2021 Annual Report on Market Issues and Performance

July 29, 2022

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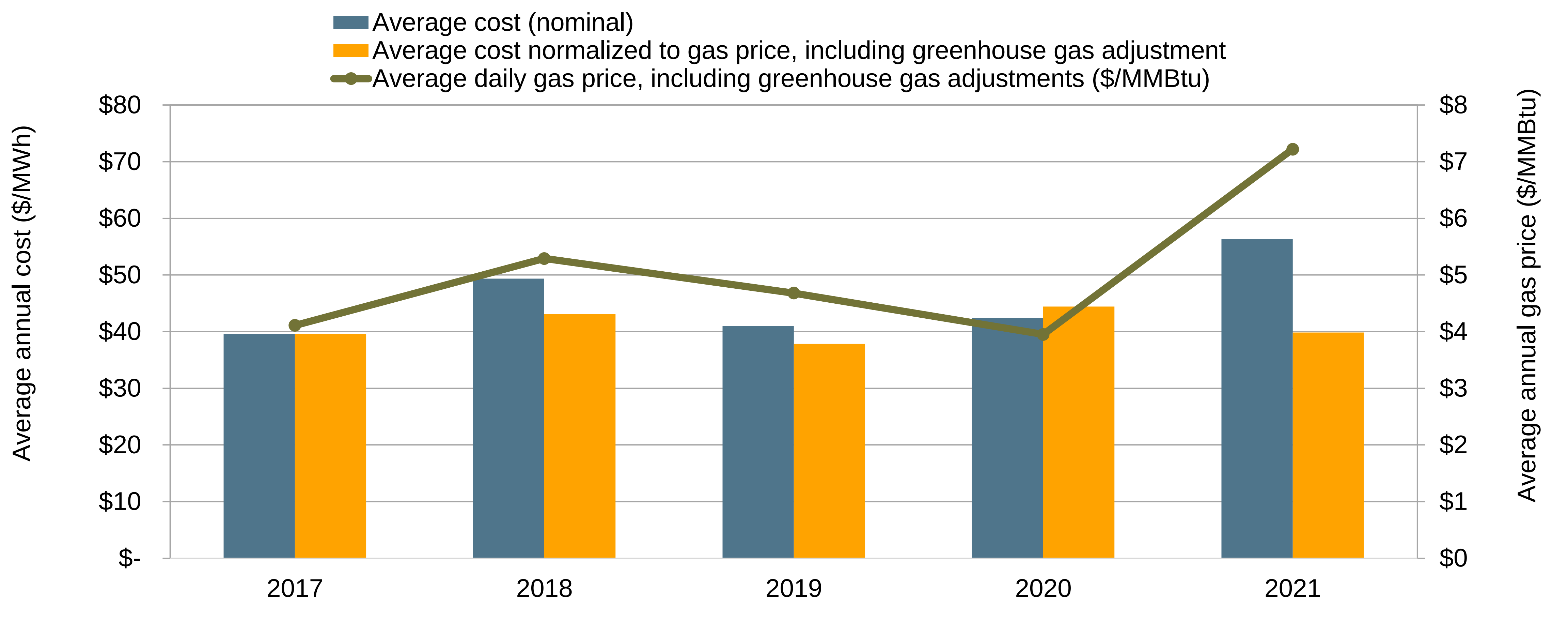
http://www.caiso.com/Documents/2021-Annual-Report-on-Market-Issues-Performance.pdf
http://www.caiso.com/market/Pages/MarketMonitoring/Default.aspx

Total CAISO wholesale costs rose by 33%, but fell 10% after accounting for higher gas and greenhouse gas costs

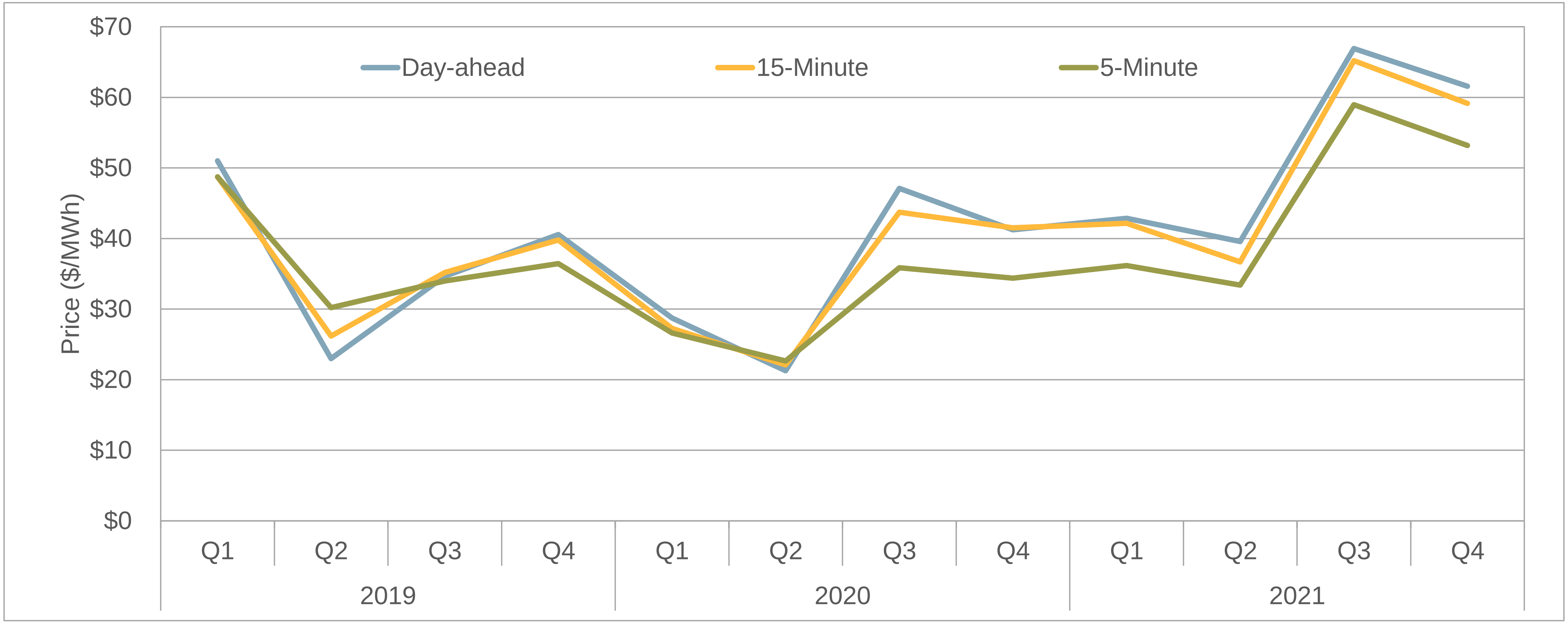


Total CAISO wholesale costs totaled $12.6 billion, $56/MWh

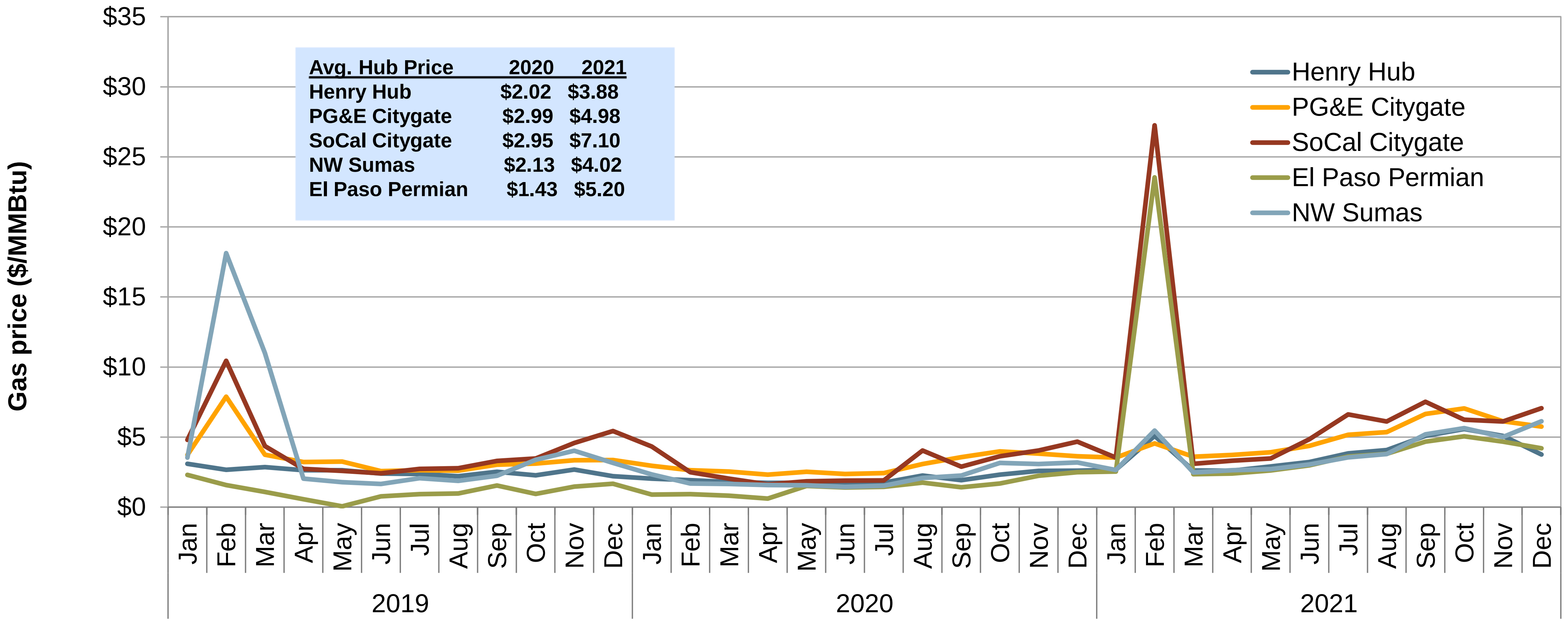
	2017	2018	2019	2020	2021	Change '20-'21
Day-ahead energy costs	$ 37.40	$ 46.05	$ 38.13	$ 38.61	$ 53.02	$ 14.41
Real-time energy costs (incl. flex ramp)	$ 0.73	$ 0.59	$ 1.02	$ 1.65	$ 1.19	$ (0.46)
Grid management charge	$ 0.44	$ 0.46	$ 0.46	$ 0.46	$ 0.43	$ (0.04)
Bid cost recovery costs	$ 0.41	$ 0.68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

Day-ahead prices slightly higher than 15-minute market, 5-minute prices lower

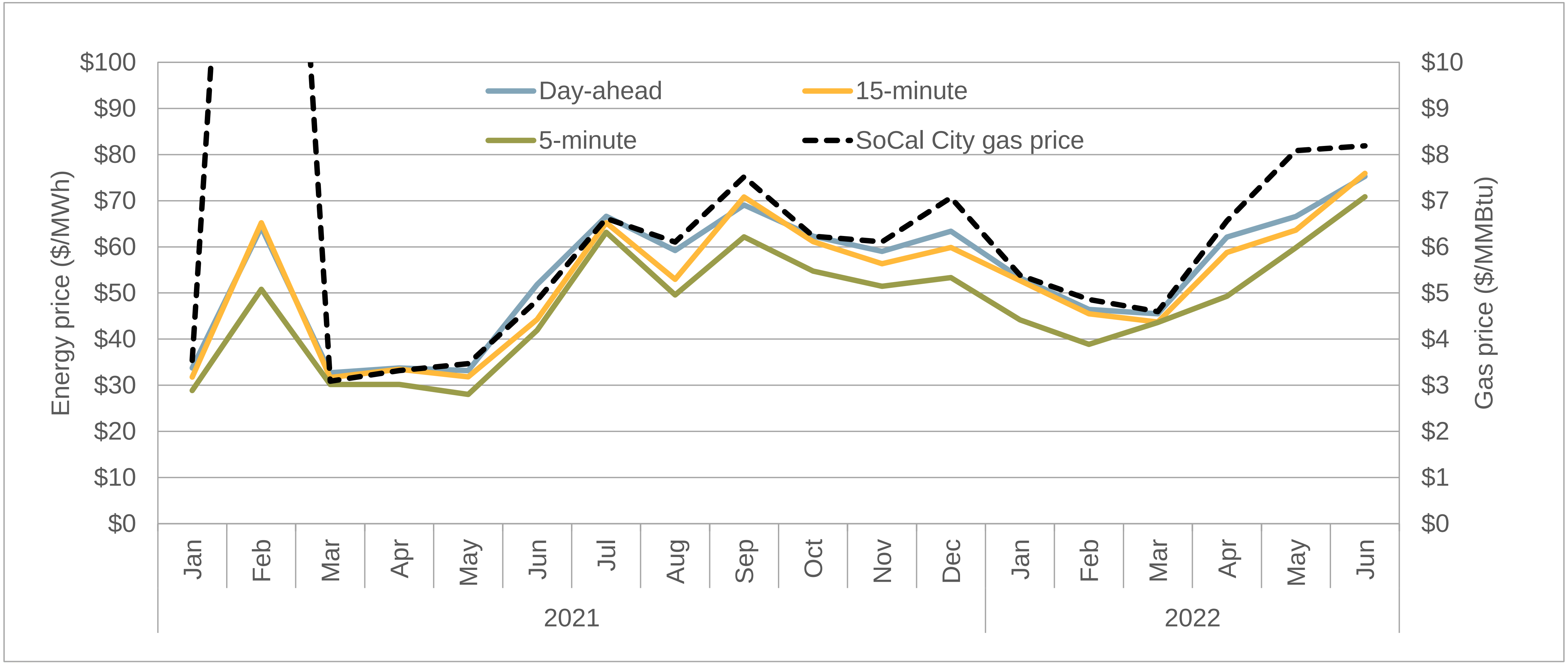
CAISO day-ahead $53/MWh, 15-minute $51/MWh, 5-minute $45/MWh



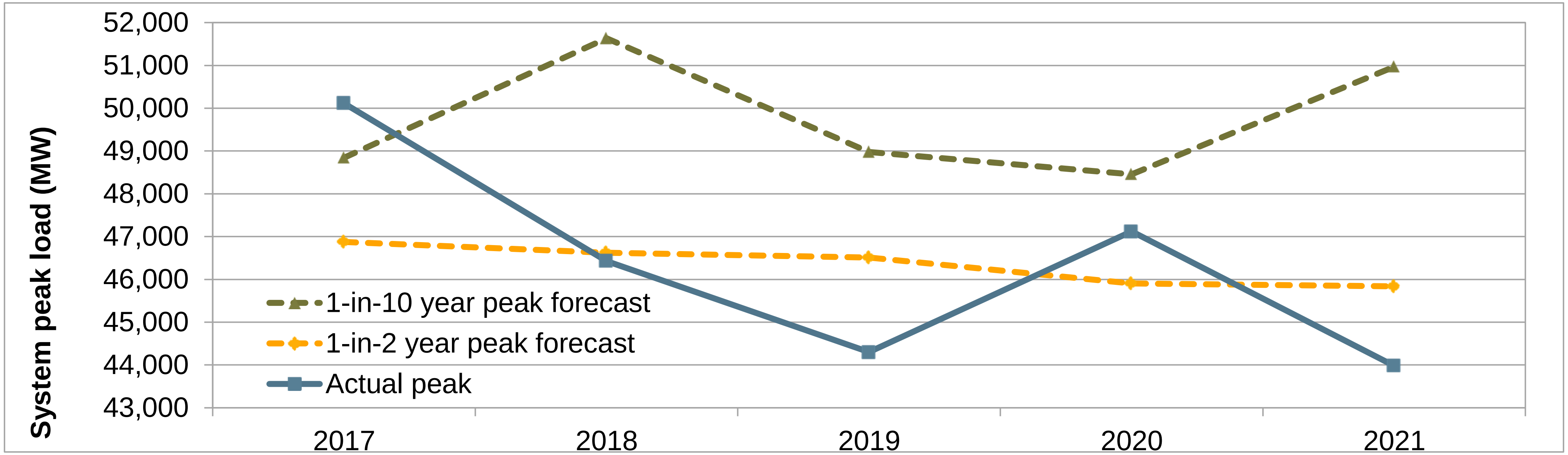
Day-ahead prices are often driven by gas prices
Higher natural gas prices support higher electricity prices



As gas prices have continued to rise in 2022, so have electricity prices



Lower CAISO peak loads and lower overall energy loads

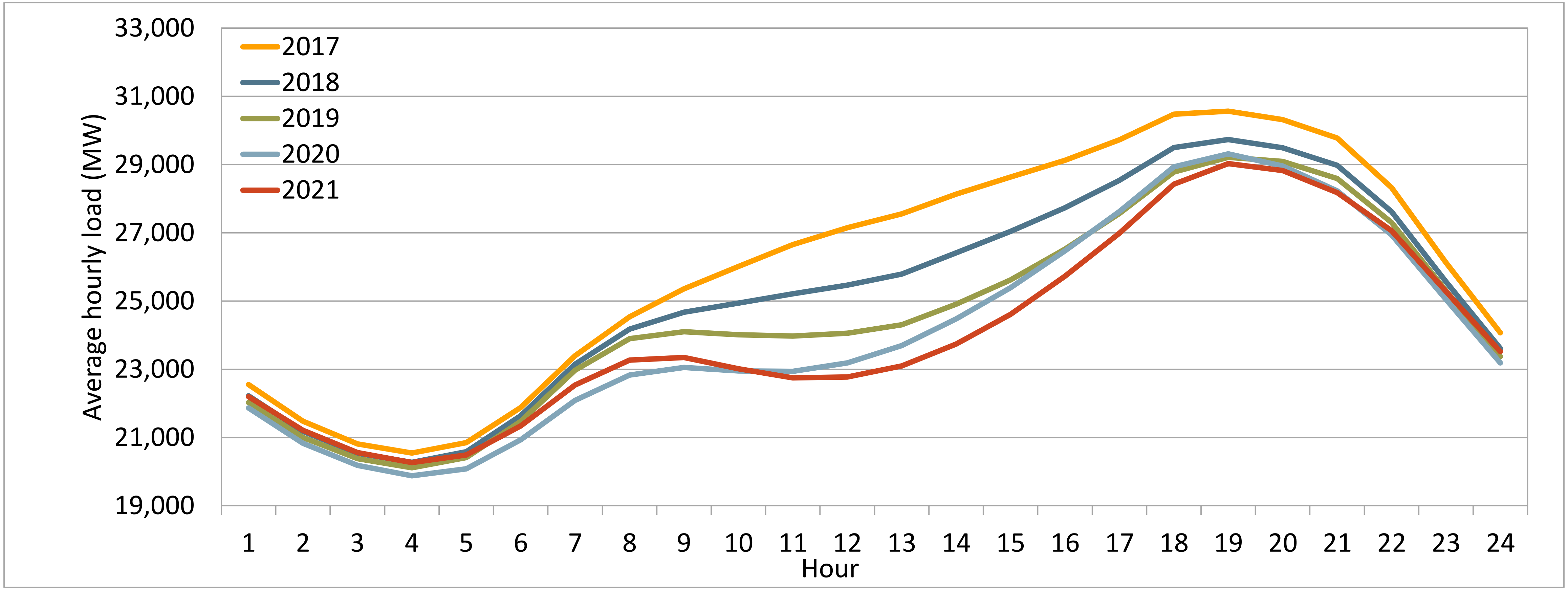


Year	Annual total energy (GWh)	Average load (MW)	% change	Annual peak load (MW)	% change
2017	227,749	26,002	0.0%	50,116	8.4%
2018	220,458	25,169	-3.2%	46,427	-7.4%
2019	214,955	24,541	-2.5%	44,301	-4.6%
2020	211,919	24,128	-1.7%	47,121	6.4%
2021	211,020	24,092	-0.1%	43,982	-6.7%

https://www.caiso.com/documents/californiaisopeakloadhistory.pdf

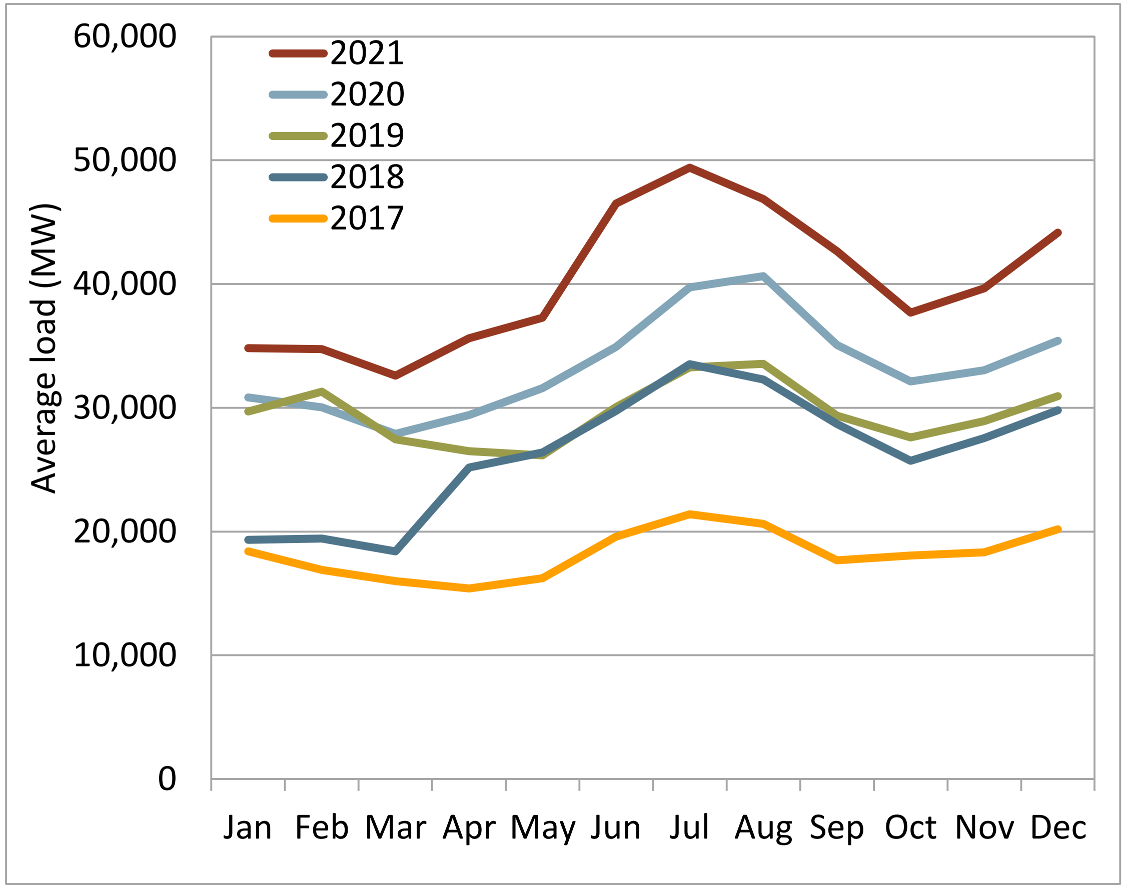
Higher CAISO behind-the-meter solar generation, COVID-19 related load changes, and energy efficiency initiatives all contributed to lower CAISO system load, despite relatively high Q3 temperatures

Average hourly load (2017-2021)



Western Energy Imbalance Market expands, improving structure and performance of the real-time market

