Electricity Report

AUSTRALIAN ENERGY REGULATOR

18 – 24 July 2021

Weekly Summary

Weekly volume weighted average (VWA) prices were between $26/MWh in Tasmania and $243/MWh in Queensland. The high weekly VWA price for Queensland was driven by high prices on 21 July, which will be analysed in our upcoming report on prices above $5,000/MWh.

There were a number of prices in New South Wales above $2,000/MWh which contributed to its higher weekly VWA price (see Detailed market analysis section).

With the high prices over recent weeks, financial year to date VWA prices are between $54/MWh (in Victoria) to $130/MWh (in Queensland) higher than the same time last year though it is only 3 weeks into the financial year.

Purpose

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 18 to 24 July 2021.

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

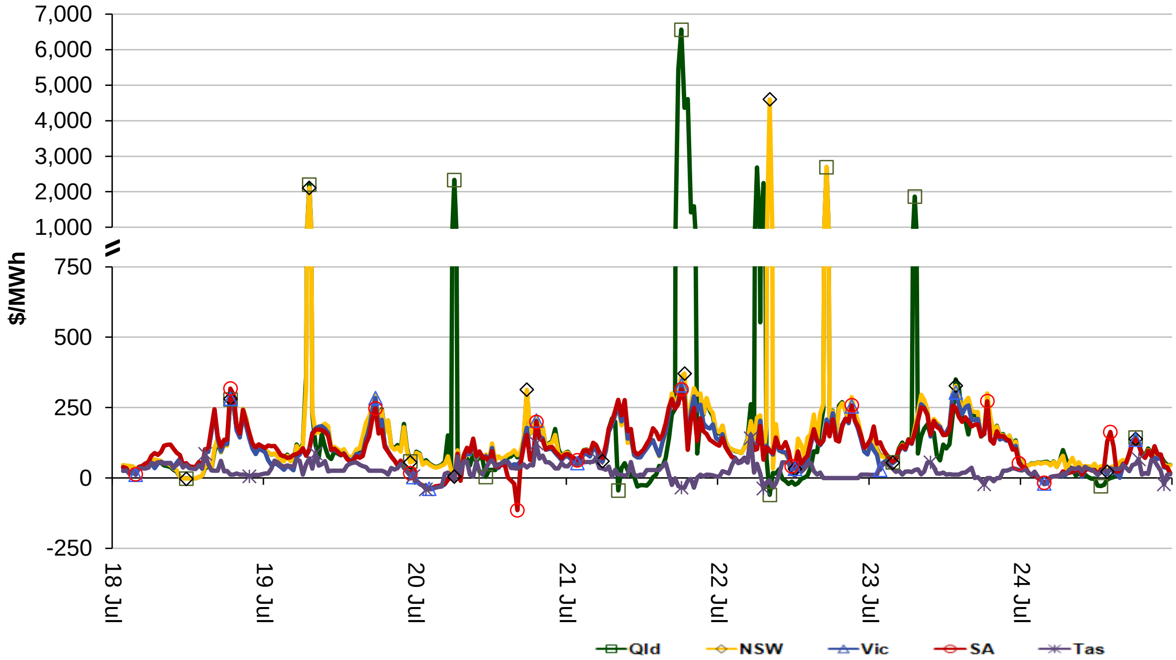


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

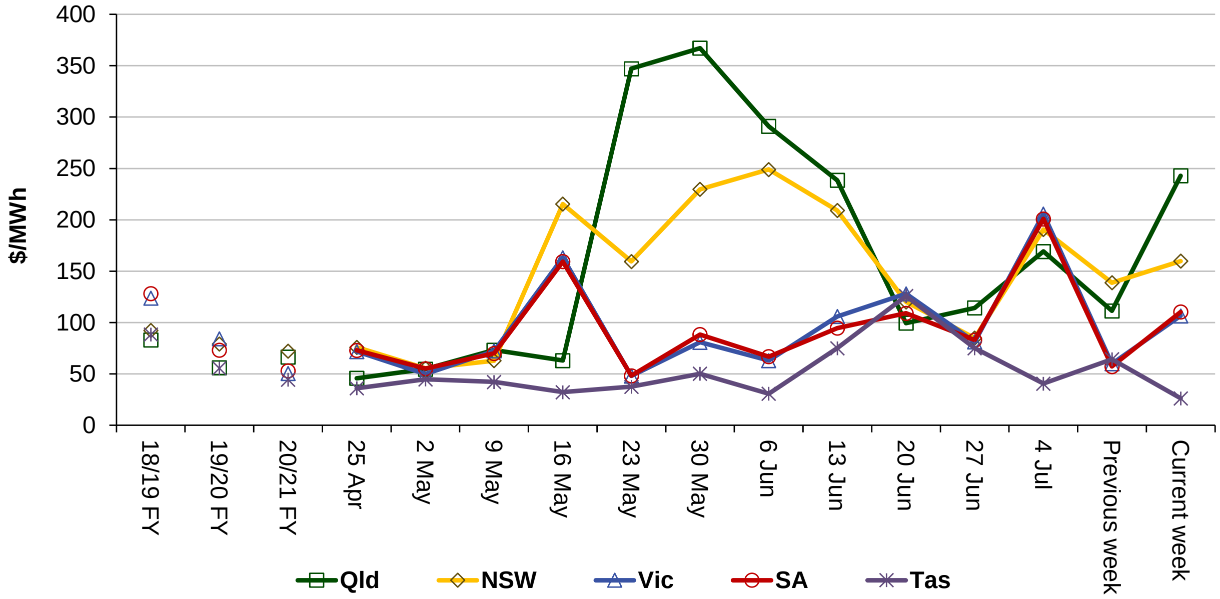


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	243	160	107	110	26
Q3 2020 QTD	42	51	66	62	56
Q3 2021 QTD	172	155	120	118	47
20-21 financial YTD	42	51	66	62	56
21-22 financial YTD	172	155	120	118	47

