California ISO

WINTER CONDITIONS REPORT
for January 2024

March 6, 2024

Prepared by Market Performance and Advanced Analytics

The following staff from the California ISO contributed to this report:

Shawn Grant

Scott Lehman

Kevin Head

Abhishek Hundiwale

Zhu Liang

Haifeng Liu

Zachary Ricciardulli

Monique Royal

Hudson Sangree

Miheer Shah

Jessica Stewart

Auswin Thomas

Katie Wikler

Kun Zhao

Rebecca Webb

Guillermo Bautista Alderete

Tim Beach (RC West)

Contents

List of Figures

Acronyms

AET	Assistance Energy Transfer
AZPS	Arizona Public Service
BAA	Balancing Authority Area
BANC	Balancing Authority of Northern California
CAISO	California Independent System Operator
DAM	Day ahead market
DLAP	Default Load Aggregated Point
DSW	Desert Southwest
EEA	Energy Emergency Alert
EIM	Energy Imbalance Market
EPE	El Paso Electric
ETC	Existing Transmission Contract
F	Fahrenheit
FMM	Fifteen Minute Market
HASP	Hour Ahead Scheduling Process
HE	Hour Ending
IFM	Integrated Forward Market
IID	Imperial Irrigation District
IPCO	Idaho Power Company
LADWP	Los Angeles Department of Water and Power
LESR	Limited Energy Storage Resource
LMP	Locational Marginal Price
LPT	Low priority export. This is a scheduling priority assigned to price-taker exports that do not have a non-RA supporting resource
LSE	Load Serving Entity
MAPE	Mean Absolute Percentage Error
MNW	Mountain Northwest
MW	Megawatt
MWh	Megawatt-hour
NEVP or NVE	NV Energy

NGR	Non-Generating Resource
NOB	Nevada-Oregon Border
NSI	Net Scheduled Interchange
NWMT	Northwestern Energy
OASIS	Open Access Same-Time Information System
OR	Operating Reserves
PACE	PacifiCorp East
PACW	PacifiCorp West
PGE	Portland General Electric
PNM	Public Service Company of New Mexico
PNW	Pacific Northwest
PRM	Planning Reserve Margin
PSEI	Puget Sound Energy
PST	Pacific Standard Time
PTK	High priority assigned to a schedule. Exports are assigned this priority when they can have a non-RA resource supporting its export.
RA	Resource Adequacy
RDRR	Reliability Demand Response Resource
RSE/RSEE	Resource Sufficiency Evaluation Enhancements
RTD	Real-Time Dispatch
RTM	Real-Time Market
RTPD	Real-Time Pre-Dispatch
RUC	Residual Unit Commitment
SCL	Seattle City Light
SMEC	System Marginal Energy Component
SRP	Salt River Project
TIDC	Turlock Irrigation District
TOR	Transmission Ownership Right
WEIM	Western Energy Imbalance Market

Executive Summary

Extreme cold weather gripped the Pacific Northwest and northern Rocky Mountain states over the Martin Luther King Jr. Day weekend, January 13 to 15, 2024.

Demand for electricity exceeded previous highs in five balancing authority areas. Limited supply forced five balancing areas to issue energy emergency alerts (EEAs). The shutdown of a major gas storage facility in Washington State led one balancing area to declare the highest level alert, an EEA 3, indicating it might have to order rotating outages.

The export of large amounts of electricity from the Desert Southwest and California helped avoid more serious consequences in the Northwest and Rocky Mountain states.

The cold-weather event again demonstrated the benefits of the Western Energy Imbalance Market (WEIM), an interstate electricity market that covers much of the West. The market's diversity of weather and generating resources allows Western regions to aid each other during winter and summer peak demand periods.

This report details key findings from January's cold-weather event including:

The Pacific Northwest and Rocky Mountain States experienced severe winter weather, with record-setting cold. Temperatures in many areas were 20 to 40 degrees below normal. Part of Northwest Montana set a record low of minus 48 degrees.

Grid conditions were strained, and balancing authority areas in the Pacific Northwest issued energy emergency alerts. The alerts ranged from seven events of EEA1 to one event of EEA3. An EEA 3 means it may be necessary for utilities to reduce demand, potentially requiring rotating outages. The sole EEA 3 occurred after a major gas storage facility stopped operating for two hours during a crucial period. Some balancing authority areas experienced multiple EEAs. California and the Southwest balancing authority areas did not have any energy emergencies during the holiday weekend.

The Western Energy Imbalance Market economically rebalanced supply across the West to meet increasing demand as real-time conditions evolved over the Martin Luther King Jr. Day weekend. The market identified least-cost solutions within the wider WEIM footprint, transferring lower-cost electricity from the Southwest into California. These transfers allowed exports scheduled in the day-ahead and hour-ahead markets to flow to the Northwest, replacing more expensive generation while managing congestion on key transmission lines.

Hourly intertie exports in the day-ahead and real-time markets increased significantly, exceeding 6,000 MW. CAISO became a net exporter over the Martin Luther King Jr. Day weekend for all hours of the day, excluding WEIM transfers. Additionally, up to 300 MW of low-priority wheel-through from south to north were transferred on the CAISO grid.

The WEIM allowed northern balancing authority areas to access assistance energy transfers. Six BAAs opted into the WEIM's Assistance Energy Transfer program, letting them receive energy transfers when they could not meet their own resource sufficiency requirements. Two Pacific Northwest areas received as much as 176 MW of assistance energy transfers which would not have been available without the Assistance Energy Transfer program.

Congestion between California and the Pacific Northwest limited the volume of exports to the Pacific Northwest. No exports could flow on the Nevada-Oregon Border (NOB) intertie because of a forced outage on the high-voltage lines, which transfer electricity from the Desert Southwest to the Pacific Northwest. The outage began before the holiday weekend and continued through its coldest days.

In addition, severe weather caused transmission outages in Oregon, limiting transfers from south to north in real time. This resulted in congestion at the Malin intertie in southern Oregon. Congestion at Malin in the day-ahead market was driven by the transmission limits and requests for exports at that location in excess of the limits.

Internal transmission constraints in California further limited the ability to move power northward.

Prices over the Martin Luther King Jr. Day weekend reflected regional conditions with high prices in the Pacific Northwest. The market bid cap rose to $2,000/MWh. Although prices increased dramatically they rarely rose above $1,000/MWh.

Transmission congestion at the Malin intertie resulted in congestion rents totaling approximately $125 million in the day-ahead market. These congestion rents are distributed to holders of congestion revenue rights (CRRs), which are financial instruments that protect holders against high congestion prices at specified locations. These rights are available to all market participants, including load-serving entities in the Pacific Northwest, to hedge themselves against congestion on CAISO's grid.

Before January, participants bought more than 900 MW of CRRs in anticipation of potential northbound congestion on California's northern boundary. None of these rights were held by external load serving entities, such as Northwest utilities, although they could have obtained the CRRS through the CAISO's CRR auction or the allocation process that provides CRRs for free to qualifying load serving entities.

CAISO is the only balancing authority in the West that manages transmission congestion through electricity prices at specific locations in its day-ahead market. Operators of transmission lines in the Pacific Northwest do not use similar market mechanisms to manage congestion in the day-ahead timeframe. Congestion in the Northwest can still result in higher prices, but those costs are not as visible to market participants as they are in the CAISO market.

The new Extended Day-Ahead Market (EDAM), to be implemented in 2026, provides additional mechanisms for managing congestion on either side of balancing area borders for participating entities, and provides transparency on the distribution of congestion revenues collected through nodal pricing. The EDAM will be able to help Pacific Northwest transmission operators better manage and allocate the costs of congestion on their systems.

A public meeting will be held on March 11, 2024, to discuss this report's findings, including the congestion issues observed during the cold spell. See [California ISO - Calendar (caiso.com)]

Weather and Demand Conditions

Temperature

Temperatures play a key role in the variables affecting the market and system operations, including renewable production and load levels. Much of the United State saw temperatures 15 or more degrees below normal the week of January 14 to 20. This is shown in Figure 1[1].

Figure 1: Mean temperature percentiles for January 14 to 20

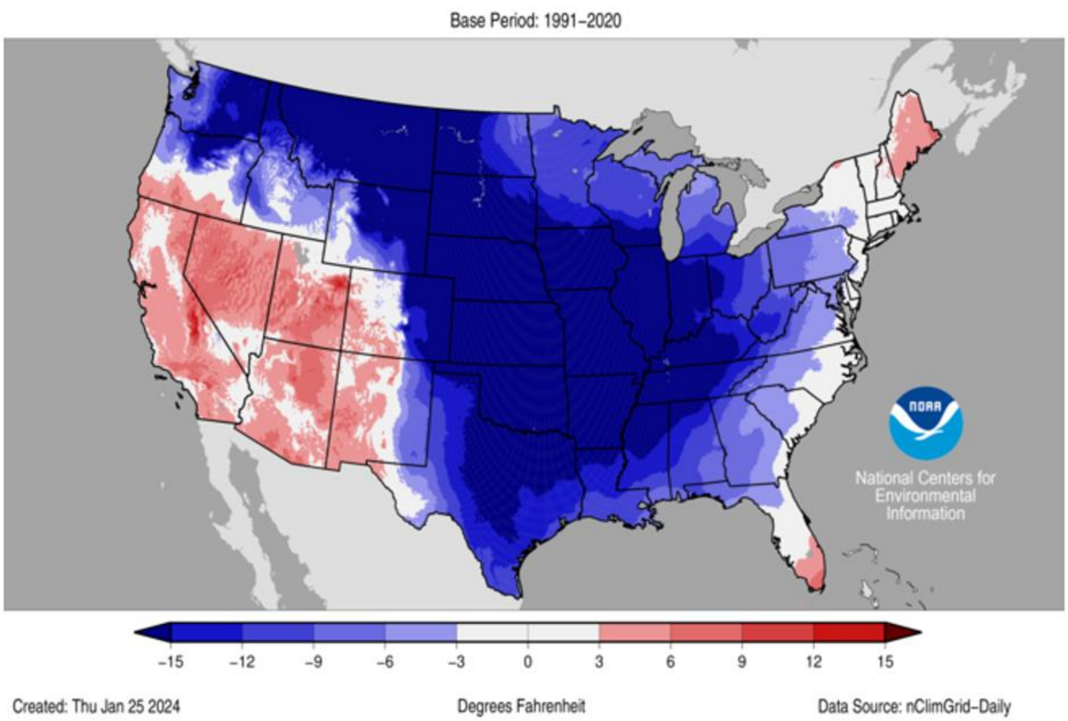
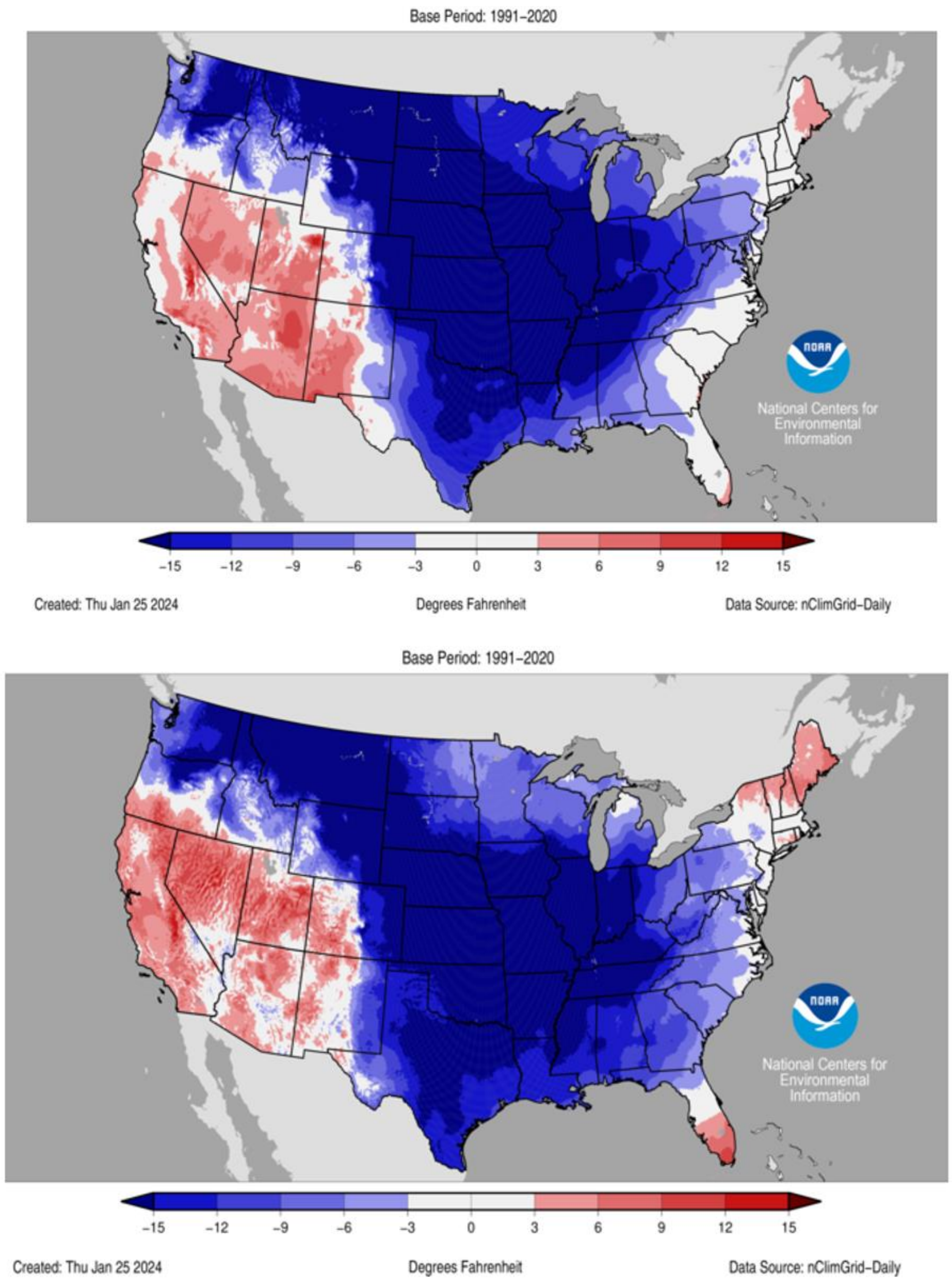


Figure 2[2] shows that both the maximum temperatures and minimum temperatures were well below average across all of the U.S. except the Desert Southwest, California, south Florida and New England. While the figure scale only shows the shading down to 15 degrees below normal, many areas observed temperatures 20 to 40 degrees below normal with the coldest temperatures across the north-central region of the U.S.

[1] https://www.ncdc.noaa.gov/temp-and-precip/us-maps/
[2] https://www.ncdc.noaa.gov/temp-and-precip/us-maps/

Figure 2: Maximum and minimum temperature departures from normal. January 14 to 20



As shown in Figure 3, while the CAISO and Desert Southwest average temperature was below normal the week before the extreme cold, conditions warmed to near normal for these regions during the period of coldest temperatures for the Pacific Northwest and Rocky Mountain regions.

Figure 3: CAISO and Desert SW average temperature departure from normal

California ISO (CAISO)

Average temperature departure from normal

January 2024

Sun	Mon	Tues	Wed	Thurs	Fri	Sat
	1: 2	2: 0	3: 1	4: 0.3	5: 0.1	6: -3
7: -4	8: -5	9: -3	10: -4	11: -2	12: -5	13: -3
14: 0	15: 0.3	16: 0.7	17: 3	18: 2	19: 3	20: 3
21: 5	22: 3	23: 5	24: 2	25: 4	26: 3	27: 7
28: 9	29: 7	30: 6	31: 5			
				days < normal	days > normal	Deg +/- normal
				24	7	+ 1.3

above normal | below normal | *Normals: 1990-2020*

Arizona Public Service (AZPS)

Average temperature departure from normal

January 2024

Sun	Mon	Tues	Wed	Thurs	Fri	Sat
	1: -0.2	2: 0.5	3: -1	4: -3	5: -6	6: -5
7: -8	8: -10	9: -10	10: -8	11: -7	12: -9	13: -6
14: -2	15: -0.3	16: -0.5	17: 0.4	18: 5	19: 6	20: 3
21: 0	22: 0	23: 0.5	24: 1	25: 0.7	26: 0.7	27: 3
28: 9	29: 10	30: 9	31: 8			
				days < normal	days > normal	Deg +/- normal
				21	10	-.6

above normal | below normal | *Normals: 1990-2020*

In the Northwest, temperatures dropped to extreme levels beginning on January 11 for Northwestern Energy (NWMT) and on January 12 for Bonneville Power Administration (BPA), remaining 10 or more degrees below normal for six consecutive days. Saturday, January 13, was the coldest day of the event across the entire region with high temperatures in Billings, Montana, at minus 8 degrees F and low temperatures at minus 26 degrees F.

Figure 4: Average temperature departure from normal for select Northwestern WEIM participants

NorthWestern Energy (NWMT)

Average temperature departure from normal

January 2024

Sun	Mon	Tues	Wed	Thurs	Fri	Sat
	1: 6	2: 4	3: 2	4: 7	5: 7	6: 6
7: -5	8: -8	9: 6	10: -5	11: -26	12: -45	13: -45
14: -37	15: -37	16: -19	17: -7	18: -16	19: -18	20: 2
21: 11	22: 6	23: 11	24: 12	25: 11	26: 10	27: 10
28: 19	29: 20	30: 20	31: 18			
				days < normal	days > normal	Deg +/- normal
				13	18	-3

above normal | below normal | *Normals: 1990-2020*

Bonneville Power Administration (BPA)

Average temperature departure from normal

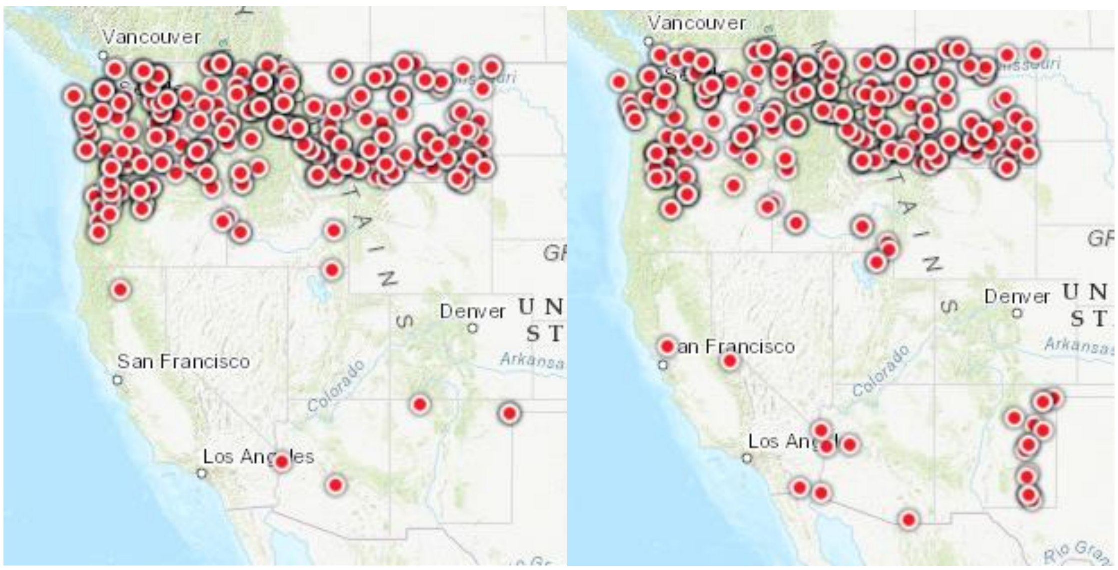
January 2024

Sun	Mon	Tues	Wed	Thurs	Fri	Sat
	1: 0.6	2: 2	3: 3	4: 3	5: 2	6: 1
7: -0.3	8: 3	9: 2	10: -3	11: -3	12: -16	13: -24
14: -20	15: -14	16: -15	17: -10	18: -7	19: -3	20: -3
21: -1	22: 2	23: 5	24: 3	25: 5	26: 3	27: 6
28: 9	29: 10	30: 10	31: 8			
				days < normal	days > normal	Deg +/- normal
				16	15	-1

above normal | below normal | *Normals: 1990-2020*

Looking at the Western United States temperature records in Figure 6[3], there were 508 daily lowest maximum temperature records tied or broken and 467 daily lowest minimum temperature records tied or broken for the period of January 12 to 19. There were 14 monthly lowest minimum records tied or broken and 13 all-time coldest minimum temperature records tied or broken. Overnights in Dunkirk, Montana, reached minus 48 degrees F on January 13, breaking their previous all-time coldest temperature of minus 46 degrees F set in 1957.

Figure 5: Lowest daily records for maximum and minimum temperatures. January 12 to 19



Load Conditions

Throughout the period of cold weather, the highest load within the California and Desert Southwest regions was observed on January 11 and 12. The highest load in the Pacific Northwest region was observed on January 13, followed by highest loads within the Central region on January 15 to 16. Five entities surpassed the previously observed peak load from the extreme cold in December 2022.

[3] https://www.ncdc.noaa.gov/cdo-web/datatools/records

Table 1: Maximum 5-minute average demand across WEIM footprint

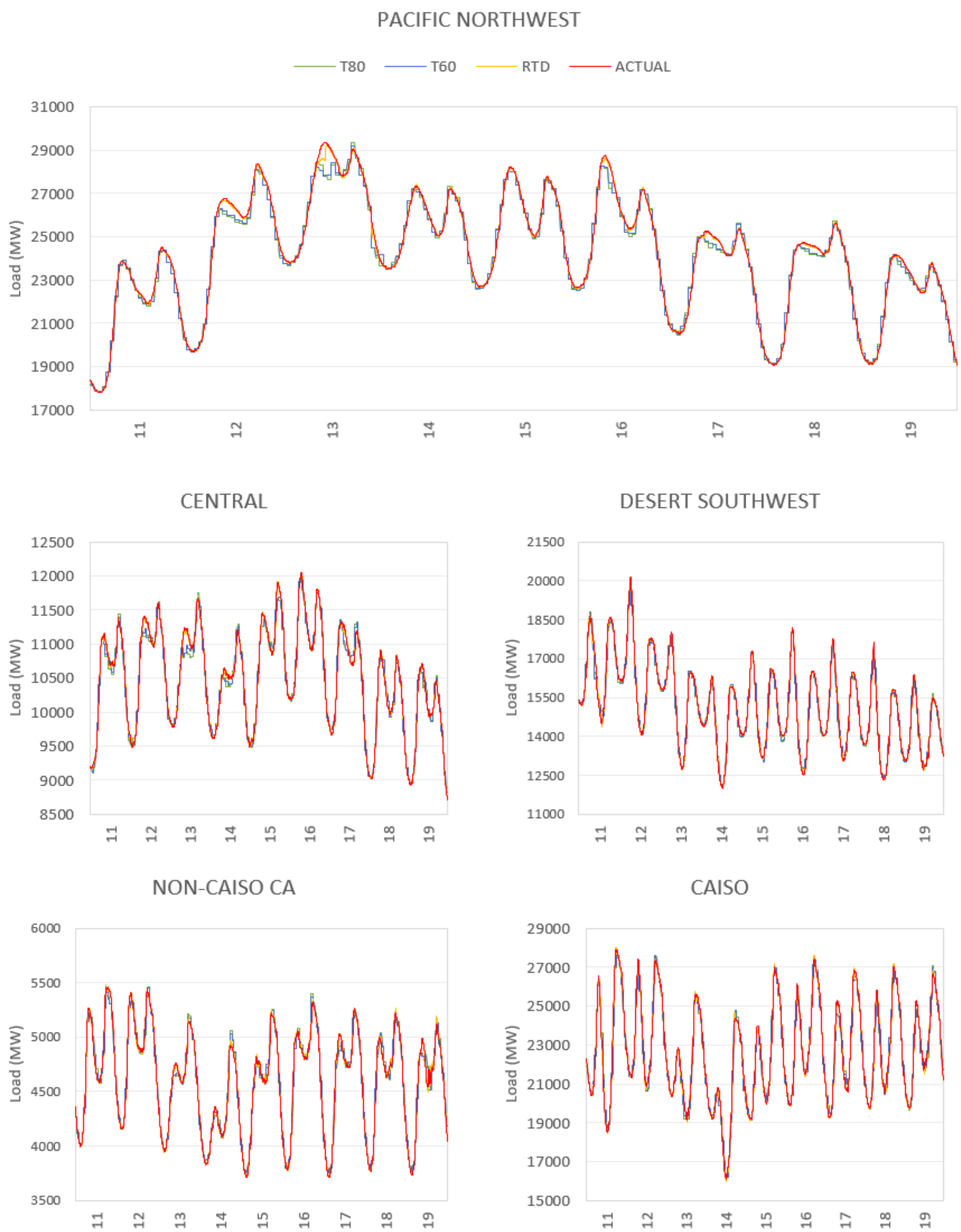
	Maximum Load (MW) Jan 11-19, 2024	**Time of 2024 Regional Max Load[4]**	**Previous Max Load (2018-2023)**
CAISO	27,891	Jan 11 17:55	
CENTRAL	12,055	Jan 16 07:35	
IPCO	3,045		4,103
NWMT	**2,083**		*2,072*
PACE	7,067		9,566
DSW	20,141	Jan 12 06:35	
AZPS	5,168		8,346
EPE	1,120		2,379
NEVP	4,756		9,479
PNM	2,062		2,747
SRP	4,632		8,322
TEPC	1,866		3,122
WALC			
NON-CAISO CA	5,465	Jan 11 17:55	
BANC	2,151		4,797
LADWP	3,043		6,037
TIDC	351		734
PNW	29,374	Jan 13 10:35	
AVA	2,338		2,391
BPAT	**11,431**		*10,976*
PACW	4,017		4,198
PGE	4,021		4,521
PSEI	**5,315**		*5,161*
SCL	**1,993**		*1,905*
TPWR	**967**		*934*

The average error for the T-60 demand forecast across all hours, morning peak, and evening peak is summarized by region in Table 2. Most regions saw higher error during their morning peak.

Table 2: T-60 MAPE for January 11 to 19

	All Hours (%)	**Morning Peak (%)**	**Evening Peak (%)**
CAISO	0.88	1.07	1.00
CENTRAL	0.60	1.31	0.88
DSW	0.75	0.46	0.40
NON-CAISO CA	0.73	1.48	0.87
PNW	0.73	1.50	0.46

Figure 6: T-80 through RTD demand forecast for WEIM Footprint

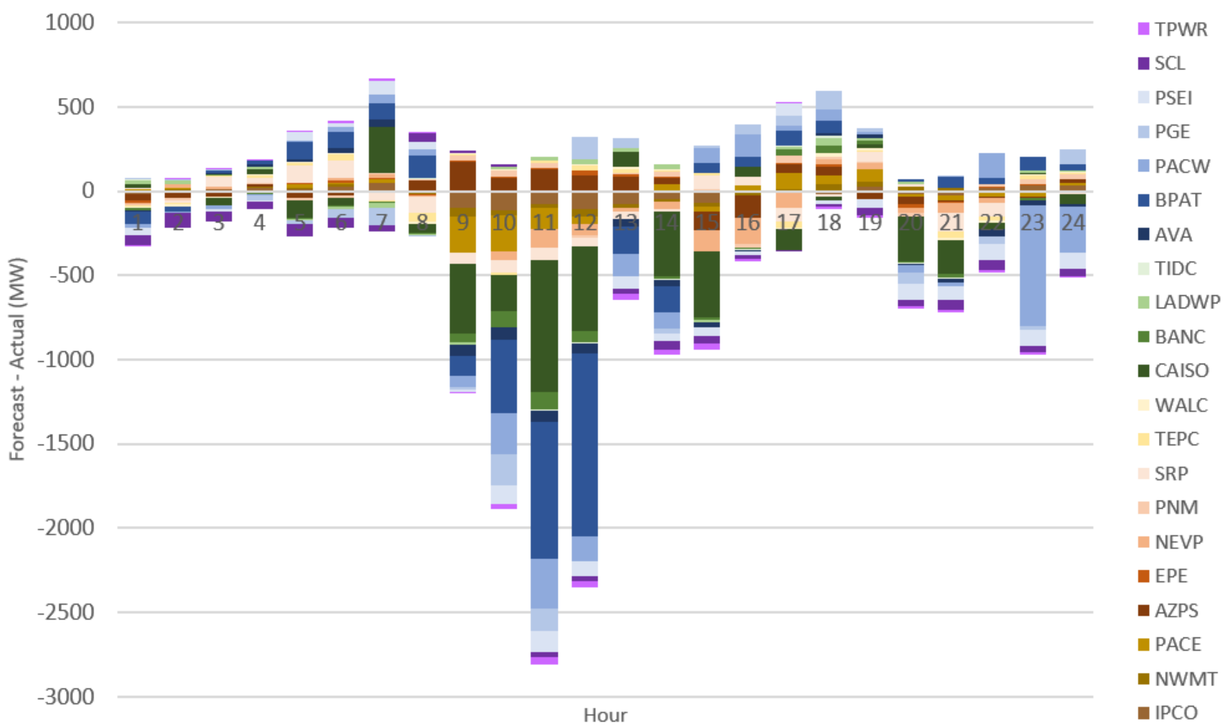


The largest errors were observed in the Pacific Northwest and Central regions from January 11 to 13 when temperatures reached their coldest values. Figure 7 shows the T-60 forecast error by hour on January 13. Despite extreme temperatures, on average the temperature forecast stayed within 2 degrees of actual temperatures, and did not contribute significantly to load-forecast error. However the models struggled to forecast the higher load levels which were outside of the model training set.

In addition, the actual load for BPA was significantly higher than the previously observed peak and exceeded maximum thresholds within the forecasting software. The observed load was artificially flagged as bad data. Because the models filter out bad data when generating the forecast, the forecast was temporarily unable to adjust to the higher observed load levels.

Seattle City Light (SCL) experienced a similar issue during the evening peak of January 12. Upon identifying the issue, the thresholds were adjusted for BPA and SCL, and forecast performance returned to normal error ranges for the duration of the cold weather period. On average the regional T-60 forecast performance stayed under 1% (Table 2).

Figure 7: January 13 T-60 load forecast error by entity



In order to manage net-load error, the real-time market markets uses flexible ramp product (FRP). One measure of the performance of the estimated FRP requirement is its coverage of realized (actual) uncertainty. The coverage is measured as the percentage of the realized uncertainty covered by the forecasted FRP requirement. Directional components of FRP has a target of 97.5% coverage, for the WEIM area, uncertainty coverage remained high at 96.6% for flex ramp up (FRU) and 98.5% for flex ramp down (FRD) during the period from January 11 to 19. The Pacific Northwest region had the largest deviation from target coverage over the period of analysis at an average of 89.3% for FRU and 94.1% for FRD.

Bilateral Power Prices

Energy trading outside the CAISO's footprint on the bilateral power market provides a useful indication of price trends and conditions in the broader West. Electricity trades bilaterally on both a spot market for physical next-day delivery and on a forward basis for future months. Next-day power trades in blocks for on-peak and off-peak periods[4].

Figure 8 shows on-peak bilateral prices for four major power trading hubs in the West. Prices at the Mid-C hub in the Pacific Northwest began climbing on January 10 and reached a maximum value of $934/MWh on January 13. Figure 74 in the Appendix shows the same trend for off-peak bilateral prices. Similarly, off-peak prices at the Mid-C hub spiked starting on January 10 and reached a maximum value of $927/MWh on January 13. While prices were elevated at other Western hubs, the increases were modest in comparison to Mid-C, not exceeding $250/MWh.

Figure 8: On-peak next-day power prices at Western hubs

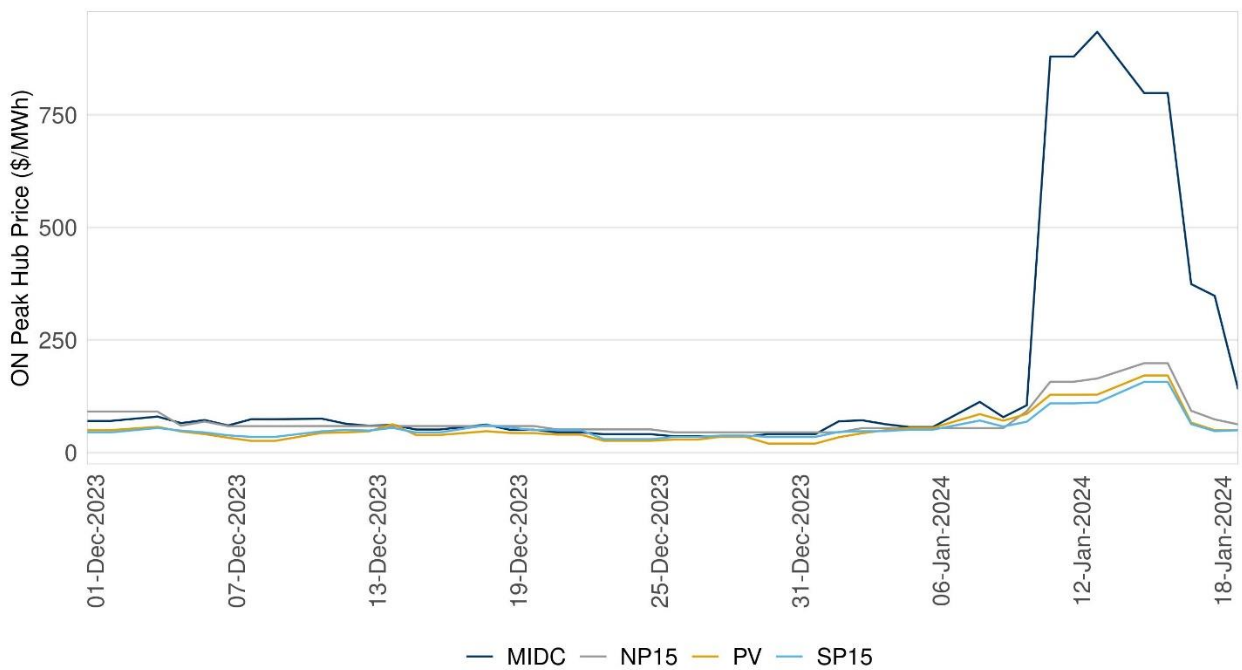
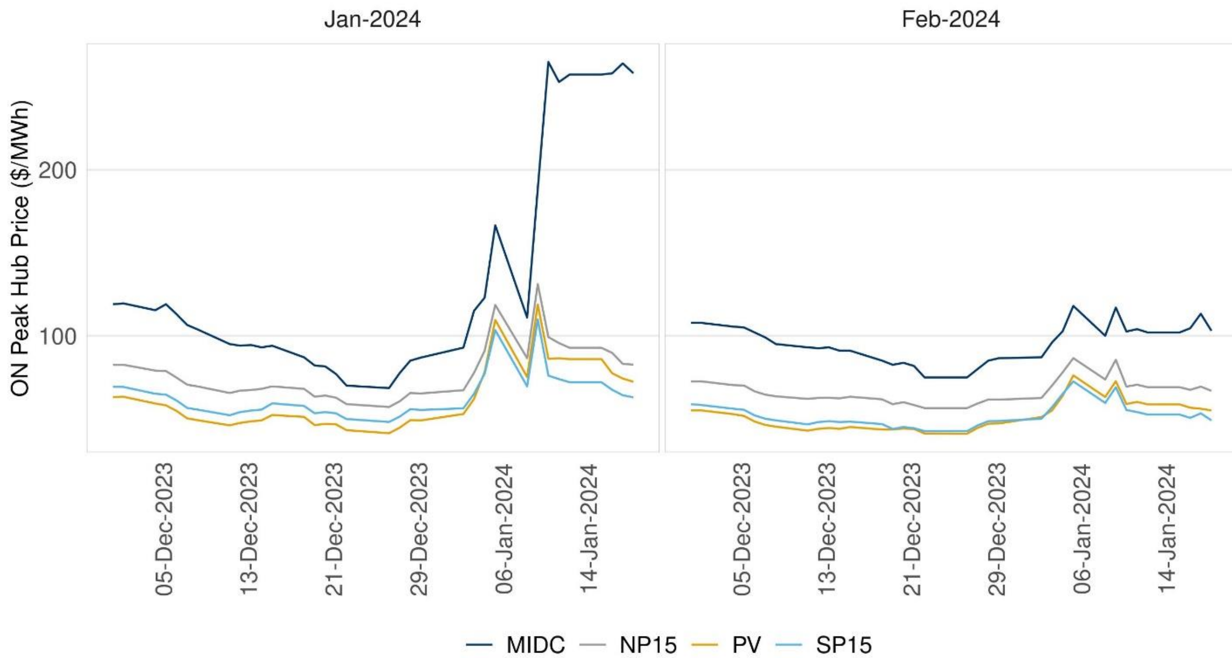


Figure 9 shows on-peak bilateral power futures at the main Western hubs for January 2024 and February 2024 futures. January 2024 futures prices started to spike on January 6 and remained elevated through the later part of the month. For the relevant future power month, trading continues through the end of that month. A similar trend was observed for the off-peak futures as shown in Figure 75 in the Appendix.