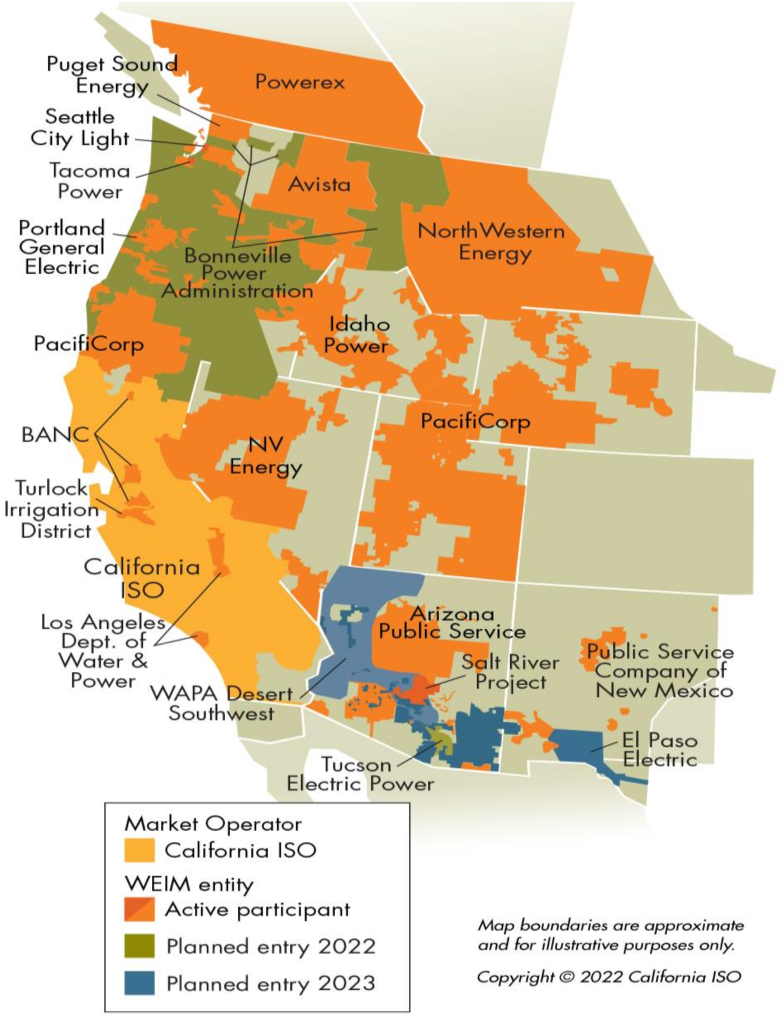
Non-CAISO WEIM load



2021 Peak load measures

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

Expansion of the Western Energy Imbalance Market (WEIM) helped improve the overall structure and performance of the real-time market



- Two new members of the WEIM in 2020
- Five new members of the WEIM in 2021

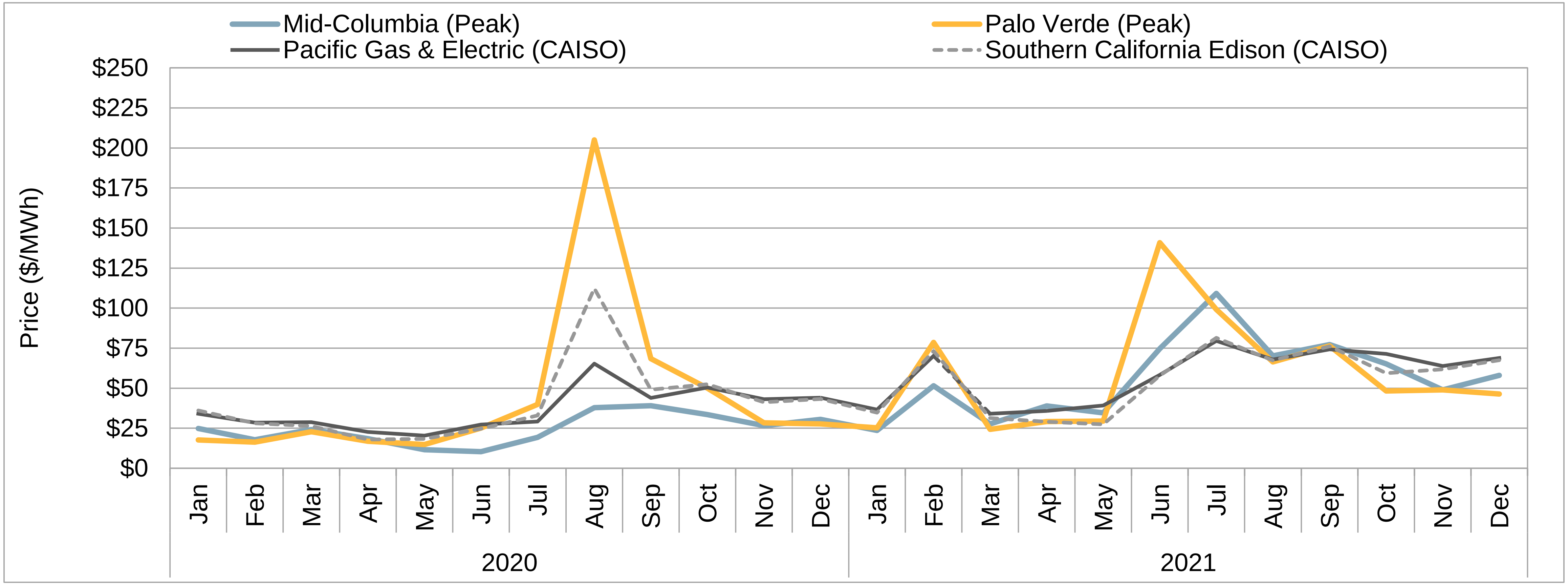
- The WEIM, including the CAISO, now accounts for over half of WECC peak load

- Northwest prices regularly lower than the rest of the system due to limited transfer capability

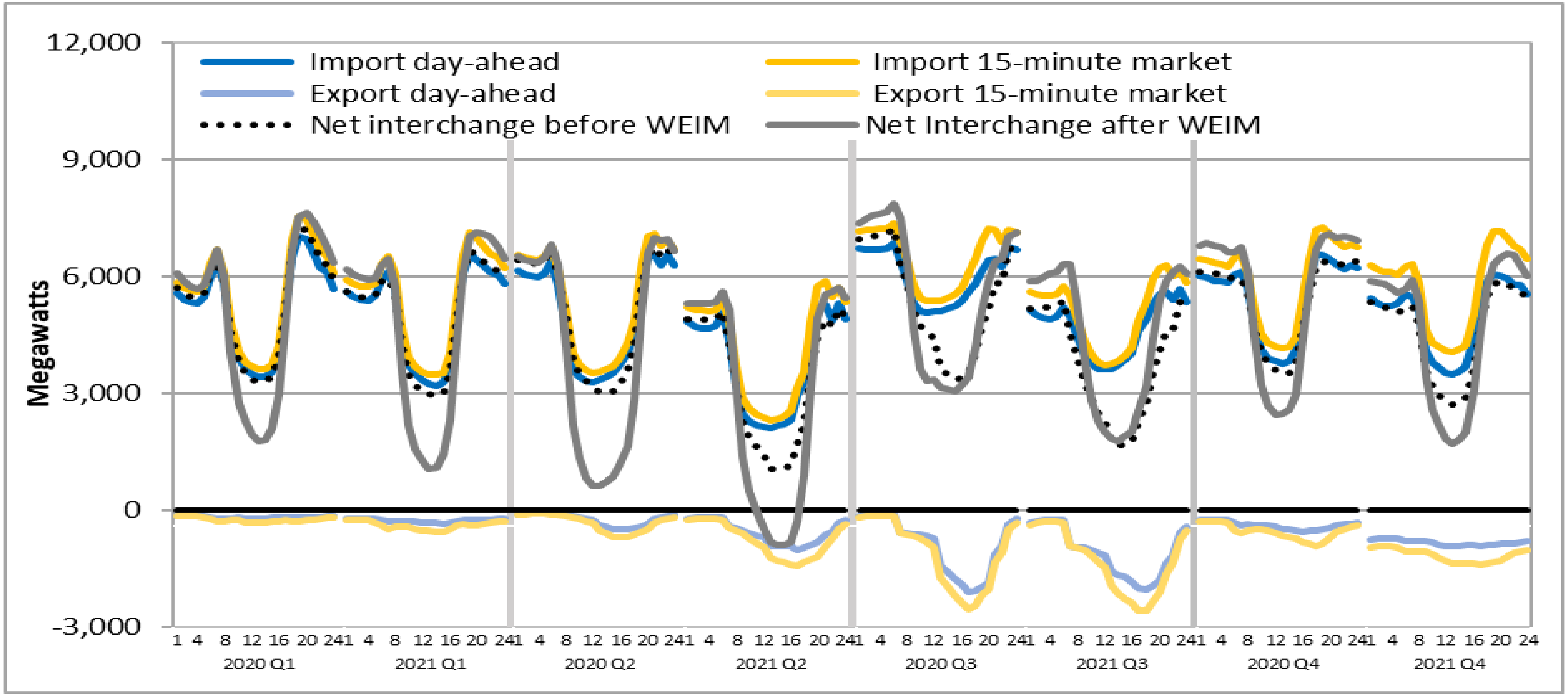
- Peak California area prices exceed other areas due to GHG and congestion

High prices in June and July driven by high regional demand and fire impacting transmission from the Northwest into the CAISO

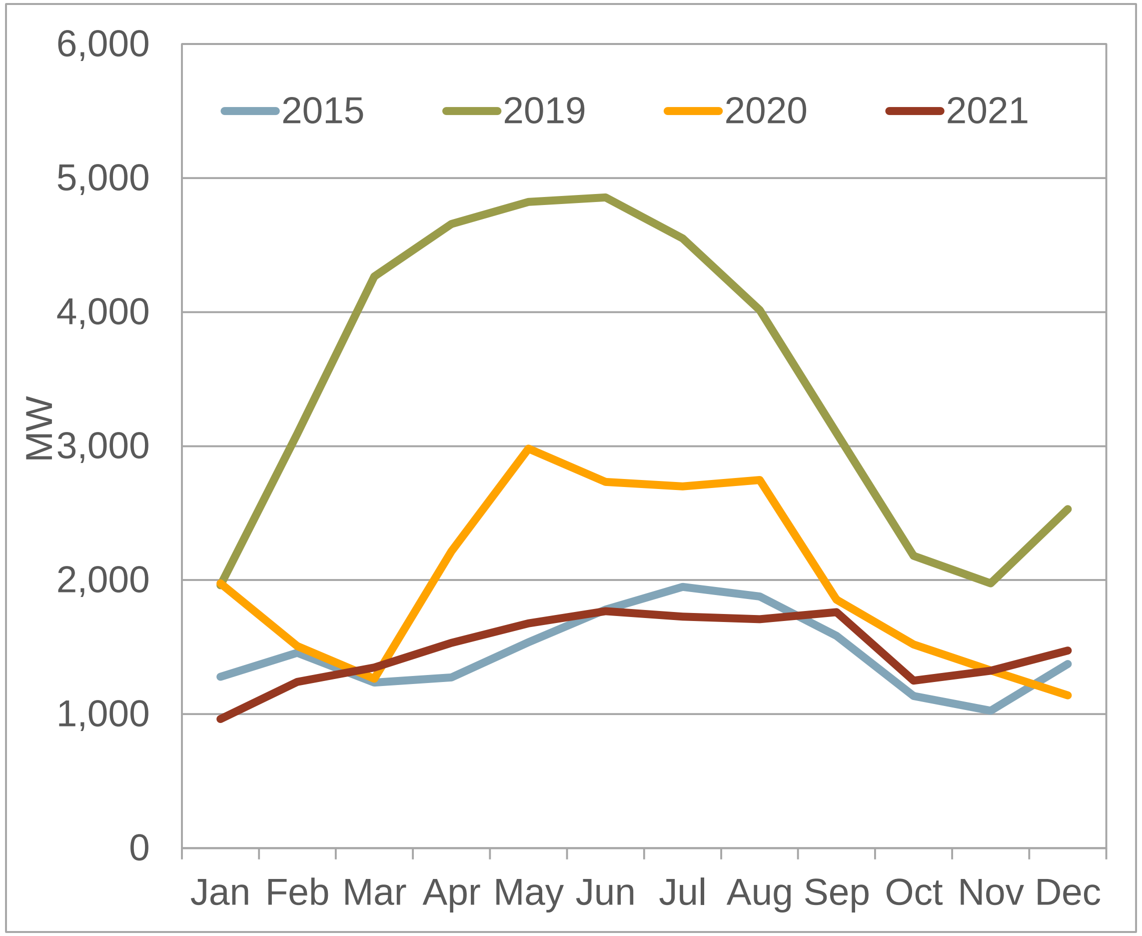
Monthly average day-ahead and bilateral market prices

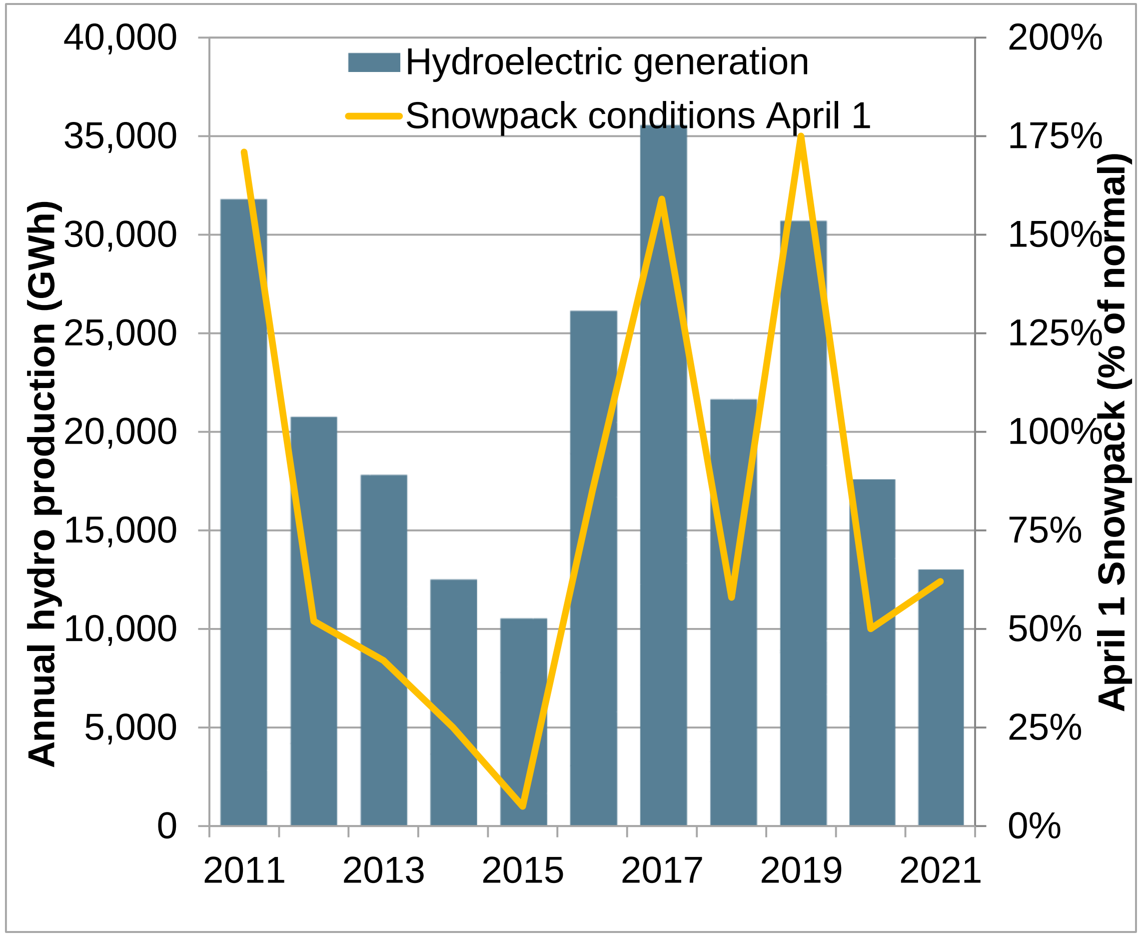


Net imports fell in each quarter, from both Southwest and Northwest

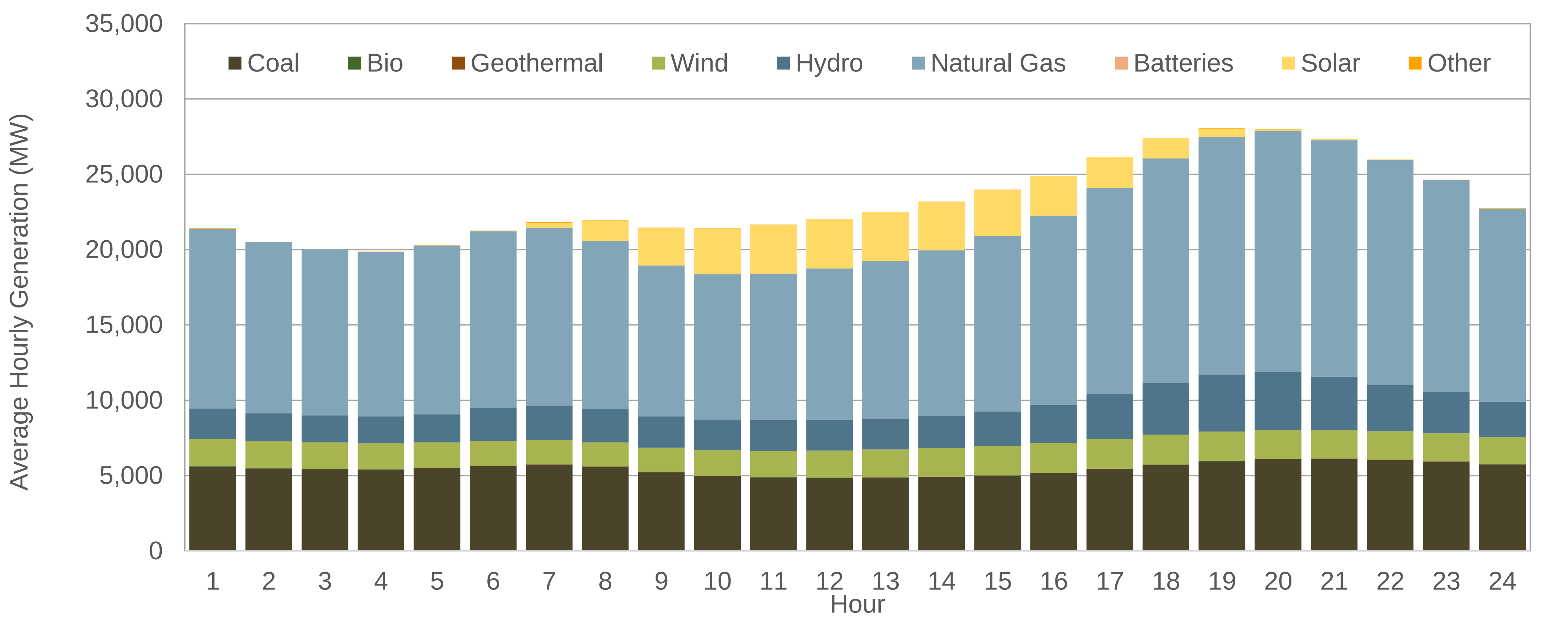


Hydroelectric generation fell 26% from 2020 in the CAISO, with continued drought across California and the Southwest

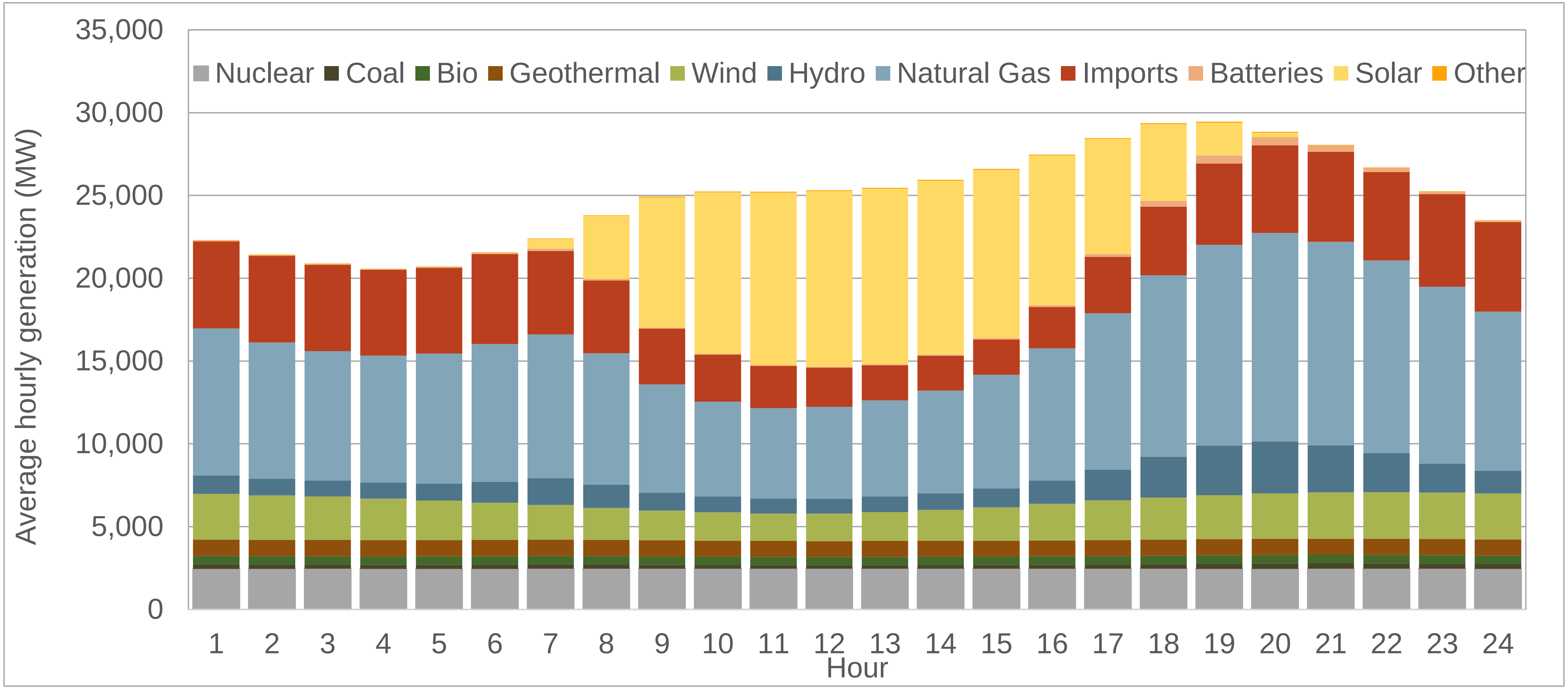




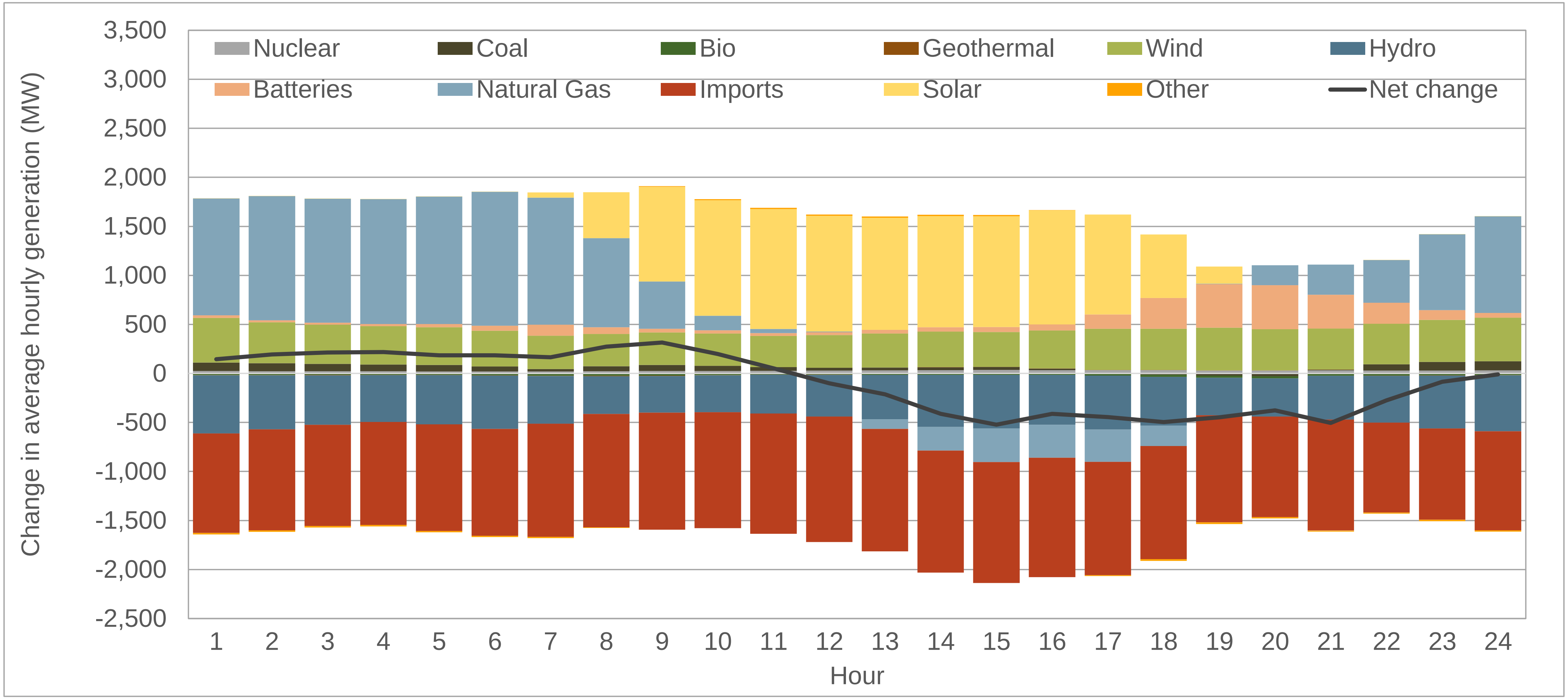
Average hourly participating non-CAISO WEIM generation by fuel type (2021)



