14 - 20 January 2018

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 14 - 20 January 2018.

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

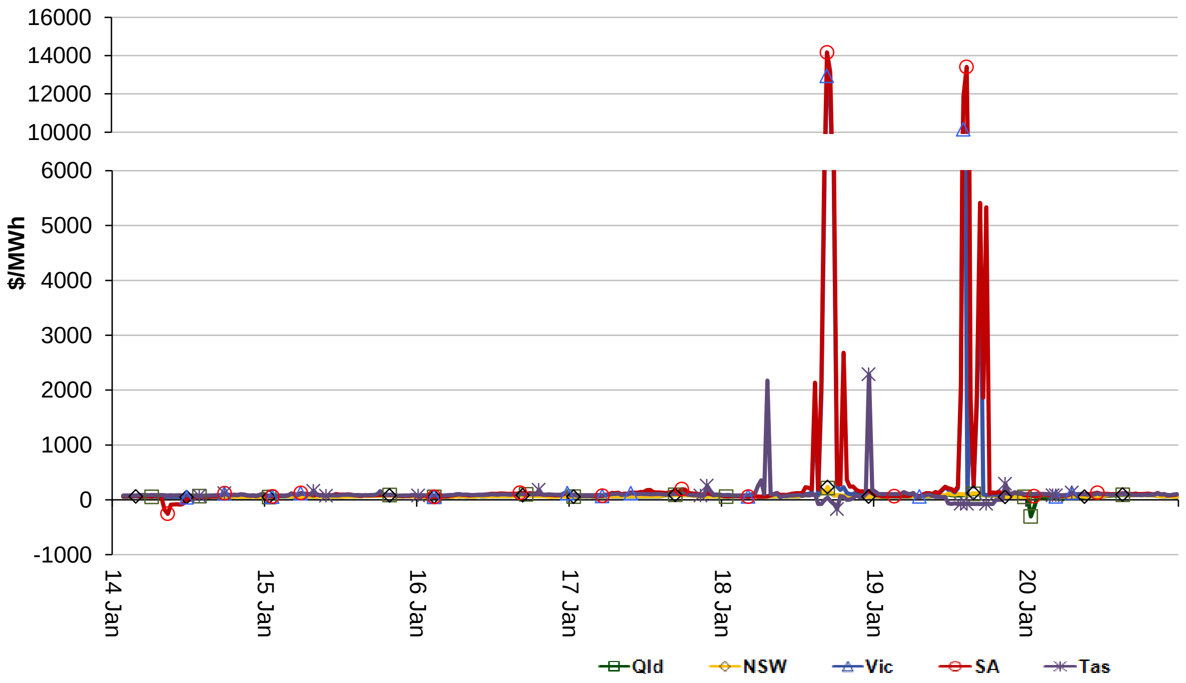


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

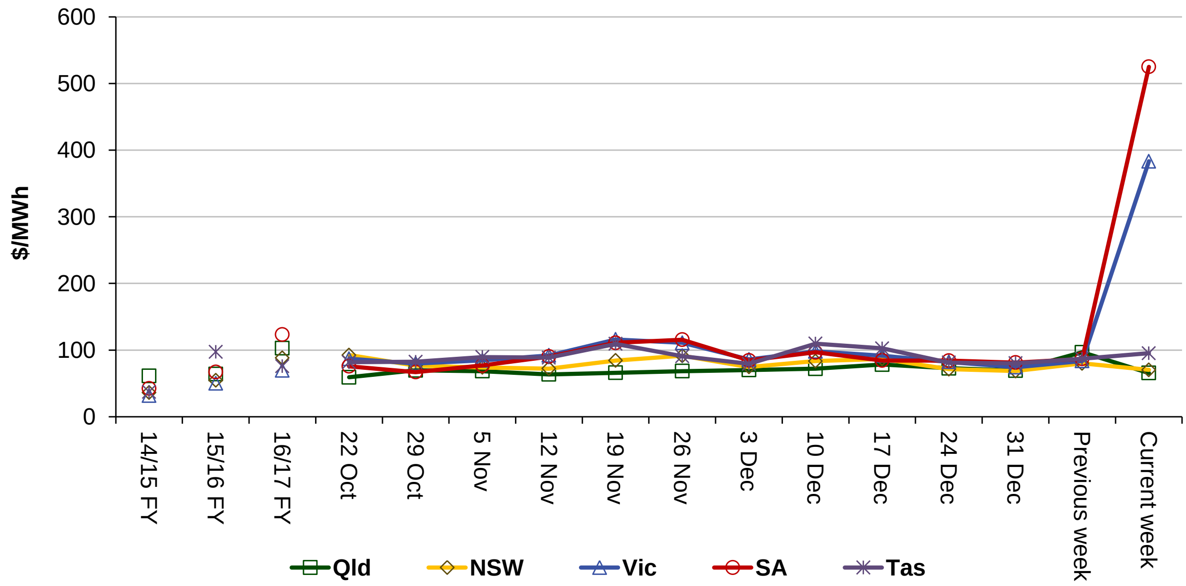


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	66	70	383	525	95
16-17 financial YTD	82	64	46	105	51
17-18 financial YTD	77	87	105	112	91

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 227 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2017 of 185 counts and the average in 2016 of 273. 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	5	24	0	1
% of total below forecast	54	14	0	2