[4] Peak is typically defined as hours-ending 7 to22 on weekdays and Saturdays; off-peak is typically defined as hours-ending 1-6 and 23-24 on weekdays and Saturdays, and hours-ending 1-24 on Sundays and holidays.

Figure 9: On-peak future power prices for January and February 2024



Gas Dynamics

Gas-fired resources are a significant portion of the generation fleet in the West, and the dynamics of the gas system and markets have a direct impact on the electric system and markets. This section covers both the conditions of the gas system and the gas-fired resources use during the cold weather event.

Gas conditions and prices in the West were generally moderate, with modest price increases across hubs in California and the Pacific Northwest. The gas dynamic conditions faced by both interstate and intrastate gas companies in the West before, during, and after the cold weather event highlights the impact on infrastructure, emergency responses, the importance of customer cooperation in energy conservation, and ongoing gas-electric coordination in the West.

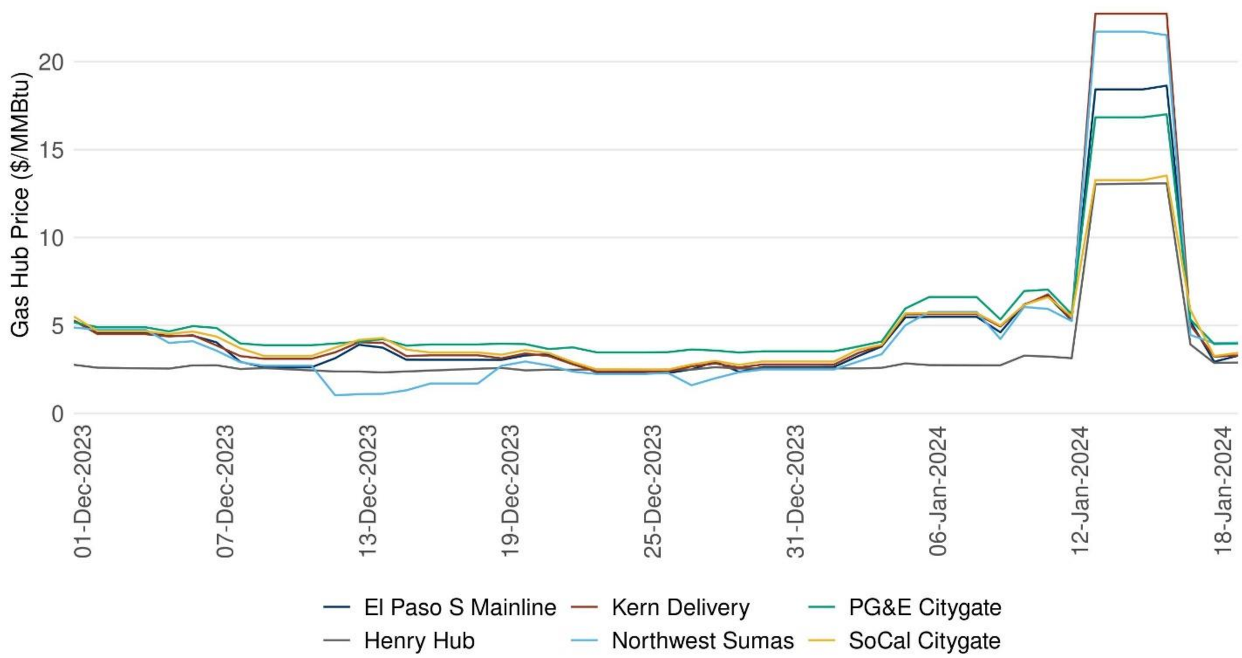
Gas Prices

Since early January 2024, the gas market experienced price volatility across many Western trading hubs in response to cold weather. Figure 10 shows the trend of settled next-day gas prices at the main Western trading hubs, including the national benchmark Henry Hub in Louisiana for reference.

Prices began spiking on January 4 and reached maximum values on January 13 as gas was traded for the Martin Luther King Jr. Day weekend. Because gas does not trade over the weekend, the settled price was remained flat over multiple days.

The Pacific Gas & Electric (PG&E) Citygate hub reached a maximum price of $17/MMBtu, while SoCal Citygate reached $13.52/MMBtu, closely tracking the Henry Hub next-day price. Other hubs like Kern Delivery and Northwest Sumas exceeded $20/MMBtu, the highest price for these hubs since the December 2022 gas market volatility. Hubs across the Northwest such as Alberta AECO, Kingsgate, Malin, and Stanfield closely followed the price trend depicted below, with prices remaining below $25/MMBtu over the Martin Luther King Jr. Day weekend.

Figure 10: Next-day gas prices at Western gas trading hubs



The natural gas hub prices shown above represent the weighted average price, also referred to as the settled index price, which is determined based on the full range of trades processed for that trading day. Figure 11 below shows the Intercontinental Exchange (ICE) high/low traded price spread for five major hubs as boxplots, where the box covers the interquartile range of the data (25^{th} to 75^{th} percentiles) and the line represents the median (50^{th} percentile). The red dots represent the settled index price at that hub for each trade date.

The greatest spread of prices materialized for weekend trading of January 13, when the settled next-day index price was correspondingly high. Despite the wider spread, the settled index price remained close to the median of trades at the five hubs below. For other days immediately before and after the Martin Luther King Jr. Day weekend, price spreads were significantly narrower.

Natural gas futures prices also saw increases during the cold weather. Figure 12 shows gas futures prices for the main Western hubs and Henry Hub for January 2024 and February 2024. February 2024 futures prices at Western hubs spiked on January 6 and remained elevated through January 14.

Figure 11. Next-day gas high/low traded price spread

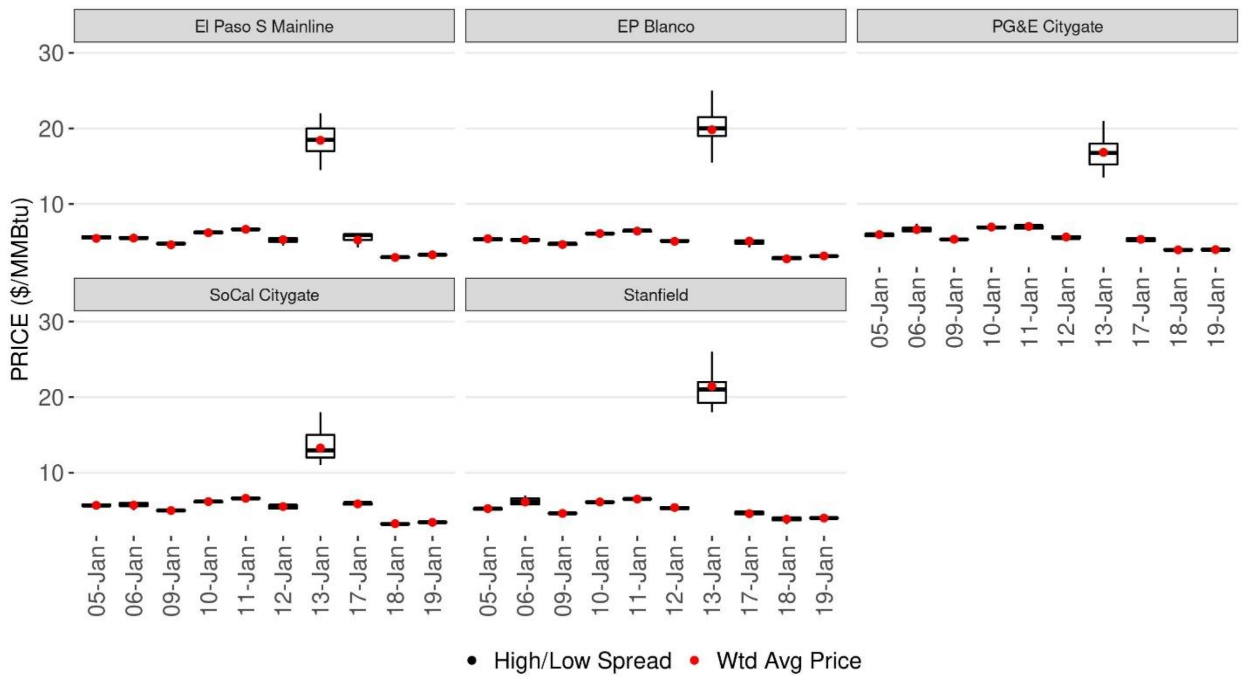
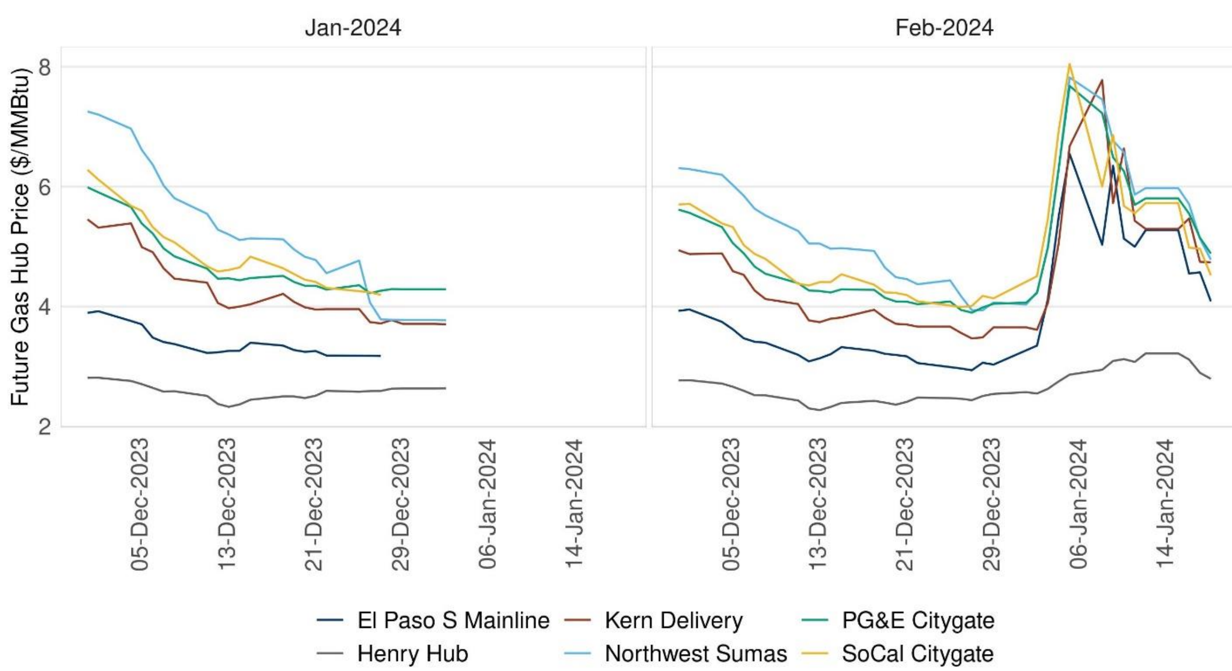


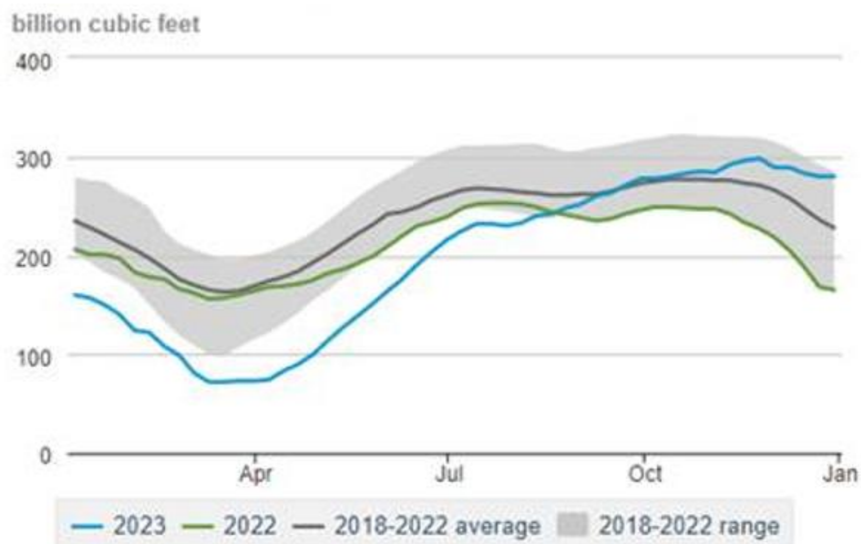
Figure 12: Futures gas prices at Western trading hubs



Gas System Conditions

In anticipation of the impending cold weather across the Pacific Northwest and Midwest, both interstate and intrastate gas companies in the West were operating under normal conditions. These companies proactively issued weather alerts to ensure heightened awareness across their operational territories. Information regarding storage levels in the West indicated that storage was above the average levels from the past five years. Figure 13 from the Energy information Administration (EIA), shows the weekly working gas in underground storage for the Pacific region, and the blue line shows that the storage levels were higher going into 2024.

Figure 13: Pacific region weekly working gas in underground storage



Notably, there were no reports of substantial capacity outages that could potentially disrupt gas deliveries. It is worth mentioning, however, that the El Paso pipeline system experienced a reduction in capacity by 175 mmcf/d due to anomalies discovered on the pipeline L2000 on January 3, 2024.

As the cold weather descended, a significant incident unfolded at the Jackson Prairie Natural Gas Storage Facility. The Jackson Prairie facility suffered a complete outage on January 13 at about 2 p.m. (14:00 hours), impacting the 1,500-mile Northwest Pipeline responsible for transporting gas to power plants and heating networks across the region. Northwest Pipeline declared an operational emergency and *force majeure* due to the Jackson Prairie outage, which was lifted once the storage facility came back online in the evening. During the event, Puget Sound Energy (PSE), issued a warning urging customers to conserve energy and natural gas due to unexpectedly higher energy use.

Subsequent investigations revealed that the outage resulted from failed fiber optic cables. Although the facility was restored to normal operations in the evening, the incident triggered an emergency situation during a period of extreme cold weather with temperatures well below normal.

In addition to the Jackson Prairie incident, other gas companies in the West – including Kern River Gas Transmission (Kern River), Pacific Gas & Electric (PG&E), and Southern California Gas Company (SoCal Gas) – encountered challenges. The companies experienced low system inventory by January 15, and Southern California Gas Company initiated a curtailment watch due to higher forecasted demand and insufficient supply to meet the increased demands.

Following the cold weather event, the gas system in the Pacific Northwest returned to normal operations. The Jackson Prairie storage facility fully recovered from the outage caused by the failed fiber optic cables. Other Western gas companies addressed the challenges encountered during the cold weather, including managing low system inventory and resolving a SoCal Gas curtailment watch, to maintain pipeline system reliability.

Gas use in CAISO balancing area's markets

Based on the bid-in cost and the overall supply availability, the day-ahead and real-time market-clearing processes determine the optimal schedule of generation, including gas generation, to meet forecasted demand. Fuel cost, as reflected in the bid-in price of resources, is a main driver to determine what generation is scheduled. The amount of supply from gas generation also depends on the relative availability and costs of other supplies. Figure 14 shows the comparison of gas burn for CAISO balancing area gas resources dispatched across the day-ahead and real-time markets. Overall, there was higher use of gas generation during the Martin Luther King Jr. Day weekend across the markets. The CAISO balancing area residual unit commitment (RUC) process projected more gas burn than the real-time market experienced. Figure 15 shows the gas burn in the RUC organized by the three main gas regions in the CAISO system: PG&E, SoCal Gas, and Kern River.

Figure 14: Gas Burn for CAISO resources across markets

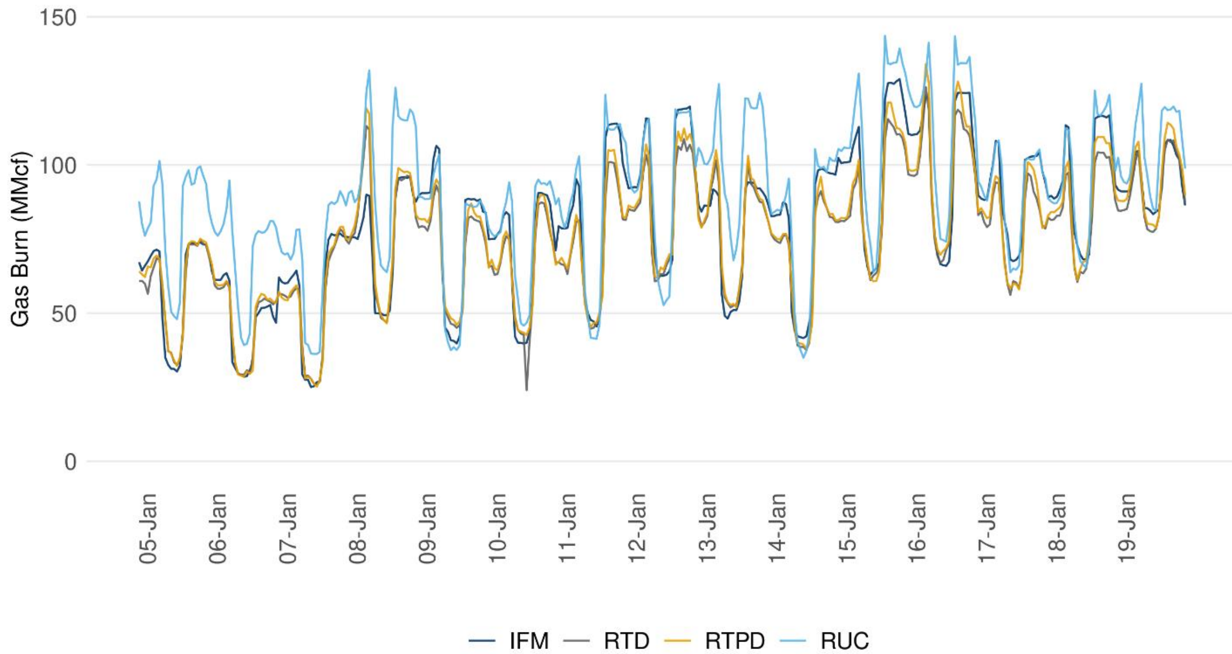
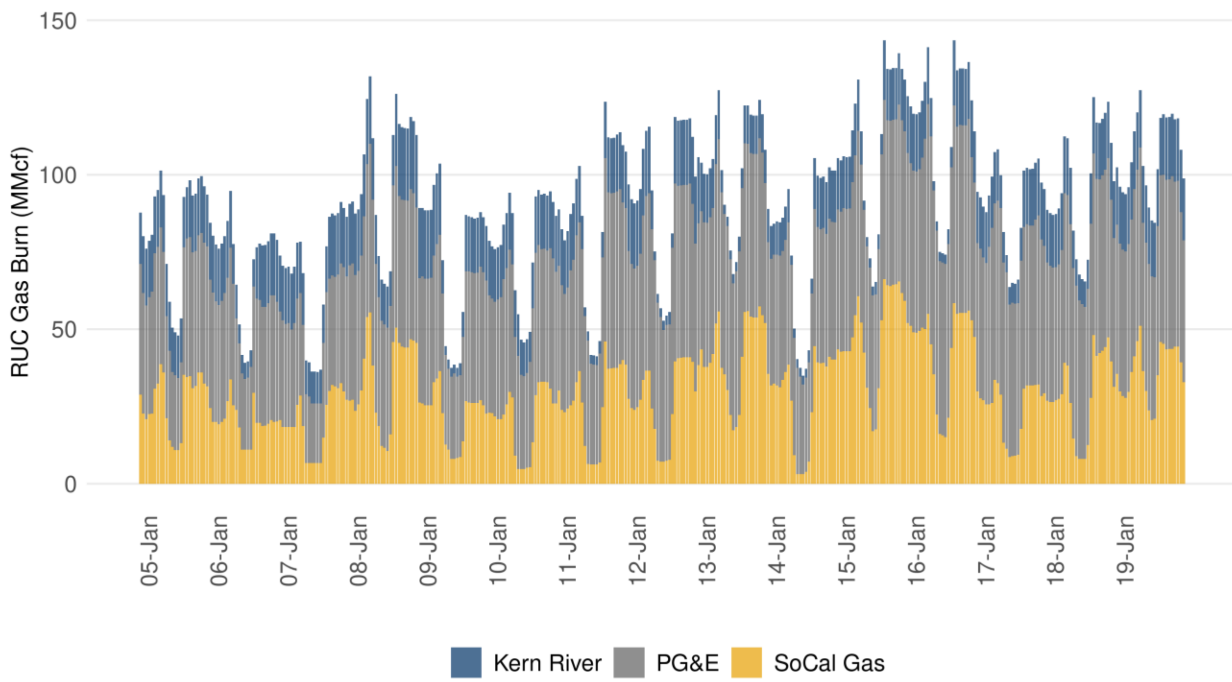
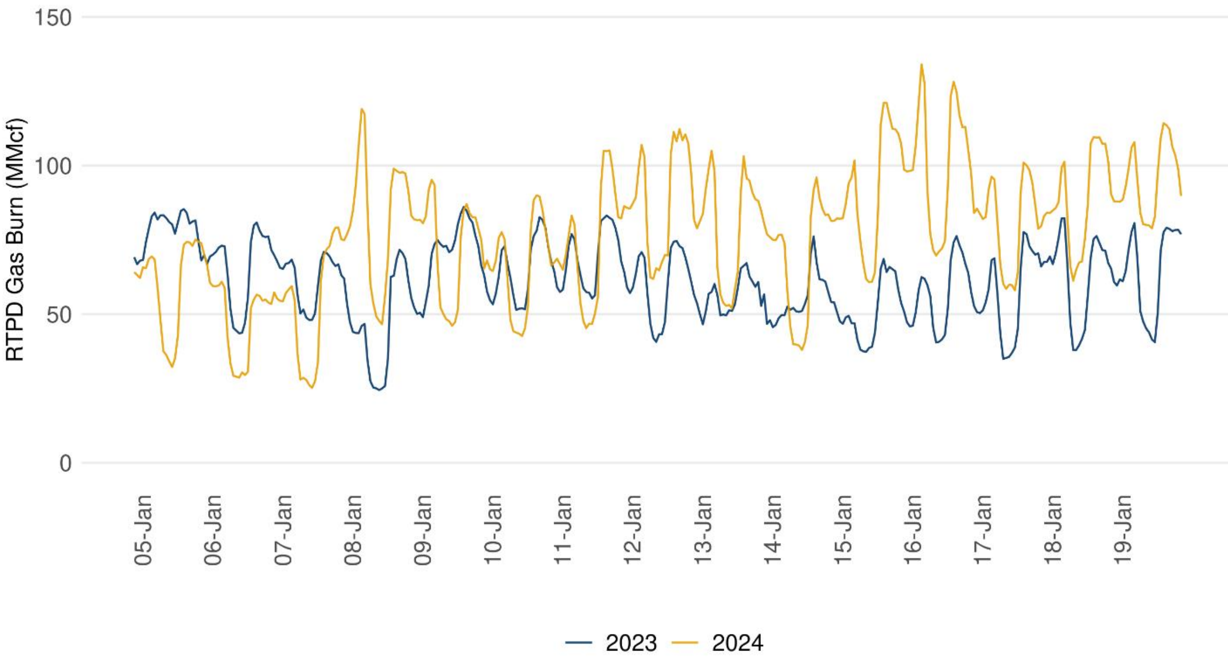


Figure 15: RUC Gas burn by gas region



Relative to the gas burn required in 2023, the period of the cold event in 2024 projected much higher use of gas-fired generation, as show in Figure 16.

Figure 16: Compare hourly gas burn across years for RTPD market



Gas Resource Bidding

Along with energy, generating resources submit bids for their resource-specific minimum load costs and startup costs, which represent the costs to operate at their minimum operating level or to start up their unit. Collectively, these costs are referred to as commitment costs. Unlike energy bids, where generating resources are able to bid up to $1,000/MWh and at times up to $2,000/MWh[5], commitment cost bids are limited to values called default commitment costs, or 125% of the CAISO-calculated proxy costs.[6] Commitment cost bids that are submitted in excess of the default commitment cost values are capped at the default commitment cost values.

During tight system conditions when gas prices increase, gas-fired resources may bid correspondingly higher commitment cost bids into the market to reflect higher operational costs. A gas-fired resource may be considered to have taken full advantage of its bidding headroom if it submits commitment cost bids up to the 125% default commitment cost caps. A headroom figure of 100% indicates the resource took full advantage of its commitment cost bid cap whereas a figure of, say, 80% indicates the resource still had additional headroom left before having their commitment bid capped in the market.

Figure 17 and Figure 18 below illustrates the distribution of headroom for both minimum load and startup bids across gas resources in the CAISO and other WEIM areas using violin plots. A violin plot is a distribution plot mirrored over the axis, where wider sections of the plot represent a higher probability

[5] See section titled “Maximum Import Bid Price and Bid Caps” for more details on the energy bid cap logic

[6] See the BPM for Market Instruments Attachment C for more details on proxy and default commitment costs

that members of the population will take on the given value whereas skinnier sections represent a lower probability.

Across the January winter period, CAISO gas resources bid either at full headroom (100%) or somewhat below full headroom (approximately 80%), with some exceptions in the real-time market on certain trade dates such as January 8 and 12. Conversely, other WEIM gas resources mostly bid below full headroom during the study period, at around 80%. Certain day such as January 12, 13 and 16 showed much wider headroom distributions, indicating that some portion of WEIM gas resources were bidding below 80% headroom. The full headroom of 100% includes the additional 25% of commitment costs multiplier plus the opportunity costs adder if applicable.

Figure 17: Commitment cost headroom distribution, CAISO area

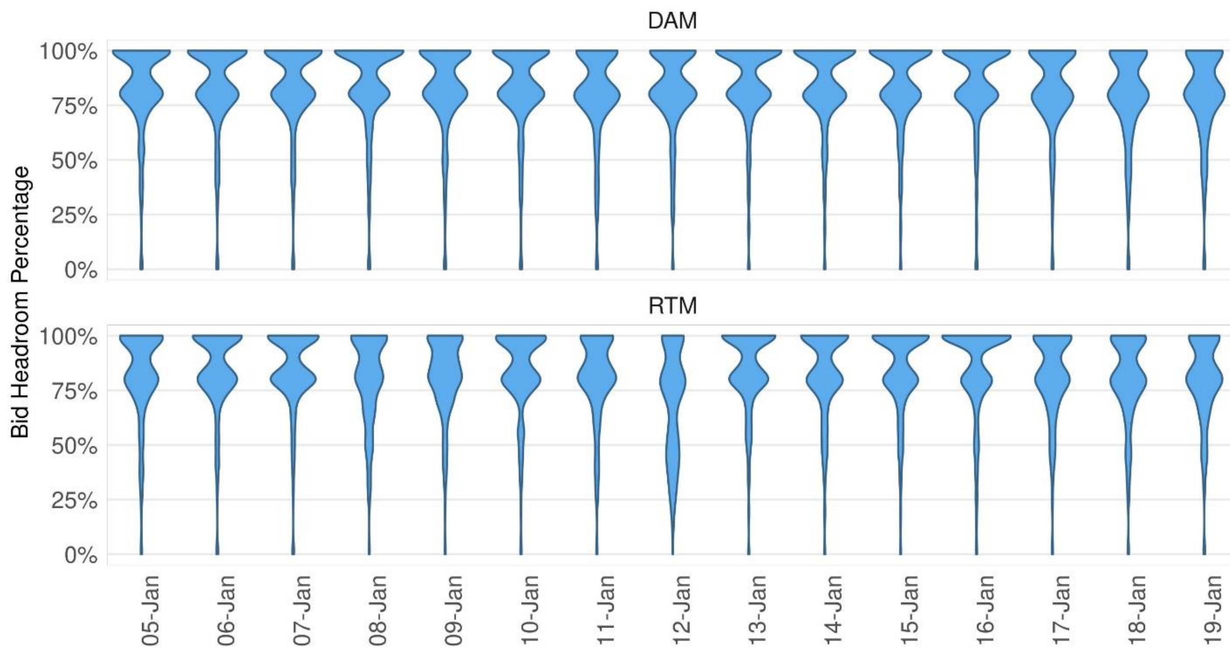
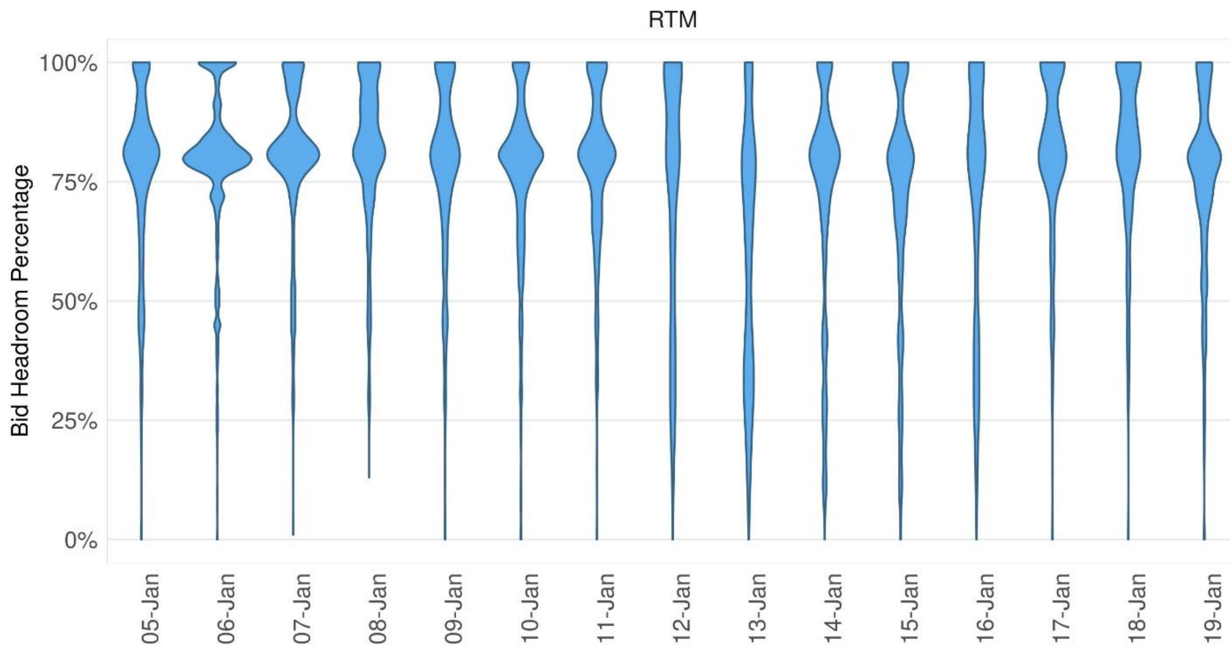


Figure 18: Commitment cost headroom distribution, WEIM area



Western Energy Imbalance Market

Capacity Test

The capacity test is part of the WEIM's resource sufficiency evaluation process, which aims to ensure each participating BAA in the WEIM has sufficient resources, capacity, and flexibility to serve its load needs prior to participating in the real-time market. Specifically, the capacity test assesses if there is sufficient capacity to meet the forecast obligation.

Figure 19 shows the percentage of capacity up failures for the regional areas within the WEIM between January 5 and January 19. The percentage is assessed daily over the 96 total fifteen-minute market intervals within each trading day across the BAAs in each regional grouping. A majority of the capacity up failures were concentrated between January 12 and 15 in the Pacific Northwest region.

Figure 20 shows the same metric for capacity down failures. In contrast to the capacity up test, there were minimal capacity down failures during this period. The percentage of capacity tests for individual BAAs are illustrated in Figure 76 and Figure 77 in the Appendix.

