Electricity Report

AUSTRALIAN ENERGY REGULATOR

7 – 13 July 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.

On Monday 8 July 2019, there was an unplanned outage at Origin Energy's Mortlake Power Station, a gas peaking generator in Victoria. The outage was due to damage to one unit at Mortlake with a registered capacity of 259 MW. Origin is aiming to bring the unit back online by 20 December 2019. The remaining unit at Mortlake remains operational and available to supply the grid. Analysis indicates this outage is unlikely to have significant impacts on long-term prices.

Spot market prices

Figure 1 shows the spot prices that occurred in each region during the week 7 to 13 July 2019.

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

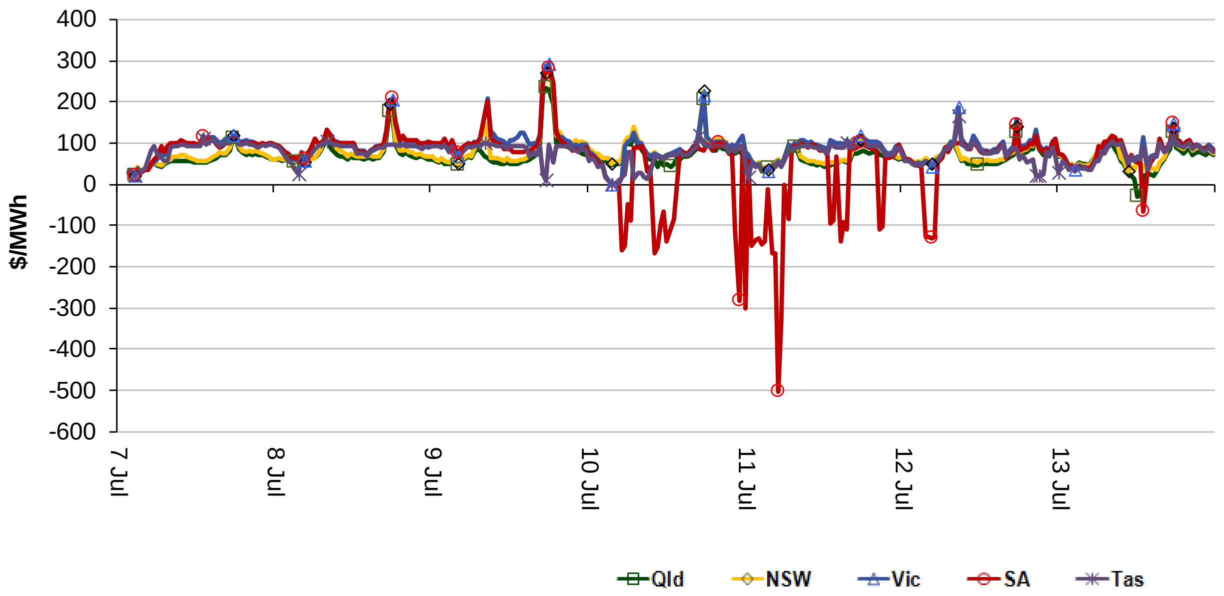


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

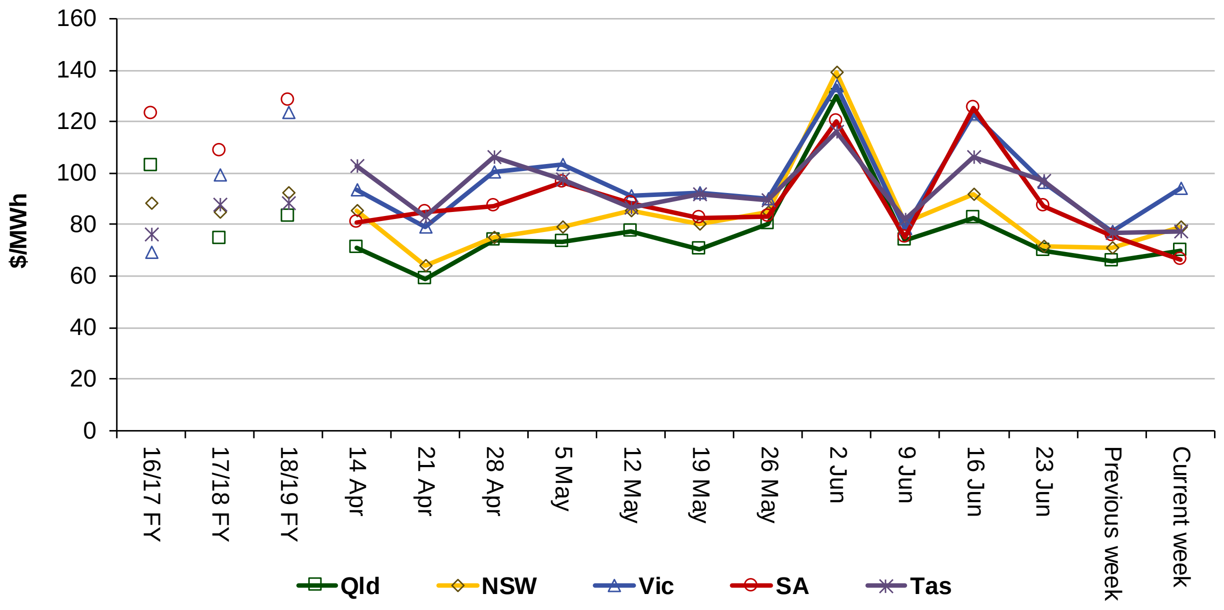


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	70	79	94	66	77
18-19 financial YTD	70	76	75	150	58
19-20 financial YTD	69	76	88	73	78

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 176 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	11	20	0	1
% of total below forecast	7	51	0	10

