules include energy schedules only.[262] This analysis caps bids, schedules, and meter amounts at the resource adequacy capacity values of individual resources, unless otherwise indicated in the tables, 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.

### Availability and performance during Energy Emergency Alert hours

The California ISO is a summer peaking balancing area with a generation mix that is becoming increasingly 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 to be available at least 100 hours per month all year round, excluding March and April.[263]

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 when there are relatively lower loads. This is because generation and transmission capacity are 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. On April 1, 2022, the California ISO moved from the Alert, Warning, and Emergency (AWE) notification system to the Energy Emergency Alert (EEA) system to align with NERC emergency levels.[264] Table 15.4 provides descriptions of the EEA systems, and how hours with these notifications are included in the analysis of this section.

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260 More information is available on the CPUC's Resource Adequacy Homepage: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage

261 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.

262 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.

263 100 hours comes from the CPUC's maximum cumulative capacity (MCC) buckets. Under this construct, all resources counted toward resource adequacy requirements (except for demand response) must be available for at least 100 hours across summer months. CPUC decision D.22-06-050 changed this requirement from 200 hours over the summer months (May through September) to the 100 hours per month. February has a 96-hour requirement.

264 This series of notifications matches the North America Electric Reliability Corporation's (NERC) Energy Emergency Alert (EEA) system. To learn more about EEAs and AWEs, go to: http://www.caiso.com/informed/Pages/Notifications/NoticeLog.aspx

**Table 15.4 Energy Emergency Alert (EEA) categories and analysis groups (effective on 4/1/2022)[265]**

| Notification category | Description | Analysis category | | | |
|---|---|---|---|---|---|
| | | Flex Alert | RMO+ | EEA Watch+ | EEA2+ |
| Flex Alerts | A call to consumers to voluntarily conserve energy when demand for power could outstrip supply. This generally occurs during heatwaves, when electrical 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 | | |
| EEA Watch | When the Day-Ahead analysis is forecasting that one or more hours may be energy deficient. | | X | X | |
| Energy Emergency Alert 1 (EEA 1) | When real-time analysis is forecasting that one or more hours may be energy deficient. | | X | X | |
| Energy Emergency Alert 2 (EEA 2) | When all resources are in use and emergency load management programs are needed. | | X | X | X |
| Energy Emergency Alert 3 (EEA3) | When all actions listed above have been taken, yet expected energy and contingency reserve requirements cannot be met. Notice issued to utilities of potential electricity interruptions through firm load shedding. | | X | 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. | | | | |

The following analysis groups emergency notification hours to show availability and performance during a variety of stressed system conditions. The California ISO may request reliability coordinators to issue an EEA 1, EEA 2, or EEA 3, depending upon the circumstance.[266] 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 categories of analysis for each year: the *Flex Alert*, *RMO+*, and *EEA Watch+.* 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. Flex Alerts typically include evening peak hours; however, they can also include hours that span over a few days. The *RMO+* category includes hours when the California ISO issued a notification at least as severe as a Restricted

[265] Upon declaration of EEA3, all impacted entities will be alerted without delay, within a maximum timeframe of 30 minutes. Notifications will be sent to all BAAs, TOPs, and Western RCs via a GMS WECC-Wide message. Market participants within the RC area will receive notifications via GMS. These notifications should include the name of the BAA, the EEA level, and contact information that other BAAs can use to provide emergency assistance. The California ISO's reliability coordinator procedure: https://www.caiso.com/Documents/RC0410.pdf

[266] An EEA Watch can be issued in the day-ahead timeframe. A Flex Alert should always be issued in conjunction with an EEA Watch. When real-time analysis predicts energy shortages for one or more hours, EEA levels 1, 2, and 3 can be issued in any order. Each EEA level enables the California ISO to trigger different emergency demand response programs and other out-of-market programs. For additional details, please see:
http://www.caiso.com/Documents/4100.pdf
https://www.caiso.com/Documents/4420.pdf

Maintenance Operations notification, which often lasts over multiple days. The *EEA Watch+* category includes hours in 2024 in which the California ISO issued a notification that was at least as severe as an Energy Emergency Alert Watch (EEA Watch).

In addition to the California ISO emergency notification categories, the ISO annually updates the availability assessment hours (AAH) to reflect the hours of greatest reliability need as part of the Resource Adequacy Availability Incentive Mechanism (RAAIM). In 2024, the availability assessment hours for system and local resource adequacy were:

- Hours-ending 18 through 22 for spring (March 1 through May 31)
- Hours-ending 17 through 21 for summer (June 1 through October 31) and winter (November 1 through February 28)

Most of the analysis in this section will focus on the availability assessment hours within the RMO+ hours.[267] All the RMO+ and EEA Watch+ alerts were in effect during the summer AAH months, so much of the analysis will examine hours-ending 17 through 21.

Figure 15.7 provides an overview of resource adequacy capacity during system emergency notification hours in 2024. The green, blue, and yellow bars show the number of hours, by month, that are in the *RMO+, Flex Alert*, and *EEA Watch+* categories, respectively. Note, there were no Flex Alerts in 2024, but for comparison to previous years, Flex Alerts were included. 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.[268] The dashed red line adds the additional capacity the CPUC credits towards load serving entity obligations.

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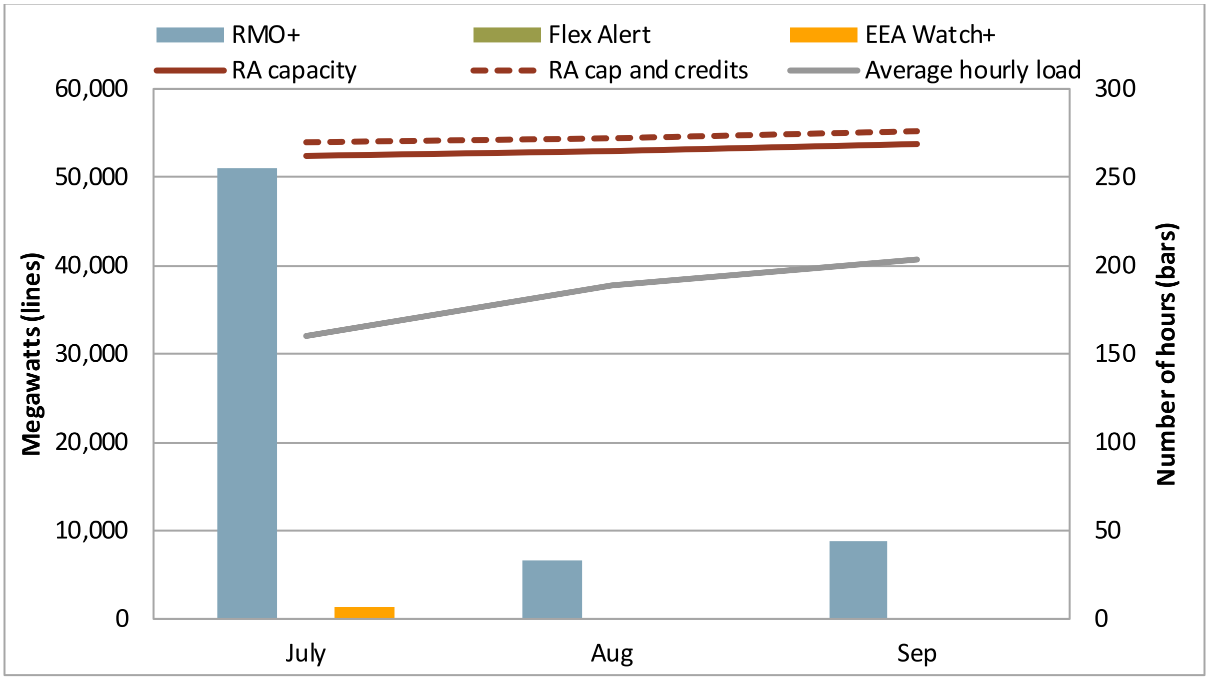
[267] The availability assessment hours for system and local resource adequacy apply only to trading days that are weekdays and non-holidays. The hours used in the analysis for this section do not exclude weekends and holidays.

[268] Monthly average load and procured resource adequacy capacity is weighted by the number of RMO+, Flex Alert, and EEA Watch+ hours.

**Figure 15.7 Average hourly resource adequacy capacity and load (2024 emergency notification hours)**




Key findings of this analysis include:

- **Hours with stressed system conditions were constrained to the summer months in 2024.** There were 332 total hours with RMO+ emergency notifications, 7 EEA Watch+ hours, and zero flex alerts. These emergency hours were exclusively confined to July, August, and September in 2024.
- **The California ISO declared 18 RMO alerts for a total of 332 hours, including 216 consecutive hours with an active RMO in effect.** Unlike in previous years where alerts only covered a portion of the day, some individual alerts in 2024 spanned multiple days and every hour of each day. There was an RMO alert active in every hour between July 3 and July 11. The most severe emergency notification in 2024 was an EEA Watch declared on July 24 which lasted 7 hours.
- **Average resource adequacy capacity exceeded average load during the emergency notification hours in 2024**. Average hourly load was about 37 GW during these hours, while average resource adequacy capacity was 53 GW.

Table 15.5 shows capacity procurement, de-rates, availability, and performance of system resource adequacy resources during emergency notification hours from 2020 to 2024. Bids and self-schedules, cleared schedules, and meter amounts are capped by resource adequacy capacity at the resource level, unless otherwise indicated.[269,270]

**Table 15.5 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 | | |
| 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% |
| 2022 | RMO+ | 151 | 49,799 | 95% | 90% | 75% | 94% | 89% | 69% | 83% | 64% | 77% |
| | Flex Alert+ | 56 | 49,509 | 95% | 91% | 85% | 93% | 89% | 77% | 88% | 72% | 81% |
| | EEA Watch+ | 35 | 49,390 | 95% | 90% | 87% | 93% | 89% | 79% | 89% | 74% | 81% |
| | EEA 2+ | 17 | 49,490 | 95% | 91% | 89% | 93% | 90% | 82% | 92% | 78% | 85% |
| 2023 | RMO+ | 72 | 41,480 | 94% | 90% | 73% | 93% | 89% | 67% | 82% | 62% | 75% |
| | EEA Watch+ | 12 | 48,878 | 96% | 94% | 68% | 94% | 92% | 58% | 80% | 54% | 75% |
| 2024 | RMO+ | 332 | 52,646 | 95% | 89% | 57% | 94% | 87% | 53% | 70% | 49% | 64% |
| | EEA Watch+ | 7 | 52,649 | 96% | 90% | 73% | 94% | 88% | 74% | 83% | 69% | 75% |
| | AAH (RMO+) | 94 | 52,805 | 95% | 92% | 77% | 94% | 91% | 71% | 87% | 66% | 80% |

Key findings of this analysis include:

- **The California ISO declared 18 RMO alerts for a total of 332 hours.** Unlike in previous years where alerts spanned a portion of the day, some individual alerts in 2024 spanned multiple days and every hour of each day. There was an RMO alert active in every hour between July 3 and July 11, which accounted for 216 of the 332 total hours. This is an additional 260 RMO+ hours from 2023.
- **Total resource adequacy capacity and schedules were on average higher during the availability assessment hours within the RMO+ alert hours.** Of the total 332 RMO+ hours, there were 94 availability assessment hours which occurred during the peak evening loads.
- **A small percentage of procured capacity was on outage during stressed hours from 2020 to 2024.** The day-ahead and real-time markets could access between 92 and 96 percent of procured capacity during these hours. Gas-fired generators and hydrogenerators 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 in 2024.** On average, between 85 and 94 percent of procured capacity bid or self-scheduled into the day-ahead and real-time markets from 2020 to 2024. In 2024, 89 to 90 percent of the procured capacity was bid or self-scheduled into the day-ahead market, and 87 to 88 percent was bid or self-scheduled into the real-time market.

[269] The current metrics for schedules and bids only consider the discharge MW for all storage and hydro resources. In contrast, reports from previous years included both discharge and charge MW in bids and schedules for these resources.

[270] Due to the change in the ISO's notification system, this analysis uses the Alert+ category before April 1, 2022, and the EEA Watch+ category after. The Alert+ category includes hours when 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.

- **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 hours before the net load peak.
- **During the most critical hours with EEA Watch+, the majority of resource adequacy was available to the market.** The California ISO declared EEA Watch alerts for a total of 7 hours during 2024. Despite the rapidly evolving real-time operations and over 8,000 MW of exports scheduled in the hour-ahead market leaving the system facing supply infeasibilities, the percentage of outages was low, with 94 to 96 percent of resource adequacy available. Furthermore, 90 and 88 percent of capacity bid into the day-ahead and real-time markets, respectively. Only 74 percent of generation was scheduled, but this was because peak demand was far below RA capacity accounting for uncapped schedules.

Load serving entities can contract with multiple types of resources to fulfill their resource adequacy obligations. Table 15.6 and Figure 15.8 show capacity procurement by resource type, capacity de-rates, availability, and performance of system resource adequacy resources during RMO+ hours in 2024.[271] Separate sub-totals are provided for the resources that the California ISO creates bids for when market participants do not submit a bid or self-schedule (must-offer), as well as the sub-totals for the resources the California ISO does *not* create bids for (other).

**Table 15.6 Average system resource adequacy capacity, availability, and performance by fuel type during availability assessment hours (within RMO+ hours)**

| Resource type | Total RA capacity | Day-ahead market | | | Real-time market | | | | | Meter | Uncapped meter | Uncapped meter + AS |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Capacity de-rate | Bids and self-schedules | Schedules | Capacity de-rate | Bids and self-schedules | Schedules | Uncapped schedules | Uncapped schedules + AS | | | |
| ***Must-Offer:*** | | | | | | | | | | | | |
| Gas-fired generators | 15,566 | 95% | 95% | 85% | 95% | 95% | 81% | 81% | 83% | 78% | 78% | 80% |
| Other generators | 1,330 | 93% | 93% | 90% | 93% | 93% | 89% | 92% | 92% | 86% | 90% | 90% |
| Subtotal | 16,896 | 95% | 95% | 85% | 94% | 94% | 81% | 82% | 84% | 78% | 79% | 81% |
| ***Other:*** | | | | | | | | | | | | |
| Imports | 3,371 | 98% | 95% | 94% | 100% | 94% | 93% | 94% | 94% | 92% | 92% | 92% |
| Imports-MSS | 323 | 100% | 78% | 78% | 100% | 78% | 78% | 79% | 79% | 77% | 78% | 78% |
| Use-limited gas units | 9,546 | 90% | 90% | 77% | 89% | 88% | 63% | 65% | 71% | 58% | 59% | 65% |
| Hydro generators | 6,010 | 94% | 91% | 80% | 92% | 88% | 64% | 82% | 99% | 57% | 73% | 90% |
| Nuclear generators | 2,895 | 100% | 99% | 99% | 100% | 99% | 99% | 100% | 100% | 99% | 100% | 100% |
| Solar generators | 2,130 | 100% | 64% | 63% | 99% | 71% | 67% | 287% | 287% | 64% | 257% | 257% |
| Wind generators | 1,227 | 100% | 75% | 73% | 100% | 91% | 90% | 251% | 251% | 82% | 227% | 227% |
| Qualifying facilities | 830 | 97% | 91% | 86% | 96% | 91% | 82% | 89% | 89% | 80% | 88% | 88% |
| Demand response (PDR) | 250 | 100% | 89% | 4% | 97% | 63% | 5% | 5% | 5% | 4% | 5% | 5% |
| Storage | 7,923 | 97% | 96% | 53% | 95% | 95% | 45% | 46% | 62% | 33% | 34% | 50% |
| Other non-dispatchable | 1,403 | 94% | 85% | 53% | 91% | 85% | 71% | 89% | 89% | 62% | 76% | 77% |
| Subtotal | 35,909 | 95% | 90% | 73% | 94% | 90% | 67% | 90% | 98% | 61% | 81% | 89% |
| **Total** | 52,805 | 95% | 92% | 77% | 94% | 91% | 71% | 87% | 93% | 66% | 80% | 86% |

[271] Bids and self-schedules in the day-ahead and real-time markets are reported as the proportion of total resource adequacy capacity.