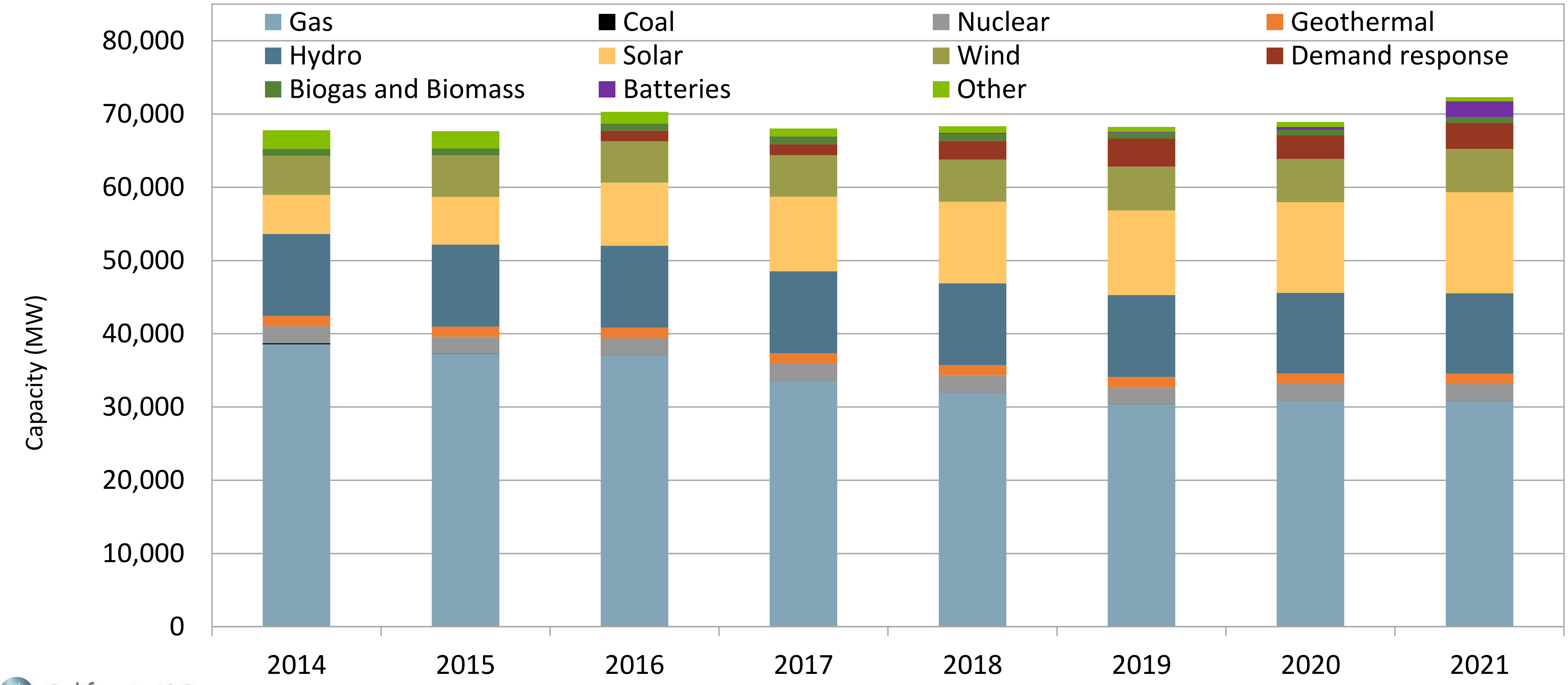
Average hourly generation by fuel type (2021)



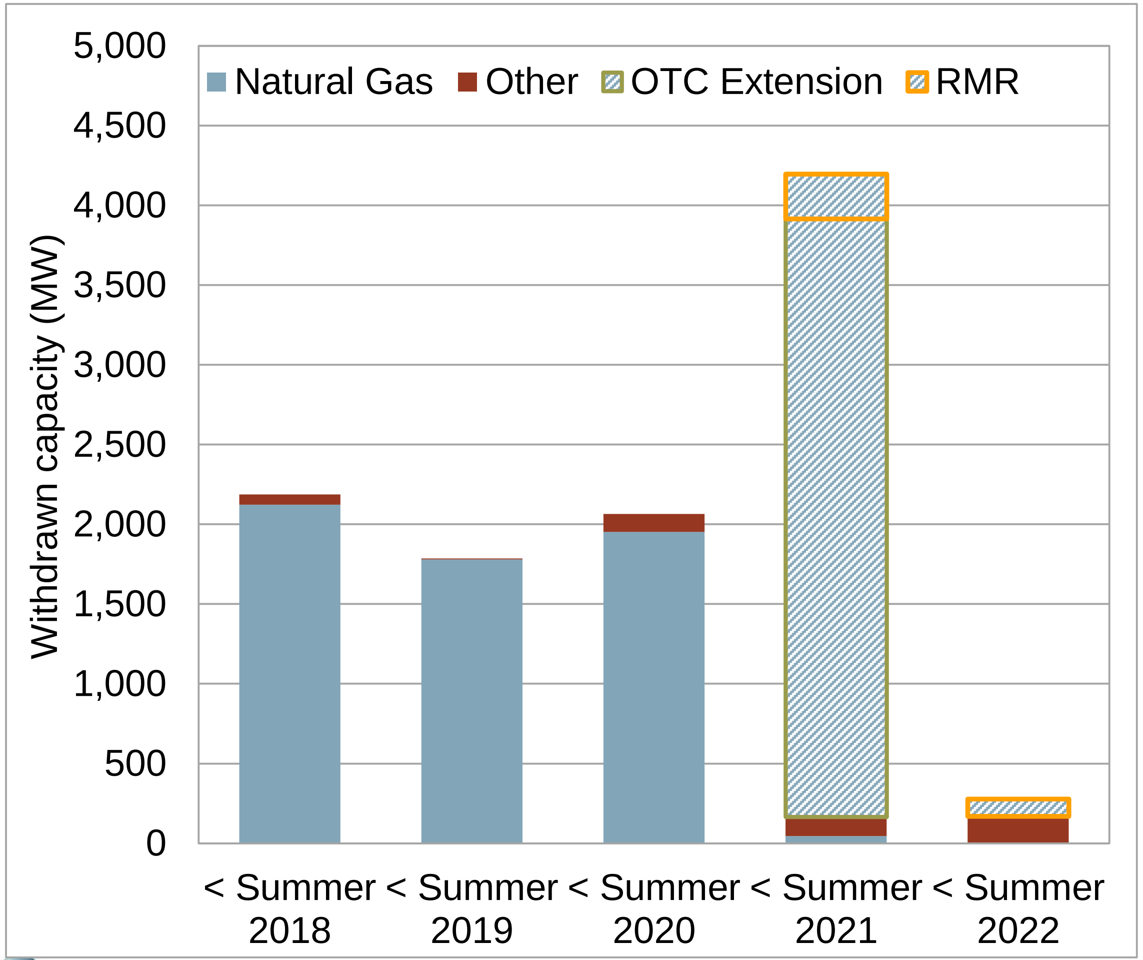
Change in average hourly generation by fuel type (2020 to 2021)



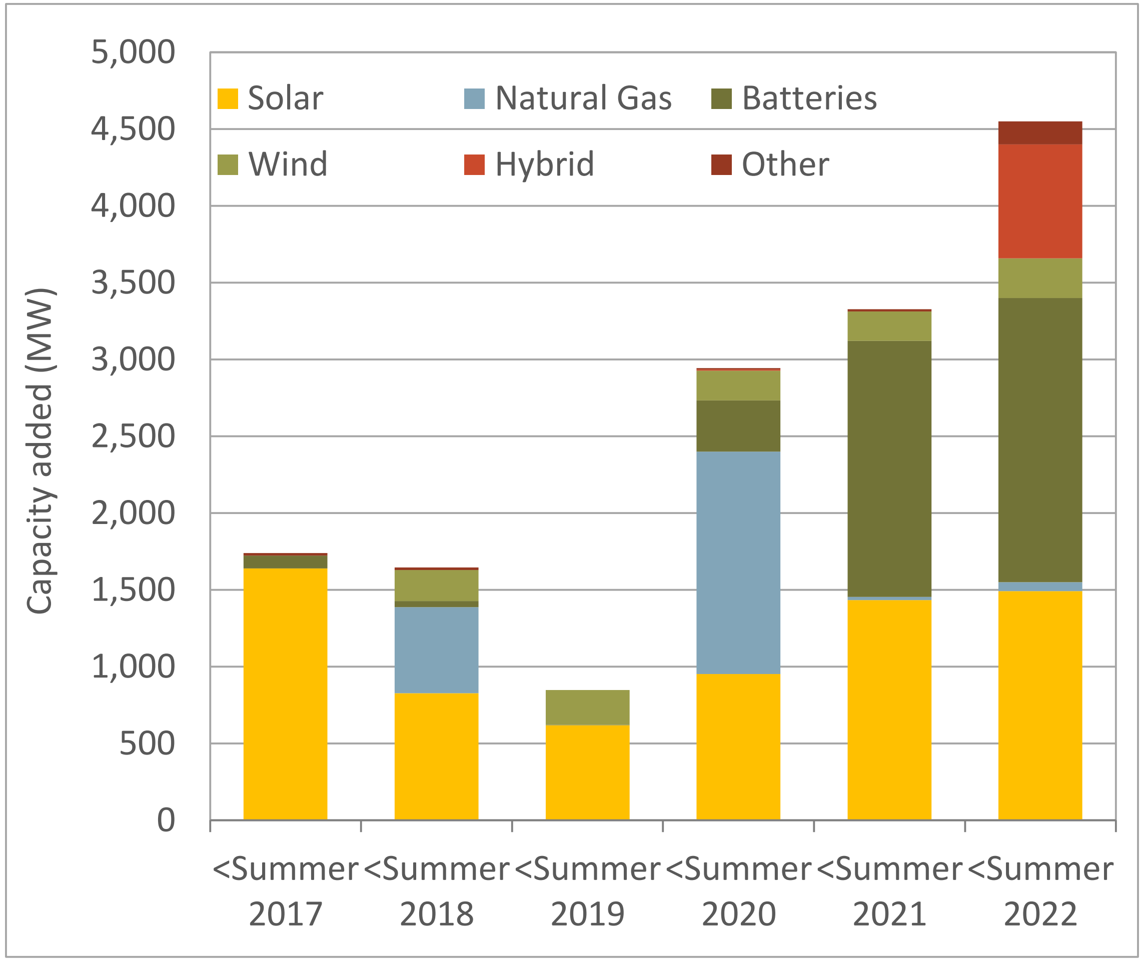
Gas capacity retiring is being largely replaced with renewables (mainly solar), demand response and storage



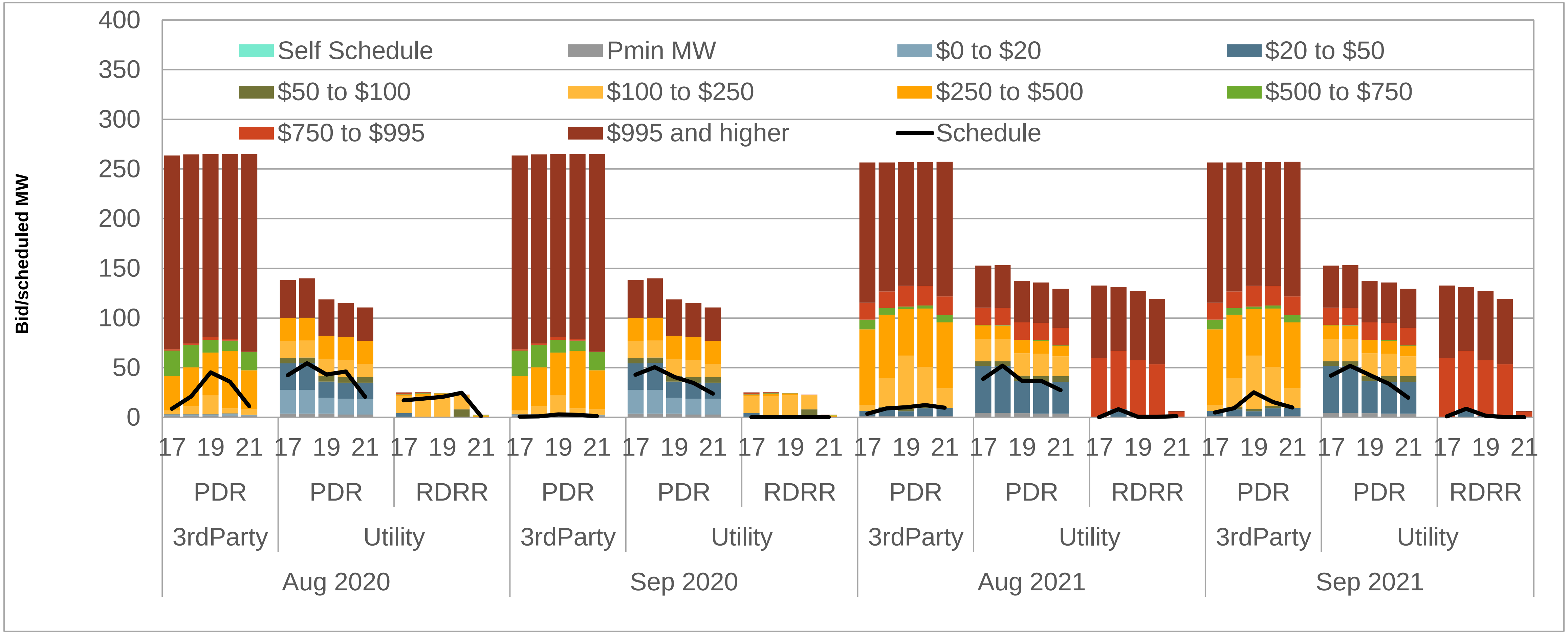
Withdrawals from CAISO market participation



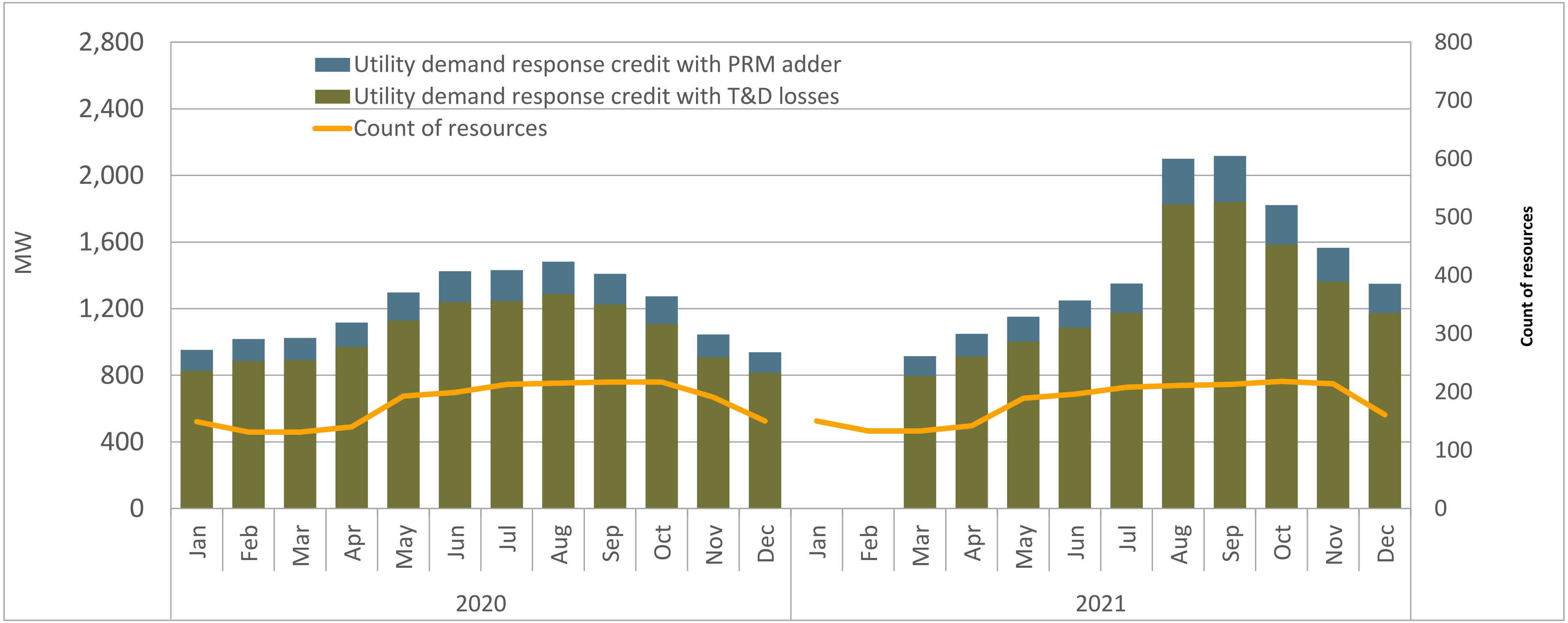
Additions to CAISO market



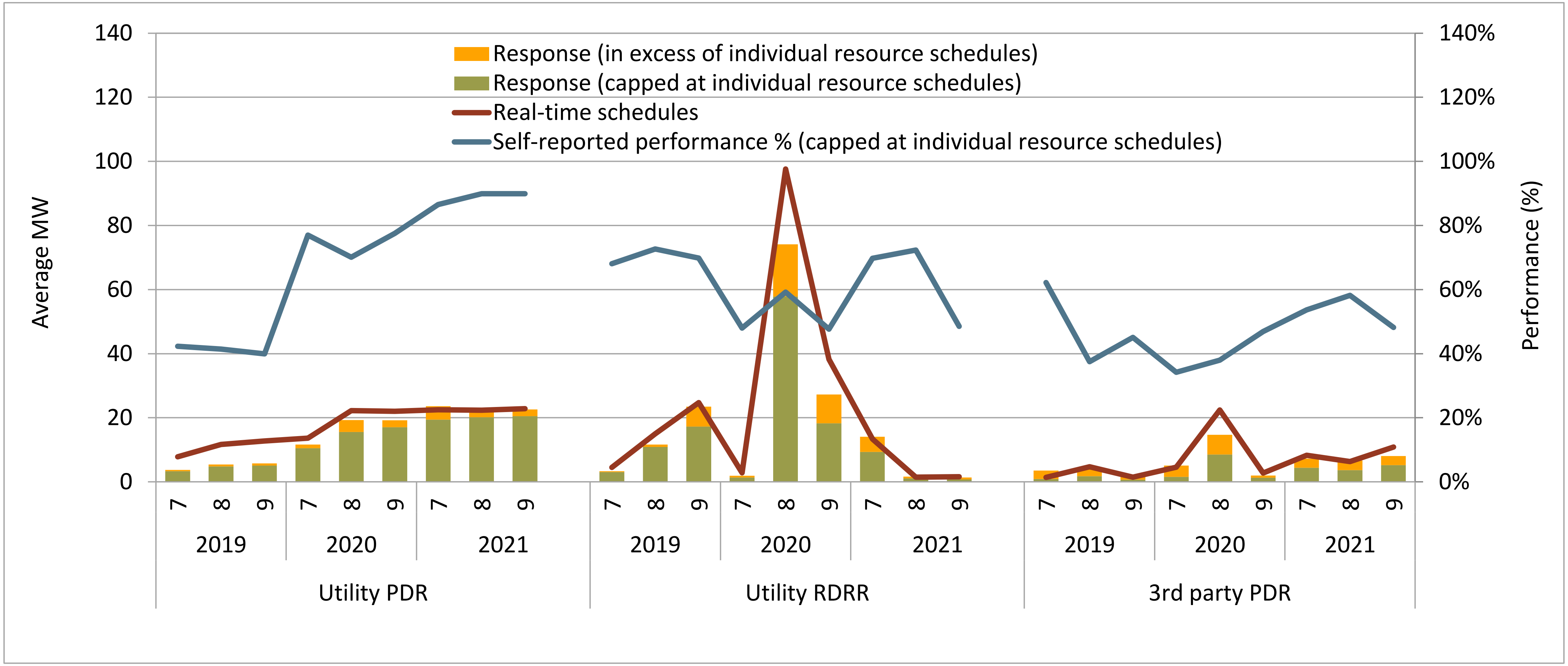
Demand response resource adequacy day-ahead bids August- September



