2019 Q4 Report on Market Issues and Performance

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http://www.caiso.com/Documents/2019FourthQuarterReportonMarketIssuesandPerformance.pdf

http://www.caiso.com/market/Pages/MarketMonitoring/AnnualQuarterlyIssuesPerfomanceReports/Default.aspx

Highlights of Q4 market performance

- Market prices were low and highly competitive
  - Wholesale energy cost ($44/MWh)
    - Decrease from Q4 2018 ($54/MWh, - 18%)
    - Increase from Q3 2019   ($39/MWh, +15%)
- Average gas prices up 19% from Q4 2018
- Real-time offset costs in Q4 of $50 million ($100 million for 2019)
- Increase in load adjustments by operators
- Congestion revenue rights losses to ratepayers fell to $22 million from $29 million in Q4 2018 ($34 million for 2019)

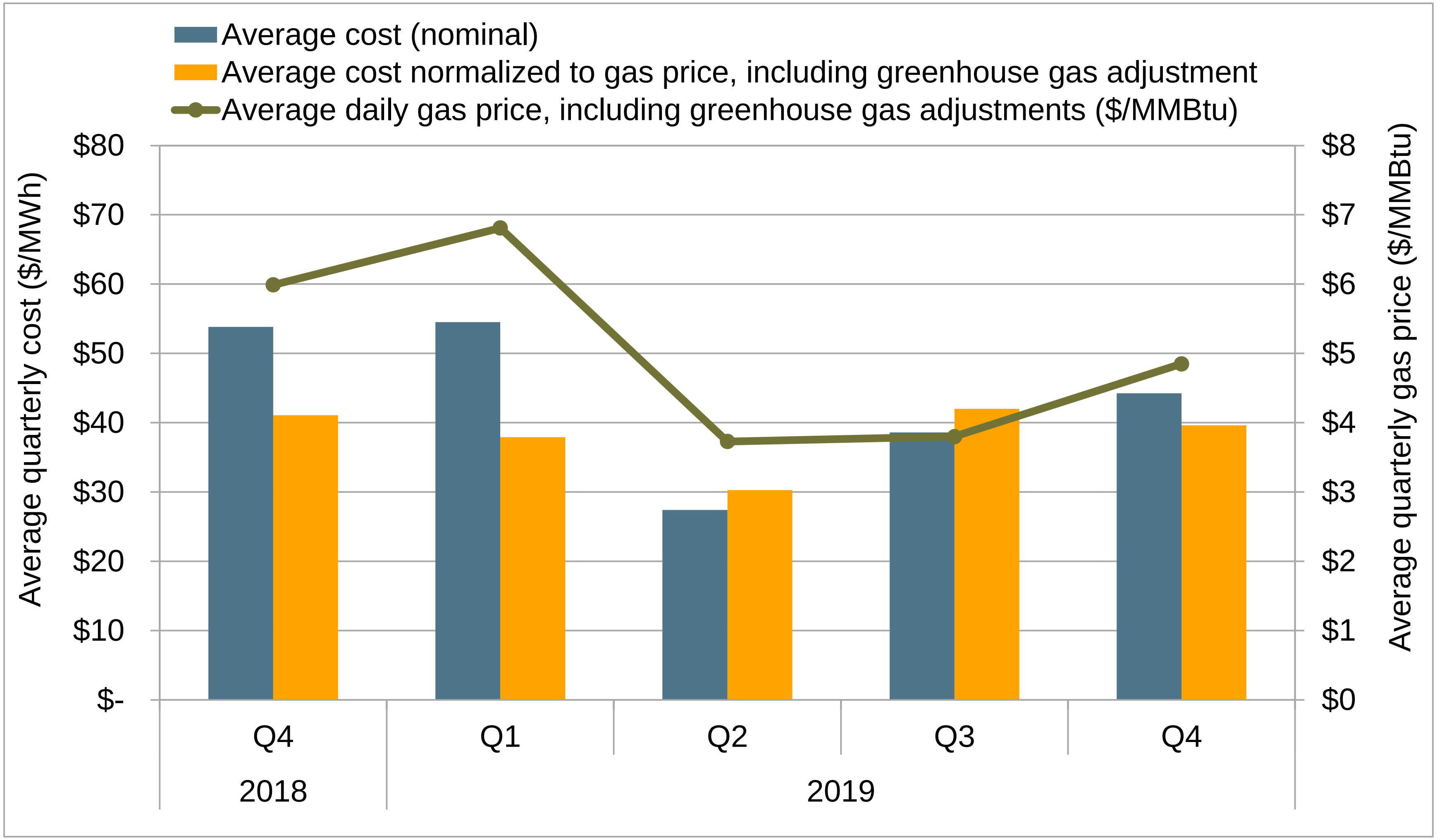
Western energy imbalance market highlights

- Northwest prices regularly lower than the rest of the system due to limited transfer capability
- Sufficiency test failures drove prices up in Arizona Public Service
- Congestion imbalance offset costs related to base schedules remained low
- Western EIM greenhouse gas prices continued to increase

Special issues covered in Q4 market report

- Energy storage and distributed energy resources phase 3
- Local market power mitigation enhancements
- Gas usage constraints
- System market power

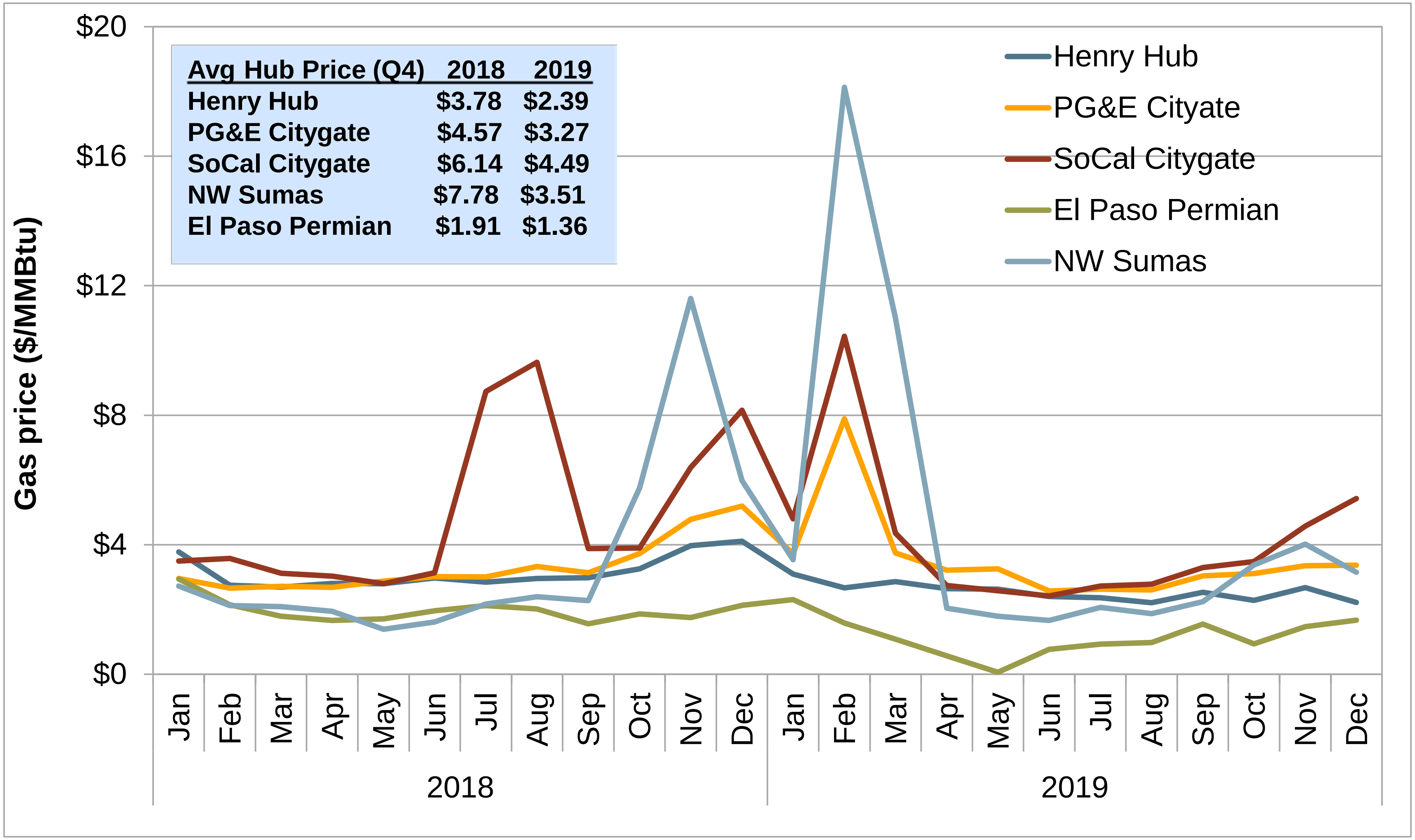
Total Q4 wholesale costs down 18% from Q4 2018, 4% after adjusting for gas and greenhouse gas costs



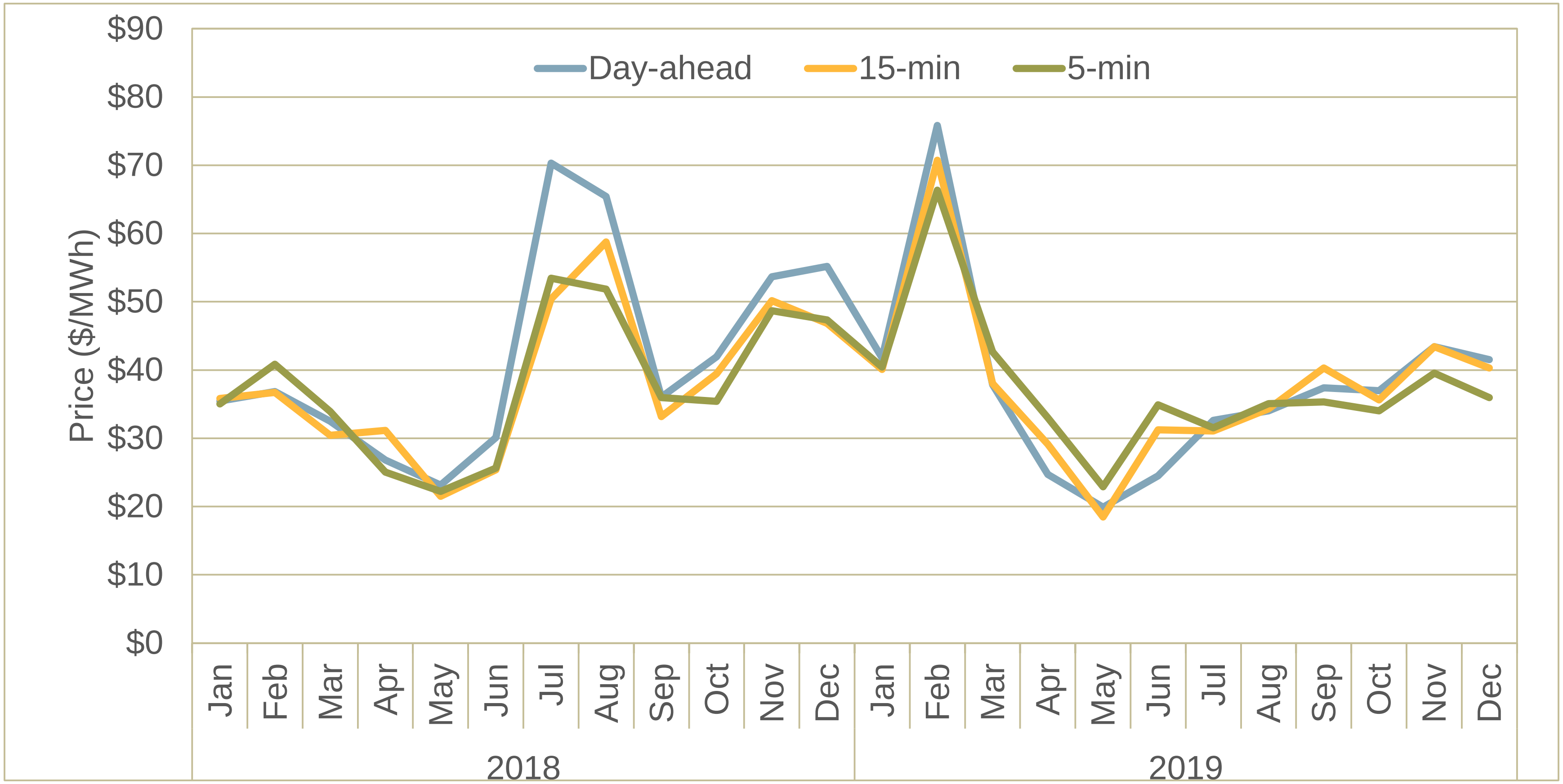
Q4 CAISO wholesale costs totaled $2.3 billion or about $44/MWh

	Q4 2018	Q1 2019	Q2 2019	Q3 2019	Q4 2019	Change Q4 2018-Q4 2019
Day-ahead energy costs	$ 51.46	$ 52.23	$ 23.97	$ 35.94	$ 41.35	$ (10.11)
Real-time energy costs (incl. flex ramp)	$ 0.01	$ 0.30	$ 1.28	$ 0.98	$ 1.44	$ 1.44
Grid management charge	$ 0.48	$ 0.46	$ 0.47	$ 0.45	$ 0.46	$ (0.02)
Bid cost recovery costs	$ 0.48	$ 0.56	$ 0.50	$ 0.72	$ 0.47	$ (0.01)
Reliability costs (RMR and CPM)	$ 0.90	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ (0.83)
Average total energy costs	**$ 53.32**	**$ 53.60**	**$ 26.28**	**$ 38.15**	**$ 43.78**	**$ (9.54)**
Reserve costs (AS and RUC)	$ 0.53	$ 0.94	$ 1.15	$ 0.46	$ 0.49	$ (0.05)
Average total costs of energy and reserve	**$ 53.85**	**$ 54.54**	**$ 27.42**	**$ 38.61**	**$ 44.27**	**$ (9.59)**

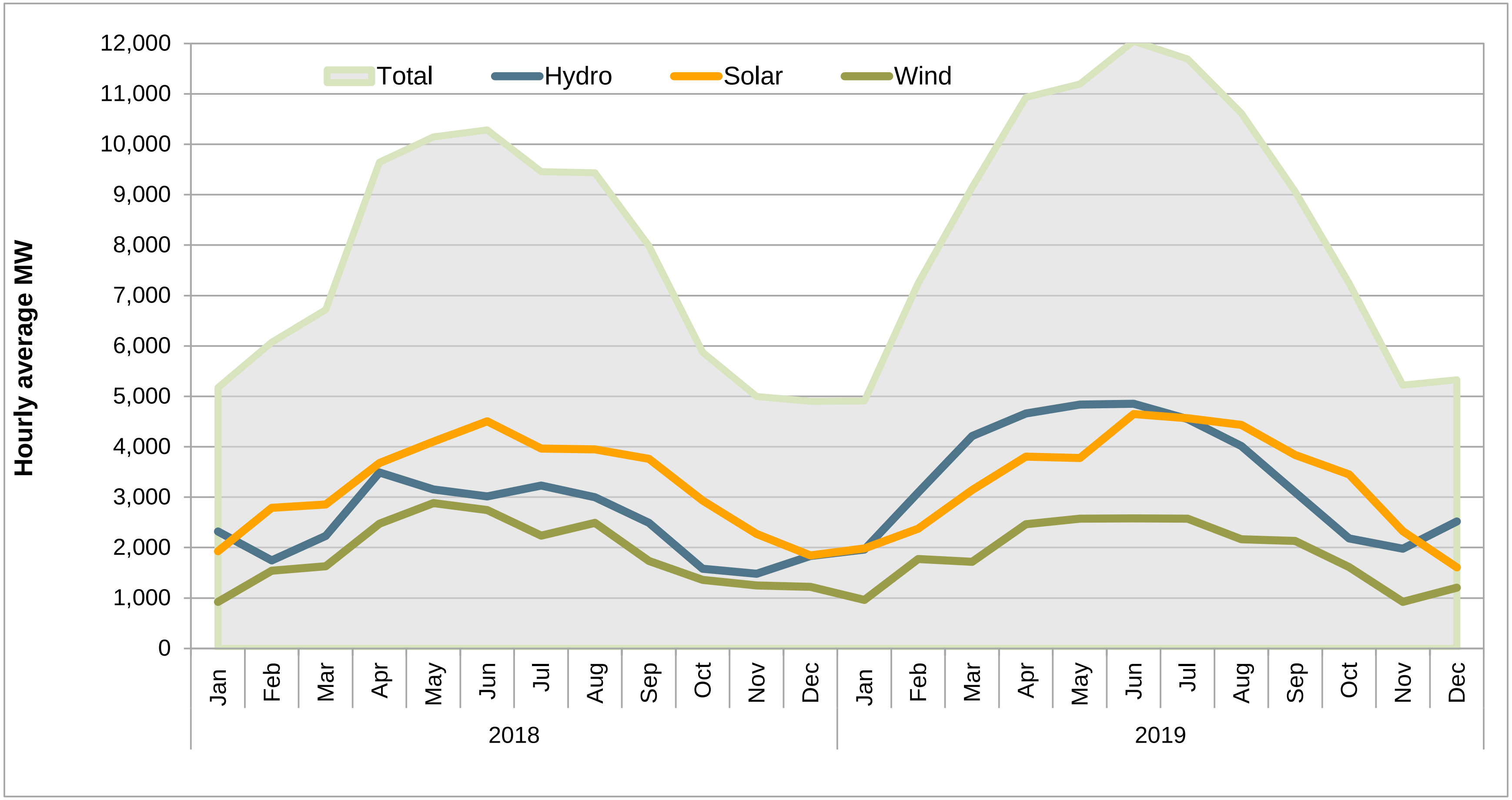
Average CAISO gas prices 19% less than Q4 2018