Key findings of this analysis include:

- **Gas-fired generators accounted for about 48 percent of capacity procurement**. Gas-fired resources (gas-fired must-offer generators and use-limited gas units) supplied about 25,100 MW of resource adequacy capacity during the RMO+ (AAH) hours of 2024.
- **Resources that are not availability-limited accounted for just 32 percent of system capacity.** About 16,900 MW of system capacity was subject to California ISO bid insertion 24x7.[272] Gas-fired generation in this category made up about 15,600 MW (30 percent) of total resource adequacy capacity. Other generators accounted for less than 3 percent.
- **Use-limited gas units made up the largest portion of resource adequacy capacity with limited availability not subject to California ISO bid insertion.** These resources contributed about 9,500 MW of total capacity (18 percent). Storage resources contributed 15 percent, hydro generators contributed 11 percent, imports (including metered subsystems) contributed 7 percent, nuclear resources contributed 5 percent, solar resources contributed 4 percent, wind resources contributed 2 percent, qualifying facility resources contributed 2 percent, demand response contributed less than one percent, and other non-dispatchable resources contributed 3 percent of system capacity.
- **The amount of resource adequacy procured from storage resources increased significantly in 2024.** Storage resources accounted for the second largest portion (about 15 percent) of total capacity behind gas resources in 2024.
- **Storage and hydro resources contributed to the provision of ancillary services during the RMO+ hours.** The "uncapped schedules + AS" column presents real-time scheduling for RA and partial RA resources with their 15-minute ancillary service schedules. Storage resources' energy schedules in real-time were only 46 percent of their RA capacity. However, upon inclusion of ancillary service schedules, the percentage of scheduled capacity rose to 62 percent. Hydro units were scheduled for 99 percent of their RA capacity, incorporating RA and partial RA energy and ancillary service schedules.
- **Capacity available after reported outages and de-rates was 95 percent in the day-ahead market and 94 percent in the real-time market**. Average resource adequacy capacity was around 52,805 MW during the RMO+ availability assessment hours in 2024.
- **The day-ahead market showed high capacity availability in 2024.** 95 percent of must-offer and 90 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 95 percent of the day-ahead availability. These are typically variable and non-dispatchable energy resources. Additionally, most of the availability assessment hours include 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 94 percent of must-offer and 90 percent of non-must-offer capacity bid or self-scheduled in the real-time market. These totals are capped by individual resource adequacy values. 89 percent of proxy demand response bid in the day-ahead market, and 63 percent bid into the real-time market. Demand response resources typically exhibit low bid availability as a percentage of procured capacity.

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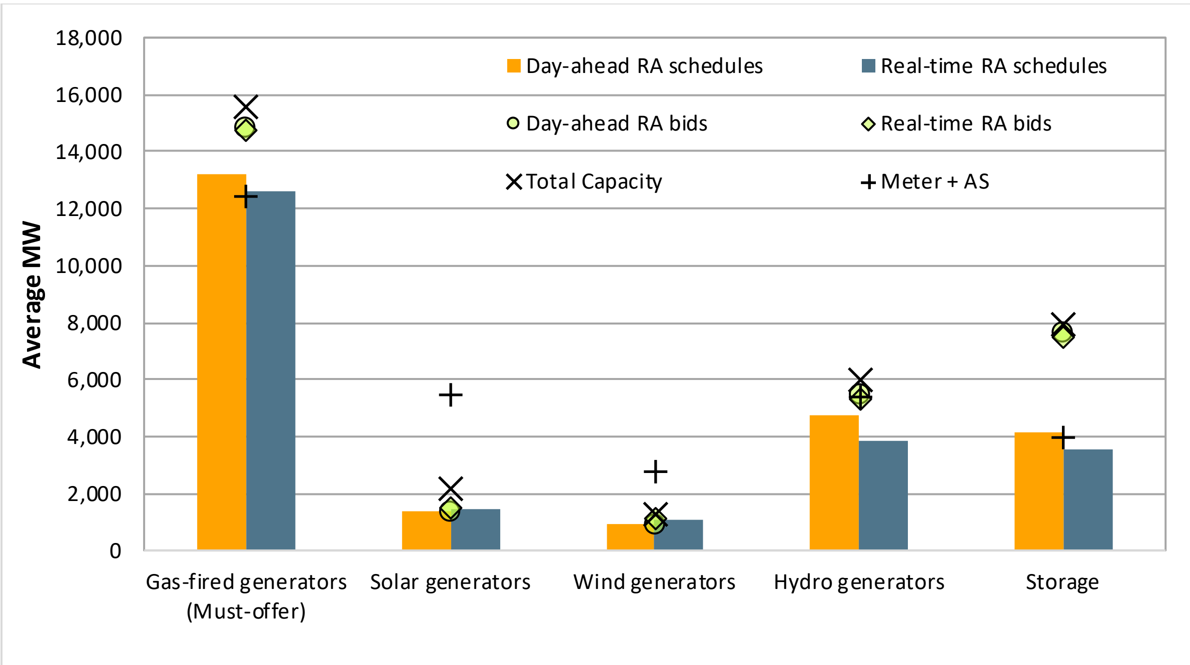
[272] When scheduling coordinators did not submit bids for these resources, the California ISO automatically generated them. Generation was excluded from the bidding requirement when an outage was reported to the California ISO.

- **A higher percentage of procured must-offer resources cleared and generated in the real-time market compared to non-must-offer resources.** About 94 percent bid into the real-time, and 81 percent of procured must-offer capacity cleared the real-time market. These percentages are capped by individual resource adequacy values.

**Figure 15.8 Average system resource adequacy by fuel type during availability assessment hours (within RMO+ hours)**




Key findings of this analysis include:

- **Solar and wind resources performed greater than their total resource adequacy capacity and schedules during the availability assessment hours.** Including their above RA production, solar and wind resources generated 257 percent and 227 percent of their capacity, respectively.
- **Including ancillary services, storage resources performed above their resource adequacy schedules.** Storage resources produced 113 percent of their real-time schedule and 81 percent of their uncapped schedules plus ancillary service requirements.

Table 15.7 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.[273] Bids, schedules, and meter values are aggregated by load type, depending on whether the entity is a community choice aggregator, direct access service, investor-owned utility, or a municipal/government

[273] 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.

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 for a capacity procurement mechanism designation, or resources held by the Central Procurement Entity.

**Table 15.7 Average system resource adequacy capacity and availability by load type (RMO+ 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 | | |
| Community choice aggregator | 13,324 | 95% | 90% | 71% | 94% | 91% | 69% | 89% | 65% | 81% |
| Direct access | 3,975 | 92% | 89% | 66% | 92% | 90% | 68% | 90% | 64% | 83% |
| Investor-owned utility | 30,681 | 96% | 94% | 81% | 95% | 93% | 73% | 86% | 68% | 79% |
| Municipal/government | 4,598 | 94% | 88% | 78% | 95% | 86% | 67% | 89% | 65% | 85% |
| Not on a plan | 226 | 86% | 82% | 42% | 80% | 77% | 51% | 82% | 42% | 66% |
| **Total** | **52,805** | **95%** | **92%** | **77%** | **94%** | **91%** | **71%** | **87%** | **66%** | **80%** |

Key findings of this analysis include:

- **Investor-owned utilities procured most of the system capacity.** Investor-owned utilities accounted for about 30,700 MW (58 percent) of system resource adequacy procurement, community choice aggregators contributed 25 percent, municipal utilities contributed 9 percent, and direct access services contributed 8 percent. The remaining is a combination of the capacity procurement mechanism and the Central Procurement Entity.
- **Capacity availability for all load types was lower in the real-time market than in the day-ahead market.** Resources bid on average 91 to 95 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 75 percent of their resource adequacy capacity from these resources, while municipal utilities procured 75 percent, community choice aggregators procured 55 percent, and direct access services procured 56 percent.
- **All load types procured a limited amount of imports to meet system resource adequacy requirements.** Municipal utilities procured 14 percent of their resource adequacy capacity from imports, while community choice aggregators procured 6 percent, direct access services procured 3 percent, and investor-owned utilities procured 7 percent.

Table 15.8 shows the availability of resource adequacy capacity in the California ISO markets based on whether the capacity was exempt from charges under the resource adequacy availability incentive mechanism (RAAIM). This analysis uses settlements data to identify resources exempt from RAAIM charges if they were unavailable during the availability assessment hours.[274]

**Table 15.8 Average system resource adequacy capacity and availability by RAAIM category during availability assessment hours (within RMO+ hours)**

| RAAIM category | 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 | | |
| Non-RAAIM exempt | 44,544 | 95% | 94% | 79% | 94% | 93% | 71% | 75% | 66% | 69% |
| RAAIM exempt | 8,261 | 94% | 78% | 69% | 94% | 81% | 71% | 156% | 66% | 141% |
| **Total** | **52,805** | **95%** | **92%** | **77%** | **94%** | **91%** | **71%** | **87%** | **66%** | **80%** |

Key findings of this analysis include:

- **RAAIM exempt resources accounted for about 16 percent of overall resource adequacy capacity during the RMO+ hours of 2024.** This was mostly solar, wind, and non-must-offer gas resources.
- **RAAIM exempt resources bid at a lower percentage in the markets**. In the day-ahead market and real-time markets, RAAIM exempt capacity bid about 78-81 percent of their capacity, while non-RAAIM exempt bid 93 to 94 percent of their capacity into the markets. This considers bids capped at individual resource adequacy values. Including the remaining capacity from partial resource adequacy resources, over 150 percent of the procured capacity from RAAIM exempt resources got scheduled into the real-time market. This is due to wind and solar resources that bid significantly above their net qualifying capacity (NQC) values.

### 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.[275]

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

[274] 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. http://www.caiso.com/rules/Pages/Regulatory/Default.aspx

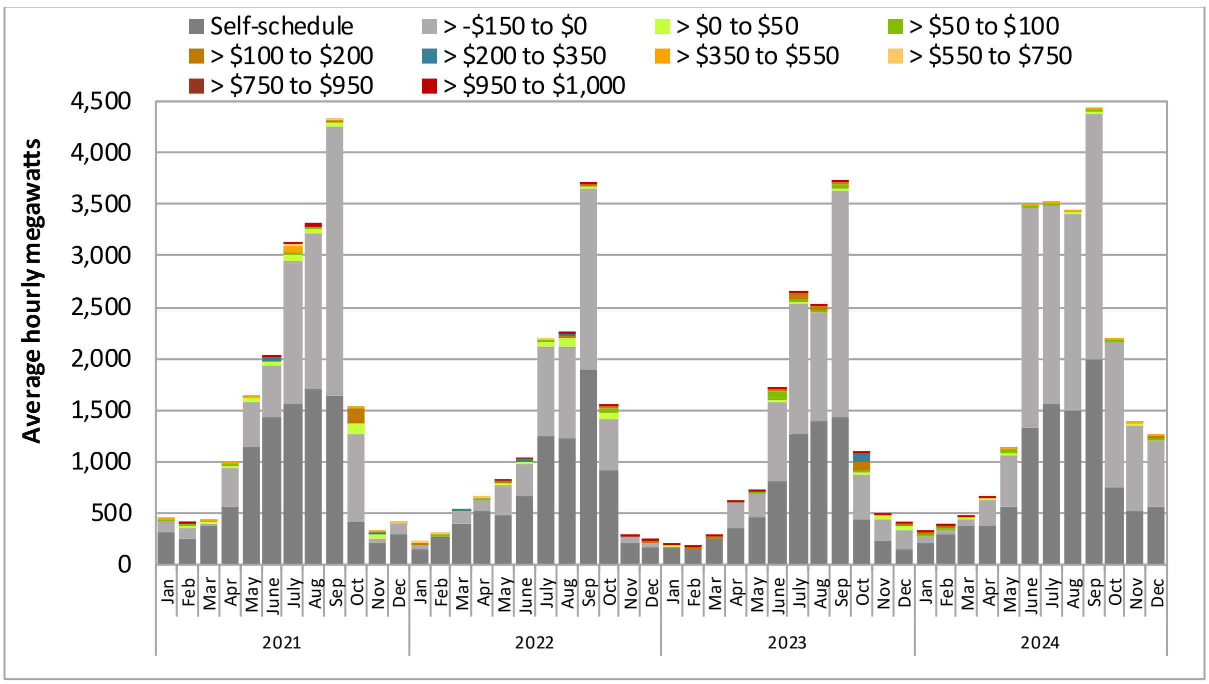
[275] In 2021, Phase 1 (March 20) and Phase 2 (June 13) of the FERC Order No. 831 compliance tariff amendment were implemented. Phase 1 allows resource adequacy imports to bid over the soft offer cap of $1,000/MWh when the maximum import bid price (MIBP) is over $1,000/MWh, or when the California ISO 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.

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 California ISO markets at or below $0/MWh during the availability assessment hours.[276] 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 2022. Imports were at similar levels in 2024 to the previous 3 years. The $0/MWh or below bidding rule does not apply to non-CPUC jurisdictional imports. In 2024, CPUC-jurisdictional entities submitted import bids exceeding $0/MWh during only a limited number of hours within the Availability Assessment Hours period.

Figure 15.9 shows the average hourly volume of self-scheduled and economic bids for resource adequacy import resources in the day-ahead market during peak hours.[277] 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.

**Figure 15.9 Average hourly resource adequacy imports by price bin**




276 *Decision Adopting Resource Adequacy Import Requirements (D.20-06-028)*, CPUC Docket No. R.17-09-020, June 25, 2020: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M342/K516/342516267.PDF

277 Peak hours in this analysis reflect non-weekend and non-holiday periods between hours-ending 17 and 21.

## 15.6 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.[278]

### 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 California ISO 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.[279,280] 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.[281]

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.

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278 For additional information, see: *149 FERC ¶ 61,042, Order on Tariff Revisions,* FERC Docket No. ER14-2574, October 16, 2014: http://www.caiso.com/Documents/Oct16_2014_OrderConditionallyAcceptingTariffRevisions-FRAC-MOO_ER14-2574.pdf

279 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.

280 Net load is total load less wind and solar production.

281 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.