Figure 19: Percentage of capacity up failures by region

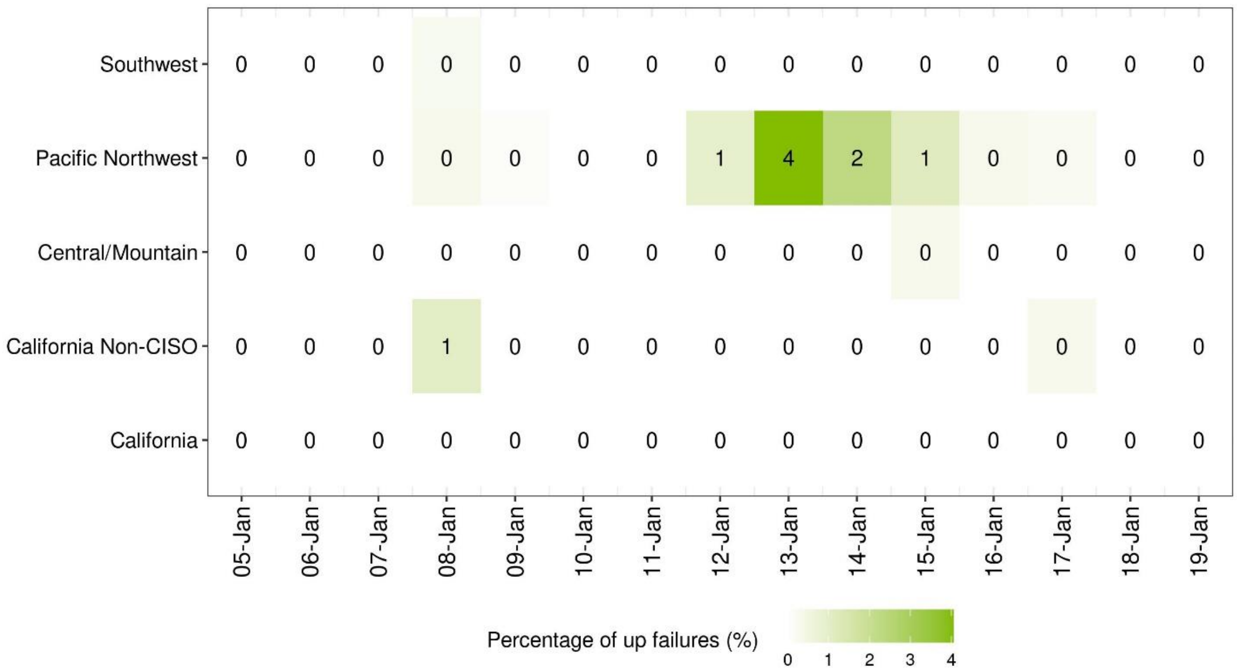
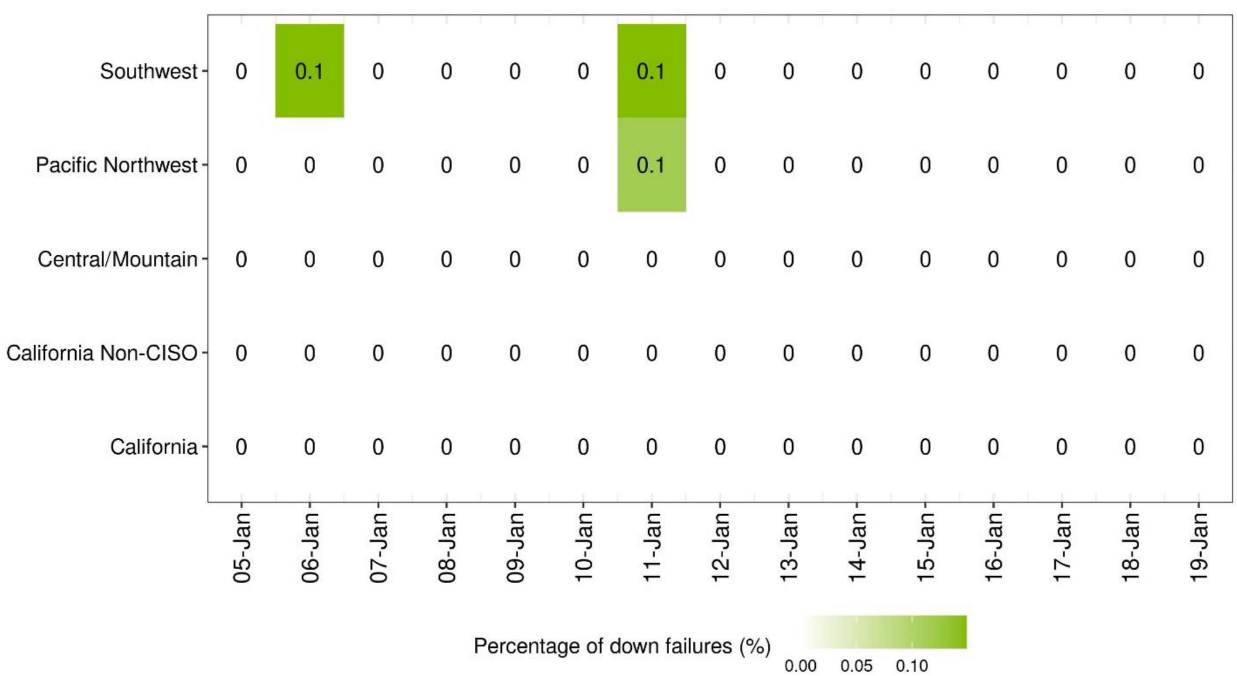


Figure 20: Percentage of capacity down failures by region



Flexible Ramping Test

The flexible ramping test is part of the WEIM resource sufficiency evaluation process. The goal of the flexible ramping test is to assess whether participating areas have sufficient ramping capability among all resources to meet the forecasted demand changes across intervals.

Figure 21 shows the percentage of flexible ramping up failures for the WEIM regional areas between January 5 and 19. The percentage is assessed daily over the 96 total FMM intervals within each trading day. The highest percentages of flexible ramping up failures occurred on January 13, though non-zero failure percentages were spread throughout the period with the highest percentages of failure occurring in the Pacific Northwest and Central/Mountain regions on January 13. Figure 22 shows the same metric for FRD failures, which were generally clustered across the same time period, though with a lower magnitude of failure percentage than the upward test.

The percentage of flexible ramp test for individual BAAs are illustrated in Figure 78 and Figure 79 in the Appendix.

Figure 21: Percentage of flexible ramping up failures by region

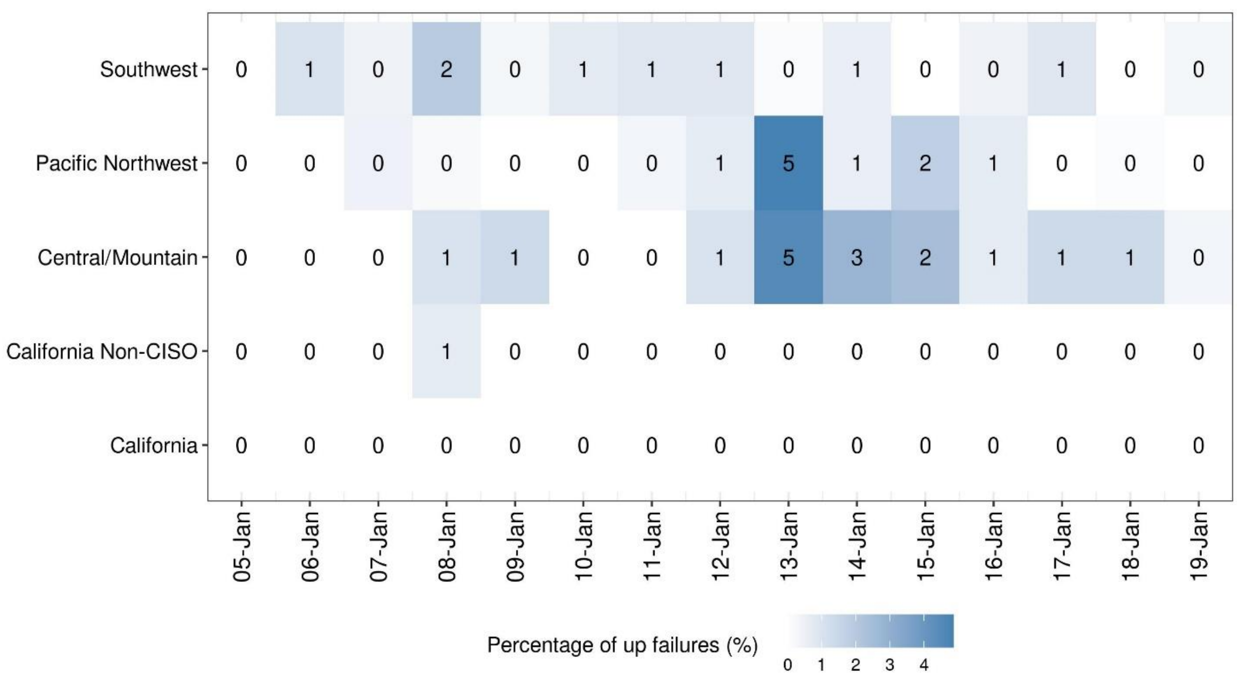
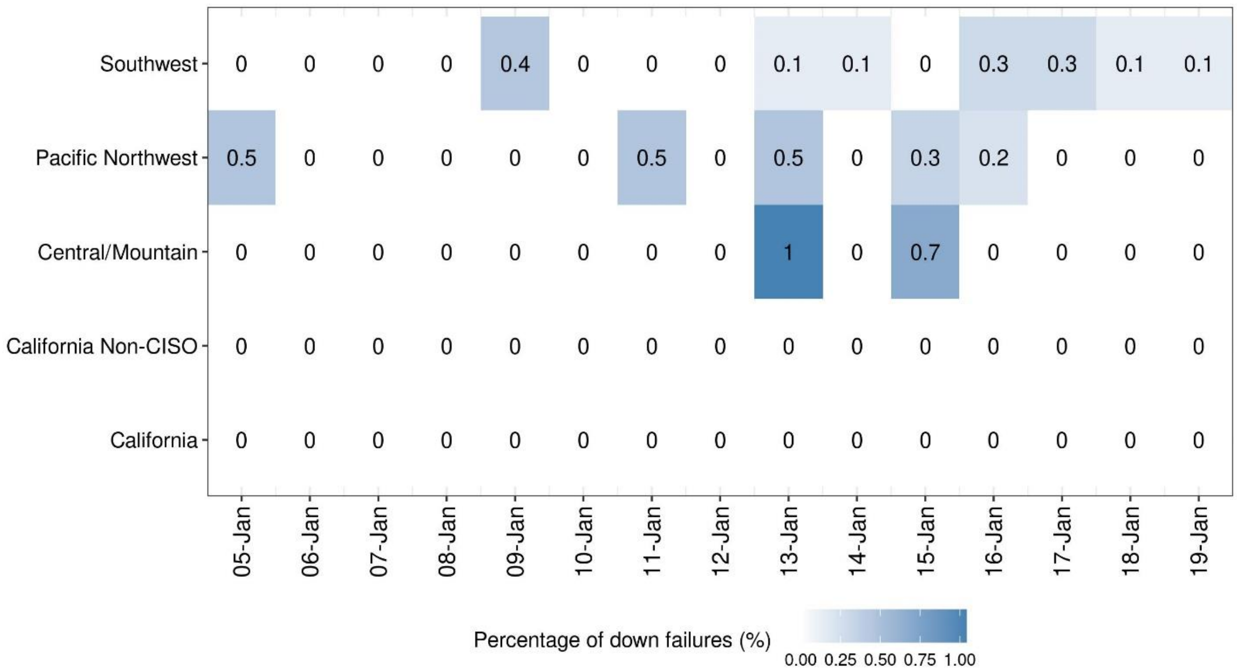


Figure 22: Percentage of flexible ramping down failures by region



WEIM Market Prices

The WEIM load aggregation point (ELAP) price provides aggregate pricing information that is representative of pricing in the overall BAA within each real-time market. Figure 23 shows average daily WEIM ELAP pricing for the period of January 5 to 19 for both FMM and RTD markets. The WEIM BAAs are grouped regionally for ease of comparison.[7]

Prices in both the Pacific Northwest region and Central/Mountain region spiked from January 12 to 17, while prices in the California and Southwest regions were more moderate. Three main factors contributed to congestion and these higher prices in the North. First, because all capacity made was available was exhausted, WEIM transfers congested and areas naturally separated areas. Second, congestion from COI constraints required decremental dispatch in Southern areas and incremental dispatches in Northern areas, adding to price separations. Third, congestion from other transmission constraints such as Path 15 in the CAISO area created similar redispatch of resources, further separating prices between the South and the North. These congested elements limited the amount of power that could flow to the Pacific Northwest.

[7] The California region designation does not include the CAISO BAA. CAISO pricing is covered in section 6.

Figure 23: Average daily WEIM ELAPs by region

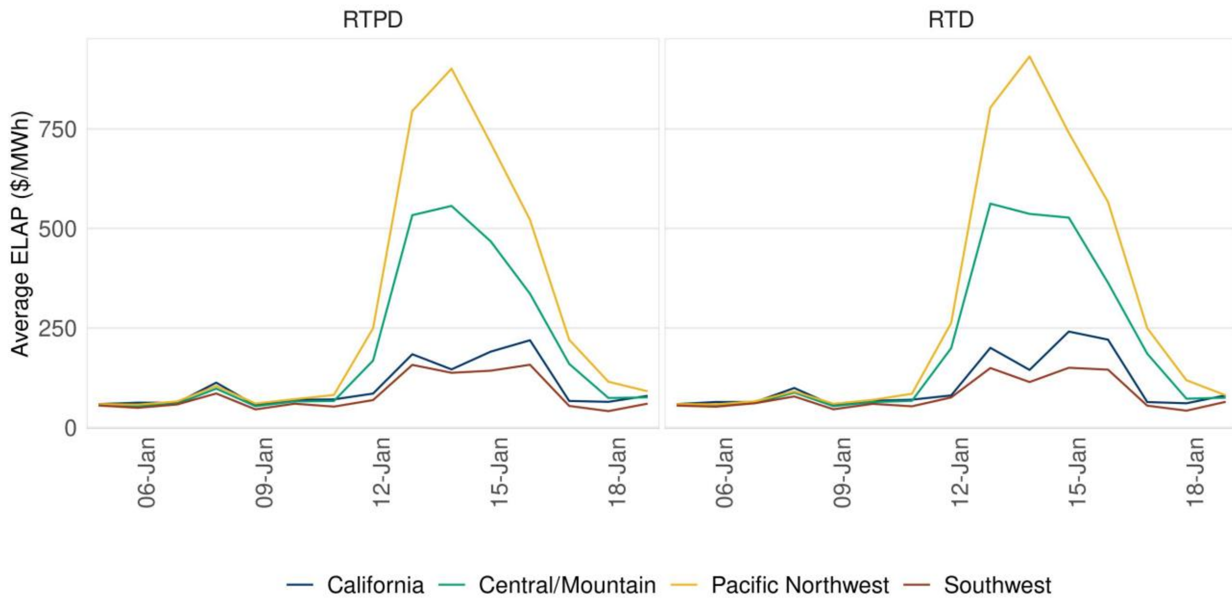
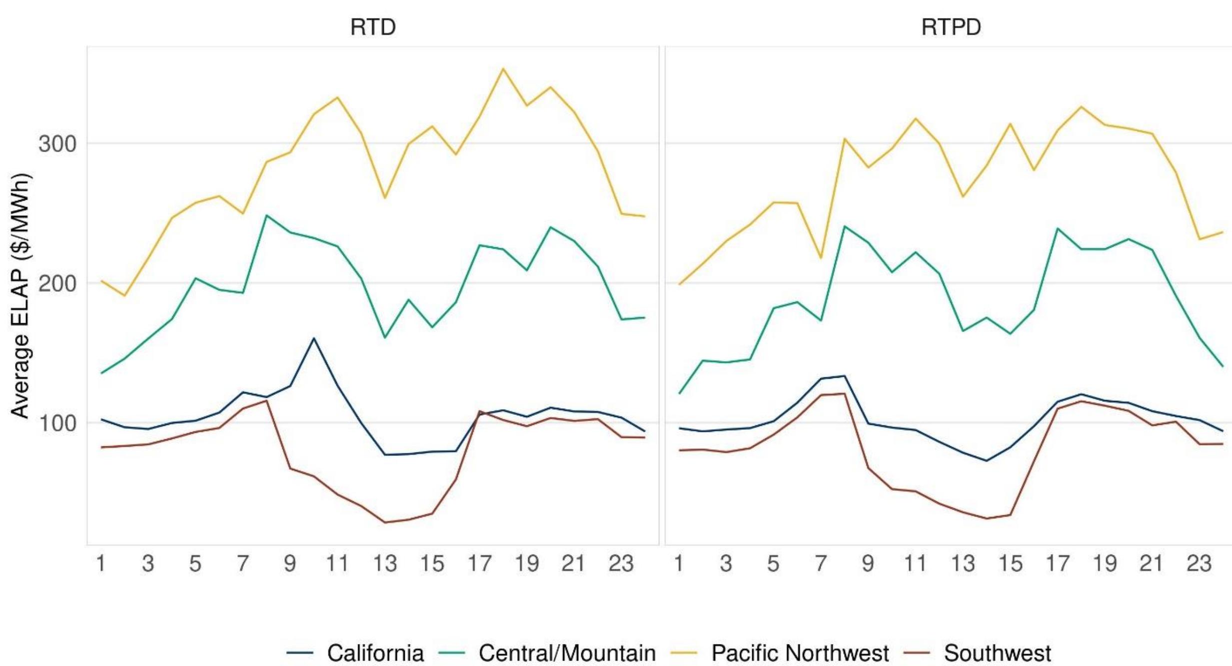


Figure 24 shows a breakdown of average hourly WEIM ELAP pricing for the period of January 5 to 19 for both the fifteen-minute and RTD markets, grouped regionally. Average hourly prices in the Pacific Northwest and Central/Mountain regions are elevated across all hours of the day with some modest spikes during morning and evening ramp hours.

Figure 24: Average hourly WEIM ELAPs by region



Assistance Energy Transfer

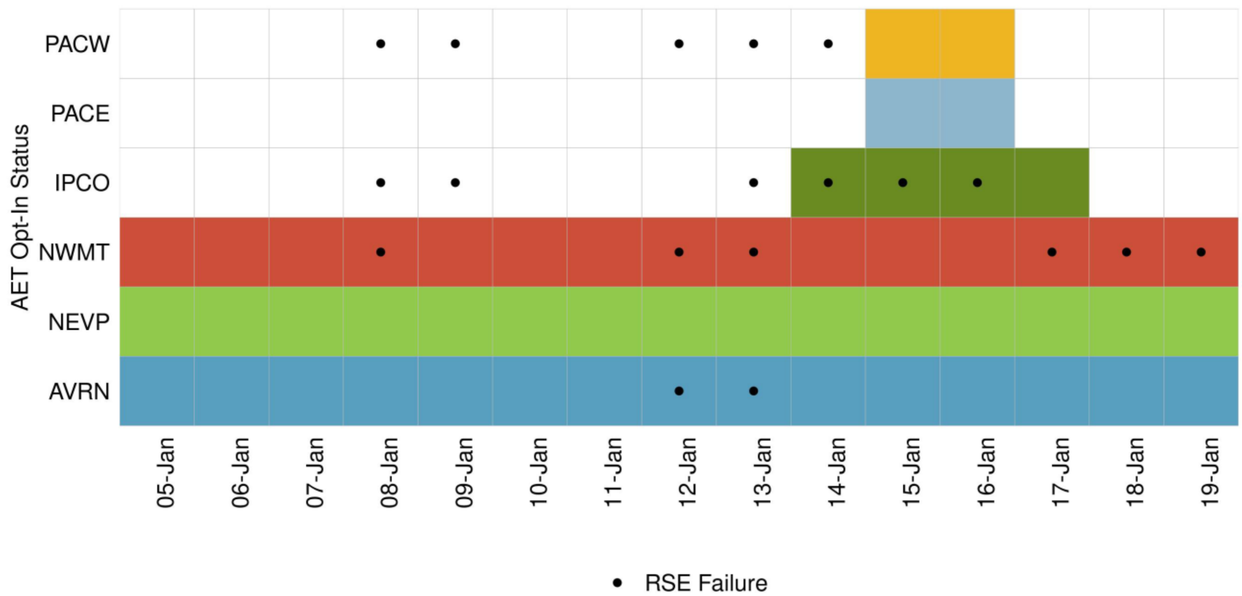
Assistance Energy Transfer (AET) was implemented with the Resource Sufficiency Evaluation Enhancements Phase 2, Track 1 effort which went live on July 1, 2023. The purpose of AET is to leverage the WEIM for energy assistance during under-supply conditions by optionally allowing incremental transfers at pre-set financial consequence following the failure of the WEIM Resource Sufficiency Evaluation (RSE). Assistance energy transfers are sourced from supply offers that are made voluntarily into the WEIM. Each WEIM BAA may voluntarily opt in to utilize assistance energy by notifying the CAISO five business days in advance for a forward requested timeframe.

When a BAA that is not opted into AET fails the RSE, the market limits its WEIM energy transfers to the greater of the transfer amount from the last passed run's interval or the base scheduled transfer amount. If a BAA is opted into AET and fails the RSE in the upward direction, the BAA will still be allowed to receive WEIM energy transfers and pay an after-the-fact surcharge that is calculated based on the energy bid cap of $1,000/MWh or $2,000/MWh. The surcharge is only applied to net-import WEIM BAAs and is limited to the lower of the quantity of the upward RSE insufficiency amount or the tagged dynamic transfers.

During the January winter conditions period, six WEIM BAAs opted into AET for some duration of the month. Three entities had opted in for a longer term prior to the January conditions, once conditions started to rapidly change during the Martin Luther King Jr. Day weekend three other entities opted in[8]. Figure 25 shows the number of BAAs opted in for each trade date during the month with a shaded box indicating opt-in status for that date. The black dots indicate instances where the BAAs failed the RSE, specifically the upward capacity test and/or the upward flexible ramping test. The CAISO BAA did not opt into AET during January 2024.

[8] As conditions quickly evolved during the Martin Luther King Jr. Day weekend, CAISO accommodated requests by three entities to opt in. This required additional and manual work by CAISO to expedite the processing of such requests in real time.

Figure 25: Summary of BAAs opted into Assistance Energy Transfers



Market outcome

A WEIM entity that opted into AET and fails the upward RSE is able to access additional transfer capacity when their transfers would have otherwise been limited due to their RSE failure. One way to quantify the operational benefit that AET provides to a WEIM BAA is to see the additional capacity the BAA was able to access as a result of being opted into AET. This additional capacity can be calculated as the difference between the BAA's would-be transfer limit as a result of failing the RSE and actual transfer quantity that materialized in the real-time. If the actual transfer quantity is greater than the would-be transfer limit, it can be surmised that AET provided a benefit to the WEIM BAA by allowing it to import more capacity under their AET opt-in status than they otherwise would have had access to. Figure 26 and Figure 27 shows this additional AET capacity on a five-minute RTD basis for the relevant dates in which the additional AET capacity was accessible. This data represents the additional capacity that each BAA gained by having AET operational. Of the six WEIM BAAs opted-into AET during this time, only three failed the RSE. Of those three, only two were experiencing net import conditions when assistance energy was enabled: Idaho Power Company (IPCO) and NWMT. The metrics cover realized transfer capacity in the RTD market only.

The additional capacity enabled by AET was made available during various hours throughout the trading days and did not follow a clear hourly pattern across BAAs. NWMT had a maximum of 158 MW of additional capacity made available on January 14, representing 8.9% of NWMT's total load during that RTD interval. IPCO had a maximum of 176 MW of additional capacity made available on January 14, representing 7.4% of IPCO's total load during the RTD interval.

Figure 26: Additional AET Capacity (MW) in RTD, IPCO

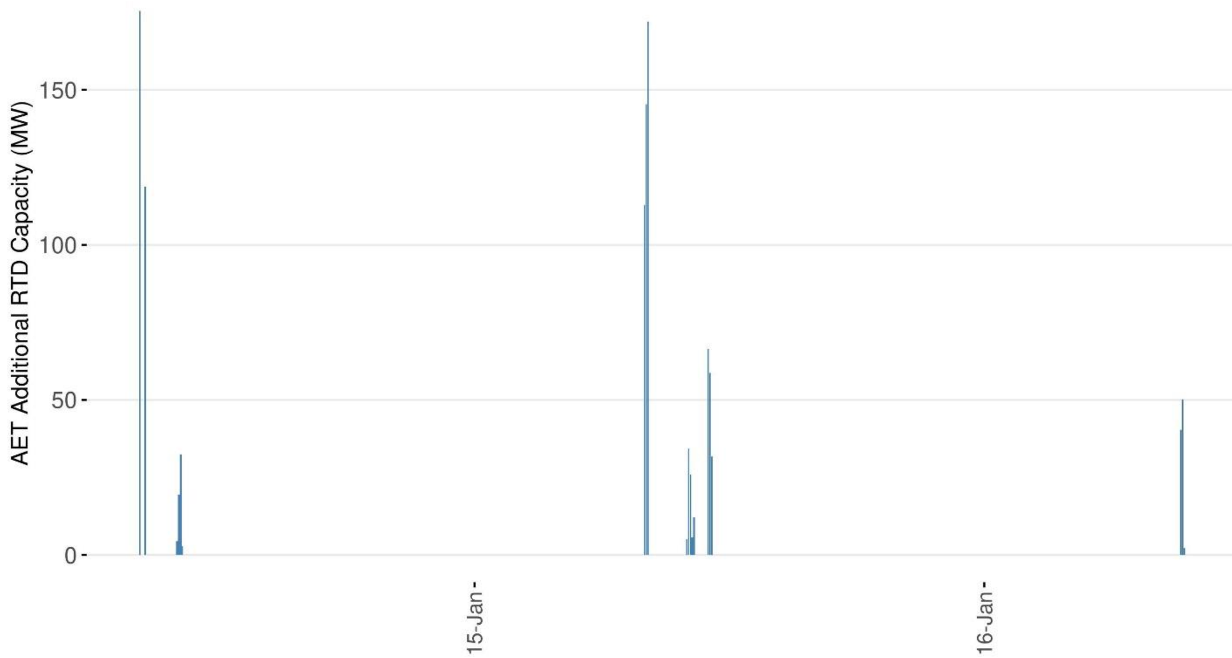
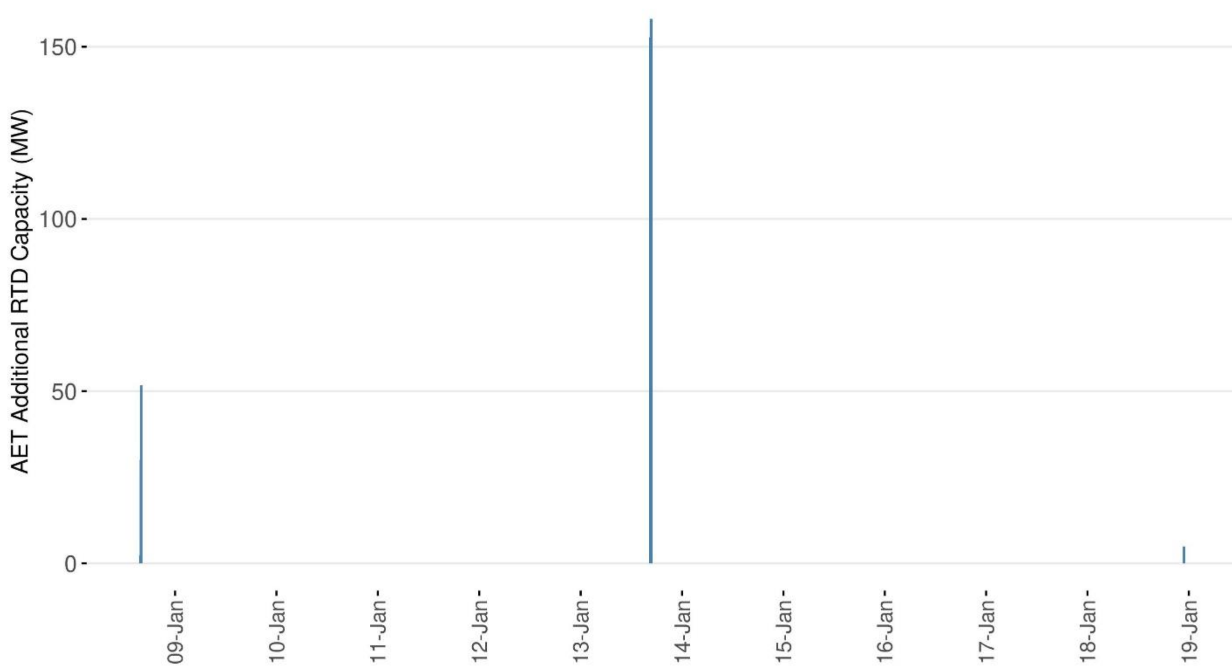


Figure 27: Additional AET Capacity (MW) in RTD, NWMT



Surcharge

The total amount of AET surcharge assessed during the period of January 5 through January 19 was $47,120. The surcharge was assessed over five trading days, during which the energy bid cap was set at $1,000/MWh or $2,000/MWh.[9] Figure 28 below shows the breakdown of total AET surcharge assessed per day. By the nature of its design, AET is only assessed for WEIM BAAs that fail the RSE *and* are opted in ahead of time. However, the AET surcharge may be $0 if any of the underlying inputs to the calculation, such as tagged dynamic WEIM transfer capacity or tagged dynamic WEIM transfer capacity less applicable credit, are zero, even if the BAA has failed the RSE and has opted-into AET.[10]

Figure 28: Total daily AET surcharge assessed

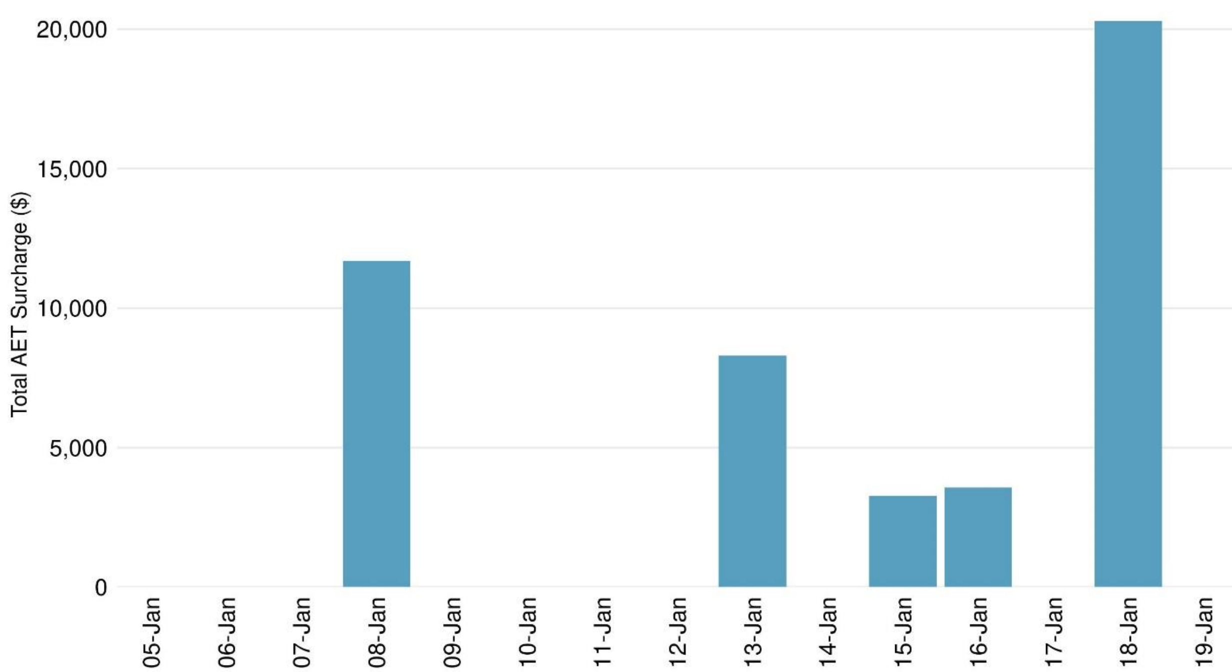
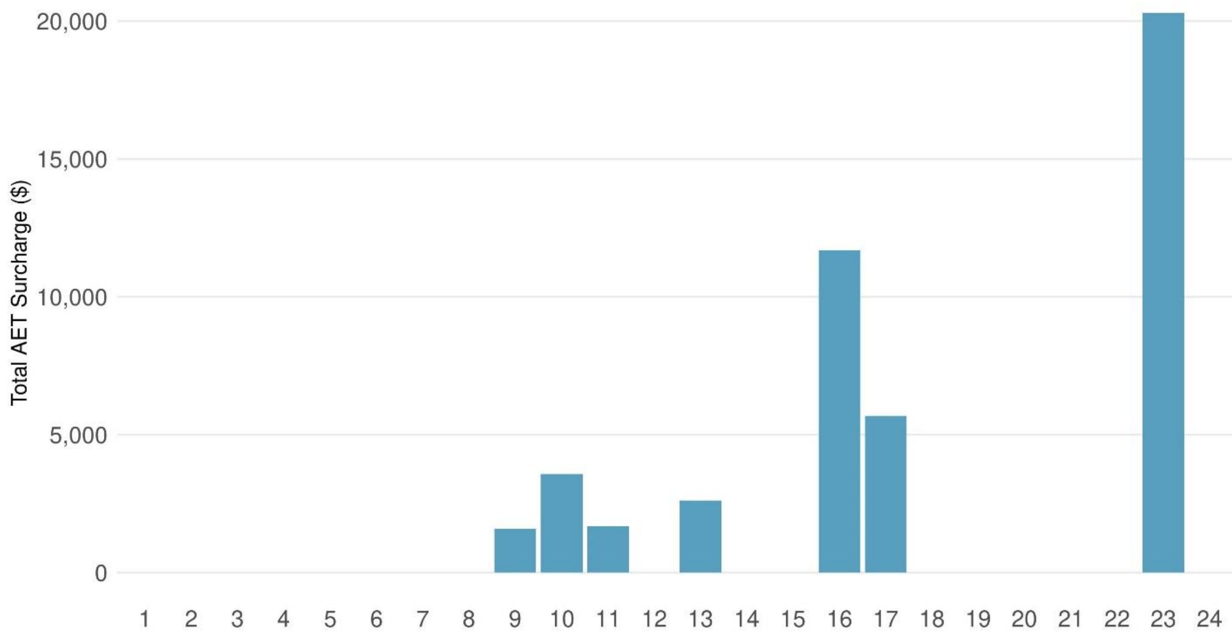


Figure 29 shows a similar breakdown of total AET surcharge assessed by hour during the period of January 5 to 19. A majority of the AET surcharge was during afternoon and evening hours, but some AET surcharge was assessed during mid-morning hours.

