27 January – 2 February 2019

Introduction

The AER is required to publish the reasons for significant variations between forecast and actual price and is responsible for monitoring activity and behaviour in the National Electricity Market. The Electricity Report forms an important part of this work. The report contains information on significant price variations, movements in the contract market, together with analysis of spot market outcomes and rebidding behaviour. By monitoring activity in these markets, the AER is able to keep up to date with market conditions and identify compliance issues.

Spot market prices

Figure 1 shows the spot prices that occurred in each region during the week 27 January to 2 February 2019.

Figure 1: Spot price by region ($/MWh)

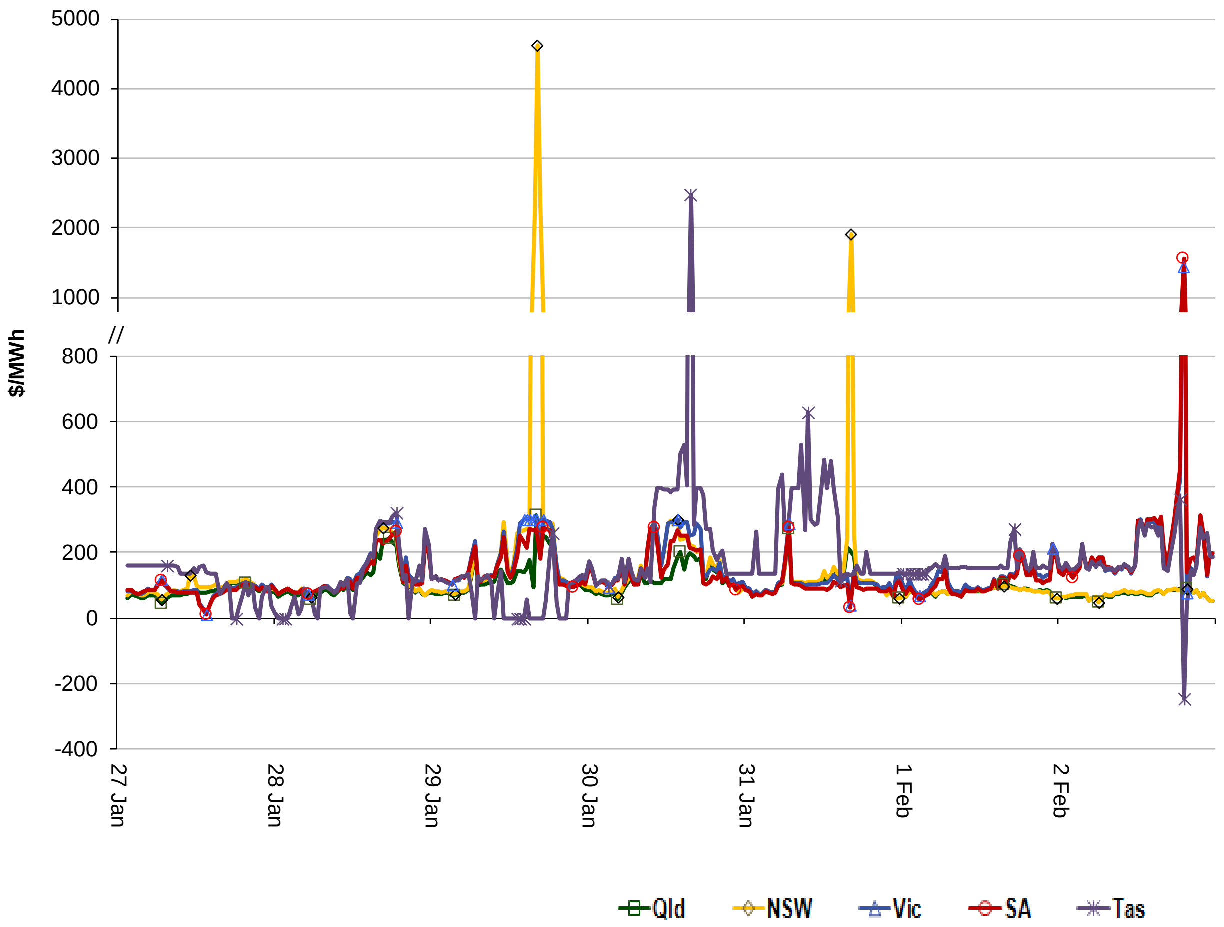


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

Figure 2: Volume weighted average spot price by region ($/MWh)