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

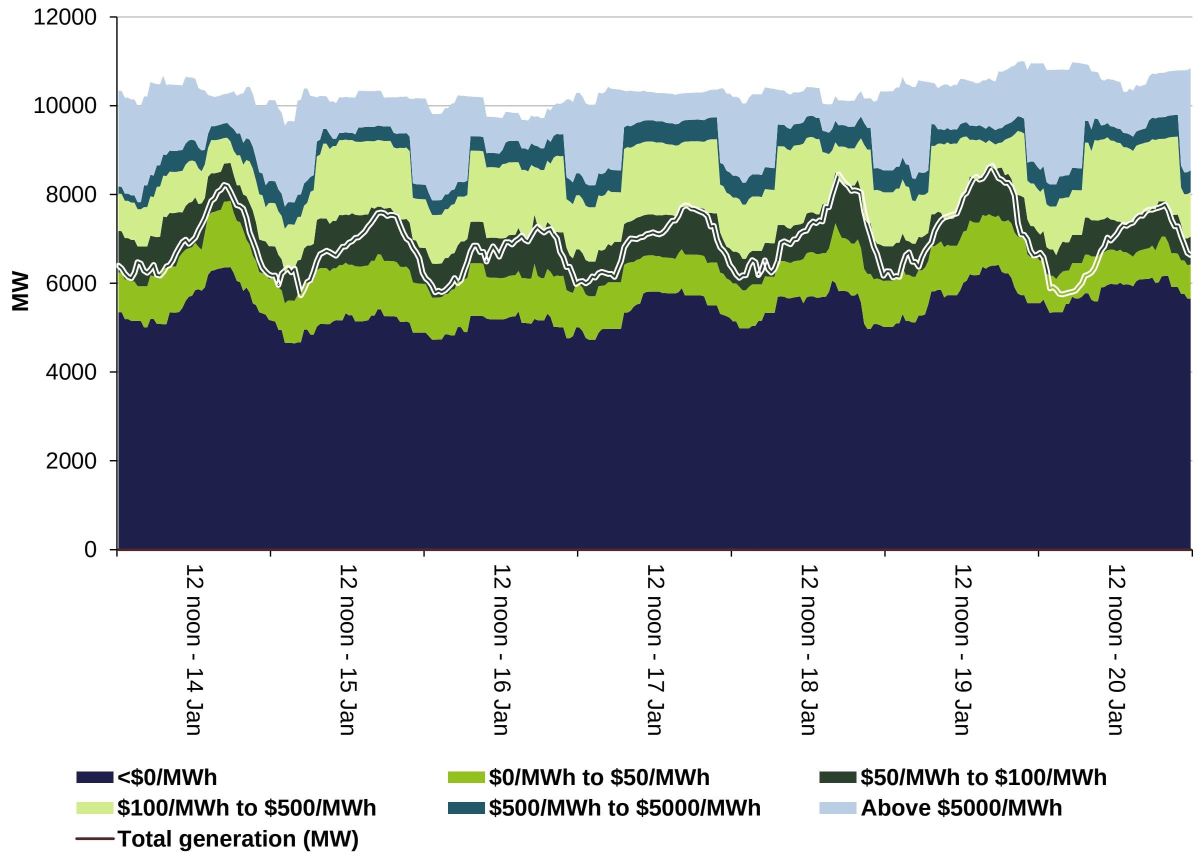


Figure 4: New South Wales generation and bidding patterns

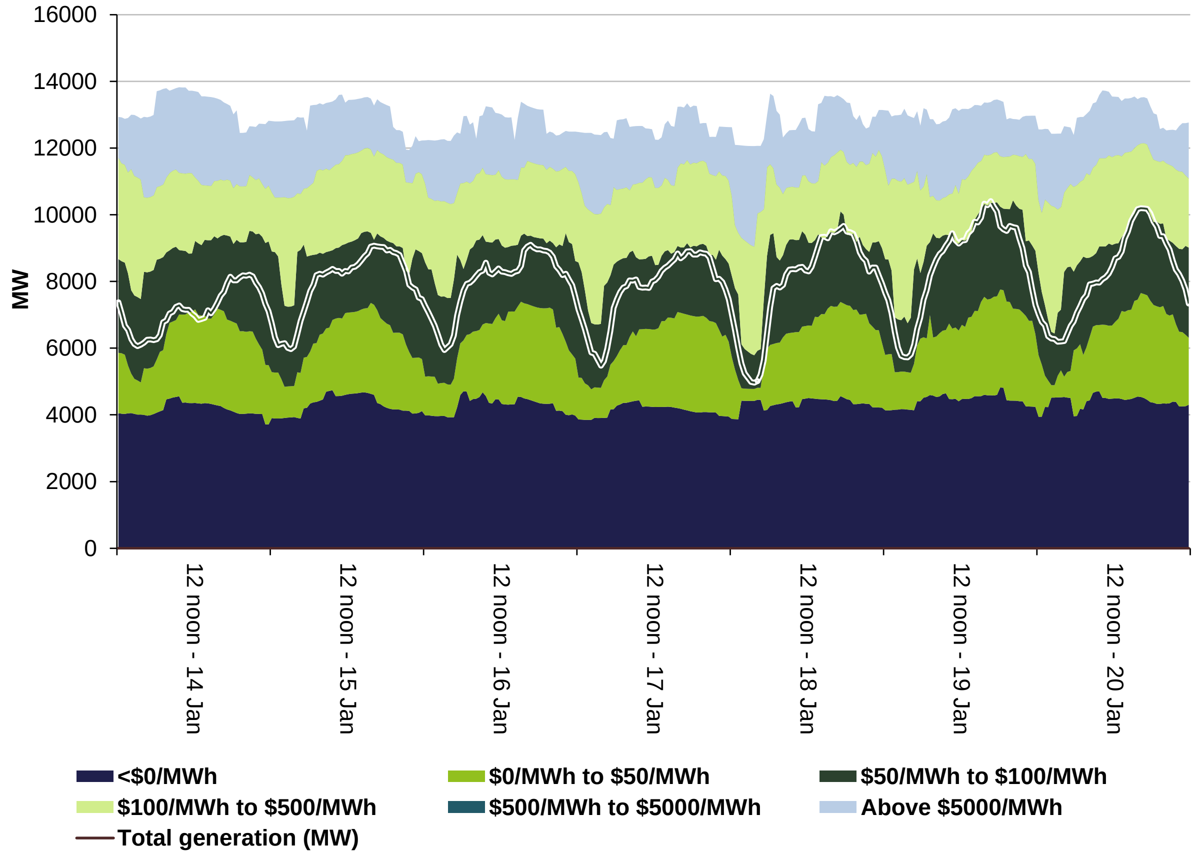