[9] See the section in this report titled Maximum Import Bid Price and Bid Caps for more details on how the bid cap was set during this time period.
[10] See Settlements BPM – CG CC 6476 Real Time Assistance Energy Transfer Surcharge.5.0 for more details on the AET surcharge settlement calculation.

Figure 29: Total hourly AET surcharge assessed



WEIM Transfers

The purpose of this section is to illustrate the trends of WEIM[11] transfers optimized by the market from January 5 to 19, including during the peak of the cold weather event from January 13 to 15.

The centralized clearing process of the WEIM allows the market to attain an optimal solution across all balancing areas, leveraging the WEIM's geographic and resource diversity. A main benefit of the WEIM is realized economic transfers among BAAs. These transfers are the realization of a least-cost dispatch by reducing more expensive generation in one BAA and replacing it with cheaper generation from other BAAs. In a given interval, one BAA may have an import transfer with another BAA while concurrently having an export transfer with a different BAA.

Figure 30 show the daily RTD WEIM transfers for all WEIM BAAs that are optimized in the market. The WEIM BAAs are grouped by region for ease of comparison. A negative value represents an import while a positive value represents an export. For the California region, which includes all areas in California, RTD transfers were in the positive direction from January 7 to January 11, but during the coldest days of January 13 to 15, there was an uptick in the import direction that leveled off after January 16. WEIM transfers for the Central/Mountain region were elevated in the export direction from January 13 to 16 in RTD. For the Pacific Northwest region, WEIM transfers were predominantly imports. WEIM transfers were net exports for the Southwest region.

[11] The WEIM transfers shown in this report does not include the base transfers.

Figure 30: RTD WEIM Transfers by Region

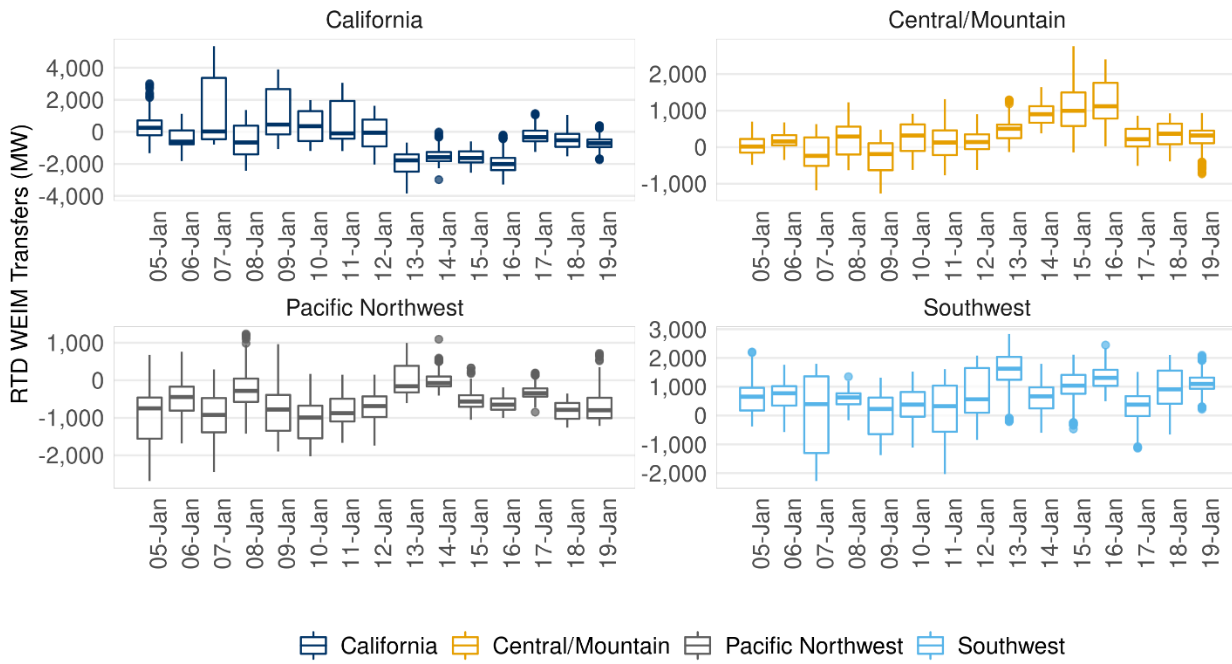
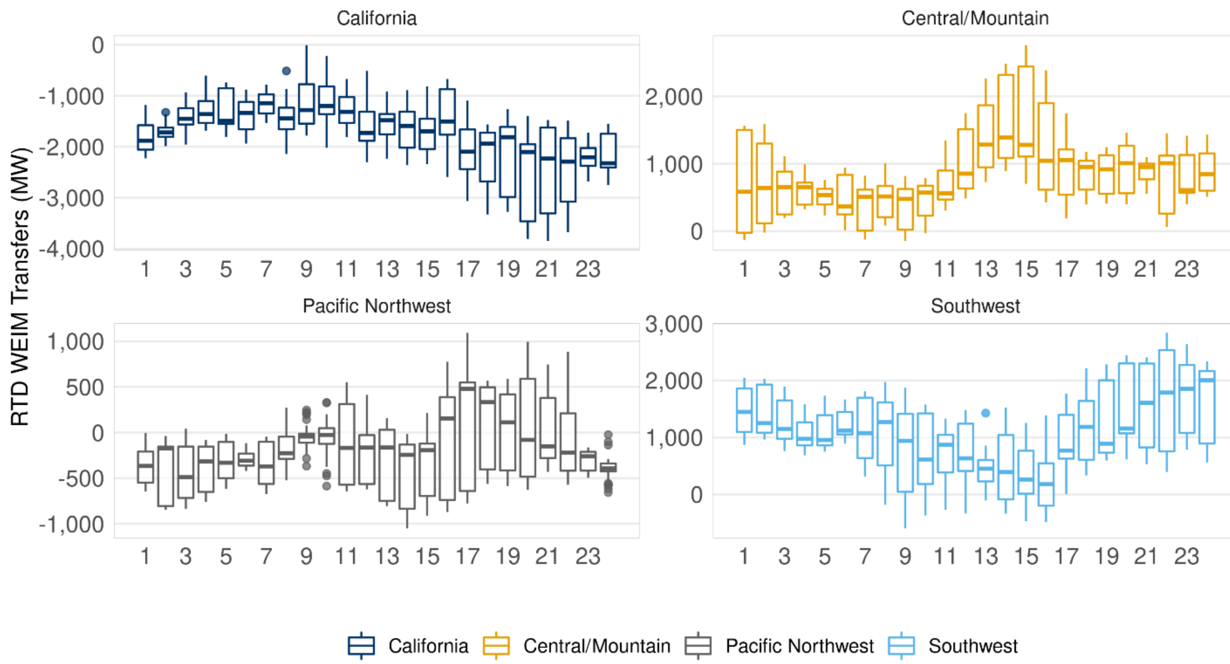


Figure 31 show the average hourly WEIM transfers for all WEIM BAAs grouped by region in RTD from January 13 to 15. For the California region, WEIM transfers were relatively high imports that gradually increased towards the peak hours of the day. The Central/Mountain region saw elevated export transfers from HE11 to HE17. In the Pacific Northwest region, transfers were elevated in the import direction during the middle hours. Transfers for the Southwest region were net exports overall.

The volume and direction of transfers are optimally and economically determined by the market taking into account not only all supply offered and the demand levels, but also and equally critical the transfer and transmission limitations in real time. There were three key elements to enable transfers into the Pacific Northwest: i) transmission limitations for COI, ii) available transfer capacity made available by all WEIM areas, and iii) congestion from Path 15.

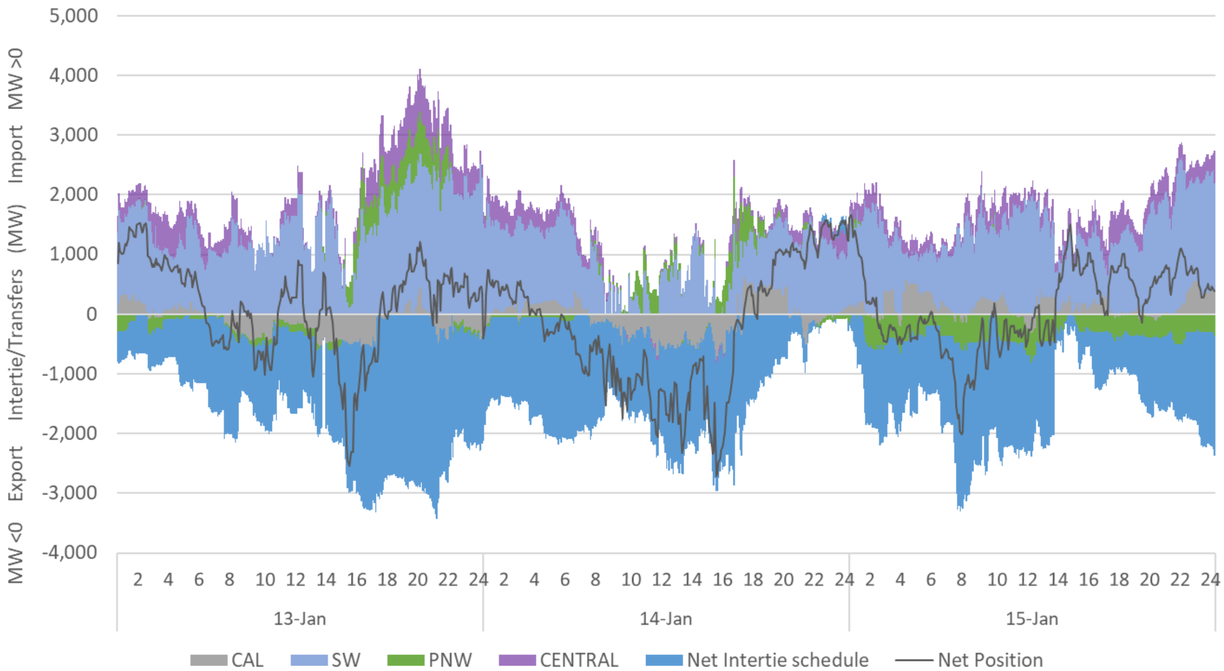
Transfers are limited by the transfer allowed by each individual balancing area. During the Martin Luther King Jr. Day weekend, different areas limited transfers in and out of their respective areas to effectively manage their own balancing area conditions. This limited not only the transfers that flow into and out of their own areas but also transfers that can flow through their areas to enable transfers between other areas. Congestion on transmission constraints related to COI conditions, due to outages in the Pacific Northwest, not only limited the power that could flow from California and the Southwest into the Pacific Northwest it also caused some transfers to flow north to South to provide counter flows and enable more flows to the North. Similarly, lower cost generation in the Southern areas incentivized northbound flows in CAISO area. This created congestion on Path 15, which then required to either reduce transfers into the Pacific Northwest or even create transfers from some areas in the Northwest to California area to create counter flows on Path 15 and relieve congestion. During these critical periods in real-time there were large level of unscheduled northbound flows that exacerbated the congestion management of Northern paths.

Figure 31: Hourly RTD WEIM Transfers by Region from January 13 to 15



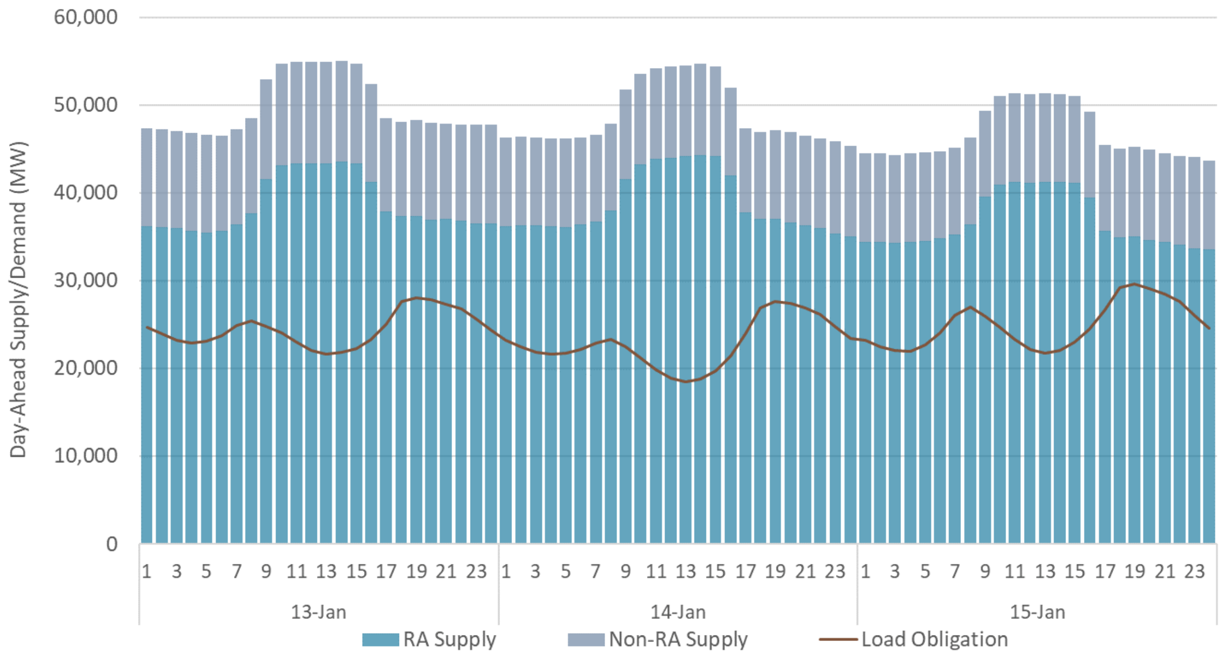
The WEIM market considers all system and resource conditions in real time to identify the optimal mix of generation that can support the demand in the wider footprint and the optimal allocation of transfers among regions. This factors in also the obligation to serve exports at the interties. The resulting market prices will reflect these economic tradeoffs. During the Martin Luther King Jr. Day weekend, there were large volume of intertie exports cleared in both the day-ahead and also in the real-time markets; on the other hand, the real-time market also determined the optimal economic transfers among areas that were largely import transfers to California. The net balance between the hourly exports flowing out of California area and the more granular WEIM import transfers into California resulted in a very dynamic profile for the CAISO area's net interchange. There were midday hours in which California area was a net exporter of up to 3,000 MW, while it became a net importer in later hours of the day. Figure 32 shows the net intertie schedule (imports minus exports), as well as the WEIM transfers to and from California area; the black line trends the net California area's interchange.

Figure 32: CAISO intertie schedules and WEIM transfers from January 13 to 15



The WEIM transfers coming in to California area were mainly form the Southwest (APS and SRP areas) which in turn were largely supporting intertie exports going to the Pacific Northwest and back to the Southwest or Central regions. These imports into California were not due to tight or limited supply in the California area. California are had excess of supply available to meet fully its own demand. When the day-ahead market cleared supply to meet CAISO demand forecast it was also able to meet additional exports in excess of 6,000 MW with no undersupply (or export reductions). Figure 33 compares the load obligation (load forecast plus reserves) for CAISO area with the available supply composed of both resource adequacy (RA) and Non-RA supply. It shows there was sufiicient RA supply available and additional non-RA supply even during peka hours.

Figure 33: CAISO available supply to meet demand from January 13 to 15



The WEIM import transfers to CAISO area were not due to limited supply in CAISO area. They were rather a reflection of economic displacement and opportunities optimized by the market and bounded by the transmission and transfers availability in the wider footprint. First, the WEIM market relied on the most economic supply available which was located in the Southwest; in turn, these import transfers displaced generation in California, which has been priced more expensively given higher gas prices. Second, there were transmission limitations to afford additional exports or WEIM exports transfers to the Pacific Northwest because Malin capacity was already fully scheduled and no exports could flow on NOB. Indeed, there were hours in which California area experienced northbound congestion on elements of Path 15, further limiting flows to northern California and to the Pacific Northwest.

The below section provides a summary of supply mix of RTD dispatches in the WEIM grouped by regions. For the below supply mix, CAISO is not included in the California region because in subsequent sections this profile is explicitly provided for CAISO balancing area. Figure 34 to Figure 36 shows the supply mix of resources dispatched in the RTD market for January 13 to January 15, 2024, respectively. The biogas, biomass, geothermal and coal fuel types are grouped together as shown in the orange color in the supply mix. The battery, hybrid, and other fuel types are grouped together in the other category. The WEIM transfers show the net transfers (import or export) in that region.

Figure 34: Supply Mix of WEIM regions for January 13, 2024

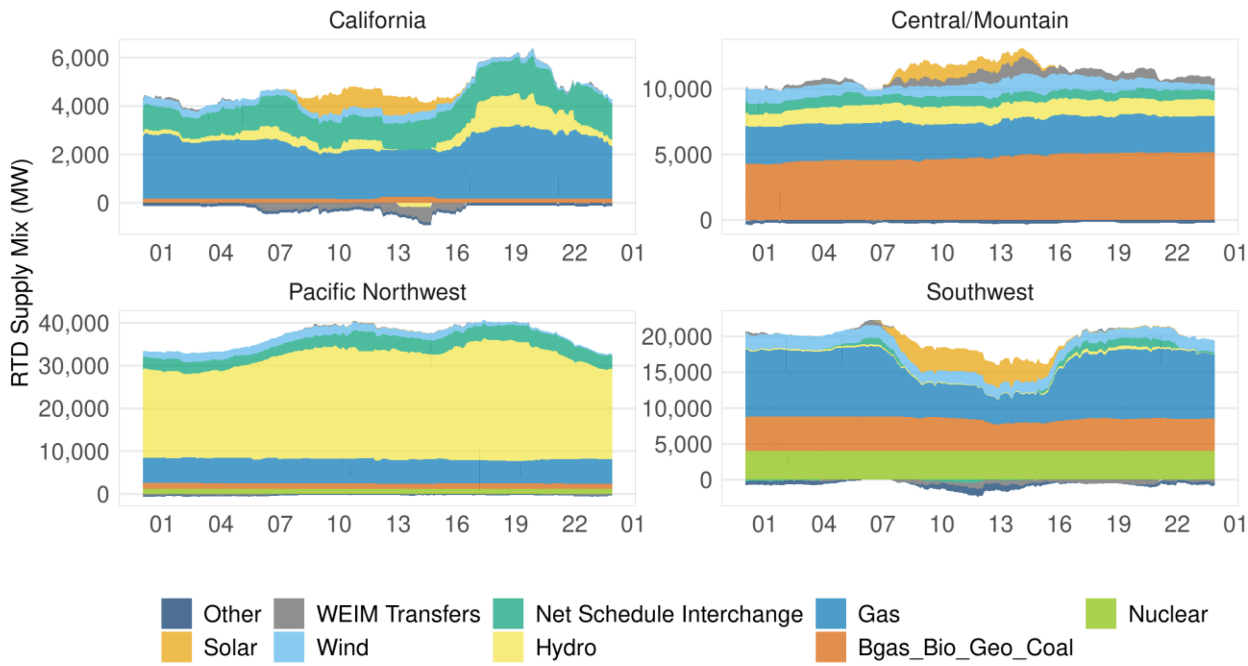


Figure 35: Supply Mix of WEIM regions for January 14, 2024

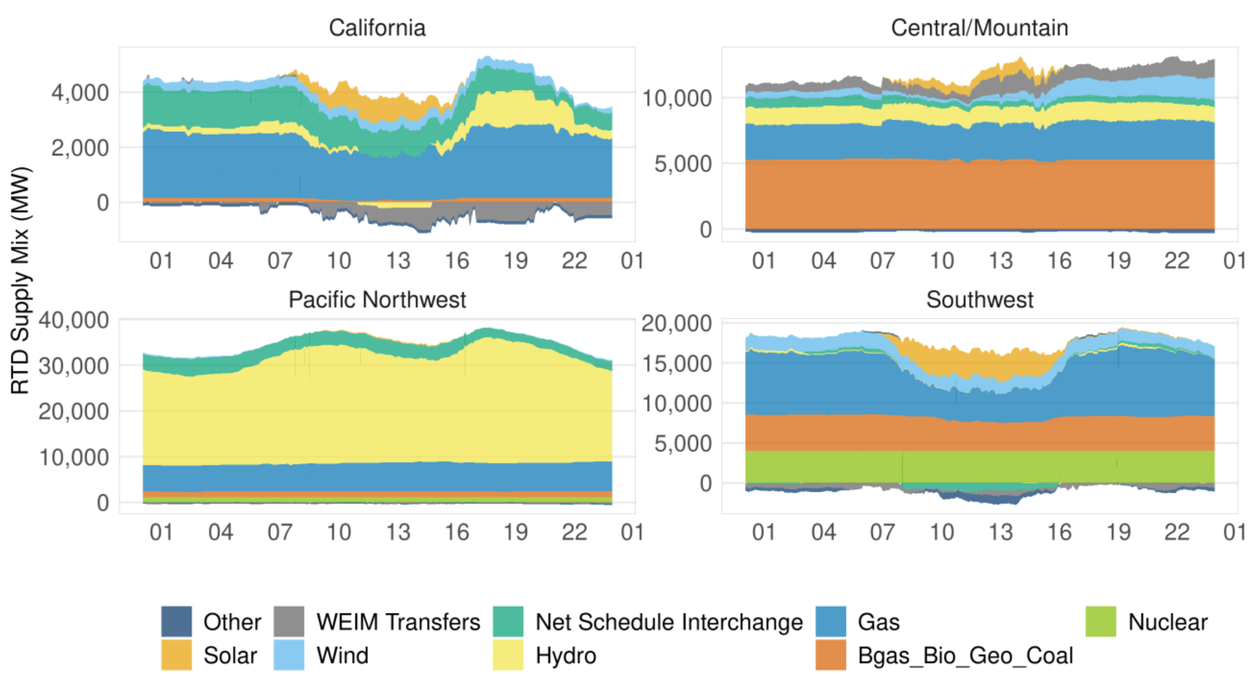
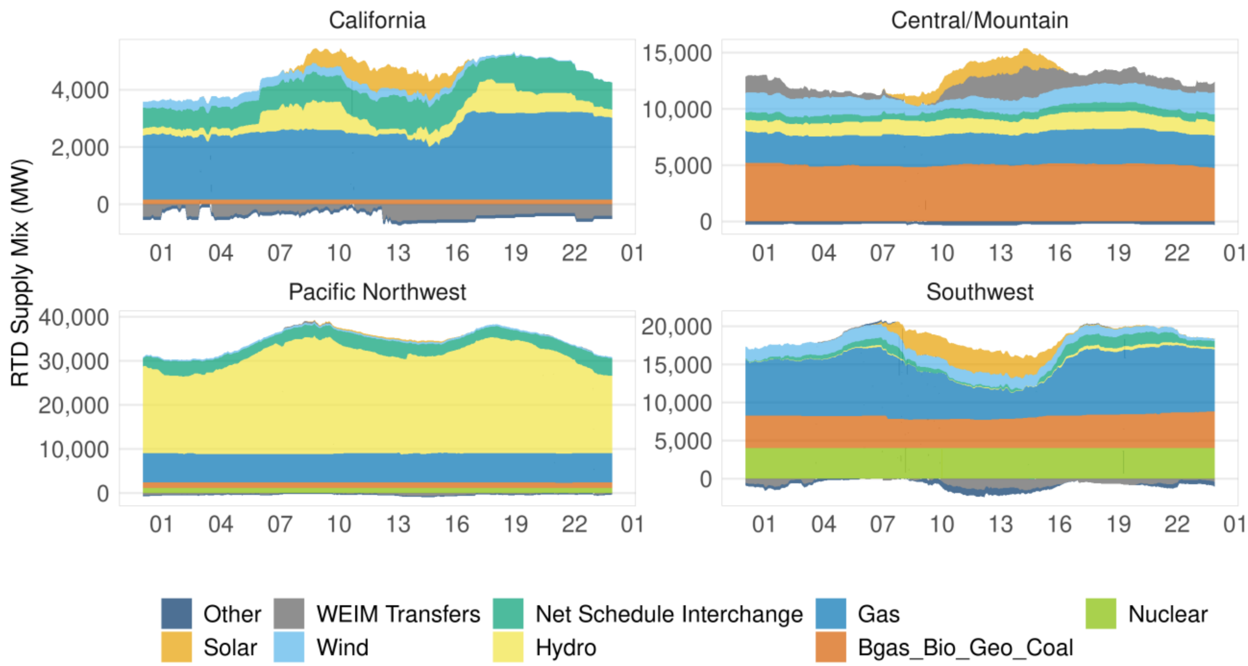


Figure 36: Supply Mix of WEIM regions for January 15, 2024



Energy Emergency Alerts

Between January 13 and 15, five balancing authorities (BAs) entered into emergency procedures via EEA declarations. RC West utilizes the following EEA levels: EEA-Watch (EEA-W), EEA-1, EEA-2 and EEA-3.

EEA-W is specific to RC West to notify the interconnection that a BA is interested in purchasing additional energy via normal standard commercial processes. EEA-W declarations can potentially avoid further steps into emergency procedures. EAA-1, 2, and 3 are formal and defined NERC terms. EEA-1 signifies that a BA has fully allocated all of its resources, is maintaining contingency reserves, and is able to manage Area Control Error (ACE). EEA-2 includes all the items in EAA-1 but also signals that load management procedures such as demand response have been implemented.

EAA-3 includes all the items in EAA-1 and EEA-2, but also signals that firm load shedding could be imminent. Typically a BA in an EEA-3 is in one of the following postures;

1) The BA has exhausted all resources and interchange, is maintaining contingency reserves, is able to control ACE, and has procured emergency assistance from an entity. (Power pools and some BAs providing emergency assistance require an EEA declaration by the receiving BA.)
2) The BA has exhausted all resources, interchange, and emergency assistance, is maintaining contingency reserves, is able to control ACE, and to maintain ACE and restore contingency reserves will have to shed firm load for the loss of a resource.
3) The BA has exhausted all resources, interchange, and emergency assistance, and has designated firm load as part of their contingency reserve. (Upon loss of a resource the BA would shed firm load, to restore ACE, and an additional amount of firm load to restore contingency reserves.)

4) The BA has exhausted all resources and interchange, and shed firm load to maintain ACE and contingency reserve.

During this event, there were seven EAA-1 and one EEA-3 declarations. All were to facilitate emergency assistance transactions. The EEA-3 on January 13 was declared at 08:41 hrs and terminated at 11:24 hrs, the requesting BA had implemented all resources and interchange, implemented demand response, dispatched contingency reserve and requested emergency assistance.

During this event no firm load was shed. All BAs were able to maintain ACE and contingency reserves or to restore contingency reserves by procurement of emergency assistance.

Table 3: RC West balancing area EEA status by date

Date	EEA-Watch	EEA-1	EEA-2	EEA-3
13-Jan	2	3		1
14-Jan	2	3		
15-Jan		1		
Total	4	7	0	1

CAISO Intertie Transactions

The CAISO's system relies on imports that arrive into the BAA through various interties, including Malin and the Nevada-Oregon Border (NOB) from the Northwest and Palo Verde and Mead from the Southwest. Interties are generally grouped into static imports and exports (non-resource specific), or dynamic and pseudo tie (resource-specific). Similar to internal supply resources, interties can participate in both the day-ahead and real-time markets through bids and self-schedules. Additionally, the CAISO's markets offer the flexibility to pair an import with an export to define a wheel-through transaction. Wheel transactions must be balanced; they do not add or subtract supply to the overall CAISO system, regardless of the cleared level. However, they utilize scheduling capacity on interties and transmission capacity on CAISO's internal transmission system. All intertie transactions will compete for scheduling and transmission capacity via scheduling priority and economic bids to utilize the scarce capacity on the transmission system.

Economic bids for imports are treated similarly to internal supply bids, while exports are treated similarly to demand bids. Intertie transactions also have the flexibility to self-schedule. The CAISO's market utilizes a series of self-schedules which define higher priorities than economic bids based on the attributes applicable to such resources. Participants with such entitlements can submit intertie self-schedules using transmission ownership rights (TORs) or Existing Transmission Contracts (ETCs), as well as high priority (PTK) and low priority exports (LPT).

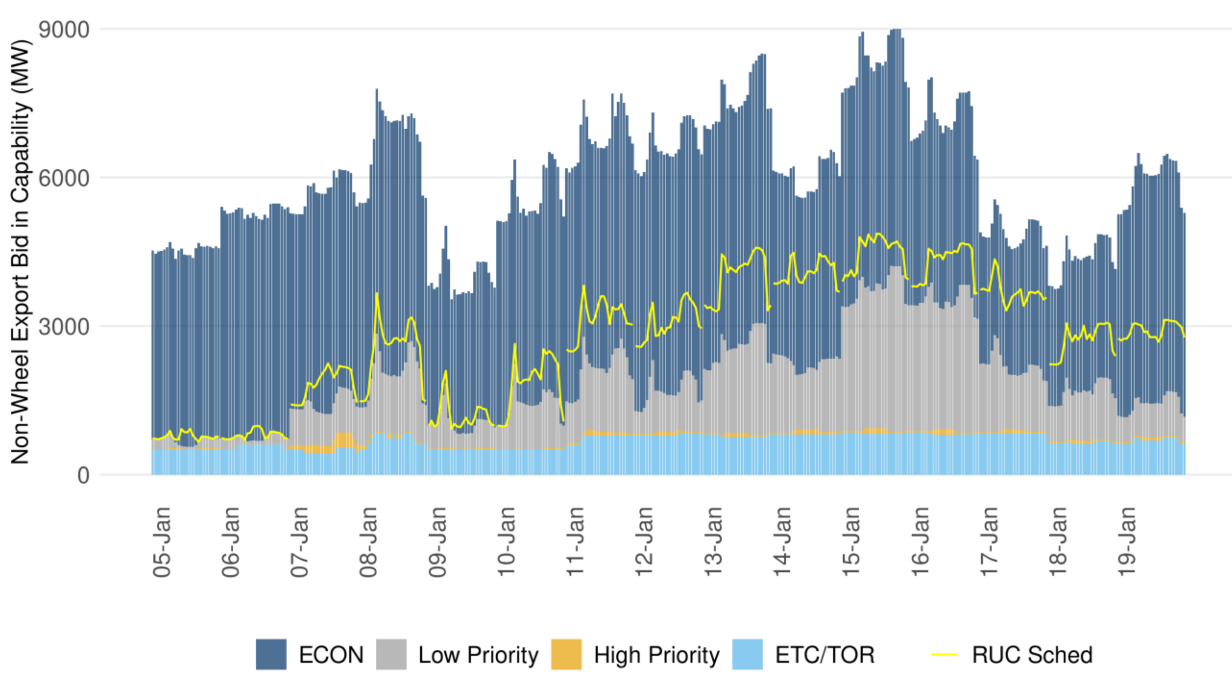
The day-ahead and real-time markets will clear intertie transactions utilizing its least-cost optimization process in each of its market runs. Bids and self-schedules are considered in a merit order to determine the clearing schedules, and all resource bids and characteristics and system conditions are taken into account. In the upward direction, when supply capacity is limited, imports with self-schedules clear first, followed by economic bids from cheapest to most expensive, up to the level of the market clearing price. Conversely, exports will clear first for ETC/TORs, then priority (PTK) exports, followed by low priority (LPT) exports and lastly economic bids from most expensive to cheapest. Wheel transactions have a higher priority in the clearing process defined as the relative spread of penalty prices between the import and export sides.

Intertie supply

Figure 37 shows the bid-in capacity for non-wheel exports in the day-ahead market for January organized by types of exports. This capacity does not include export capacity associated with wheel transactions of any type because the export side of wheels is balanced with their import side and does not reduce supply to the CAISO supply stack.

This figure also illustrates the clearing schedules from the RUC process with the line in yellow. The RUC schedules are used as reference, instead of the IFM schedules, because they are the relevant schedules for tagging interties.

Figure 37: Day-ahead Bid-in capacity and RUC cleared export



Export bid capacity in the day-ahead market varies by hour and typically follows a daily profile. About 62%, 27%, 9% and 1% of the export capacity were for economic bids, ETC/TOR, LPT and PTK, respectively. Due to winter conditions and the additional demand needs in the Pacific Northwest, there was a marked increase in the volume of exports bid-in and cleared in the CAISO's markets. That increase was mainly on economic and low priority exports and reached the highest levels on January 15.