### Bidding and scheduling obligations

All resources providing flexible capacity are required to submit economic energy and ancillary service bids to 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 is 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

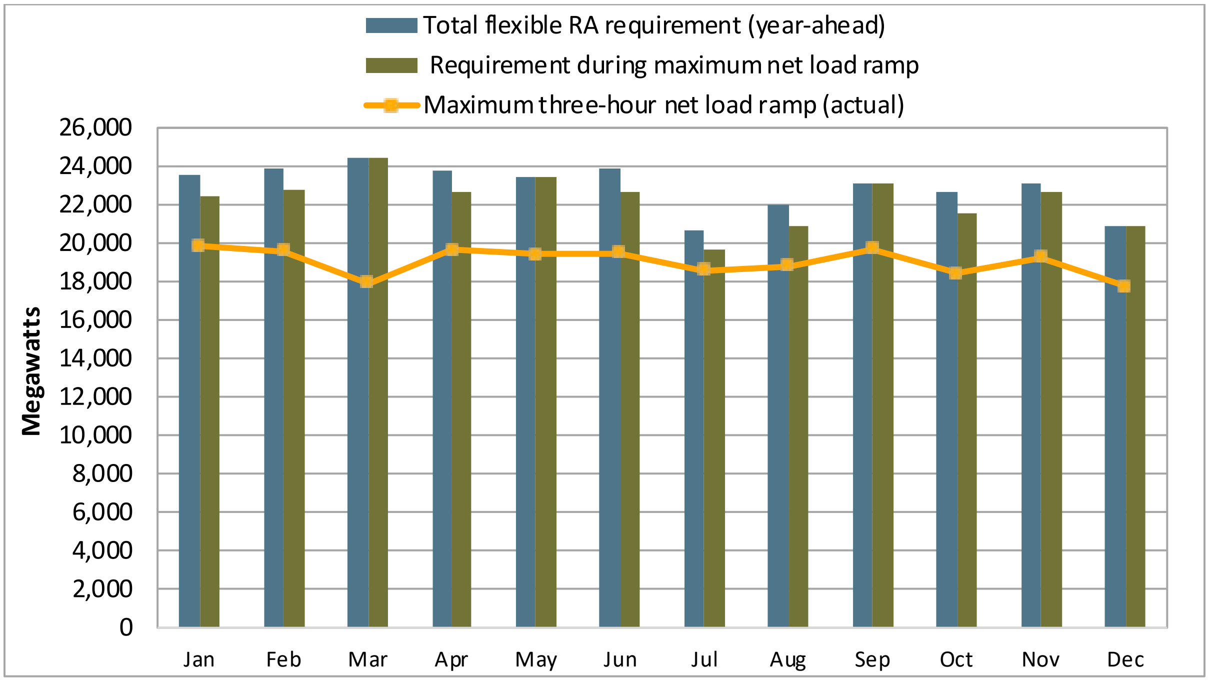
Figure 15.10 investigates how well flexible resource adequacy requirements addressed system load ramping needs in 2024 by comparing the requirements and the actual maximum three-hour net load ramp on a monthly basis.[282] The blue bars represent total three-hour requirements for the month and the gold 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 adequacy capacity has different must-offer hours, the requirement will effectively differ from day-to-day and hour-to-hour.[283] 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.

[282] 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. For the 5-minute net load calculation, DMM incorporates a range of renewable resources including California ISO's solar, wind, and co-located resources from the 5-minute interval data.

[283] 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.

**Figure 15.10 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 2024.** This is where the blue bars are at or 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 all months.** This is when the green bars are higher than the gold line.

The effectiveness of flexible requirements and must-offer rules in addressing supply during maximum load ramps depends on the ability to predict the size and timing of the maximum net load ramp. This analysis suggests the 2024 requirements and must-offer hours were sufficient in reflecting actual ramping needs in all cases.

Table 15.9 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 15.9 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) |
|---|---|---|---|---|---|---|
| Jan | 19,857 | 23,583 | 22,404 | 1/7/2024 | 14:00 | Y |
| Feb | 19,607 | 23,924 | 22,728 | 2/10/2024 | 14:30 | Y |
| Mar | 17,943 | 24,445 | 24,445 | 3/14/2024 | 16:05 | Y |
| Apr | 19,632 | 23,816 | 22,625 | 4/21/2024 | 15:55 | Y |
| May | 19,435 | 23,484 | 23,484 | 5/9/2024 | 16:40 | Y |
| Jun | 19,478 | 23,896 | 22,701 | 6/16/2024 | 16:55 | Y |
| Jul | 18,588 | 20,650 | 19,618 | 7/28/2024 | 16:45 | Y |
| Aug | 18,794 | 22,017 | 20,916 | 8/18/2024 | 15:55 | Y |
| Sep | 19,680 | 23,134 | 23,134 | 9/30/2024 | 14:55 | Y |
| Oct | 18,427 | 22,653 | 21,521 | 10/5/2024 | 14:55 | Y |
| Nov | 19,256 | 23,080 | 22,611 | 11/7/2024 | 13:50 | Y |
| Dec | 17,779 | 20,900 | 20,900 | 12/31/2024 | 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 all months.** The average requirement was at least 1,000 MW greater than the maximum 3-hour net load ramp in all months.
- **The average maximum three-hour net load ramp across all months in 2024 is about 1,465 MW higher than in 2023, while the average requirement during the net load ramp is 703 MW higher.**

### Procurement

Table 15.10 shows what types of resources provided flexible resource adequacy, and details the average monthly flexible capacity procurement in 2024 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, natural gas-fired generation composed the majority of flexible ramping procurement. However, procurement of energy storage resources has risen significantly in 2024.

**Table 15.10 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 | 8,159 | 36% | 54 | 1% | 0 | 0% |
| Use-limited gas units | 6,076 | 27% | 528 | 13% | 1 | 0% |
| Use-limited hydro generators | 297 | 1% | 19 | 0% | 0 | 0% |
| Other hydro generators | 122 | 1% | 0 | 0% | 0 | 0% |
| Geothermal | 399 | 2% | 0 | 0% | 0 | 0% |
| Energy Storage | 7,548 | 33% | 3,204 | 76% | 377 | 100% |
| Hybrid | 31 | 0% | 397 | 9% | 0 | 0% |
| **Total** | **22,632** | **100%** | **4,202** | **100%** | **378** | **100%** |

Key findings of this analysis include:

- **Gas-fired resources (both use-limited and non-use limited) accounted for most flexible resource adequacy capacity procurement.** About 14,800 MW (or 54 percent) of total flexible capacity came from these resources. Almost all (96 percent) of the capacity supplied by gas-fired generators served as Category 1 resources in 2024.
- **Energy storage resources made up the second largest volume of Category 1 flexible resource adequacy capacity.** These generators accounted for about 7,500 MW (33 percent) of Category 1 capacity in 2024, an increase from 4,100 MW (19 percent) in 2023.
- **Load serving entities procured more flexible capacity across Category 1 and Category 2 compared to the previous year.** Load serving entities procured 772 MW more capacity in Category 1 and 2,103 MW more in Category 2.

Table 15.11 shows flexible resource adequacy procurement by load serving entity type in 2024, including community choice aggregator (CCA), direct access service (DA), investor-owned utility (IOU), and municipal/government entity (Muni). The analysis uses supply plans to determine monthly LSE procurement and average it over the year by flexible resource adequacy category.

**Table 15.11 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 | 5,145 | 23% | 1,313 | 31% | 26 | 7% |
| DA | 1,305 | 6% | 844 | 20% | 0 | 0% |
| IOU | 15,395 | 68% | 1,938 | 46% | 351 | 93% |
| Muni | 786 | 3% | 108 | 3% | 1 | 0% |
| **Total** | **22,632** | **100%** | **4,202** | **100%** | **378** | **100%** |

Key findings of this analysis include:

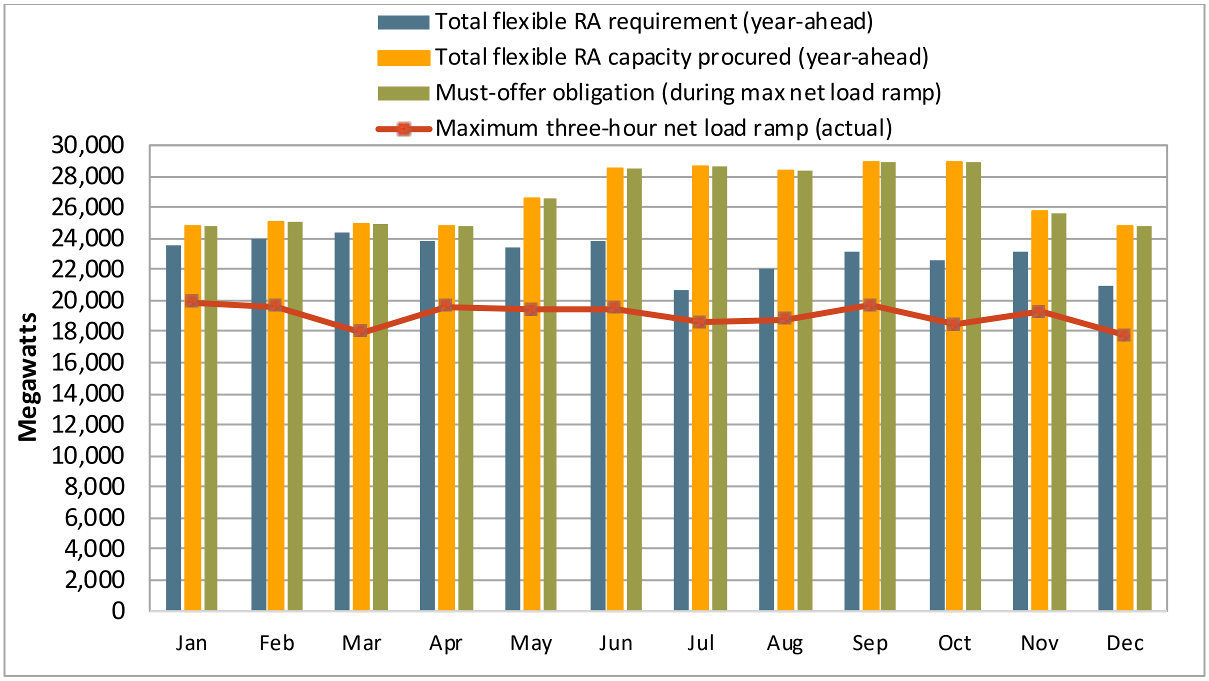
- **Investor-owned utilities procured the highest proportion of each flexible resource adequacy category**. Investor-owned utilities procured 65 percent of total flexible capacity, community choice aggregators procured 24 percent, direct access services procured 8 percent, and municipal utilities procured 3 percent. Investor-owned utilities procured at least 46 percent of the capacity of each category. IOUs procured a large majority of category 3 flexible resource adequacy at 93 percent.
- **Community choice aggregators procured the second highest proportion of all flexible resource adequacy capacity**. CCAs procured 23 percent of Category 1, 31 percent of Category 2, and 7 percent of Category 3 capacity.

Due in part to greater amounts of Category 1 capacity, total flexible resource adequacy procurement exceeded requirements for all months in 2024. Figure 15.11 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.[284] Must-offer obligations differ from

[284] 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.

the total flexible capacity procured because the actual net load ramps can occur outside of Category 2 and 3 must-offer hours.

**Figure 15.11 Flexible resource adequacy procurement during the maximum net load ramp**




Key findings of this analysis include:

- **Year-ahead total flexible resource adequacy procurement exceeded total requirements**. Total flexible resource adequacy procurement (gold bars) exceeded the total requirement (blue bars) in all months of the year.
- **The must-offer obligation for procured resources during the maximum three-hour net load ramp is the same as total procurement in most months**. Must-offer obligations during maximum net load ramps (green bars) are the same as total procurement (gold bars) for all months except for November. For November, the must-offer obligation is about 100 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 2024 by an average of 7,600 MW.

### Availability

Table 15.12 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 resources 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 2024. This analysis is not intended to replicate the method by which the resource adequacy availability incentive mechanism measures availability.

**Table 15.12 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 | 22,248 | 17,516 | 79% | 19,725 | 17,266 | 88% |
| February | 22,496 | 17,968 | 80% | 19,303 | 17,284 | 90% |
| March | 21,952 | 15,775 | 72% | 19,239 | 17,166 | 89% |
| April | 22,181 | 15,482 | 70% | 19,514 | 17,473 | 90% |
| May | 23,383 | 17,636 | 75% | 20,005 | 18,121 | 91% |
| June | 25,360 | 19,528 | 77% | 22,755 | 20,024 | 88% |
| July | 25,648 | 19,319 | 75% | 24,117 | 20,192 | 84% |
| August | 25,178 | 18,959 | 75% | 23,059 | 20,323 | 88% |
| September | 25,610 | 19,422 | 76% | 22,551 | 20,195 | 90% |
| October | 25,234 | 18,727 | 74% | 22,787 | 20,418 | 90% |
| November | 22,294 | 15,945 | 72% | 19,520 | 16,953 | 87% |
| December | 21,071 | 15,964 | 76% | 18,313 | 16,618 | 91% |
| **Total** | **23,555** | **17,687** | **75%** | **20,907** | **18,503** | **88%** |

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 2024**. Average availability in the day-ahead market was 75 percent and ranged from 70 percent to 80 percent. This is lower than 2023, when average availability in the day-ahead market was about 79 percent, with a range from 68 percent to 86 percent. Average availability in the real-time market was 88 percent, and ranged from 84 percent to 91 percent. This is higher than 2023, when average real-time availability was 85 percent, and ranged from 81 percent to 90 percent.
- **The real-time average must-offer obligation is much lower than the day-ahead obligation**. Flexible capacity must-offer requirements were about 23,600 MW in the day-ahead market and only about 20,900 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 15.13 includes the same data summarized in Table 15.12, but aggregates average flexible resource adequacy availability by the type of load serving entity contracting the capacity. 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 (CCA), direct access service (DA), investor-owned utility (IOU), or a municipal/government entity (Muni).

**Table 15.13 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 | 5,559 | 4,512 | 81% | 4,680 | 3,966 | 85% |
| DA | 1,549 | 1,280 | 83% | 1,381 | 1,229 | 89% |
| IOU | 15,632 | 11,159 | 71% | 14,084 | 12,650 | 90% |
| Muni | 814 | 736 | 90% | 762 | 658 | 86% |
| **Total** | **23,555** | **17,687** | **75%** | **20,907** | **18,503** | **88%** |

Key findings from this analysis include:

- **Flexible resource adequacy resources in the day-ahead had lower availability on average than in real-time markets across load types**. In both markets, most of the flexible resource adequacy capacity was contracted with investor-owned utilities. These resources that were contracted with IOUs had far higher availability in the real-time market than in the day-ahead market.

## 15.7 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 2024 availability assessment hours for:

**System and local resource adequacy resources:**

- Spring (March 1 through May 31) – hours-ending 18 to 22
- Summer (June 1 through October 31) – hours-ending 17 to 21
- Winter (November 1 through February 28) – hours-ending 17 to 21

**Flexible resource adequacy resources:**

- Base ramping (Category 1) – hours-ending 6 to 22 in all months.
- Peak ramping (Category 2) – hours-ending 15 to 19 in January through February and November through December, hours-ending 17 to 21 in March through August, and hours-ending 16 to 20 in September through October.
- Super-peak ramping (Category 3) – hours-ending 15 to 19 in January through February and November through December, hours-ending 17 to 21 in March through August, and hours-ending 16 to 20 in September through October. Excludes holidays and weekends.