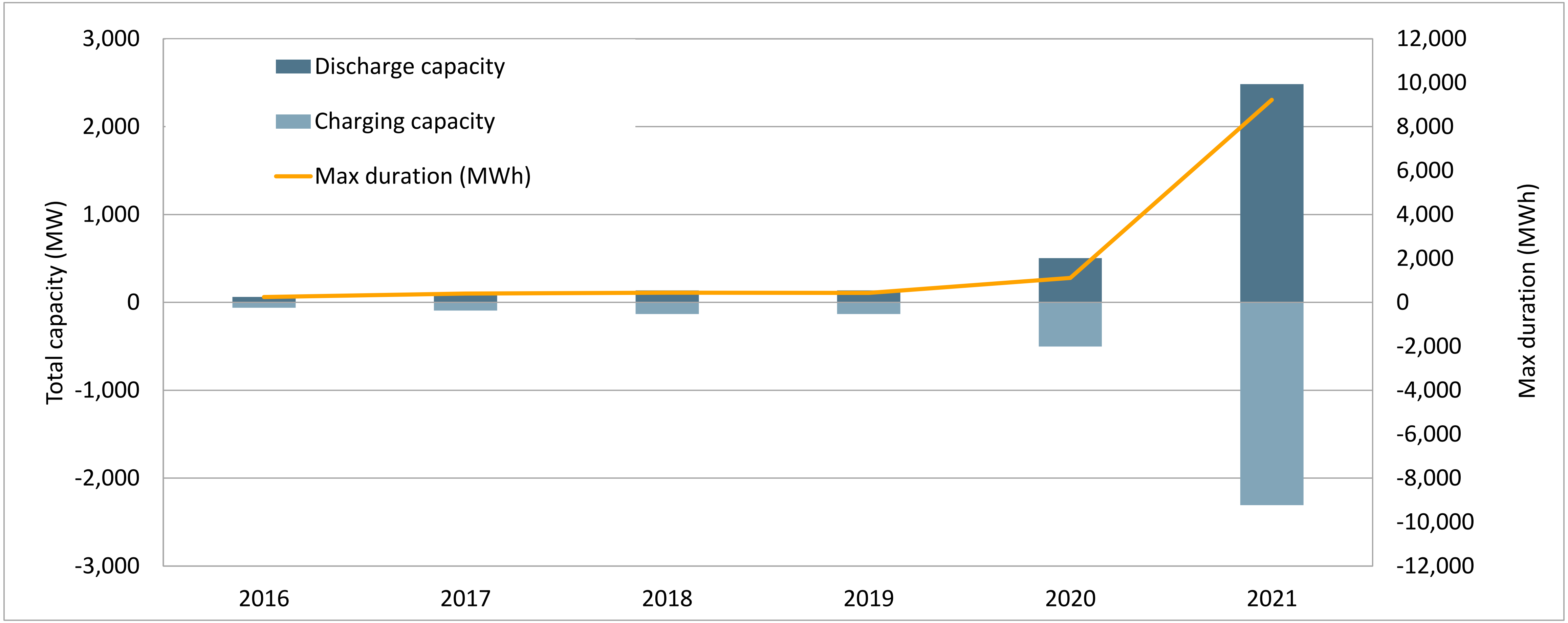
CPUC-jurisdictional utility demand response resource adequacy credits



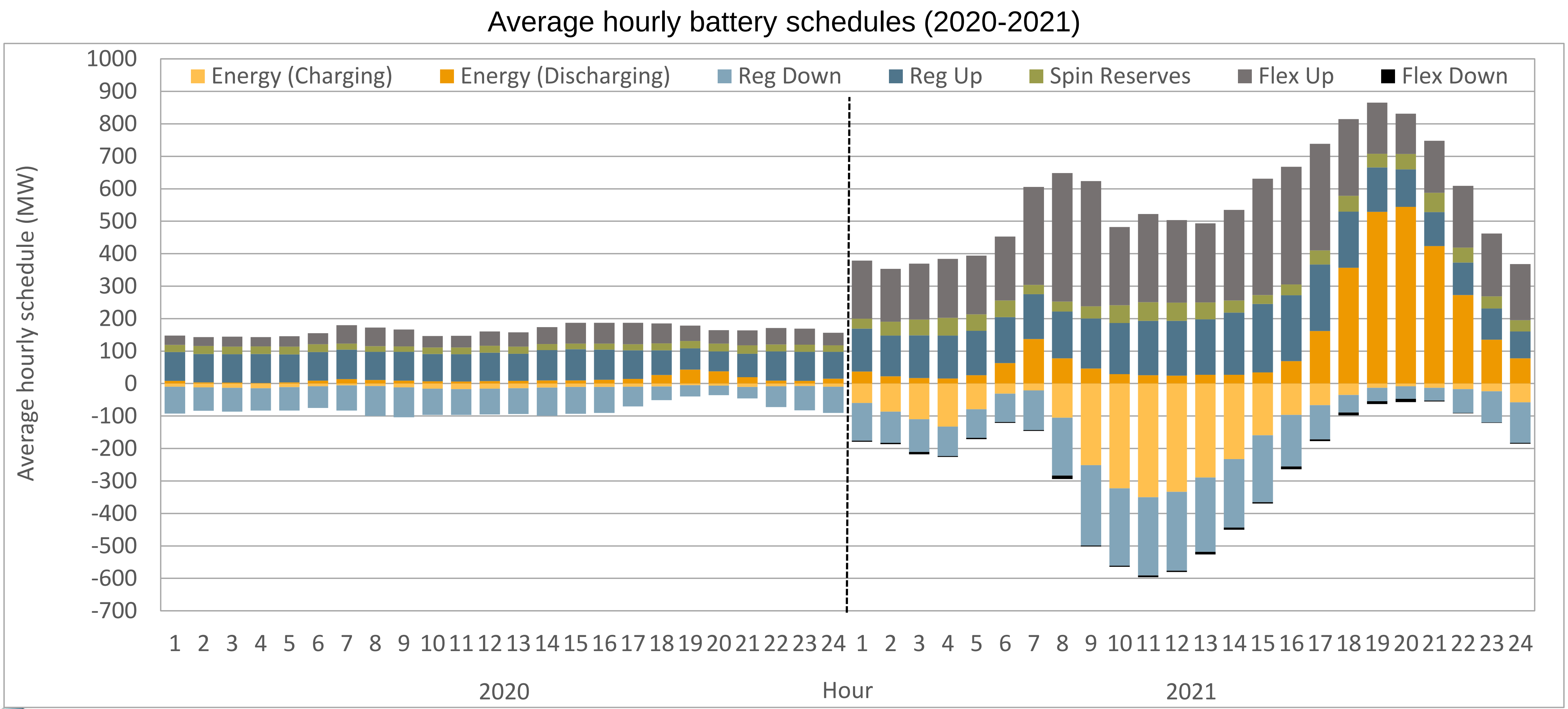
Demand response resource adequacy performance, July-Sept 4-9 p.m.



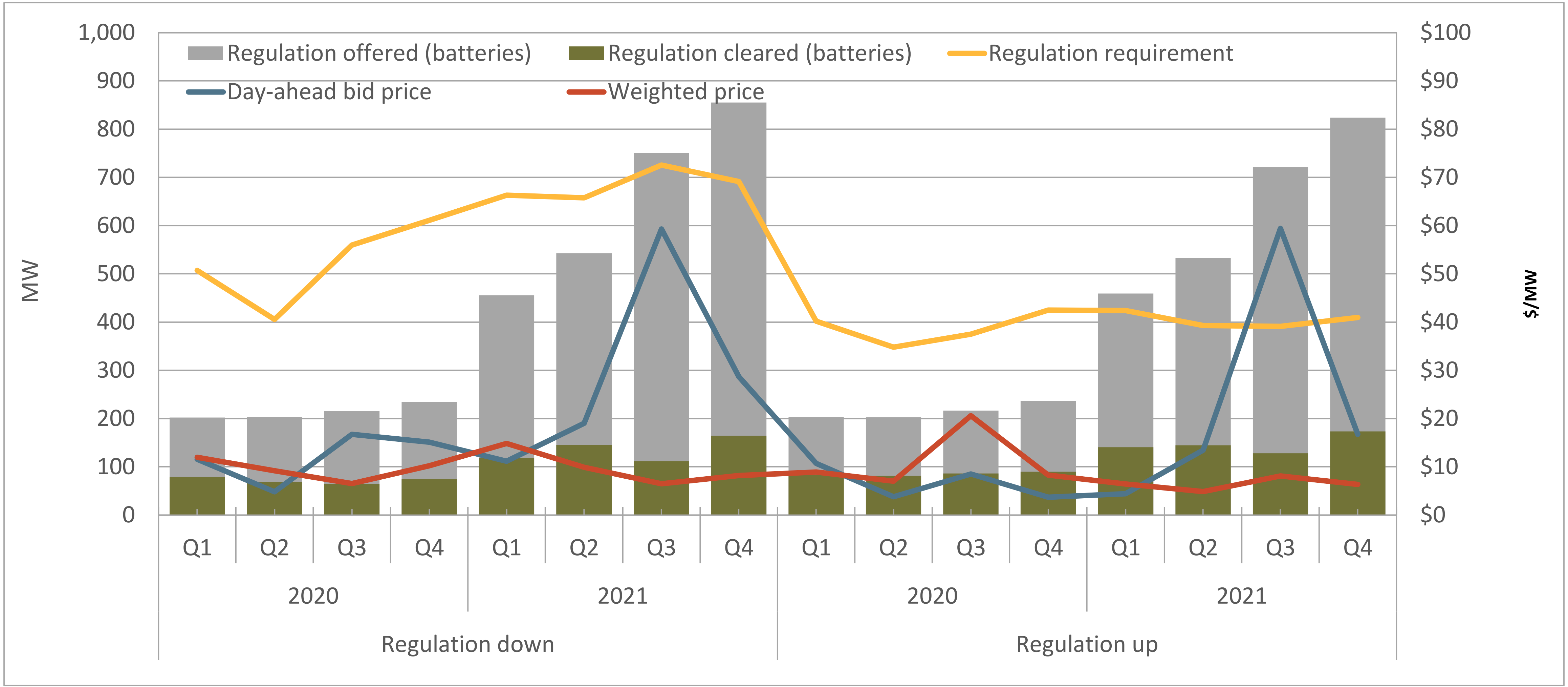
Battery capacity grew dramatically in 2020 and continues in 2021



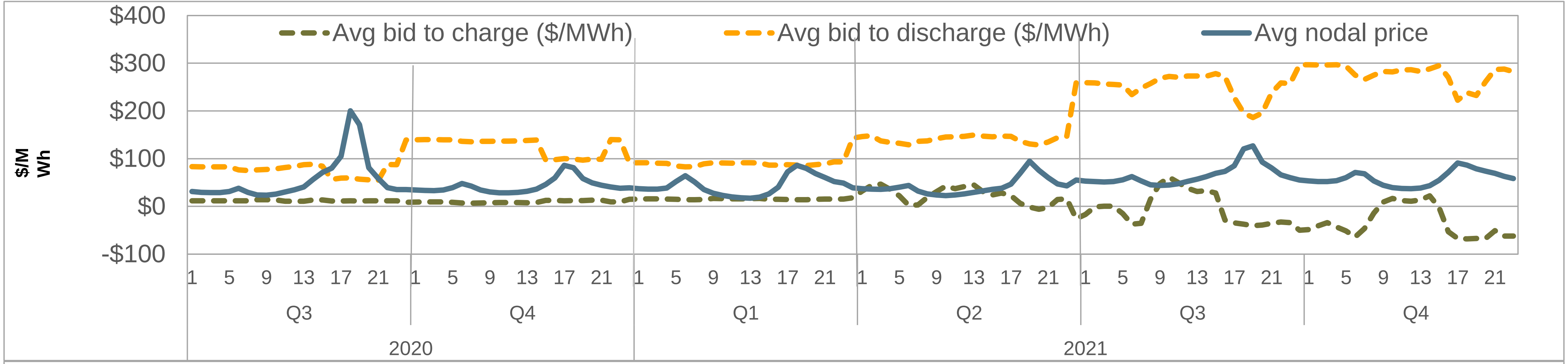
As battery fleet grows, increasingly scheduled for energy and flexible ramping product

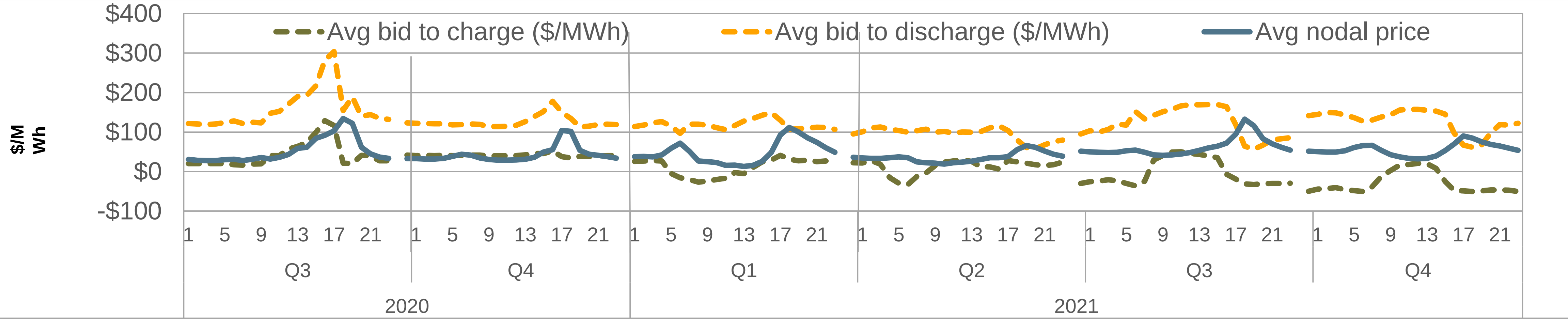


Day-ahead regulation requirements met by battery storage



Average hourly battery bids and nodal prices, day-ahead (top) and real-time (bottom) (Q3 2020 – 2021)

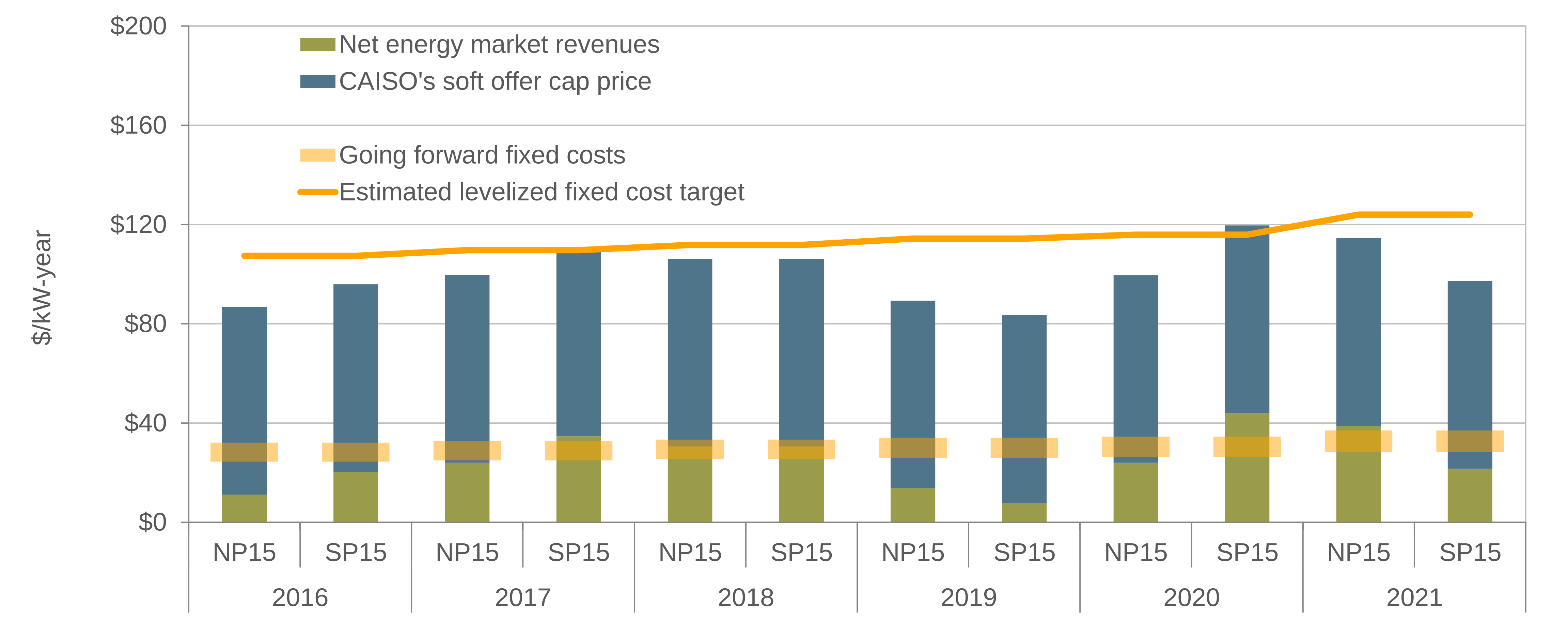




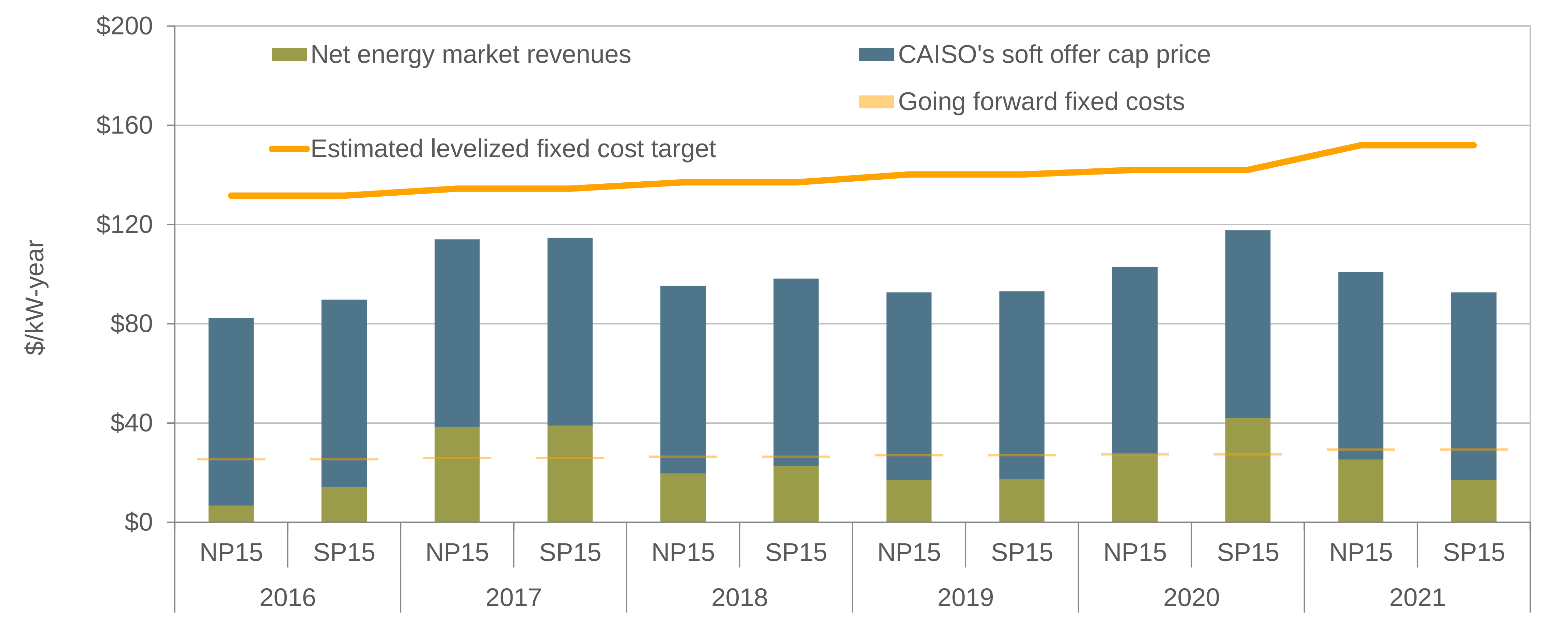
New battery energy storage net market revenues by local capacity area

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

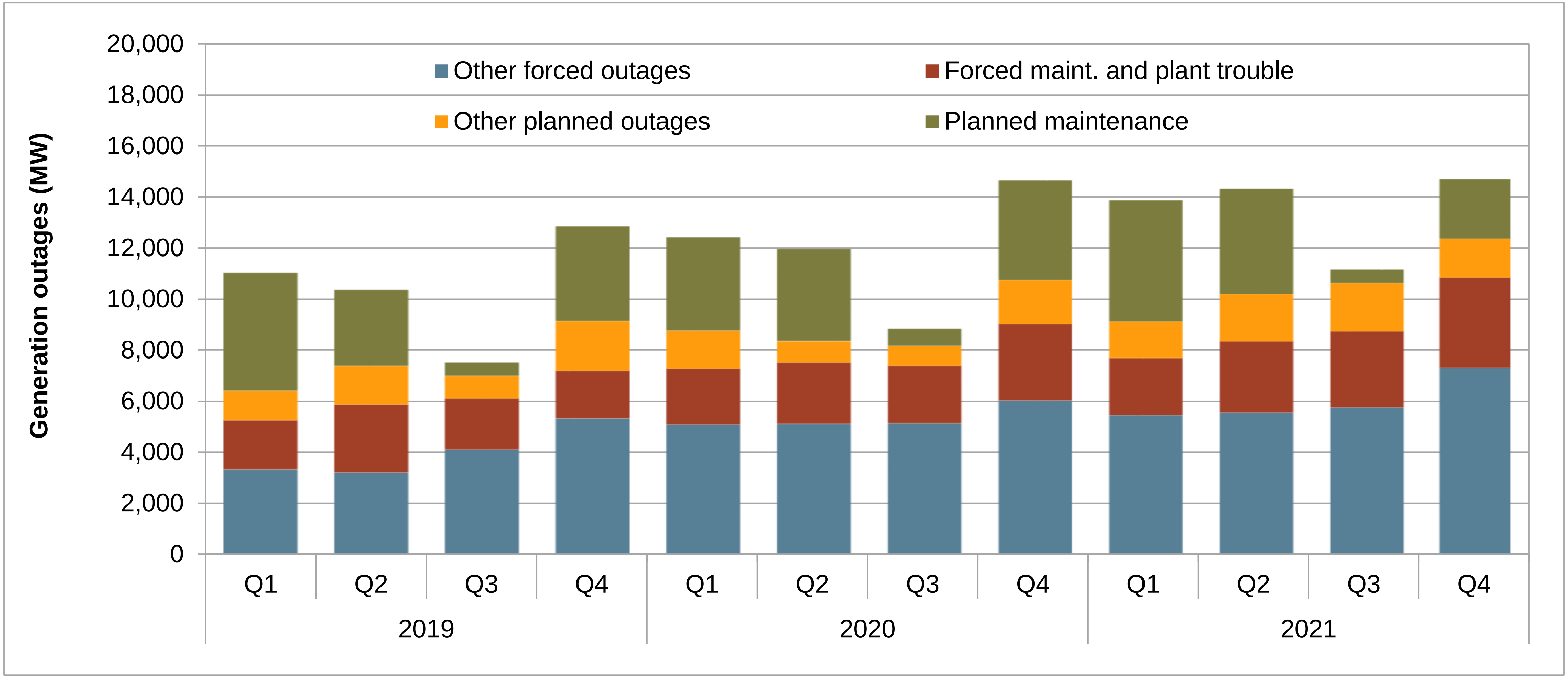
Estimated net revenue of hypothetical combined cycle unit rose to $39/kW-year in NP15 and fell to less than $22/kW-year in SP15