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 311 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2020 of 233 counts and the average in 2019 of 204. 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	14	17	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

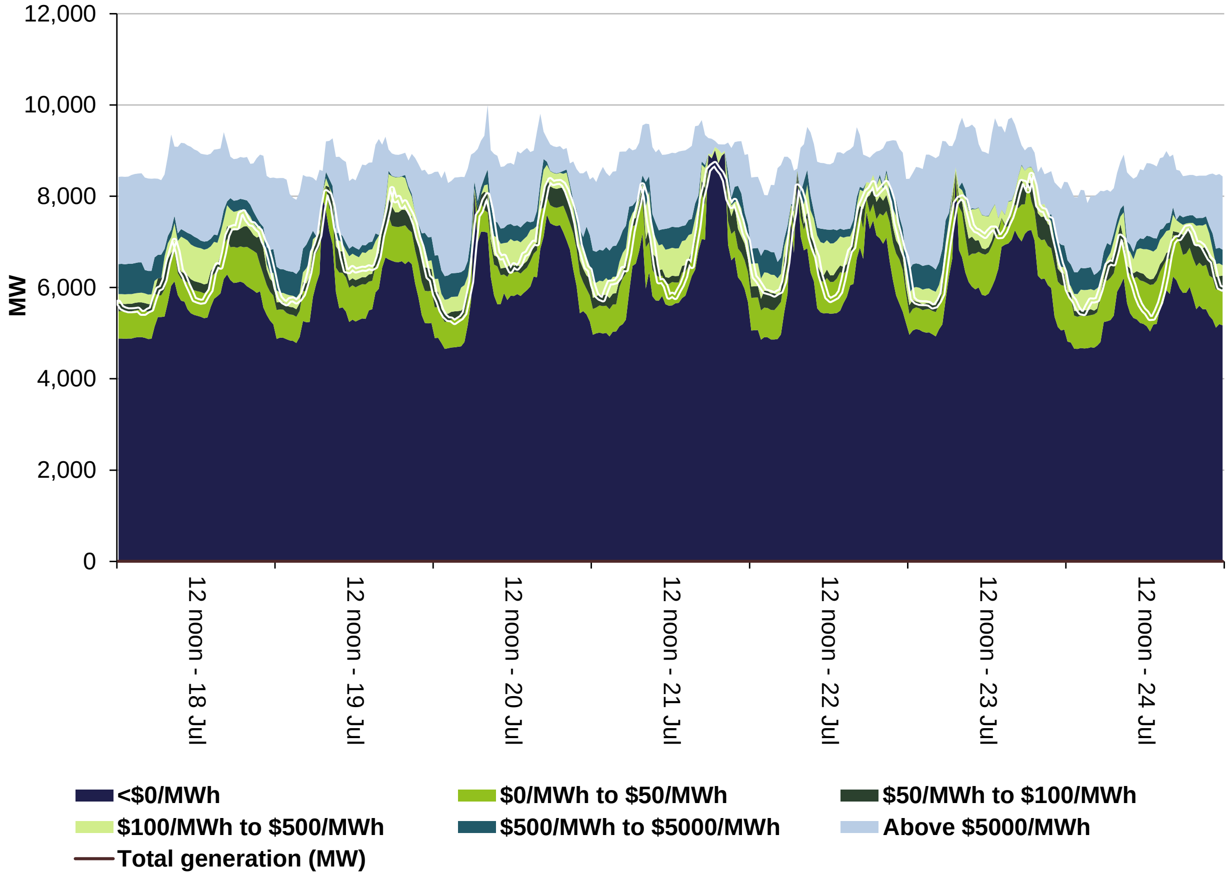


Figure 4: New South Wales generation and bidding patterns

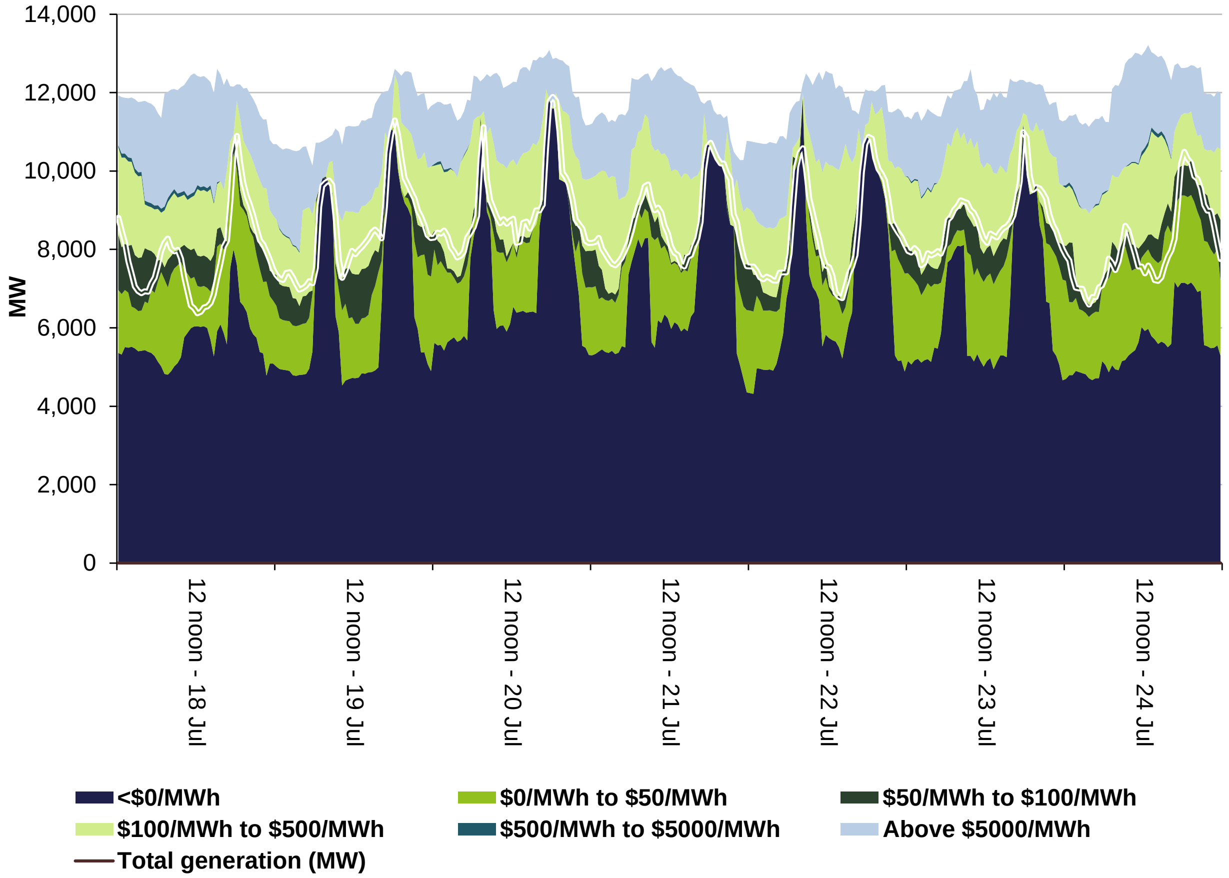