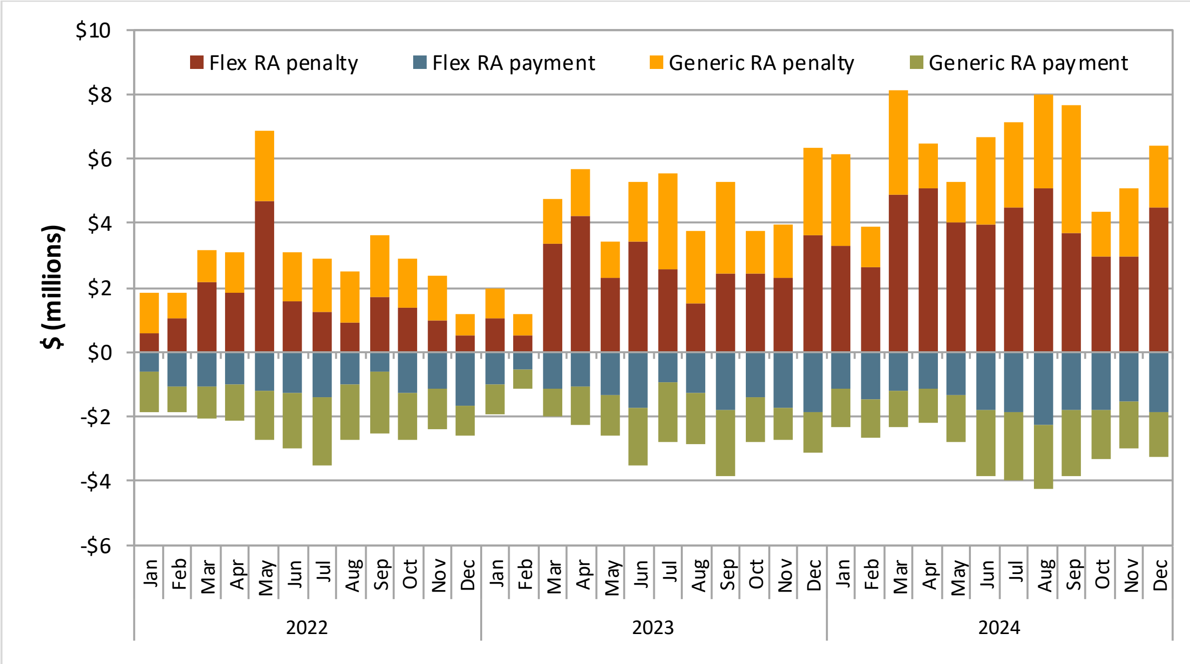
Resources that provide local, system, or flexible resource adequacy are either charged or paid each month, depending on their average capacity availability during the availability assessment hours. Resources whose average monthly capacity availability is more than 2 percent *less* than the availability standard of 96.5 percent are *charged* a non-availability charge for the month. Resources whose average capacity availability is more than 2 percent *greater* than the availability standard are *paid* an incentive payment for the month. The RAAIM price is set at 60 percent of the capacity procurement mechanism (CPM) soft offer cap price, or about $4.40/kW-month.[285,286]

Figure 15.12 summarizes monthly RAAIM charges and payments to resource adequacy resources from January 2022 to December 2024. Financial sums are presented in relation to how money flows through the California ISO. RAAIM penalties that resources pay the California ISO are in the positive direction on the graph, while RAAIM payments where the California ISO pays resources are in the negative direction. Charges and payments are presented for generic and flex resource adequacy resources.

[285] 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.

[286] Effective June 1, 2024, the CPM soft offer cap increased to $7.34/kW-month.

Figure 15.12 Monthly RAAIM penalties and payments[287]




Key findings from this analysis include:

- **In 2024, RAAIM penalties were about double that of payments.** RAAIM charges totaled about $75.3 million while RAAIM payments totaled around $37.6 million. The payments were about the same between generic and flexible resource adequacy resources.
- **RAAIM penalties increased by around $24.4 million from 2023.** Much of this is attributable to flexible resource adequacy charges increasing to $47.7 million from about $29.7 million. Generic resource adequacy charges increased from $21.1 million to $27.6 million.
- **In 2024, most RAAIM charges and payments occurred in the third quarter.** In the third quarter, the RAAIM charges averaged $7.6 million per month while the payments averaged $4 million. The fourth quarter had the lowest average RAAIM charges at $6.1 million per month and the payments were lowest during the first quarter at $2.4 million.

287 The values for 2022 and 2023 might differ from previous versions of the report due to re-settlements.

## 15.8 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 California ISO 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 California ISO capacity procurement mechanism. For the first half of 2024, bids may have ranged up to a soft offer cap set at $6.31/kW-month ($75.68/kW-year). Effective June 1, 2024, the soft offer cap increased to $7.34/kW-month ($88.09/kW-year).[288]

The California ISO inserts bids above the soft offer cap for each resource with qualified resource adequacy capacity not offered in the competitive solicitation process up to the maximum capacity of each resource as additional capacity that could be procured. If capacity in the California ISO generated bid range receives a designation through the capacity procurement mechanism, its clearing price is set at the soft offer cap. Resources can also file at FERC for costs that exceed the soft offer cap. A scheduling coordinator receiving a designation for capacity with a California ISO 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 LSEs and suppliers show insufficient cumulative system, local, or flexible capacity in annual resource adequacy plans, the California ISO may procure backstop capacity through a year-ahead competitive solicitation process using annual bids. The California ISO may also use the year-ahead process to procure backstop capacity to resolve a collective deficiency in any local area.
- Second, the California ISO may procure backstop capacity through a monthly competitive solicitation process in the event of insufficient cumulative capacity in monthly plans for local, system, or flexible resource adequacy. The California ISO may also use the monthly process to procure backstop capacity in the event that cumulative system capacity is insufficient due to planned outages.
- Third, exceptional dispatch or other significant events can also trigger the intra-monthly competitive solicitation process.

[288] For additional information, see: FERC Docket No. ER24-1225-000, April 25, 2024: https://www.caiso.com/documents/apr25-2024-letterorderacceptingcapacityprocurementmechanism-soft-offer-cap-tariffamendment-er24-1225.pdf

### Annual designations

There were no annual capacity procurement designations in 2024. 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 designations in 2024. Since the implementation of the current capacity procurement mechanism framework in 2016, the only monthly designations were made in 2023.

### Intra-monthly designations

There were no intra-monthly capacity procurement designations that were accepted in 2024.

Multiple 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 California ISO through appropriate channels within 24 hours of the designation. A scheduling coordinator may choose to decline a designation to avoid the associated must-offer obligation, which could reduce capacity costs passed to a single transmission access charge area or to the system as a whole.

## 15.9 Reliability must-run contracts

As of December 31, 2023, there were 0 MW of capacity designated as reliability must-run (RMR) as the remaining contracts for RMR were terminated. 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 implemented the resource adequacy program and provided a cost-effective alternative to reliability must-run contracting by the California ISO. A majority of the RMR designated resources from 2016 entered into resource adequacy contracts. Table 15.14 shows designated reliability must-run resources from 2016 through 2023. In 2017, the California ISO designated three new efficient gas units that represented almost 700 MW to provide reliability must-run service beginning in 2018.[289] The California ISO did not designate about 600 MW of this 700 MW of gas-fired generation for reliability must-run service in 2019. Metcalf Energy Center's designation as a resource adequacy unit in 2019, and transmission upgrades completed in December 2018 and January 2019, eliminated the need to designate the resource as a reliability must-run unit. The California ISO did not re-designate the remaining 100 MW of gas-fired generation for reliability must-run service in 2020. Yuba City Energy Center and Feather River Energy Center returned as resource adequacy units in 2020. No new resources were designated for reliability must-run in 2024.

[289] These included 593 MW of capacity from the combined cycle Metcalf Energy Center, and 94 MW of peaking capacity owned by Calpine.

**Table 15.14 Designated reliability must-run resource capacity (2016–2023)**

| RMR start date | RMR end date | RMR resource name | MW |
|---|---|---|---|
| 5-Dec-2016 | 31-Dec-2023 | Oakland Station Unit 1 | 55.00 |
| 5-Dec-2016 | 31-Dec-2020 | Oakland Station Unit 2 | 55.00 |
| 5-Dec-2016 | 31-Dec-2023 | 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 | 31-Dec-2022 | Channel Islands Power | 27.50 |
| 1-Jun-2020 | 31-Dec-2020 | E.F. Oxnard | 47.70 |
| 1-Jun-2020 | 31-Dec-2023 | Greenleaf II Cogen | 49.20 |
| 1-Feb-2021 | 31-Dec-2022 | Midway Sunset Cogeneration Plant | 248.00 |
| 1-May-2021 | 31-Dec-2022 | 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. This extended the life of the units to the retirement dates originally considered in system planning. In 2019, these units entered the resource adequacy program after not entering into reliability must-run contracts with the California ISO.

In 2020, the California ISO designated E.F. Oxnard, Greenleaf II, and Channel Islands Power (aggregating 124.4 MW of capacity) for service as reliability must-run units. The ISO filed contracts for these three units at FERC in the May-June timeframe. About 47.7 MW of capacity from E.F. Oxnard returned as a resource adequacy unit in 2021. Greenleaf II got released from its reliability-must-run contract at the end of 2023 and entered into the resource adequacy program.

In 2021, the California ISO designated about 282.5 MW of new capacity from Midway Sunset Cogeneration Plant and Kingsburg Cogen as reliability must-run. In 2021, the California ISO could have entered a reliability must-run contract for about 28.56 MW with Agnews Power Plant.[290] Ultimately, this did not happen because it received a resource adequacy contract in 2022. On January 20, 2022, this resource notified the California ISO 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 recommended designating it for reliability must-run services for year 2023, but that never occurred.[291]

In 2022, the Kingsburg Cogen unit secured a multi-year resource adequacy capacity contract, and as a result, did not receive an extension for its reliability must-run contract for 2023. The Midway Sunset Cogeneration Plant also entered into resource adequacy contracts for the full amount of their available capacity through 2026. Furthermore, the Channel Islands Power unit signed a contract with the California Department of Water Resources, making the unit accessible to the ISO as the California

290 *Potential reliability must-run designation – Agnews Power Plant,* California ISO, presented by Catalin Micsa, May 18, 2021: http://www.caiso.com/Documents/PresentationPotentialReliabilityMustRunDesignationAgnewsPowerPlant-May182021.pdf

291 *Potential Reliability Must-Run Designation: Agnews Power Plant*, California ISO Market Notice, May 19, 2022: http://www.caiso.com/Documents/Potential-Reliability-Must-Run-Designation-Agnews-Power-Plant-Call-051922.html

Strategic Reliability Reserve Program while being released from its reliability must-run contract. By the end of 2023, the Greenleaf II and Oakland Station Units 1 and 3 got released from their contracts, leaving no reliability must-run units entering into 2024.[292]

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.[293] 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.

## 15.10 Demand response

Demand response programs are operated and scheduled by load serving entities as well as third-party providers. Only demand response resources scheduled by third-party providers are shown in monthly resource supply plans. In contrast, demand response scheduled by CPUC-jurisdictional load serving entities are not shown in monthly resource adequacy supply plans; instead, under local regulatory authority provisions, all demand response scheduled by utilities is credited against (a reduction from) load serving entity resource adequacy obligations.

Monthly utility demand response resource adequacy averaged 986 MW in 2024. During the peak summer months (July, August, and September) of 2024, utility-operated demand response programs reported curtailing 92 percent of their real-time schedules. Monthly third-party demand response resource adequacy capacity averaged about 188 MW in 2024, and their self-reported performance during the peak summer months of 2024, including load curtailments in excess of individual resource schedules, averaged 118 percent of their real-time schedules. In general, demand response resources are primarily scheduled on days with high loads and tight supply conditions. DMM's report on demand response analyzes performance on these high load days in more detail. Performance on high load days for utility demand response was similar to average performance, averaging 90 percent of their real-time schedules. Third-party demand response, however, performed better than 2023 on high load days, averaging 54 percent of their real-time schedules.[294]

Figure 15.13 shows the total third-party demand response resource adequacy capacity (shown on monthly supply plans) in 2023 and 2024. Third-party demand response participating in the California ISO market decreased from 2023, with a monthly average of 188 MW across 2024.

[292] *Update on results of reliability must-run contract extensions for 2024*, California ISO Memorandum, November 1, 2023: https://www.caiso.com/Documents/UpdateonReliabilityMust-RunContractExtensionsfor2024-Nov2023.pdf

[294] *Demand response issues and performance 2024,* Department of Market Monitoring, February 20, 2025: https://www.caiso.com/documents/demand-response-issues-and-performance-2024-feb-20-2025.pdf

**Figure 15.13 Third-party demand response shown on monthly resource adequacy supply plans**

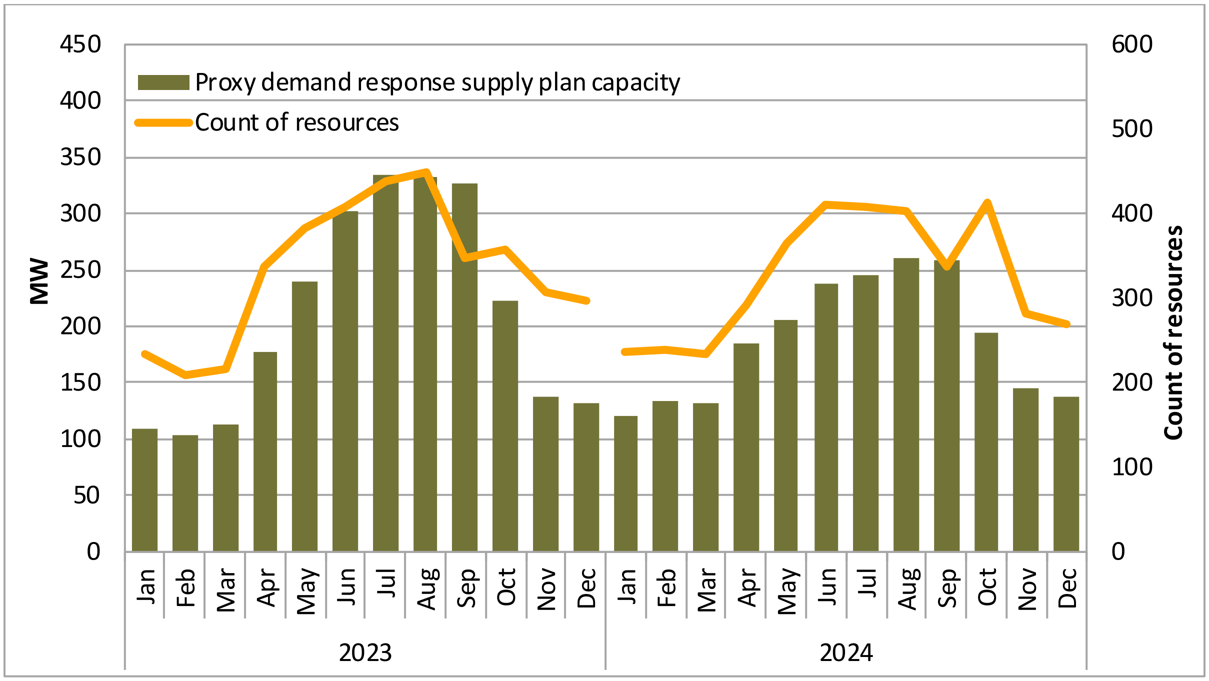
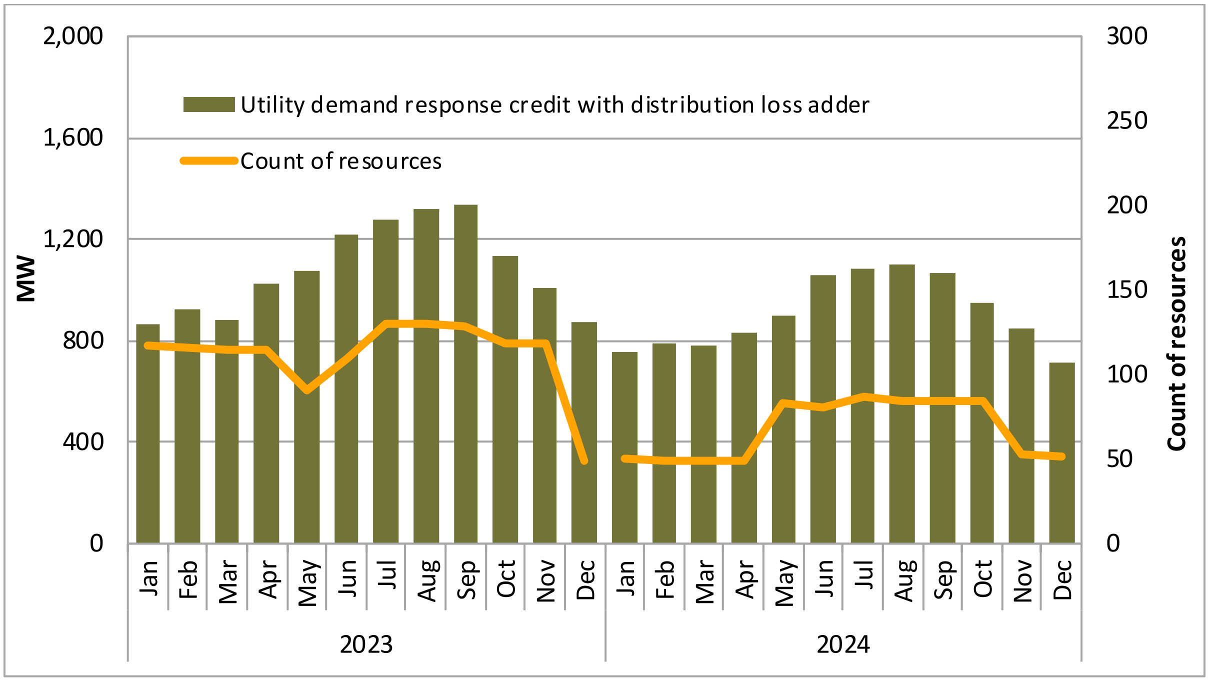