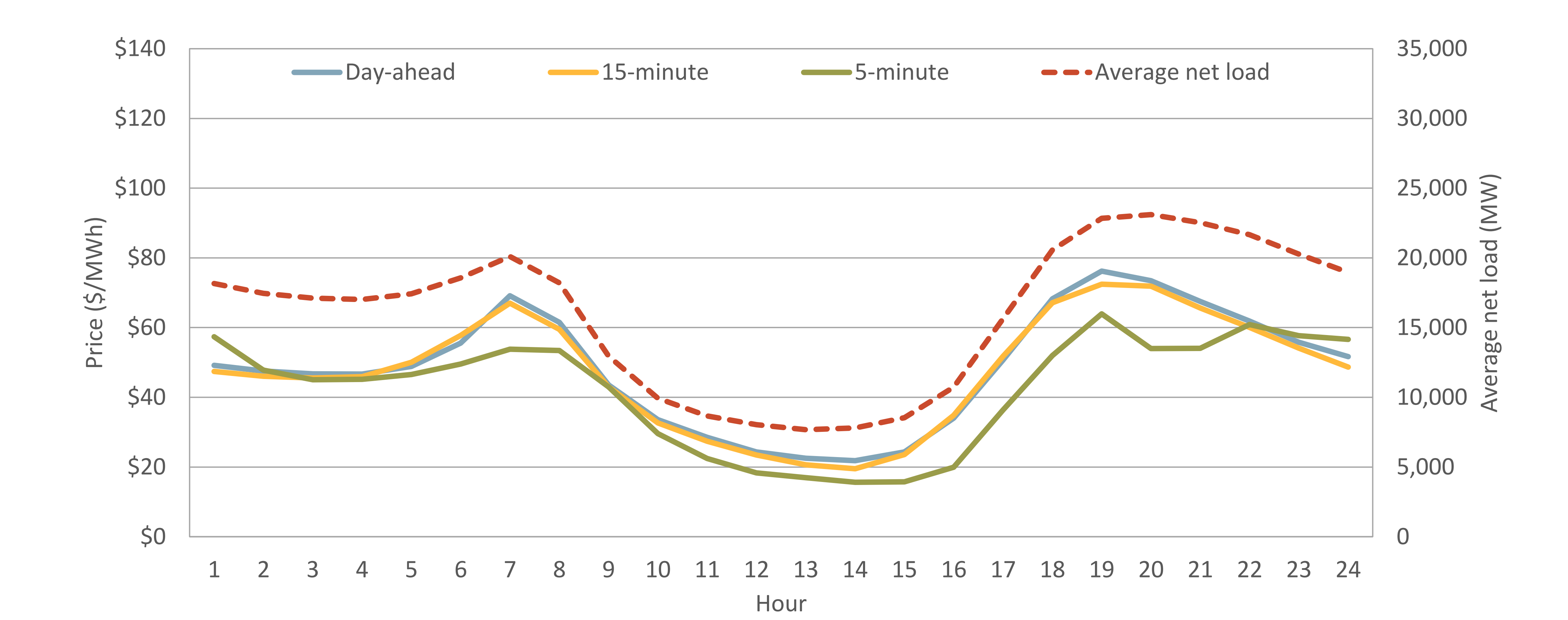
Estimated net revenues of hypothetical combustion turbine fell to $25/kW-year in NP15 and $17/kW-year in SP15



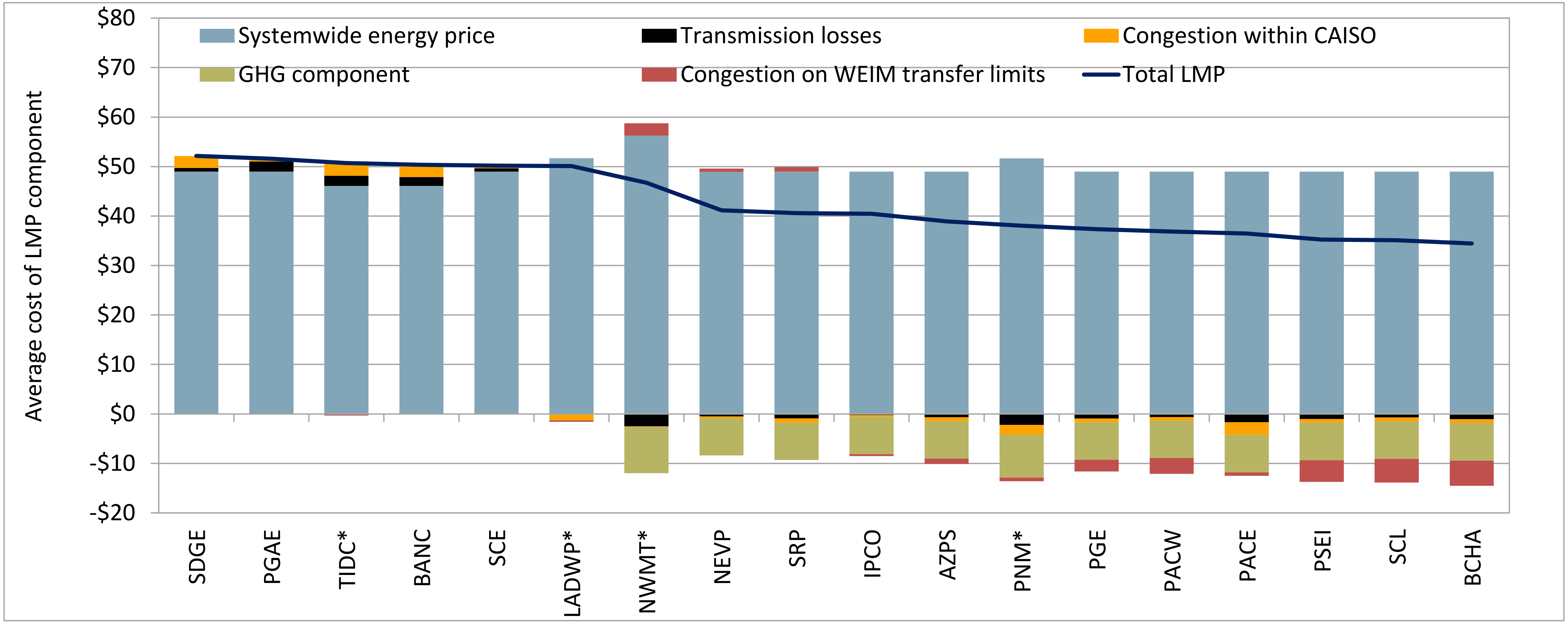
CAISO generation outages increased 13% from 2020, 29% from 2019



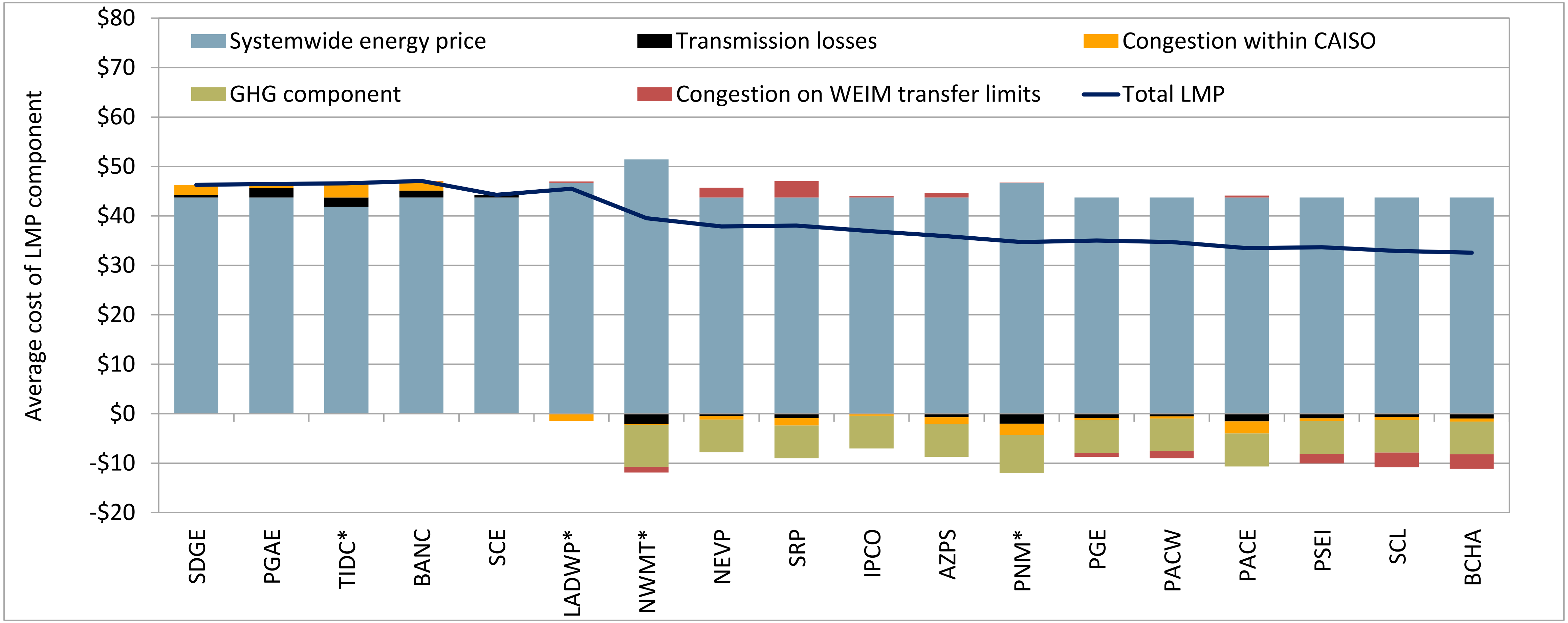
Average hourly prices mirror net load, with day-ahead prices higher than 5-minute real-time in peak hours



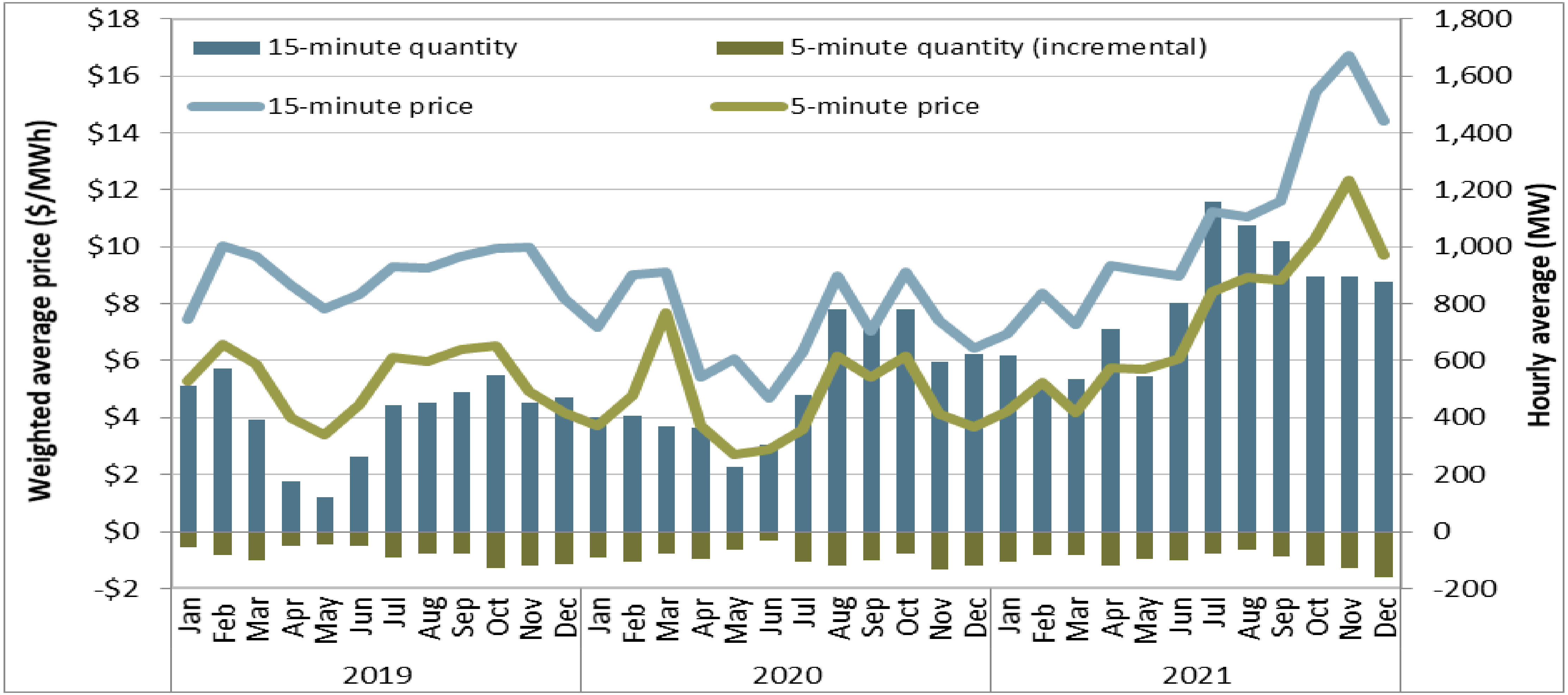
Impact of congestion and greenhouse gas on 15-minute prices (2021)



Impact of congestion and greenhouse gas on 5-minute prices (2021)



Western Energy Imbalance Market greenhouse gas price, cleared quantity and fuel type



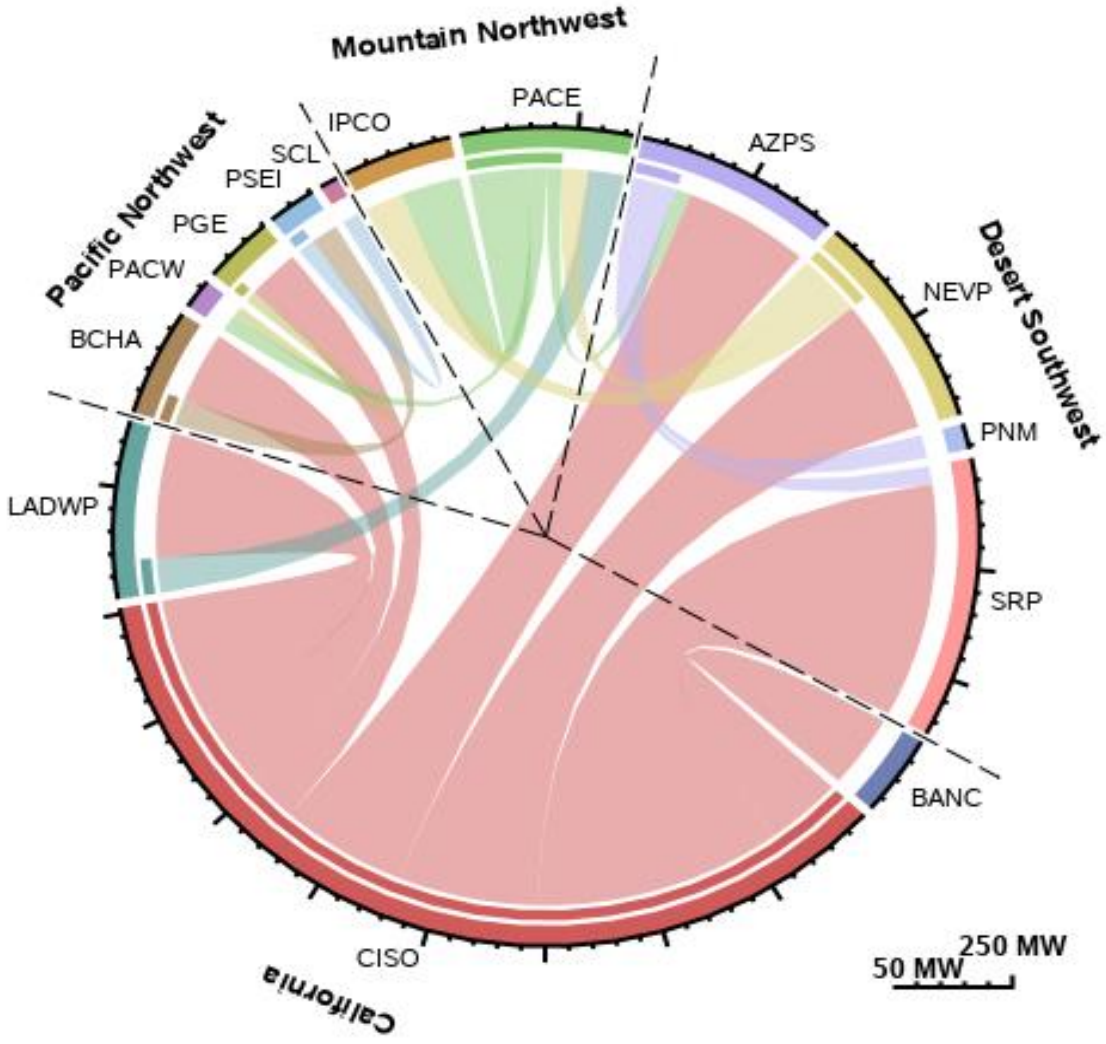
Prices and transfers of energy reflect differences in regional supply conditions and transfer limitations

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

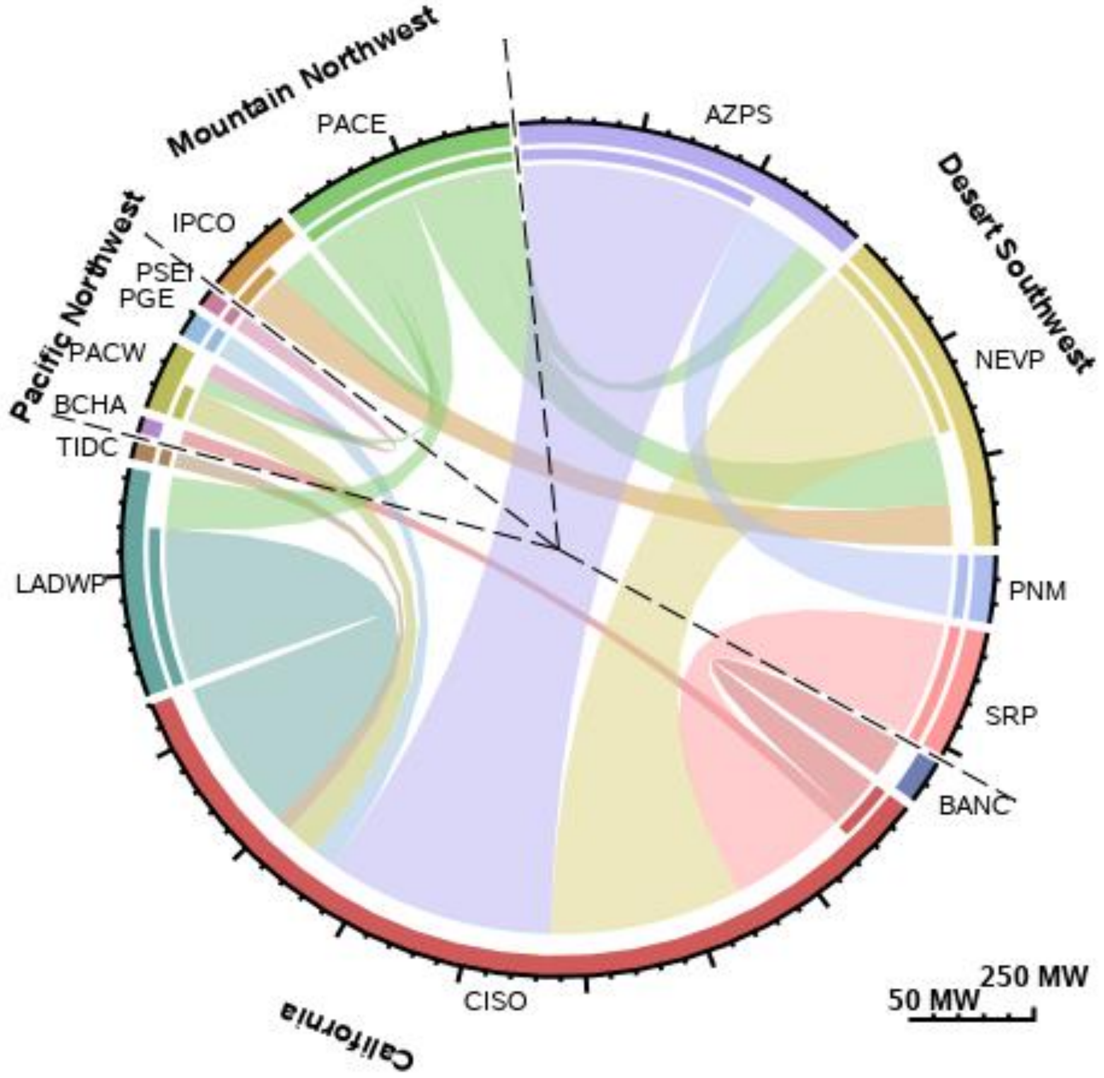
WEIM transfer constraint congestion had greater impact on prices than internal constraint congestion in all areas outside of the CAISO, lowering prices in Northwest

	15-minute market		5-minute market	
	Congestion Frequency	Price Impact ($/MWh)	Congestion Frequency	Price Impact ($/MWh)
BANC*	1%	-$0.27	1%	$0.15
Turlock Irrigation District	1%	-$0.50	1%	-$0.11
Arizona Public Service	2%	-$0.92	3%	$0.89
L.A. Dept. of Water and Power*	2%	-$0.30	2%	$0.26
NV Energy	2%	$0.63	3%	$2.00
Public Service Company of NM*	5%	-$0.77	5%	$0.01
PacifiCorp East	6%	-$0.73	6%	$0.40
Idaho Power	7%	-$0.40	7%	$0.24
Salt River Project	10%	$1.03	10%	$3.35
NorthWestern Energy*	30%	$4.41	26%	-$0.24
PacifiCorp West	34%	-$3.15	24%	-$1.37
Portland General Electric	36%	-$2.33	26%	-$0.77
Seattle City Light	42%	-$4.73	40%	-$2.96
Puget Sound Energy	43%	-$4.32	40%	-$1.90
Powerex	39%	-$5.05	54%	-$2.93