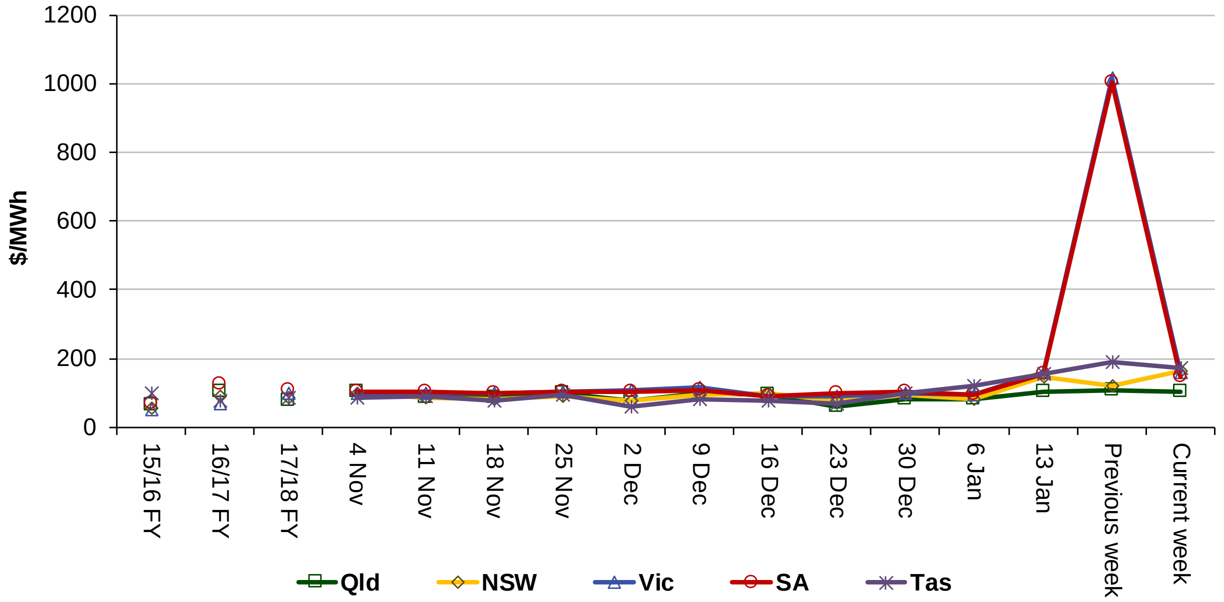


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	102	165	158	146	171
17-18 financial YTD	77	87	106	113	92
18-19 financial YTD	85	95	130	140	75

Longer-term statistics tracking average spot market prices are available on the AER website.

Spot market price forecast variations

The AER is required under the National Electricity Rules to determine whether there is a significant variation between the forecast spot price published by the Australian Energy Market Operator (AEMO) and the actual spot price and, if there is a variation, state why the AER considers the significant price variation occurred. It is not unusual for there to be significant variations as demand forecasts vary and participants react to changing market conditions. A key focus is whether the actual price differs significantly from the forecast price either four or 12 hours ahead. These timeframes have been chosen as indicative of the time frames within which different technology types may be able to commit (intermediate plant within four hours and slow start plant within 12 hours).

There were 266 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2018 of 199 counts and the average in 2017 of 185. Reasons for the variations for this week are summarised in Table 2. Based on AER analysis, the table summarises (as a percentage) the number of times when the actual price differs significantly from the forecast price four or 12 hours ahead and the major reason for that variation. The reasons are classified as availability (which means that there is a change in the total quantity or price offered for generation), demand forecast inaccuracy, changes to network capability or as a combination of factors (when there is not one dominant reason). An instance where both four and 12 hour ahead forecasts differ significantly from the actual price will be counted as two variations.

Table 2: Reasons for variations between forecast and actual prices

	Availability	Demand	Network	Combination
% of total above forecast	7	22	0	1
% of total below forecast	13	48	0	9

Note: Due to rounding, the total may not be 100 per cent.

Generation and bidding patterns

The AER reviews generator bidding as part of its market monitoring to better understand the drivers behind price variations. Figure 3 to Figure 7 show the total generation dispatched and the amounts of capacity offered within certain price bands for each 30 minute trading interval in each region.