Figure 38: Day-ahead bid-in capacity and RUC-cleared imports

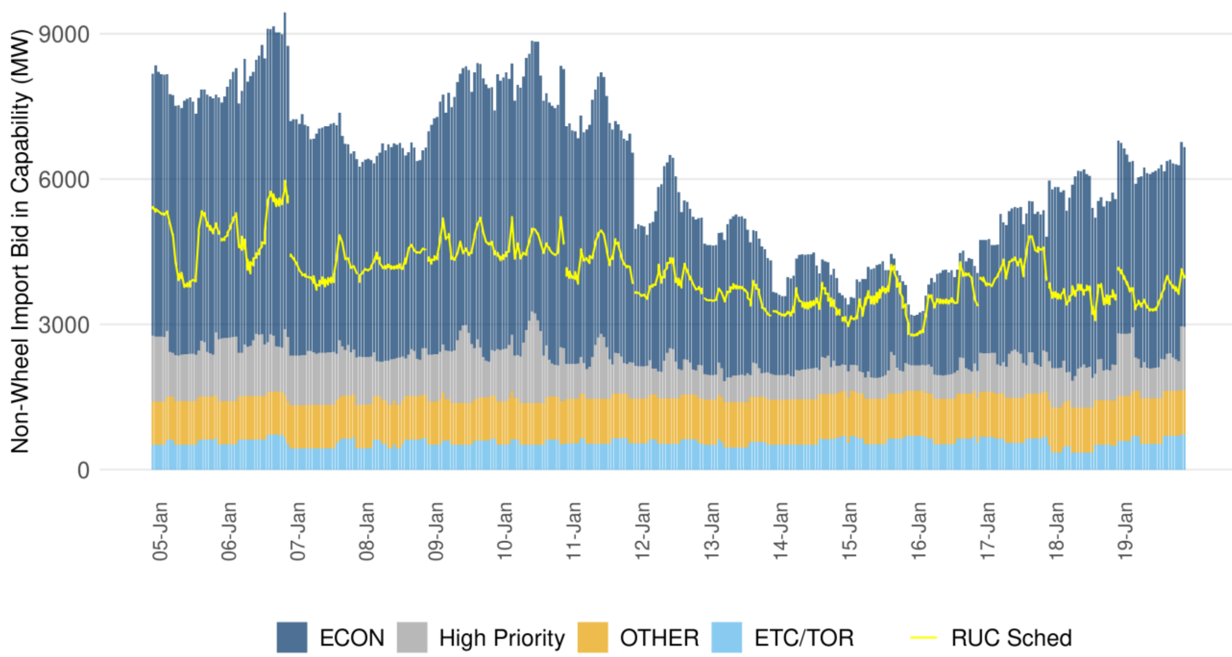
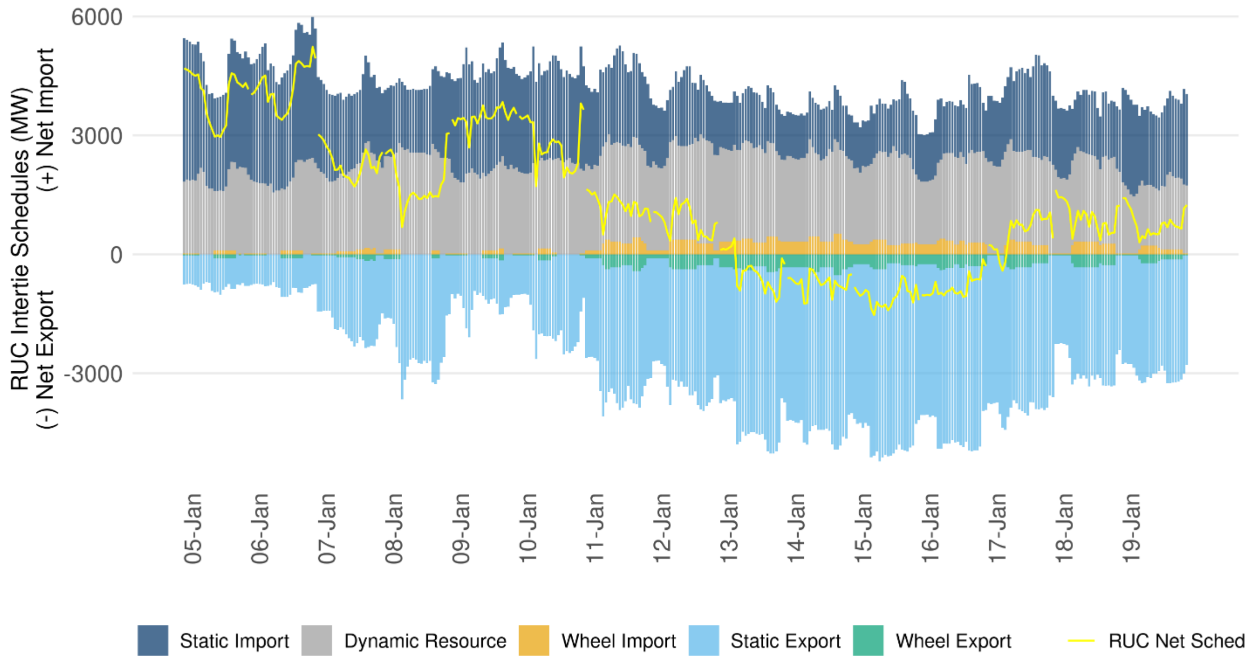


Figure 38 shows the same illustration for imports. These volumes include both static imports and dynamic resources. Both ETC/TOR remained relatively stable through the month, while hourly economic imports continued to see variations with high imports cleared during early January. The economic imports decreased during the January 13 to 16 period because of the conditions in Pacific Northwest. The “other” group includes regulatory must-run priority capacity and the power minimum (Pmin) for dynamic resources.

Figure 39 shows the overall intertie schedules organized by type of schedule, as well as the net interchange based on the RUC solution. The yellow line represents the net schedules cleared in RUC (imports plus dynamics less exports). The net interchange projected in the RUC process reached its lowest levels on January 15 in HE 8 at about 1,531 MW due to the higher level of exports cleared. The day-ahead market cleared interties with an atypical net export position for all hours of January 13 to 16.

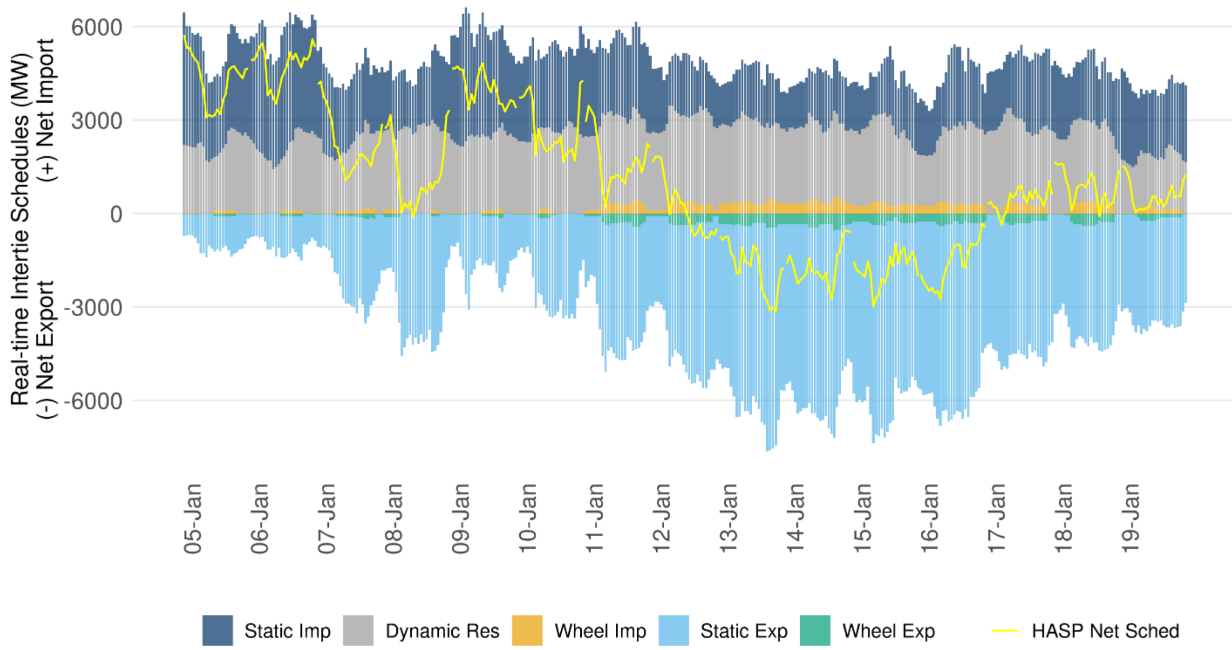
Figure 39: Breakdown of RUC cleared schedules



Intertie positions are largely set from the day-ahead market. Import or exports cleared in the day-ahead may tend to self-schedule into the real-time to preserve the day-ahead award. There may still be incremental participation in the real-time market through the HASP process, which allows resources to bid-in economically to buy back their day-ahead position, or procure or clear of additional capacity in the real-time market.

Figure 40 shows the cleared schedules in HASP for interties organized by the various types of transactions, and the net intertie schedules cleared, referred to as Net Schedule Interchange (NSI). The total exports cleared in real time exceed at times 7,000 MW during the Martin Luther King Jr. Day weekend. NSI was at its lowest value in January 13, HE 21 at 3,154 MW due to the highest level of exports cleared through the peak hours. The real-time market largely follows the trend observed in the day-ahead market.

Figure 40: HASP cleared schedules



The HASP market presents an opportunity for interties to clear through the market clearing process after the day-ahead market is complete. Interties cleared in day ahead can submit self-schedules into real-time. Clearing the RUC in the day-ahead process indicates that these exports were feasible to flow based on the projected system conditions in RUC[12]. Additionally, exports can participate directly into the real-time market with either self-schedules or economic bids.

Both RUC and HASP, assess the ability to support exports based on the overall system conditions and economics. Export reductions in RUC cannot self-schedule into real-time with day-ahead priority but they are able to be rebid into the real-time market and to be fully reassessed based on real-time conditions. LPT or economic exports reductions in the RUC process are most likely to be reduced again in HASP since they will have the lowest priority in the presence of tight supply conditions.

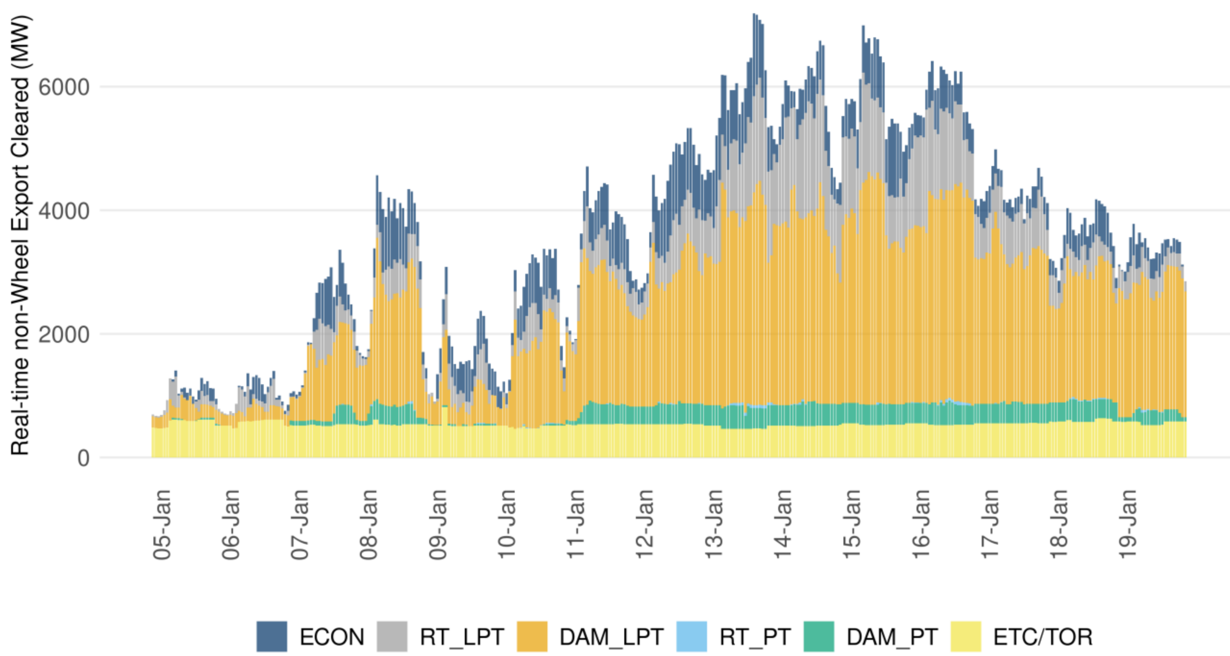
Figure 41 shows all the exports cleared in the HASP process and identifies the nature of the exports. The groups of DA_PT or DA_LPT stand for day-ahead exports coming into real-time as self-schedules with high or low priorities, respectively. Similar classification is followed for those high and low priority exports coming into real-time directly (RT_PT and RT_LPT). ECON stands for economic exports. These exports are only for non-wheel transactions. A granular breakdown of wheels is provided in a subsequent section of wheels.

---

[12] Based on these rules implemented on August 4, 2021, through the summer enhancements described earlier and now in place, the ISO will no longer provide exports a higher priority than load in the real-time, and will only provide them equal in priority to load if the participant demonstrates that they continue to be supported by resources contracted to serve external load. Details are available at http://www.caiso.com/Documents/Jun25-2021-OrderAcceptingTariffRevisionsSubjecttoFurtherCompliance-SummerReadiness-ER21-1790.pdf

There was a significant increase in low priority exports from the day ahead market and real time market, peaking on January 13 HE 18 at about 7,600 MW. In the January study period, a significant portion of cleared exports were those with low priority and economic bids.

Figure 41: Exports schedules in HASP



Imports and exports were scheduled over multiple intertie scheduling points. Although a significant volume of exports were through Malin to the Pacific Northwest, the largest share of exports actually went through several other interties for the Southwest and central areas. Figure 42 shows the exports awarded in HASP and organized by intertie location. For the reported period, the majority of the exports about 31 % were on Malin, 14 % on Palo Verde, 11 % on IPPUTAH, 10 % on Mead230 and 9 % on Tracy COTP.

Figure 43 to Figure 45 illustrate the trend of import and export schedules cleared in HASP for the top three intertie points. For trade dates in January, exports on Malin were significantly higher than imports so that the net flows on the intertie were in the export direction. The NOB intertie was out of service during the Martin Luther King Jr. Day weekend due to scheduled maintenance and could not help with supporting additional flows to the Pacific Northwest. This intertie together with Malin are the two main interfaces connecting California with the Pacific Northwest.

Figure 42: Exports organized by intertie

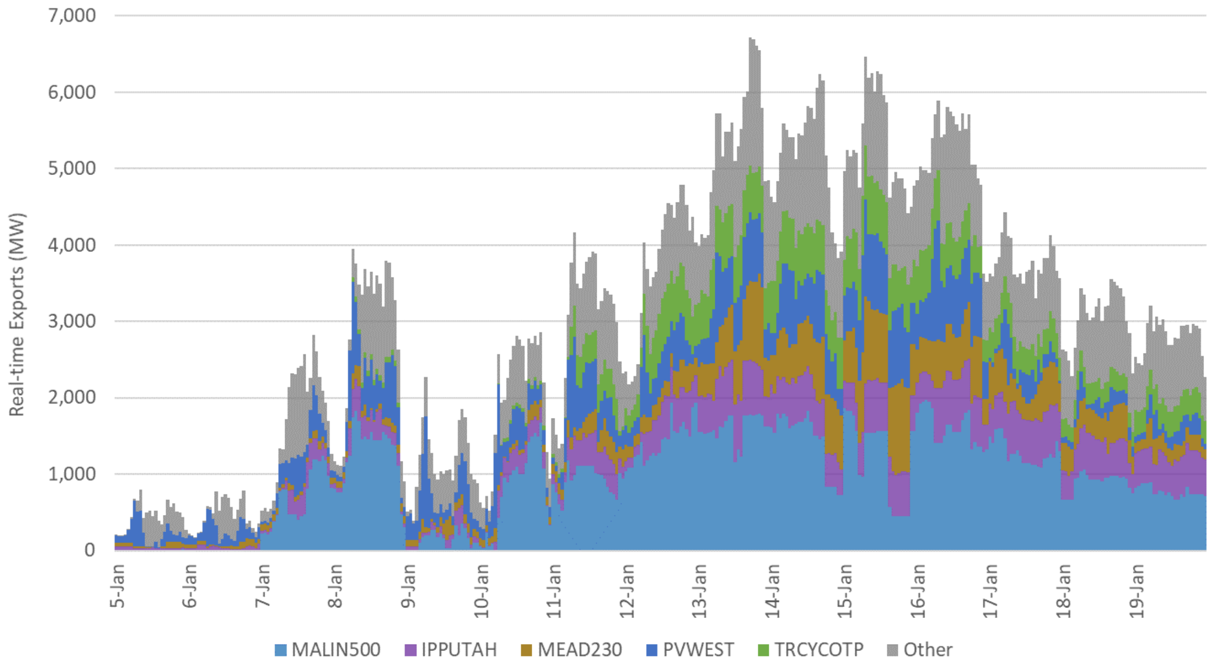


Figure 43: HASP schedules at Malin intertie

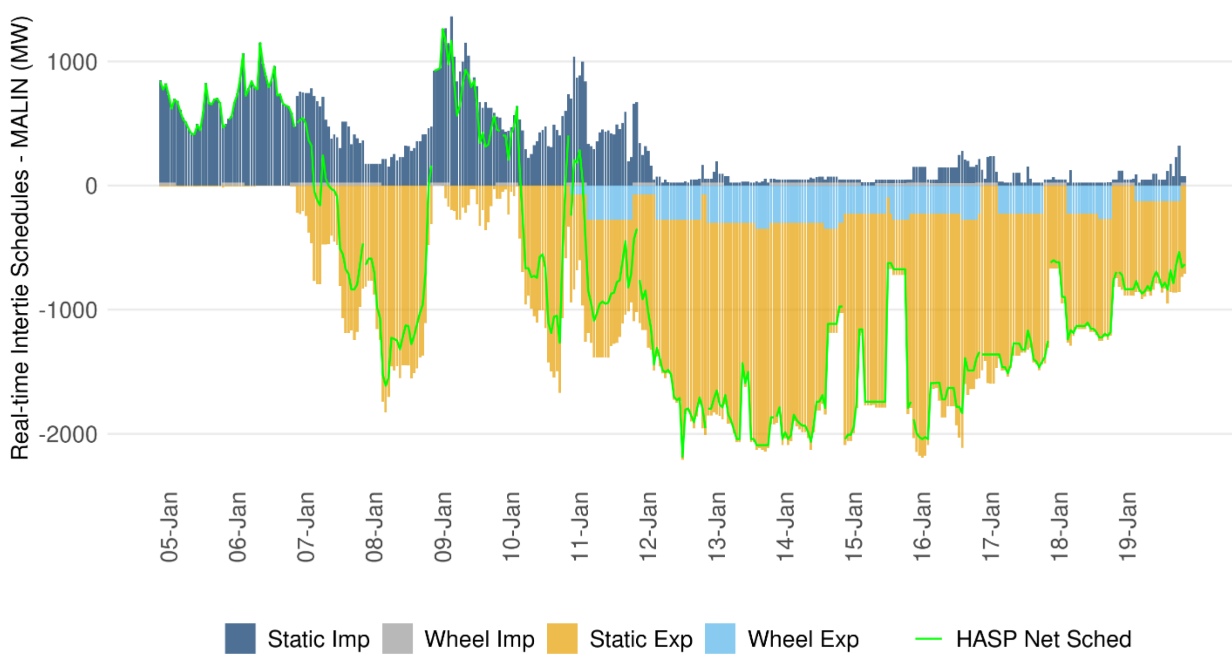


Figure 44: HASP schedules at Palo Verde intertie

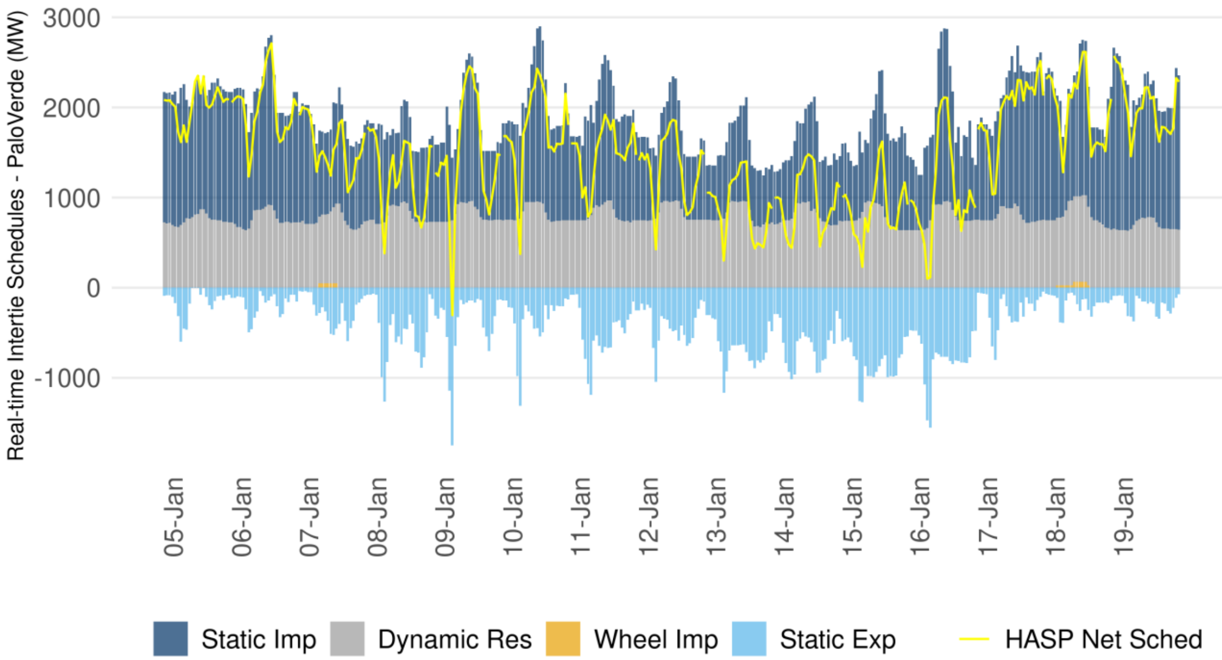
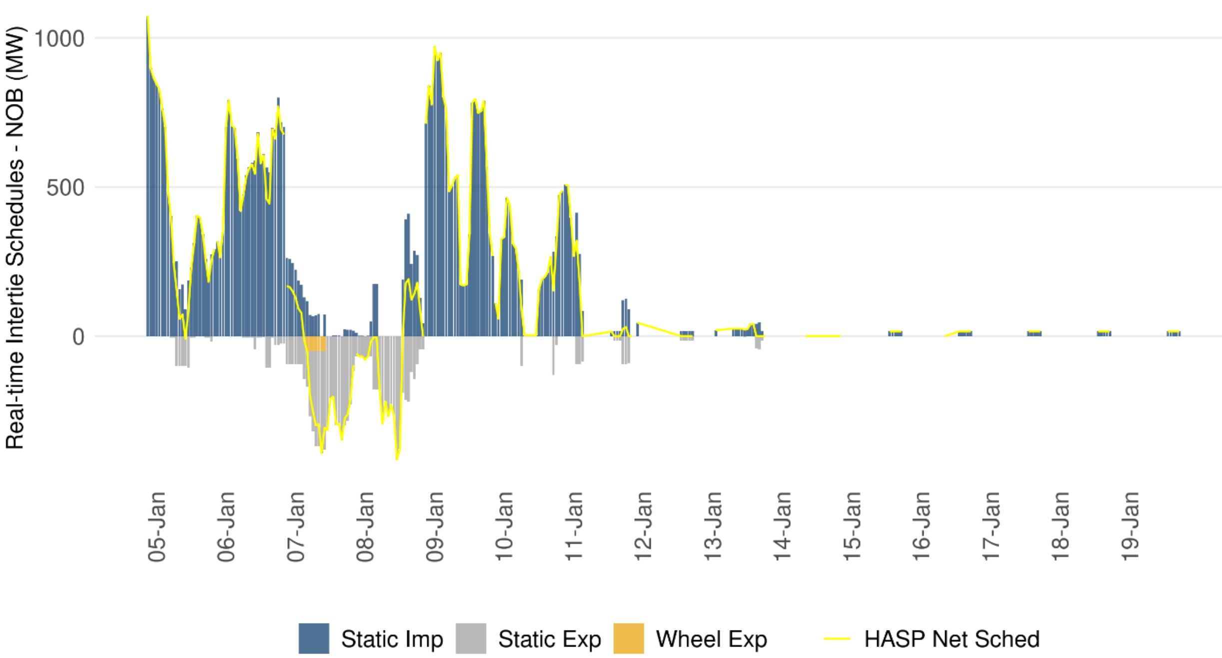


Figure 45: HASP schedules at NOB intertie

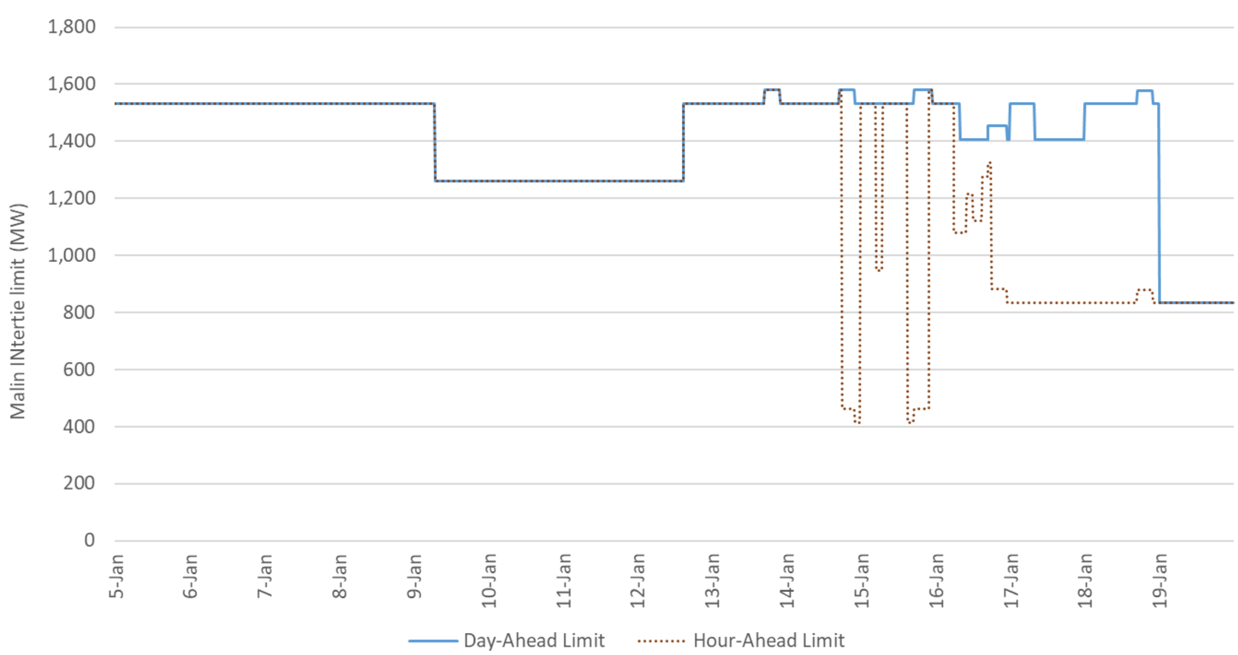


Malin Intertie Conditions

The Malin intertie, a main corridor connecting the CAISO area with the Pacific Northwest, experienced intermittent derates due to forced outages in the Pacific Northwest. This led to export reductions in the real-time market to comply with the reduced intertie capacity. During the Martin Luther King Jr. Day weekend, this intertie was fully utilized to carry exports to the Northwest.

Malin and NOB are the two main interties between CAISO and the Pacific Northwest. During the Martin Luther King Jr. Day weekend, no exports could flow on the NOB intertie due to a forced outage on an alternate current (AC) transmission element. This was a forced outage that occurred prior to another planned outage already scheduled. In winter conditions it is typical that flows on Malin are predominantly exports. During the Martin Luther King Jr. Day weekend, the Malin intertie carried a significant volume of exports to the Pacific Northwest. Due to weather conditions, there were multiple transmission outages in the Pacific Northwest. There were no forced outages in the California balancing area impacting Malin. For instance, due to an ice storm damage, facilities north of Malin were forced out, returned to service and forced out again, resulting in transfer limit cycling (decrease-increase-decrease). These resulted in intermittent capacity reductions on the Malin intertie from January 14 to 17. The limits of the Malin intertie used in the day-ahead and real-time markets are shown in Figure 46.

Figure 46 Schedule capacity on Malin intertie



Since these capacity reductions were originated from forced transmission outages, depending on the time of these outages, the limits used between markets were different. For instance, the outage in the afternoon of January 14 happened after the day-ahead market for this trading date was already run and completed the day before. Even the day-ahead market for January 15 was already run and completed and used a Malin limit between 1,531 MW and 1,581 MW. Then the real-time market limit for January 14 was reduced to 464 MW to reflect the transmission outage. The outage ended in HE 24 of January 14.

Consequently, the real-time market used lower limits than what the day-ahead market used to clear higher level of exports than feasible in real time.

Figure 47 compares the limit used in the hourly ahead scheduling process with the schedules cleared in both the day-ahead and hour-ahead markets. The instances where the schedules cleared in the day-ahead market are above the real-time limit, reflecting hours in which the real-time market had to reduce exports already awarded in the day-ahead market to comply with the newly imposed intertie limitation.

Figure 48 shows the clearing prices of the Malin intertie constraint. The Malin intertie was congested at high prices throughout the weekend. Prices in HASP will be high when reductions of the intertie limit trigger congestion from the intertie. The HASP must reduce self-scheduled exports to comply with the derated capacity of the intertie. However, HASP prices are not financially binding. All intertie transactions, including hourly schedules, are settled at the FMM prices. The FMM prices at Malin tend to be low because HASP has already reduced schedules to be feasible to the most restrictive limit. Consequently, there is no congestion on the intertie in the FMM as long as the limit has not changed in FMM.

Figure 47: Market schedules at Malin intertie

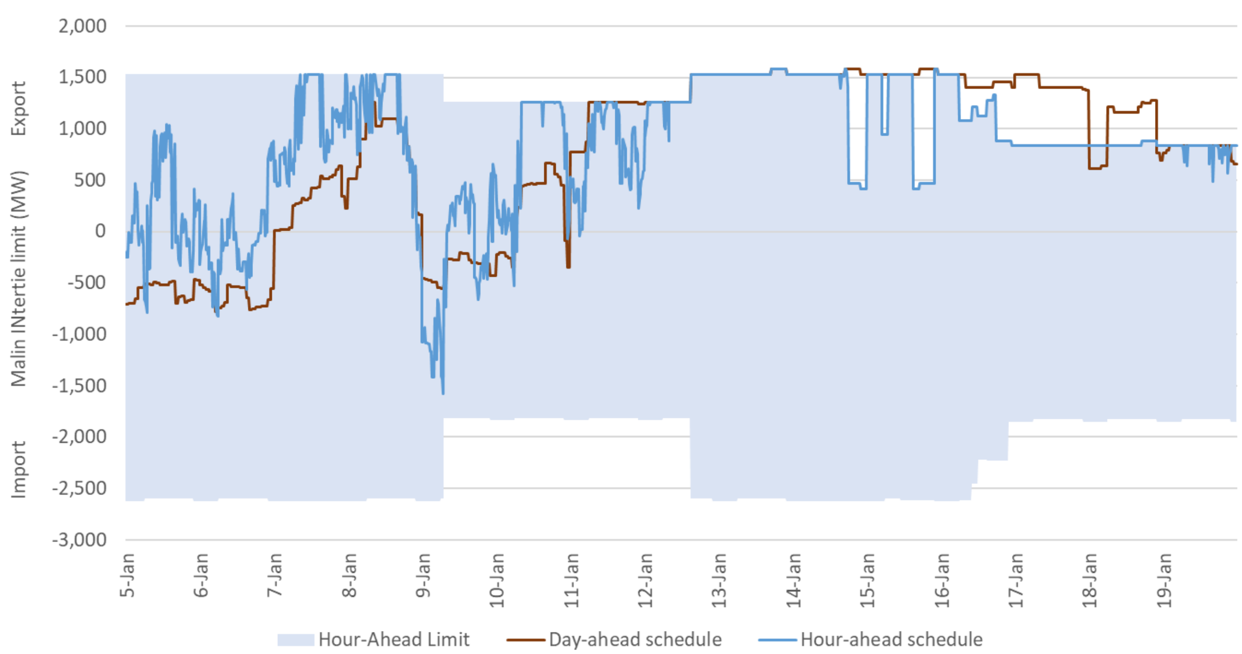
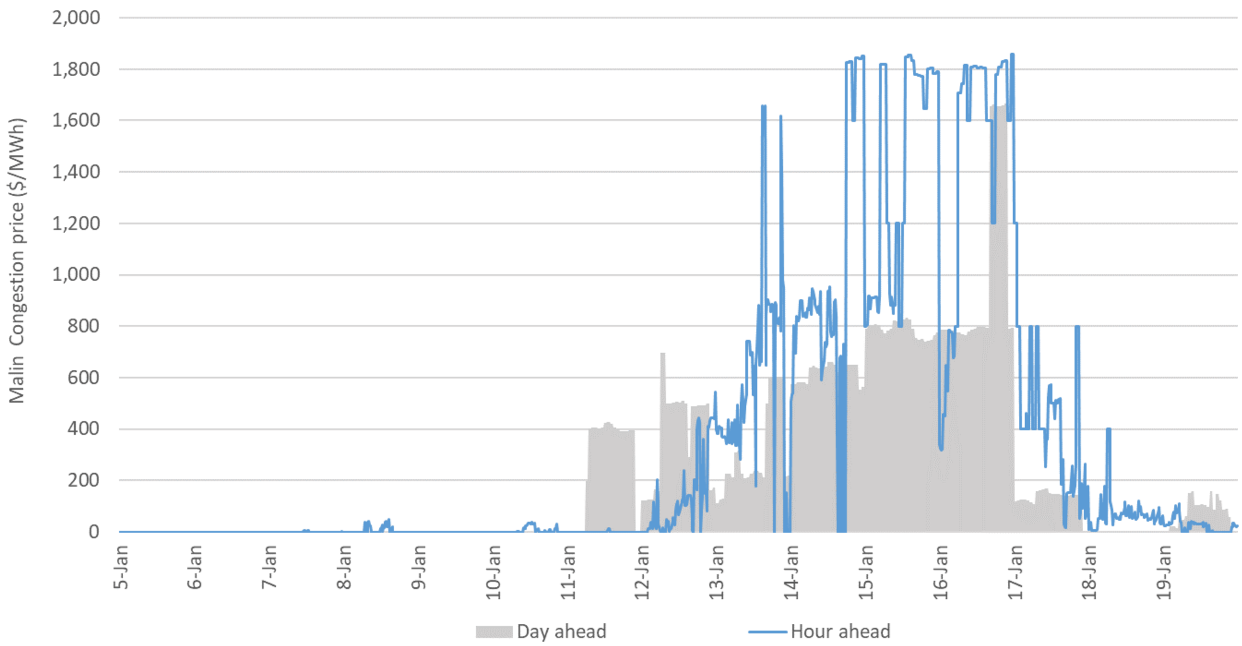
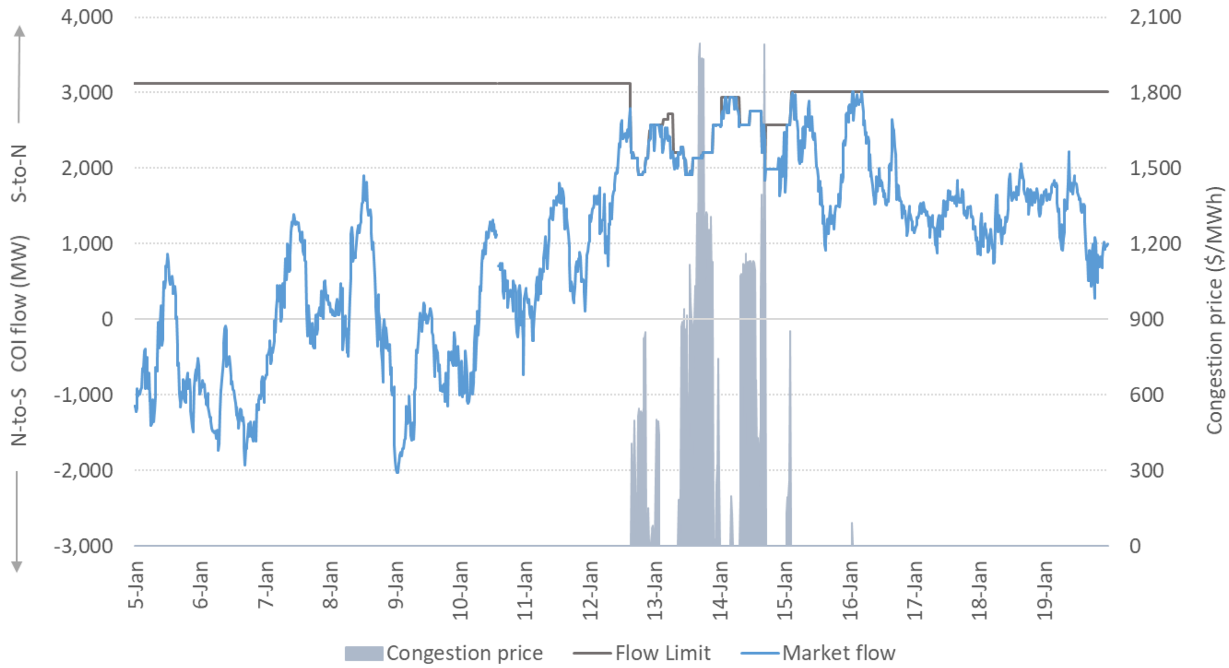