Figure 15.14 shows the total demand response resource adequacy capacity (including both proxy demand response and reliability demand response resources) scheduled and operated by CPUC-jurisdictional utility demand response programs. Any demand response capacity scheduled by a utility-operated demand response program is credited against that utility's resource adequacy obligations, reducing the amount of resource adequacy capacity that load serving entity is required to procure. In previous years, credits received by utilities for demand response capacity included adders for transmission and distribution line losses. Beginning in 2024, transmission loss gross-ups and planning reserve margin adders were removed from credited utility demand response resource adequacy values, resulting in a reduction of over 11 percentage points in adders relative to 2023. 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.

The majority of utility demand response resource adequacy capacity is scheduled from reliability demand response resources. While these resources are generally only dispatched under emergency conditions, they may bid economically in the day-ahead market. In the real-time market, however, reliability demand response resources can only be dispatched if the California ISO is in an EEA Watch or higher, regardless of their bids.

**Figure 15.14 CPUC-jurisdictional utility demand response resource adequacy credits**




### Dispatch and performance of demand response

The California ISO scheduled demand response resources, including reliability demand response, during high load days through July–September in 2024. The CAISO economically scheduled proxy demand response (PDR) resources throughout the summer and similarly scheduled reliability demand response resources (RDRR) on four days during the summer. More details on the performance of demand response resources on these specific high load days can be found in DMM's 2024 report on demand response issues and performance.[295]

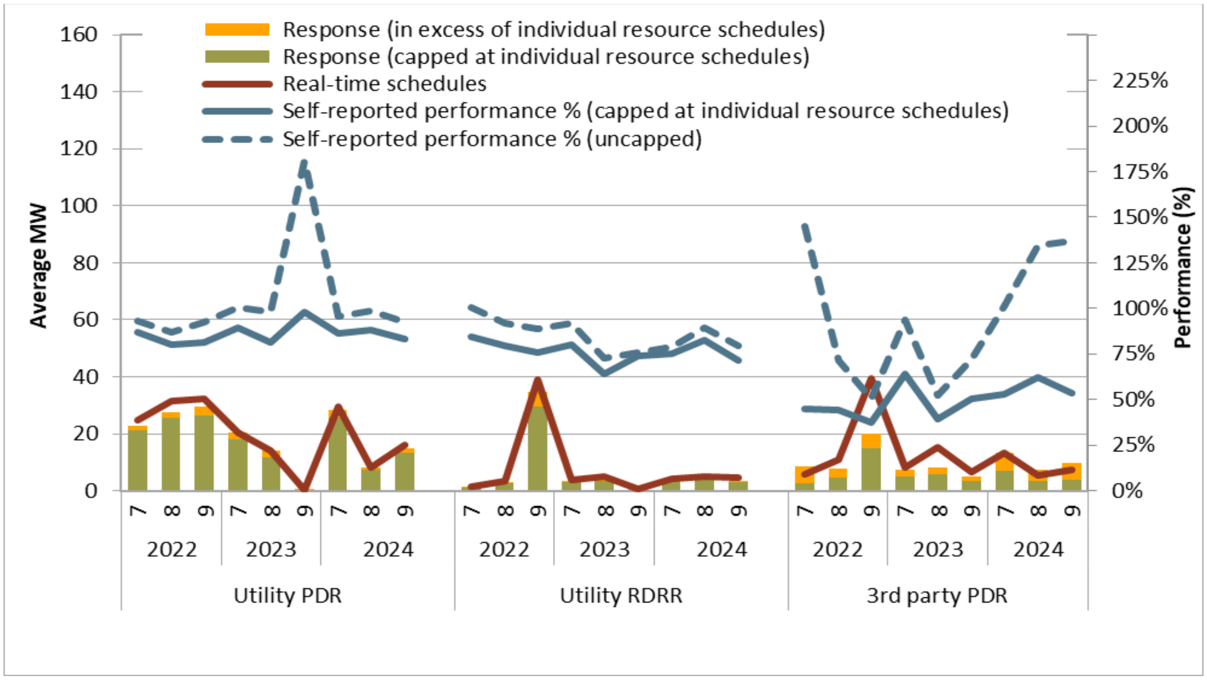
Figure 15.5 shows the expected load curtailment (schedule) of demand response resource adequacy resources compared to reported performance from July to September of 2022–2024 in peak net load hours (4–9 p.m.). In 2024, self-reported performance for utility demand response resources was lower compared to third-party demand response resources, where the opposite was the case in previous years. In July through September of 2024, uncapped performance of utility proxy demand response and reliability demand response averaged 96 percent and 83 percent, respectively, of their real-time schedule. Third-party demand response resources, however, averaged 118 percent across July, August, and September of 2024, but averaged only 54 percent of real-time schedules during high load days.[296]

295 *Demand response issues and performance 2024*, Department of Market Monitoring, February 20, 2025: https://www.caiso.com/documents/demand-response-issues-and-performance-2024-feb-20-2025.pdf

296 *Demand response issues and performance 2024*, Department of Market Monitoring, February 20, 2025, p 21: https://www.caiso.com/documents/demand-response-issues-and-performance-2024-feb-20-2025.pdf

In summer of 2024, there were four days when reliability demand response resources were dispatched: July 11, August 7, and September 4 and 5. On all four days, these resources self-scheduled in the day-ahead and were dispatched in real-time.[297]

**Figure 15.15 Demand response resource adequacy performance – July to September (4–9 p.m.)**




[297] *Demand response issues and performance 2024*, Department of Market Monitoring, February 20, 2025, p 17: https://www.caiso.com/documents/demand-response-issues-and-performance-2024-feb-20-2025.pdf

# 16 Wheeling rights

The ISO began developing a framework that establishes high-priority wheeling through scheduling priorities in the CAISO balancing area following the power outages in the summer of 2020. In July 2021, the ISO started the Transmission Service and Market Scheduling Priorities (TSMSP) initiative that had two phases: an interim phase to establish wheeling-through priorities for the challenging system conditions in the summer of 2022, and a longer-term framework that started in 2024. External suppliers and load serving entities can now reserve the capacity to self-schedule wheel-through transactions that have the same scheduling priority as CAISO demand in advance of the market runs on rolling monthly and daily timeframes.

This chapter provides analysis on priority wheel-through capacity and reservations. Key findings include:

- **Scheduling coordinators reserved 675 MW of priority wheel-through capacity on the CAISO balancing area transmission system in June, 690 MW in July, 735 MW in August, 510 MW in September, and 35 MW in October.**
- **Scheduling coordinators did not reserve all available capacity on the interties where they reserved any priority wheel-through capacity after June**. These interties had an additional 1,615 MW of available capacity in July, 2,136 MW in August, 159 MW in September, and 329 MW in October.
- **Priority wheel-through reservations plus native load needs exceeded the final available transmission capacity on the NOB intertie in June and September.** In June, this was due to the ISO awarding priority wheel-through reservations before a major transmission outage derated NOB to zero for part of the month. In September, final native load needs exceeded the estimates the ISO used when awarding priority wheel-through reservations in an early reservation window.
- **The ISO underestimated native load needs on the set of interties that market participants made priority wheel-through reservations on.** The ISO estimated native load needs on these interties would be about 1,553 MW in June, 2,955 MW in July, 5,903 MW in August, 5,702 MW in September, 3,106 MW in October, and 224 MW in November. This underestimated native load needs by about 596 MW (or 28 percent) in June, 677 MW (19 percent) in July, 288 MW (5 percent) in August, and 187 MW (6 percent) in October.

## 16.1 Implementation details

### Available transmission capacity reservation process

The ISO manually disseminated available transmission capacity (ATC) calculations and processed priority wheel-through (PWT) reservations before the automated system was operational. On January 17, 2024, the ISO posted monthly available transmission capacity values for a set of interties selected based on historic wheel-through activity. The ISO calculated these values based on expected total transmission capacity (TTC), legacy ownership rights (ETC/TORs), native load needs, and a transmission reliability margin (TRM). Starting on January 18, 2024, market participants submitted power contracts to the ISO for validation during the first reservation window, with reservations beginning June 2024. The ISO awarded priority wheel-through capacity, and updated intertie available transmission capacity values based on these awards and evolving available transmission capacity component expectations. The ISO followed this process for the first three reservation windows in 2024.

As of April 19, 2024, market participants can reserve and establish priority wheel-through access on the CAISO system via the WebWheel application. This application allows participants to submit power contracts, request priority wheel-through access on the monthly and daily horizons, and view priority wheel-through awards. The ISO also began posting aggregated available transmission capacity and available transmission capacity components on OASIS on the same date.

### Wheel through reservation resales

The ISO included resale and assignment provisions for priority wheel-through reservations in the TSMSP framework that FERC accepted in October 2023. On April 12, 2024, the ISO requested a waiver from FERC to extend the effective date of the tariff provisions that allow for resale of monthly wheel-through priority until no later than December 17, 2024. This is because the ISO needed more time to modify systems to make sure the market recognizes when a scheduling coordinator receives priority wheel-through status after a resale, and settlements correctly applies the wheeling access charge to the appropriate parties. DMM will monitor resales when the WebWheel functionality is completed and the ISO makes the data available.

### Malin available transmission capacity

The Malin intertie is one of two major interties linking the Pacific Northwest to the CAISO balancing authority area (BAA). This intertie is a key intertie for scheduling power into, from, and across the CAISO BAA. The ISO initially released limited available transmission capacity on the Malin intertie for priority wheel-through reservations. For the first reservation window, the ISO calculated a Malin available transmission capacity for wheel imports of 248 MW for June, 77 MW for July, 149 MW for August, and 0 MW for September.

Participants reserved 72 MW of priority wheel-through capacity for June, 77 MW for July, and 97 MW for August. Despite the available transmission capacity made available for the first reservation window exceeding final participant reservations for June and August, Malin had no excess monthly transmission capacity for these months. This is because unanticipated transmission outages reduced capacity after the first reservation window. This is explained in more detail with the figures in the following subsection.

### Transmission capacity reservations and usage

The following analysis shows the reserved priority wheel-through capacity, native load need estimates, and the actual market usage of the reserved capacity on the Malin and NOB interties. The ISO calculates transmission capacity values for many interties in the CAISO system. However, this analysis focuses on these two large Northern interties, which are the primary interties used to wheel from north-to-south across the CAISO system. Stakeholders were concerned about the congestion impacts priority wheel-through transactions importing from the North at Malin and exporting from the South could have on the system during the policy development. Imports at the NOB intertie are an injection into the southern portion of the CAISO BAA via the Pacific DC Intertie, and do not create flows on Path 26. However, this intertie is an important source of import capacity into the CAISO system from the Pacific Northwest.

Table 16.1 shows all the monthly priority wheel-through reservations made in 2024 by CAISO market tie point. The table presents data from June, when the policy started, to October, because the market participants did not reserve priority wheel-through capacity past October on the monthly horizon.

**Table 16.1 2024 monthly high priority wheel-through reservations by CAISO market tie point**[298]

| Quarter | Month | CAISO market tie point | Monthly PWT |
|---|---|---|---|
| Q2 | Jun | MALIN500 | 72 |
| | | NOB | 378 |
| | | RDM230 | 225 |
| Q3 | Jul | MALIN500 | 77 |
| | | NOB | 378 |
| | | PVWEST | 10 |
| | | RDM230 | 225 |
| | Aug | IPP | 25 |
| | | MALIN500 | 97 |
| | | NOB | 378 |
| | | PVWEST | 10 |
| | | RDM230 | 225 |
| | Sep | IPP | 25 |
| | | NOB | 250 |
| | | PVWEST | 10 |
| | | RDM230 | 225 |
| Q4 | Oct | IPP | 25 |
| | | PVWEST | 10 |

Figure 16.1 shows reservations made on the daily horizon that were incremental to what participants reserved on the monthly horizon. Participants can reserve priority wheel-through capacity closer to the operation date on the daily horizon if there is available transmission capacity left over after the monthly reservation horizon. This only happened a few times over the year for 75 MW on Mona 345 on October 3, and 1 MW on Mirage-Coachella 230 on November 12 and 13.