Figure 3: Queensland generation and bidding patterns

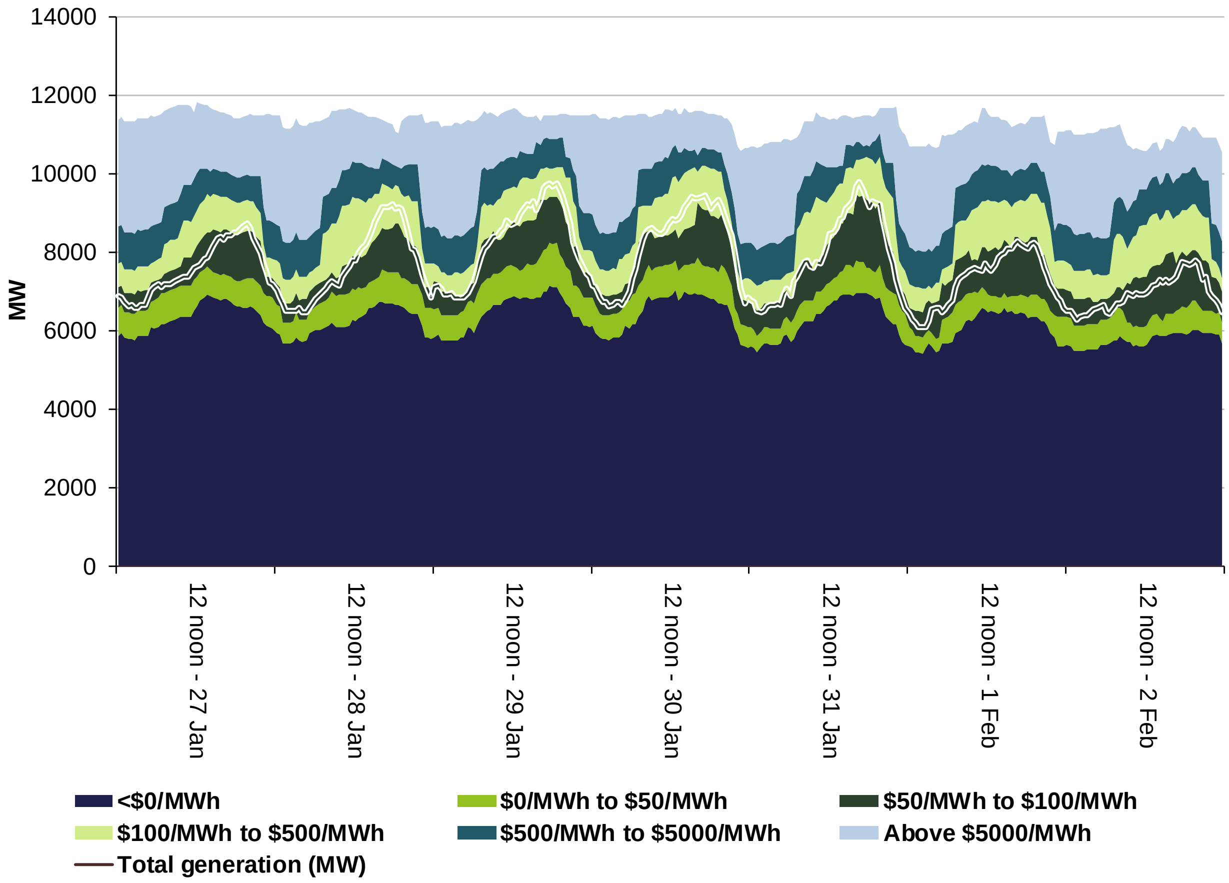


Figure 4: New South Wales generation and bidding patterns

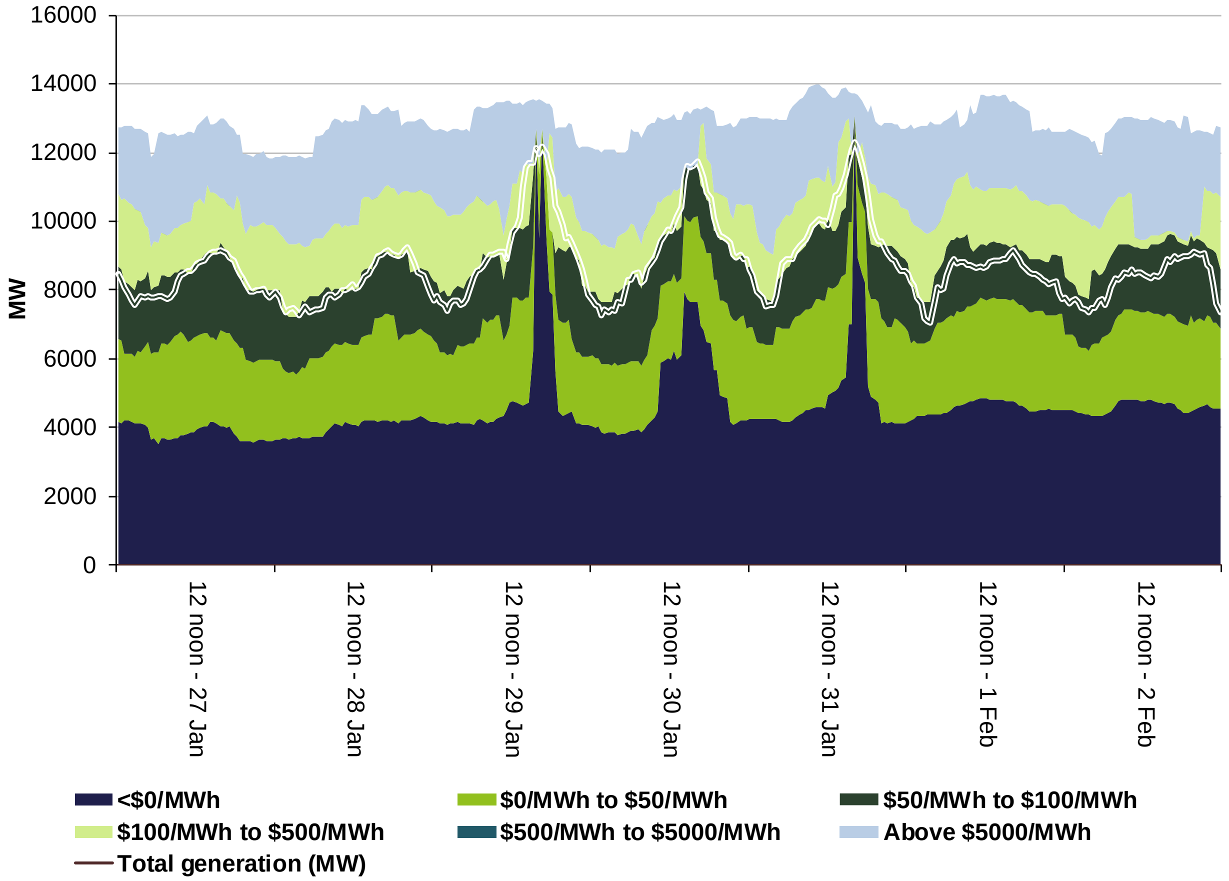


Figure 5: Victoria generation and bidding patterns

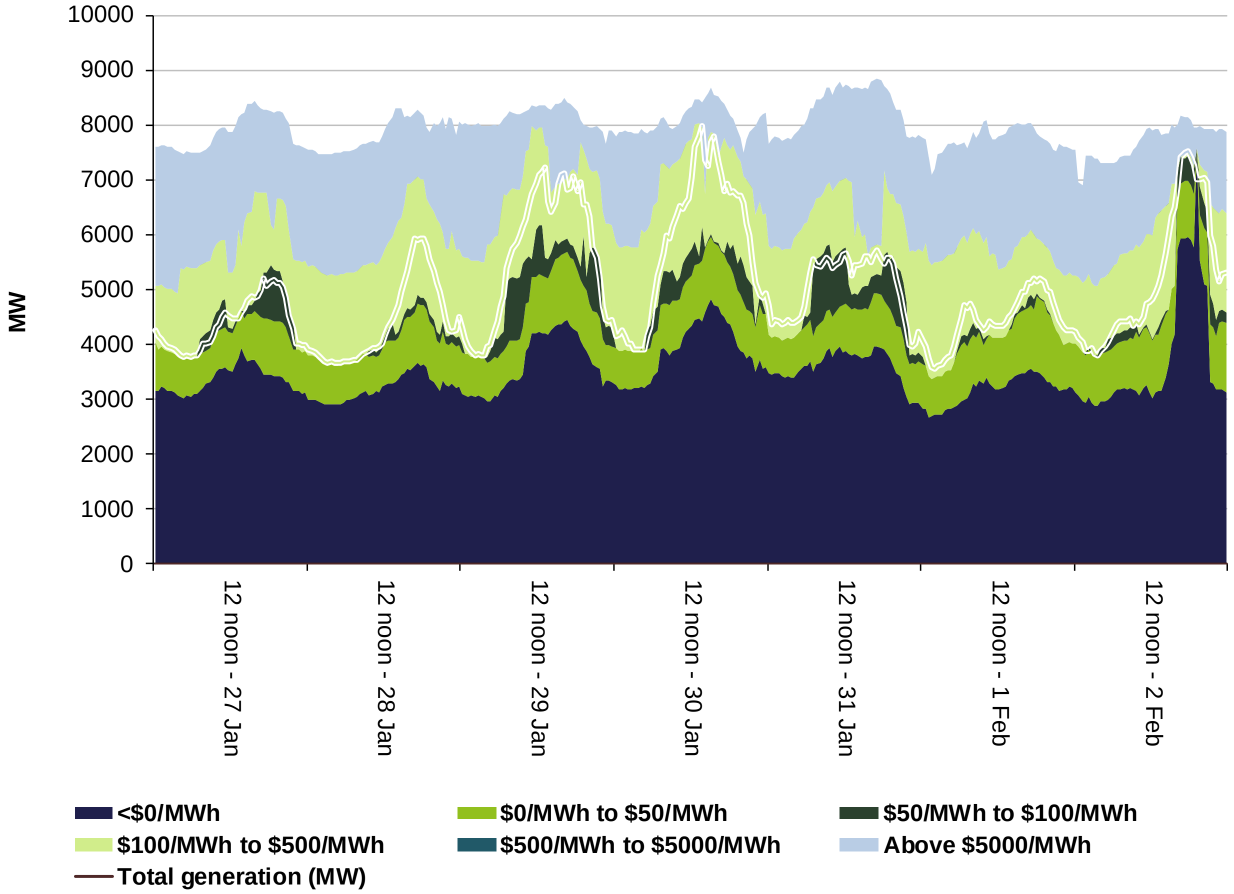


Figure 6: South Australia generation and bidding patterns

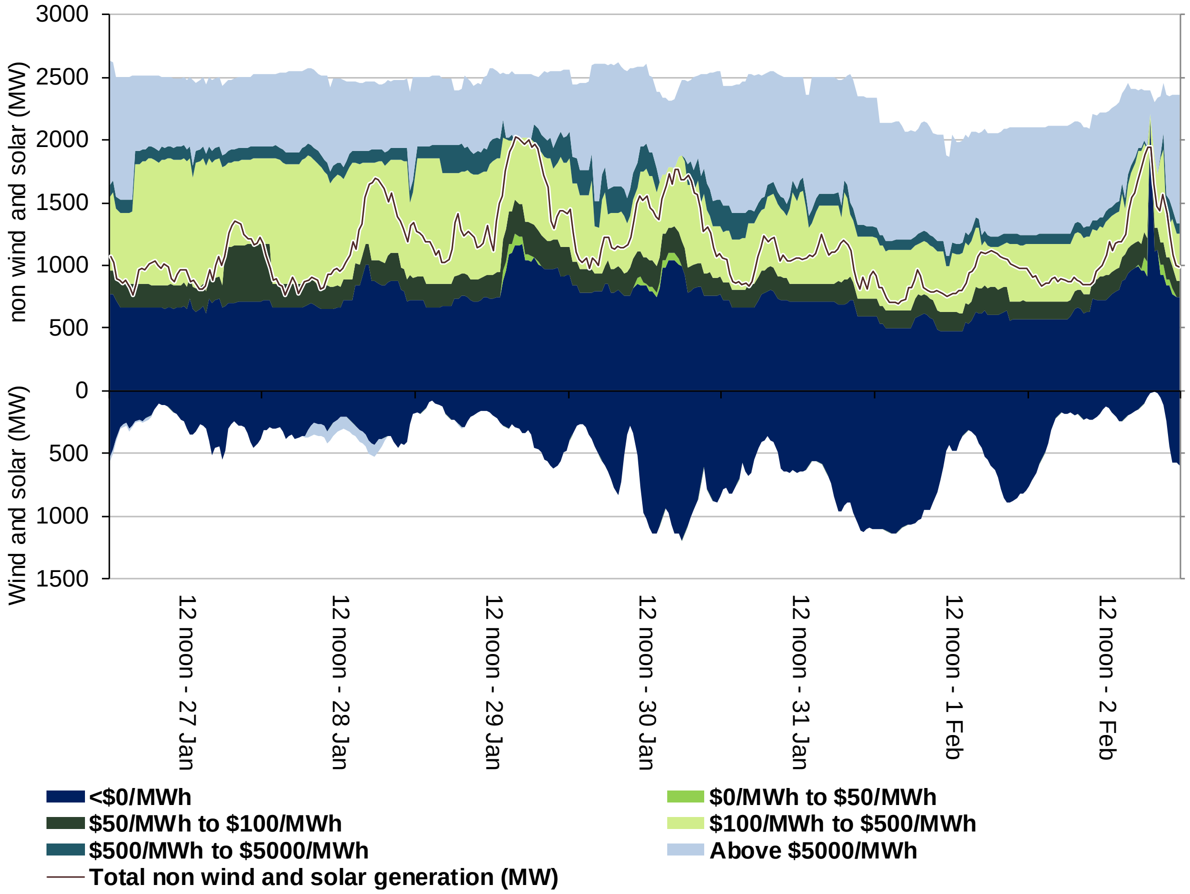
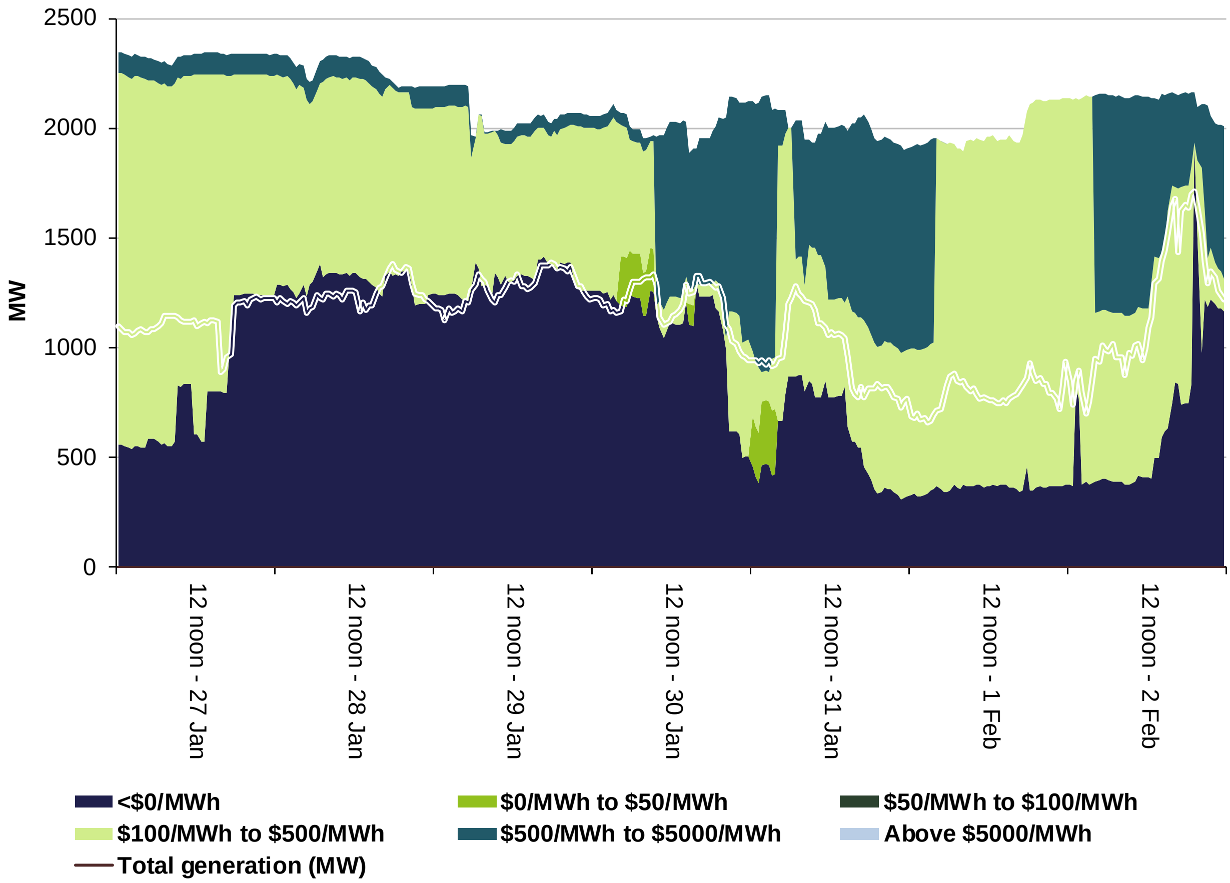


Figure 7: Tasmania generation and bidding patterns



Frequency control ancillary services markets

Frequency control ancillary services (FCAS) are required to maintain the frequency of the power system within the frequency operating standards. Raise and lower regulation services are used to address small fluctuations in frequency, while raise and lower contingency services are used to address larger frequency deviations. There are six contingency services:

- fast services, which arrest a frequency deviation within the first 6 seconds of a contingent event (raise and lower 6 second)
- slow services, which stabilise frequency deviations within 60 seconds of the event (raise and lower 60 second)
- delayed services, which return the frequency to the normal operating band within 5 minutes (raise and lower 5 minute) at which time the five minute dispatch process will take effect.