Figure 5: Victoria generation and bidding patterns

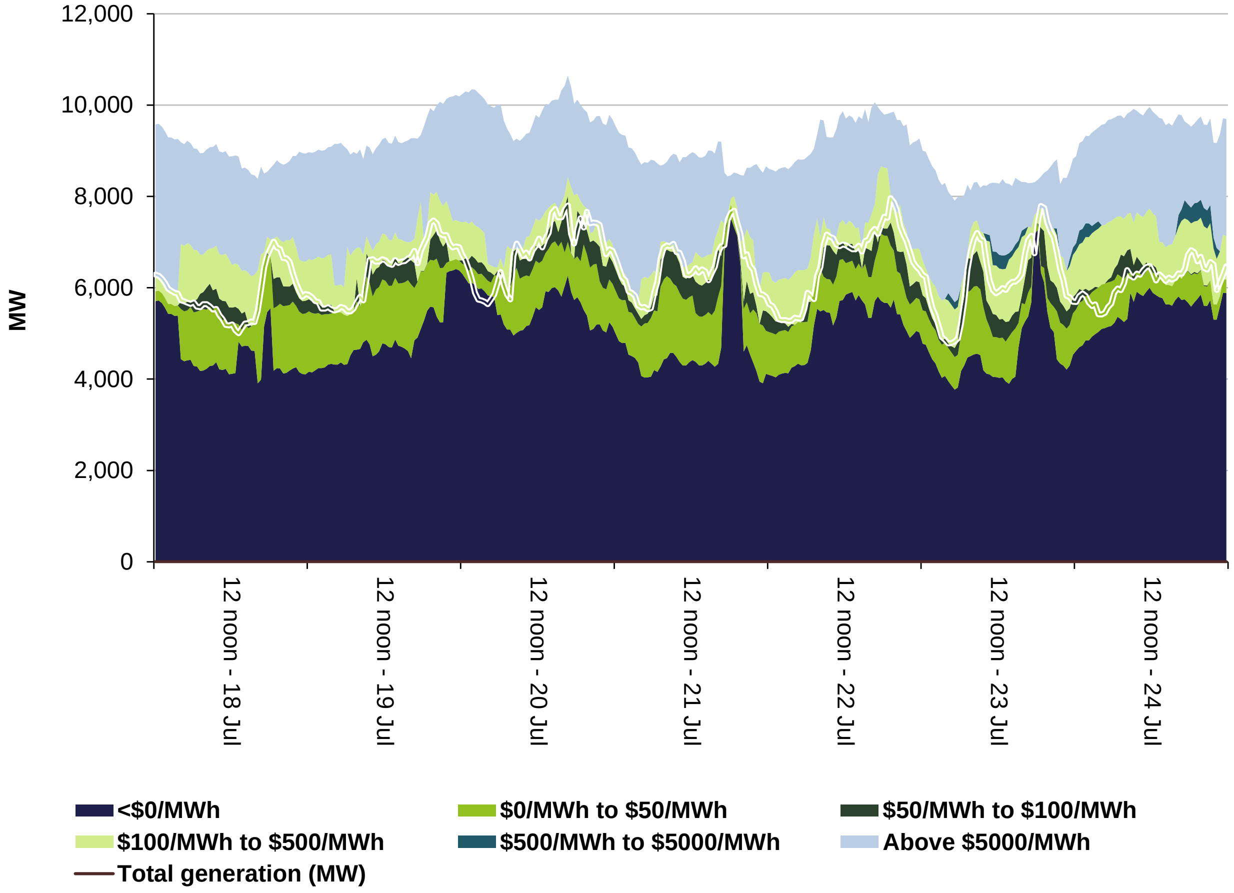


Figure 6: South Australia generation and bidding patterns

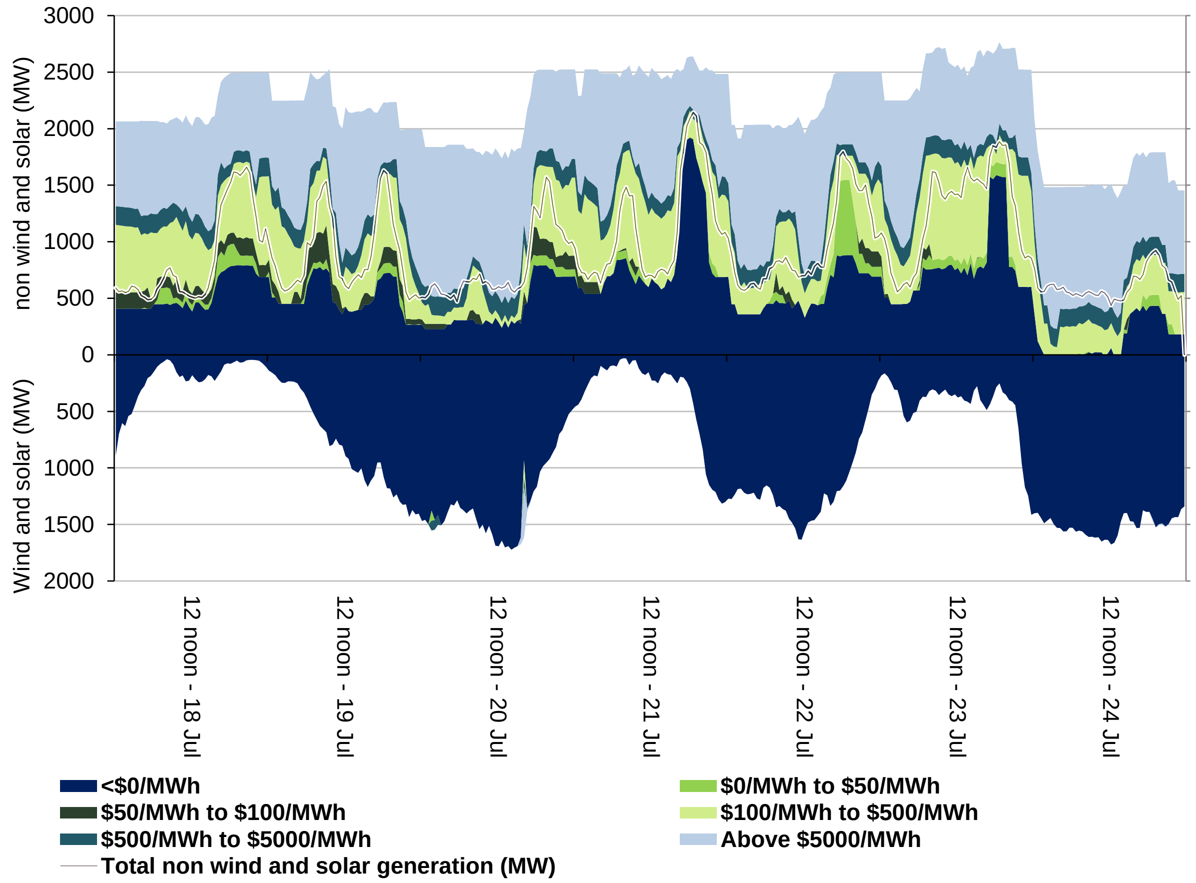
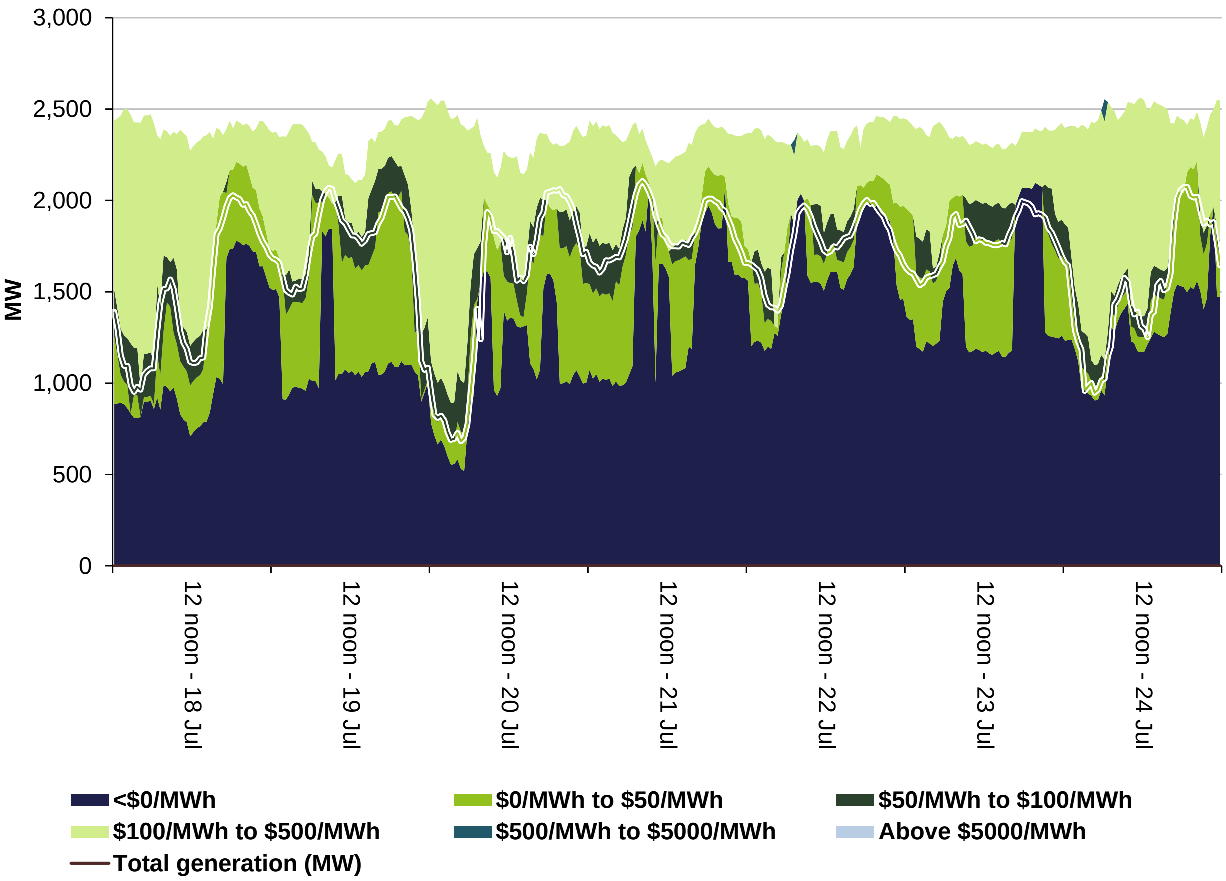