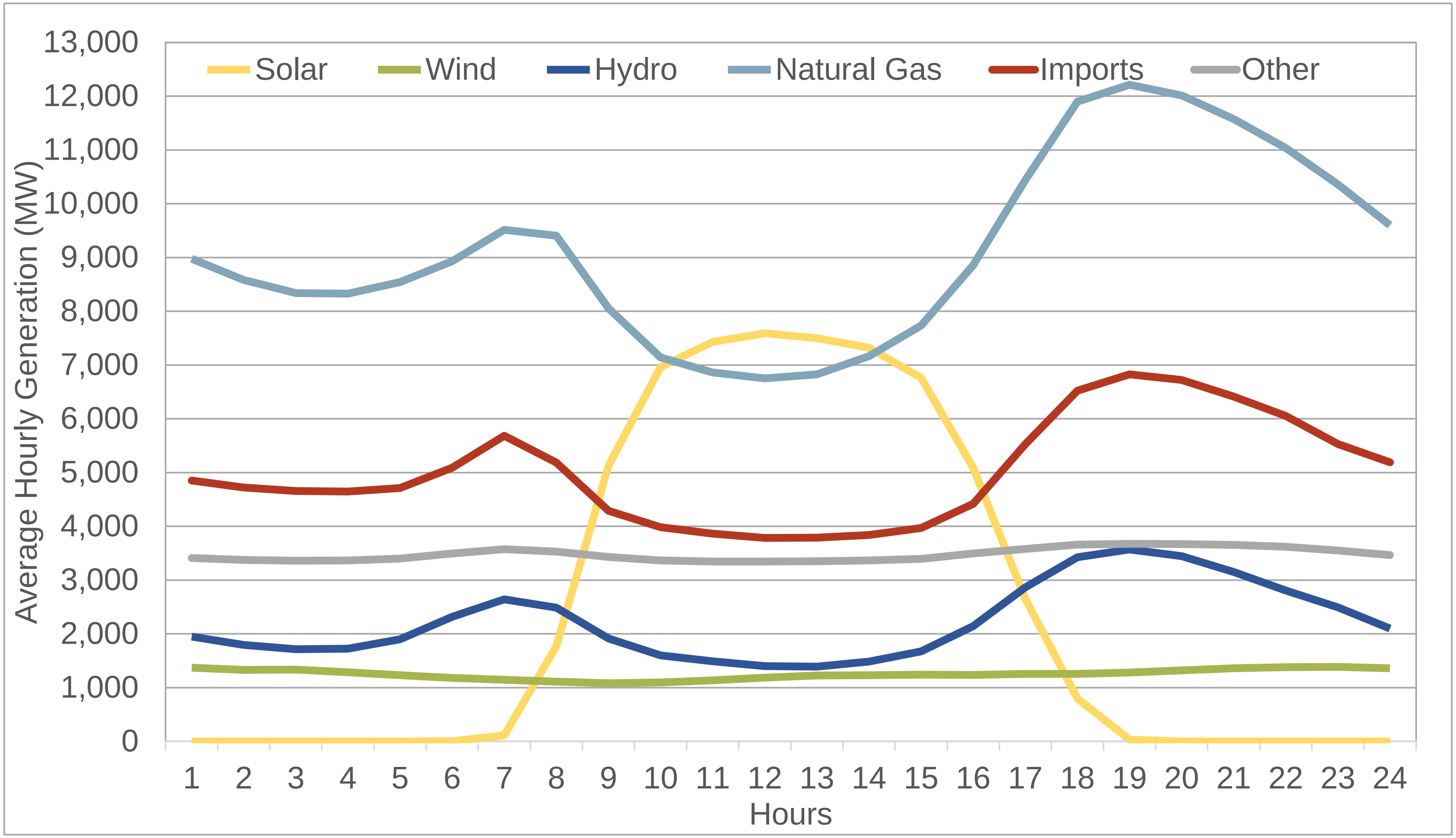
Energy prices decreased compared to the same quarter in 2018, increased over Q3 2019 Day-ahead and 15-minute prices closely aligned



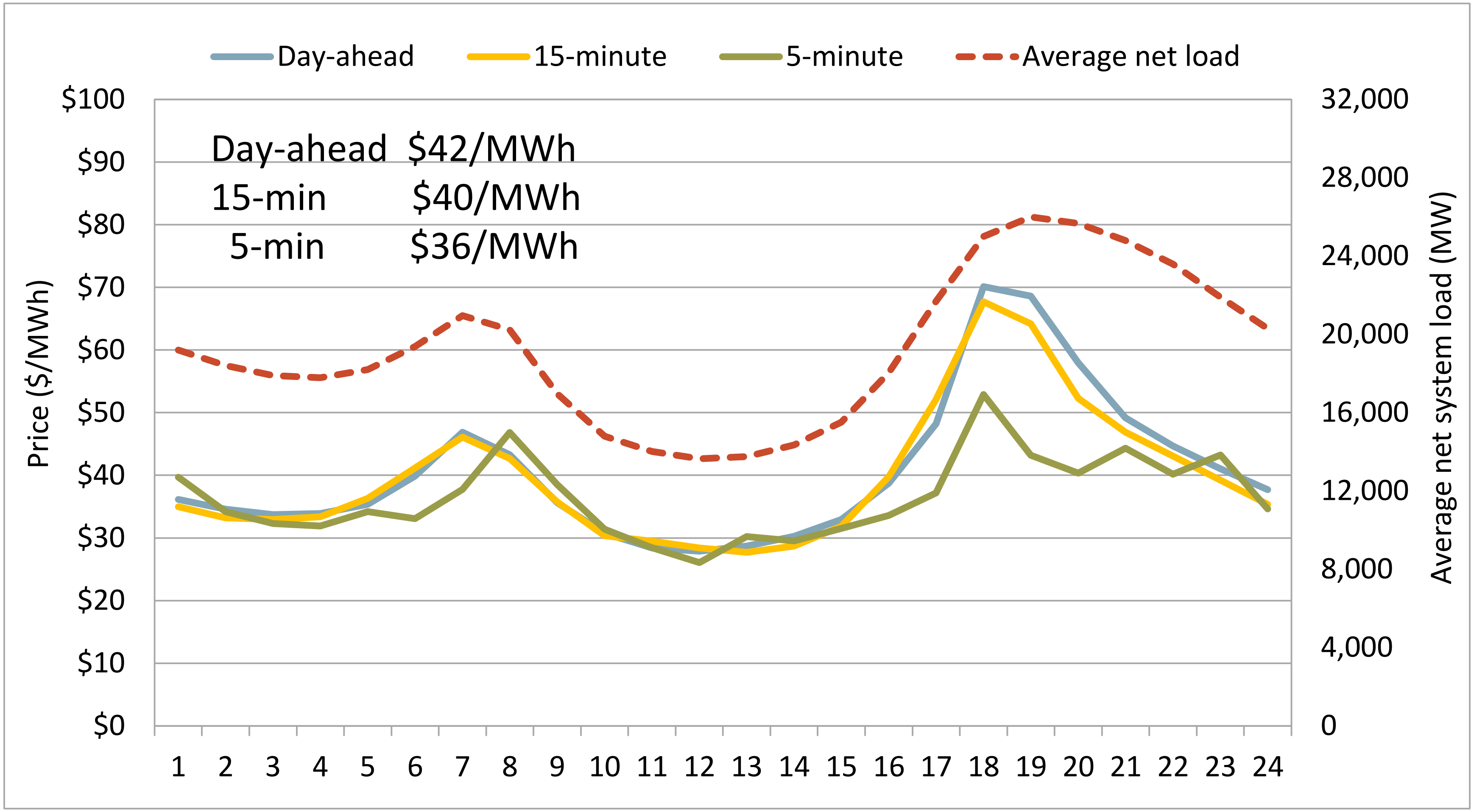
Renewable generation increases over Q4 2018 (13%) due to higher hydro (up 36%)



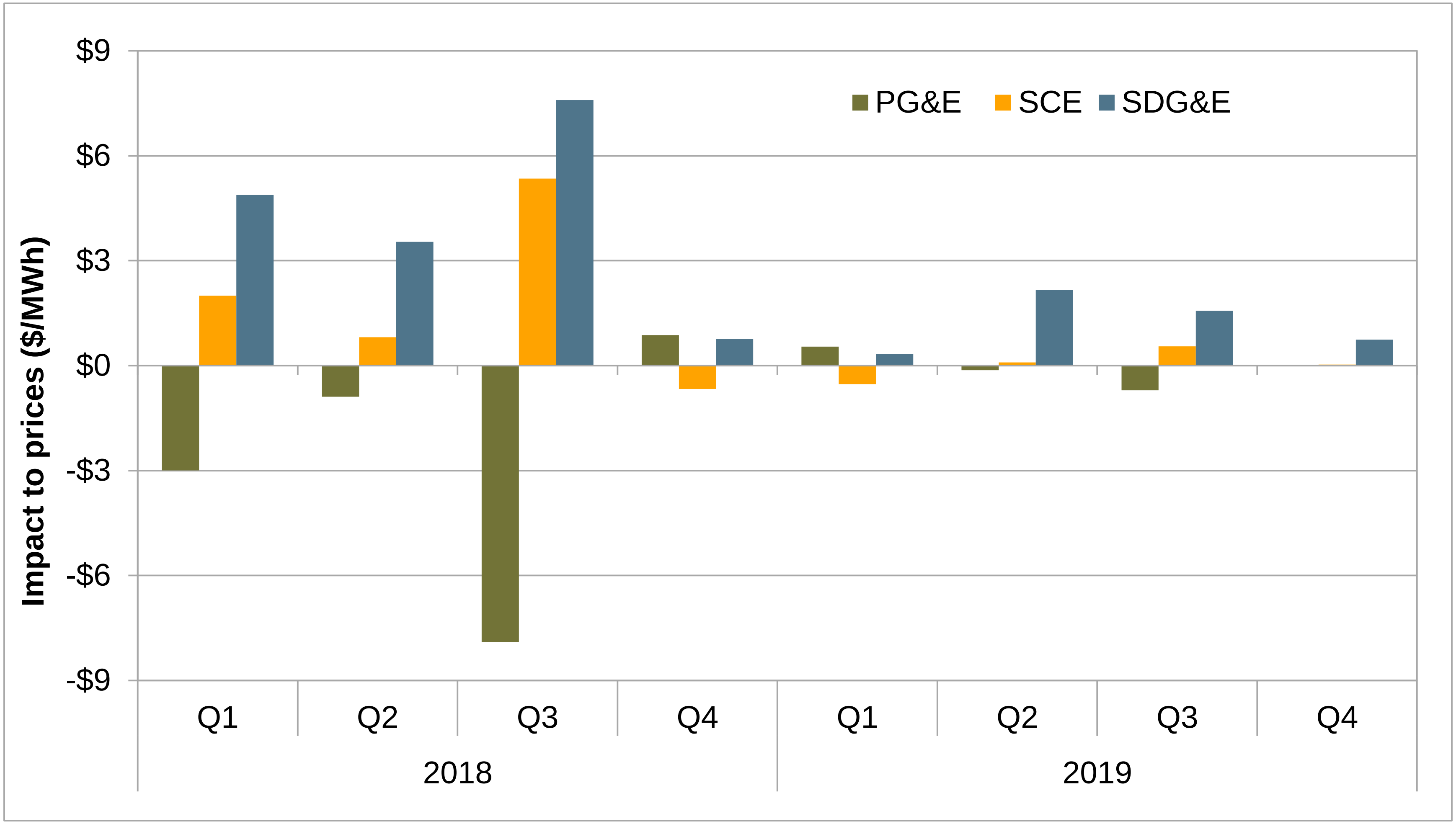
Hourly variation in generation by fuel type (Q4 2019), hourly variation driven by solar



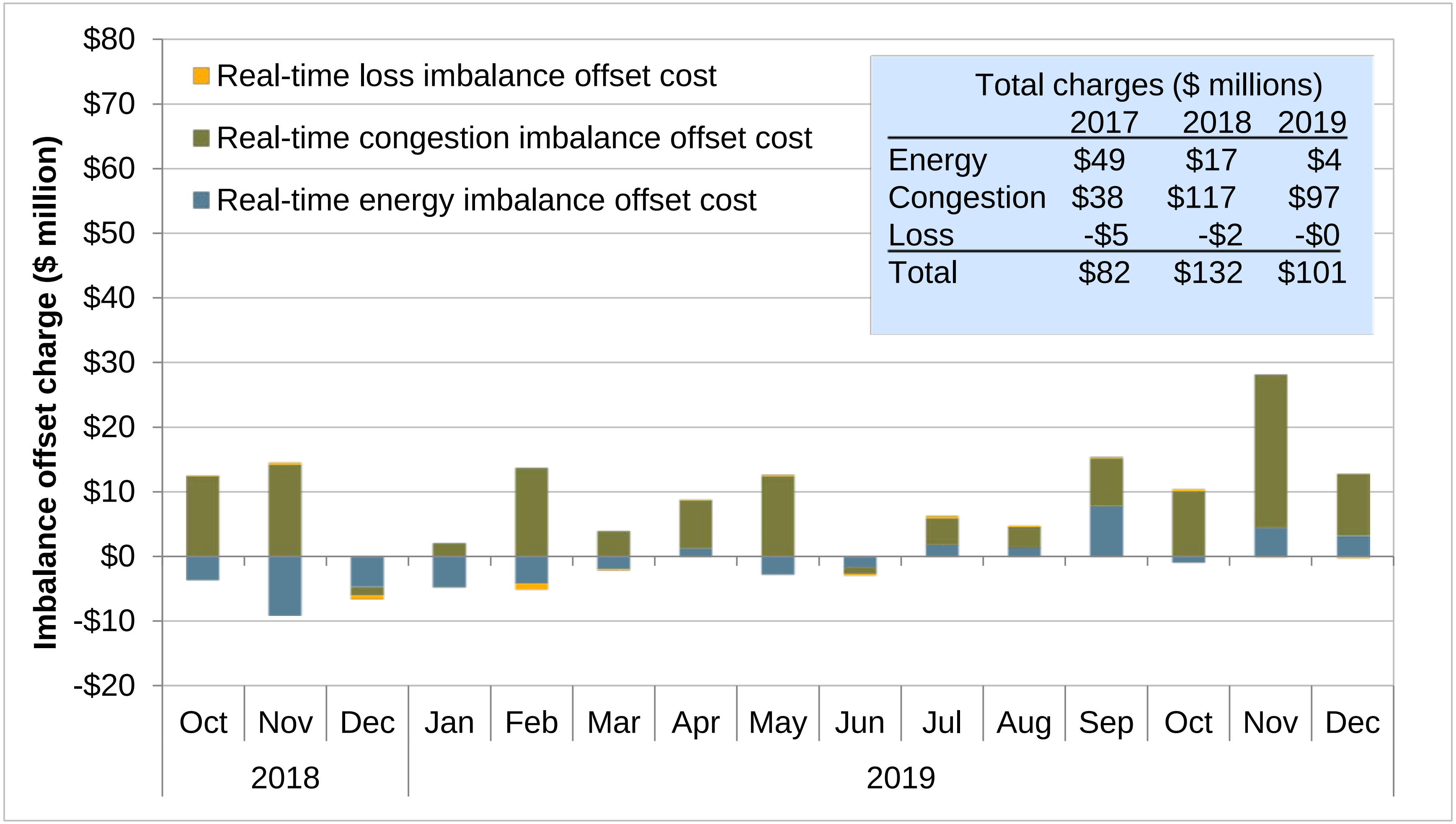
Average prices continue to follow net load, increasing over Q3 2019 with day-ahead prices over real-time