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

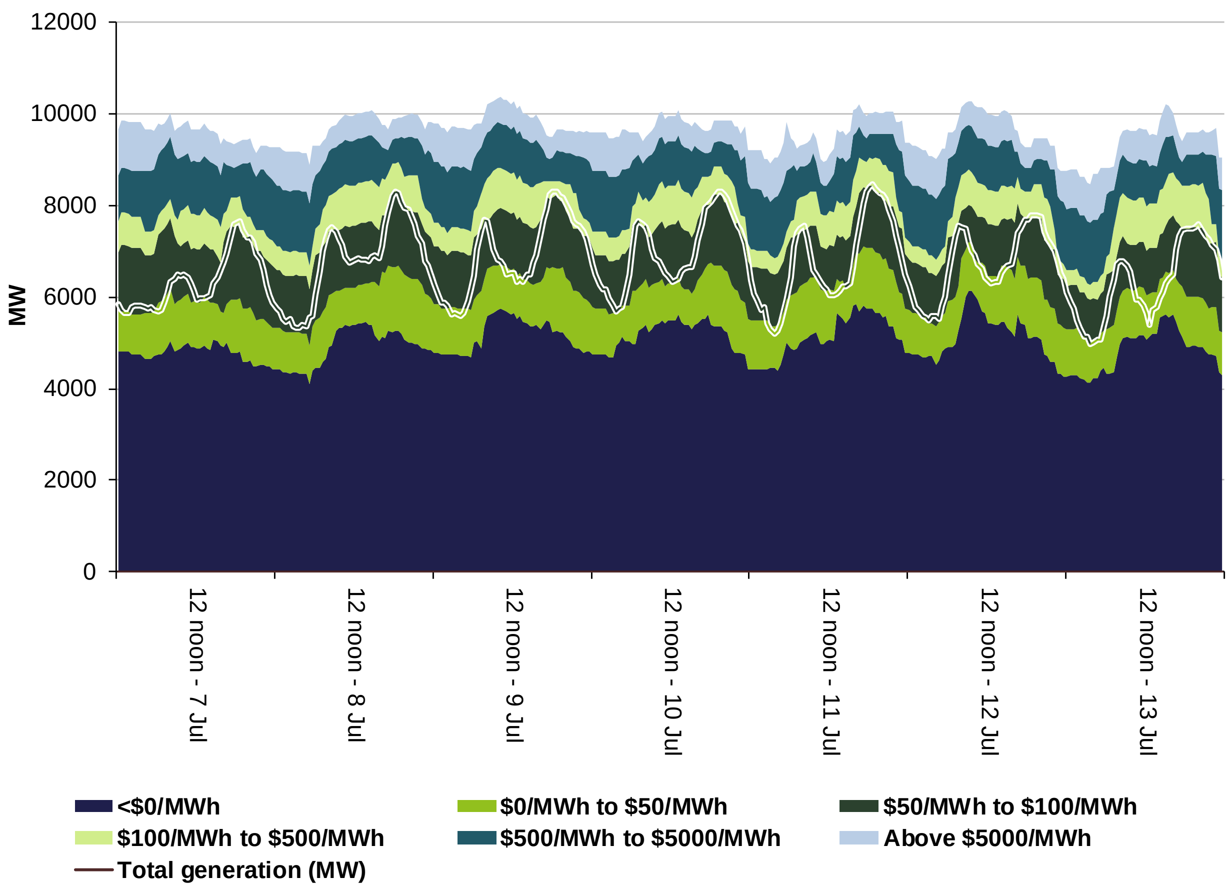


Figure 4: New South Wales generation and bidding patterns

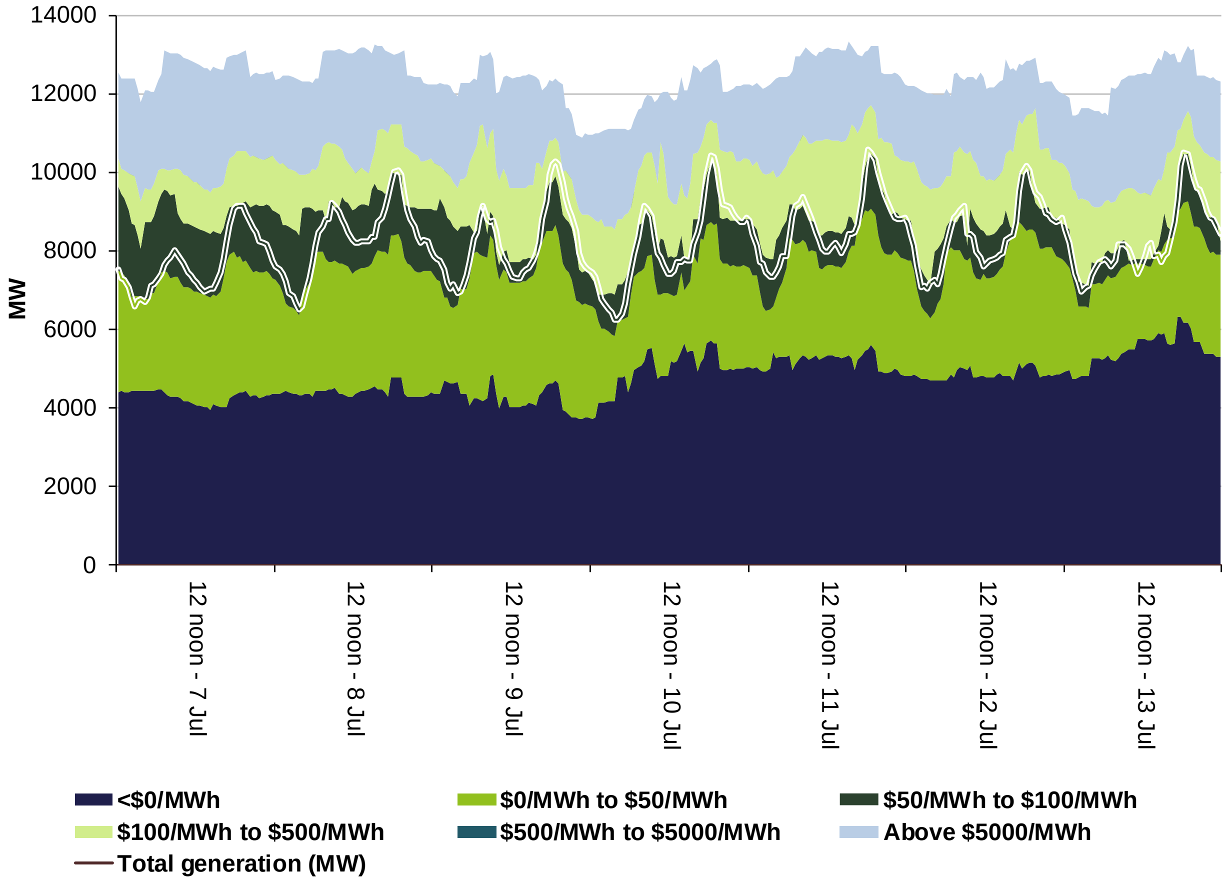