Figure 5: Victoria generation and bidding patterns

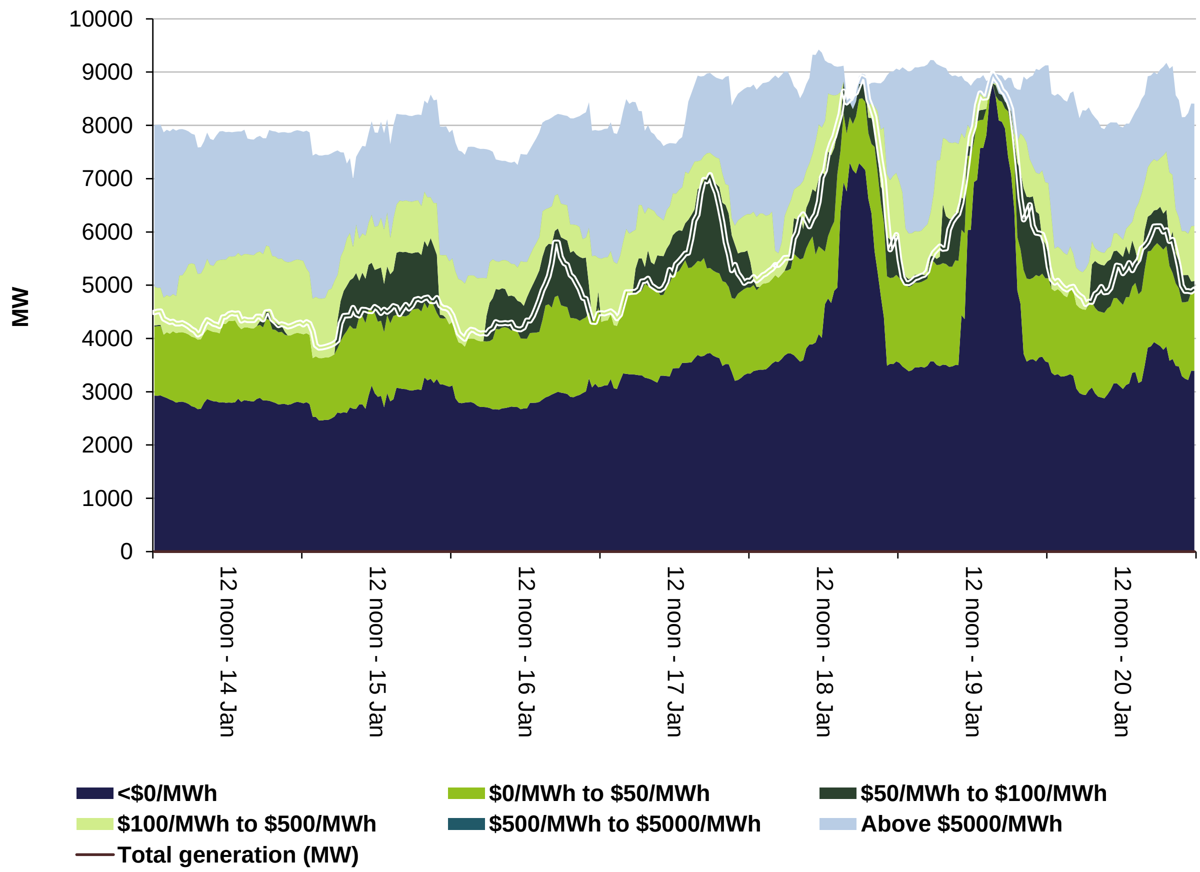


Figure 6: South Australia generation and bidding patterns

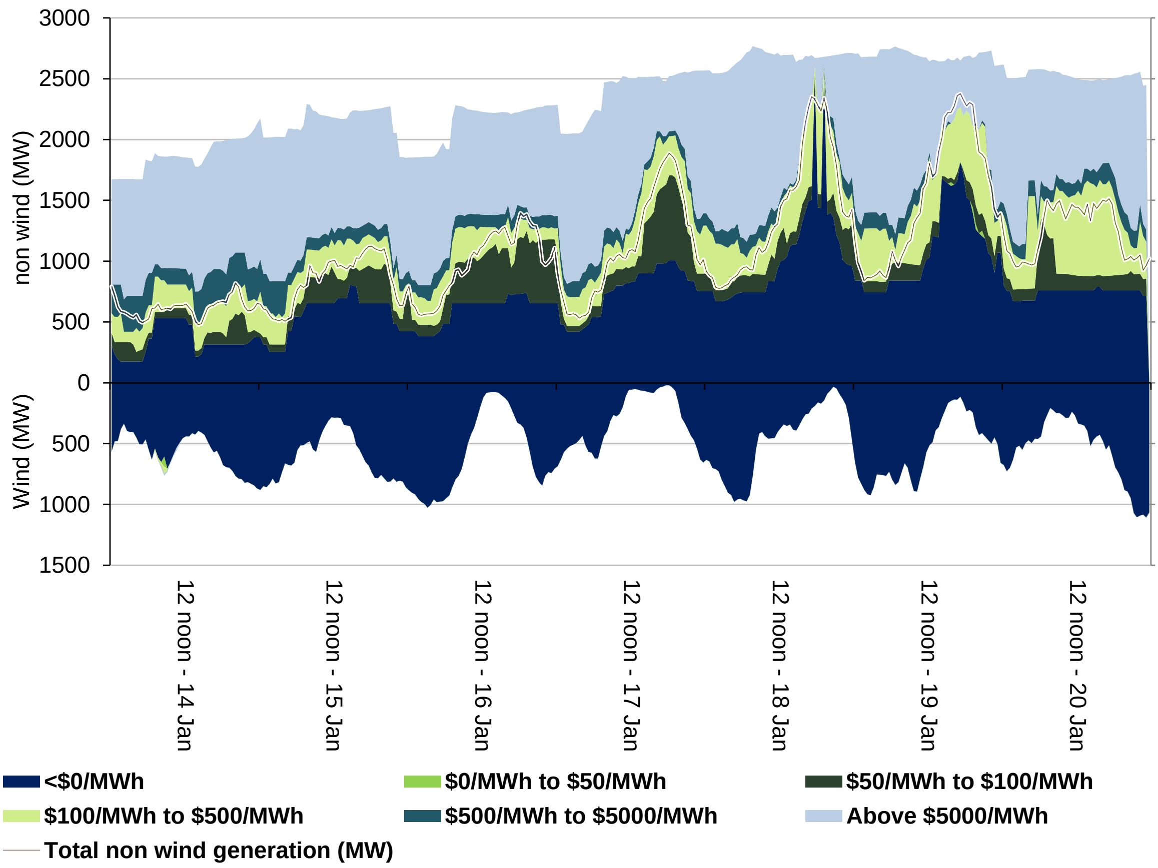
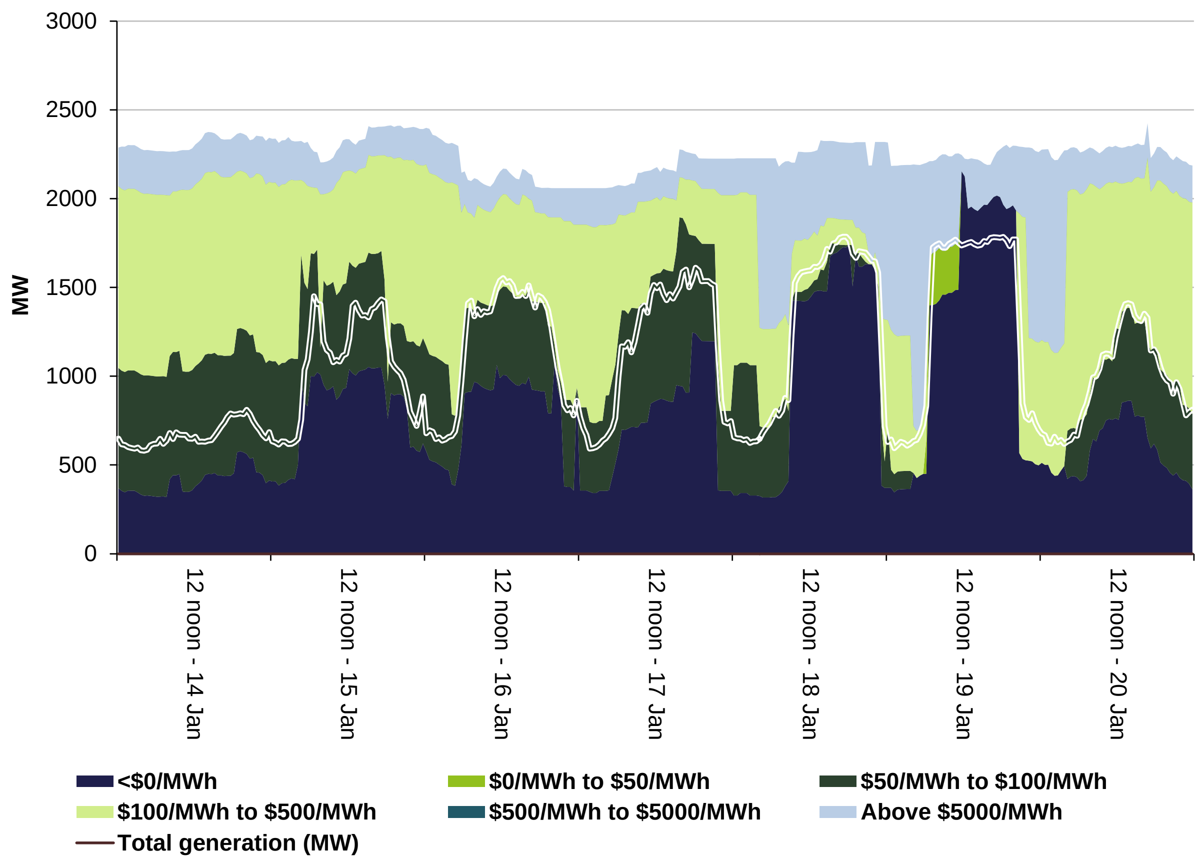