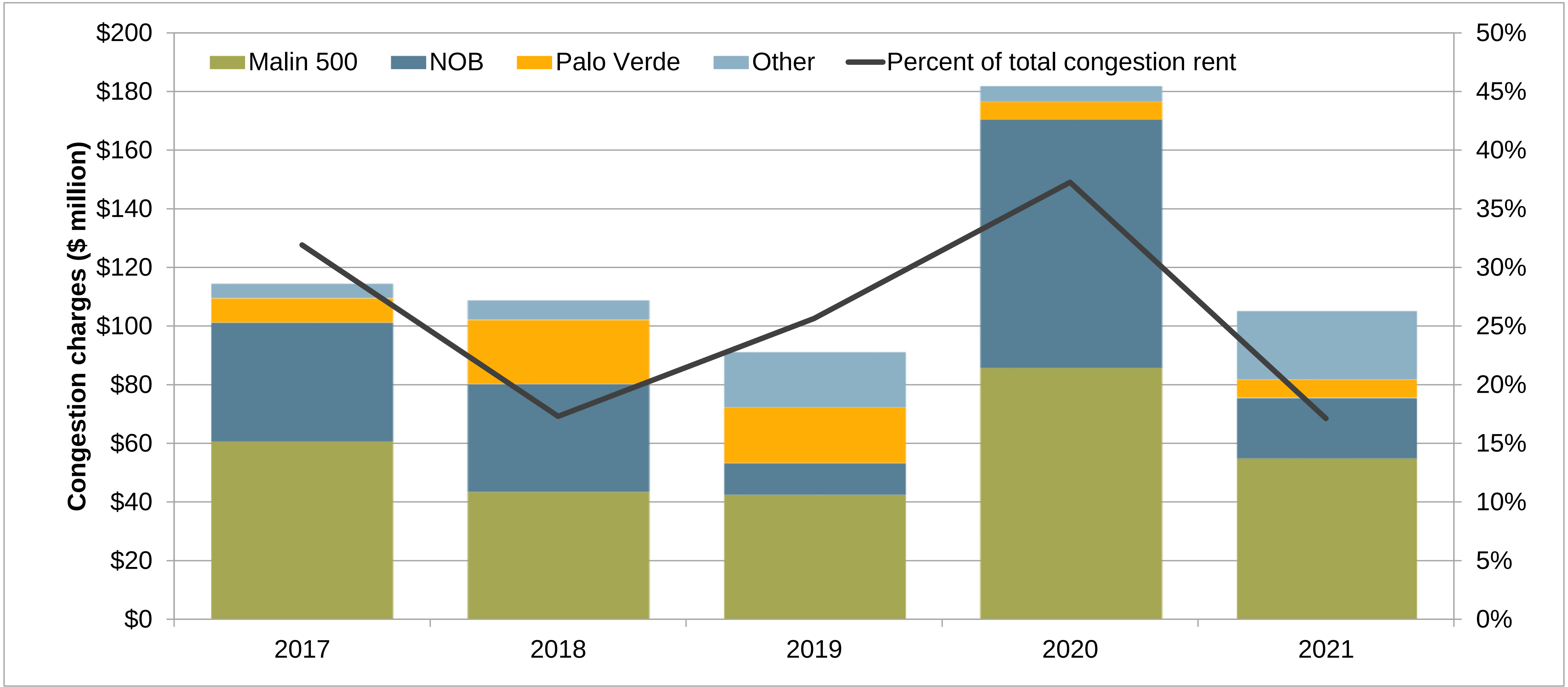
Average 15-minute WEIM exports, mid-day hours, April – May, 2021



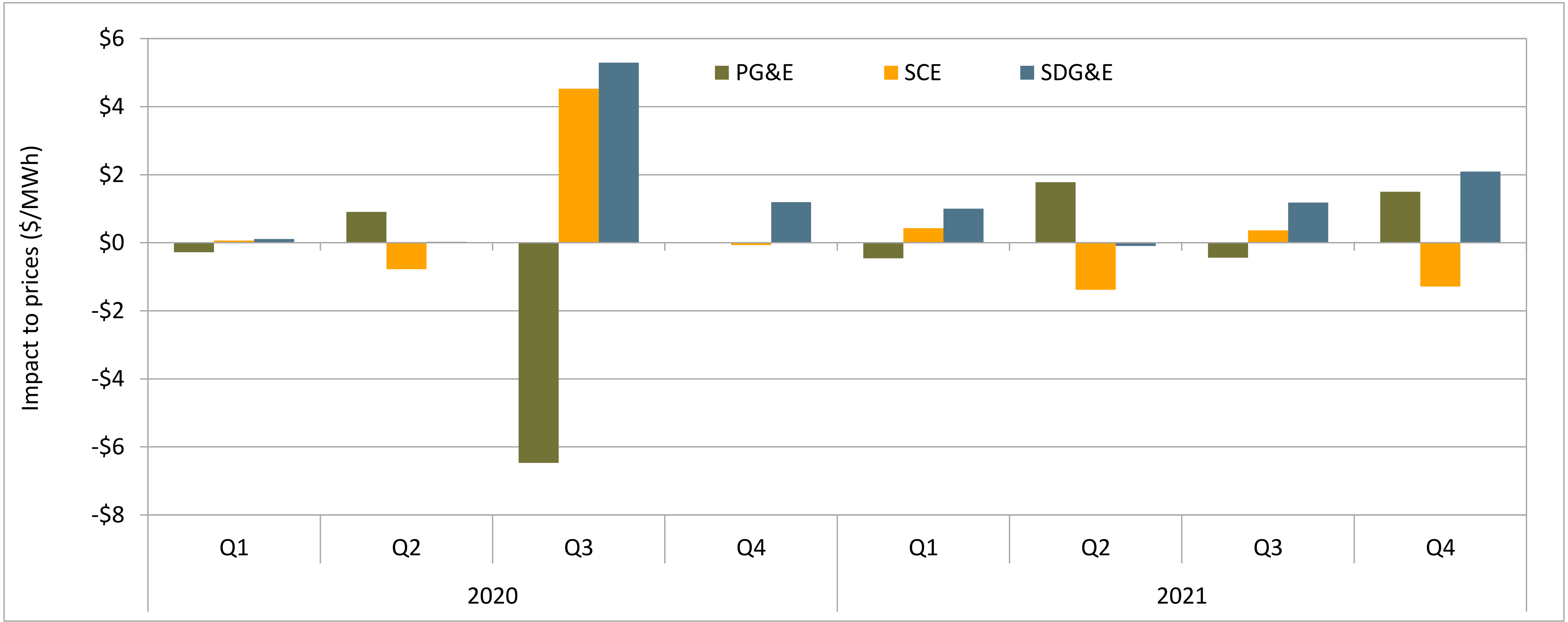
Average 15-minute WEIM exports, peak load hours, June – September, 2021



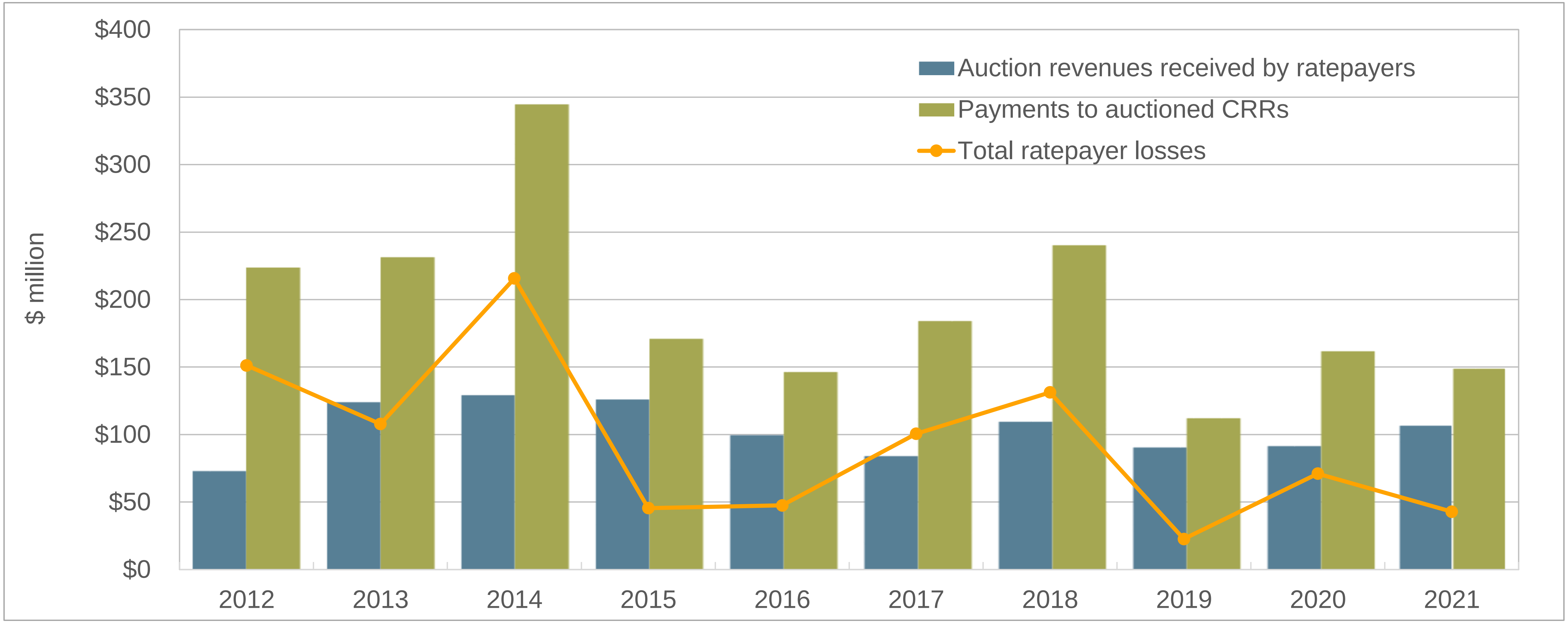
Day-ahead import congestion charges on major interties (2017-2021)



Day-ahead congestion impact decreases, congestion revenues total 5% of total day-ahead market energy costs, compared to about 6% in 2020



Transmission ratepayers lost over $43 million from auctioned CRRs in 2021, down from $70 million in 2020, but up from $22 million in 2019

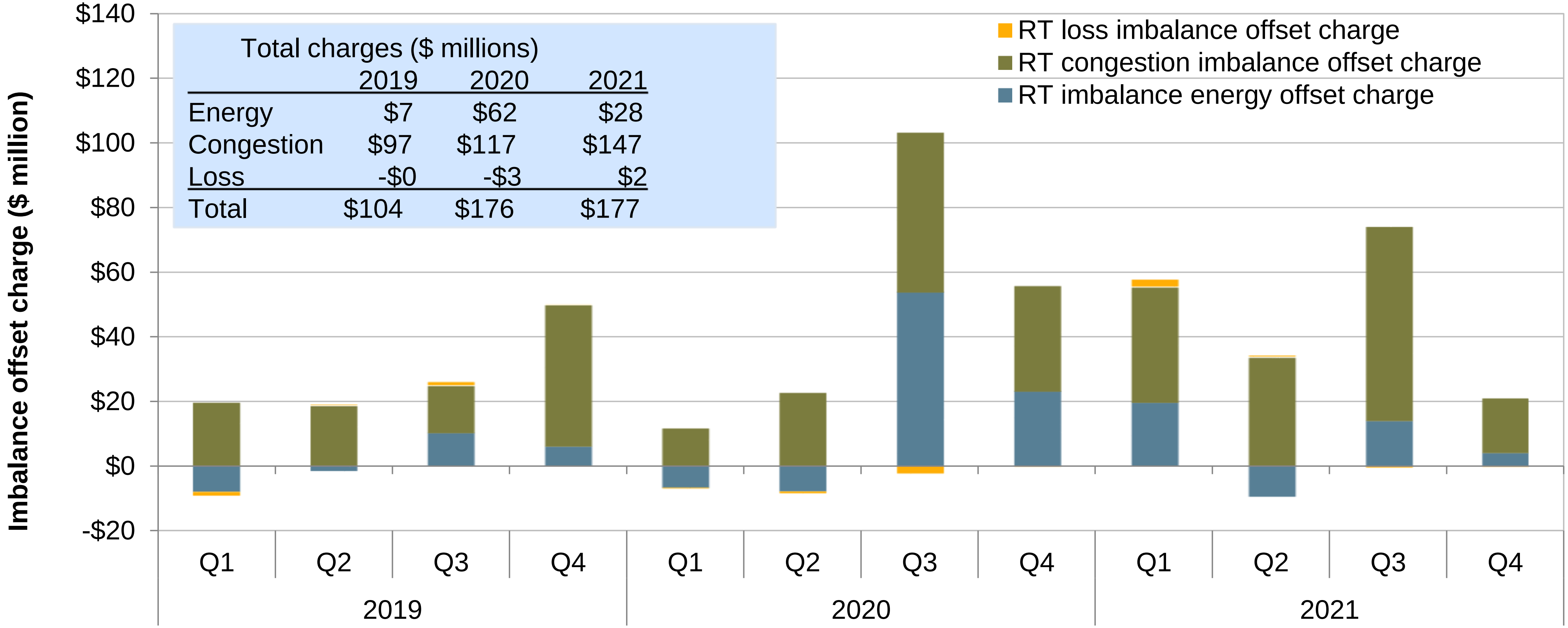


Congestion revenue right auction changes implemented January 2019

- Implemented in response to systematic losses from congestion revenue right auction sales since 2009
- Transmission ratepayer losses are significantly lower
  - averaged $45 million per year 2019-2021, compared to $114 million in the 7 years before the changes
  - averaged 9% of day-ahead congestion rent, down from 27% before the changes

DMM believes the current auction is unnecessary and could be eliminated or (if the CAISO believes a market is necessary for hedging) replaced with a market of willing buyers and sellers

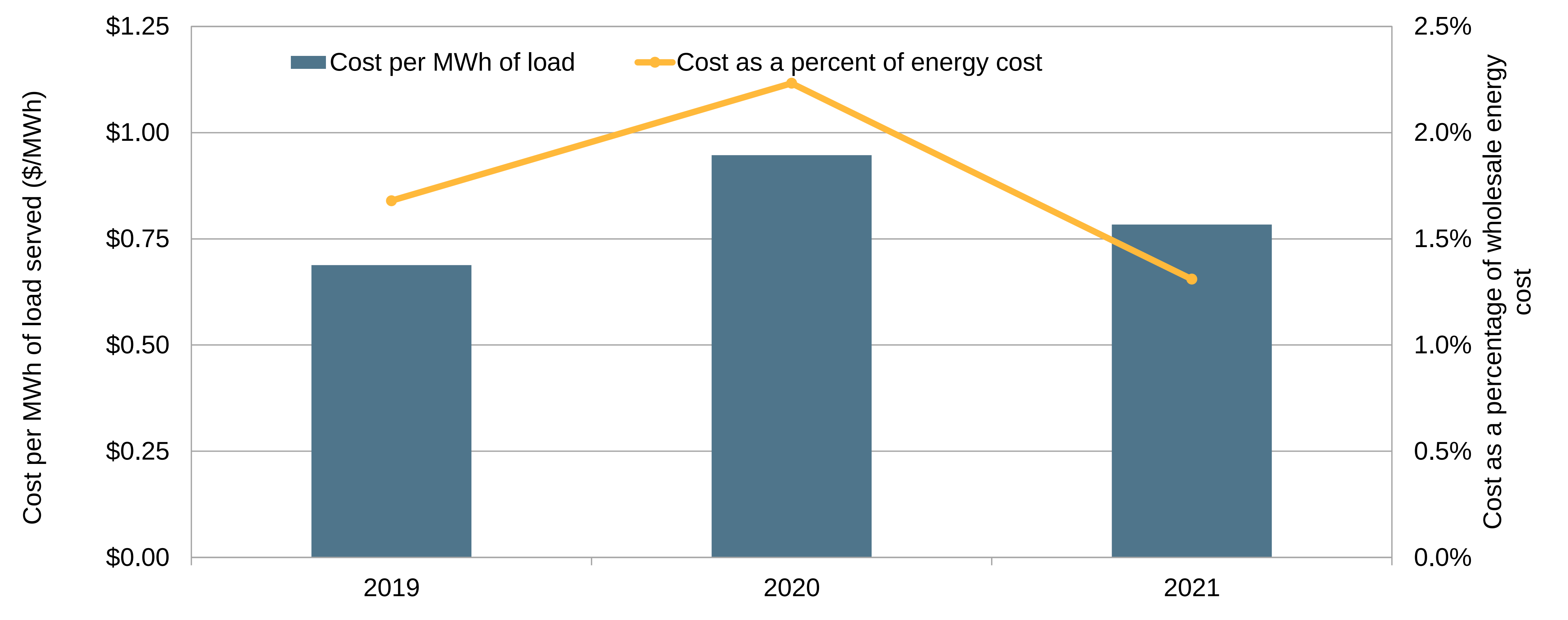
Real-time imbalance offset costs increased to $177 million; most congestion offset costs were due to reductions in constraint limits between day-ahead and real-time



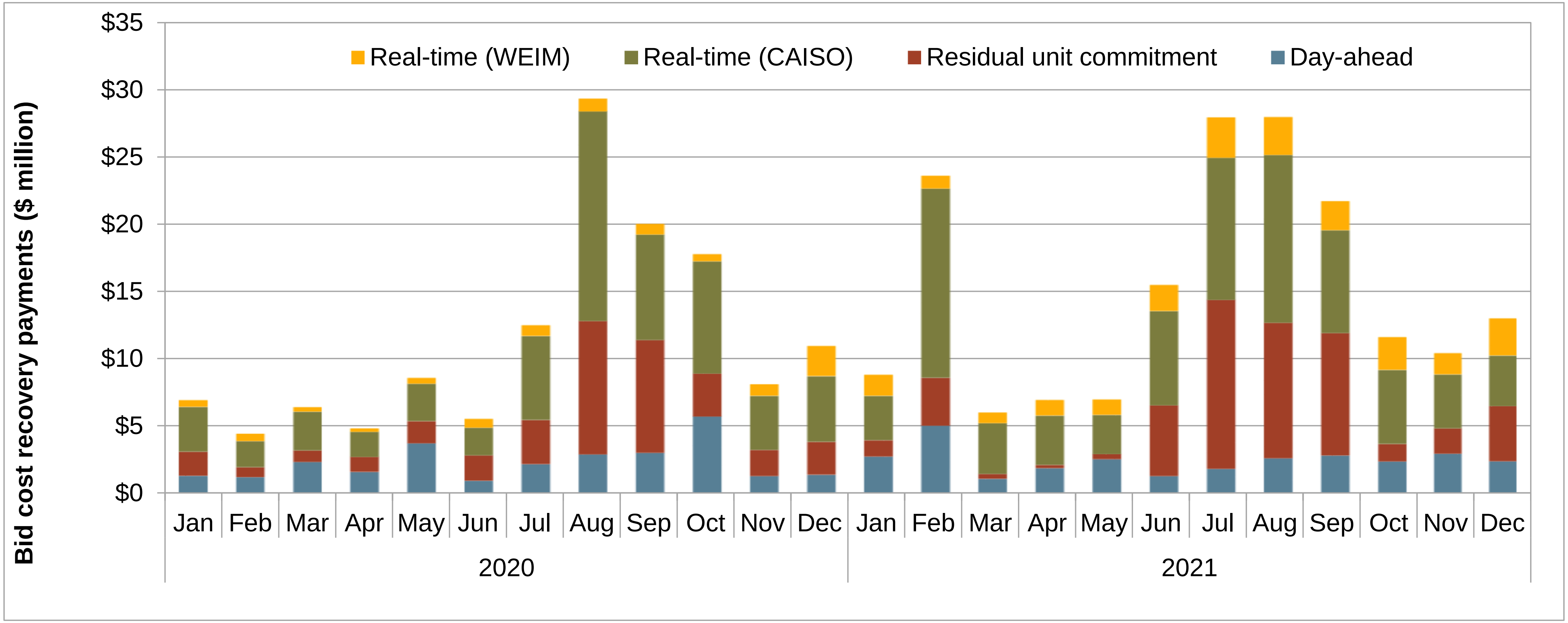
Total charges ($ millions)

	2019	2020	2021
Energy	$7	$62	$28
Congestion	$97	$117	$147
Loss	-$0	-$3	$2
Total	$104	$176	$177

Ancillary service costs decreased to $165 million and 1.3% of wholesale energy costs



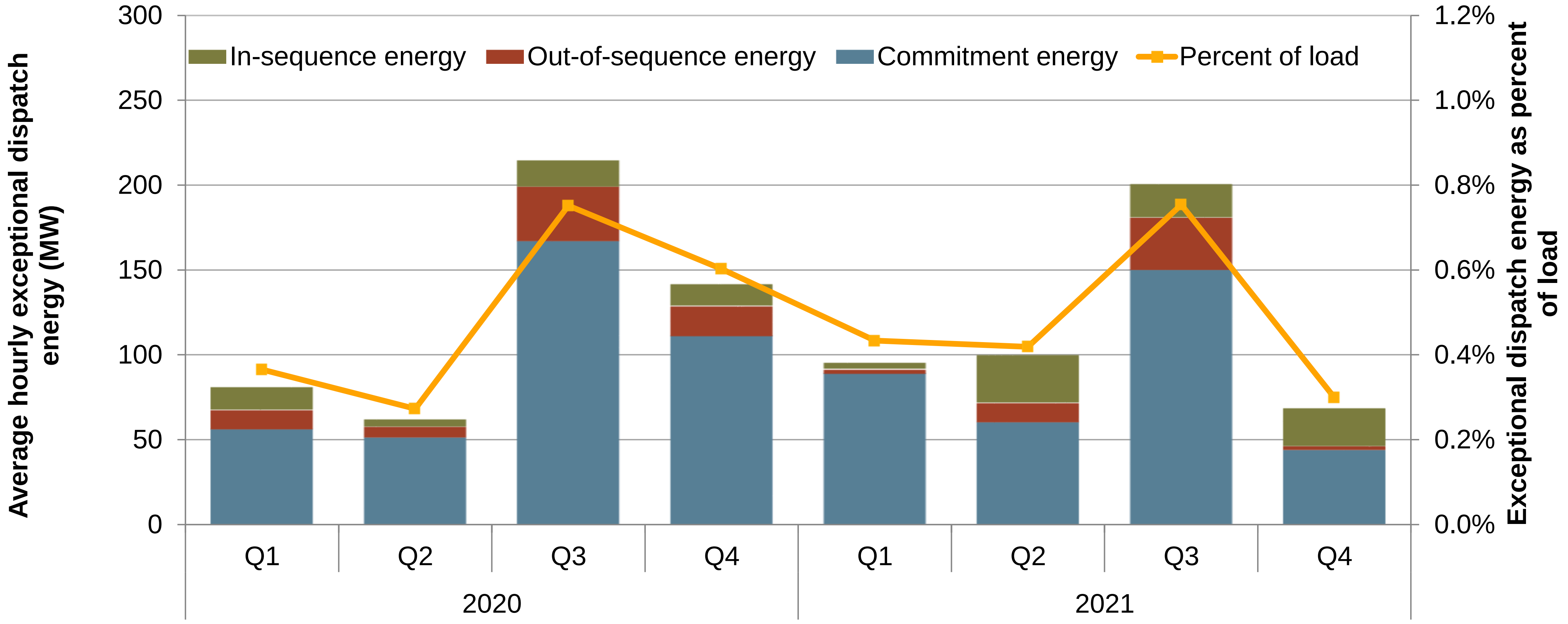
Bid cost recovery payments in the CAISO increased to $158 million or about 1.2% of total energy costs, up from $126 million in 2020 (1.4%), highest value since 2011 WEIM bid cost recovery: $22 million