Figure 5: Victoria generation and bidding patterns

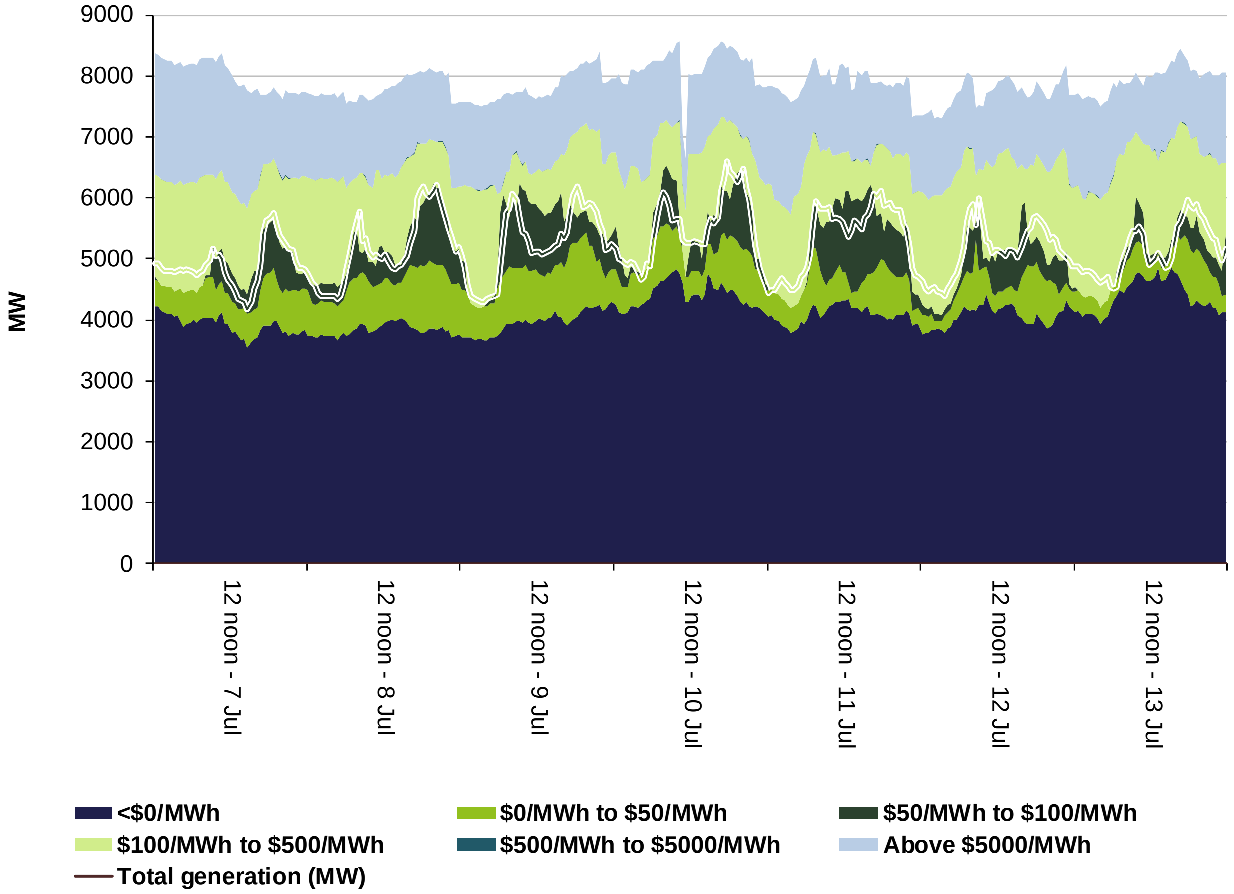


Figure 6: South Australia generation and bidding patterns