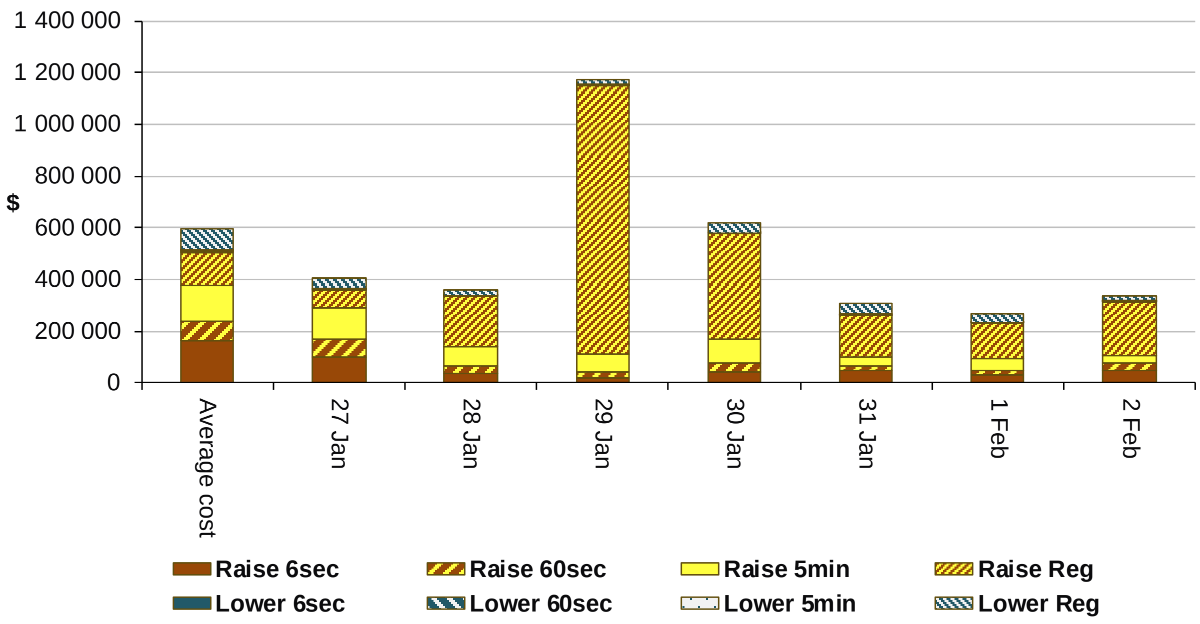
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $3 180 500 or less than 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $286 000 or around 1 per cent of energy turnover in Tasmania.

Figure 8 shows the daily breakdown of cost for each FCAS for the NEM, as well as the average cost since the beginning of the previous financial year.

Figure 8: Daily frequency control ancillary service cost



Raise regulation FCAS costs on 29 January exceeded $1 million on the mainland for global raise regulation services when the price exceeded $10 000/MWh for three dispatch intervals. This coincided with high energy prices in New South Wales (explained in the below section) and was a result of the co-optimisation of the energy and FCAS markets.

Detailed market analysis of significant price events

Queensland

There was one occasion where the spot price in Queensland was greater than three times the Queensland weekly average price of $102/MWh and above $250/MWh.

Tuesday, 29 January

Table 3: Price, Demand and Availability

Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
4.30 pm	312.12	223.73	223.73	8235	8338	8192	11 409	11 494	11 546

Conditions at the time saw demand and availability close to forecast.

At 4.02 pm, effective from 4.10 pm, CS Energy rebid 320 MW of capacity from prices below $224/MWh to above $413/MWh with the reason relating to FCAS/Energy co-optimisation. As a result dispatch prices were set by Gladstone at around $400/MWh for most of the remaining dispatch intervals.

New South Wales

There were four occasions where the spot price in New South Wales was greater than three times the New South Wales weekly average price of $165/MWh and above $250/MWh.

Tuesday, 29 January

Table 4: Price, Demand and Availability

Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
4 pm	2258.55	12 527.76	13 341.69	12 923	12 348	12 365	13 523	13 463	13 513
4.30 pm	4631.98	12 761.33	13 508.55	12 871	12 492	12 435	13 550	13 465	13 481
5 pm	2325.06	12 518.05	13 589.14	12 843	12 450	12 459	13 520	13 459	13 452

Conditions at the time saw demand and availability higher than forecast.

Price were lower than forecast for the 4 pm and 5 pm trading intervals as participants rebid capacity from higher to lower prices in response to a high dispatch price. For the 4 pm trading interval a total of around 2200 MW of capacity was rebid to the price floor mainly by Delta, Snowy Hydro and EnergyAustralia. For the 5 pm trading interval Snowy Hydro rebid around 1050 MW of capacity to the price floor.

The lower than forecast price for 4.30 pm trading interval wasn't as low as the other two intervals as there was significantly less rebidding to lower prices; around 100 MW. With no capacity priced between $107/MWh and $13 300/MWh, small changes were enough to keep prices down for the first four dispatch intervals until demand increased.

Thursday, 31 January

Table 5: Price, Demand and Availability

Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
4.30 pm	1913.00	785.07	5957.85	13 701	13 310	13 295	13 714	13 719	13 682

Demand was 391 MW higher than forecast and availability was 5 MW lower than forecast, both four hours ahead. Imports across the Victoria to New South Wales interconnector were around 500 MW lower than forecast four hours ahead. This led to a dispatch price above $10 000/MWh for the 4.15 pm dispatch interval. Generators in New South Wales responded to this high price by rebidding more than 1145 MW of capacity from prices above $13 000/MWh to the price floor. As a result, dispatch prices stayed below $300/MWh for the rest of the trading interval.

Victoria

There was one occasion where the spot price in Victoria was greater than three times the Victoria weekly average price of $158/MWh and above $250/MWh.

Saturday, 2 February

Table 6: Price, Demand and Availability

Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
7 pm	422.69	266.15	830.52	7177	6369	6280	7950	8072	7981
7.30 pm	1446.87	168.57	755.26	6937	6127	6001	7934	8082	8086

The 7 pm Victorian price did not breach the AER reporting threshold, but it was aligned with South Australia where the threshold was breached. As this price was mainly triggered by higher than forecast demand in Victoria, it is analysed as a Victorian event.

Combined demand between South Australia and Victoria was 855 MW higher than forecast (of which 808 MW was in Victoria) and combined availability was 109 MW lower than forecast (most reduction in availability was for capacity priced below $200/MWh), both four hours ahead.

At 7.30 pm, the price was aligned with the South Australian price for the entire trading interval. Combined demand between South Australia and Victoria was 918 MW higher than forecast and combined availability was 177 MW lower than forecast (of which 120 MW of the reduction in availability was for capacity priced below $150/MWh), both four hours ahead. The dispatch price reached $9875/MWh in Victoria at 7.10 pm. In response participants in Victoria and South Australia rebid more than 3000 MW of capacity to the price floor, and prices fell for the rest of the trading interval.