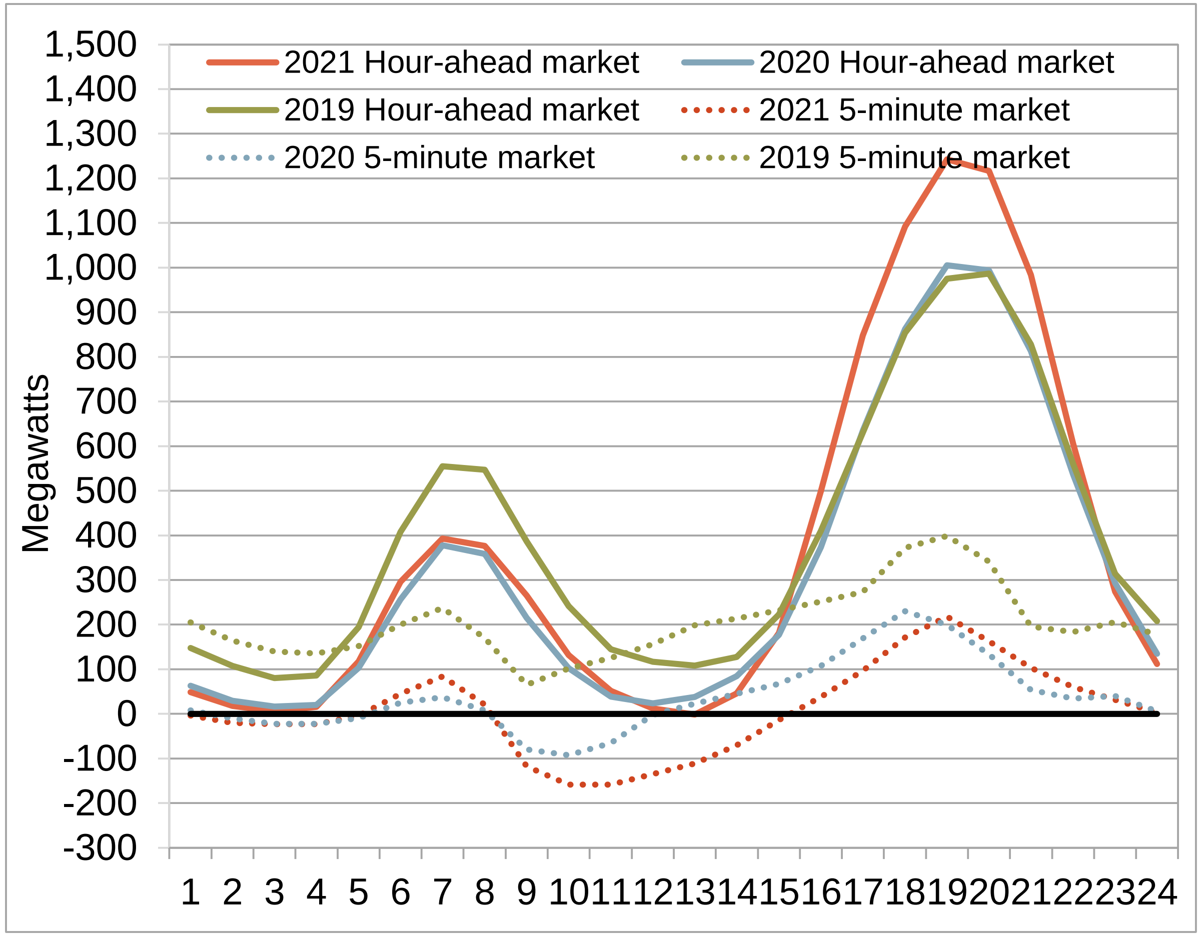
Convergence bidding net profits fell to about $38 million from $45 million in 2020

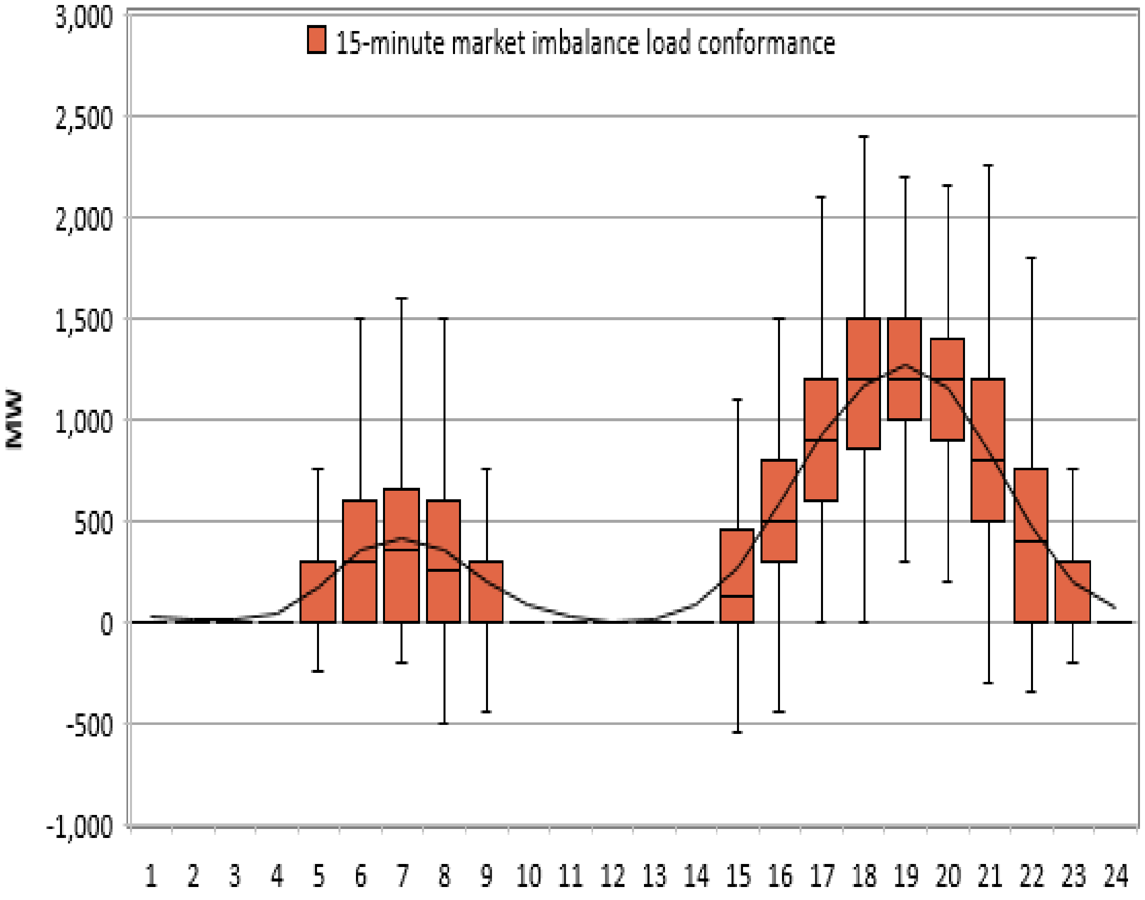
Trading entities	Average hourly megawatts			Revenues\Losses ($ million)				Total Revenue after BCR
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply before BCR	Virtual bid cost recovery	Virtual supply after BCR	
Financial	1,172	1,821	2,993	$3.37	$47.31	-$15.40	$31.91	$35.29
Marketer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

Total energy from exceptional dispatches remained low in 2021, accounting for only 0.5% of system load. Costs increased to $27 million from $16 million in 2020



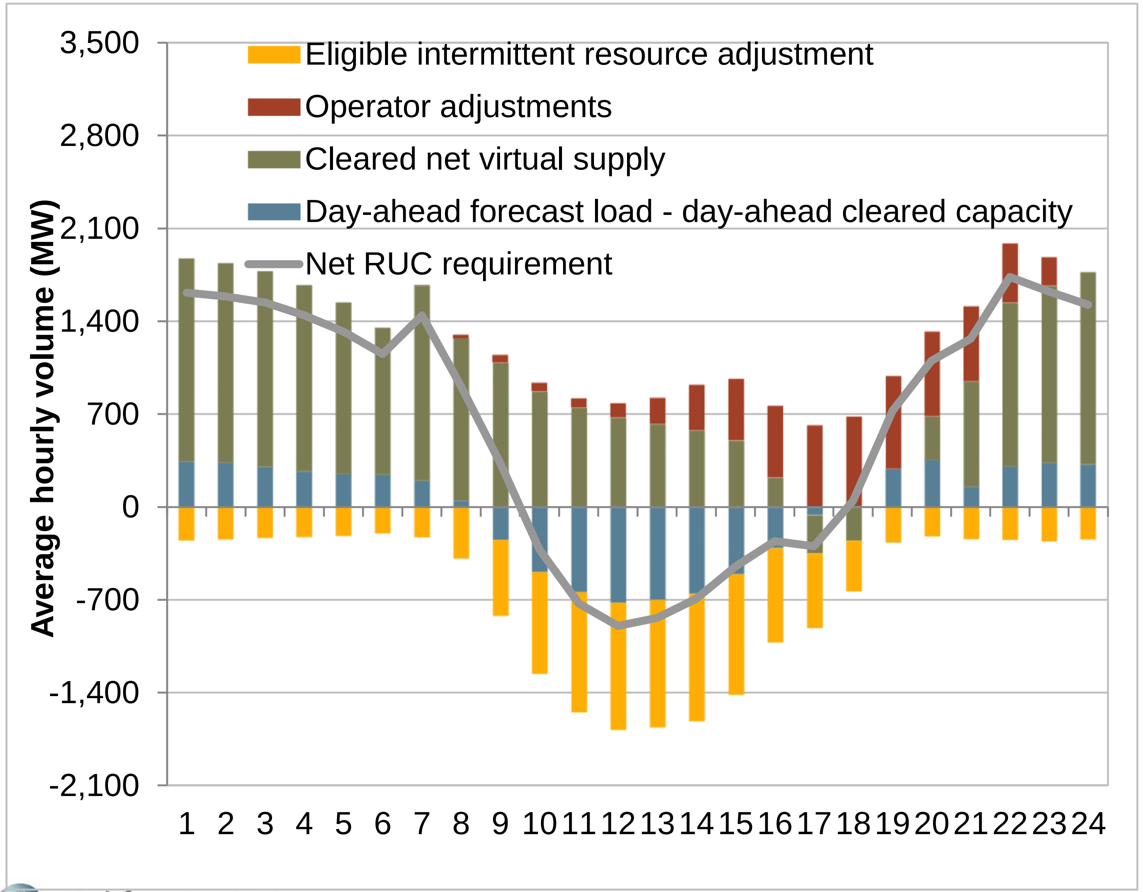
Load adjustment by grid operators remained high, particularly in ramping hours



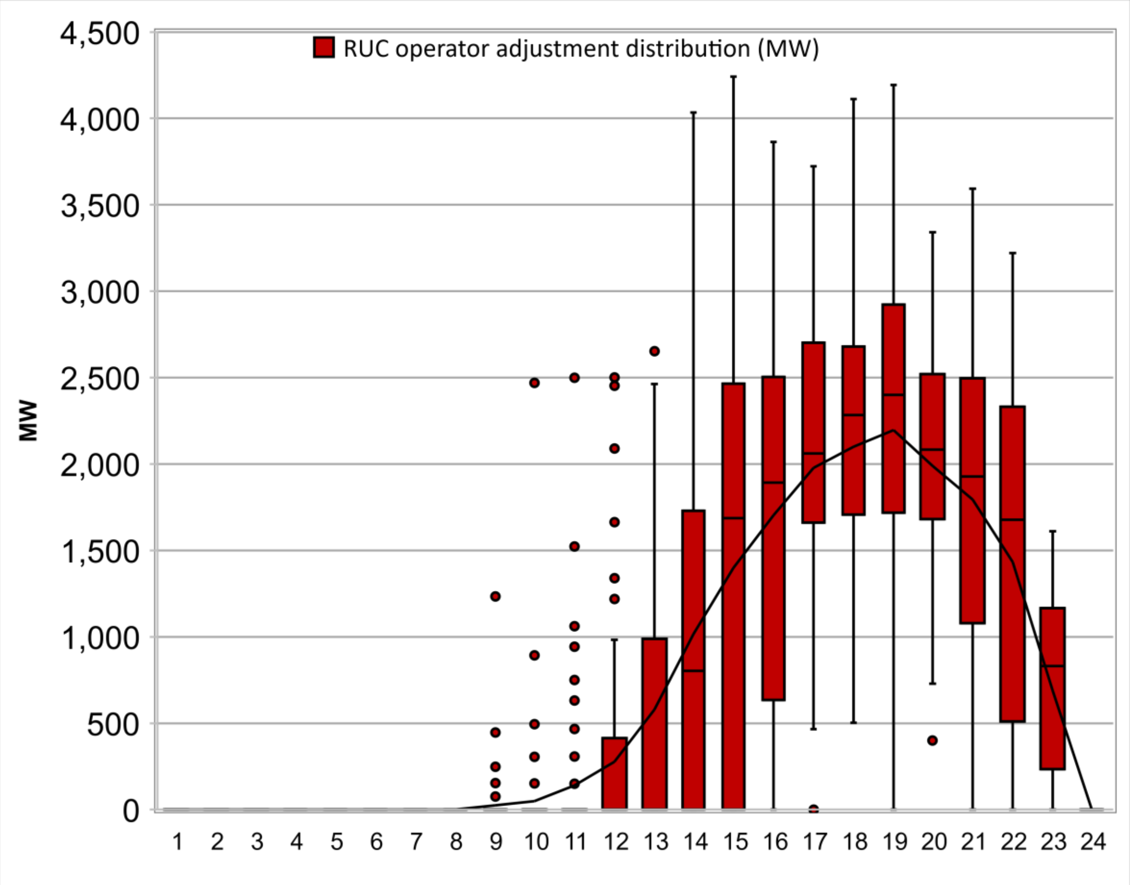


California ISO operator residual unit commitment operator adjustments declined by 36%

RUC requirement determinants



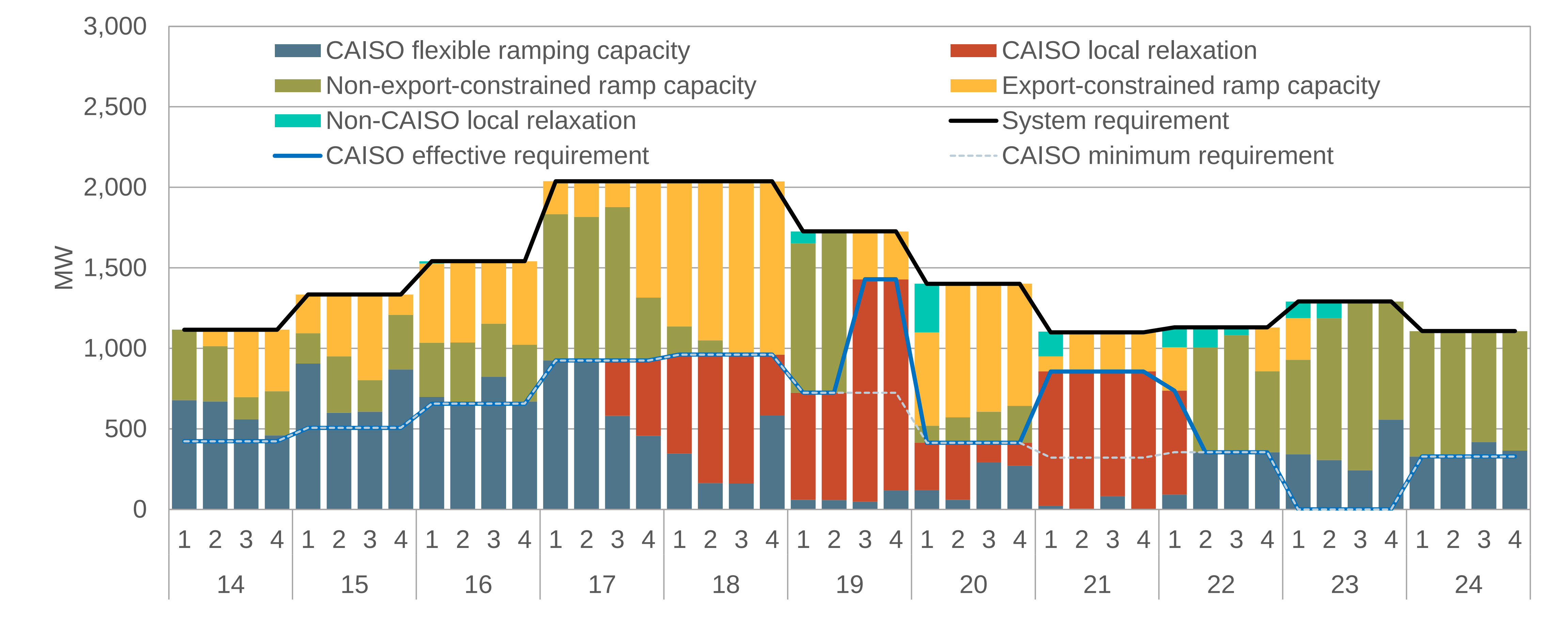
Operator adjustments (Jul – Sep)



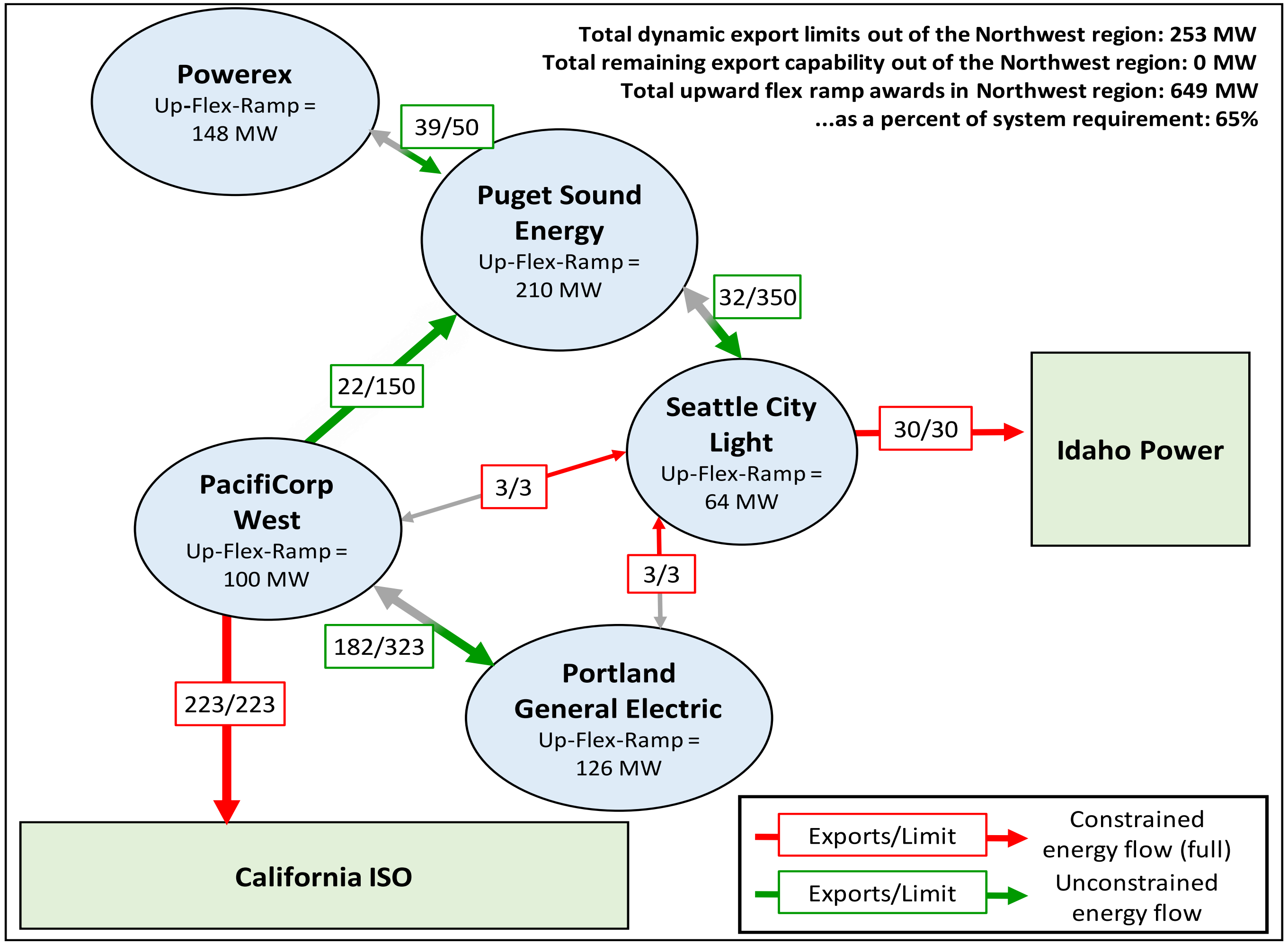
Flexible ramping capacity

- Designed to enhance reliability and market performance by procuring real-time ramping capacity to help manage variability and uncertainty
- Flexible ramping prices were frequently zero
- Minimum area constraint implemented in November 2020, only in the 15-minute market
  - Added to the 5-minute market on February 16, 2022
  - Frequently binding in CAISO, but not other areas
- DMM supports the CAISO's planned Fall 2022 implementation of nodal procurement:
  - Procurement of capacity from resources not able to meet system uncertainty because of resource characteristics or congestion
  - This can reduce the effectiveness of the product to manage net load volatility and prevent power balance violations
- Uncertainty over load and the future availability of resources to meet that load contributes to operators needing to enter systematic and large imbalance conformance adjustments

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

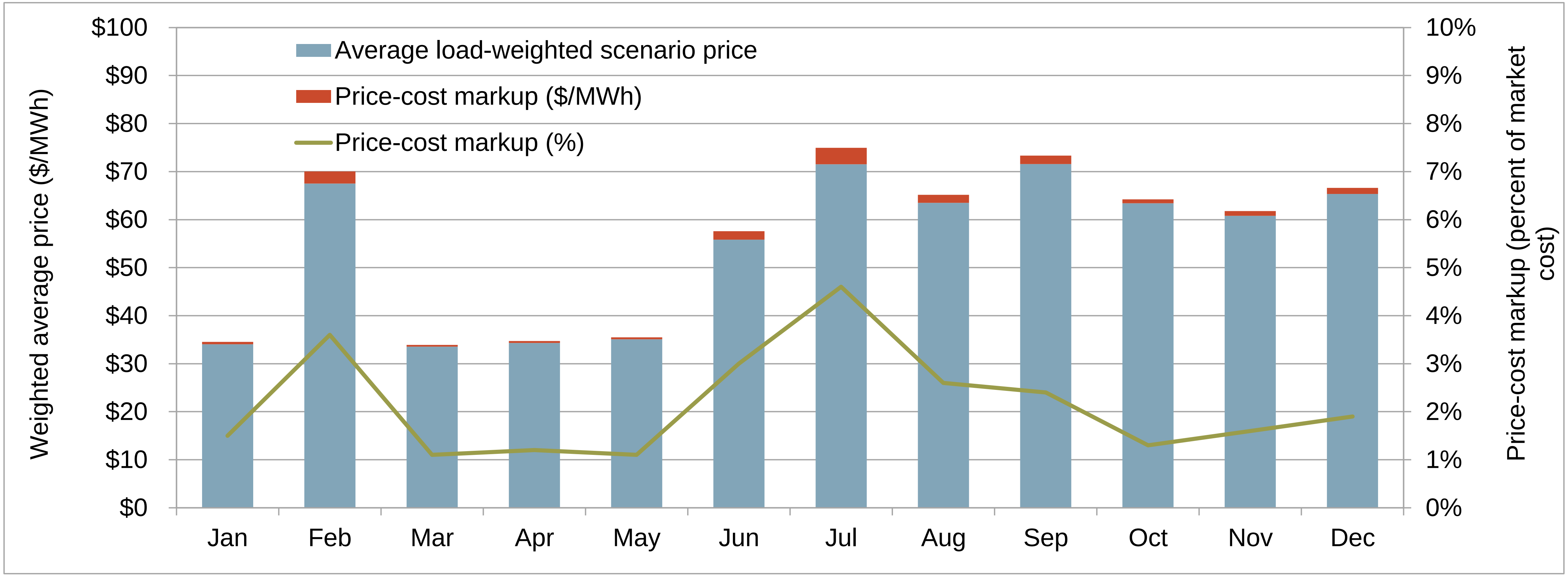


Example interval — stranded upward ramping capacity in the Northwest (September 7, 2021)