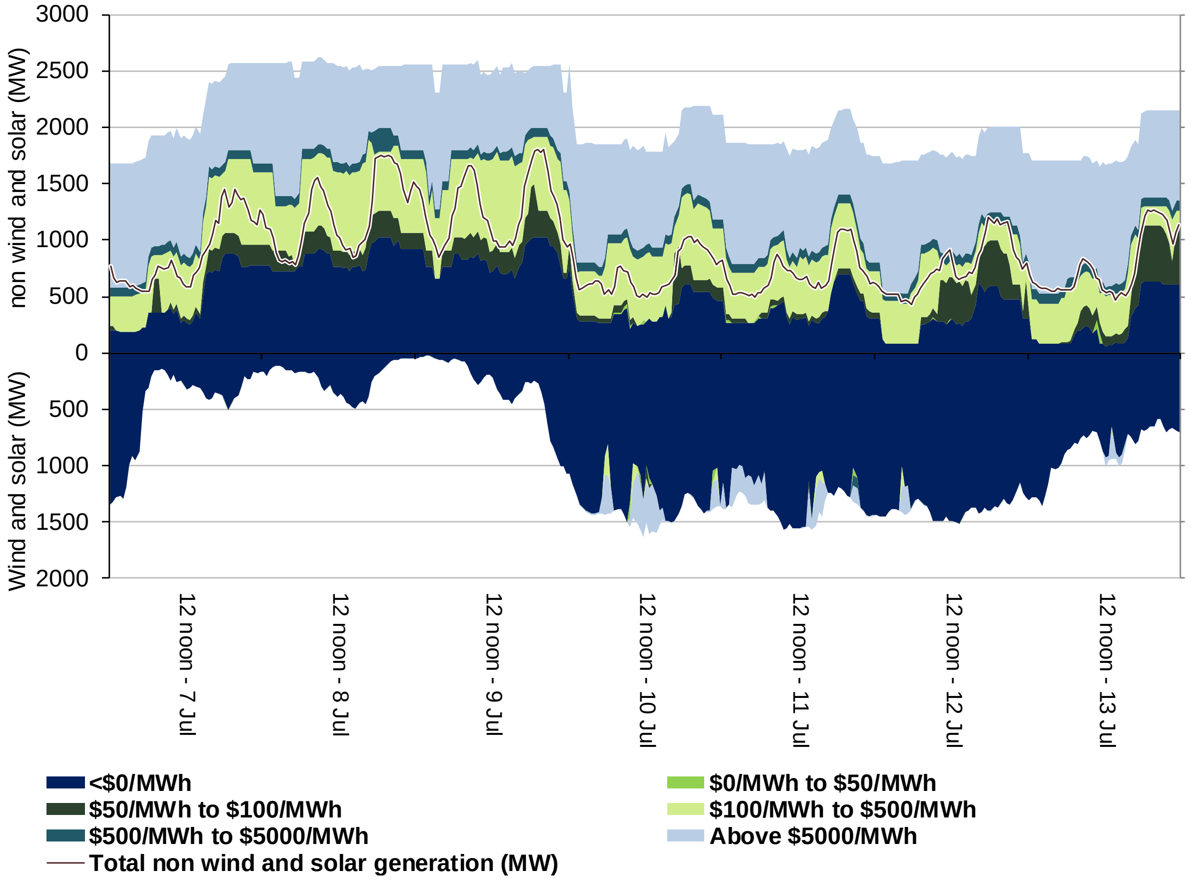
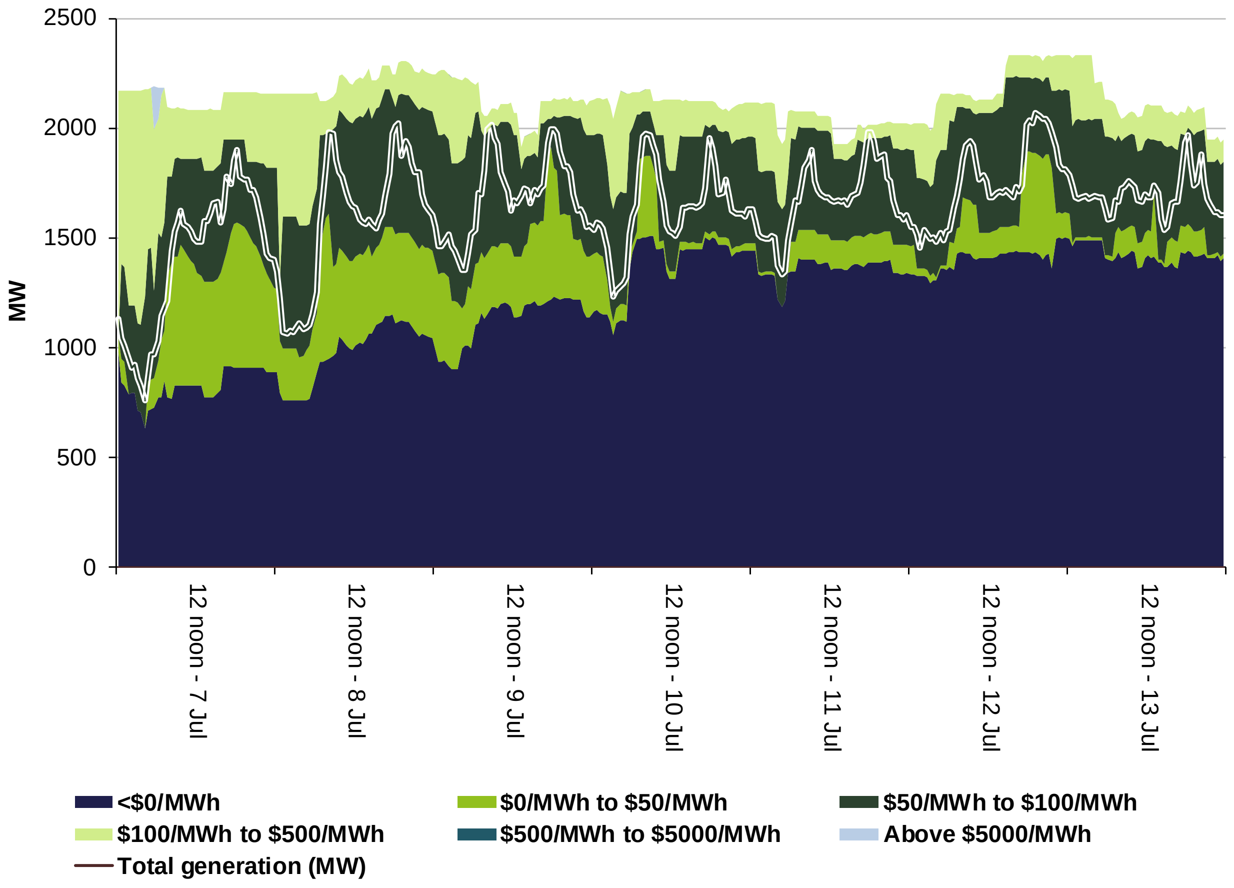


Figure 7: Tasmania generation and bidding patterns



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.