Figure 7: Tasmania generation and bidding patterns



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.

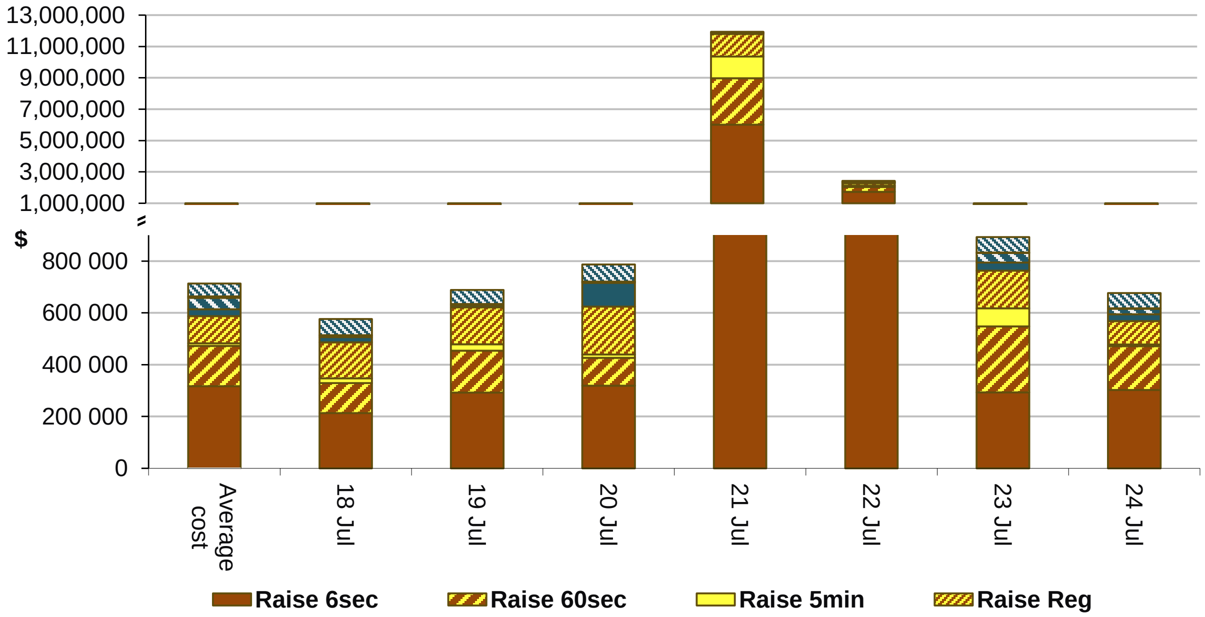
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $17,208,000 or less than 3% of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $778,500 or around 14% 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



High costs on 21 July were driven by high prices in Queensland. Queensland experienced the highest winter demand since the start of the NEM. Supply of low-priced generation and FCAS capacity was limited due to around 2,400 MW of baseload generation on planned and unplanned outages, some of which normally provide FCAS. In addition, planned network outages as part of the QNI upgrade meant Queensland had to supply its own FCAS. This led to co-optimisation between the Energy and FCAS markets, resulting in high prices for some dispatch intervals during the 6 pm to 8 pm trading intervals.

Detailed market analysis of significant price events

Queensland

There were 12 occasions where the spot price in Queensland was greater than 3 times the Queensland weekly average price of $243/MWh and above $250/MWh.