Overall impact of congestion on prices in the day-ahead market continues to be lower in 2019



Offset costs increase to $50 million, over 2% of wholesale energy cost, primarily congestion offset



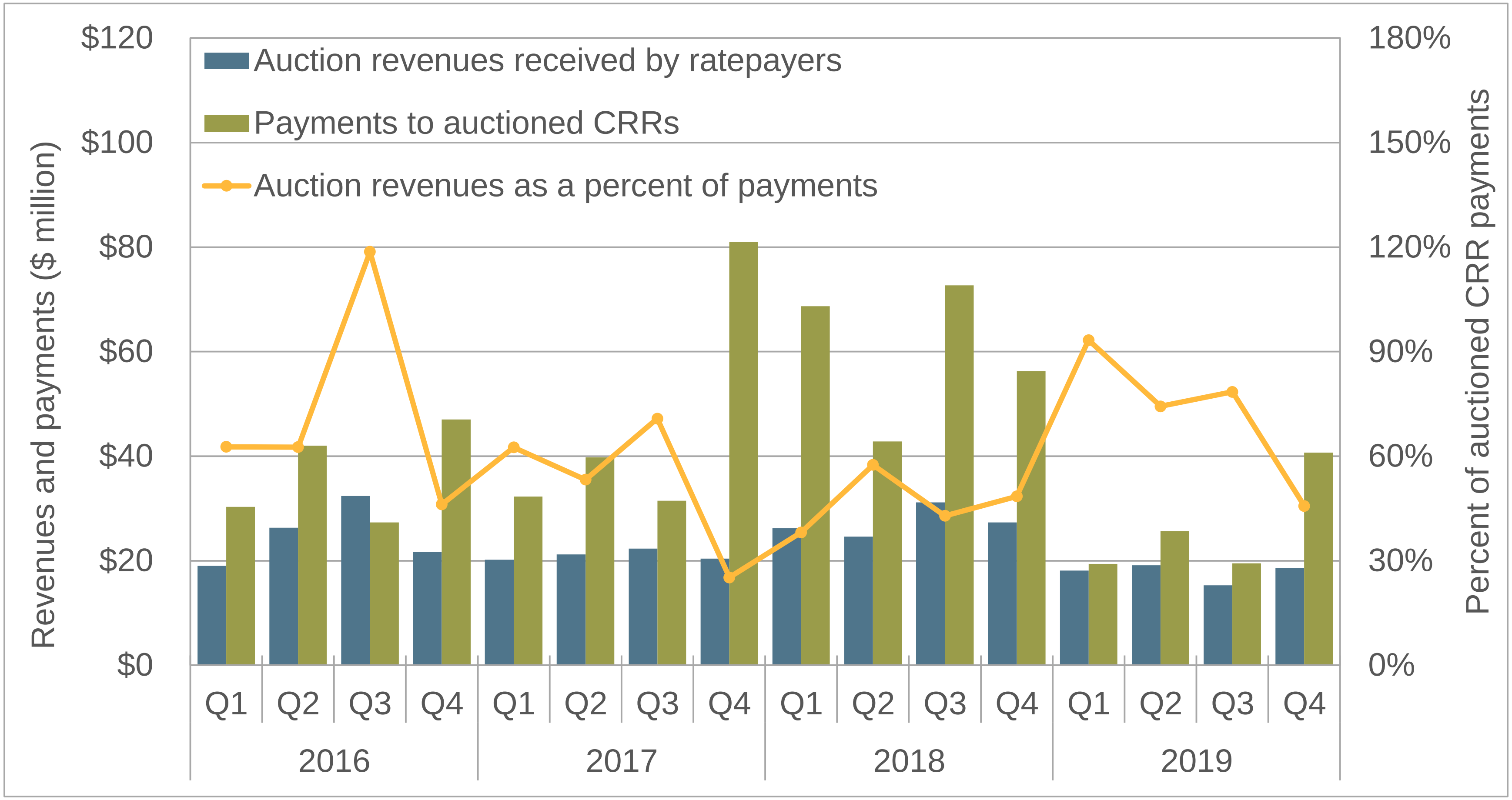
	2017	2018	2019
Energy	$49	$17	$4
Congestion	$38	$117	$97
Loss	-$5	-$2	-$0
Total	$82	$132	$101

Congestion revenue right auction changes implemented January 2019

- **Track 1A:**
  - Significantly reduces the number and pairs of nodes at which congestion revenue rights can be purchased in the auction.
  - Designed to limit auction sales to pairs of nodes with physical generation / load due to potential use as hedges for actual sales and trading of energy.

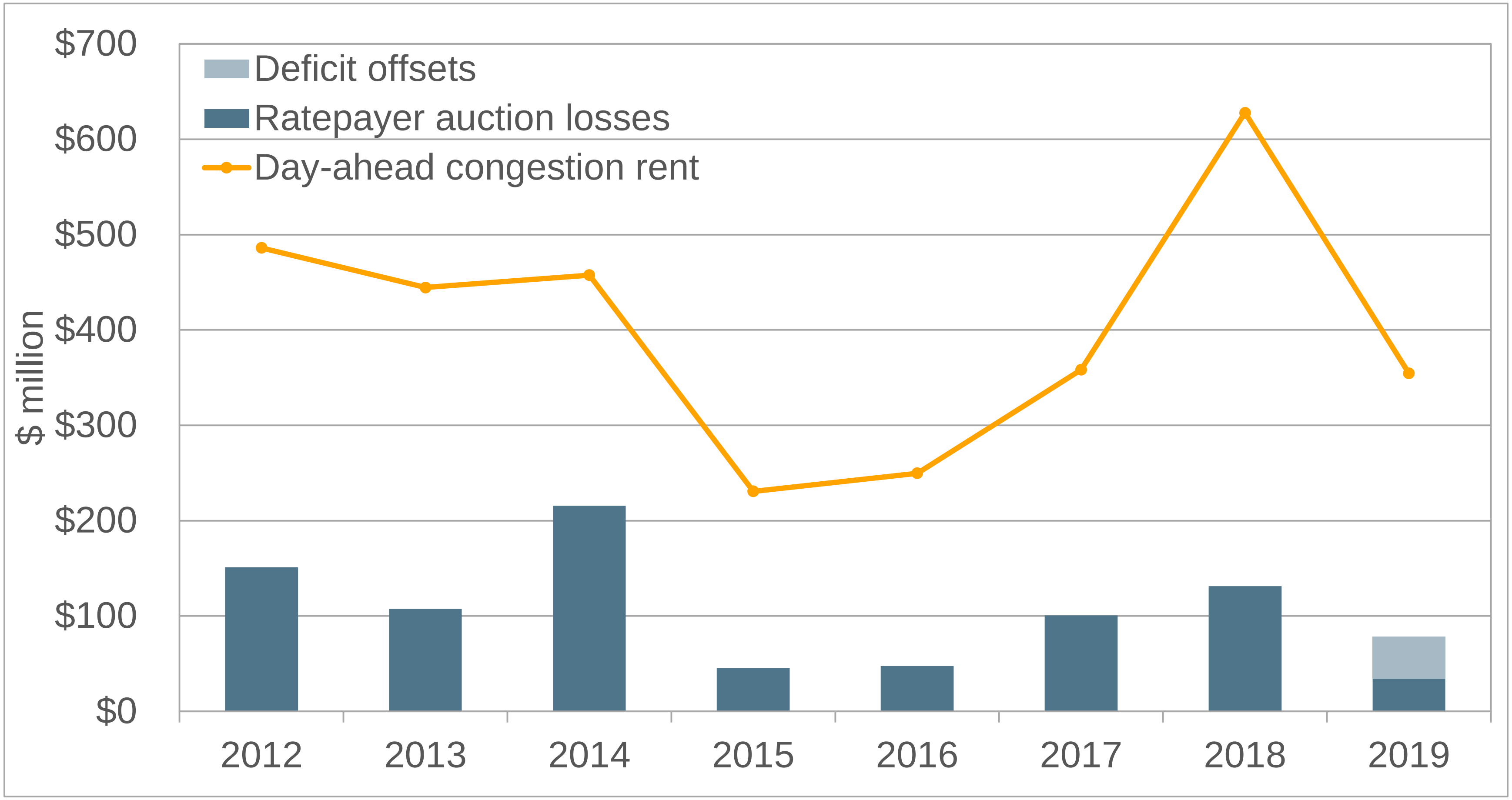
- **Track 1B:**
  - Limits the net payments to CRR holders if payments exceed congestion charges collected in the day-ahead market on a targeted constraint-by-constraint basis.

Congestion revenue right Q4 losses $22 million, auction revenues and payments to non-load-serving entities

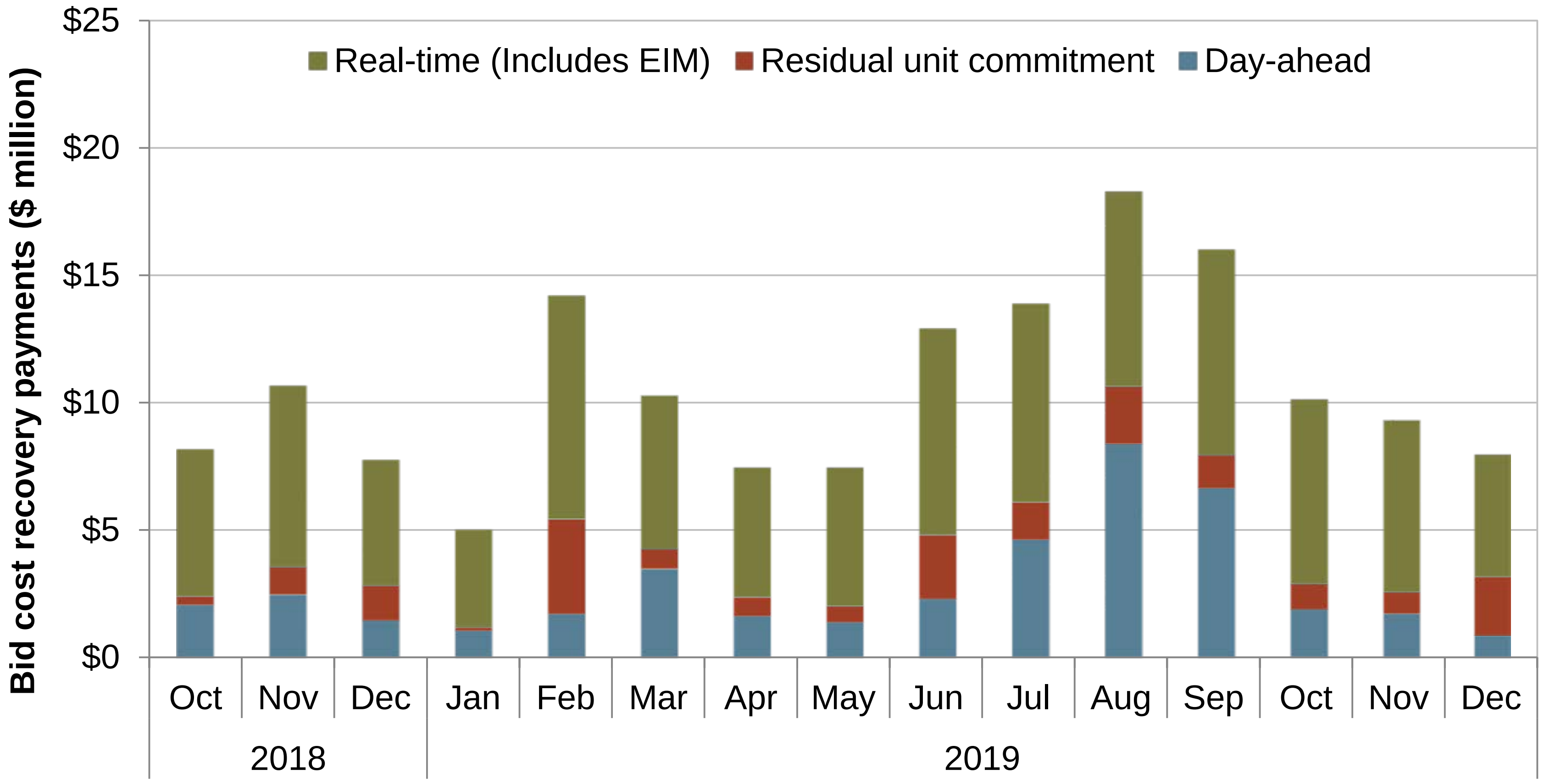


2019 ratepayer losses fall to $34 million from $131 million in 2018, driven by auction changes and lower congestion

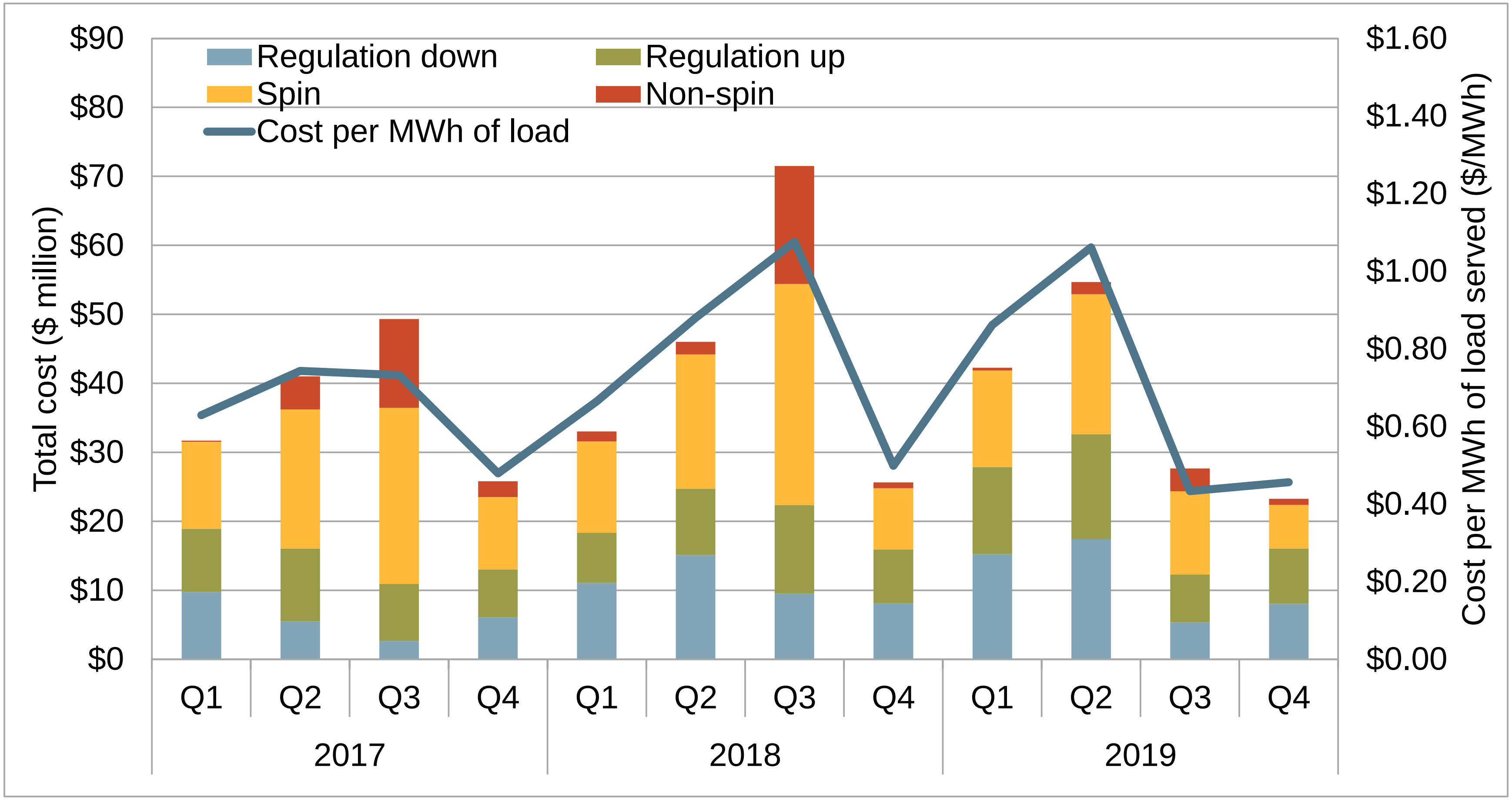
http://www.caiso.com/Documents/ReportonResultsof2019CongestionRevenueRightsAuction-Jan272020.pdf