Figure 7: Tasmania generation and bidding patterns



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.

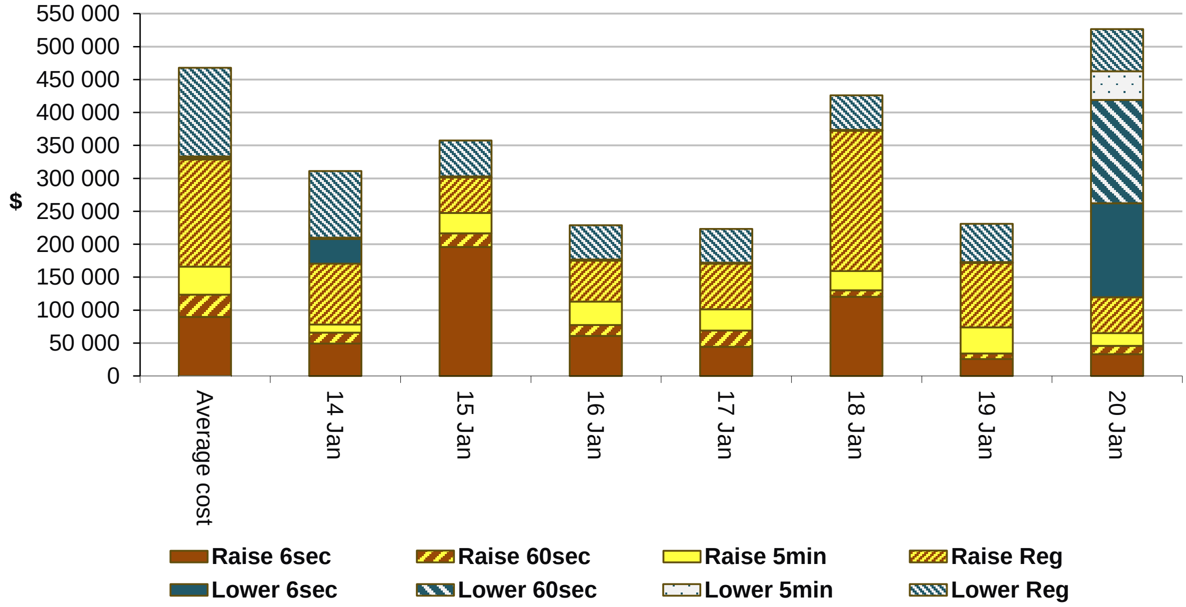
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $1 578 500 or around one quarter per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $724 500 or around four 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



On 20 January, an unplanned outage of the Armidale to Bulli Creek line in New South Wales created a requirement for around 270 MW of lower ancillary services in Queensland. The price for these services reached the cap for one dispatch interval.

Detailed market analysis of significant price events

Queensland

There were two occasions where the spot price in Queensland was below -$100/MWh.

Saturday, 20 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
1 am	-303.61	60.75	49.48	5630	5755	5665	10 908	10 899	10 982
1.30 am	-140.52	52.93	52.27	5485	5591	5530	10 759	10 767	10 833

Conditions at the time saw demand up to 125 MW lower than forecast and availability was close to that forecast four hours ahead.