Monday, 19 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
7.30 am	2,205	15,100	15,100	7,538	7,391	7,346	8,509	8,909	8,994

Demand was 147 MW less than forecast and availability was 400 MW less than forecast, 4 hours prior. Lower than forecast available was due to removal of almost 300 MW of capacity at a number of generators from 6 am onwards (Table 4), and lower than forecast wind generation which often offers below $0/MWh.

From 3.50 am participants rebid almost 830 MW of capacity from the price cap to the price floor. This resulted in prices lower than forecast (Table 4).

Table 4: Significant rebids

Submit time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
3.53 am		Origin Energy	Mt Stuart	210	15,100	-1,000	0350A constraint management - n^^q_nil_b1 sl
6.06 am		RTA Yarwun	Yarwun	-10	-967	N/A	alumina refinery constraints
6.18 am		Origin Energy	Darling Downs	-30	<67	N/A	0617P change in avail - db limitation sl
6.32 am		QGC Sales	Condamine	-89	-1,000	N/A	06:30:23 P change in plant capabilities sl
6.50 am		Origin Energy	Mt Stuart	60	15,100	-1,000	0642A constraint management - n::n_cncw_2 sl
6.57 am	7.05 am	CleanCo	Wivenhoe	50	15,100	-1,000	0656A qld rrp $1602 in dispatch sl
7.01 am	7.10 am	AGL Energy	Yabulu	-160	0	N/A	0700~P~020 reduction in avail cap~202 run up issues~
7.05 am	7.15 am	ERM Power	Oakey	173	15,100	-1,000	A 0705 0705 maintain unit at max output following unexpected target
7.05 am	7.15 am	Arrow Energy	Braemar 2	165	15,100	-1,000	0705A start target received sl
7.12 am	7.20 am	CS Energy	Gladstone	45	15,100	-1,000	0711A qld1 ti 19-07-2021 07:30:00 p30 rrp $15,100 vs p30 rrp $1602 @ p30 run 19-07-2021 06:31:23 - rrp change of $13498-sl
7.18 am	7.25 am	Origin Energy	Mt Stuart	126	15,100	-1,000	0717A constraint management - nrm_nsw1_vic1 sl

Tuesday, 20 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
6.30 am	2,335	85.73	60.73	6,980	6,753	6,709	8,980	8,901	8,906

Demand was 227 MW higher than forecast and availability was close to forecast, 4 hours prior.

There was little available capacity offered between $85/MWh and $14,000/MWh so small changes in price could cause large fluctuations in price. At 6.15 pm demand increased by 71 MW and with lower priced capacity ramp constrained and unable to set price, price was $13,959/MWh for 5 minutes. In response to the high price, participants rebid almost 900 MW of capacity from prices above $13,959/MWh to the floor. Prices were below $-5/MWh for the rest of the trading interval.

Wednesday, 21 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
6 pm	5,434	11,580	15,100	8,160	8,077	8,185	9,264	9,212	9,273
6.30 pm	6,564	15,100	15,100	8,154	8,208	8,283	9,258	9,205	9,272
7 pm	4,364	15,100	15,100	8,179	8,252	8,316	9,212	9,192	9,233
7.30 pm	4,608	14,215	15,100	8,038	8,171	8,224	9,142	9,152	9,237
8 pm	1,416	548.90	15,100	7,951	8,080	8,121	9,136	9,167	9,212
8.30 pm	1,590	294.22	514.25	7,846	8,018	8,061	9,135	9,183	9,200

Prices will be analysed in our report on $5,000/MWh prices in Queensland.

Thursday, 22 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
6.30 am	2,685	189.50	115.87	7,215	6,924	6,878	8,806	9,025	8,826
7.30 am	2,244	997.94	997.94	7,951	7,626	7,599	8,645	9,164	8,955
5.30 pm	2,692	120.02	298.33	7,382	7,418	7,417	9,001	9,101	9,101

For the 6.30 am trading interval, demand was 291 MW higher than forecast and availability was 219 MW lower than forecast, 4 hours prior. Lower than forecast availability was due to removal of capacity by QGC Sales (Condamine, 90 MW priced at the floor), CS Energy (Gladstone 55 MW priced up to the cap) due to technical issues, and lower than forecast wind generation which mostly offers below $0/MWh.

At 6.15 am, demand increased by 127 MW and with other generators ramp-constrained price was set at $15,095/MWh. In response to the high price, participants rebid around 600 MW from the price cap to the floor. Prices were below $148/MWh for the rest of the trading interval.

For the 7.30 am trading interval, demand was 325 MW higher than forecast and availability was 519 MW lower than forecast, 4 hours prior. Lower than forecast availability was due to removal of capacity from the same generators as the 6.30 am trading interval and lower than forecast wind generation, plus –

- Stanwell – 33 MW at the floor at Tarong North for technical reasons
- AGL Energy – 160 MW at the cap at Yabulu due to pipeline conditions
- Origin Energy – 38 MW at Roma and 120 MW at Mt Stuart price at or close to the cap, both to avoid an uneconomic start.

There was no capacity offered between $999/MWh and $15,000/MWh, so small changes in demand or availability could cause large fluctuations in price. At 7.05 am, demand increased by 88 MW and with lower-priced generation ramp-constrained the price was set at the cap for 5 minutes.