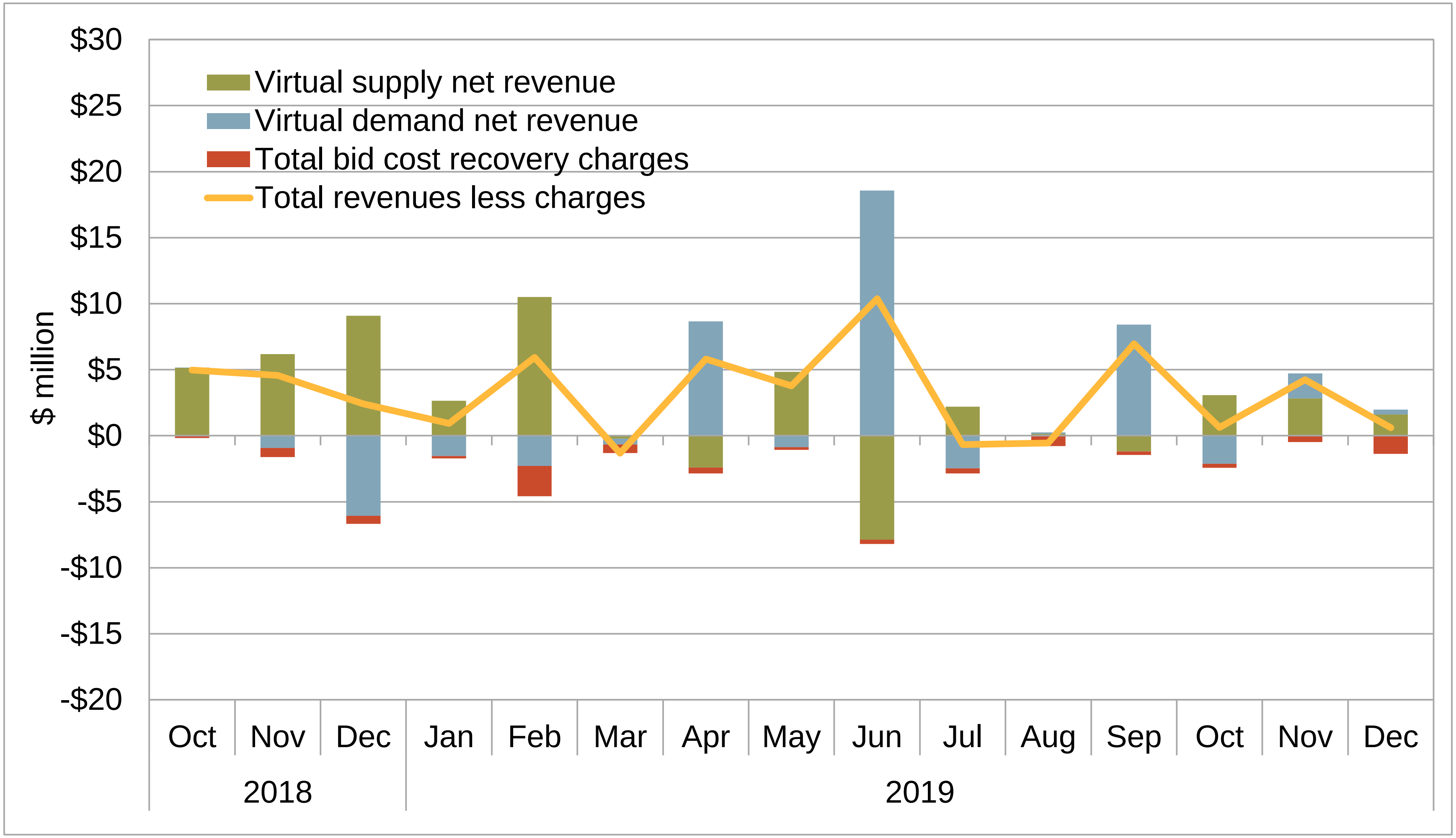
Q3 bid cost recovery $27.4 million, down from Q3 ($48 million) and about equal to Q4 2018 ($26.6m)



Ancillary service cost total $23 million, lower than Q3 despite an increase in scarcities



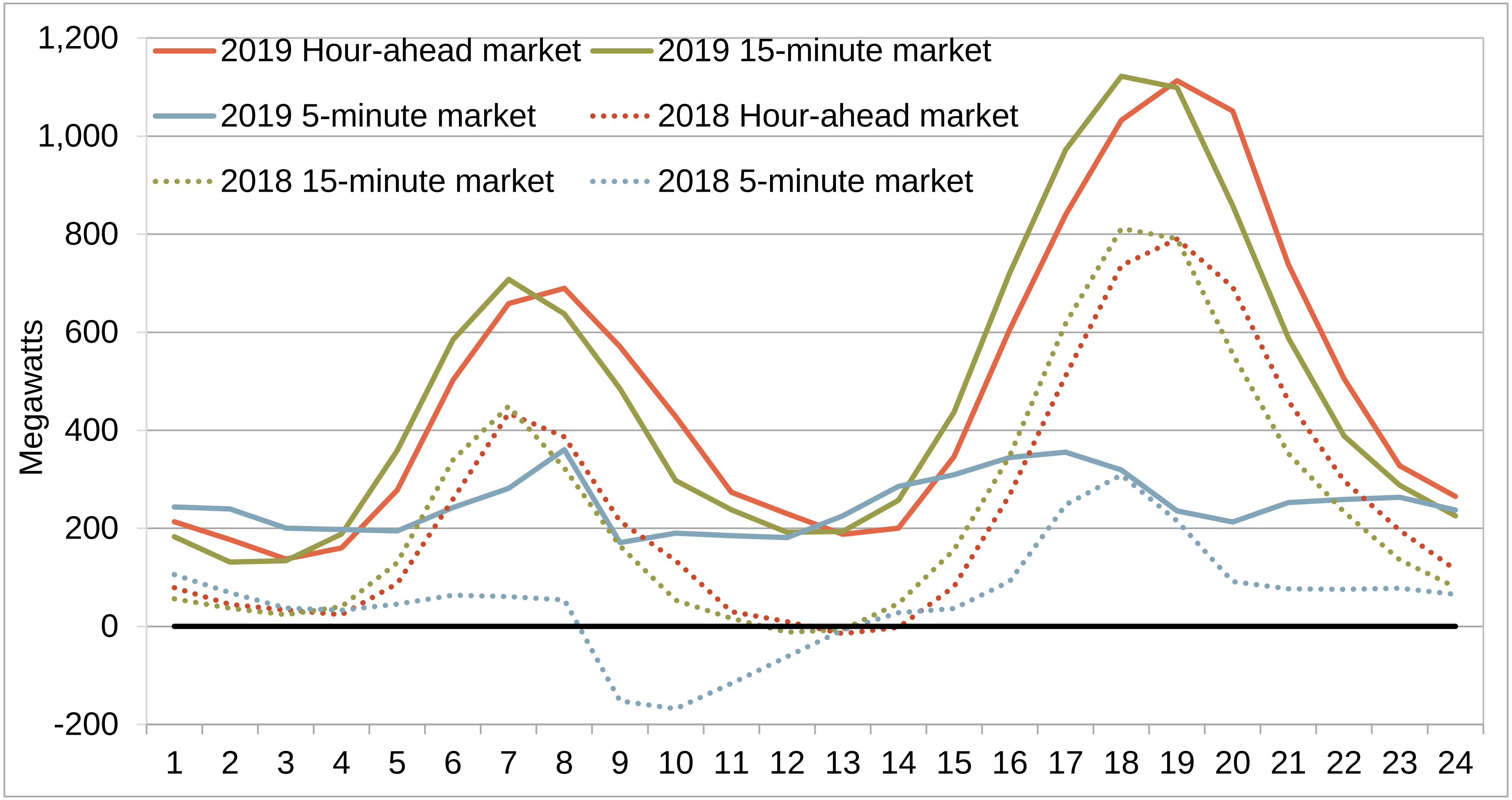
Convergence bidding revenue totaled $5.5 million in Q4, with most revenue to financial virtual supply



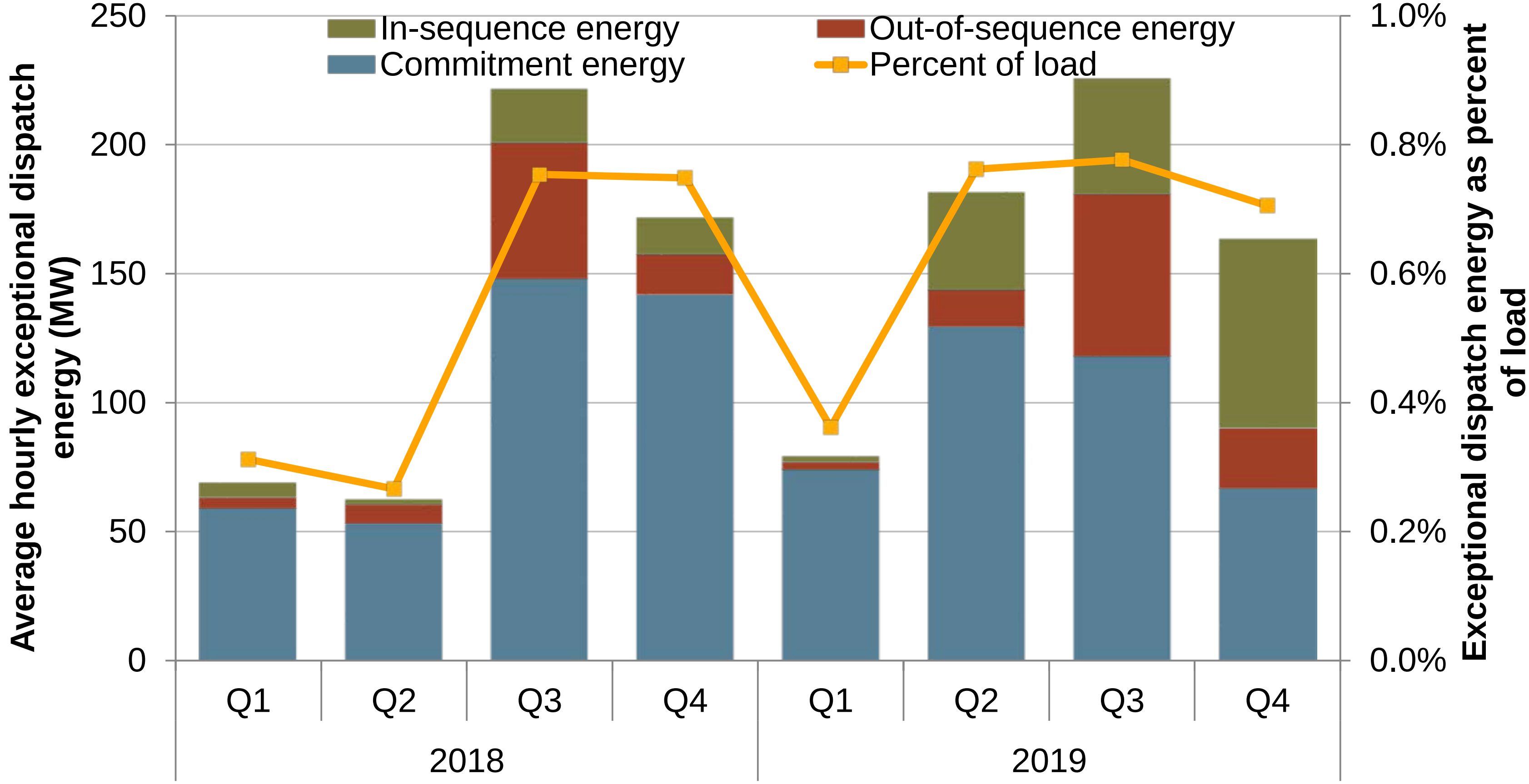
Flexible ramping capacity

- Flexible ramping prices were frequently zero
- Total uncertainty payments to generators were around $1.5 million, compared to around $0.6 million in Q3
- Recent ISO and DMM reports highlighted several issues with design and implementation including:
  - 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

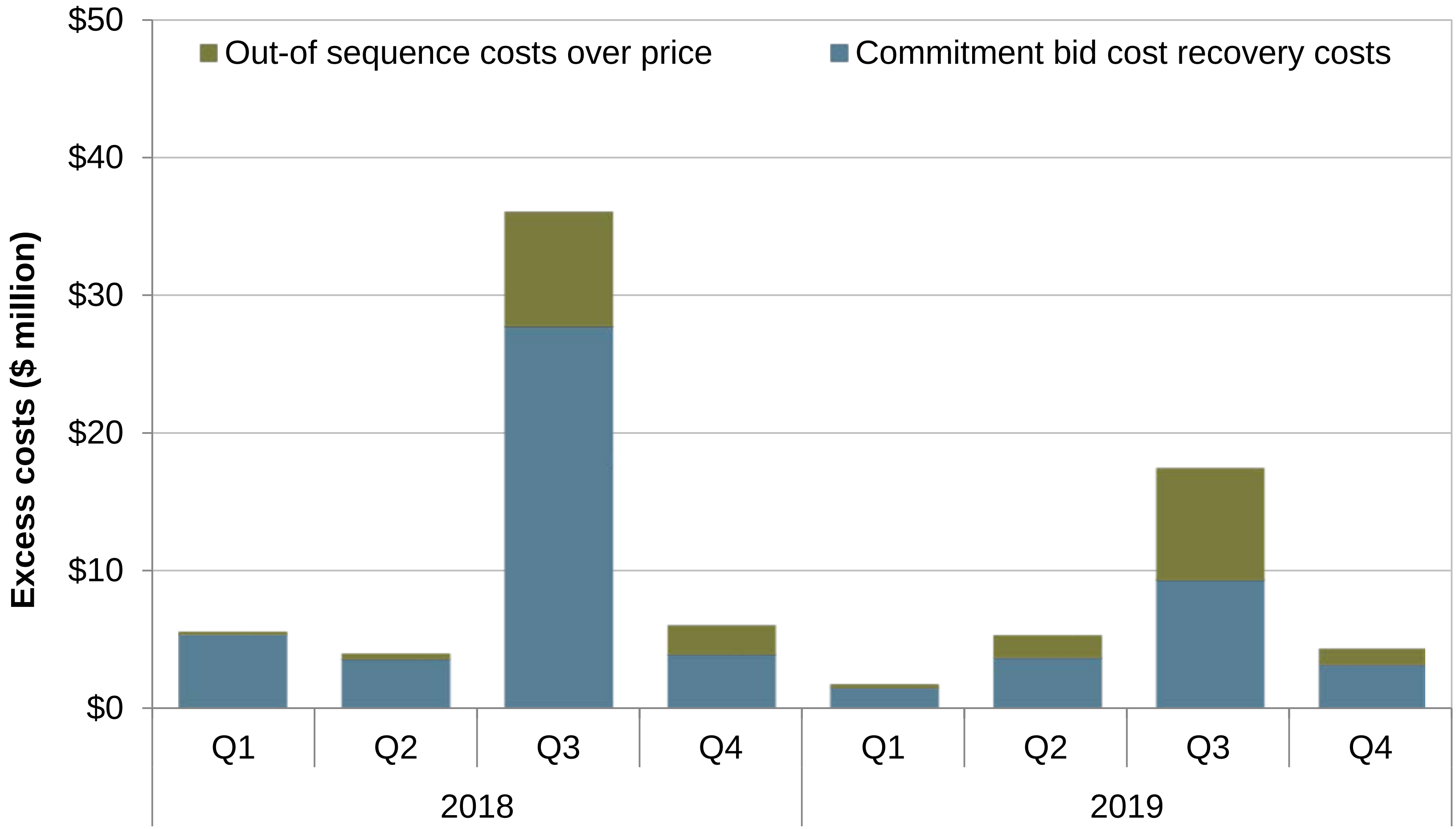
Average hourly load adjustment increase despite moderate system conditions (Q4 2018, Q4 2019)