Figure 48: Congestion prices at Malin intertie



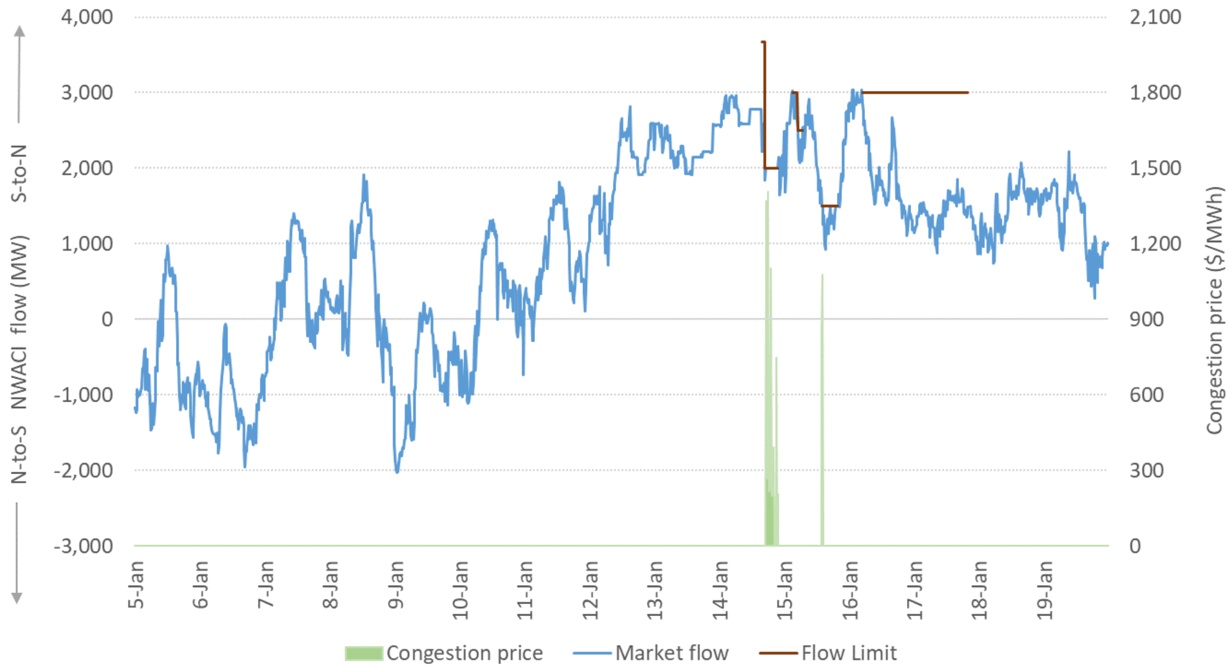
During the times of reduced limits on the Malin intertie, there was also congestion on the 6110_COI_S_N nomogram in the CAISO area; this constraint was enforced to protect for N-1 overload on system elements in Northern California and was managed dynamically as real-time conditions evolved. There was also congestion from the NWACI_SN flowgate, which is a constraint in the BPA area. These two constraints have very similar definitions and effectuate similar congestion management in the WEIM. They will result in decremental dispatches for resources located south of the constraint (CAISO and Southwest WEIM areas) and incremental dispatches for resources located north of the constraints (WEIM areas in the Pacific Northwest). These constraints effectively create price separation between areas, with higher prices the Pacific Northwest areas, and lower prices in the California and Southwest areas. The FMM limits, flows, and prices for these two constraints are shown in Figure 49 and Figure 50. These two constraints did not bind concurrently; at any time only the most limiting constraint exhibit congestion with its resulting prices.

Figure 49: FMM Congestion prices on COI_S_N constraint in CAISO area



Early in January the power flows were from the Pacific Northwest to CAISO area (Import to CAISO area). As the system conditions progressed with the cold snap of the Martin Luther King Jr. Day weekend, the southbound flow started to diminish and eventually switched direction. With the real-time conditions and unscheduled flows, the limit had to be dynamically managed during the Martin Luther King Jr. Day weekend and the constraints bound with high congestion prices.

Figure 50: FMM Congestion prices on NWACI constraint in BPA area

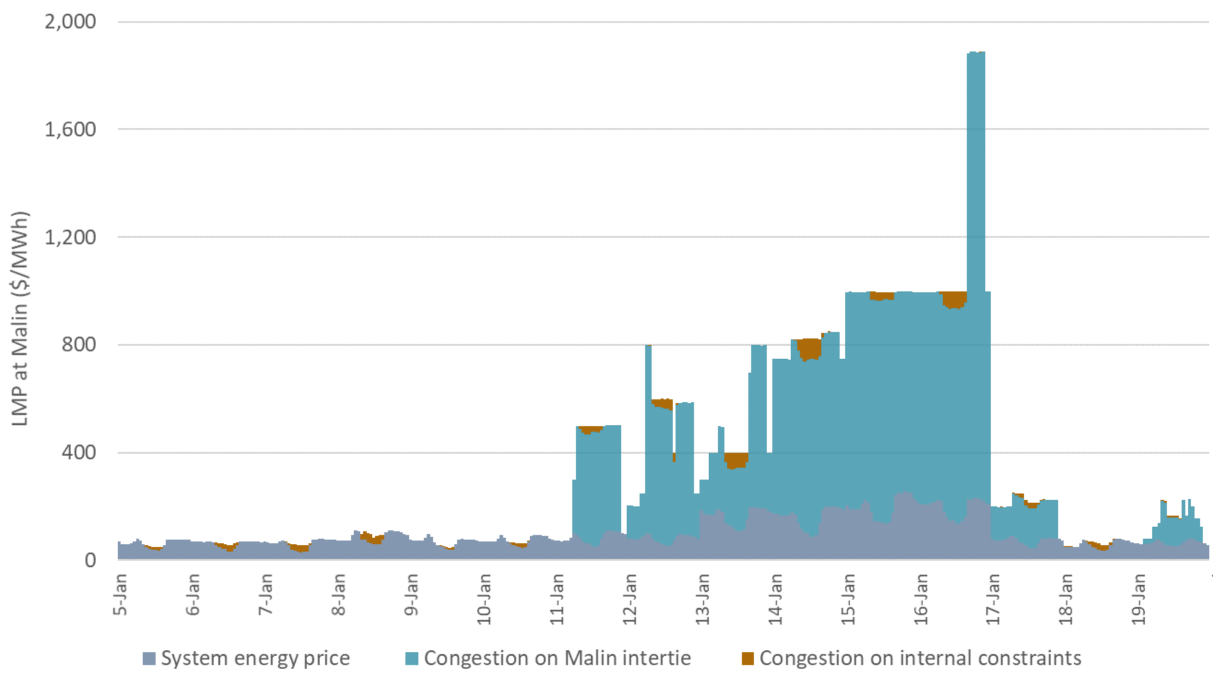


The congestion prices of the Malin intertie are reflected a 100% on the marginal congestion component of the Malin scheduling point, which is the location used to settle all schedules flowing on Malin intertie. The MCC may also reflect contributions from any other internal transmission constraint of the CAISO area.

Figure 51 shows the price composition for the Malin scheduling point. The energy component saw moderate increases during the Martin Luther King Jr. Day weekend, while the MCC component increased significantly. The main contribution to the congestion prices came from the Malin intertie congestion, while other internal constraints to CAISO area contributed mildly to the congestion. These internal constraints include Tesla-Los Banos, Gates-Midway and Warnervl-Wilson flowgates. During the Martin Luther King Jr. Day weekend, the full prices at Malin location reached up to the bid cap of $1,000/MWh and even reached prices at about $1,800/MWh on January 16 when CAISO markets increased the bid caps based on the maximum bid import price (MIBP) logic using the external bilateral power prices.

The standard market design that is common in nodal markets in the U.S. complements the day-ahead market with a financial market for financial transmission rights, also known as Congestion revenue right (CRRS) in the CAISO market. These are financial instruments that provide congestion hedges to participants exposed to day-ahead congestion. An integral component of a nodal market is congestion management, in which a variety of transmission constraints, including scheduling limits, are enforced. The market solution dispatches or schedules resources to manage the transmission and scheduling limits. When such constraints are at or near the limit (binding), the market dispatches available supply to address the congestion and the resulting congestion prices reflected in the locational marginal prices, reflects the cost of the resources that are dispatched to meet the demand taking into consideration the binding constraints. These congestion prices are charged or paid to schedules and awards of the day-ahead markets only for resources participating in the CAISO market.

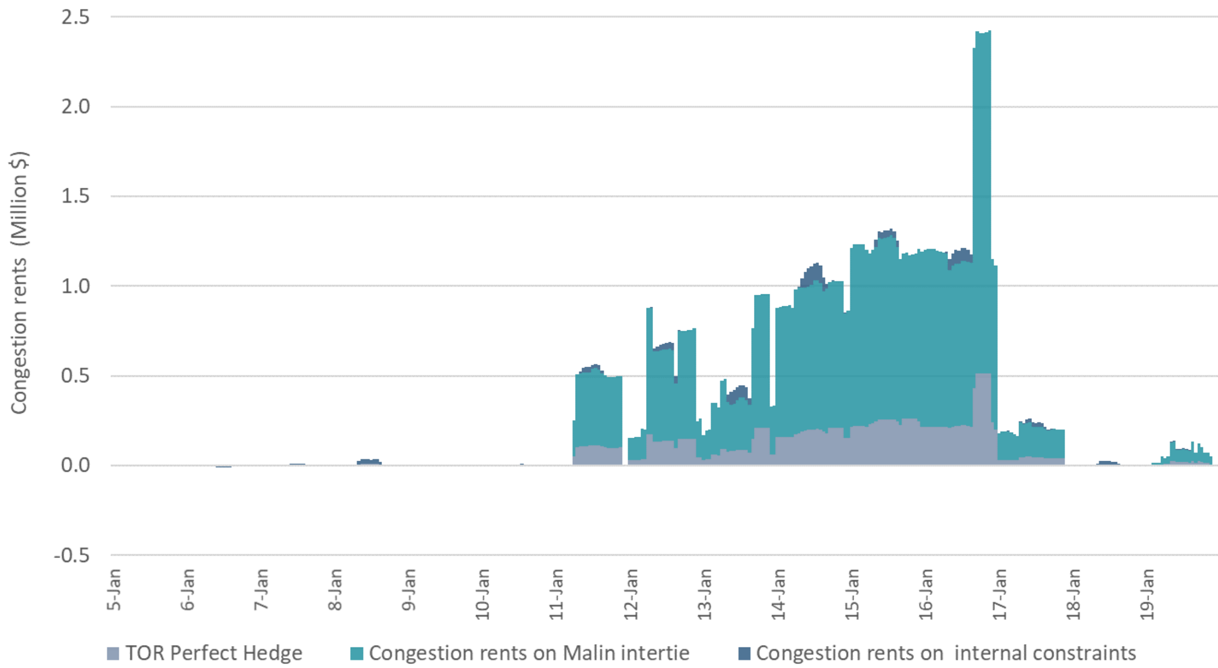
Figure 51: Day-ahead price at Malin scheduling point



For the northbound congestion to Malin observed during the Martin Luther King Jr. Day weekend in the day-ahead market, there were no resources redispatch in the Pacific Northwest to manage Malin congestion because the CAISO does not manage the external system, only internal CAISO resources and intertie schedules were dispatched and priced for that congestion. When congestion arises, there is an excess of money collected from the settlements of the day-ahead awards known as congestion rents. The CAISO does not retain these congestion rents as they are distributed to CRR holders based on their entitlements. Any market entity can participate in either the allocation or auction process to secure the proper financial hedges for their exposure to congestion at any given location of the CAISO market.[13] Figure 52 shows the day-ahead congestion rents collected at the Malin scheduling point.

[13] External load serving entities can obtain CRRs through the annual and monthly CRR allocation process through the Out of Balancing Authority Area Load Serving Entity (OBAALSE) process (See Section 36.9 of the CAISO Tariff). Market participants can also obtain annual and monthly CRRs through the CRR auction process (See Section 36.13 of the CAISO Tariff). During the month of January 2024, there were CRRs with sinks at Malin location obtained through the auctions. CRR holdings can be accessed through the public OASIS at www.oasis.com under the tab of Congestion Revenue rights.

Figure 52: Day-ahead congestion rents at Malin scheduling point



Congestion rents were significant at the Malin point during the Martin Luther King Jr. Day weekend due to the high congestion prices. The Malin intertie accrued about $100.9 million of congestion rents between January 5 and 19, while other internal constraints contributing to congestion prices at Malin accrued about $3 million. There were also transmission ownership rights and existing transmission rights exercised in this period. The capacity on Malin associated with these rights do not accrue congestion rents since their holders are fully insulated from congestion charges. The capacity value associated with these rights was about $25 million.

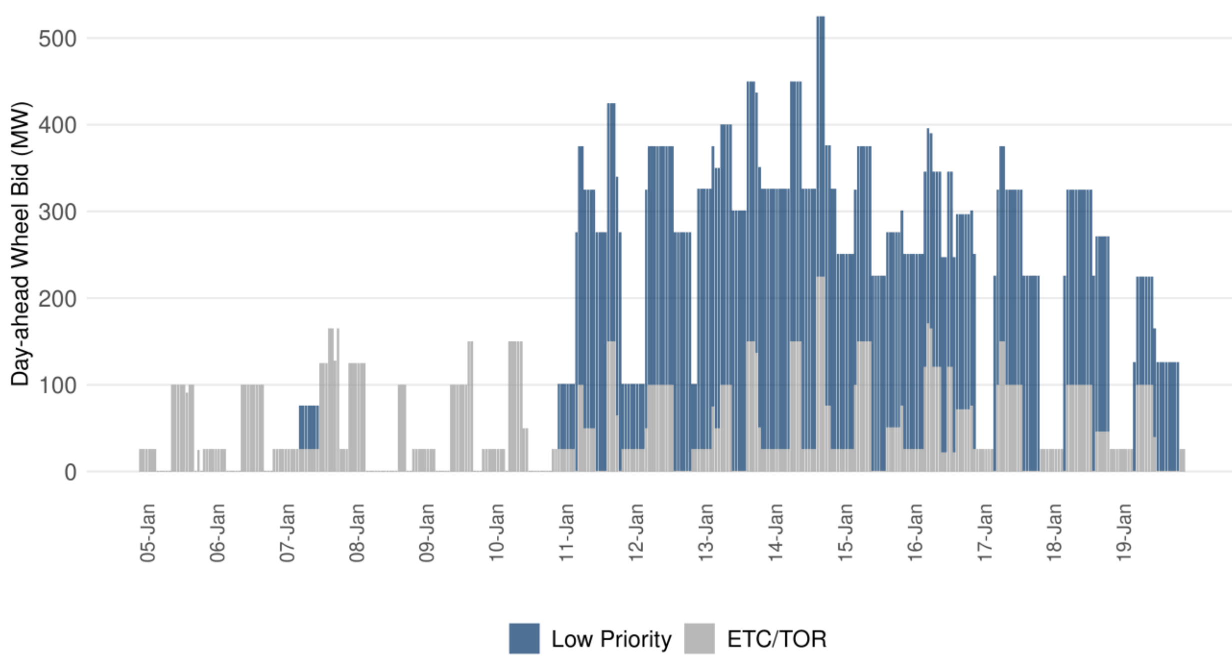
As part of the day-ahead settlements, these congestion rents are distributed to the CRR holders based on the MW awards and the day-ahead price differential between the source and sinks. In the month of January, there were over 900 MW of CRRs purchased in the CRR auctions sinking at Malin scheduling point, which mimicked the northbound congestion observed during the Martin Luther King Jr. Day weekend. These CRRs were allocated the congestion rents accrued on Malin. Additionally, there were under 200 MW of CRRs from the allocation processes sourcing at Malin. These CRRs mimicked the typical southbound flows when imports flow into California. Since congestion during the Martin Luther King Jr. Day weekend were in opposite direction, these CRRs were charged the congestion from Malin.

Wheel-through transactions

Wheel-through transactions consist of one import and one export transaction paired to clear at the same schedule. They allow entities to schedule flows through the CAISO system. With the enhancements for exports, loads and wheeling scheduling priorities extended for summer 2023, wheels seeking a high scheduling priority in the market equal to CAISO load are required to register their wheel transactions up to 45 days prior to the start of month and meet specific requirements.[14] If the requirements are not met and the wheel transaction is not registered, the transaction receives a low scheduling priority. Figure 53 shows the hourly wheels cleared in the RUC process throughout the month. Wheels participating in the day-ahead market in the month of January were ETC/TOR, and low-scheduling priority. The volume of wheel-through transactions peaked at about 300 MW of low priority wheels. There were also about 225 MW of TORs. The volume of explicit wheels associated with ETC/TOR was stable throughout the month with higher values in peak hours.

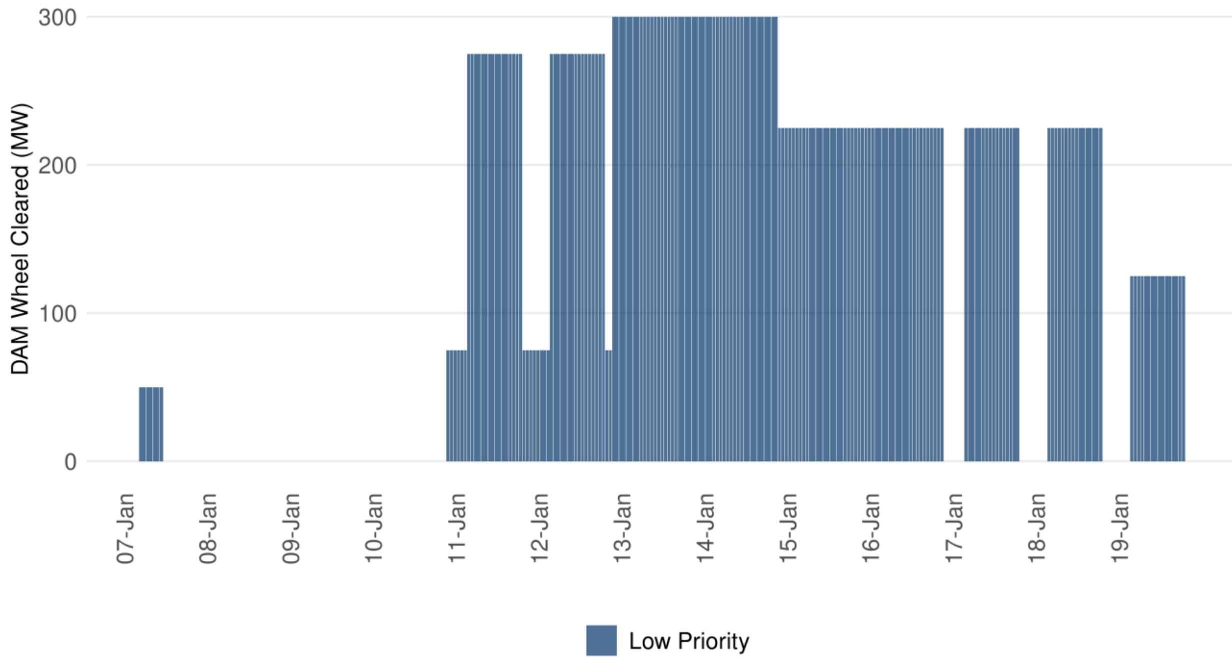
During the Martin Luther King Jr. Day weekend, there were low-priority wheels bid and cleared in the market for all hours of the day. The low priority exports were sourcing from MEAD230 and sinking at MALIN500. This path added to the northbound flow of exports.

Figure 53: Hourly volume of day-ahead wheel transactions by type of self-schedule



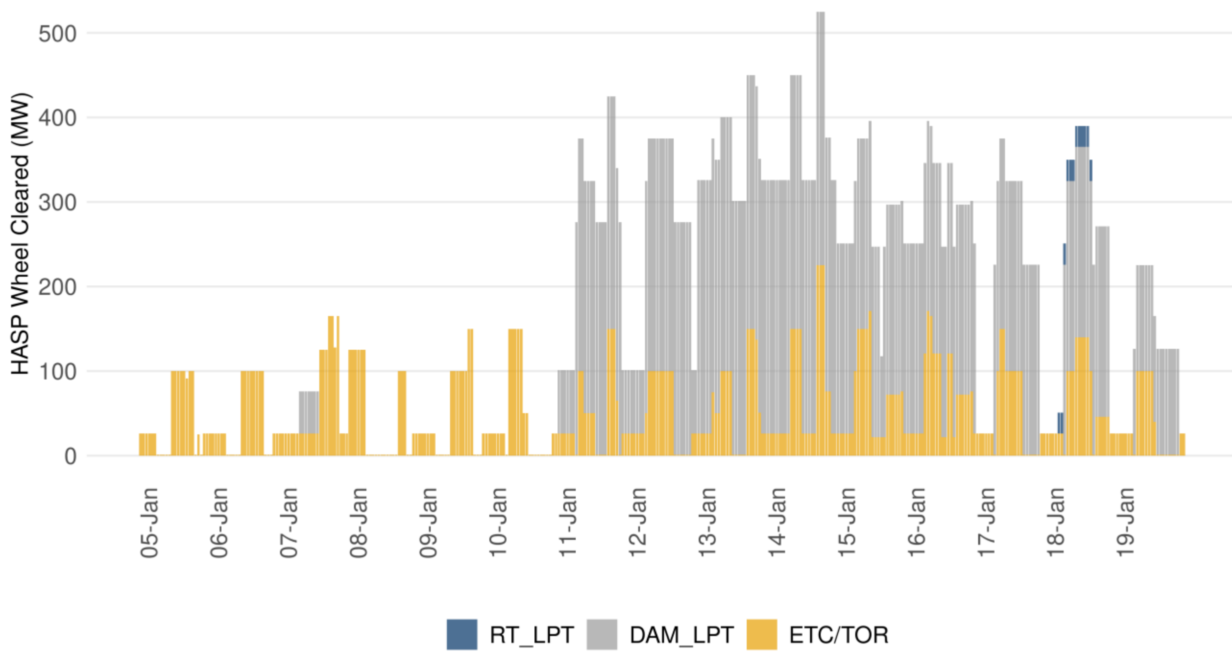
[14] Market Operations Business Practice Manual, section 2.5.5 (2021).

Figure 54: Hourly volume low-priority wheels cleared in RUC



Wheels cleared in the day-ahead market can be carried over into the real-time market with a day-ahead priority or be directly self-scheduled in the HASP process. Figure 55 shows the volume of wheels cleared eventually in the real-time market, organized by the various types of priority and relative changes.

Figure 55: Wheels cleared in real-time market



The ETC/TOR groups represent the wheels associated with either existing or owner transmission rights. The majority of ETC/TOR wheels scheduled in the day-ahead market carried over to real-time. DAM_LPT is for wheels with low priority cleared in day-ahead and rebid into real-time. Similarly, RT_LPT is for wheels bid in directly into real time.

Market Prices

Market prices reflect overall supply and demand conditions. As the market supply tightens or other system conditions materialize, prices may rise. Locational marginal prices (LMP) have three components: the marginal cost of energy on the system, the marginal cost of congestion reflecting constraints, and the marginal cost of losses. The marginal energy component reflects the impact of supply and demand conditions. Congestion conditions may also create local or regional price separations based on the cost of redispatch to meet a binding transmission constraint or scheduling limit.

Figure 56 compares the daily average prices across CAISO's area during the cold-weather period of January 2024[15]. Daily-average prices in all markets tripled, going from under $70/MWh to about $200/MWh, during the Martin Luther King Jr. Day weekend.

[15] Default Load Aggregation Point (DLAP) prices are a good indicator of overall prices. However, congestion may create price separation among DLAPs. The metrics presented here are based on a weighted average price of the DLAPs within the ISO area.

Figure 56: Average daily CAISO prices across markets

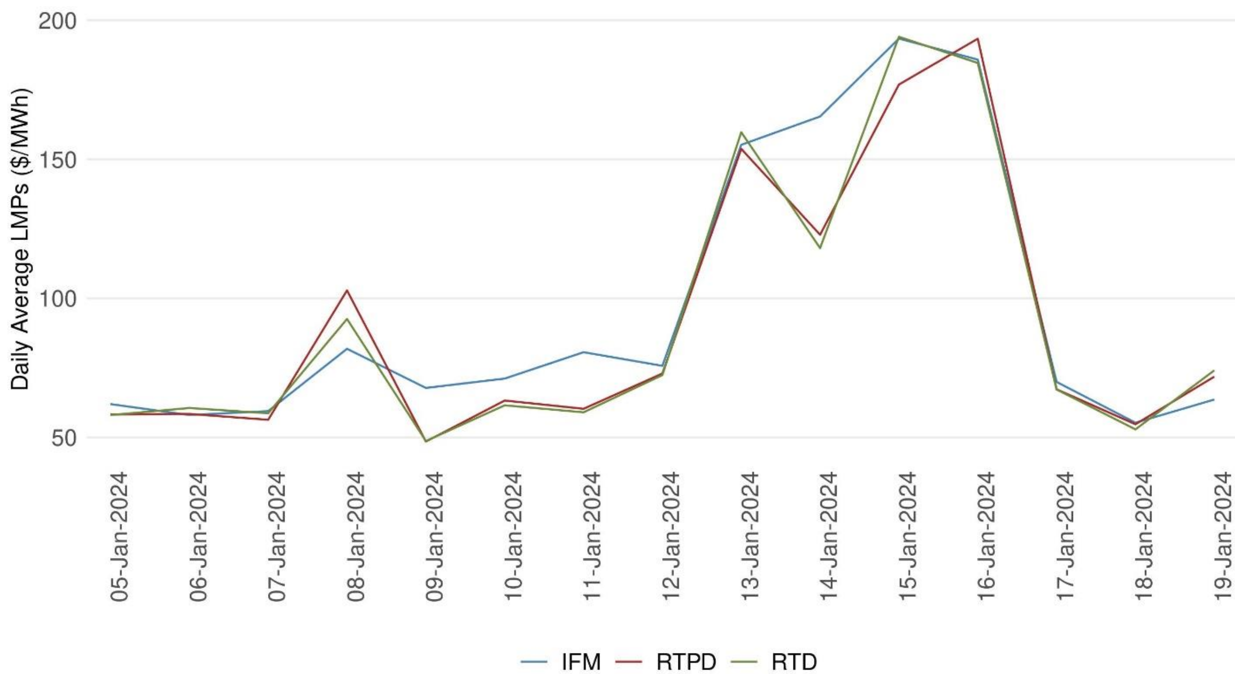


Figure 57 shows the daily distribution of integrated forward market (IFM) prices with box-whisker plots. These plots illustrate the full distribution of prices observed throughout the days and hours of the January winter event. The whiskers represent the maximum and minimum prices in a given day or hour, while the boxes represent the 10th and 90th percentile of the prices. The red dots represent the average prices for the day or hour. The average day-ahead LMP during the period of January 5 to 19 was $96.37/MWh and the maximum LMP of $599.77/MWh occurred on January 14, 2024.

Figure 57: Daily distribution of IFM prices

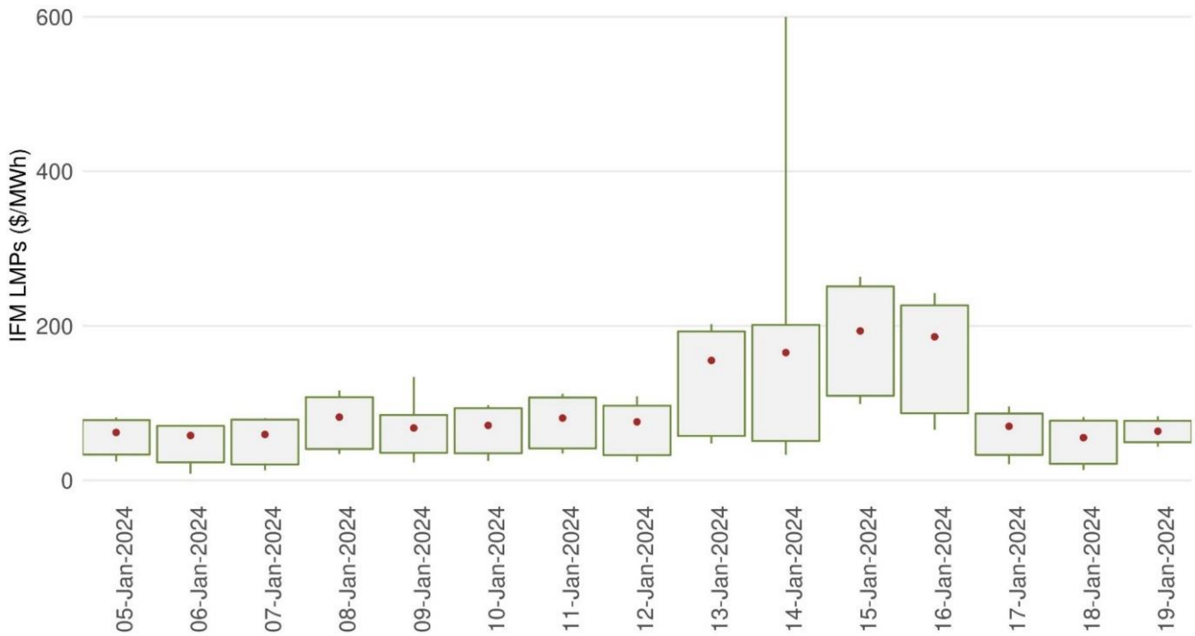
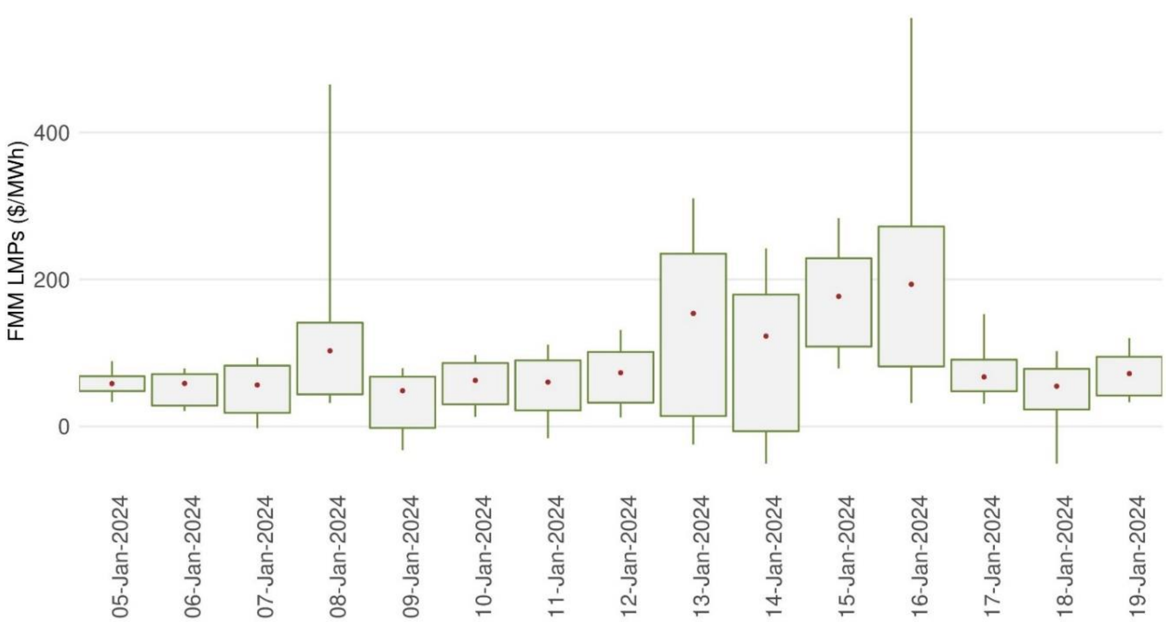


Figure 58 shows daily distributions of fifteen-minute market (FMM) prices throughout the January winter event. The average FMM LMP during the period of January 5 to 19 was $90.74/MWh and the maximum LMP of $555.39/MWh occurred on January 16, 2024. The January FMM prices exhibited similar price spreads to IFM prices.

Figure 58: Daily distribution of FMM prices



Maximum Import Bid Price and Bid Caps

During the January cold event, the energy bid cap increased above $1,000/MWh for multiple days. The energy bid cap can be raised above $1,000/MWh and up to $2,000/MWh if either:

1. The CAISO-calculated Maximum Import Bid Price (MIBP)[16] exceeds $1,000/MWh.
2. Or a scheduling coordinator submits a cost-verified energy bid[17] above $1,000/MWh.