For the 5.30 pm trading interval, price was aligned with New South Wales and will be analysed as 1 region. Demand was cumulatively close to forecast and availability was cumulatively 201 MW lower than forecast, 4 hours prior. Lower than forecast availability was mainly due to the removal of capacity by AGL Energy (160 MW at Yabulu priced at $0/MWh due to pipeline conditions) and EnergyAustralia (160 MW at Mount Piper priced at the floor due to technical issues). At 5.30 pm, demand increased by over 260 MW, mostly in New South Wales, and with lower-priced generators ramp-constrained or trapped/stranded in FCAS and unable to set price the price was over $14,856/MWh for the last 5 minutes.

Friday, 23 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
7.30 am	1,864	164.92	162.69	7,648	7,510	7,465	9,248	9,255	8,984

Demand was 138 MW higher than forecast and availability was close to forecast, 4 hours prior.

There was only 90 MW of capacity offered between $85/MW and $15,095/MWh so small fluctuations in demand or availability could cause large variations in price. Effective 7.10 am, rebids by CleanCo at Wivenhoe and Alinta Energy at Braemar A shifted 195 MW from the price floor to the cap. At the same time demand increased by over 100 MW and price was set at $15,095/MWh. In response to the high price, participants rebid around 700 MW from the price cap to the floor. This resulted in prices at the floor for the remainder of the trading interval.

New South Wales

There were 3 occasions where the spot price in New South Wales was greater than 3 times the New South Wales weekly average price of $160/MWh and above $250/MWh.

Monday, 19 July

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
7.30 am	2,115	158.01	155.00	9,796	10,058	10,067	10,749	11,709	11,551

Demand was 262 MW lower than forecast and availability was 960 MW lower than forecast. Lower than forecast availability was due to removal of over 1,100 MW of capacity, most of which was priced below $110/MWh.

There was no capacity offered between $58/MWh and $14,288/MWh, so small changes in demand or availability could cause large fluctuations in price. At 7.10 am demand increased by

100 MW and with lower-priced capacity trapped/stranded in FCAS or ramp-constrained the price was $14,552/MWh for 5 minutes.

Table 10: Significant rebids, 7.30 am 19 July 2021

Submit time	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
4.48 am	AGL Energy	Liddell	-40	0	N/A	0445~P~010 unexpected/plant limits~101 milling limits~
5.02 am	AGL Energy	Bayswater	-290	<36	N/A	0500~P~010 unexpected/plant limits~106 aux/plant failure~
5.15 am	Delta Electricity	Vales Point	-470	14,288	N/A	0510~P~pa fan limit~~
5.48 am	AGL Energy	Bayswater	-100	-1,000	N/A	0536~P~010 unexpected/plant limits~106 aux/plant failure~
6.02 am	AGL Energy	Bayswater	-50	-1,000	N/A	0600~P~010 unexpected/plant limits~108 load/ramp variation during ramp down~
6.32 am	AGL Energy	Bayswater	-150	-1,000	N/A	0630~P~010 unexpected/plant limits~108 load/ramp variation during ramp down~
6.50 am	EnergyAustralia	Mt Piper	-20	-1,000	N/A	0645~P~adj avail revised cv limit sl~~

Thursday, 22 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
8.30 am	4,604	299.98	299.40	10,925	11,016	10,976	12,182	12,123	12,369
5.30 pm	2,705	125.32	297.78	10,945	10,937	11,087	11,759	11,860	12,012

For the 8.30 am trading interval, demand and availability were close to forecast, 4 hours prior. There was a planned outage of the Upper Tumut to Stockdill lines in New South Wales that impacted flows over the VIC-NSW interconnector.

There was no capacity offered between $277/MWh and $14,288/MWh, so small changes in demand or availability could cause large fluctuations in price. In preparation for the line outage, generation at Tumut was constrained off (priced at $-1,000/MWh) and flows forced over the VIC-NSW interconnector into Victoria. This resulted in price for 8.05 am and 8.10 am being set above $14,450/MWh.

For the 5.30 pm trading interval, price was aligned with Queensland and is analysed as 1 region. See Queensland section.

Victoria

There was 1 occasion where the spot price in Victoria was greater than 3 times the Victoria weekly average price of $107/MWh and above $250/MWh.

Wednesday, 21 July

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 pm	328.82	14,071	14,950	7,391	7,467	7,517	8,463	9,234	9,204

Demand was 76 MW lower than forecast while availability was 771 MW lower than forecast, 4 hours prior. Lower than forecast availability was mainly due to EnergyAustralia removing 510 MW of capacity at Newport priced at the floor due to a unit trip. To replace this capacity, EnergyAustralia rebid almost 430 MW of capacity at Jeeralang from prices above $14,950/MWh to the price floor, but then removed 84 MW of this capacity due to a unit trip. Another 70 MW at was removed by EnergyAustralia at Yallourn due to mill issues. From 4 hours before the start of the trading interval, participants rebid a further 330 MW of capacity from prices above $14,000/MWh to the floor. This led to prices lower than forecast.

South Australia

There was 1 occasion where the spot price in South Australia was below -$100/MWh.