Average hourly energy from exceptional dispatch was lower than Q4 2018 totaling 0.71% system load



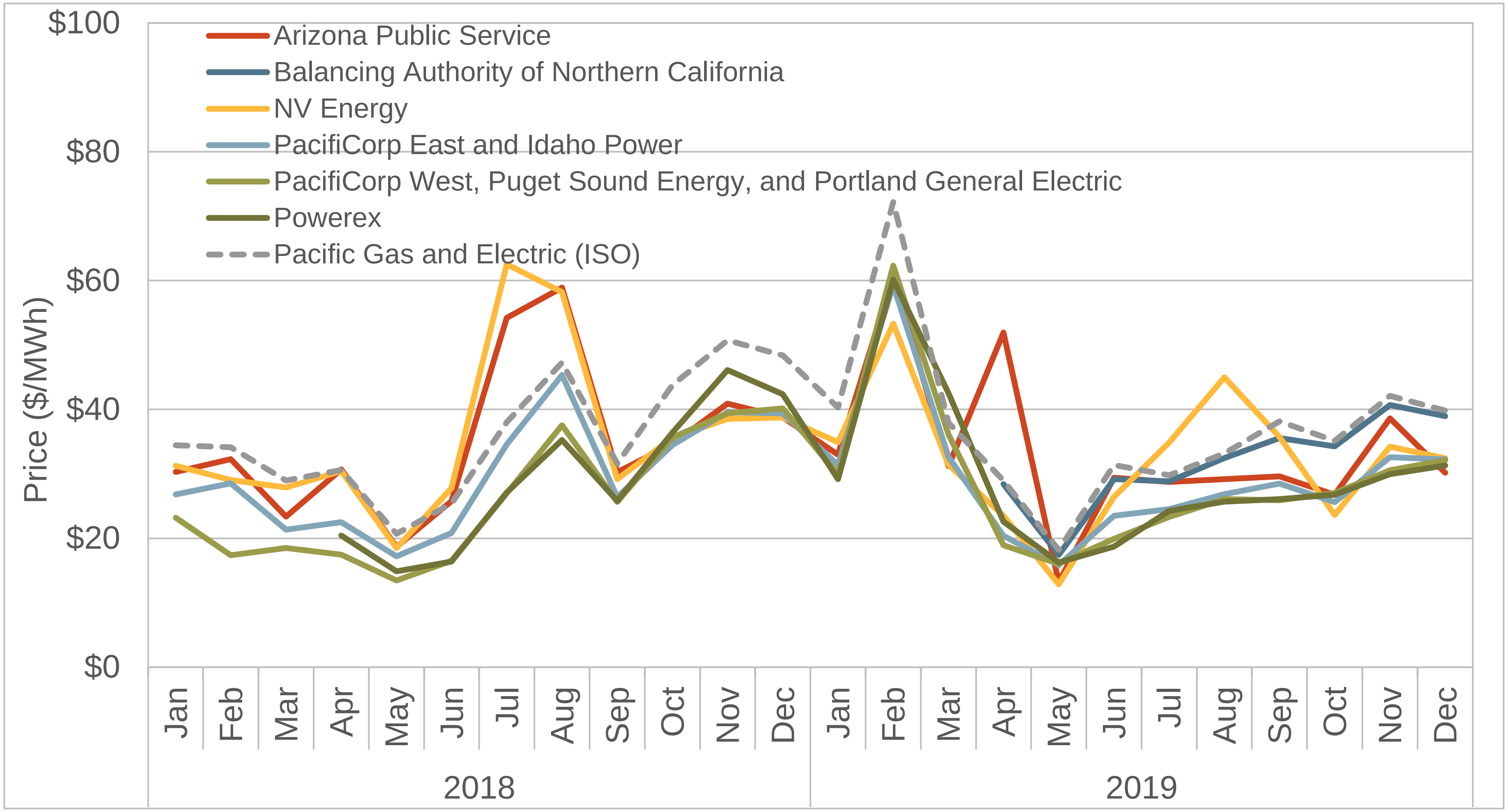
Exceptional dispatch cost total $4.4 million



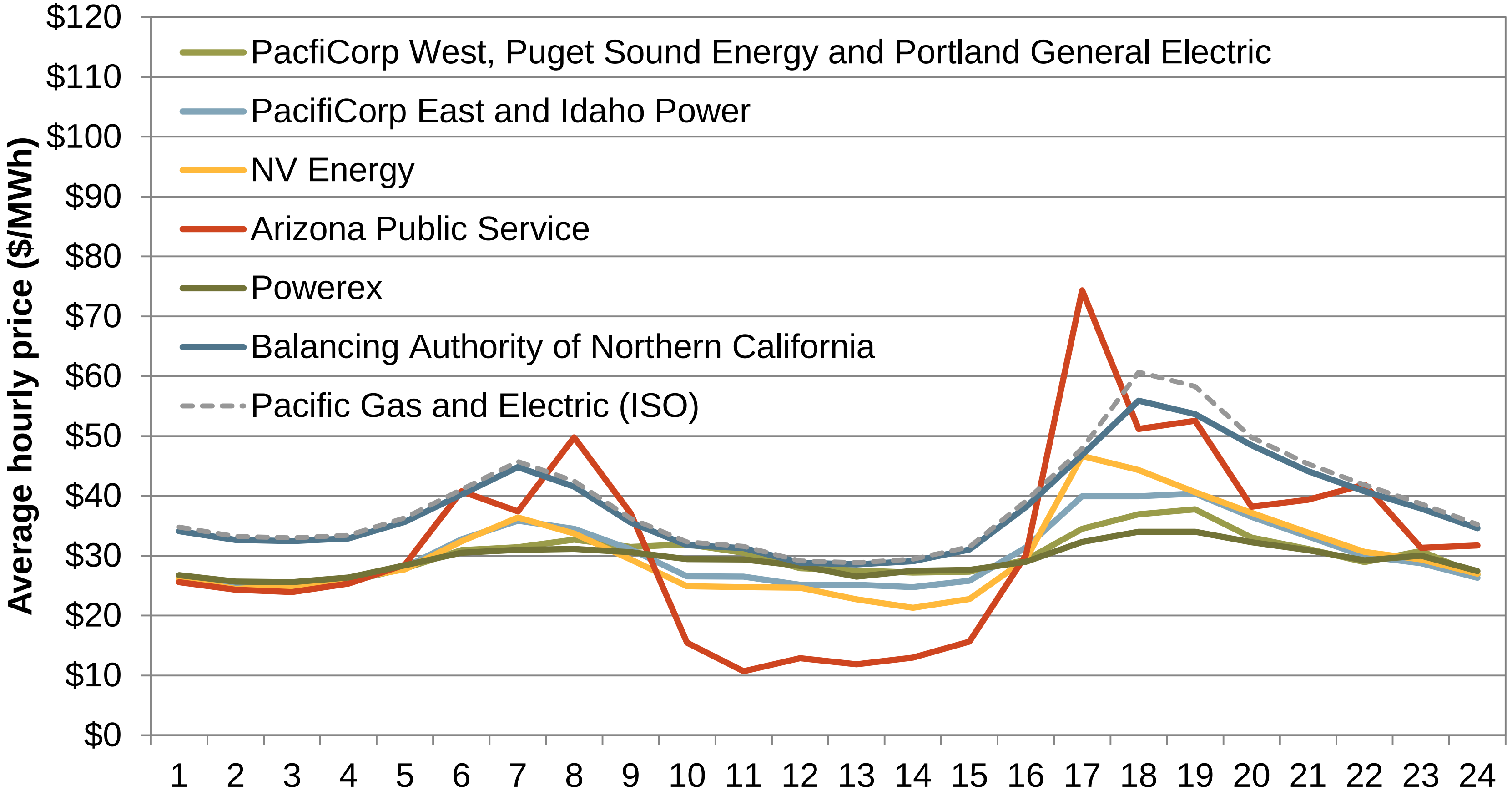
EIM highlights

- May 2019 sufficiency test enhancement decreases failure frequency.
- February load conformance limiter enhancement impacts prices Arizona Public Service and NV Energy
- During peak system load hours, prices in the Northwest region (PacifiCorp West, Puget Sound Energy, Portland General Electric, and Powerex) were low relative to other EIM areas due to limited transmission capacity.
- Congestion imbalance deficits related to base schedule changes remained very low

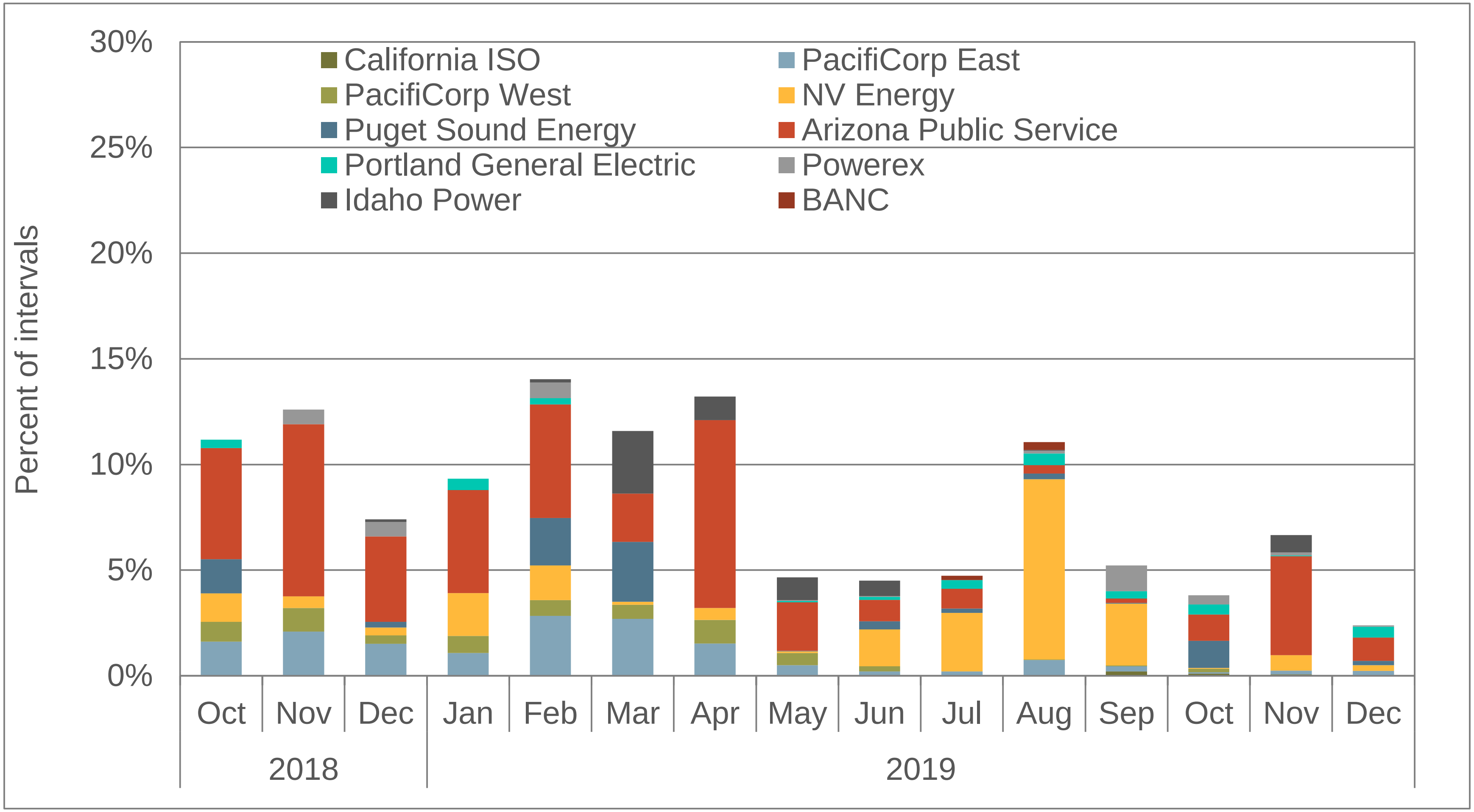
Prices in NV Energy and APS driven up by power balance constraint violations following resource sufficiency test failures in some months (15 minute market)



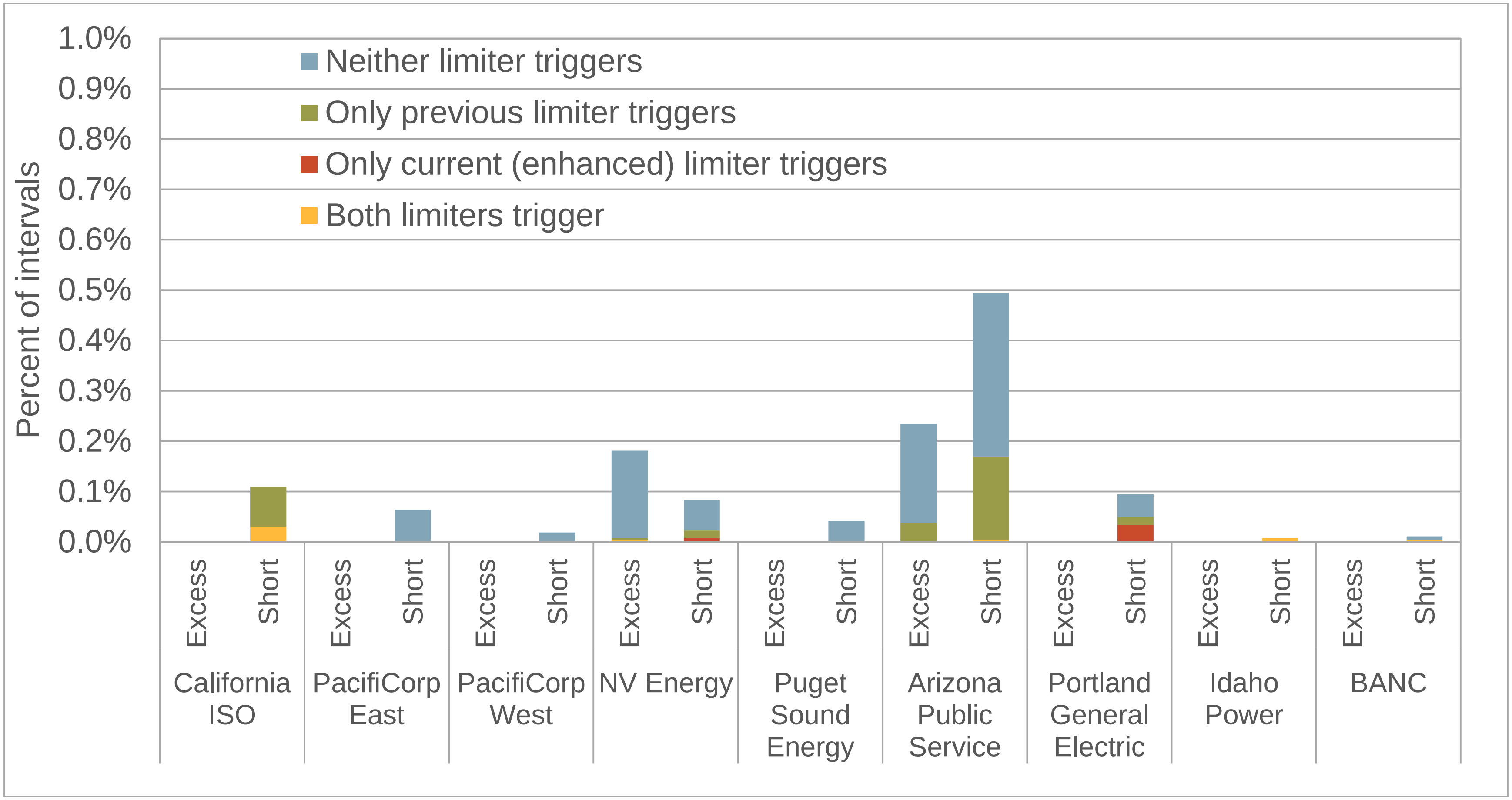
Recent EIM price trends continue in Q4 – with lower prices in north and higher prices in south of CAISO/EIM footprint during peak net load hours