At 12.50 am, there was an outage between Armidale and Bulli Creek in New South Wales. Constraints were invoked reducing exports from Queensland to New South Wales by around 440 MW. With excess generation being constrained down and unable to set price, the price fell to the price floor for two dispatch intervals.

Energy consumption by pump loads must be offset by an increase in generation. At 1.12 am, effective 1.20 am, CS Energy rebid 235 MW of load capacity at Wivenhoe Pump 1 from $151/MWh to the price floor. The reason related to a change in price sensitivities in Queensland. This meant they went from pumping 235 MW at 1.15 pm to 0 MW at 1.20 pm. This resulted in a similar decrease in generation. With excess generation being ramped down the dispatch price fell to the price floor at 1.20 am.

Victoria

There were 11 occasions where the spot price in Victoria was greater than three times the Victoria weekly average price of $383/MWh and above $250/MWh.

Thursday, 18 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
3 pm	1775.20	87.02	118.68	8201	8024	8057	9107	9087	8916
4 pm	1960.54	142.85	10 978.85	8556	8593	8537	8629	8990	8880
4:30 pm	5682.01	9999.81	11 347.09	8718	8716	8652	8546	8976	8781
5 pm	12 931.04	9999.81	11 928.24	8888	8695	8636	8455	8957	8786
5.30 pm	11 960.16	117.65	10 978.85	8900	8461	8405	8578	8957	8781
6 pm	5078.60	114.94	10 978.85	8955	8317	8244	8926	8956	8797

Conditions for the 3 pm trading saw demand greater than forecast four hours ahead by 177 MW in Victoria and 64 MW in South Australia. Availability was greater than forecast by 20 MW in Victoria and 50 MW in South Australia. Prices were aligned between Victoria and South Australia so will be discussed as one region.

For the 3 pm dispatch interval, net demand across both states increased by 142 MW and wind fell by 34 MW. System normal constraints reduced 140 MW of generation at Murray power station priced at $108/MWh. With other cheap generation taking longer than five minutes to start, the dispatch price reached $10 000/MWh in Victoria and $11 953/MWh in South Australia for one dispatch interval.

For the 4 pm trading interval, four hours ahead demand was close to forecast in Victoria and 84 MW lower than forecast in South Australia. Availability was around 360 MW lower than that forecast in Victoria, due to the trip of Loy Yang B unit 1, and close to forecast in South Australia.

The four hour forecast is significantly different to the 12 hour forecast because at 8.16 am Origin rebid 437 MW of capacity at Mortlake, priced greater than $10 979/MWh to $100/MWh and below.

At 1.04 pm, AGL rebid 170 MW of capacity at its Torrens Island power station, from prices less than $135/MWh to the price cap, the reason related to a change in contract position. At around 3.30 pm Loy Yang B unit 1 tripped, effectively removing 530 MW of capacity priced below $10/MWh from the market.

For the 4 pm dispatch interval, net demand increased by 83 MW. With only a total of 21 MW of capacity priced between $370/MWh and $10 000/MWh across both regions, the dispatch price reached $10 000/MWh in Victoria and $11 953/MWh in South Australia for one dispatch interval.

Analysis of the 4.30 pm to 6 pm trading intervals will be discussed in the Electricity spot prices above $5000/MWh, Victoria and South Australia – 18 January 2018 report, to be released by 20 March 2018.

Early analysis shows, although around 95 per cent of capacity offered in both regions was priced below $500/MWh, high prices still eventuated due to:

- the trip of unit 1 at Loy Yang B power station resulted in a reduction of over 500 MW of cheaply priced generation being removed from the market
- the highest levels of demand in both states since early February 2017

Friday, 19 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
2 pm	1894.67	10 140.08	311.57	8798	8989	8744	8944	8897	8963
2.30 pm	10 152.42	14 200.00	12 898.48	8814	9113	8854	8838	8947	8979
3.30 pm	1709.88	14 200.00	11 829.84	8943	9338	9042	8981	8941	9052
4.30 pm	1716.91	13 961.92	11 167.39	8916	9277	9000	8929	8919	8997

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
5 pm	4966.75	13 262.58	9999.81	8889	9105	8764	8922	8926	8988

Analysis of the 2.30 pm and 5 pm trading intervals will be discussed in the Electricity spot prices above $5000/MWh, Victoria and South Australia – 19 January 2018 report, to be released by 20 March 2018.

Early analysis shows, due to forecast high levels of demand and lack of reserve conditions, AEMO invoked RERT contracts from 2 pm to 8 pm. As a result of AEMO's intervention in the market special pricing arrangements applied in all regions.

Although around 93 per cent of capacity offered in both regions was priced below $2000/MWh and demand was lower than forecast, wind generation in South Australia decreased to levels materially lower than forecast during the afternoon. While final prices were lower than the forecast prices greater than $13 000/MWh four hours ahead, they still exceeded $5000/MWh at 2.30 pm in Victoria and on a number of occasions during the afternoon in South Australia.

For the 2 pm, 3.30 pm and 4.30 pm trading intervals prices in Victoria and South Australia were aligned and acting as one region.

Conditions for the 2 pm trading interval saw demand lower than forecast four hours ahead by around 190 MW in Victoria and 100 MW in South Australia. Availability was higher than forecast four hours ahead by around 50 MW in Victoria and lower than forecast fours ahead by 220 MW in South Australia, mainly due to lower than forecast wind generation.

From 11.48 am over 200 MW of capacity across both regions was rebid from prices above $10 000/MWh to below $370/MWh. The main rebids are in Table 6 below. With a total of only around 50 MW priced between and $10 000/MWh and $362/MWh across both regions, the price fluctuated between the price ranges.

Table 6: Significant rebids

Region	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
Vic.	11.52 am	Ecogen Energy	Jeeralang A	84	>11501	<10 000	1150~A~adj bnds mat chnge vic 5p price @ 1245 $9506~
Vic.	12.27 pm	Snowy Hydro	Murray	30	14194	-1000	12:26:00 A vic 5min pd price $9,077.29 higher than 5min pd 12:50@12:21 ($9,406.18)
SA	11.48 am	Engie	Mintaro	69	14200	<119	1135~A~SA 5mpd higher than 30mpd: $10,549.67 @ 12:45~
SA	12.28 pm	Engie	Dry Creek	116	13100	<300	1205~A~SA 5mpd higher than 30mpd $10549.67 12:50~

Across both regions (Victoria and South Australia), conditions for the 3.30 pm trading interval saw demand and availability lower than forecast four hours ahead by around 540 MW and 160 MW respectively.