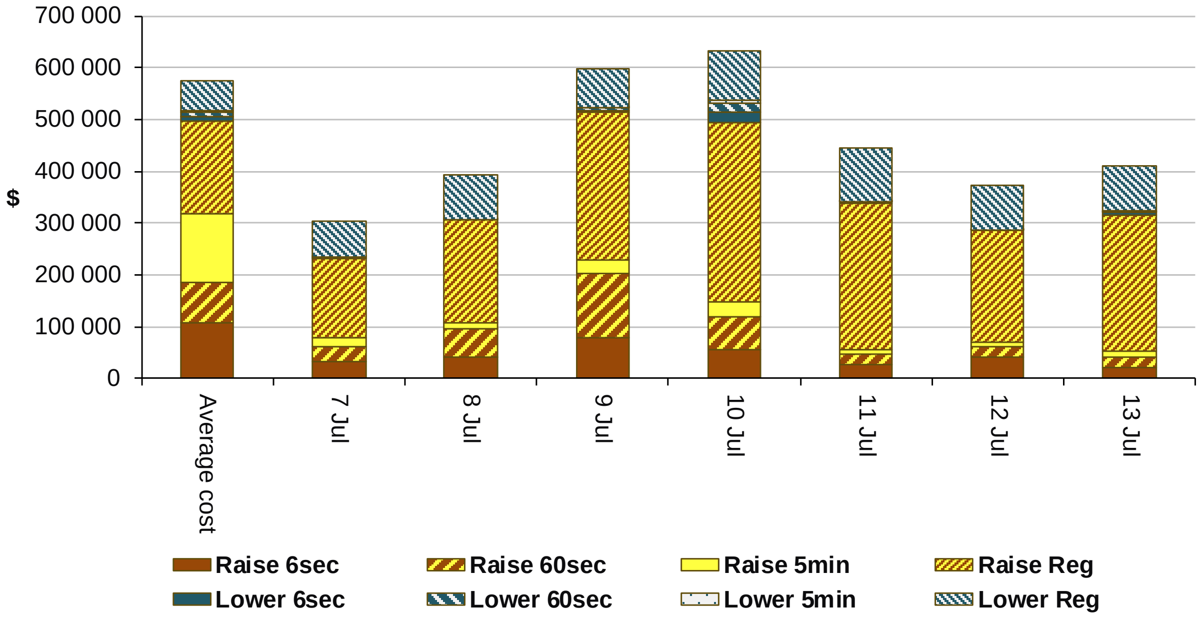
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $2 906 000 or less than 2 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $250 500 or less than 2 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



Detailed market analysis of significant price events

New South Wales

There were three occasions where the spot price in New South Wales was greater than three times the New South Wales weekly average price of $79/MWh and above $250/MWh.

Tuesday, 9 July

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
5.30 pm	252.67	287.56	106.33	10 049	10 091	10 215	12 194	12 525	13 193
6 pm	270.19	285.05	286.46	10 632	10 678	10 819	12 360	12 525	13 261
6.30 pm	268.66	287.56	282.06	10 770	10 891	11 026	12 313	12 601	13 237

Conditions at the time saw prices close to forecast, four hours prior.

Victoria

There were two occasions where the spot price in Victoria was greater than three times the Victoria weekly average price of $94/MWh and above $250/MWh.

Tuesday, 9 July

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
6 pm	287.86	290	290	6751	6670	6706	8083	8224	8151
6.30 pm	290	290	290	6801	6719	6735	8134	8256	8197

Conditions at the time saw prices close to forecast, four hours prior.

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 $66/MWh and above $250/MWh and there were twenty-six occasions where the spot price was below -$100/MWh.

Tuesday, 9 July

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
6 pm	276.12	291.01	282.76	1732	1737	1737	2790	2803	2830

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	282.27	299.53	294.53	1874	1887	1905	2808	2790	2829

Conditions at the time saw prices close to forecast, four hours prior.

Wednesday, 10 July

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
5.30 am	-159.33	14.55	36.57	989	1009	1011	3282	3040	3022
6 am	-150.45	23.95	40.44	1157	1050	1052	3286	3043	3006

At times, AEMO may need to override the normal dispatch process to maintain system security. On this day AEMO had directed a gas plant in South Australia, triggering an intervention event. Special pricing arrangements applied for all significant price events on 10 July in all regions following an intervention in the market.

At 5.32 am, AEMO reclassified the simultaneous trip of transmission lines connecting South Australia to Victoria as a credible contingency due to severe weather warning. This resulted in a sharp reduction in export on the Heywood interconnector, from 287 MW at 5.25 am to 56 MW at 5.35 am, and left South Australia with excess generation. With more expensive generation being limited by a semi-scheduled dispatch cap, dispatch prices fell to the floor at 5.30 am and 5.35 am.

Wednesday, 10 July

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
10.30 am	-167.16	91.95	82.96	1230	1373	1354	3299	3157	3186
11 am	-154.67	80.91	77.49	1232	1303	1285	3357	3171	3195

For the 10.30 am trading interval, demand was 143 MW less than forecast while availability was 142 MW higher than forecast, both four hours prior. The higher than forecast availability was due to higher wind generation, mostly priced below $0/MWh. These conditions lead to the price falling to the floor at 10.15 am.

For the 11 am trading interval, demand was 71 MW less than forecast while availability was 186 MW more than forecast, both four hours prior. At 10.35 am, semi-scheduled dispatch caps on Snowtown and Waterloo wind farms were removed. Their total output increased from 0 MW at 10.30 am to 216 MW at 10.40 am, all priced at the floor. With higher priced generation either ramp-down constrained and unable to set price or limited by a semi-scheduled dispatch cap, the price fell to the floor at 10.40 am.

Wednesday, 10 July

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
12.30 pm	-139.60	-1000	-487.65	1140	1146	1187	3286	3132	3149
1 pm	-107.17	-1000	-1000	1160	1123	1175	3402	3142	3144

For the 12.30 pm trading interval, demand was close to forecast while availability was 154 MW more than forecast due to higher wind generation, both four hours prior. Rebids from the price floor to higher price bands caused the dispatch price to settle around $60/MWh for four dispatch intervals. See Table 9 for details. The price remained close to forecast at -$900/MWh for the 12.15 am dispatch interval.