South Australia

There were two occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $146/MWh and above $250/MWh.

Saturday, 2 February

Table 7: Price, Demand and Availability

Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
7 pm	453.02	325.25	931.32	2276	2229	2277	2483	2470	2517
7.30 pm	1553.90	222.47	856.62	2276	2168	2226	2458	2487	2504

The price was aligned with the Victoria price for both trading intervals. See the Victoria section for this analysis.

Tasmania

There were four occasions where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $171/MWh and above $250/MWh and there was one occasion where the spot price was below -$100/MWh.

Wednesday, 30 January

Table 8: Price, Demand and Availability

Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
3 pm	528.97	898.34	395.38	1186	1172	1181	1934	2022	2009
4 pm	2484.14	898.34	18.72	1244	1189	1219	1906	2051	2036

Conditions at the time saw demand close to forecast and availability lower than forecast.

Within four hours of the 3 pm trading interval, Hydro Tasmania rebid twice to shift a total of 128 MW of capacity from $890/MWh to -$70/MWh because of unexpected dispatch targets and flows over Basslink. As a result, prices fell to around $300/MWh for most of the 3 pm trading interval.

At 3.35 pm, exports into Victoria increased by around 106 MW. This meant that the requirement for lower FCAS in Tasmania increased, in case Basslink tripped. As a result the FCAS and Energy markets were co-optimised and the dispatch price reached $13 668/MWh. Basslink flows reduced the next dispatch interval and the price fell to around $300/MWh.

Thursday, 31 January

Table 9: Price, Demand and Availability

Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
9 am	531.12	133.49	114.71	1092	1062	1050	1944	1959	2028
10 am	627.39	395.40	106.40	1047	1031	1020	1937	1957	2028

Conditions at the time saw demand and availability close to forecast four hours ahead.

At 6.52 am Hydro Tasmania rebid 735 MW of capacity from below $396/MWh to $898/MWh across its portfolio. The reason given was “0630A change to envoked constraint: t_wind_100”. As a result the dispatch price at 8.35 am and 8.40 am was $898/MWh. At 8.38 am, effective from 8.45 am, Hydro Tasmania rebid around 210 MW of capacity across its portfolio from $898/MWh to below $396/MWh and the price reduced to $427/MWh.

The same rebids were effective for the 10 am trading interval which saw the price at $898/MWh for the first three dispatch intervals before Hydro Tasmania rebid more capacity from 9.36 am to prices below $269/MWh and the price fell to $396/MWh at 9.50 am.

Saturday, 2 February

Table 10: Price, Demand and Availability

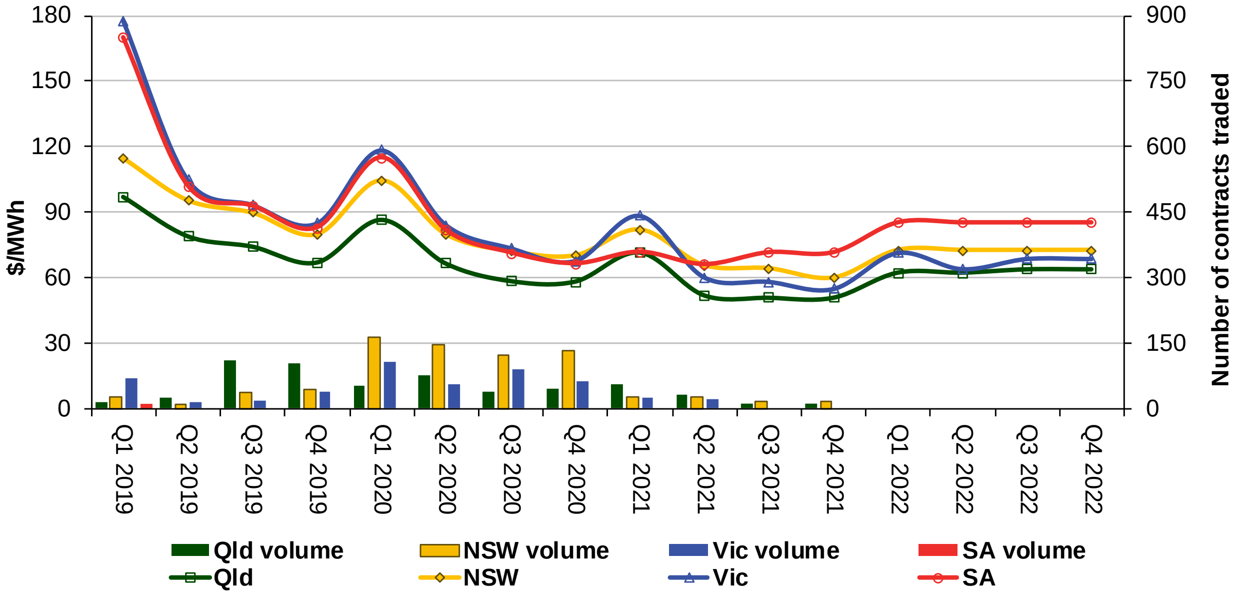
Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
7.30 pm	-245.61	154.90	685.57	1134	1061	1057	2161	2143	2149

Demand and availability was slightly higher than forecast. The dispatch price in Victoria rose to around $10 000/MWh at 7.10 pm. In response, Hydro Tasmania rebid around 1300 MW of capacity to the price floor. This resulted in the dispatch price in Tasmania dropping to below $0/MWh for the rest of the trading interval.

Financial markets

Figure 9 shows for all mainland regions the prices for base contracts (and total traded quantities for the week) for each quarter for the next four financial years.