Significant rebidding of capacity from prices above $10 000/MWh to less than $300/MWh in the four hours leading up to the start of the trading interval resulted in the lower than forecast price. The significant rebids are highlighted in Table 7 below.

Table 7: Significant rebids

Region	Submitted time	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
Vic.	1.16 pm	Ecogen Energy	Jeeralang B	38	10 000	<274	1310~P~adj bnds port redist yallourn tcv limits~
Vic.	2.09 pm	Ecogen Energy	Jeeralang A	24	10 000	-1000	1405~A~adj bnds vic price 12,916 abv fcast sl~
Vic.	2.09 pm	Ecogen Energy	Jeeralang B	19	10 000	-1000	1405~A~adj bnds vic price 12,916 abv fcast sl~
SA	11.48 am	Engie	Mintaro	69	14 200	<119	1135~A~SA 5mpd higher than 30mpd: $10,549.67 @ 12:45~
SA	12.28 pm	Engie	Dry Creek	116	13 100	<300	1205~A~SA 5mpd higher than 30mpd $10549.67 12:50~
SA	12.36 pm	EnergyAustralia	Hallett	30	13 999	-1000	1225~A~adj bnds mat change sa 5p 1325 10549 ~
SA	1.19 pm	AGL Energy	Torrens Island	30	14 200	105	1220~F~040 chg in contract pos~see log
SA	2.08 pm	EnergyAustralia	Hallett	20	>10 579	-1000	1355~A~adj bnds sa price 14200 abv 5p fcast sl~
SA	2.08 pm	Origin Energy	Quarantine	74	10 550	-1000	1405A ensure economic dispatch - avoid short shutdown sl
SA	2.14 pm	Origin Energy	Quarantine	25	13 099	-1000	1410A ensure economic dispatch - avoid short shutdown sl

Across both regions, conditions for the 4.30 pm trading interval saw demand around 500 MW lower than forecast four hours prior. Availability was around 140 MW lower than forecast four hours prior, mainly due to lower than forecast wind generation in South Australia.

In the four hours leading up to the start of the trading interval over 200 MW of capacity priced above $10 000/MWh was rebid to prices below $370/MWh. Significant rebids from both regions are shown below in Table 8. The rebids combined with the lower than forecast demand resulted in the price of the first five trading intervals being below $310/MWh. At 4.24 pm, effective from 4.30 pm, Ecogen Energy rebid around 170 MW of capacity at their Jeeralang B and Newport power stations from prices below $275/MWh to above $10 000/MWh and the dispatch price increased to around $10 000/MWh in both regions.

Table 8: Significant rebids

Region	Submitted time	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
Vic.	1.16 pm	Ecogen Energy	Jeeralang B	38	10 000	<274	1310~P~adj bnds port redist yallourn tcv limits~
Vic.	4.24 pm	Ecogen Energy	Jeeralang B	96	<274	>10000	1615~A~band adj due to material change in demand 11615 vs 11815 @ 1650 vicsa sl~
Vic.	4.24 pm	Ecogen Energy	Newport	70	94	11053	1615~A~band adj due to material change in demand 11615 vs 11815 @ 1650 vicsa sl~
SA	12.36 pm	Energy Australia	Hallett	30	13 999	-1000	1225~A~adj bnds mat change sa 5p 1325 10549 ~
SA	1.19 pm	AGL Energy	Torrens Island	55	14 200	105	1220~F~040 chg in contract pos~see log
SA	2.14 pm	Origin Energy	Quarantine	25	13 099	-1000	1410A ENSURE ECONOMIC DISPATCH - AVOID SHORT SHUTDOWN SL
SA	2.34 pm	Energy Australia	Hallett	40	>10 579	<369	1425~P~ADJ AVAIL BNDS MATCH AMBIENT COND SL~

South Australia

There were 15 occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $525/MWh and above $250/MWh and there were two occasions where the spot price was below -$100/MWh.

Sunday, 14 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
8.30 am	-180.06	53.50	45.30	941	879	866	2560	2389	2455
9 am	-254.51	47.74	46.38	932	842	829	2623	2408	2461

Conditions at the time saw demand between 60-90 MW higher than forecast and availability between 170-215 MW higher than that forecast four hours ahead. The higher than forecast demand can mostly be attributed to lower than forecast non-scheduled generation, while the increase in availability can mostly be attributed to higher than forecast semi-scheduled wind generation.

For both trading intervals with only a small amount of capacity priced between $88/MWh and -$150/MWh, small changes to demand and supply (in this case wind generation) caused large variations in price.

At 8.15 am, with both interconnectors exporting at their limits, demand decreased by 29 MW and semi-scheduled wind generation increased by 24 MW, this resulted in higher priced generation ramp down constrained and unable to set price and the price decreased to the floor.

For the 9 am trading interval, due to the higher than forecast semi-scheduled wind generation, all dispatch intervals were negatively priced. The 8.50 am the dispatch price was at the floor due to a 32 MW decrease in demand and a 52 MW increase in semi-scheduled wind generation.

Thursday, 18 January

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
3 pm	2134.46	105.55	145.50	2452	2388	2408	3030	2979	2968
4 pm	2196.00	349.95	12 600.41	2523	2607	2556	2952	2945	2921
4:30 pm	6255.54	11 915.66	13 100.02	2617	2680	2628	2948	2910	2856
5 pm	14 166.50	13 100.02	13 998.99	2680	2759	2691	2942	2851	2797
5:30 pm	13 136.09	13 100.02	13 808.83	2735	2829	2779	2900	2815	2780
6 pm	5693.03	13 998.99	13 966.43	2781	2858	2792	2875	2809	2771
7:30 pm	2682.53	300.02	13 100.02	2880	2796	2746	2825	2718	2734

Analysis for the 3 pm and 4 pm trading intervals is under the Victorian section above.

Trading intervals 4.30 pm to 6 pm inclusive will be discussed in the Electricity spot prices above $5000/MWh, Victoria and South Australia – 18 January 2018 report, to be released by 20 March 2018.

For the 7.30 pm trading interval, demand was around 85 MW higher than forecast and availability was around 110 MW higher than forecast, both four hours ahead.

The four hour forecast was significantly lower than the 12 hour forecast because at 9.51 am Origin rebid 188 MW of capacity at Ladbroke and Quarantine power stations, priced at the cap to $99/MWh and below.