Table 9: Significant rebids

Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
12.05 pm	Origin Energy	Bungala One Solar Farm	110	-1000	14 700	1152A constraint management - F_S++HYSE_L6_1
12.05 pm	Origin Energy	Bungala Two Solar Farm	110	-1000	14 700	1152A constraint management - F_S++HYSE_L6_1
12.20 pm	Energy Australia	Waterloo WF	130	-142	400	12:12 ~ A ~ band adj to 5min negative DP ~ sl
12.20 pm	HWF3 Pty Ltd	Hornsdale Wind Farm 3	109	-150	60	1212 A Change in forecast prices
12.20 pm	Trustpower	Snowtown WF	99	-1000	14 700	1210 A SA 5min PD RRP for 1220 ($-259.36) published at 1210 is 418.73% lower than 5min PD RRP published at 1205 ($-50.0) - time of alert: 1213

For the 1 pm trading interval, demand was 37 MW higher while availability was 260 MW higher than forecast due to higher wind generation, both four hours prior. Rebids from the price floor to higher price bands caused the dispatch price to settle between -$160/MWh and -$50/MWh for the entire trading interval. See Table 10Table 9 for details.

Table 10: Significant rebids

Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
10.44 pm	HWF3 Pty Ltd	Hornsdale Wind Farm 3	109	-1000	>60	1044 A constraint management

Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
11.55 pm	Origin Energy	Bungala One Solar Farm	110	-1000	14 700	1152A constraint management - F_S++HYSE_L6_1
11.55 pm	Origin Energy	Bungala Two Solar Farm	110	-1000	14 700	1152A constraint management - F_S++HYSE_L6_1

Wednesday, 10 July

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
11 pm	-112.73	60.47	60.81	1384	1374	1350	3492	3352	3264
11.30 pm	-283.02	-1000	55.91	1387	1313	1304	3474	3359	3263

For the 11 pm trading interval, demand was close to forecast while availability was 140 MW more than forecast, both four hours prior. At 10.50 pm, demand in South Australia decreased by 37 MW. As a result Pelican Point, which was setting price at $68/MWh in the previous dispatch interval, was backed off. With no other capacity offered between $68/MWh and the price floor at the time, the price fell to the floor for one dispatch interval. In response, Infigen rebid 159 MW at Lake Bonney 2 Wind Farm from the price floor to over $12 000/MWh effective 10.55 pm. Dispatch prices stayed around $60/MWh until 10.20 pm when Infigen reversed the previous rebid. This rebid caused price to drop to the floor for the 10.20 pm and 10.25 pm dispatch intervals. Price returned to above $90/MWh at 11.30 pm after Infigen reversed the rebid again along with a number of other rebids. See Table 12 for details.

Table 12: Significant rebids

Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
10.55 pm	Infigen	Lake Bonney 2 Wind Farm	159	-1000	12 879	2245~A~SA price DP@2250 for 2250 1066 lwr thn 5PD@2245
11.20 pm	Infigen	Lake Bonney 2 Wind Farm	159	-12 879	-1000	2310~A~SA price 5PD@2315 for 2325 1034 hghr thn 5PD@2300
11.25 pm	Infigen	Lake Bonney 2 Wind Farm	159	-1000	12 879	2315~A~SA price 5PD@2320 for 2325 1068 lwr thn 5PD@2315
11.25 pm	HWF3 Pty Ltd	Hornsdale Wind Farm 3	-109	-1000	N/A	2318 A Constraint management

Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
11.25 pm	Trustpower	Snowtown WF	99	-1000	14 700	2301 A SA1 30min PD RRP for 2330 ($-1000.0) published at 2301 is 1866.18% lower than 30min PD RRP published at 2231 ($50.86) – time of alert: 2318
11.25 pm	Energy Australia	Waterloo Wind Farm	130	-1000	400	23:16 ~ A ~ band adj to 5min negative dp

Thursday, 11 July

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
12.30 am	-302.48	59.58	52.59	1389	1397	1383	3501	3347	3254
1.30 am	-150.49	54.05	42.14	1209	1227	1218	3210	3085	3241

At times, AEMO may need to override the normal dispatch process to maintain system security. On this day AEMO had directed a gas plant in South Australia, triggering an intervention event. Special pricing arrangements apply for all significant price events on 11 July from 12.30 am to 5 pm in all regions following an intervention in the market.

From 12.30 am to 1.30 am, there was little to no capacity priced between $68/MWh and the price floor in South Australia. Consequently small reductions in demand within a trading interval resulted in higher priced generation to be backed off and caused price to drop to the price floor for either one or two dispatch intervals.

Thursday, 11 July

Table 14: 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 am	-133.58	48.48	40.18	1228	1143	1133	3238	3120	3250
2.30 am	-130.73	42.55	38.36	1182	1083	1072	3132	3122	3254
3 am	-146.04	42.05	41.04	1158	1043	1035	3099	3122	3012
3.30 am	-138.15	40.76	26.61	1131	1012	1000	3110	3095	3020

For the 2 am trading interval, the dispatch price fell to the price floor at 1.45 am. Effective 1.45 am, Neoen rebid 109 MW at Hornsdale Wind Farm 3 from $14 700/MWh to the price floor due to constraint management. This coupled with an increase in wind generation and a decrease of 82 MW in demand saw the dispatch price fall to the floor.

For the 2.30 am and the 3.30 am trading intervals, the dispatch price fell to the price floor in the first dispatch interval. Effective for both 2.05 am and 3.05 am, Trustpower rebid 99 MW at Snowtown Wind Farm from -$40/MWh to the price floor in response to a high forecast price. In the same instances, the semi-scheduled dispatch cap on Snowtown Wind Farm lifted and generation increased by 50 MW at both 2.05 am and 3.05 am. With higher priced generation ramp-down constrained and unable to set price, the dispatch price fell to the floor.

For the 3 am trading interval, the dispatch price fell to the price floor for one dispatch interval. At 2.55 am, demand in South Australia decreased by 61 MW. With higher priced generation ramp-down constrained and unable to set price, the dispatch price fell to the floor at 2.55 am.