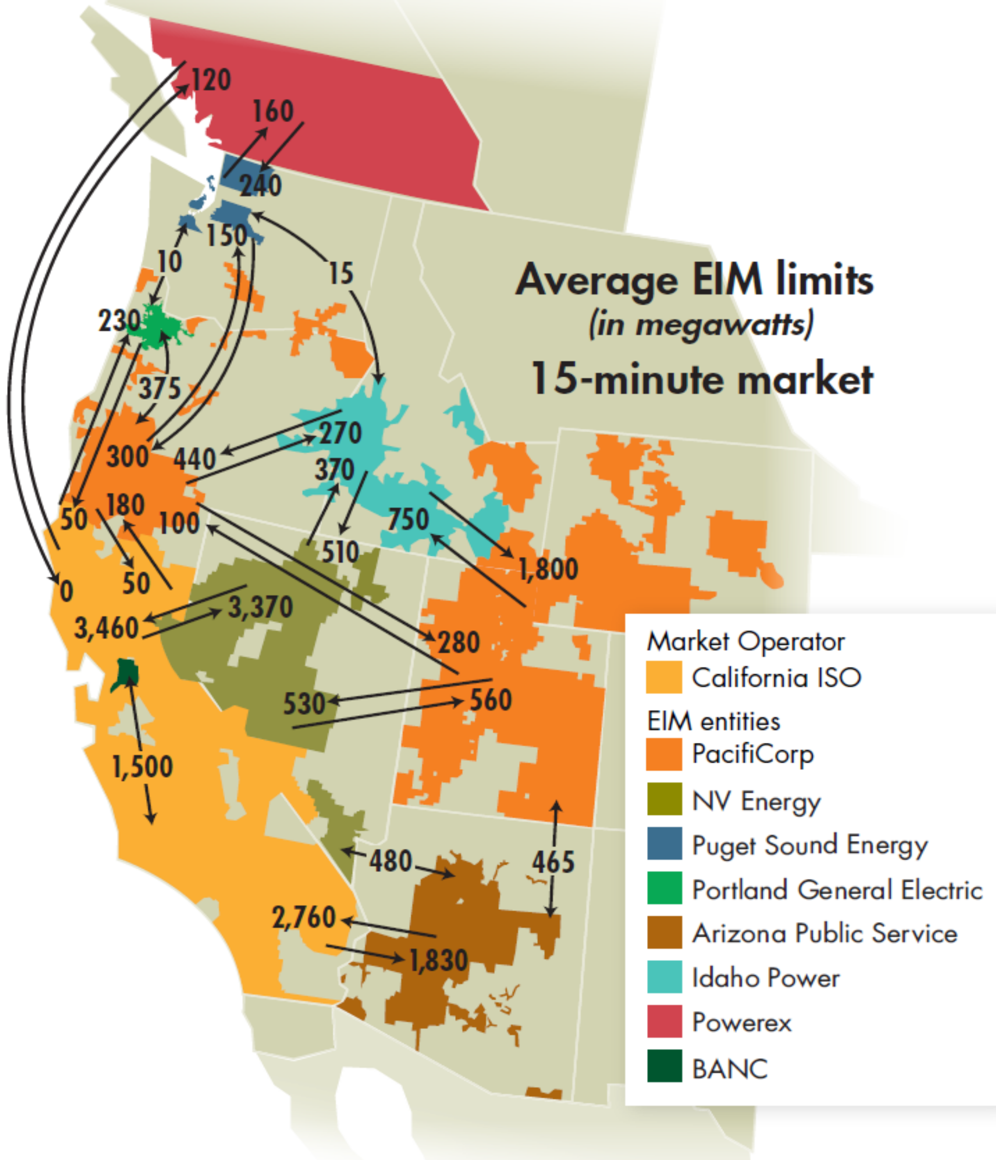
Frequency of upward failed sufficiency tests falls following May 2019 change



Q4 frequency of load conformance limiter in the 5-minute market, prices set at penalty more often after February policy change



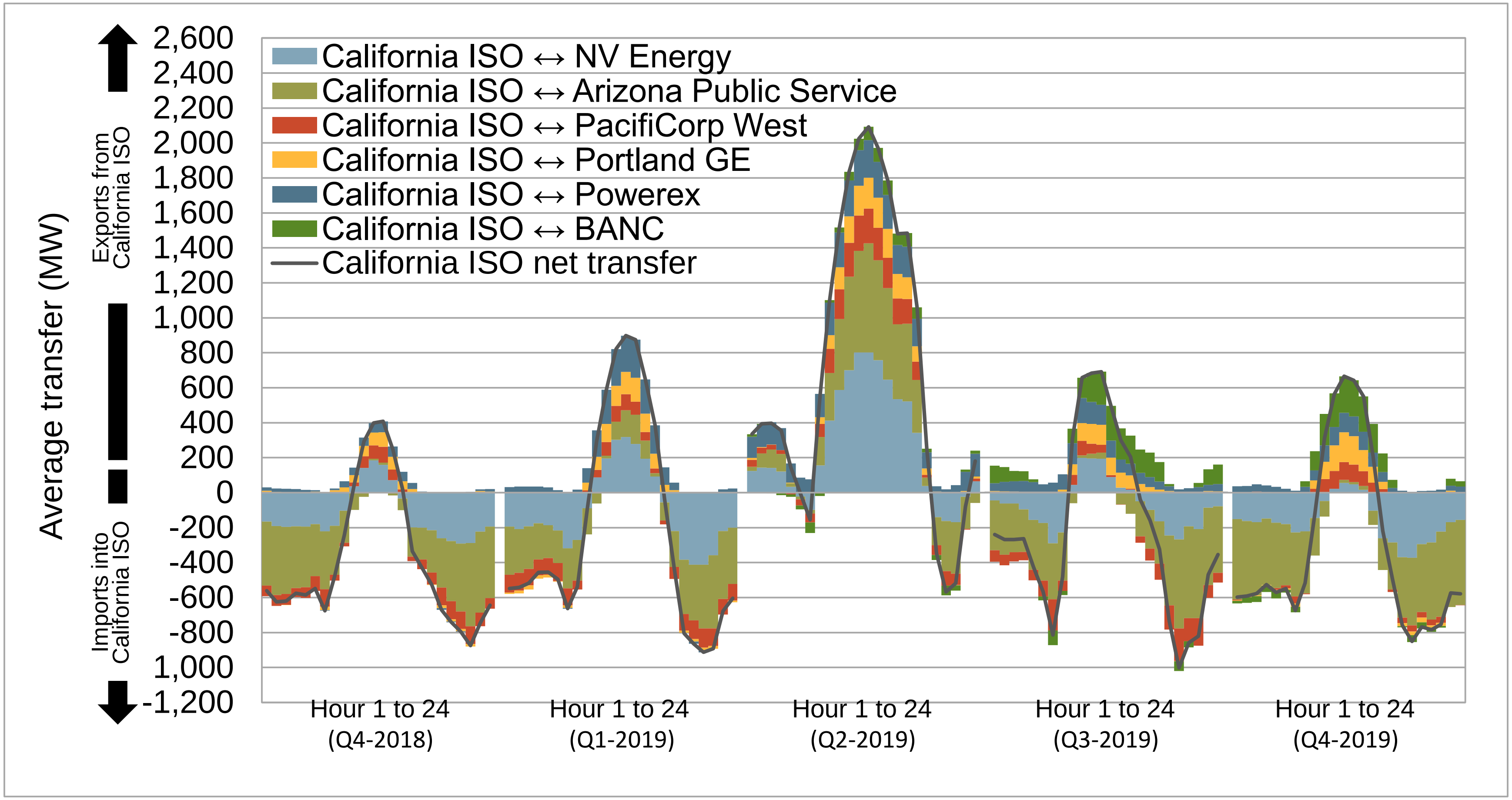
Average 15-minute market energy imbalance market limits



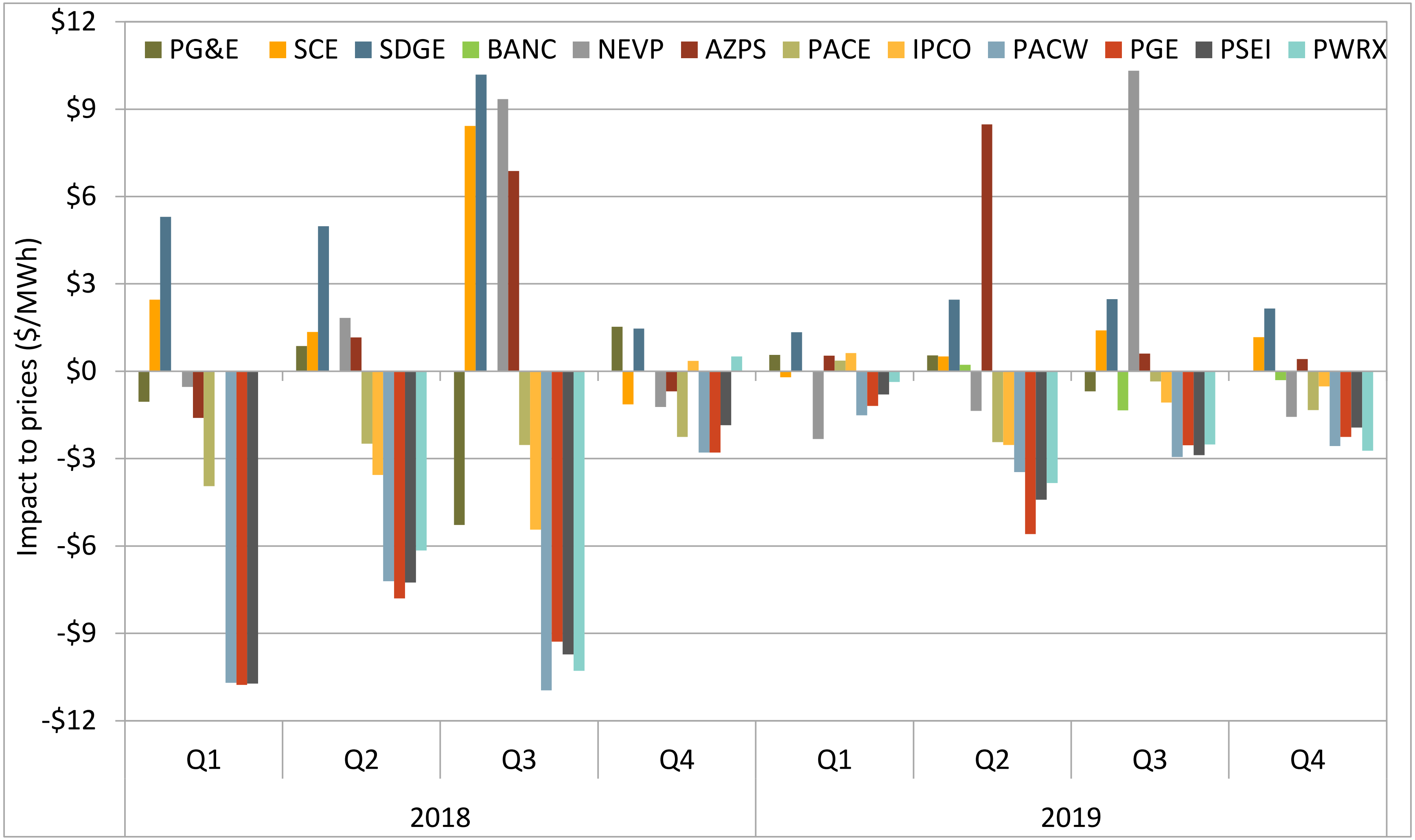
Congestion between an EIM area and the ISO causes price separation

	15-minute market		5-minute market	
	Congested toward ISO	Congested from ISO	Congested toward ISO	Congested from ISO
BANC	0%	0%	0%	0%
Arizona Public Service	0%	2%	0%	1%
PacifiCorp East	2%	0%	1%	1%
Idaho Power	2%	3%	1%	4%
NV Energy	1%	0%	1%	0%
PacifiCorp West	26%	4%	13%	5%
Portland General Electric	26%	4%	13%	5%
Puget Sound Energy	26%	12%	13%	15%
Powerex	28%	16%	16%	27%

California ISO - average hourly 15-minute market transfer



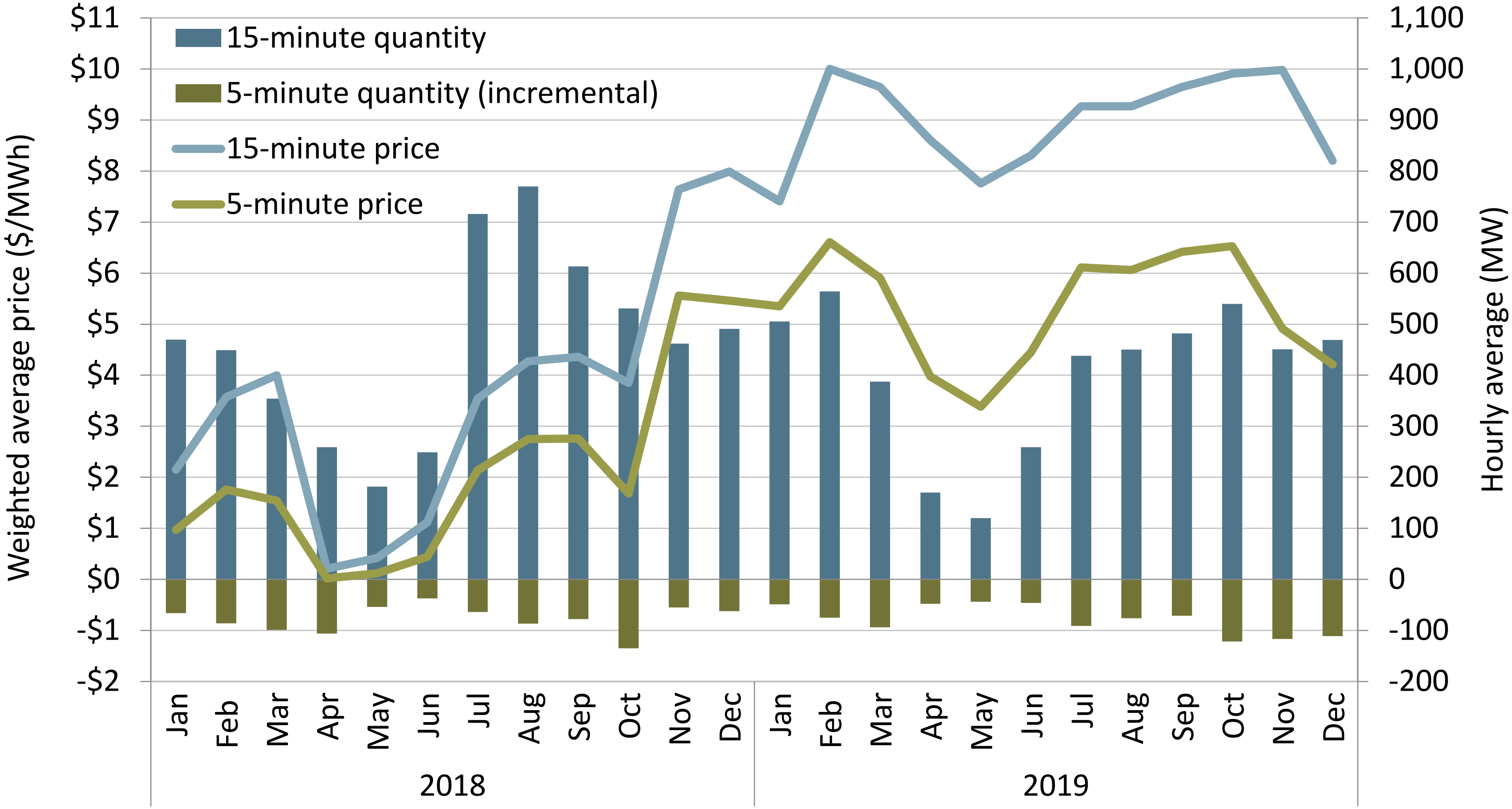
Impact of congestion on 15-minute prices



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

	Annual				2019 Quarterly			
Balancing Authority Area	**2016**	**2017**	**2018**	**2019**	**Q1**	**Q2**	**Q3**	**Q4**
Arizona Public Service	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
BANC				$0.0	$0.0	$0.0	$0.0	$0.0
Powerex	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
California ISO	-$51.1	-$26.2	-$70.4	-$92.3	-$17.9	-$18.4	-$14.0	-$42.0
Idaho Power Company			$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
NV Energy	-$0.3	-$0.8	-$0.3	-$0.4	-$0.3	-$0.1	$0.0	$0.0
PacifiCorp - East	-$4.0	-$18.1	-$2.0	$0.7	$0.8	$0.0	$0.1	-$0.3
PacifiCorp - West	$0.0	$0.0	-$0.1	$0.0	$0.0	$0.0	$0.0	$0.0
Portland General Electric		$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Puget Sound Energy	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0