298 Table 16.1 reports priority wheel-through reservations for the CAISO market tie point of the wheel import leg. OASIS reports priority wheel-through reservations by the relevant intertie constraints that can limit intertie capacity. Multiple intertie constraints can affect the flows over different tie points and, therefore, OASIS reports the same priority wheel-through reservation amount for each related intertie constraint. This section reports transmission and priority wheel-through capacity for the most limiting intertie constraint related to the CAISO market tie point of the wheel import legs to avoid double counting. See CAISO Operating Procedure 2510A for additional detail on the relationship between CAISO market tie points and intertie constraints: https://www.caiso.com/documents/2510a.pdf

**Figure 16.1 Monthly transmission capacity values at all interties with PWT reservations**

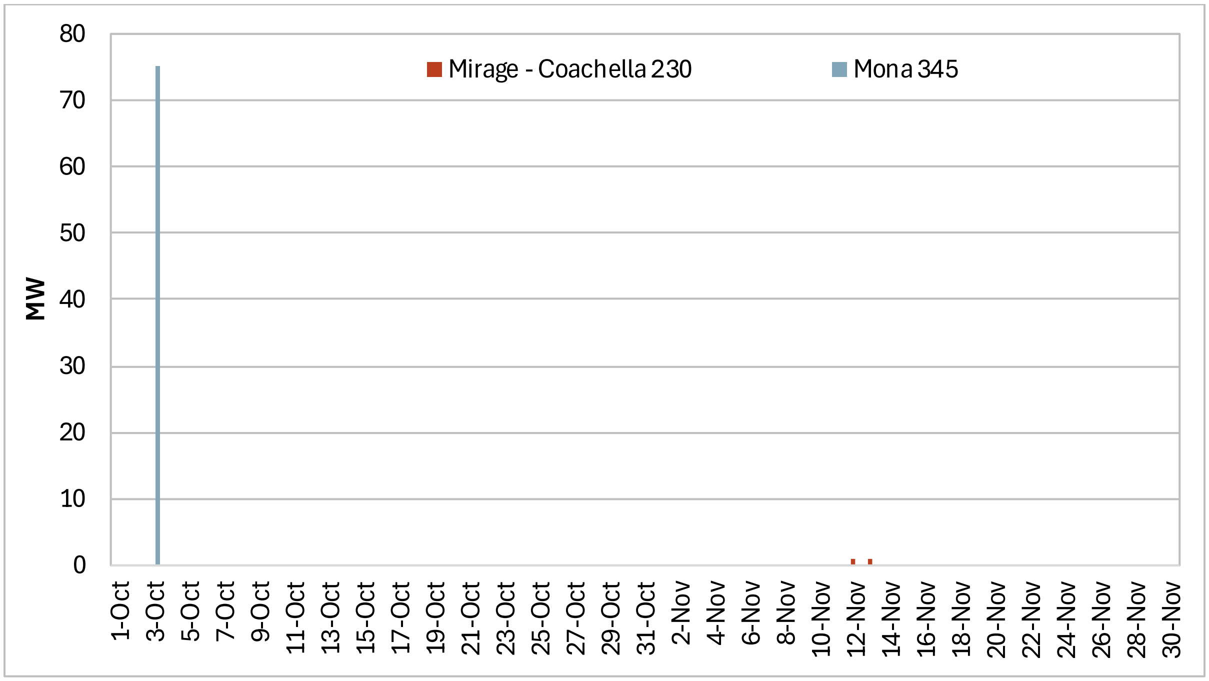



Figure 16.2 and Figure 16.3 show monthly capacity categories for all interties with priority wheel-through reservations in aggregate, as well as for Malin, NOB, and RDM230 individually for the year. Scheduling coordinators can reserve available priority wheel-through capacity (grey bars) at interties if there is leftover available transmission capacity after accounting for (1) native load need (green bars), (2) any previously reserved priority wheel-through capacity (turquoise bars), and a transmission reliability margin (yellow bars). The thick horizontal red lines in these figures show the available transmission capacity (ATC), which is the total transmission capacity leftover after accounting for outages and existing transmission rights (TTC – outages – ETC/TORs).

The total volume of capacity in these four categories (shown by the stacked bars) can total more than the available capacity of an intertie if outage conditions or native load need values change between reservation windows. For example, the final capacity values for June could total more than the final available transmission capacity if the ISO underestimates the native load need before the final resource adequacy (RA) showings, or if new intertie outages lower intertie availability below values the ISO assumed would be available for the month in previous reservation windows.

Figure 16.2 shows the monthly transmission capacity categories for all interties with priority wheel-through reservations in aggregate. Scheduling coordinators reserved 675 MW of priority wheel-through capacity in June, 690 MW in July, 735 MW in August, 510 MW in September, and 35 MW in October. Scheduling coordinators did not reserve all available capacity on the interties where they reserved any priority wheel-through capacity after June. These interties had an additional 1,615 MW of available capacity in July, 2,136 MW in August, 159 MW in September, and 329 MW in October. While Figure 16.2 aggregates the capacity of all interties with priority wheel-through reservations to present a high level view of how much available capacity scheduling coordinators reserved, it is important to note that the aggregated available capacity (red lines) are not simultaneously deliverable.

**Figure 16.2 Monthly transmission capacity values at all interties with PWT reservations**

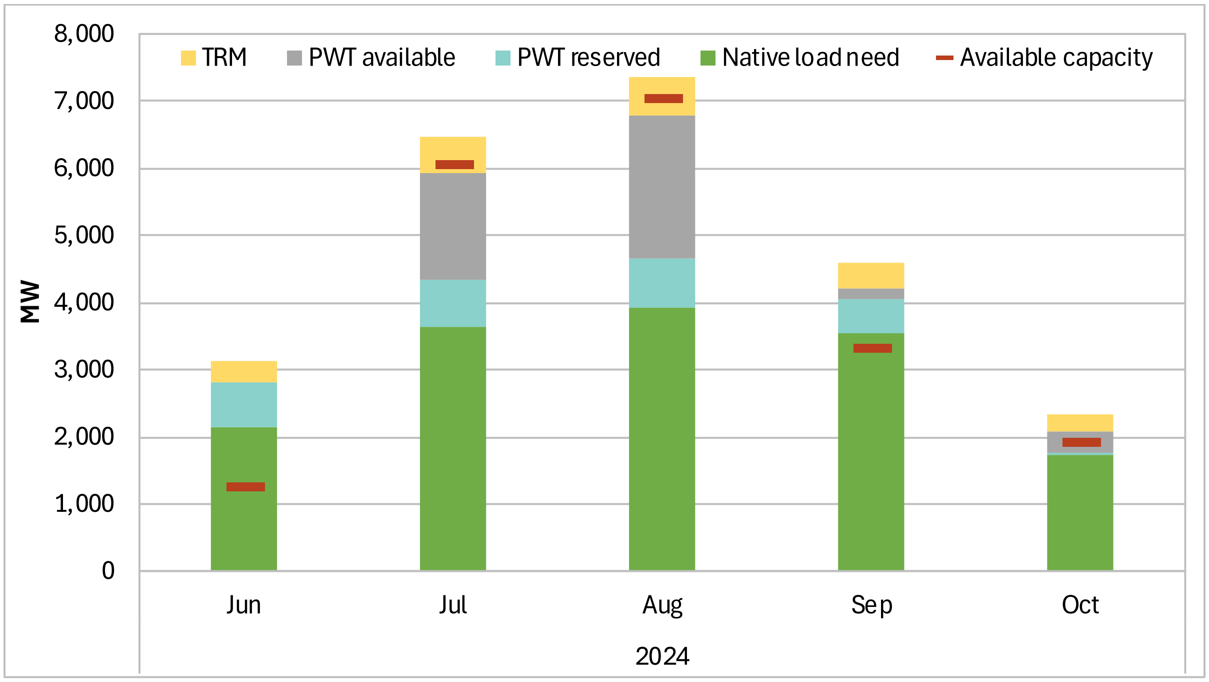



Figure 16.3 shows the monthly transmission capacity reservations at Malin. For June, Malin had an available capacity of 1,241 MW; a native load need of 1,192 MW; a transmission reliability margin (TRM) of 180 MW; and priority wheel-through reservations of 72 MW. Due to the iterative nature of transmission capacity reservations—where the ISO may update intertie availability and native load needs while honoring priority wheel-through (PWT) reservations made in previous reservation windows—final intertie capacity values may be oversubscribed compared to the final transmission availability number. Participants also reserved 77 MW in July and 97 MW in August. There were no priority wheel-through reservations on Malin from September through the end of 2024. Native load needs increased to 1,425 MW in July and 1,495 MW in August, however the transmission reliability margin capacity covered any changes in intertie availability and native load need during the monthly time horizon.

**Figure 16.3 Monthly transmission capacity values at MALIN500 market tie point (2024)**

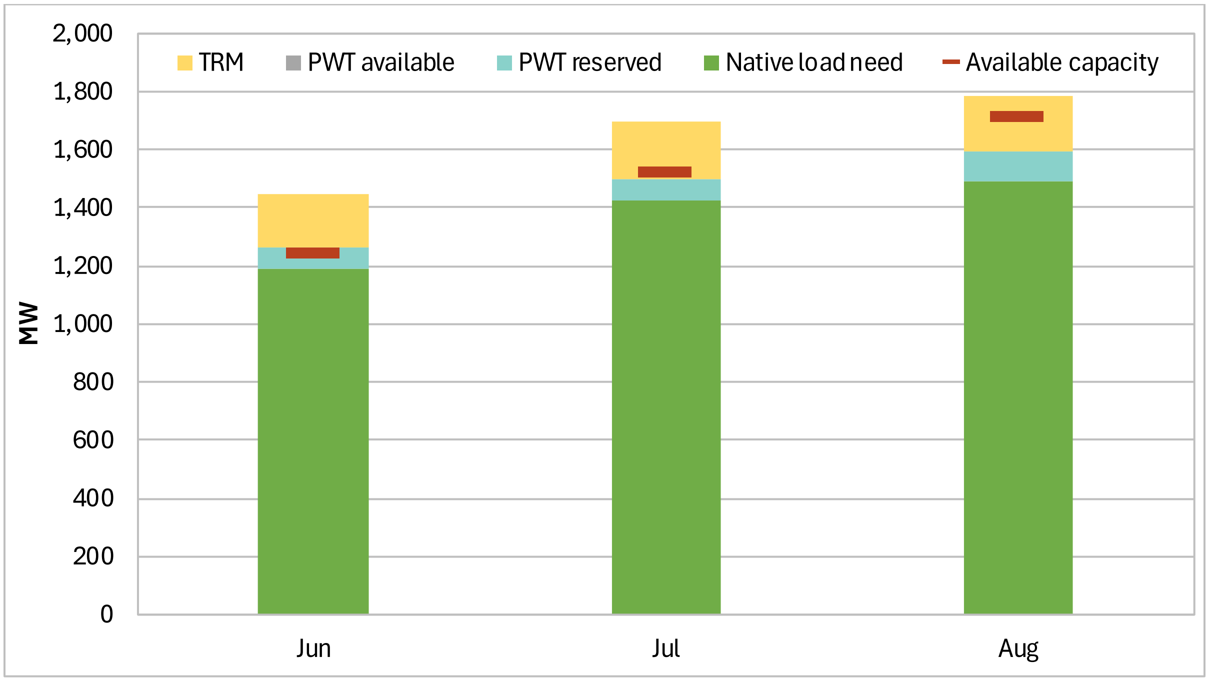



Figure 16.4 shows daily transmission capacity reservations at Malin. Monthly capacity values carry over to the daily timeframe. Scheduling coordinators and load serving entities can reserve more capacity for priority wheel-throughs and native load needs in the daily timeframe when there is additional available transmission capacity. This can happen if there is available transmission capacity left over from the monthly reservation process or if there is an increase in available transmission capacity due to a change in outage status. The daily timeframe available transmission capacity increased above the monthly capacity values for 15 days in June. As a result, the grey bars indicate the amount of extra priority wheel-through reservation capacity that became available. Market participants made no incremental priority wheel-through reservations on Malin between the monthly and daily timeframes.

**Figure 16.4 Daily transmission capacity values at MALIN500 (2024)**

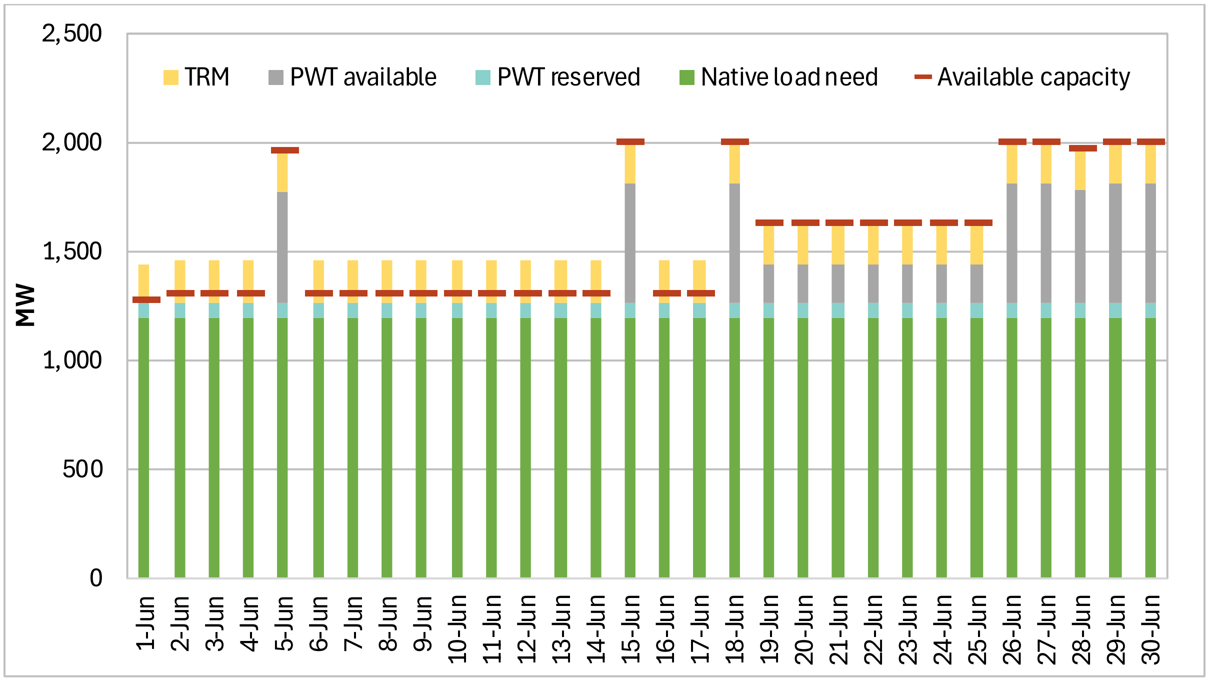



Figure 16.5 shows the monthly transmission capacity reservations at NOB. For the final June values, NOB had an available capacity of 0 MW, a native load need of 958 MW, a transmission reserve margin of 97 MW, and priority wheel-through reservations of 378 MW. Due to the iterative nature of transmission capacity reservations, scheduling coordinators reserved priority wheel-through capacity and the ISO determined available transmission capacity component values before an outage drove the monthly available transmission capacity value to zero.

Priority wheel-through reservations did not increase from the June level for the first two months of the third quarter. Reservations decreased to 250 MW in September. There was another 191 MW of available capacity that scheduling coordinators could have reserved as priority wheel-through capacity in August. The NOB intertie was oversubscribed in September. Scheduling coordinators reserved priority wheel-through capacity and the ISO determined available transmission capacity component values before resource adequacy showings determined the final native load need amount to be above the ISO's estimate.