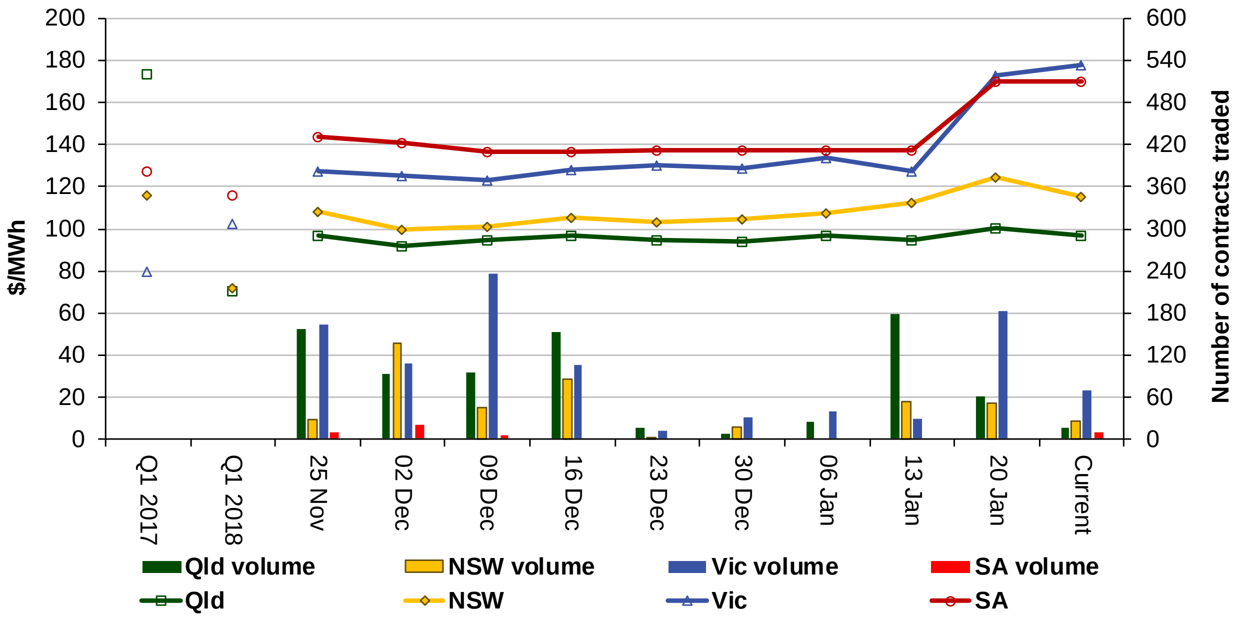
Figure 9: Quarterly base future prices Q1 2019 – Q4 2022



Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional Q1 2019 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2017 and quarter 1 2018 prices are also shown. The AER notes that data for South Australia is less reliable due to very low numbers of trades.

Figure 10: Price of Q1 2019 base contracts over the past 10 weeks (and the past 2 years)



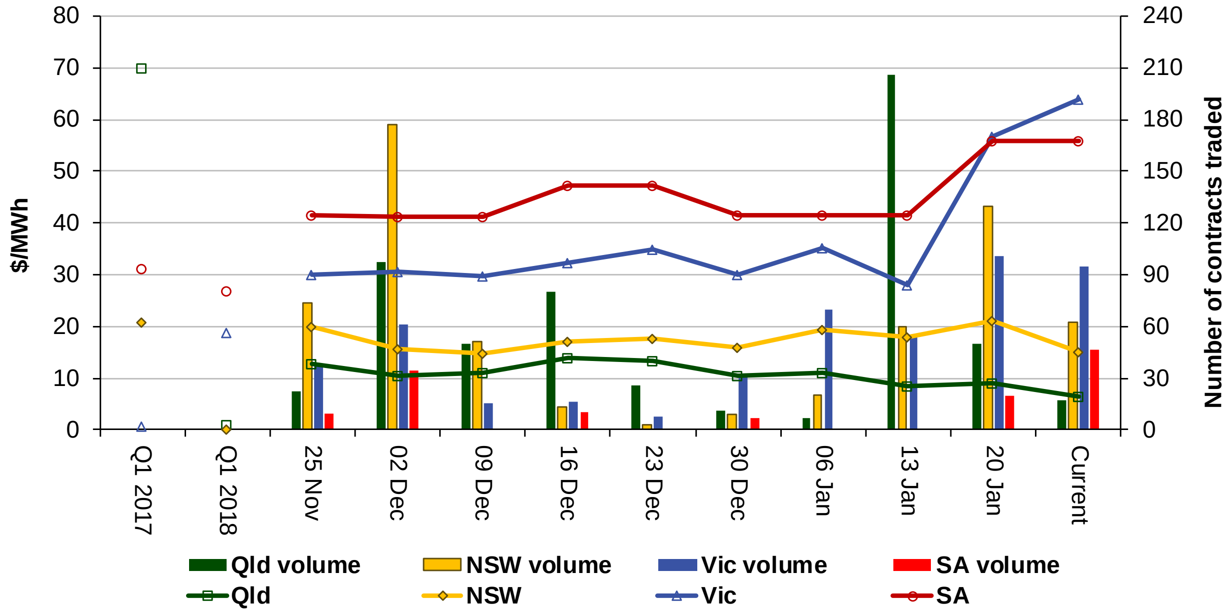
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

Source. ASXEnergy.com.au

Prices of other financial products (including longer-term price trends) are available in the Industry Statistics section of our website.

Figure 11 shows how the price for each regional quarter 1 2019 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2017 and quarter 1 2018 prices are also shown.

Figure 11: Price of Q1 2019 cap contracts over the past 10 weeks (and the past 2 years)



Source. ASXEnergy.com.au

Australian Energy Regulator
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