Western EIM greenhouse gas prices increased as the deemed delivered resources shifted from lower to higher greenhouse gas emissions after November 2018 change



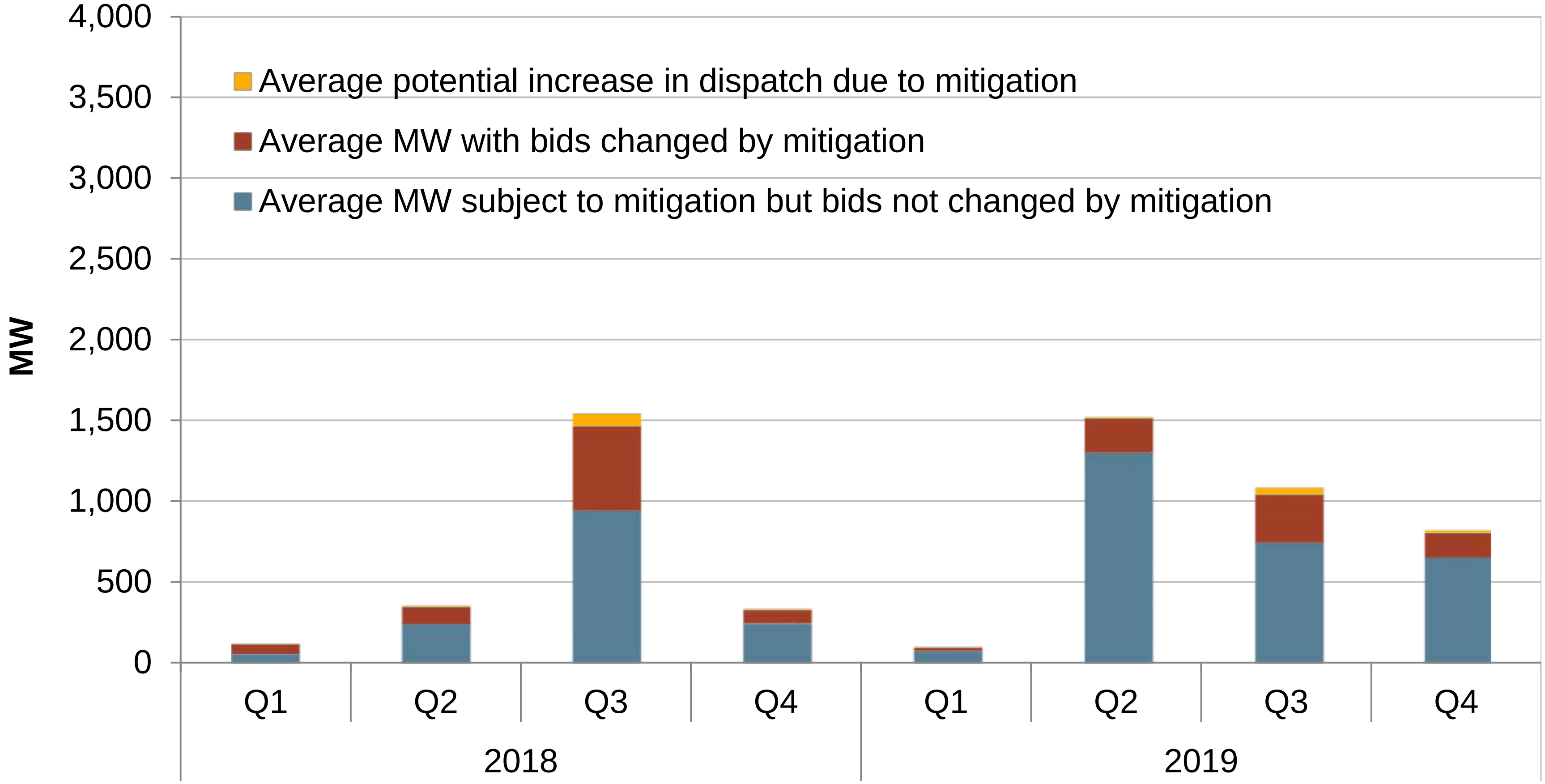
Energy storage and distributed energy resources phase 3 implementation had little market impact

- Implemented November 13
- Added new demand response dispatch options (hourly and 15-minute)
- Removed single load-serving entity aggregation requirement
  - Expected to increase registration of aggregations >1MW
- Little use of either new option

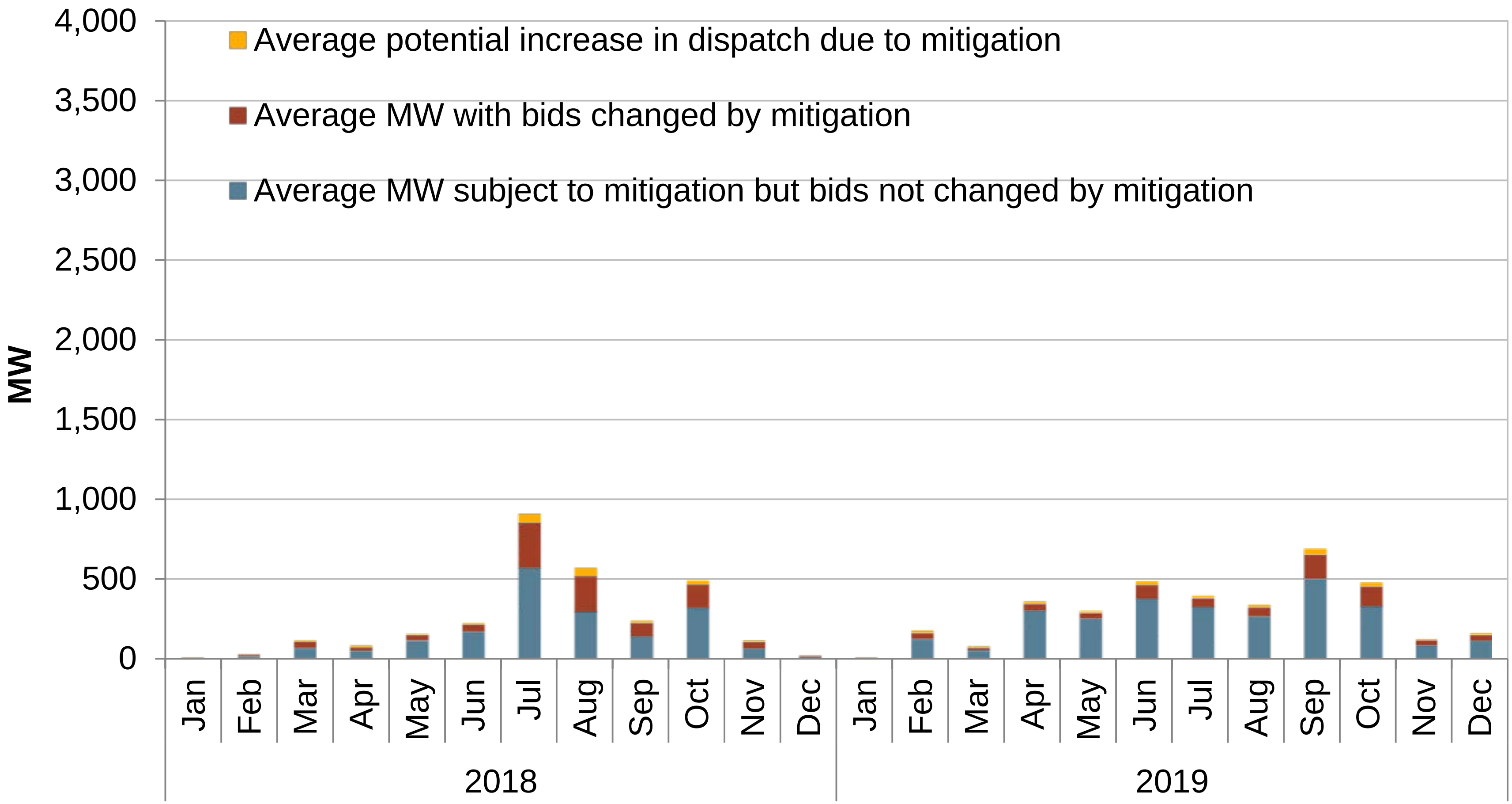
Local market power mitigation enhancements

- Implemented November 13, 2019
- Eliminated carryover mitigation in both real-time markets
- Added a new default energy bid option (hydro DEB//0
- Proposal to allow an EIM entity balancing authority area to limit dispatch of incremental net exports when mitigation is triggered due to import congestion was rejected by FERC

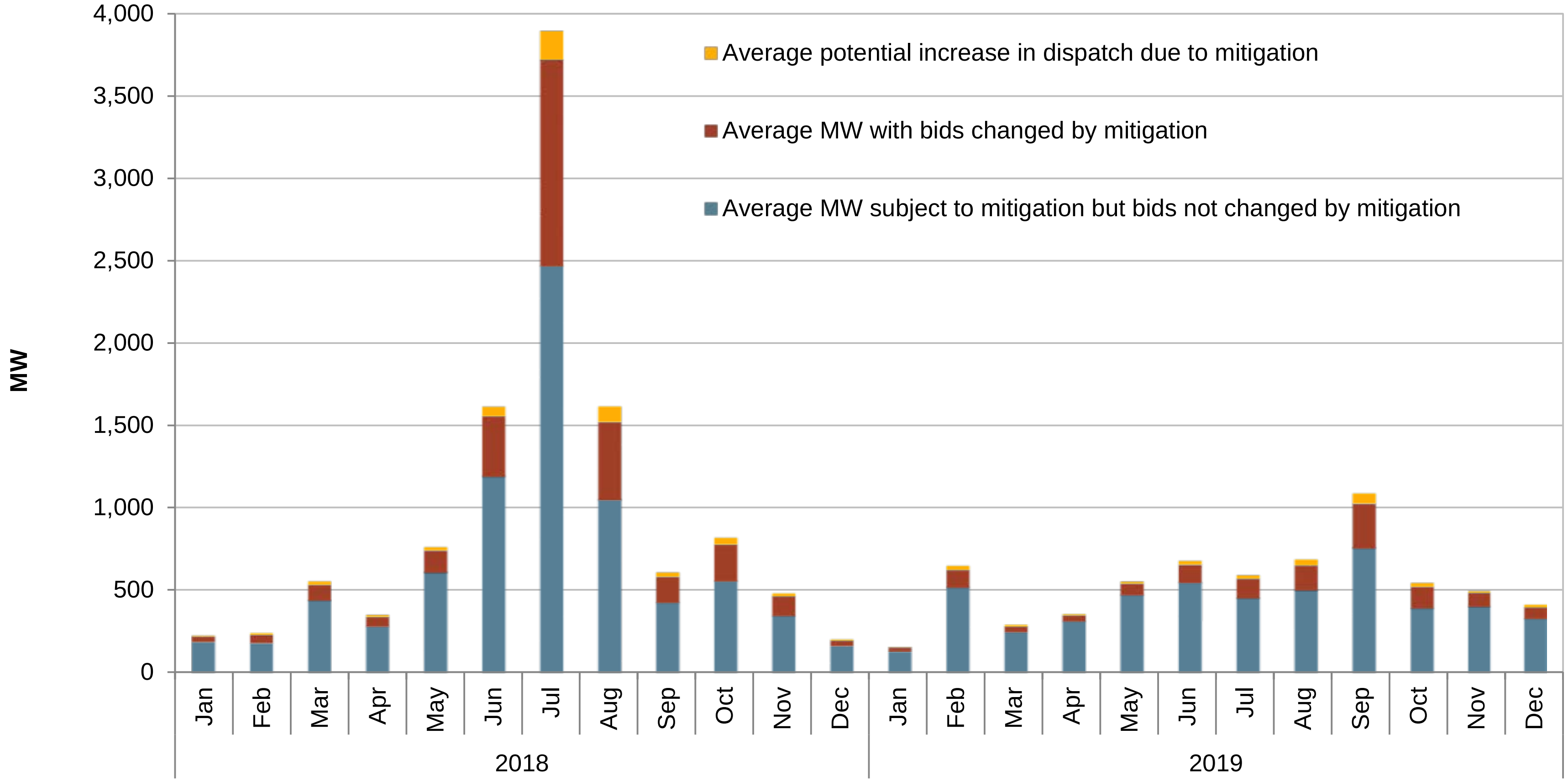
Elimination of carryover mitigation reduced rates of mitigation in the ISO and EIM



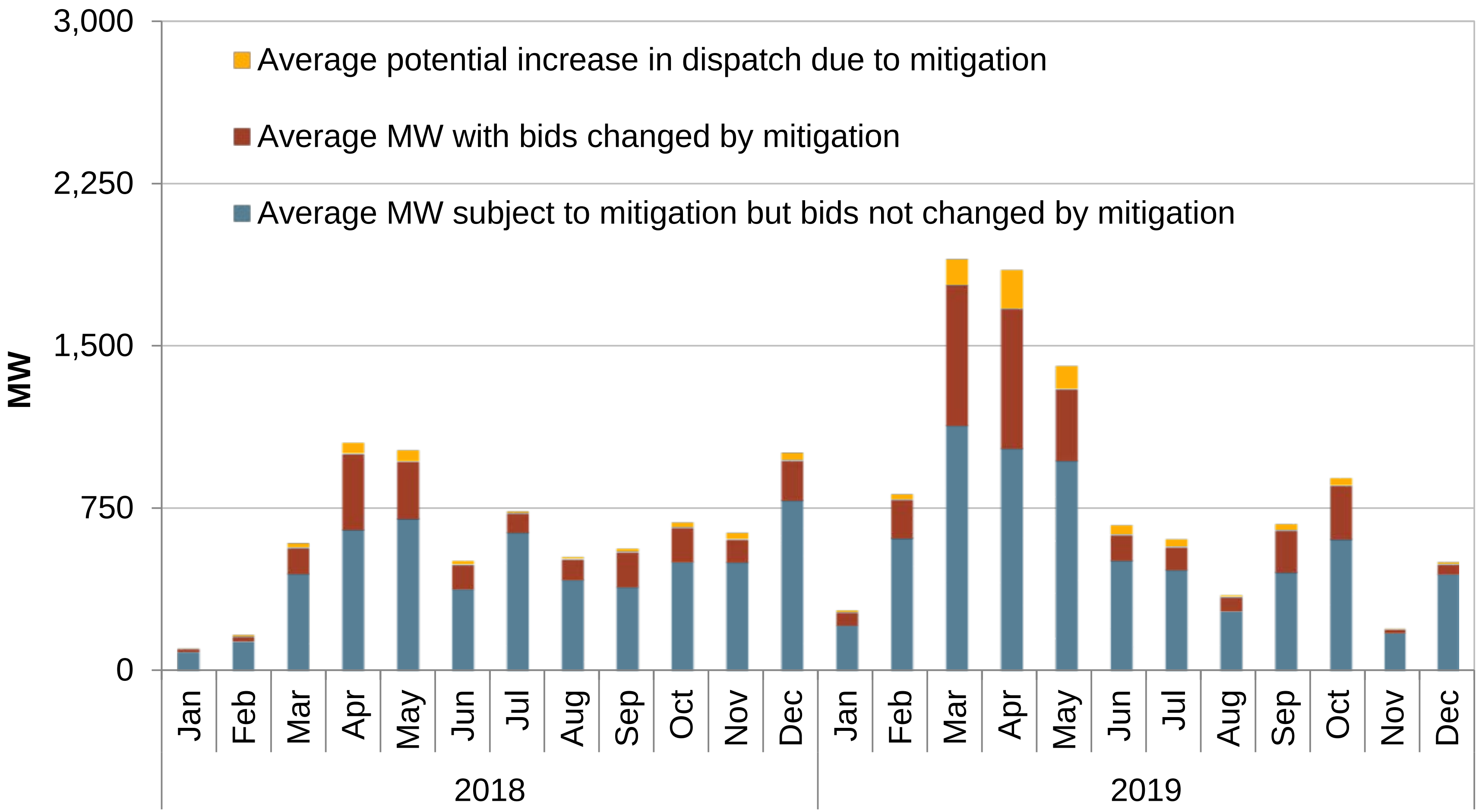
Average incremental energy mitigated in 15-minute real-time market (ISO)