**Figure 16.5 Monthly transmission capacity values at NOB market tie point (2024)**

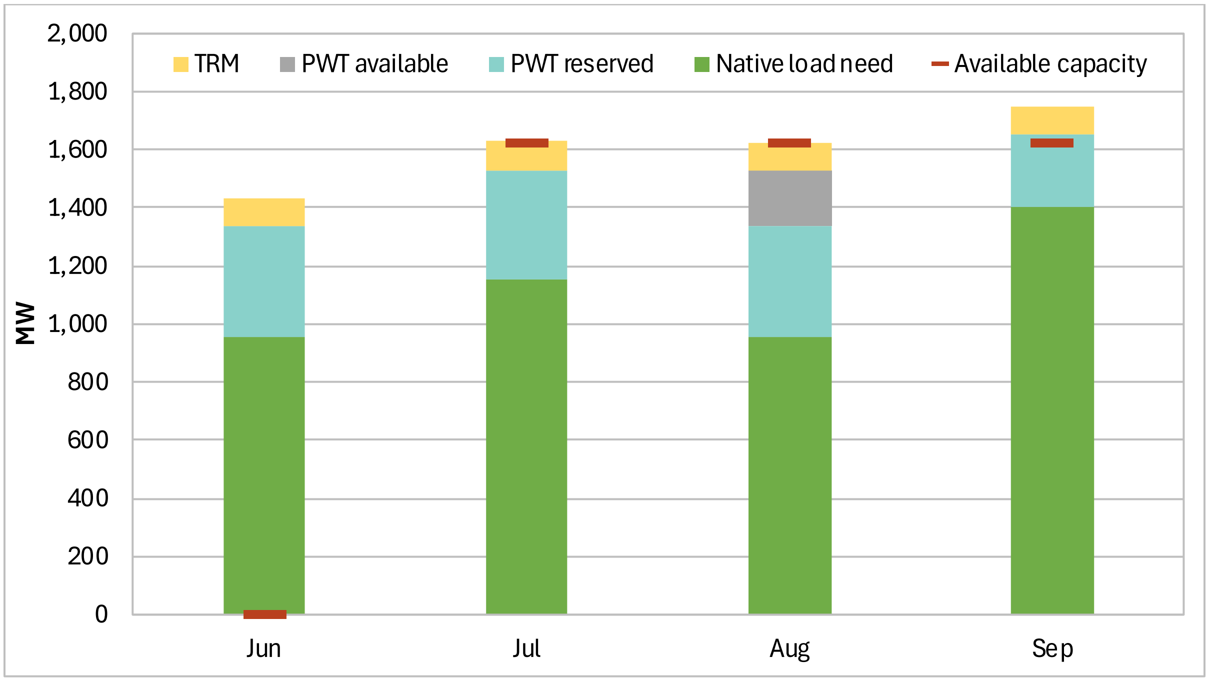



Figure 16.6 shows that the complete NOB intertie outage lasted for two days in June. This happened on June 22 and June 23. On the other days, available transmission capacity equaled NOB's total transmission capacity value, which indicates there were no outages and ETC/TOR rights on the intertie. The higher daily available transmission capacity values allowed for more priority wheel-through reservations on the other days (189 MW); however, there were no incremental priority wheel-through reservations between the monthly and daily timeframes.

**Figure 16.6 Daily transmission capacity values at NOB market tie point for June (2024)**

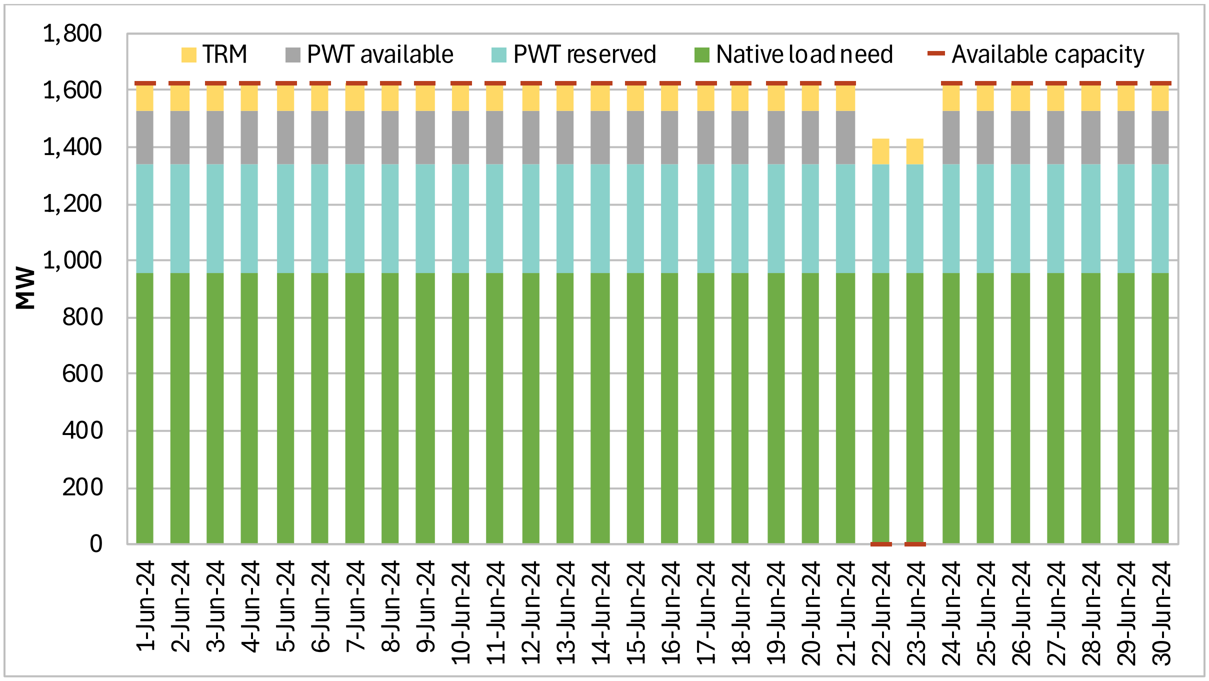



Figure 16.7 shows the monthly transmission capacity reservations at RDM230. RDM230 had priority wheel-through reservations of 225 MW and a transmission reliability margin of 20 MW for each month depicted. RDM230 is a special case where the intertie is almost entirely dedicated to ETC/TOR capacity, which is why the intertie appears oversubscribed with an available transmission capacity of 0 MW for each month. A market participant utilized TORs to reserve priority wheel-throughs at RDM230, which is why the priority wheel-through reserved (turquoise bars) are above the indicated transmission availability (red lines). RDM230 does not have a native load need component.

**Figure 16.7 Monthly transmission capacity values at RDM230 market tie point**

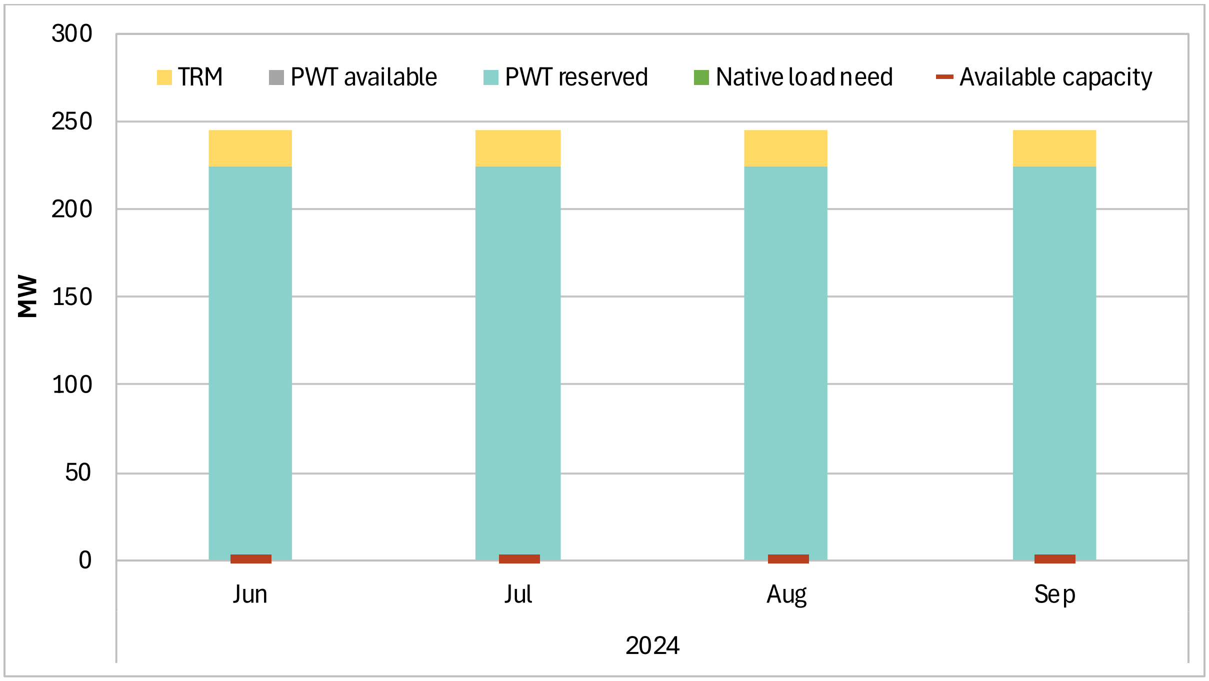



Figure 16.8 and Figure 16.9 show how native load need estimates compare to final import showings from load serving entities. In calculating available transmission capacity for priority wheel-throughs for future months, the ISO sets aside transmission capacity by estimating what native load needs will be. Ultimately, the amount of native load need capacity on interties is the sum of shown import resource adequacy, as well as non-resource adequacy contracts that load serving entities may show the ISO.

Final resource adequacy plans are due 30 days prior to the relevant month. Before T-30, the ISO estimates how much intertie transmission capacity native loads will need by taking the maximum amount of shown import RA and non-RA contracted imports delivered on that intertie for the same month over the previous two years.

In addition, the ISO accounts for the impact that load growth may have on native load needs by calculating a load growth value from the California Energy Commission load forecast. This is because loads may have increased over the value that determined maximum resource adequacy obligations over the past two years. The ISO updates these native load need numbers after load serving entities submit their final resource adequacy plans.

If the ISO overestimates actual native load needs, and the final resource adequacy and non-resource adequacy import showings are below the estimate based on historic data, the ISO will release excess transmission as available capacity that scheduling coordinators can reserve for priority wheel-throughs. Conversely, if the ISO underestimates native load needs, the ISO will reduce any previously unreserved available transmission capacity. However, if there is not any remaining available transmission capacity, then the ISO will revert to the originally calculated native load need estimate and will honor all of the previously reserved priority wheel-through capacity.

Figure 16.8 shows the cumulative native load need estimates and final values on all of the interties that had priority wheel-through reservations throughout the year. The ISO estimated native load needs for these interties would be about 1,553 MW in June, 2,955 MW in July, 5,903 MW in August, 5,702 MW in September, 3,106 MW in October, and 224 MW in November. This underestimated native load needs by about 596 MW (or 28 percent) in June, 677 MW (19 percent) in July, 288 MW (5 percent) in August, and 187 MW (6 percent) in October for interties that had priority wheel-through reservations.

**Figure 16.8 Native load need estimate vs. final import RA at all relevant market tie points (2024)**

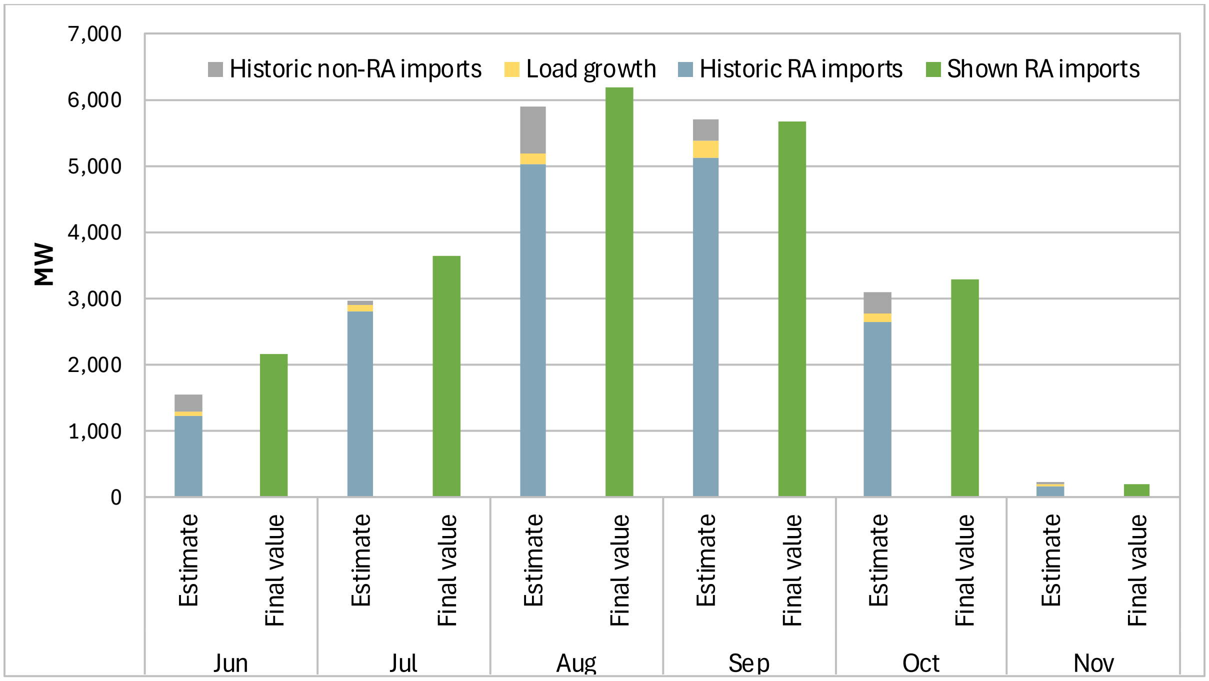



Figure 16.9 shows the native load need estimates and final values for the MALIN500 market tie point. The ISO estimated native loads would need 1,087 MW in June, 1,250 MW in July, and 1,495 MW in August. This underestimated actual native load needs by 105 MW (or 9 percent) in June and 497 MW (45 percent) in November, and overestimated native load needs by 95 MW (7 percent) in August.

**Figure 16.9 Native load need estimate vs. final import RA at MALIN500 market tie point**

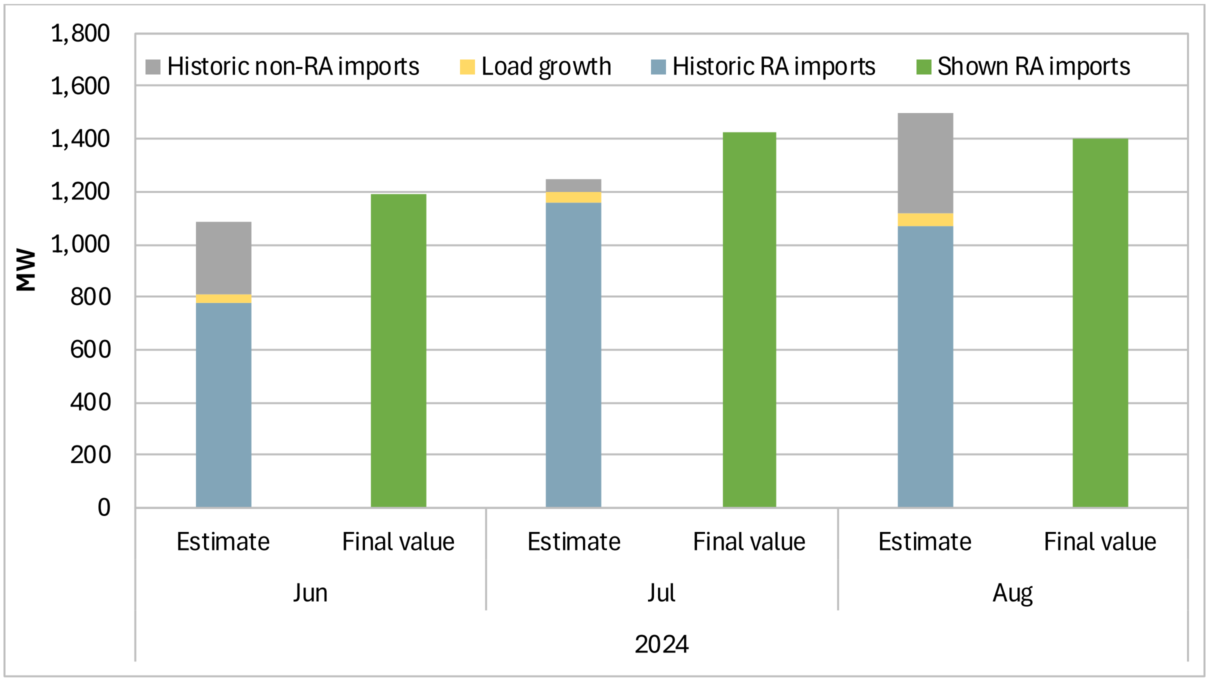



Figure 16.10 shows the native load need estimates and final values for the NOB market tie point. The ISO estimated native loads would need 467 MW in June, 797 MW in July, 956 MW in August, and 1,261 MW in September. This underestimated actual native load needs by 491 MW (or 51 percent) in June, 357 MW (31 percent) in July, 190 MW (17 percent) in August, and 144 MW (10 percent) in September.