Thursday, 11 July

Table 15: 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 am	-167.50	-1000	26.15	1093	967	948	3193	3109	3084
5 am	-167.50	-1000	26.35	1090	965	947	3203	3112	3086
5.30 am	-502.79	-1000	31.49	1101	969	959	3199	3106	3088
6 am	-334.00	-1000	32.28	1144	1009	993	3198	3104	3128

For the 4.30 am to 6 am trading intervals, actual spot prices were higher than forecast, four hours prior. Rebids from the price floor to higher price bands caused dispatch prices to either settle at -$1/MWh or at the price floor as forecasted. See Table 16 for details.

Table 16: Significant rebids

Trading Interval	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
4.30 am, 5 am, 5.30 am, 6 am	HWF3 Pty Ltd	Hornsdale Wind Farm 3	109	-1000	14 700	0255 A Constraint management
4.30 am, 5 am, 5.30 am, 6 am	Infigen	Lake Bonney 2 Wind Farm	159	-1000	12 879	0315~A~const mgmt S_NIL_Strength_1 SL~
4.30 am, 5 am, 5.30 am, 6 am	AGL Energy	Bluff Wind Farm	30	-1000	-1	0401~A~050 chg in AEMO PD~54 PD price decrease [SA] $999PE0430 - 0630
4.30 am, 5 am, 5.30 am, 6 am	AGL Energy	Hallett 1 Wind Farm	55	-1000	-1	0401~A~050 chg in AEMO PD~54 PD price decrease [SA] $999PE0430 - 0630
4.30 am, 5 am, 5.30 am, 6 am	AGL Energy	Hallett 2 Wind Farm	48	-1000	-1	0401~A~050 chg in AEMO PD~54 PD price decrease [SA] $999PE0430 - 0630

Trading Interval	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
4.30 am, 5 am, 5.30 am, 6 am	AGL Energy	North Brown Hill Wind Farm	60	-1000	-1	0401~A~050 chg in AEMO PD~54 PD price decrease [SA] $999PE0430 - 0630

Thursday, 11 July

Table 17: 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	-137.89	78.28	-29.89	1266	1223	1188	3360	3096	3134
4 pm	-110.47	83.84	80.72	1357	1274	1234	3279	3044	3097
9 pm	-109.72	101	97.66	1584	1576	1523	3401	3282	3327
9.30 pm	-100.89	98.31	99.33	1554	1537	1478	3355	3207	3318

The dispatch price fell to the price floor once in each of the above four trading intervals. These were due to a reduction in demand in South Australia. With higher priced generation either ramp-down constrained or trapped in FCAS and unable to set price, the dispatch price fell to the floor.

Friday, 12 July

Table 18: 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 am	-128.31	39.40	46.29	951	947	976	3087	2941	2704
4.30 am	-129.04	36.25	43.77	1017	927	956	3119	2953	2784
5 am	-132.43	35.82	41.13	1036	923	956	3134	2953	2790
5.30 am	-126.72	36.85	44.20	1043	934	971	3123	2955	2790

At times, AEMO may need to override the normal dispatch process to maintain system security. On this day AEMO had directed a gas plant in South Australia, triggering an intervention event. Special pricing arrangements apply for all significant price events on 12 July in all regions following an intervention in the market.

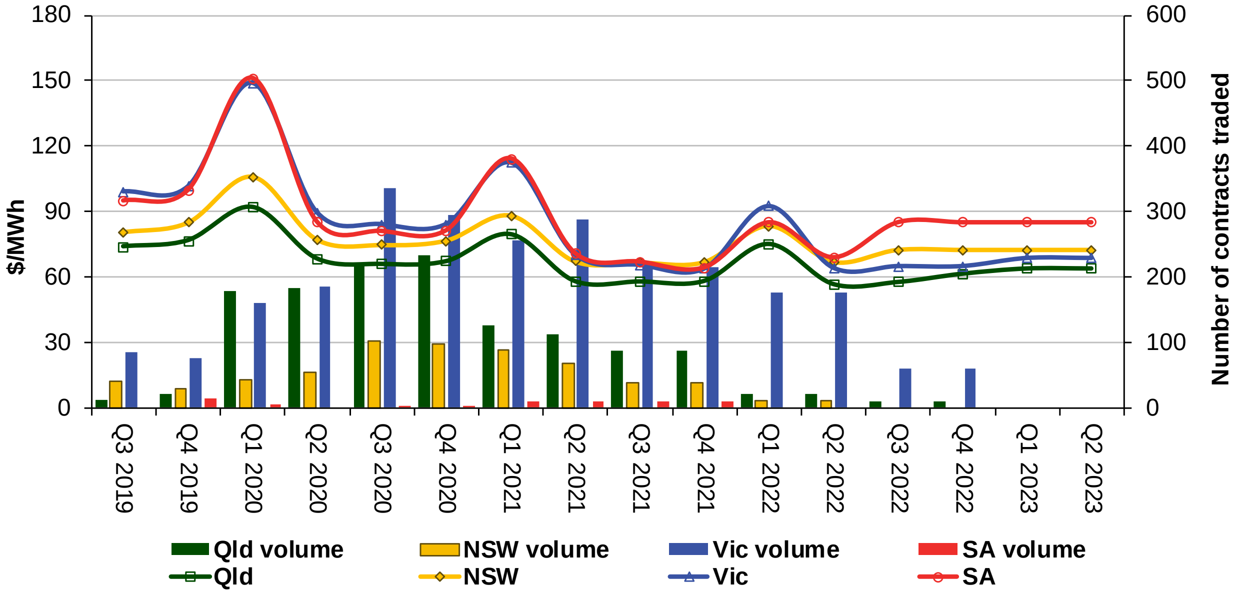
For the 4 am trading interval, demand was close to forecast while availability was 146 MW more than forecast, both four hours prior. The higher than forecast availability was due to higher than forecast wind generation, mostly priced below $0/MWh. At 4 am, demand in South Australia decreased by 8 MW. With higher priced generation ramp-down constrained and unable to set price, the dispatch price fell to the floor for one dispatch interval.