For the period of January 5 to 19, the energy bid cap was raised solely due to the MIBP. When the MIBP exceeds $1,000/MWh, there are three scenarios to define the caps imposed to different resources:

- Cap of $2,000/MWh: This applies to Non-resource adequacy (RA)-backed import bids, reliability demand response resources (RDRRs) in the Real-Time Market (RTM), non-participating load, exports, and virtual bids.
- Cap based on the MIBP price between $1,000-2,000/MWh: This applies RA-backed import bids.
- Cap of $1,000/MWh: This applies to generators[18], participating load, and reliability demand response resources (RDRRs) in the day-ahead market (DAM), tie-gens, non-generator resources (NGRs), and proxy demand response (PDR) resources.

The MIBP approximates prevailing bilateral energy prices outside the CAISO's BAA on an hourly basis and utilizes the maximum of either the Mid-Columbia or Palo Verde next-day bilateral price on the Intercontinental Exchange (ICE) for the applicable on-peak or off-peak hours. The MIBP calculation also utilizes day-ahead hourly CAISO system marginal energy cost (SMEC) values. The MIBP is calculated separately for both DAM and RTM.

In addition to the ability for scheduling coordinators to submit higher bids, the increase of the energy bid cap above $1,000/MWh automatically triggers the various penalty parameters in the market to be scaled based on the $2,000/MWh value. This functionality has been in place since the implementation of Federal Energy Regulatory Commission (FERC) Order 831 in 2021.

The increased bid cap also causes adjustments to the RDRR bid price range in the RTM. When the bid cap is $1,000/MWh, RDRR resource bids must be between $950/MWh and $1,000/MWh. This range doubles to $1,900-$2,000/MWh when the bid cap increases above $1,000/MWh. This functionality is only effective in the RTM.

For any hour that the energy bid cap is raised based on day-ahead market conditions/calculations, the cap is raised for the same hour in RTM. Additionally, the cap can be raised for incremental hours in RTM based on RTM conditions/calculations.

---

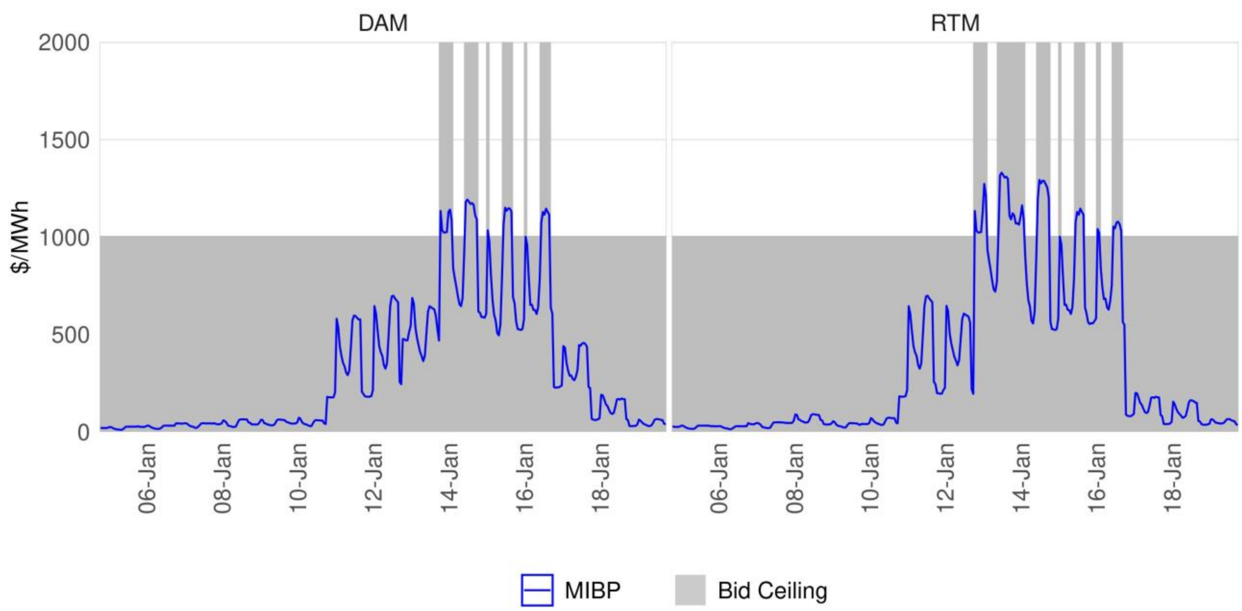
[16] Details on the Max Import Bid Price (MIBP) calculation can be found in the BPM for Market Instruments, Attachment P.2.

[17] Details on cost-verified bids can be found in the BPM for Market Instruments Attachments O and P.

[18] Resource-specific resources can submit energy bids above $1,000/MWh (and up to $2,000/MWh) if they have the ability to prove that they have costs above $1,000/MWh; *i.e.*, cost-verify their bids.

Figure 59 shows a trend of the MIBP in blue overlaid with the bid ceiling in grey, for both DAM and RTM between January 5 and January 19, 2024. The high MIBP between January 14 and 17 derived from the high bilateral prices caused the bid ceiling to rise to $2,000/MWh for certain hours and markets. This consequently allowed the market prices to rise in some cases above the $1,000/MWh level.

Figure 59: Maximum Import Bid Price and bid ceiling, DAM and RTM



Hourly Submitted Energy Bids

Different resource types are subject to different bid caps. During the winter weather, market participants submitted a wide range of bid prices. Given gas price dynamics described in earlier sections, the most notable bid-in price changes were for gas-fired resources in the CAISO area, as shown in Figure 60. This plot organizes all bid-in price in ranges and highlights the steep change in the volume of bids with higher prices during the Martin Luther King Jr. Day weekend. Since gas prices increased moderately, the main change was a significant increase of bids falling in the range of $100-$200, followed by a more modest increase of bids in the range of $200-$500.

Figure 60: Day – Ahead Bid-in capacity for gas-fired resources

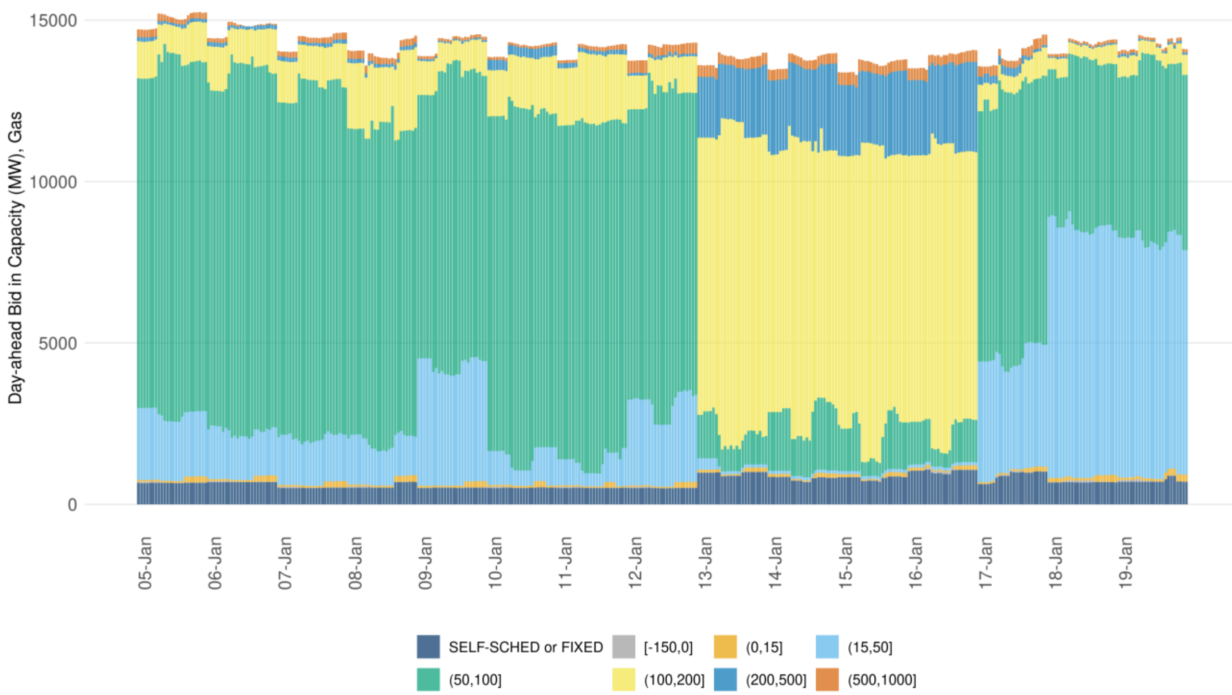


Figure 61 shows the trend of bid-in supply from import resources organized by price range. During the Martin Luther King Jr. Day weekend, imports did not materially change their bid-in prices, but the volume of imports gradually dried up since most of the intertie transactions turned out to be for exports transactions as the Pacific Northwest experienced colder conditions.

Figure 61: Day – Ahead Bid-in capacity for imports

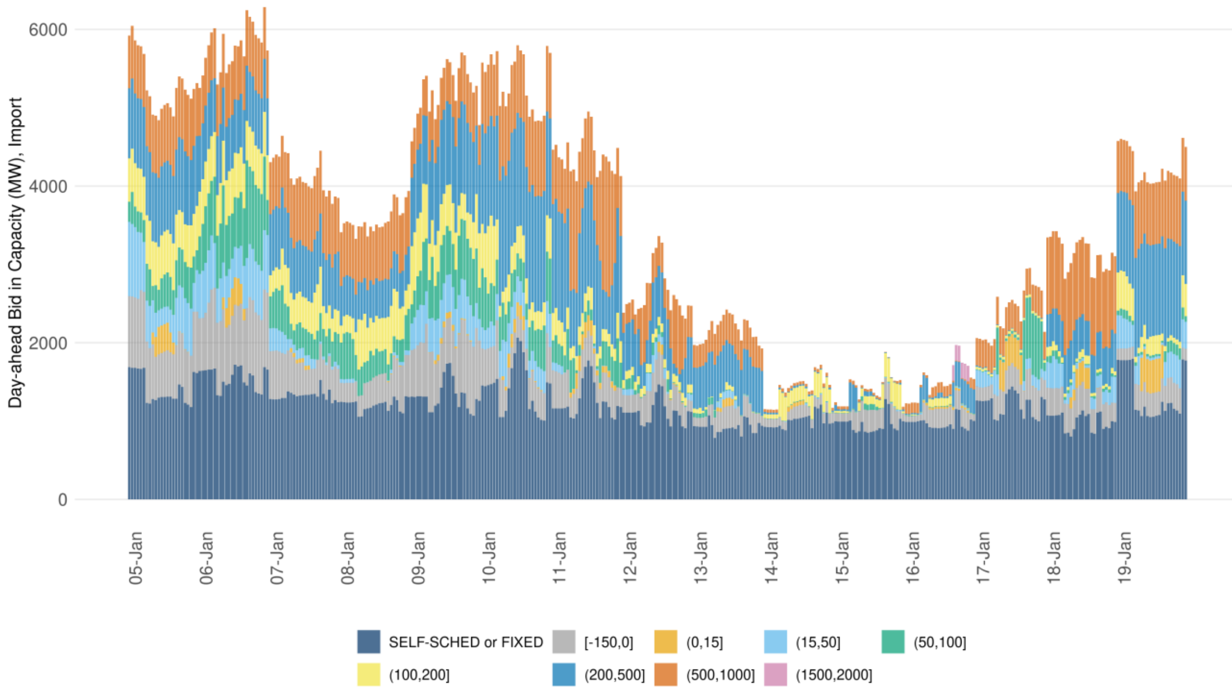


Figure 62 and Figure 63 show the bids submitted in the day-ahead and real-time markets, respectively, for an hour in which the energy bid cap was raised. Bid prices ranged from the bid floor (-$150/MWh) to close to $2,000/MWh. The diversity of bid prices reflect varying intentions of scheduling coordinators, with bids at the bid floor indicating willingness to be dispatched at any price and bids near the $2,000/MWh bid cap indicating a desire to only be scheduled at the highest market prices. Note that these are the bid prices prior to any bid mitigation during the local market power mitigation process.

In Figure 62, with the exception of virtual supply bids, all bid prices were at or below $1,000/MWh. This is in line with the statement above noting that no resources submitted cost-verified energy bids above $1,000/MWh. Figure 62 only displays bids related to the CAISO BAA; no WEIM bids are shown.

Figure 63 shows a similar pattern, though there was a small quantity of RDRRs with bids at $1,950/MWh. Another clear difference between markets is that there was a higher proportion of bid prices near $1,000/MWh in real time. This difference was due to the greater volume of bids submitted by WEIM resources from the Pacific Northwest, where cold weather conditions were most acute.

Figure 62: Submitted energy bids by resource type for DAM January 15, 2024 hour-ending 19

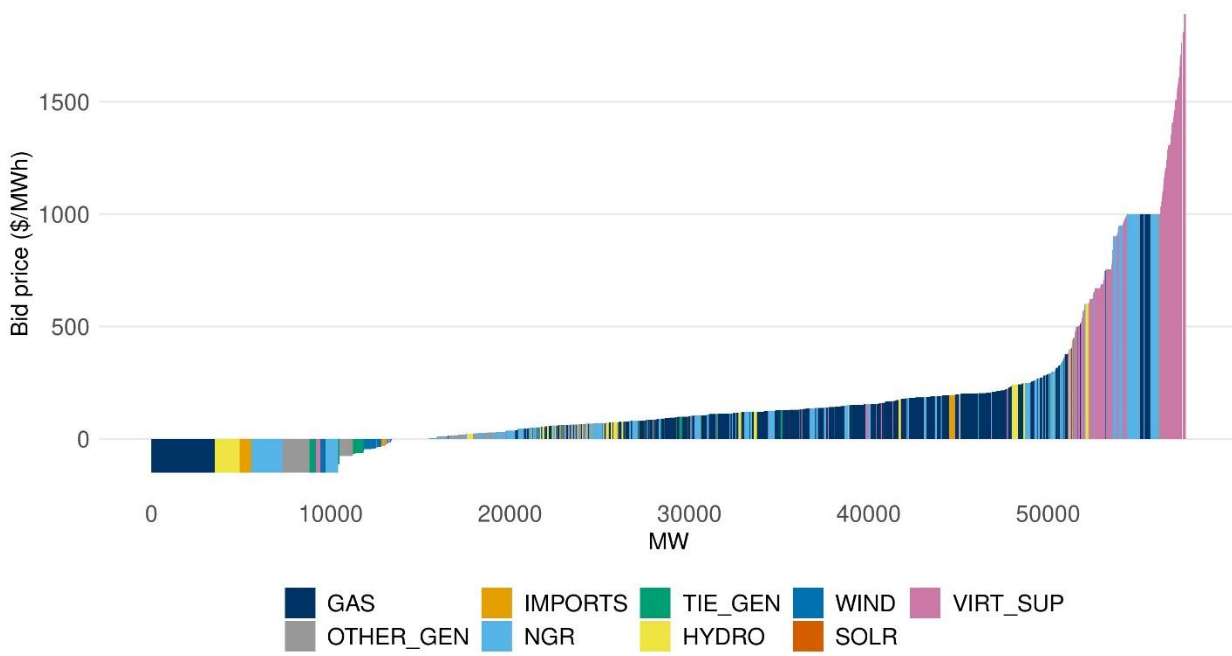
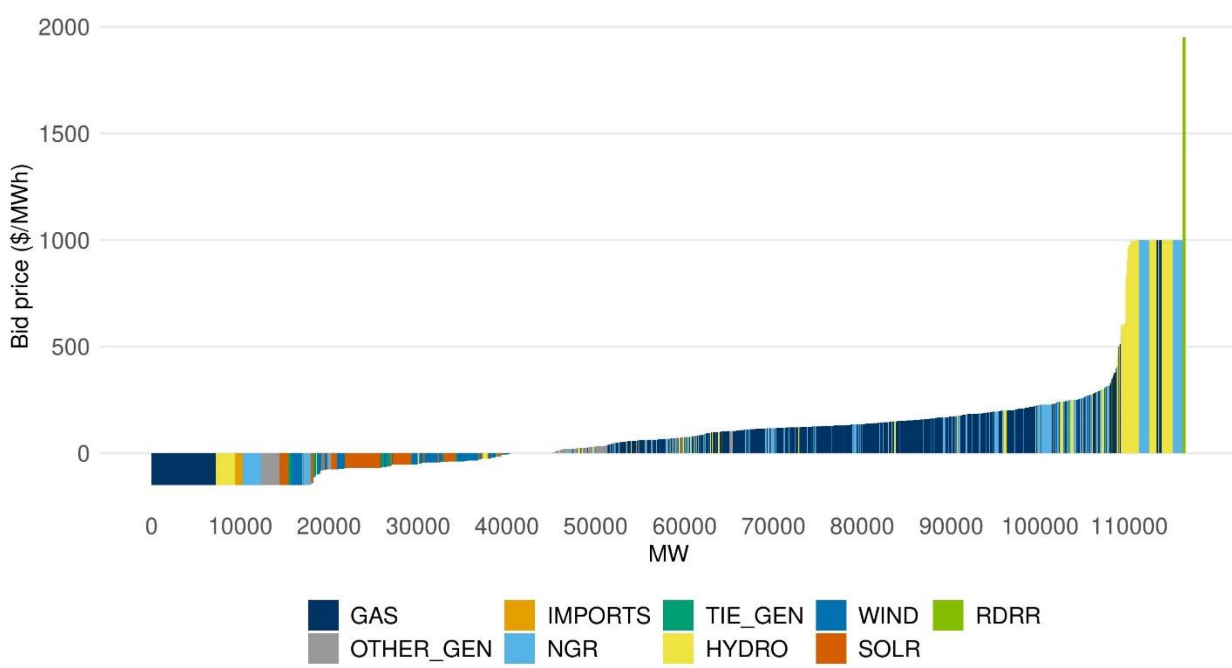


Figure 63: Submitted energy bids by resource type for RTM January 15, 2024 hour-ending 19



CAISO Supply and Demand

CAISO Supply Mix

Figure 64 shows the CAISO's resource hourly breakdown on January 13. Gas production represented about 58% of the total supply in the CAISO area on January 13. Gas production reduced in the midday hours when solar production was at maximum. Energy from the gas fired generation peaked at about 70% of the total supply in in HE 7. The increase in solar production during the middle hours reduced the reliance on gas fired generation. During the middle hours, the exports and battery charging are shown with negative energy as they represent as much as 4,000 MW of additional demand.

Figure 64 to Figure 66 shows the supply mix for January 14 and 15, respectively. The cumulative exports and battery charging reached a maximum of about 6, 000 MW in HE 12 on January 14. The net load for January 14 reached a minimum of about 9,000 MW in HE 13. The reliance on gas fired generation was higher on January 15 at about 63% of total supply for the CAISO area on average.

Figure 64: Supply Mix of the Energy Produced on January 13, 2024

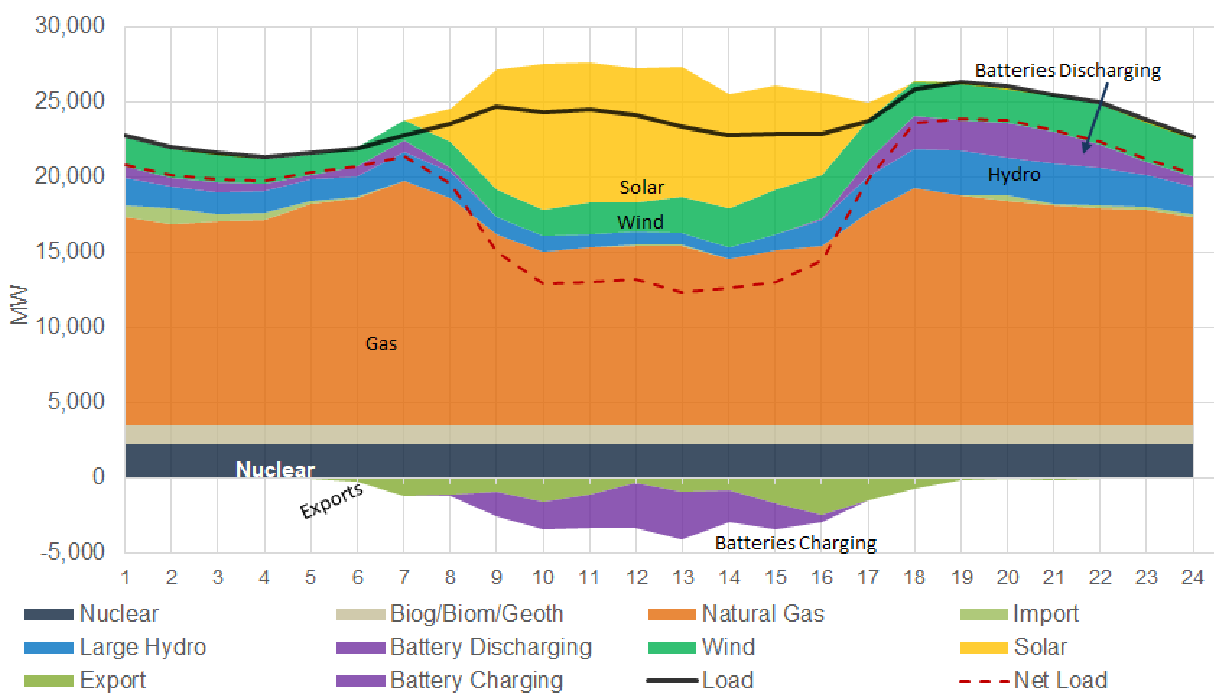


Figure 65: Supply Mix of the Energy Produced on January 14, 2024

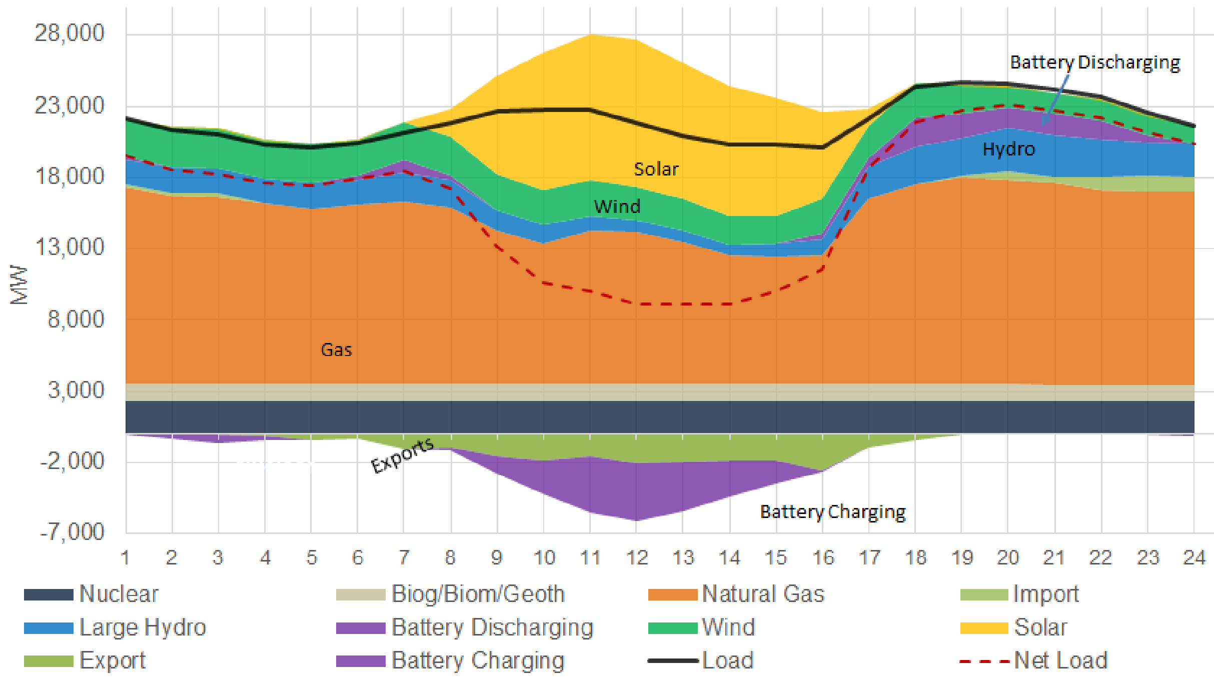
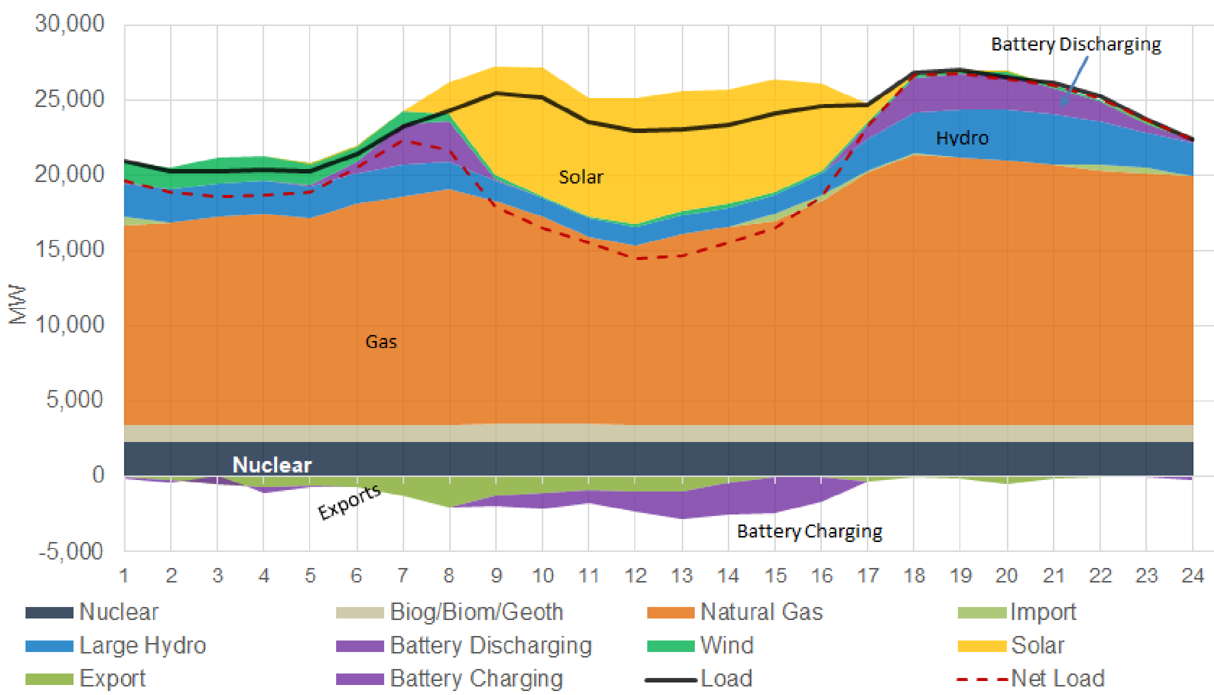


Figure 66: Supply Mix of the Energy Produced on January 15, 2024

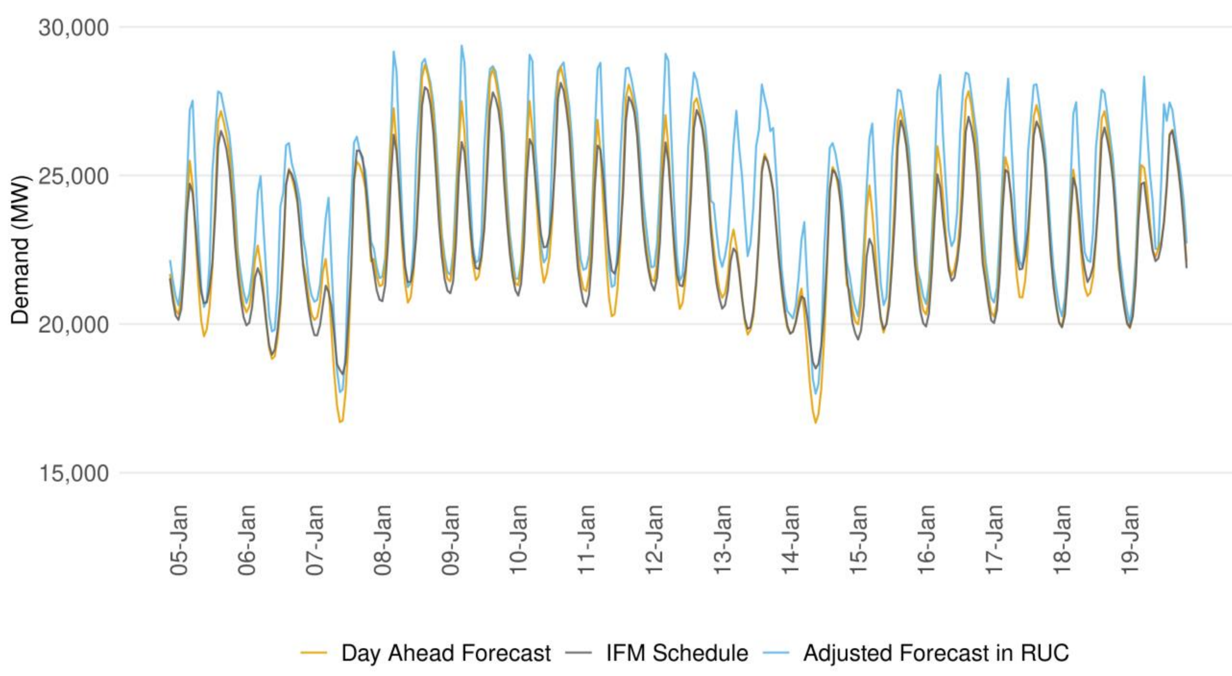


CAISO demand and supply cleared in the markets

The IFM market clears both physical and convergence bid supply against bid-in demand, convergence bid demand and exports, and produces awards and prices that are financially binding for all resources. The RUC process uses the IFM solution as a starting point to further refine the supply schedules that can meet the day-ahead load forecast. Operators may adjust the day-ahead forecast to factor in other foreseeable conditions such as load and renewable uncertainty. The RUC process will clear supply against the final adjusted load forecast. The most critical condition of the cold event occurred during the Martin Luther King Jr. Day weekend. Usually the demand level on weekends in the CAISO area is lower than weekdays, and during this cold event were well under 30,000 MW. This low levels of demand did not represent any significant supply-capacity for the CAISO system fleet.

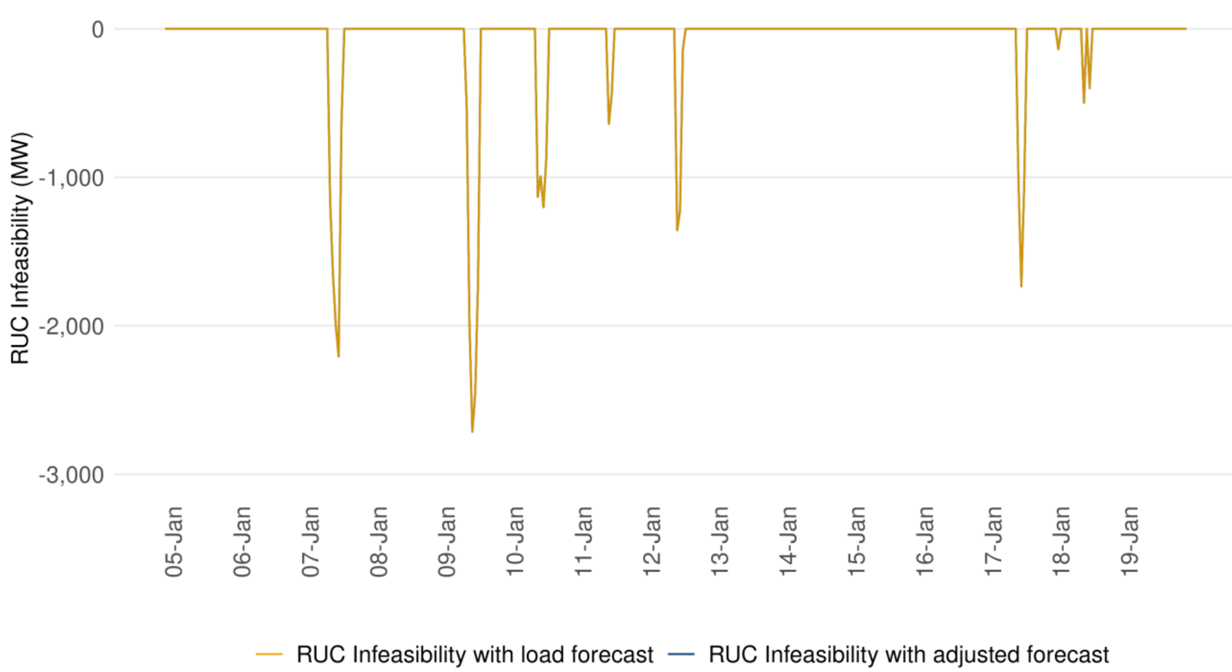
Figure 67 compares the IFM schedules for physical resources versus the day-ahead load forecast and the adjusted load forecast eventually used in the RUC process. For the month of January, the day ahead forecast was consistently higher than the IFM schedule. There is a load forecast adjustment in the RUC process that is added on top of the day ahead forecast, shown in blue.

Figure 67: Day-ahead demand trend



The RUC market clears against a load forecast that is not price sensitive. Under certain conditions RUC may relax the power balance constraint due to a surplus or shortfall of supply capacity. A relaxation signals that there is an imbalance between load requirements and available supply. An infeasible power balance can be in either direction. In hours with low levels of load and minimum downward capability, RUC may observe an oversupply condition, resulting in a negative infeasibility. Conversely, in hours where there is insufficient supply to meet the load requirement, RUC may have an undersupply condition, resulting in a positive infeasibility. Negative RUC infeasibilities occur because RUC can only dispatch a resource down to its minimum load and cannot actually de-commit a resource or clear additional exports. Figure 68 shows RUC infeasibilities against two reference points. One infeasibility is relative to the final adjusted forecast in RUC, while the other is relative to the raw day-ahead forecast. There were no RUC under-supply infeasibilities for the month of January. In contrast there were multiple hours with over-supply infeasibilities in days on either side of the holiday weekend, indicating excess of supply in the CAISO area, as shown in Figure 68.