**Figure 16.10 Native load need estimate vs. final import RA at NOB market tie point**

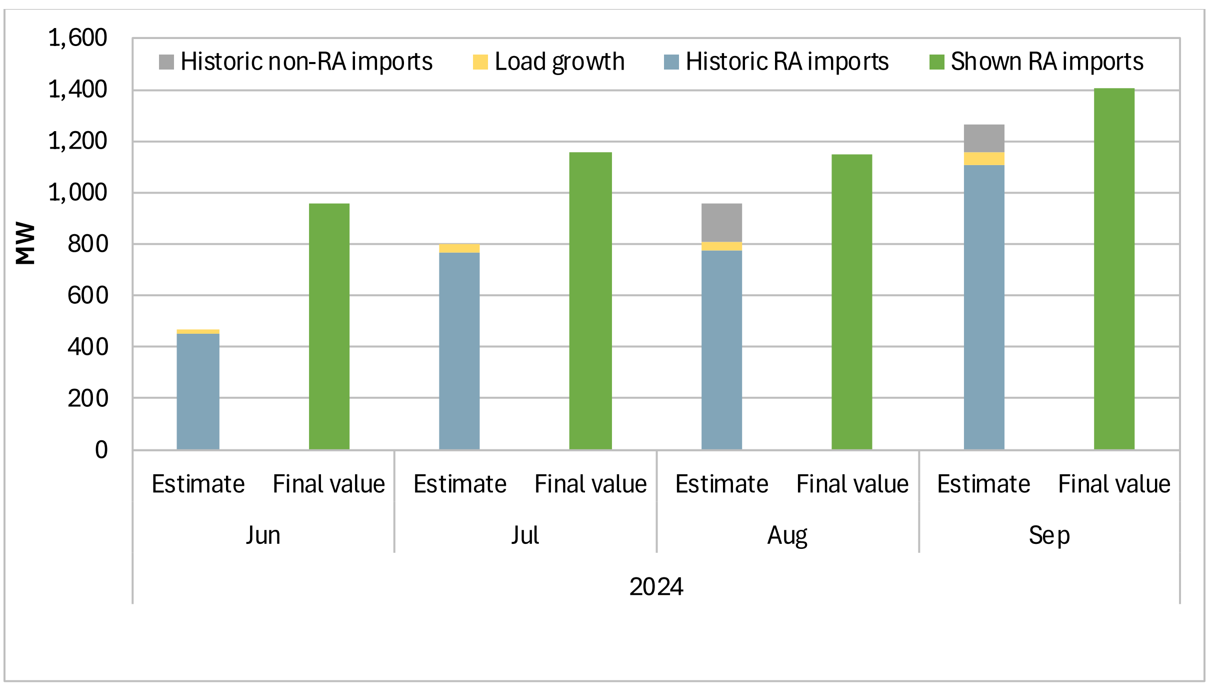


Figure 16.11 to Figure 16.14 show how scheduling coordinators used priority wheel-through reservations on Malin and NOB. Priority wheel-through reservation values (blue lines) are dependent on the contract parameters that scheduling coordinators submit to the ISO. Priority wheel-through awards can vary by hour. For example, a scheduling coordinator may show a contract with an outside load serving entity for a 16-hour block. In this case, the ISO would award the contract amount for 16 hours and 0 MW for the other 8 hours. Integrated forward market (IFM) self-schedules (green bars) show how often, and to what extent, scheduling coordinators used their priority wheel-through awards. This analysis aggregates awards and schedules by intertie.

Figure 16.11 shows the hourly priority wheel-through awards and associated average hourly IFM self-schedules for Malin. The ISO awarded 72 MW of priority wheel-throughs for hours-ending 7 to 22 in June, 77 MW in July, 97 MW in August, and zero MW for the other hours in each month. On average, scheduling coordinators self-scheduled about 7 MW (or about 10 percent) of priority wheel-through capacity during awarded hours in the IFM in June, 40 MW (52 percent) in July, and 26 MW (27 percent) in August.

**Figure 16.11 Average hourly PWT reservations vs. IFM self-schedules at MALIN500**

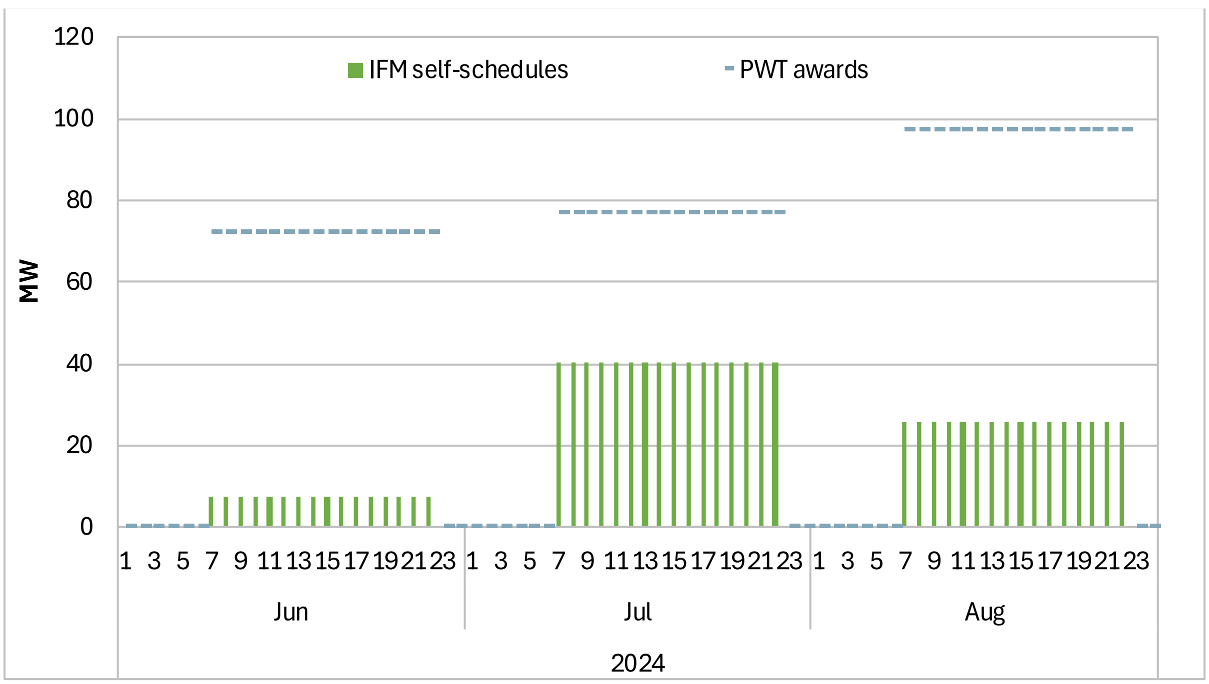



Figure 16.12 uses hour-ending 19 as a representative hour to show the low average priority wheel-through award usage is typically due to bidding infrequency—as opposed to bidding amount—on the Malin intertie. Scheduling coordinators bid within 93 percent of the full priority wheel-through award amount in the IFM on three days in June, 16 days in July, and three days in August. On the other days, scheduling coordinators either did not bid or bid less than 75 percent of their priority wheel-through award in HE19.

**Figure 16.12 Hour-ending 19 PWT reservations vs. IFM self-schedules at MALIN500 (2024)**

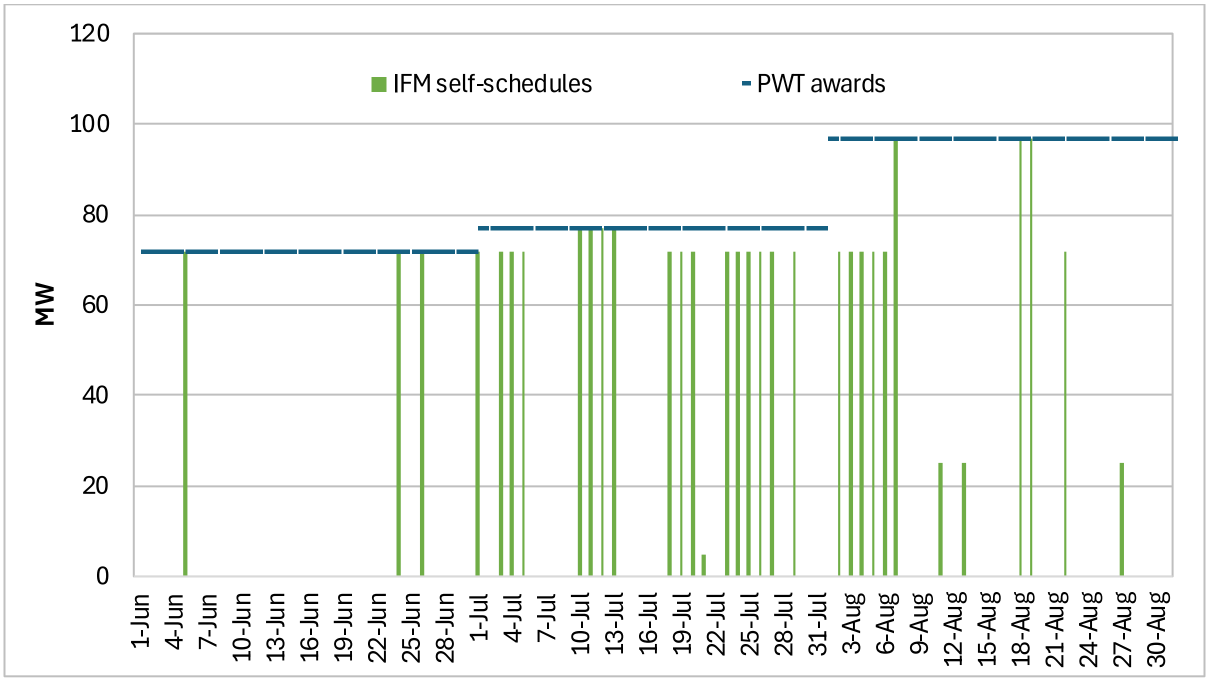



Figure 16.13 shows the hourly priority wheel-through awards and associated average hourly IFM self-schedules for NOB. In June, the ISO awarded 128 MW for priority wheel-throughs for hours-ending (HE) 7 to 14, 153 MW for HE15-HE18, 378 MW for HE19-HE22, and 0 MW for the other hours. On average for the month, scheduling coordinators self-scheduled about 3 MW, or about two percent, of priority wheel-through capacity during awarded hours in the IFM. In July, the ISO awarded 128 MW for HE7-HE14, 328 MW for HE15-HE17, and 378 MW for HE18-HE22. On average, scheduling coordinators self-scheduled about 39 to 56 MW, or about 12 to 30 percent, of priority wheel-through awards. August had the same priority wheel-through awards as July, and scheduling coordinators self-scheduled 29 to 45 MW, or about 9 to 28 percent, of priority wheel-through awards on average for the month. In September, the ISO awarded 200 MW for HE15-HE17 and 250 MW for HE18-HE22. On average, scheduling coordinators self-scheduled 0 to 24 MW, or 0 to 10 percent, of priority wheel-through awards.

**Figure 16.13 Average hourly PWT reservations vs. IFM self-schedules at NOB**

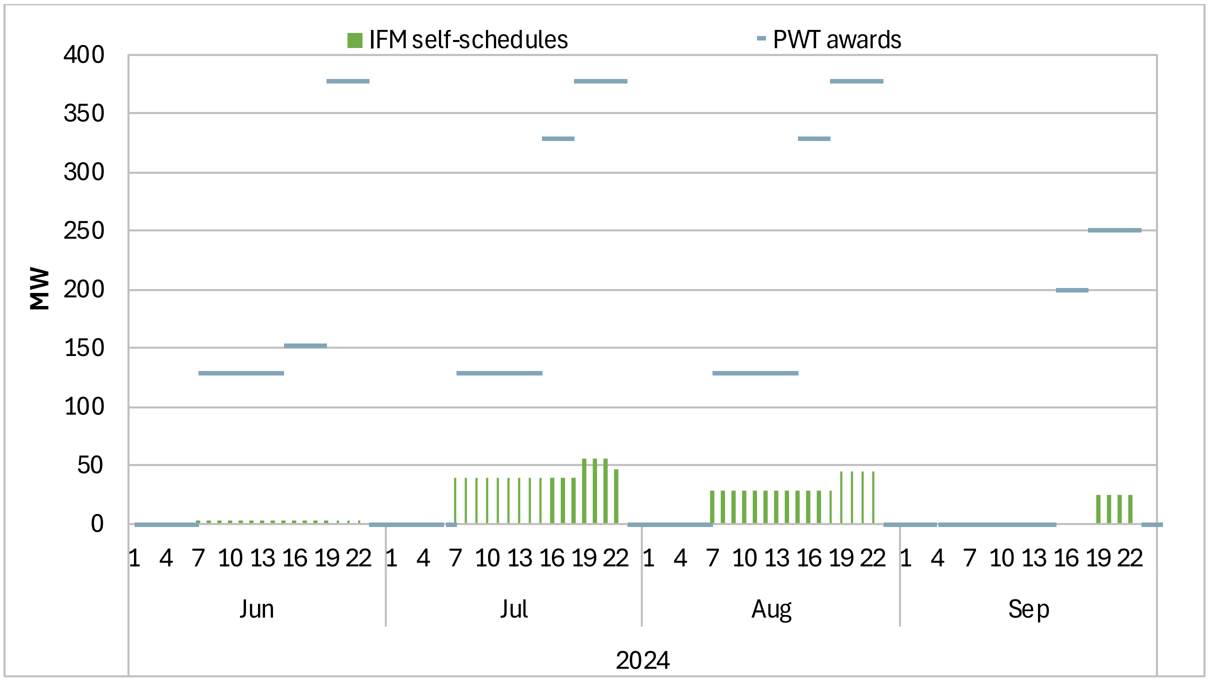



Figure 16.14 uses HE19 as a representative hour to show the low average priority wheel-through award usage is due to both bidding infrequency and bidding amount on the NOB intertie. Scheduling coordinators bid 25-28 MW (or about seven percent of total priority wheel-through awards) during HE19 in the IFM on four days in June and did not bid the other days. Scheduling coordinators bid the entirety of priority wheel-through reservations four times during HE19 in July, August, and September, while most days had 0 to 128 MW (zero to 34 percent) self-schedules.

**Figure 16.14 Hour-ending 19 PWT reservations vs. IFM self-schedules at NOB (2024)**