With only 96 MW offered between $300/MWh and $13 999/MWh, any small increase in demand or decrease in wind would lead to price volatility. For the 7.15 pm dispatch interval, demand increased by 65 MW and wind decreased by 7 MW. This led to the dispatch price reaching the price cap for one dispatch interval. Falling demand and participants rebidding capacity into lower priced bands kept the dispatch price below $100/MWh for the remainder of the trading interval.

Friday, 19 January

Table 11: 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
2 pm	2092.57	10 549.67	349.98	2430	2528	2525	3028	3248	3230
2.30 pm	11 864.29	14 200.00	13 100.02	2458	2566	2566	2926	3150	3165
3 pm	13 408.28	14 200.00	13 998.99	2447	2607	2610	2878	3090	3086
3.30 pm	1855.67	14 200.00	13 100.02	2498	2641	2649	2829	3028	3016
4.30 pm	1912.55	14 200.00	13 100.02	2603	2740	2732	2790	2934	2906
5 pm	5412.78	14 200.00	13 100.02	2602	2784	2758	2806	2877	2853
5.30 pm	1864.87	14 200.00	13 100.02	2639	2810	2772	2760	2848	2823
6 pm	5332.34	11 686.04	13 099.09	2620	2771	2735	2836	2827	2799

Trading intervals 2.30 pm, 3 pm, 5 pm and 6 pm will be discussed in the Electricity spot prices above $5000/MWh, Victoria and South Australia – 19 January 2018 report, to be released by 20 March 2018.

The analysis for the lower than forecast prices for the 2 pm, 3.30 pm and 4.30 pm trading intervals are under the Victorian section above.

Conditions for the 5.30 pm trading interval saw demand around 170 MW lower than forecast while availability was around 90 MW lower than forecast four hours ahead, mainly due to lower than forecast wind generation.

The first dispatch interval saw the price close to that forecast, at $10 550/MWh. At 5.02 pm, effective from 5.10 pm, Origin Energy rebid 82 MW of capacity at its Quarantine power station from above $10 500/MWh to the floor. The reason given was “1700A constraint management - VS_250 SL”. This resulted in the dispatch price decreasing to $135/MWh at 5.10 pm and remaining close to this level for the remainder of the trading interval.

Tasmania

There were four occasions where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $95/MWh and above $250/MWh and there was one occasion where the spot price was below -$100/MWh.

Thursday, 18 January

Table 12: 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
6.30 am	355.16	405.68	405.68	1164	1127	1105	2227	2232	2265
7.30 am	2171.94	405.68	405.68	1142	1145	1129	2202	2207	2210

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
6.30 pm	-168.19	85.61	130.77	1183	1150	1148	2314	2333	2339
11.30 pm	2290.17	405.68	466.19	1000	1017	1039	2319	2322	2329

For the 6.30 am trading interval, demand was 37 MW higher than forecast and availability was close to that forecast four hours ahead.

At 6.16 am, effective 6.25 am, Hydro Tasmania rebid 57 MW of capacity at Poatina from $406/MWh to $80/MWh. The reason was “0615P delay in outage start: Poatina #5. correcting error in poat#3 bid”. As a result of the rebid and co-optimisation of the energy and FCAS markets, the dispatch price fell from $406/MWh at 6.20 am to $103/MWh for the last two dispatch intervals.

For the 7.30 am trading interval demand and availability were close to forecast.

Between 7.06 am and 7.08 am, effective 7.15 am, Hydro Tas removed 29 MW of capacity from Liap, Cata, Waya and 57 MW from Poatina power stations, priced at -$75/MWh and $80/MWh respectively. The reasons related to delays in returning to service and a change in outage schedule. With cheaper generation limited, the price reached $12 529/MWh for the 7.15 am dispatch interval. At 7.12 am, effective 7.20 am, Hydro Tas rebid 77 MW of capacity at Gordon from $12 459/MWh to $100/MWh. The reason related to the FCAS requirement higher than forecast. As a result, Gordon set price at $100/MWh for the remainder of the trading interval.

For the 6.30 pm trading interval demand was 33 MW higher than forecast and availability was 19 MW lower than that forecast four hours ahead.

In the four hours leading up to the start of the trading interval, Hydro Tas rebid 194 MW of capacity across its portfolio from $107/MWh and above to less than -$75/MWh. This resulted in no capacity priced between these two price bands. At 6.15 pm demand fell by 41 MW and the dispatch price fell to -$75/MWh. Between 6.20 pm and 6.30 pm demand fell by a further 53 MW, leading to the last dispatch interval priced at the floor.

For the 11.30 pm trading interval, demand and availability were close to forecast.

At 11.05 pm there was a step change in offers, around 280 MW of capacity, priced less than $200/MWh was replaced by capacity priced above $10 000/MWh. With no capacity priced between $405/MWh and $12 400/MWh, cheaper price generation ramp rate limited or trapped in FCAS and Basslink reducing exports at its rate of change limit, the dispatch price reached $12 439/MWh.

Friday, 19 January

Table 13: Price, Demand and Availability

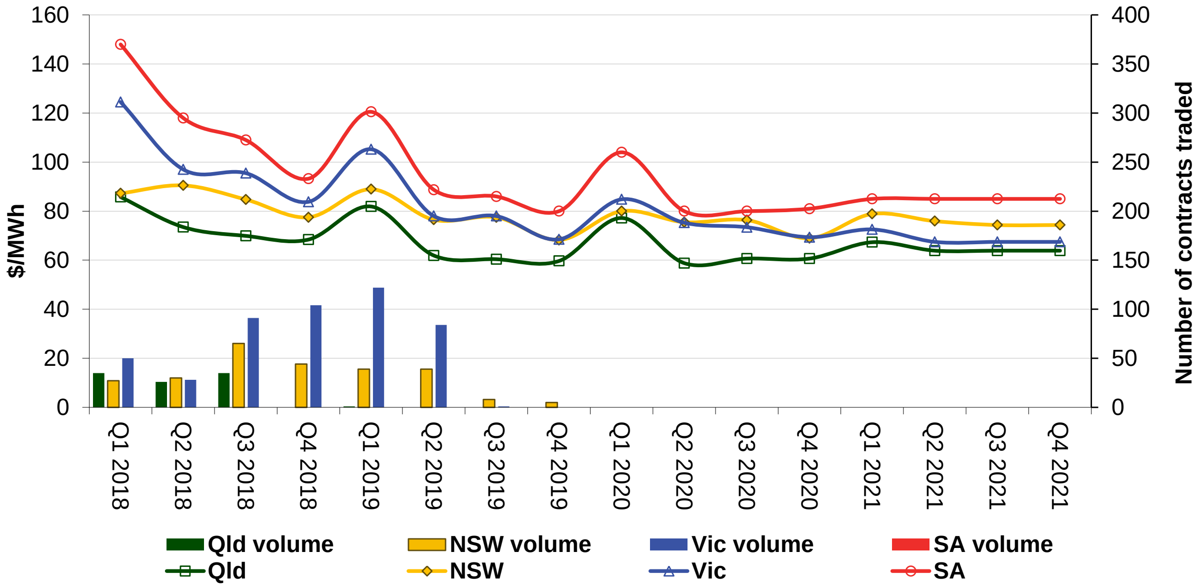
Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
9 pm	291.64	508.96	292.14	1103	1091	1107	2293	2268	2308