From 4.30 am to 5.30 am, while demand was between 90 MW to 110 MW higher than forecast while availability was between 160 MW and 180 MW higher than forecast, four hours prior. The higher than forecast availability was mostly due to higher than forecast wind generation, the majority of which was priced below $0/MWh. These conditions led to dispatch prices dropping to the price floor for the first dispatch interval in all three trading intervals.

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 Q3 2019 – Q2 2023

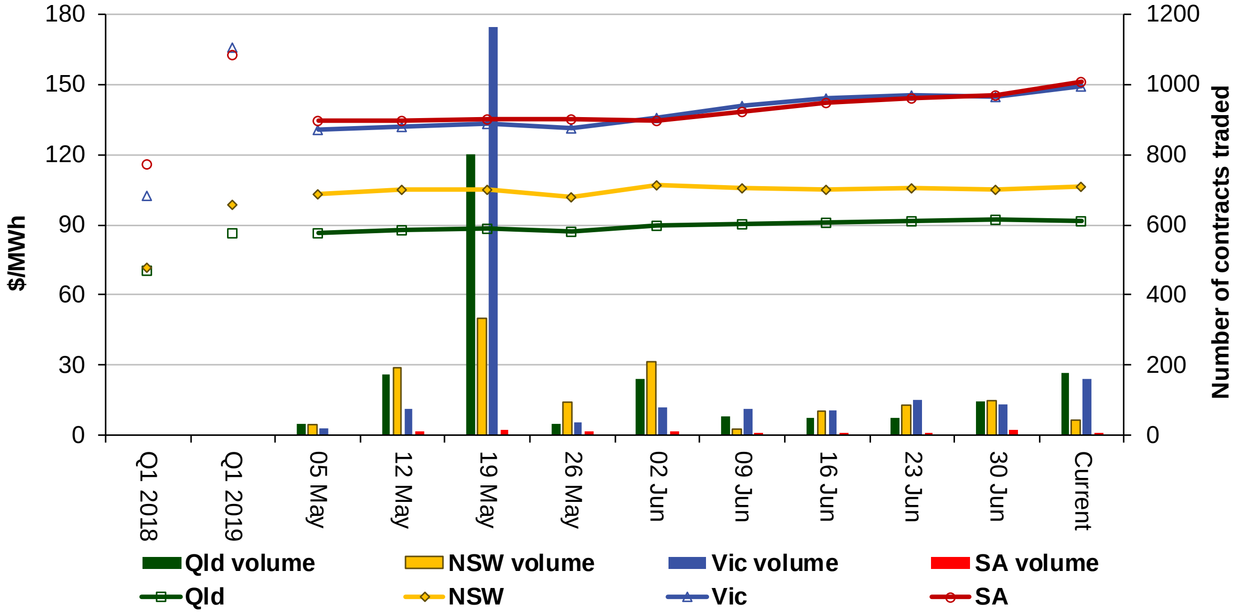


Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional Q1 2020 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2018 and quarter 1 2019 prices are also shown. The AER notes that data for South Australia is less reliable due to very low numbers of trades.

The high volume of trades in Figure 10 is a result of the conversion of base load options to base future contracts on Monday 20 May 2019.

Figure 10: Price of Q1 2020 base contracts over the past 10 weeks (and the past 2 years)



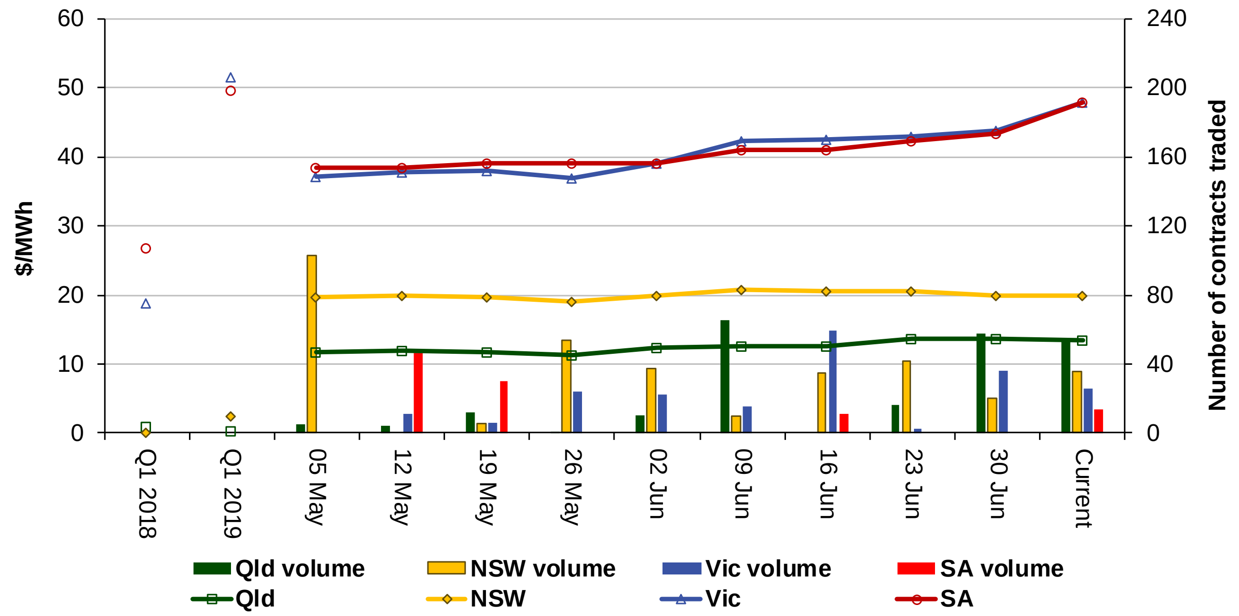
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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 2020 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2018 and quarter 1 2019 prices are also shown.

Figure 11: Price of Q1 2020 cap contracts over the past 10 weeks (and the past 2 years)



Source. ASXEnergy.com.au

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July 2019