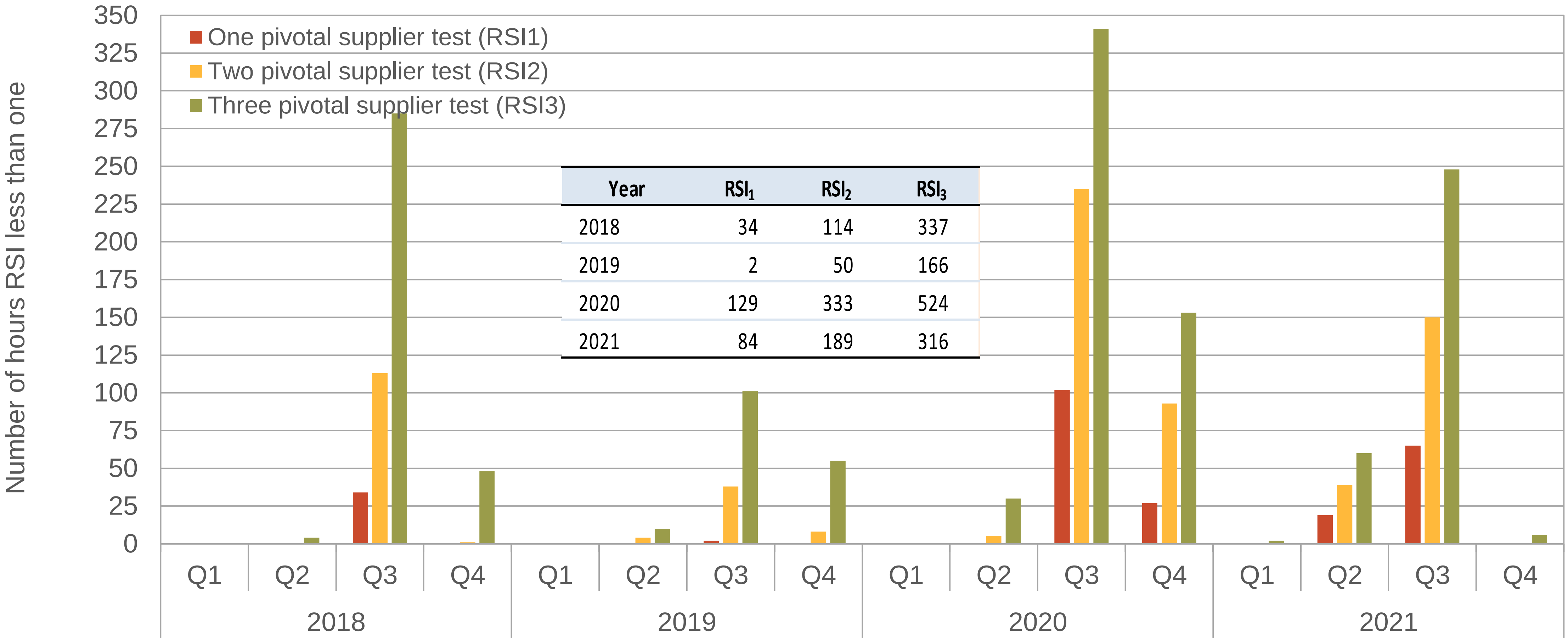


The CAISO energy markets were competitive in 2021, with energy prices about equal to competitive baseline prices calculated by DMM

Total markup about $1.41/MWh or about 2.5 percent



Day-ahead market was more structurally competitive than 2020



Year	RSI_1	RSI_2	RSI_3
2018	34	114	337
2019	2	50	166
2020	129	333	524
2021	84	189	316

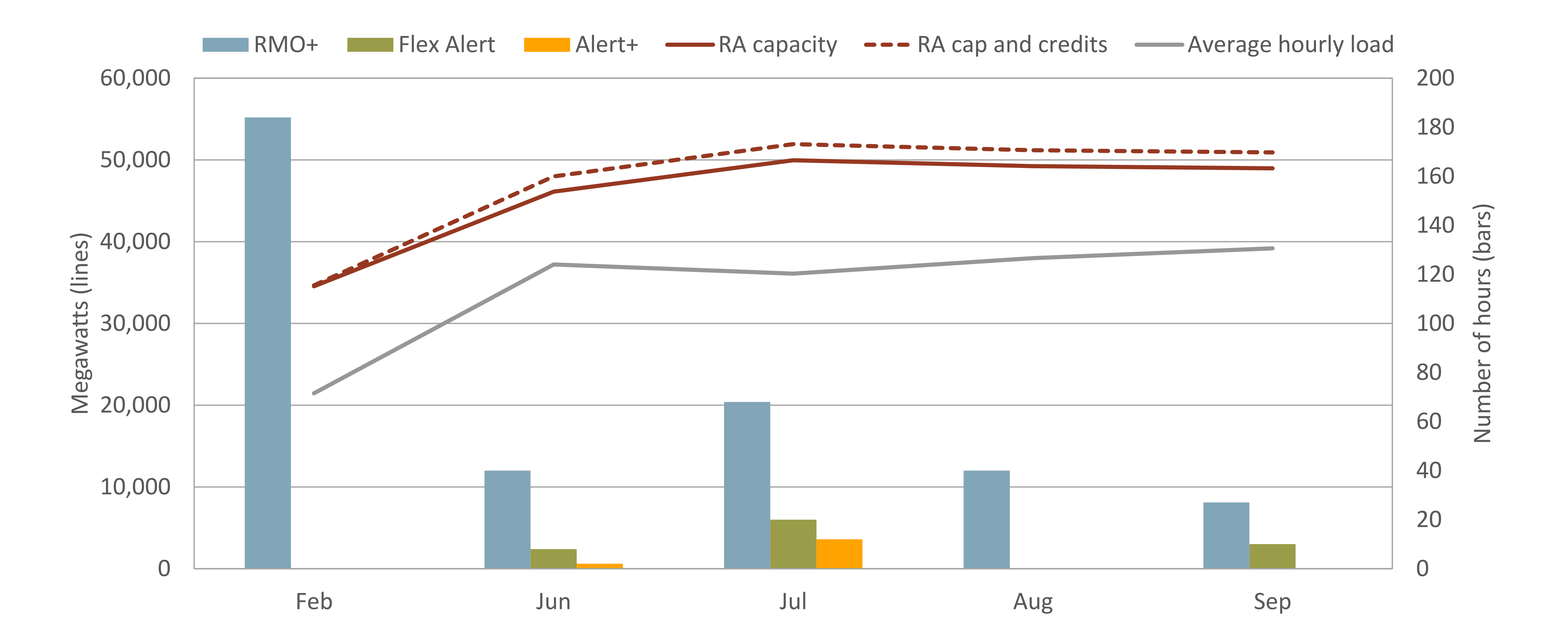
State policy creates a basis for competitive market outcomes in CAISO

- California currently relies on long-term procurement planning and resource adequacy requirements placed on load serving entities by the CPUC to ensure that sufficient capacity is available to meet system and local reliability requirements
- CPUC policies also have a major impact on the type of different generating resources retained and added to the CAISO system
- Load shift from investor owned utilities to community choice aggregators
- Decrease in long-term capacity contracts

Average total system resource adequacy capacity, availability, and performance by system emergency notification category

Year	Alert Category	Number of hours	Total RA capacity	Day-ahead market			Real-time market				Meter	Uncapped meter
				Capacity derate	Bids and self-schedules	Schedules	Capacity derate	Bids and self-schedules	Schedules	Uncapped schedules		
2019	RMO +	45	48,605	95%	87%	61%	94%	85%	61%	73%	59%	69%
	Flex Alert	6	47,605	94%	84%	67%	91%	80%	70%	77%	65%	71%
	Alert +	17	48,177	96%	87%	60%	95%	86%	61%	73%	58%	68%
2020	RMO +	390	47,723	94%	87%	61%	93%	86%	58%	68%	55%	64%
	Flex Alert	154	48,602	95%	87%	67%	93%	85%	63%	73%	61%	68%
	Alert +	97	45,404	95%	89%	72%	94%	88%	68%	79%	65%	73%
2021	RMO +	359	41,480	93%	88%	57%	92%	87%	52%	66%	50%	63%
	Flex Alert	38	48,878	94%	88%	81%	92%	87%	77%	87%	73%	81%
	Alert +	14	49,359	93%	85%	80%	92%	85%	77%	85%	73%	80%

Average hourly resource adequacy capacity and load (2021 emergency notification hours)



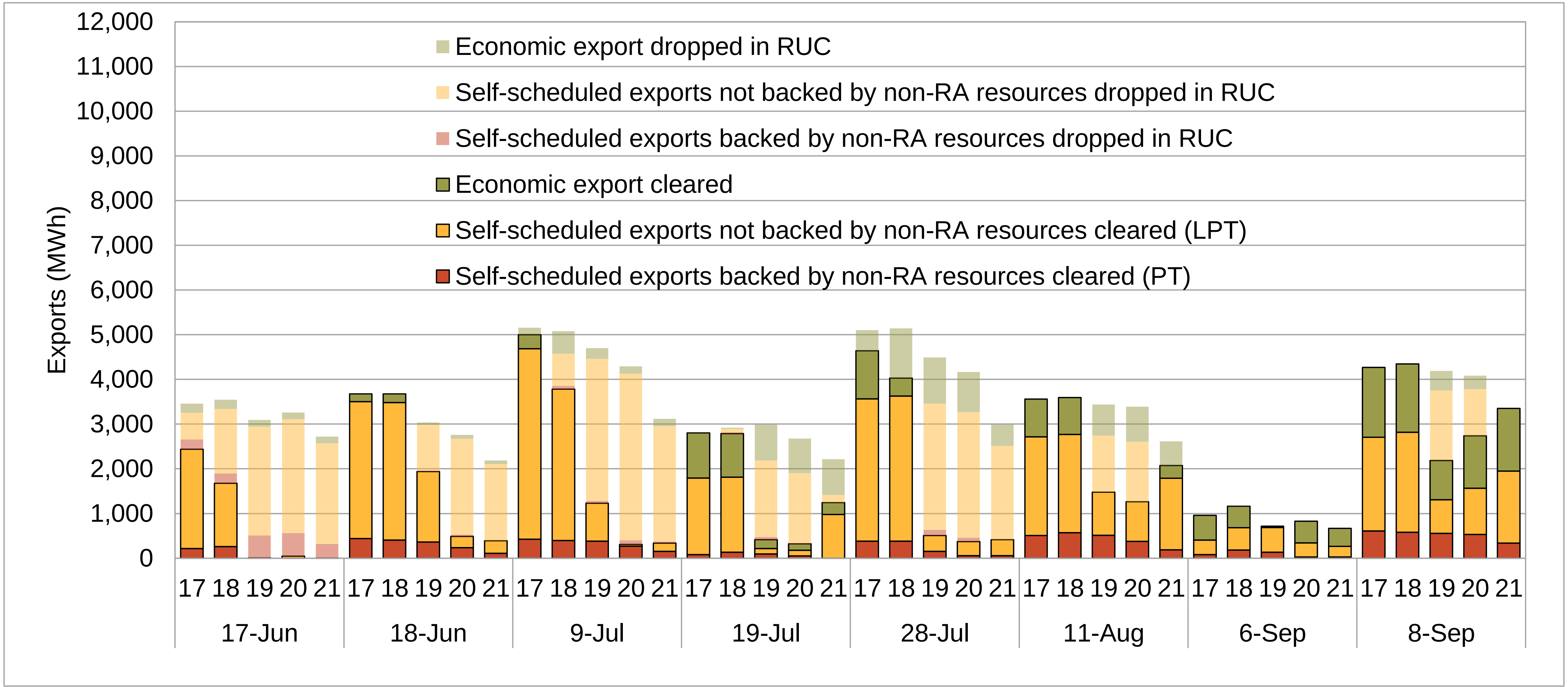
Average system resource adequacy capacity, availability, and performance by fuel type (Alert+ hours)

Resource type	Total RA capacity	Day-ahead market			Real-time market				Meter	Uncapped meter
		Capacity derate	Bids and self-schedules	Schedules	Capacity derate	Bids and self-schedules	Schedules	Uncapped schedules		
Must-Offer:										
Gas-fired generators	19,230	87%	87%	79%	86%	86%	82%	85%	80%	82%
Other generators	1,407	93%	93%	93%	93%	93%	93%	96%	92%	96%
Subtotal	20,637	88%	88%	80%	86%	86%	83%	86%	81%	83%
Other:										
Imports	2,771	97%	96%	88%	99%	88%	69%	70%	56%	57%
Imports - MSS	336	100%	85%	85%	100%	85%	85%	85%	78%	78%
Use-limited gas units	8,407	98%	97%	91%	96%	96%	84%	87%	78%	79%
Hydro generators	5,855	94%	88%	88%	92%	87%	64%	71%	62%	68%
Nuclear generators	2,867	100%	99%	99%	100%	99%	99%	101%	99%	101%
Solar generators	4,697	99%	35%	35%	97%	43%	38%	53%	35%	48%
Wind generators	1,468	100%	82%	82%	99%	93%	95%	231%	90%	204%
Qualifying facilities	844	99%	94%	90%	98%	94%	90%	107%	87%	106%
Demand response	257	100%	68%	9%	99%	46%	18%	18%	9%	10%
Storage	866	99%	89%	66%	99%	92%	71%	76%	54%	58%
Other non-dispatchable	354	96%	94%	94%	95%	94%	92%	101%	91%	99%
Subtotal	28,722	97%	84%	80%	97%	84%	72%	85%	67%	78%
Total	**49,359**	**93%**	**85%**	**80%**	**92%**	**85%**	**77%**	**85%**	**73%**	**80%**

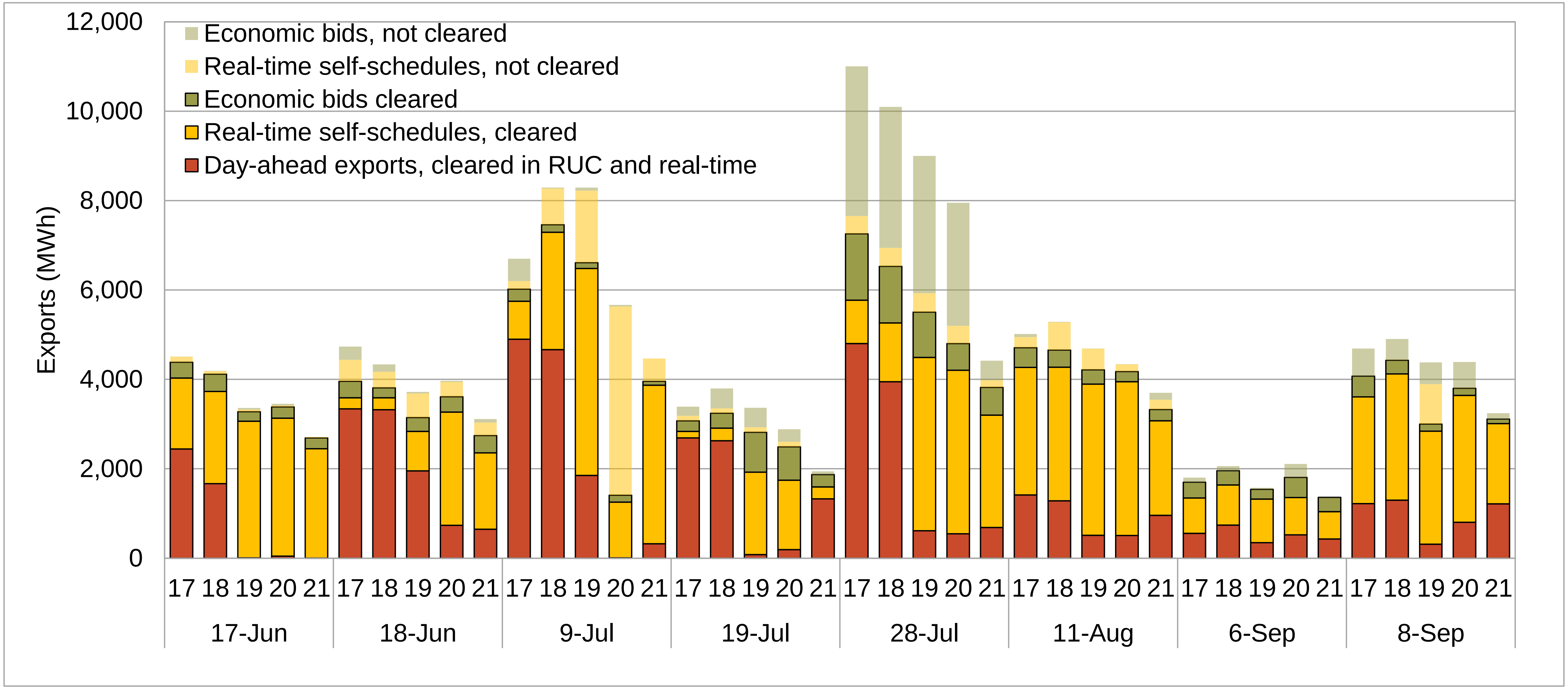
Following events of August 2020, the CAISO took steps to ensure exports were limited to physically feasible levels

- Effective September 5, 2020, the CAISO made important changes to RUC and the real-time scheduling priority of the day-ahead energy market export schedules that do not receive RUC awards.
- CAISO's current policy still prioritizes exports that receive day-ahead RUC awards over native CAISO balancing area load in real-time.
- The rules and processes for limiting/curtailing exports used by the CAISO and other balancing areas should be reviewed, clarified, and potentially modified -- with a goal of establishing equal treatment and expectations of exports by all balancing areas.

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



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



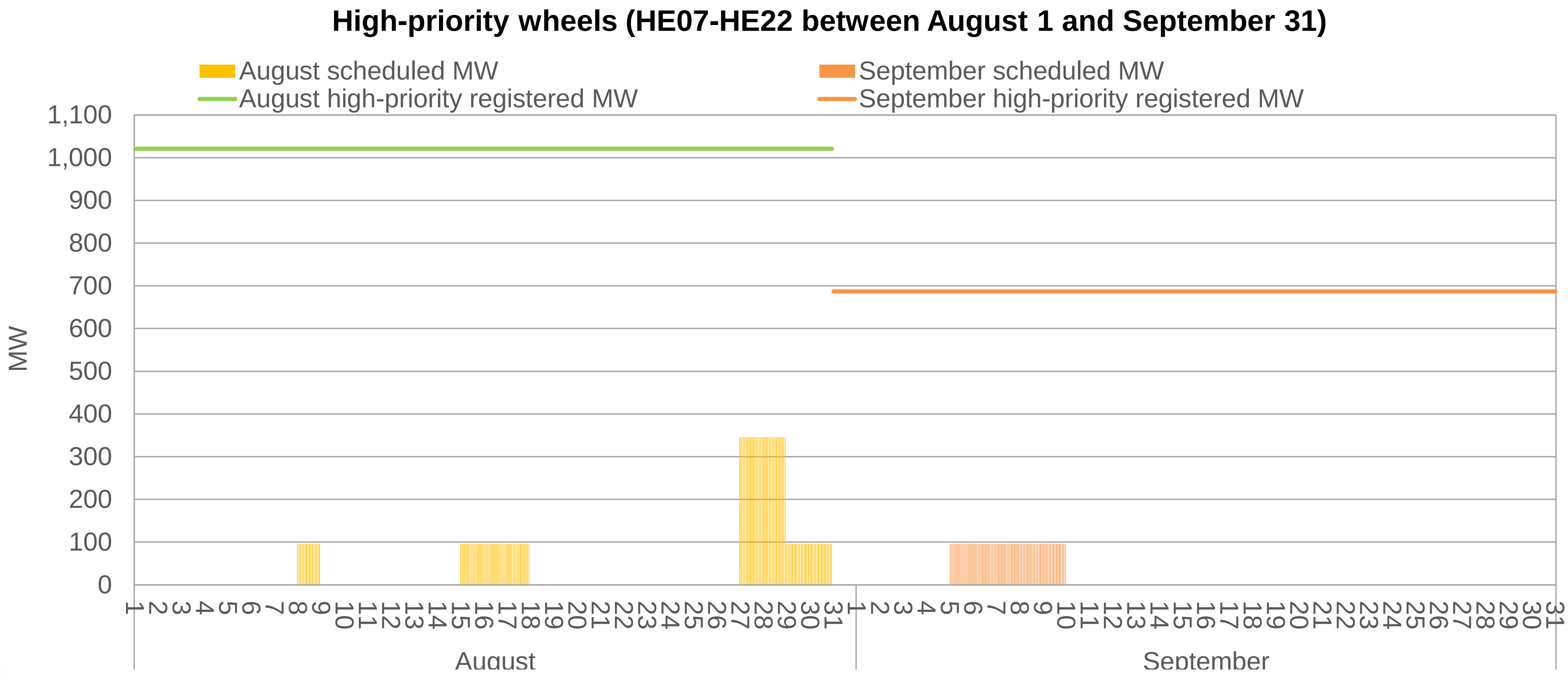
The CAISO implemented a number of additional market changes in 2021

- Residual unit commitment process export prioritization (September 2020)
- Minimum flexible ramping product requirement (November 2020)
- WEIM resource sufficiency evaluation error correction (February)
- Default energy bid and commitment cost bid cap real-time adjustment (February)
- Bidding above the $1,000/MWh energy bid cap (March)
- Gas burn constraint shaping and addition to market power mitigation (May)
- Addition of net load uncertainty to the bid range capacity test (June)

The CAISO implemented a number of additional market changes in 2021

- FERC Order No. 831 compliance, phase 2 (June)
- Market enhancements for summer readiness (June)
- Self-scheduled export priority changes (August)
- Wheeling priority changes (August)
- Ancillary service testing changes (September)
- Battery energy storage resource mitigation (November)
- WEIM resource sufficiency evaluation enhancements (June 2022)

On August 4, the CAISO implemented changes to load, export, and wheeling priorities (penalty prices for self-schedules)



The CPUC has identified options for addressing issues and is moving forward with more detailed market design options and decisions:

- Multi-year framework for local resource adequacy requirements and procurement by load serving entities
- Central buyer framework for meeting any local RA requirements not met by RA capacity procured by CPUC-jurisdictional load serving entities
- Development of RA requirements that consider both energy and capacity needs across all hours of the day, including the peak net load hours
- Development of RA requirements that ensure sufficient flexible capacity needed to integrate a high level of renewables
- Strengthening requirements for imports to meet system level RA requirement

DMM supports these efforts and views the options being considered by the CPUC as potentially effective steps

Recommendations

- Western EIM resource sufficiency tests (capacity & ramping)
  - Reconsider how to deal with uncertainty
  - Economic consequence if balancing areas fail tests and not shortage in other balancing areas
- Flexible ramping product (real-time)
  - Implement locational procurement
  - Expand time horizon beyond current 15 minute period (e.g. 2-3 hours?)
- Congestion revenue rights
  - Eliminate or further limit auction of congestion revenue rights
  - If need for congestion hedging instruments considered so important, then establish market for hedges based on willing buyers and sellers

Recommendations (continued)

- Day-ahead market enhancements (DAME)
  - Consider energy imbalance product or other mechanism for ensuring capacity in real-time in context of expanded day-ahead market (EDAM)
- Expanded day-ahead market enhancement (EDAM)
  - Mechanism for ensuring capacity in real-time must be carefully designed if eliminating current real-time must offer obligation in CAISO
  - Clarify details of what happens after EDAM in real-time during very tight conditions/shortages in real-time
- Scarcity pricing/system market power
- Battery resources
- Demand response resources