Conditions at the time saw demand, availability and price close to forecast 12 hours ahead.

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.

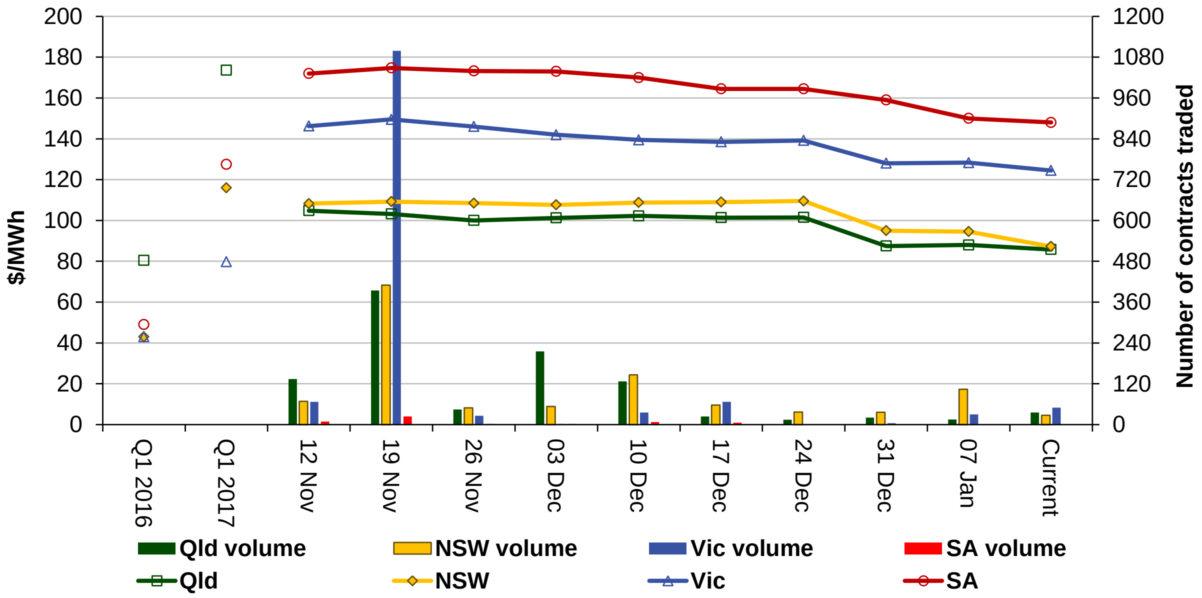
Figure 9: Quarterly base future prices Q1 2018 – Q4 2021



Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional Q1 2018 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2016 and quarter 1 2017 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 2018 base contracts over the past 10 weeks (and the past 2 years)



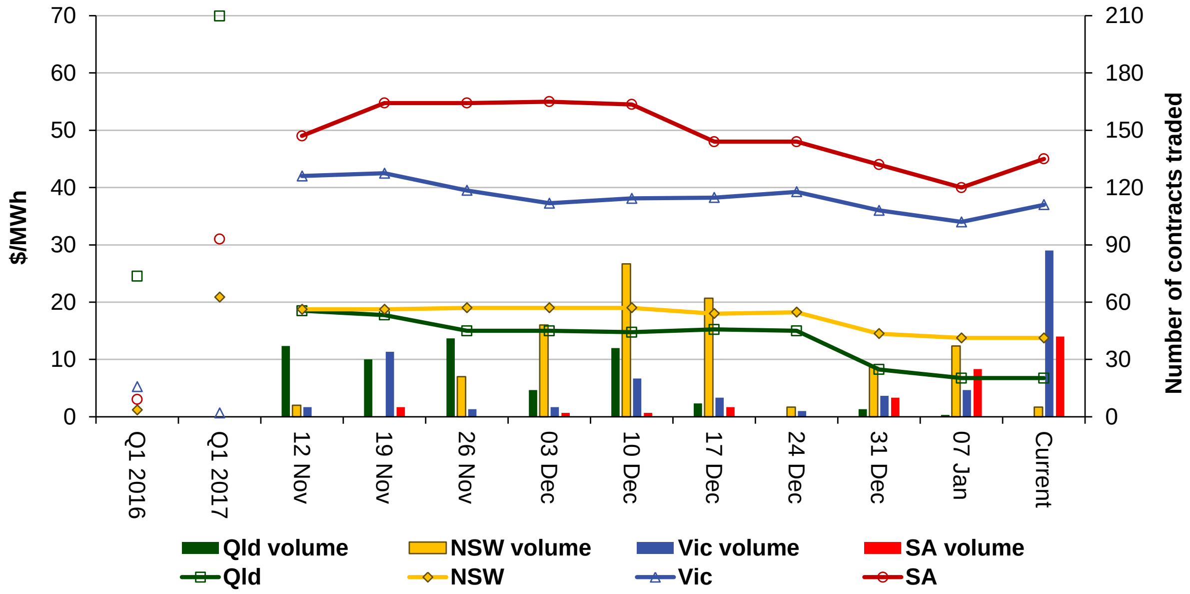
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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 2018 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2016 and quarter 1 2017 prices are also shown.

Figure 11: Price of Q1 2018 cap contracts over the past 10 weeks (and the past 2 years)



Source. ASXEnergy.com.au

Australian Energy Regulator
February 2018