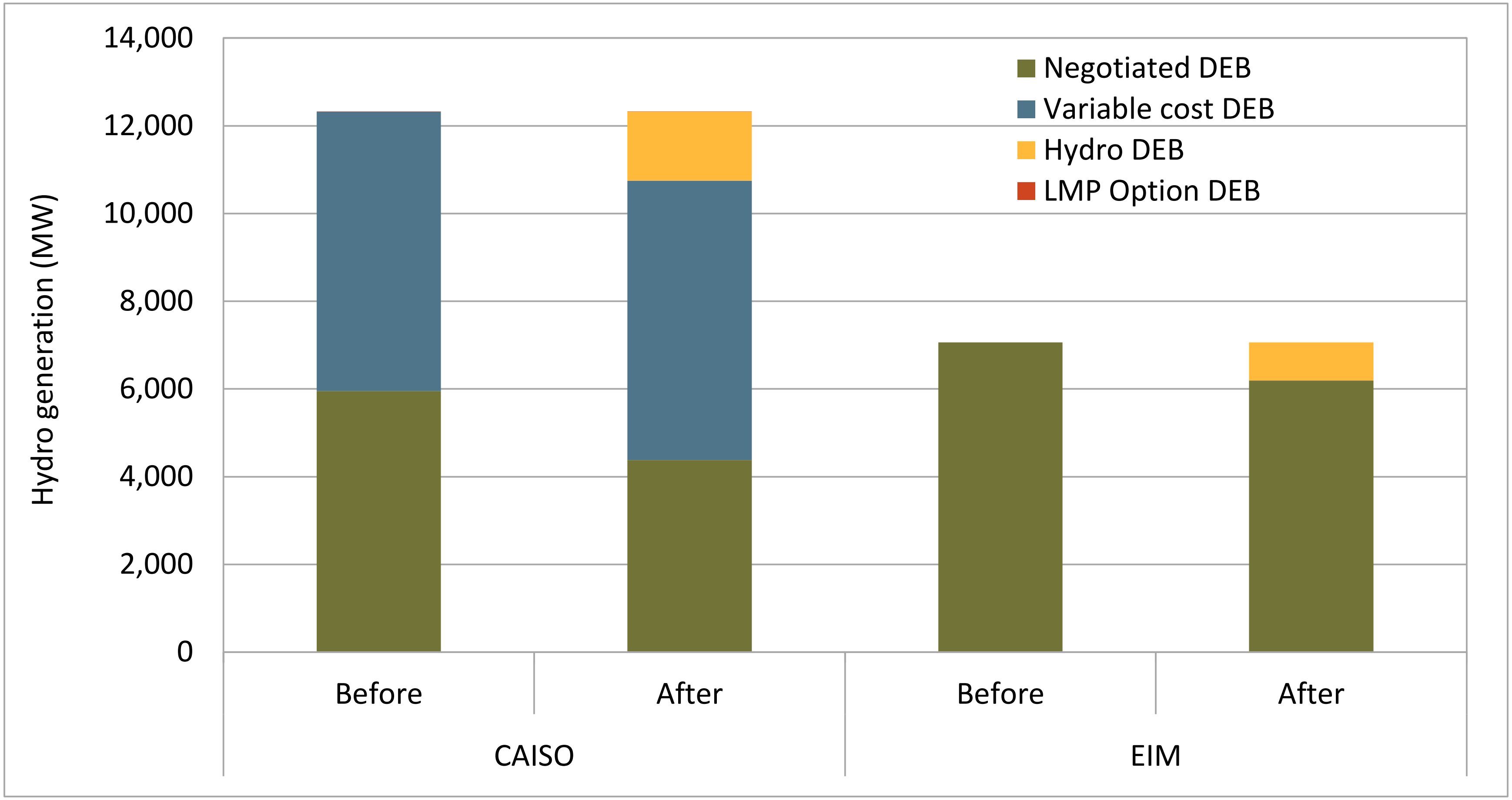
Average incremental energy mitigated in 5-minute real-time market (ISO)



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



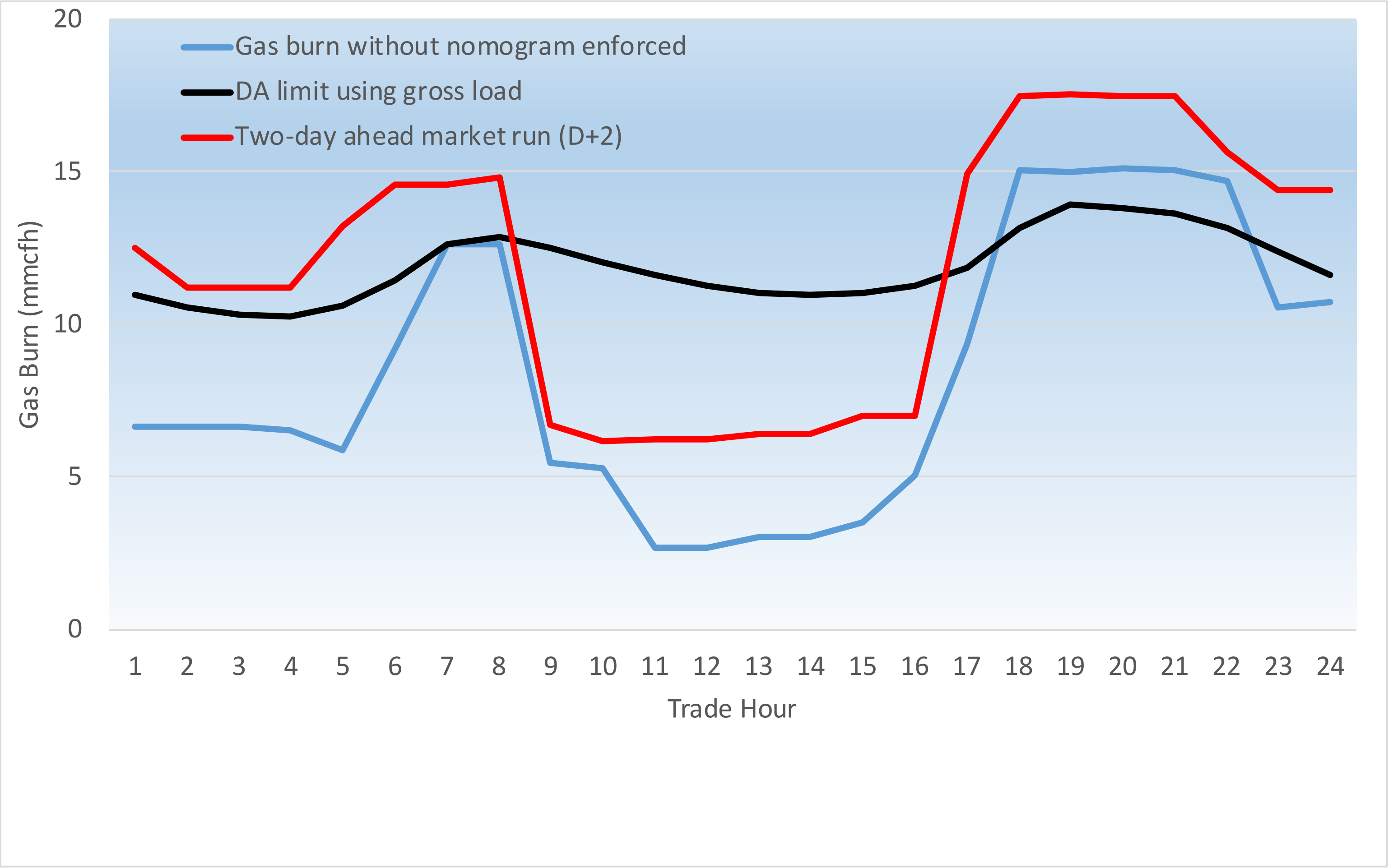
Most resources not yet using new hydro default energy bid option (November 1 and December 31)



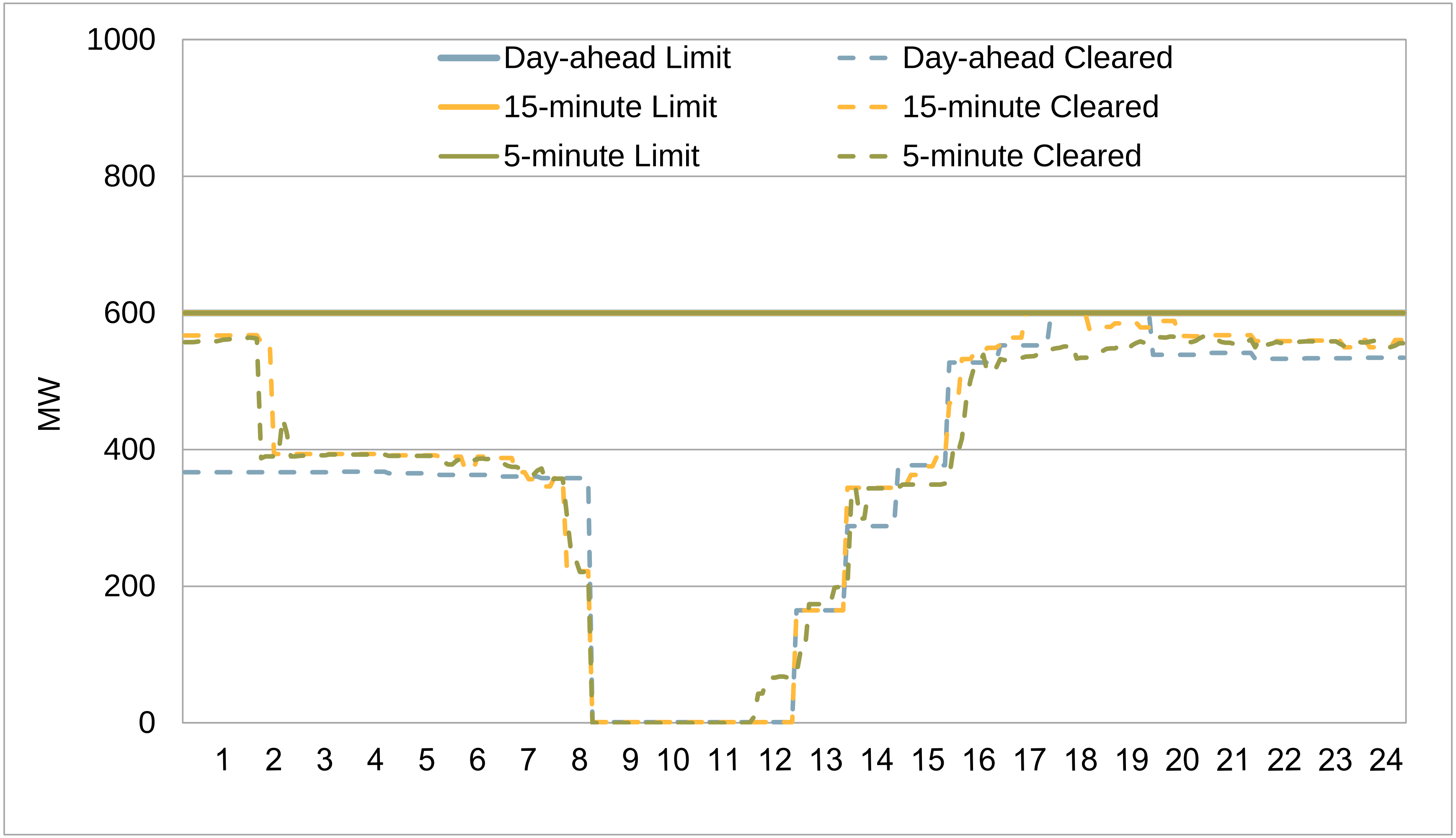
Gas usage constraints

- Enforced in the SoCal Gas region, but bound infrequently
- DMM recommends using D+2 projected gas burn or net load to shape gas burn limitations
  - Shaping based on D+2 gas burn may be better than net load
- Doing so would allow gas to be used during ramping hours when gas units are needed most

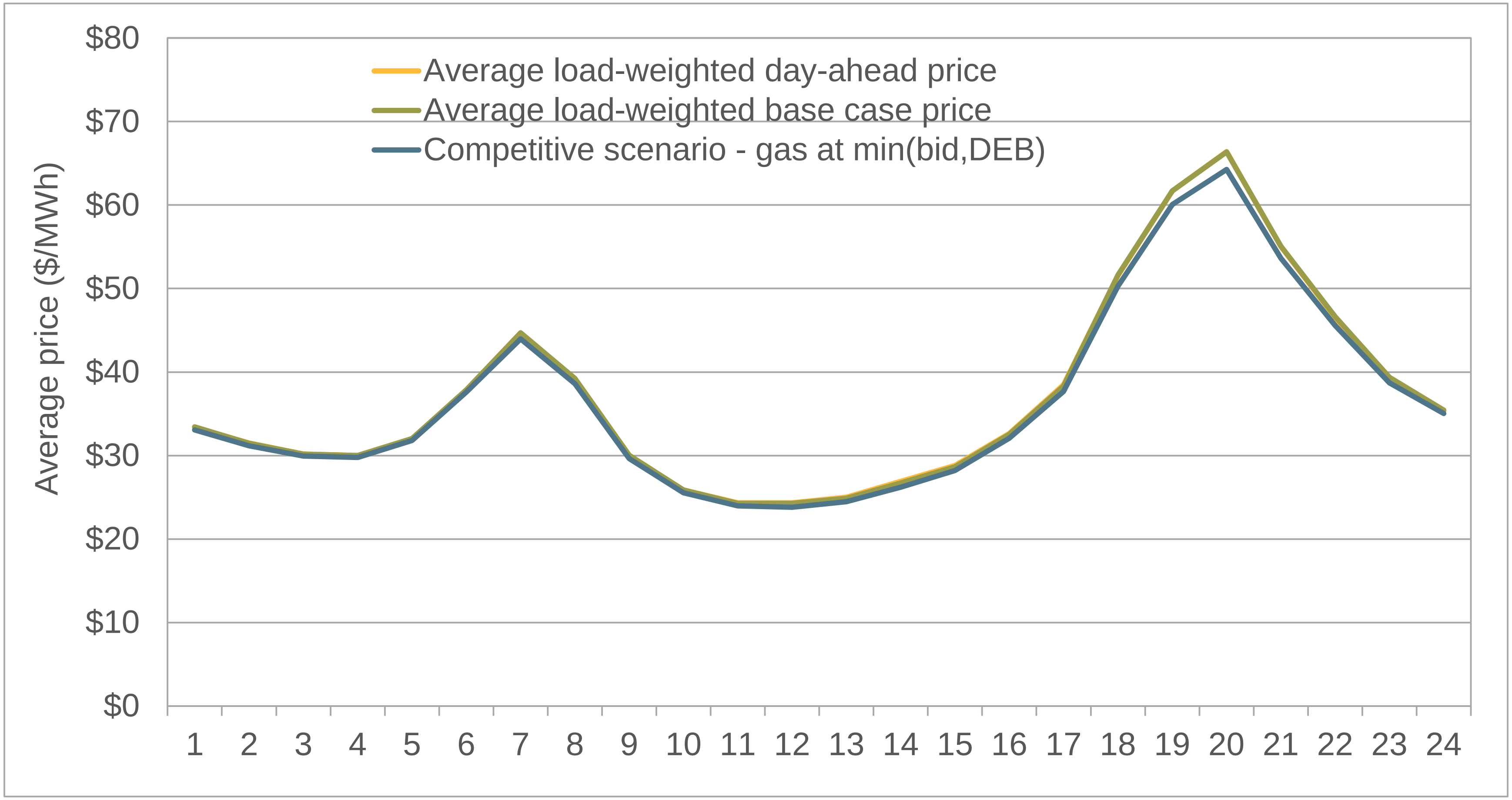
Predicted gas burn (D+2) may be superior to net load for gas limitation nomogram shape



SDG&E gas nomogram binding status in day-ahead and real-time market (Nov 9, 2019)



The price-cost markup averaged $0.71/MWh or just under 2 percent for 2019



System market power

- Market power has had a very limited effect on system market prices even during hours when the ISO system was structurally uncompetitive
- However, DMM has expressed concern that market conditions may evolve in a way that will increase the potential for system-level market power
- DMM supports the ISO's initiative as a an incremental improvement
- Continues to recommend other market design changes:
  - Increasing supply availability of RA imports
  - Ensure that import bids over $1,000/MWh are subject to ex ante cost verification
  - Avoid setting penalty prices at $2,000/MWh except when needed