Figure 68: RUC infeasibilities

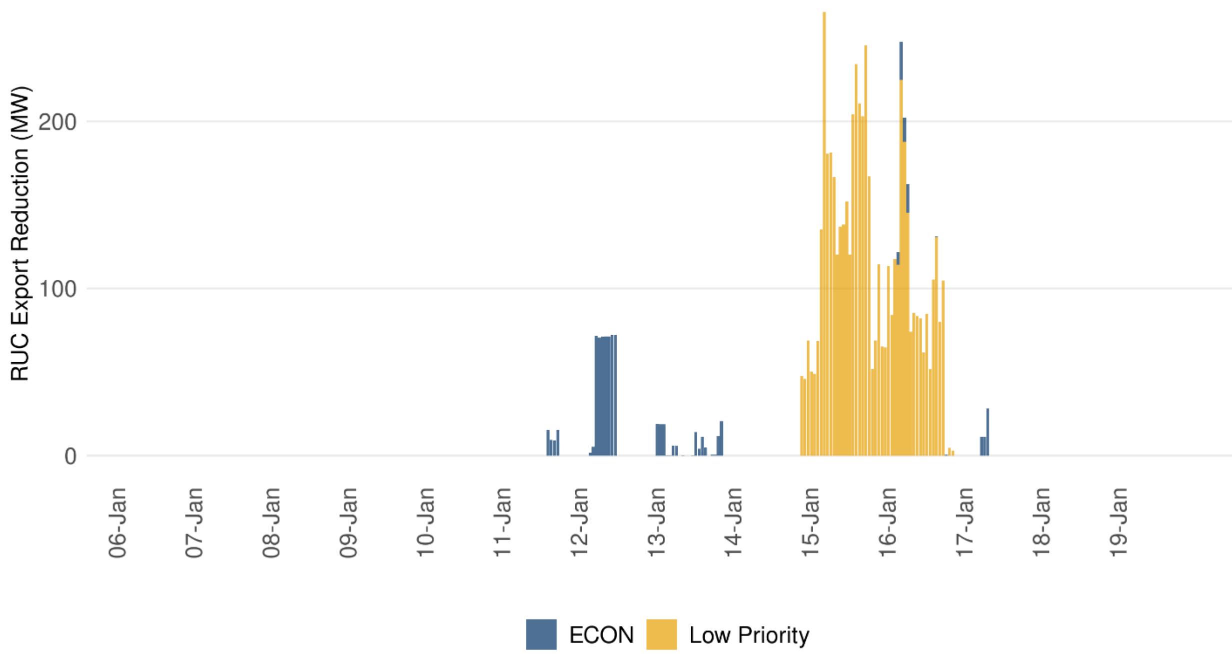


In addition to relaxing the power balance constraint, the RUC process may utilize other scheduling priorities to meet the power balance. Indeed, before relaxing the power balance (and based on current scheduling priorities), RUC will first reduce economic exports (exports bid-in at a given price) and lower priority price-taker exports. If there is still need to for further reductions, the market will either reduce PT exports or relax the power balance.[19] There are also instances where exports can be reduced in the market to manage scheduling and transmission constraints.

Figure 69 shows the volume of hourly export reduction in the RUC process, which happened only for low priority exports across the month of January.

[19] Under the current setup of scheduling priorities, PT exports and the RUC power balance constraint have the same priority reflected with the same penalty price utilized in the market optimization. What level of reductions relative to the level of power balance relaxation is achieved will depend on many other conditions in the optimization process, such as the location of the exports that may look more or less attractive for reduction in comparison to the power balance. Thus, typically, both export reduction and power balance infeasibilities can be observed in an RUC solution under tight supply conditions.

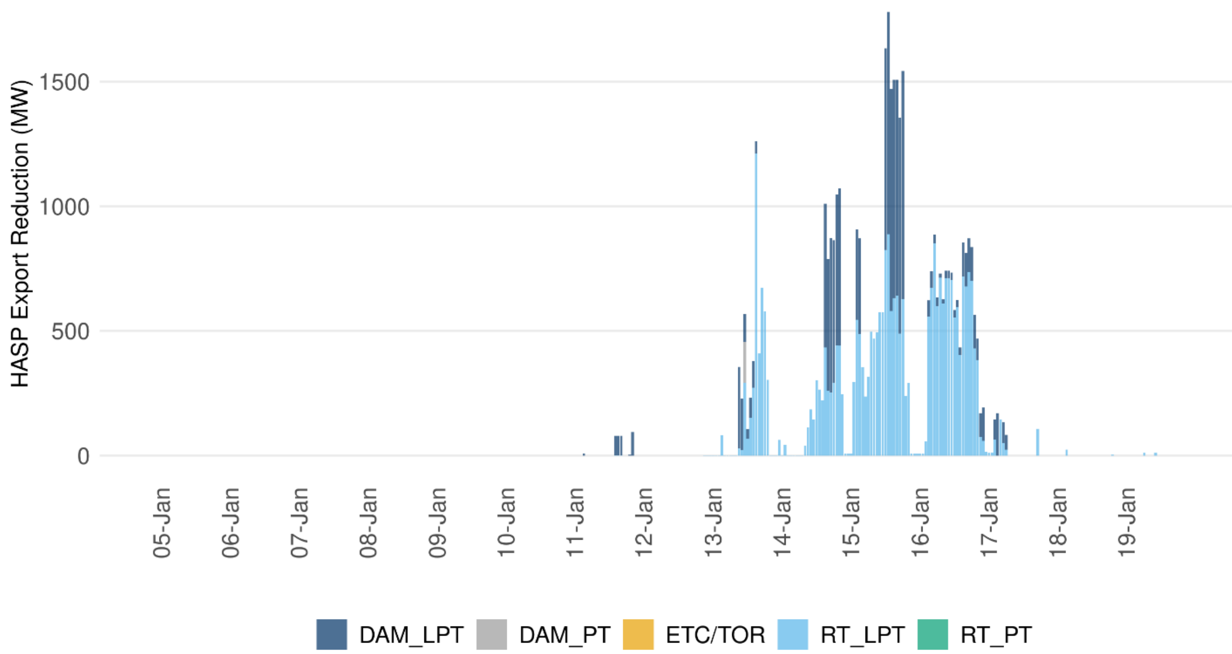
Figure 69: Exports reduction in RUC



Exports can still participate in the real-time market by rebidding directly into real-time market with low priority economic bids. Market participants can self-schedule exports cleared in the day-ahead into the real-time market. The schedules cleared from the RUC process are treated in the real-time market as having a day-ahead priority, which is above the corresponding priority of LPT exports submitted directly in real-time. Thus, exports cleared in the day-ahead are less likely to be cut in the real-time. Participants can also submit LPT self-schedules in the real-time market, which are more at risk of reductions in the hour-ahead scheduling process (HASP) process. The PTK or high-priority exports can be bid in either the day-ahead or real-time market and will have the same priority as CAISO load, which is higher than the low-priority exports. The real-time market issued reductions for a few days in January, mainly for low priority exports as shown in Figure 70.

As explained in a previous section about the Malin intertie, these export reductions in real-time were not due to limited supply in the CAISO area; they were due to limit derates on the Malin intertie because of forced outages in the Pacific Northwest. The Malin derates in real time required the reduction of exports already cleared in the day-ahead market and to last-minute exports bid in the real-time market.

Figure 70: Exports reductions in HASP



Wholesale Market Costs

The CAISO's markets are settled based on awards and prices derived from the markets through specific settlement charge codes; these include day-ahead and real-time energy and ancillary services. The majority of the overall costs accrue on day-ahead settlements.

Figure 71 shows the daily overall settlement costs for the CAISO balancing area between January 5 and January 19; this does not include WEIM settlements. As demand or prices rise, the overall settlements are expected to increase. When considering the overall costs relative to the volume of demand transacted, the dotted red line provides a reference of an average cost per MWh. The average daily cost over the period was $62.12 million, representing an average daily price of $119.74/MWh. The maximum daily cost of $112.86 million occurred on January 16.

Two components of this overall cost are the real-time energy and congestion offsets. These costs reflect the settlements of differences between the day ahead and real-time markets for energy and congestion.

Figure 71: CAISO daily total and average market costs

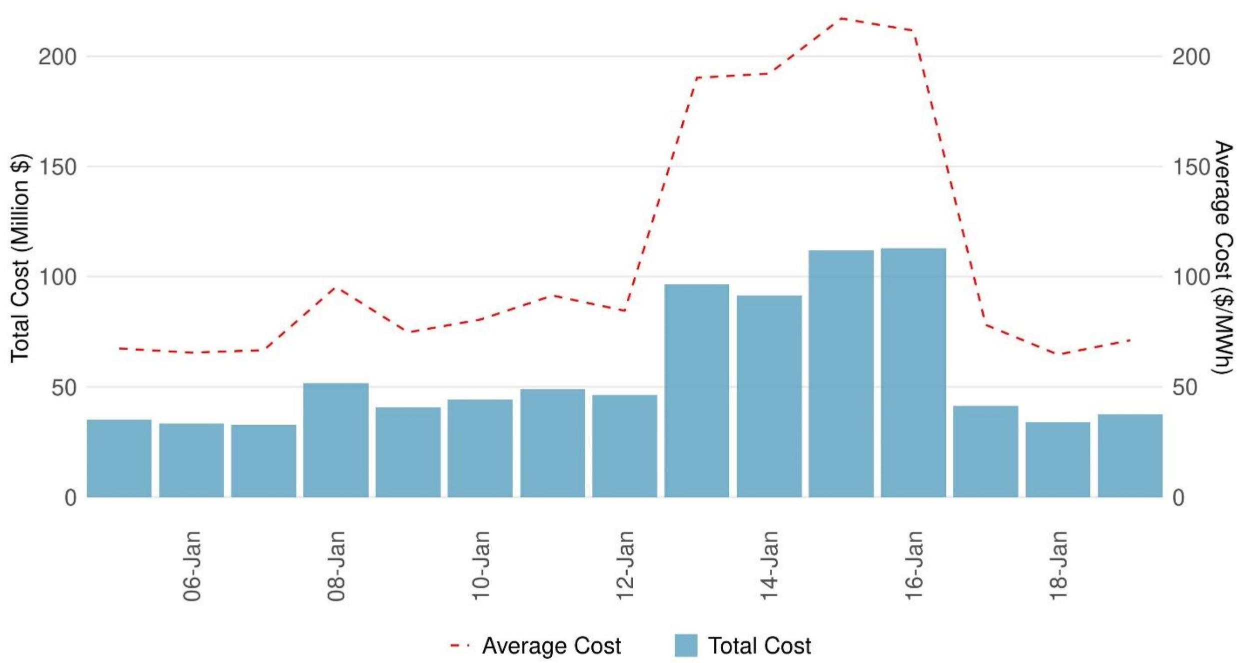


Figure 72 and Figure 73 show the real time offset costs for the CAISO and WEIM regions. The real time congestion offsets for the CAISO area increased to about $2.2 million on January 13, further increasing to about $7.5 million on January 14. The real time imbalance energy offset for the CAISO area increased to about $4 million to January 13 and about $2.8 million on January 14.

Real time congestion offset costs arise due to congestion differences among markets. The real time imbalance energy offsets arises to achieve cost neutrality. The real time congestion offset for the WEIM area was about $9.3 million, $10 million and $8.5 million for January 13, 15 and 16 respectively. The real time imbalance energy offset was about $3.1 million on January 13. For January 14, the congestion from the COI S_N nomogram was one of the significant drivers that increased the congestion offset for the CAISO area. This nomogram was in place due to the outages in the Pacific Northwest, and was binding in both FMM and RTD markets for January 14.

Figure 72: Real-time energy and congestion offsets for CAISO

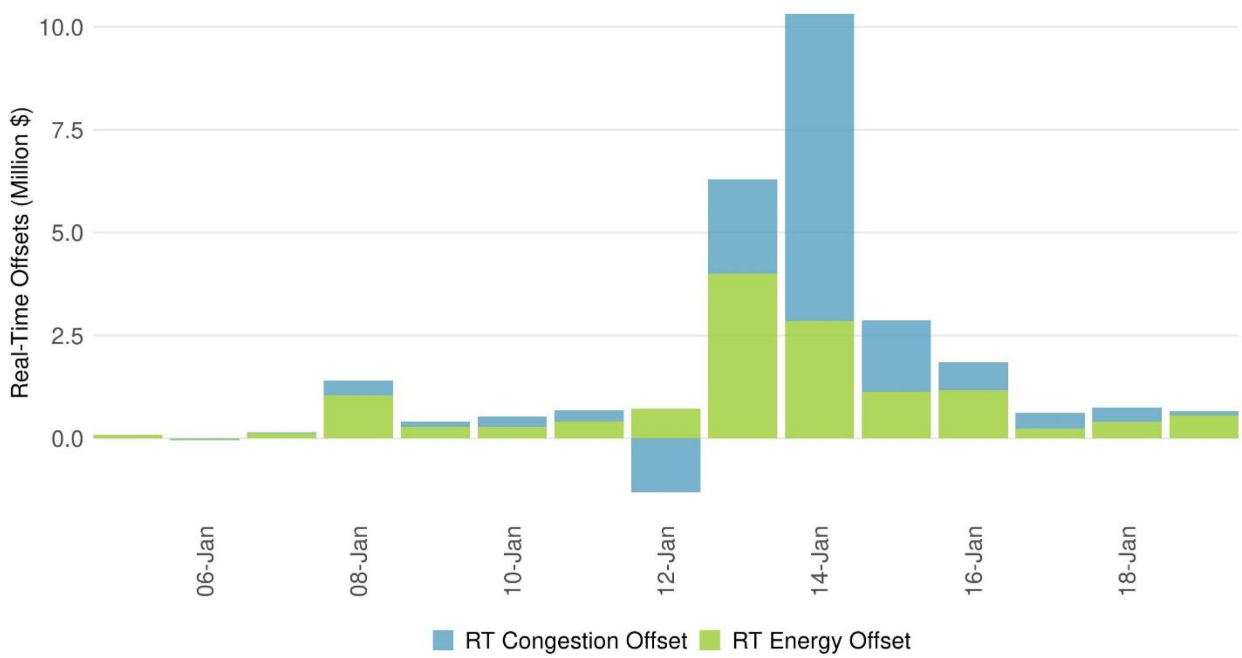
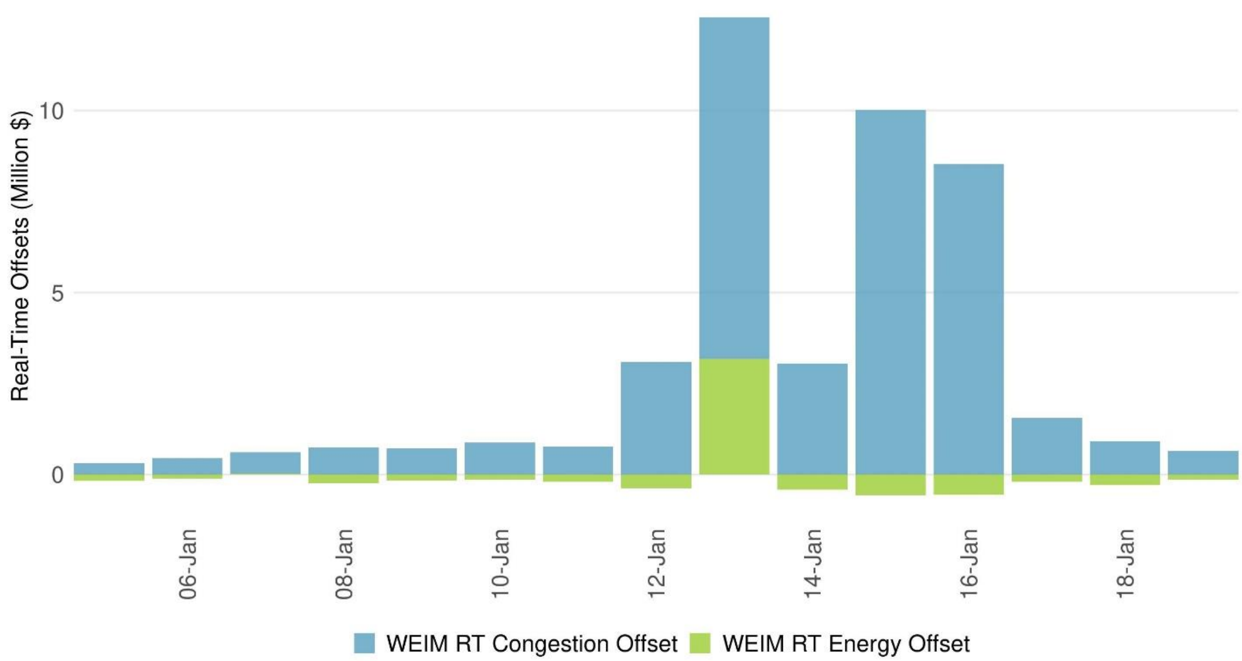


Figure 73: Real-time energy and congestion offsets for WEIM



Appendix

Figure 74: Off-peak next-day power price at Western hubs

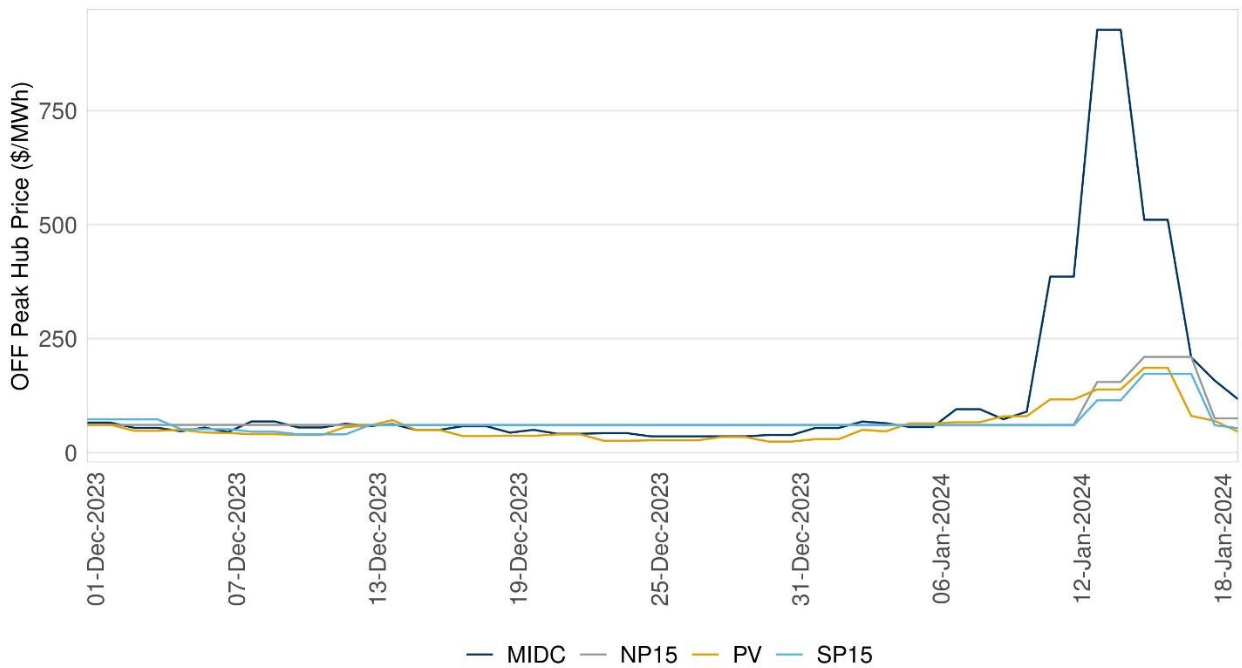
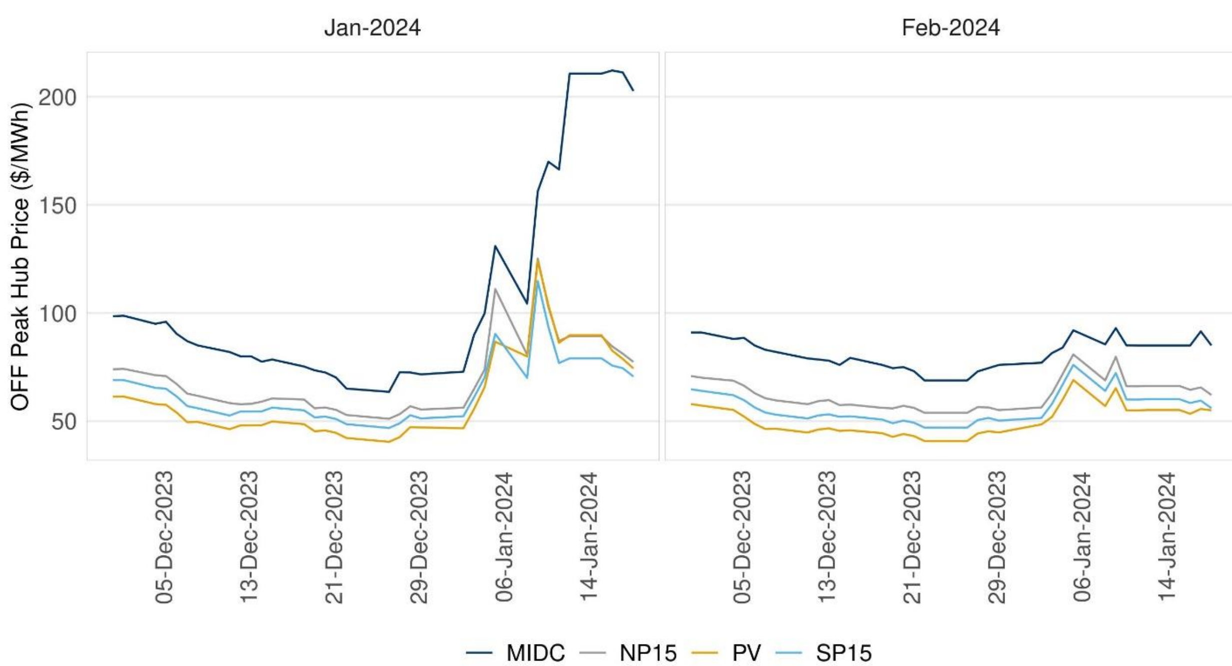


Figure 75: Off-peak future power prices for January and February 2024



The plots below show a more granular breakdown of flexible ramping and capacity test failures across the WEIM BAAs between January 5 and January 19.

Figure 76. Percentage of capacity up failures per BAA

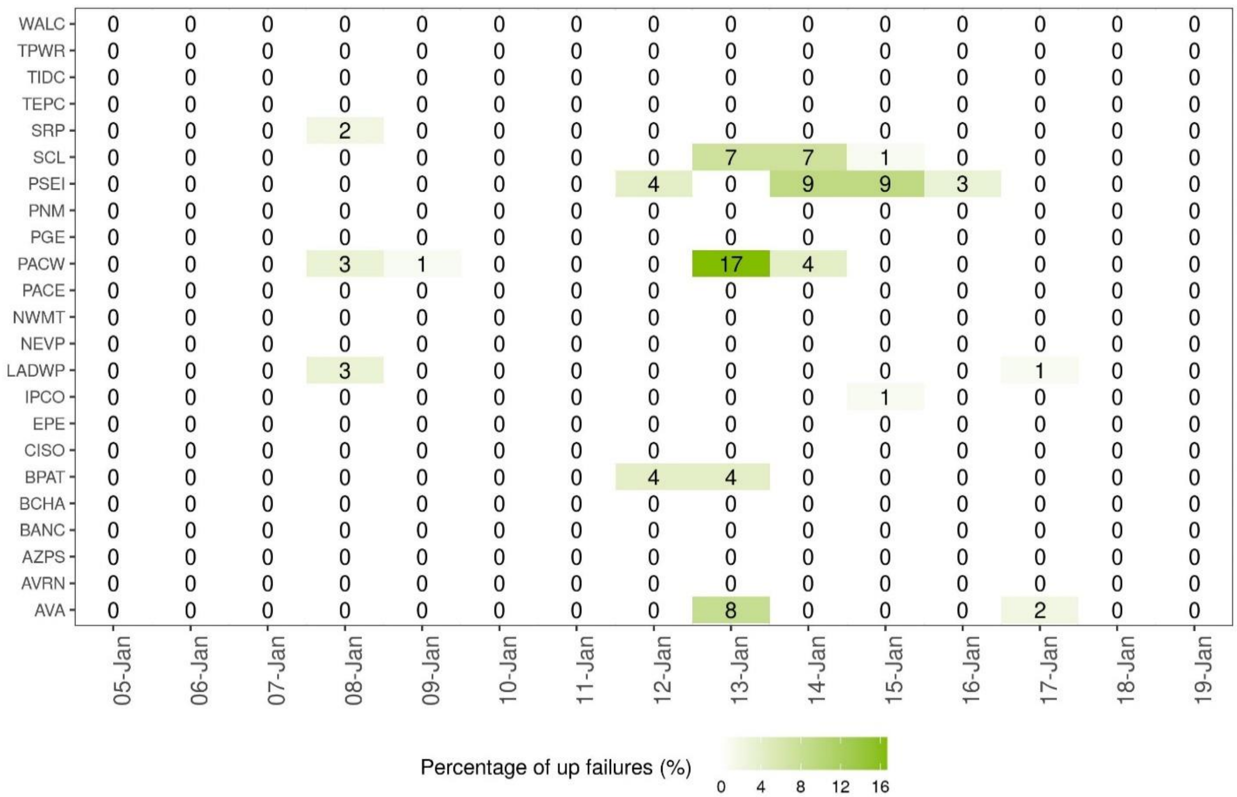


Figure 77: Percentage of capacity down failures per BAA

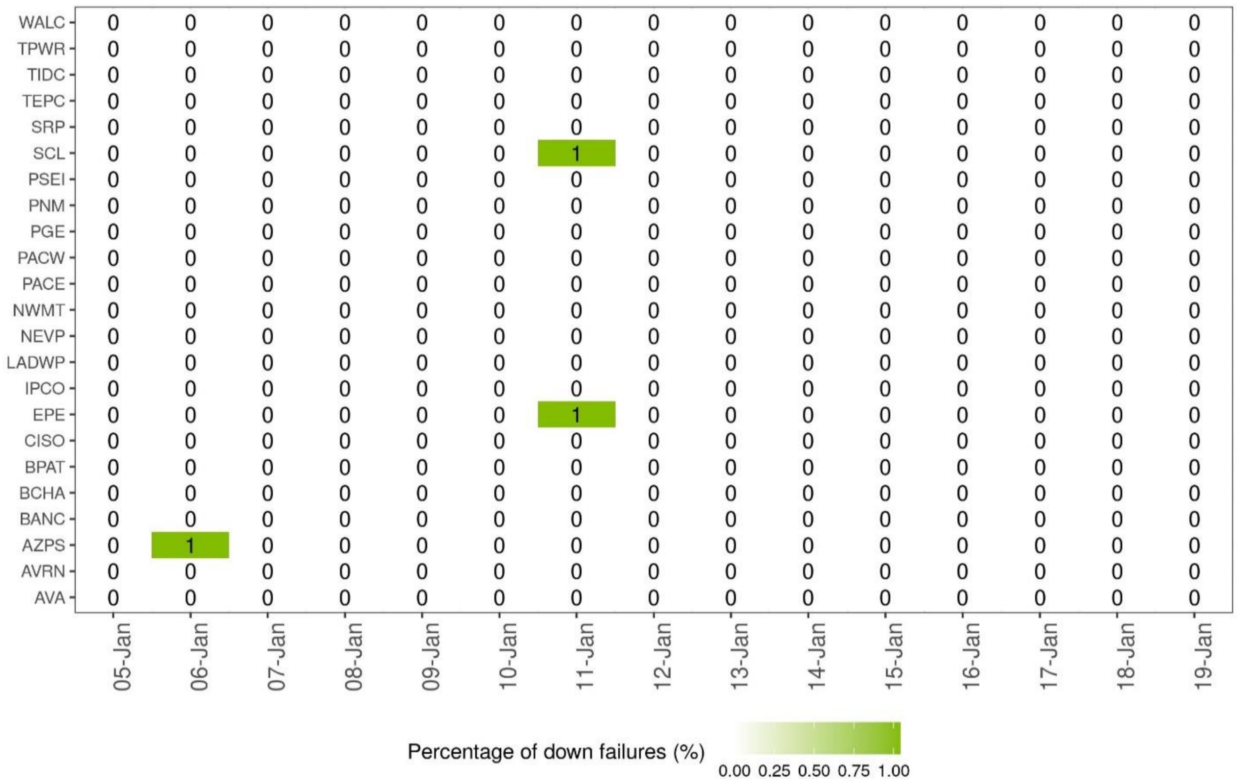


Figure 78: Percentage of flexible ramping up failures per BAA

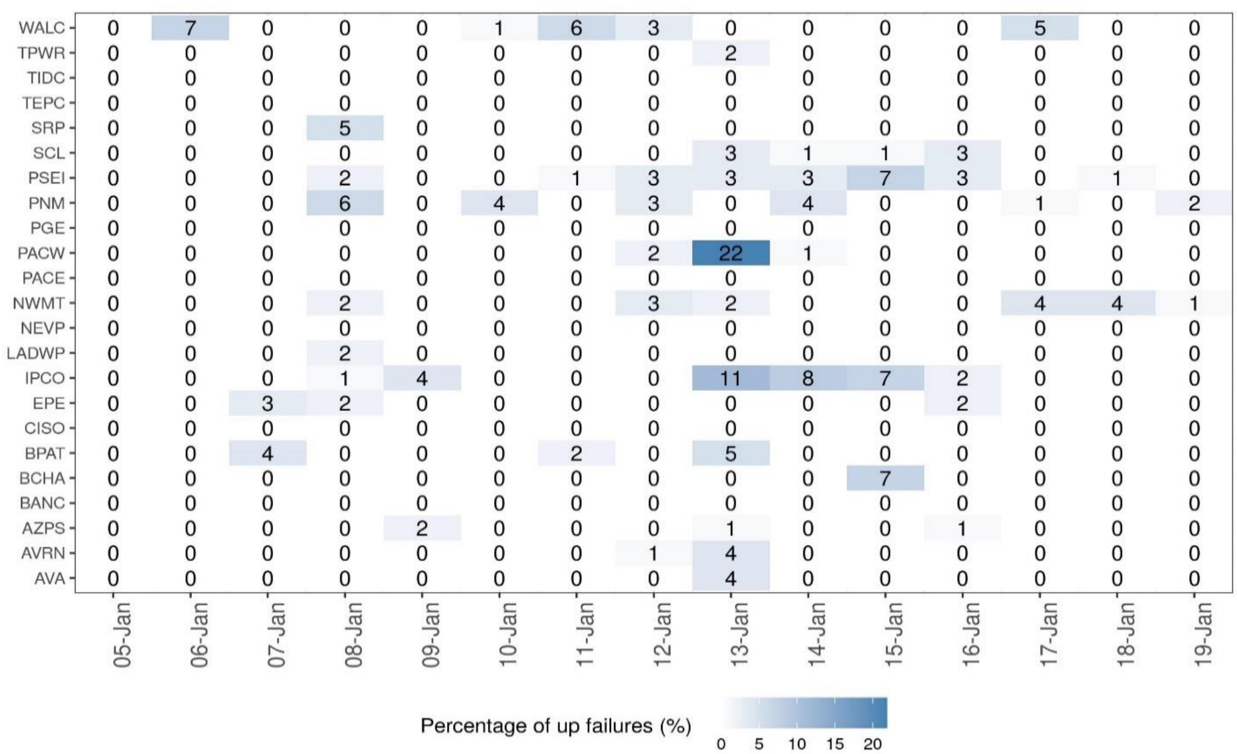


Figure 79: Percentage of flexible ramping down failures per BAA

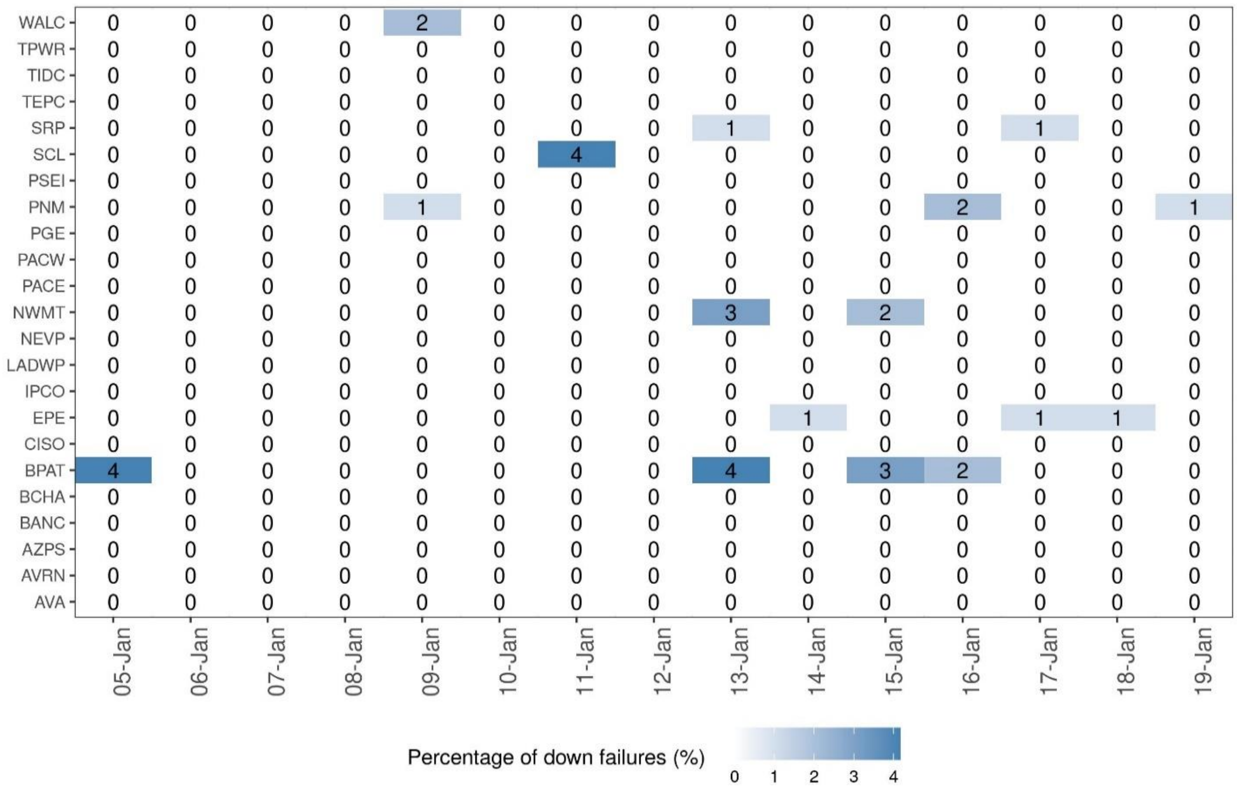


Figure 80: Day-ahead demand forecast for WEIM Footprint