Tuesday, 20 July

Table 13: Price, Demand and Availability

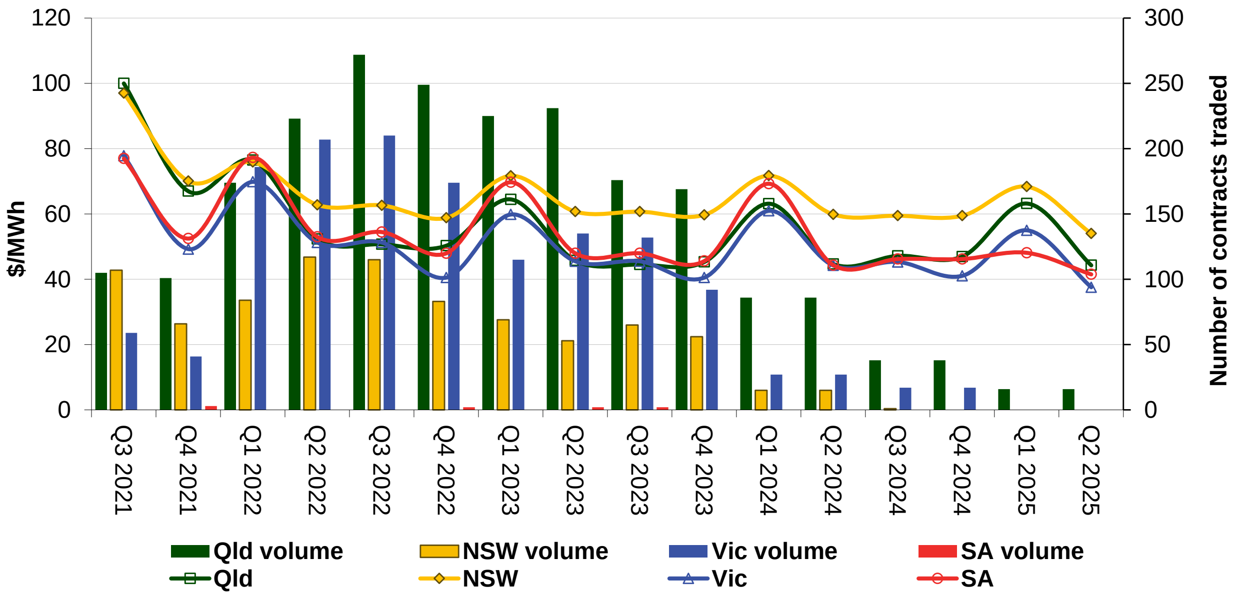
Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
4.30 pm	-114.88	40.50	55.92	1,372	1,230	1,288	3,596	3,266	3,224

Demand was 142 MW higher than forecast and availability was 330 MW higher than forecast, 4 hours prior. Higher than forecast availability was due to higher than forecast wind generation, which mostly offers below $0/MWh. At 4.05 pm, a constraint managing system strength in South Australia by limiting at least 500 MW of capacity of wind farms was no longer binding. This saw an immediate 170 MW increase of capacity priced at the floor resulting in the price dropping to the floor. In response to the low price, participants rebid over 670 MW of capacity from the floor to prices above $71/MWh. Price was between $15/MWh and $83/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.

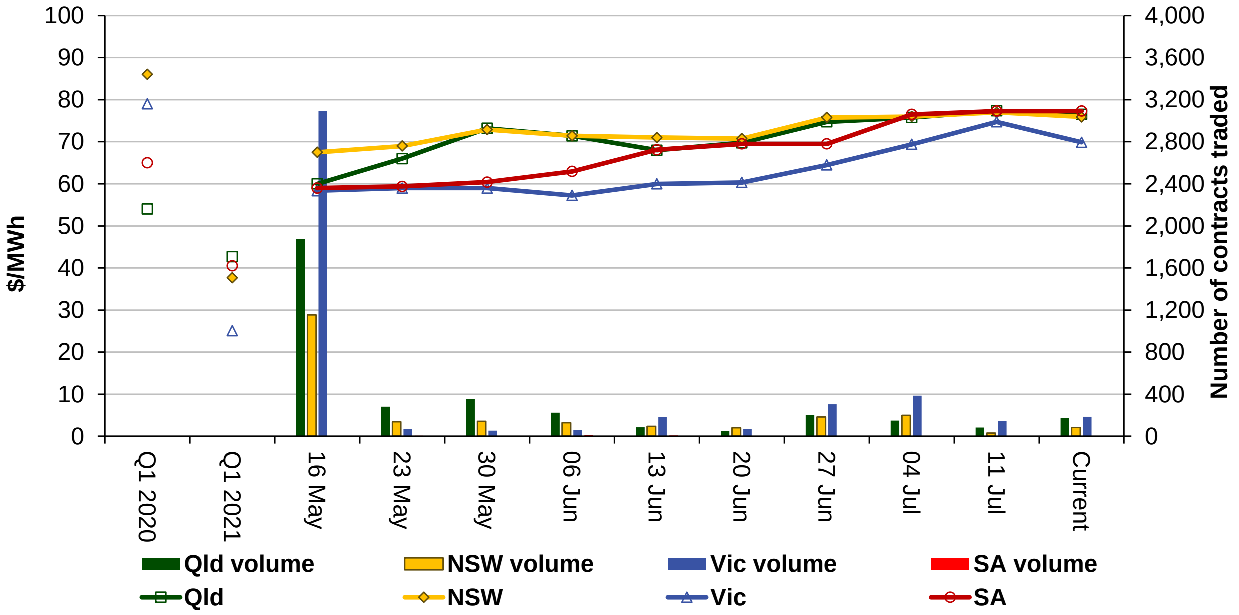
Figure 9: Quarterly base future prices Q3 2021 – Q2 2025



Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional Q1 2022 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing Q1 2021 and Q1 2020 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 2022 base contracts over the past 10 weeks (and the past 2 years)

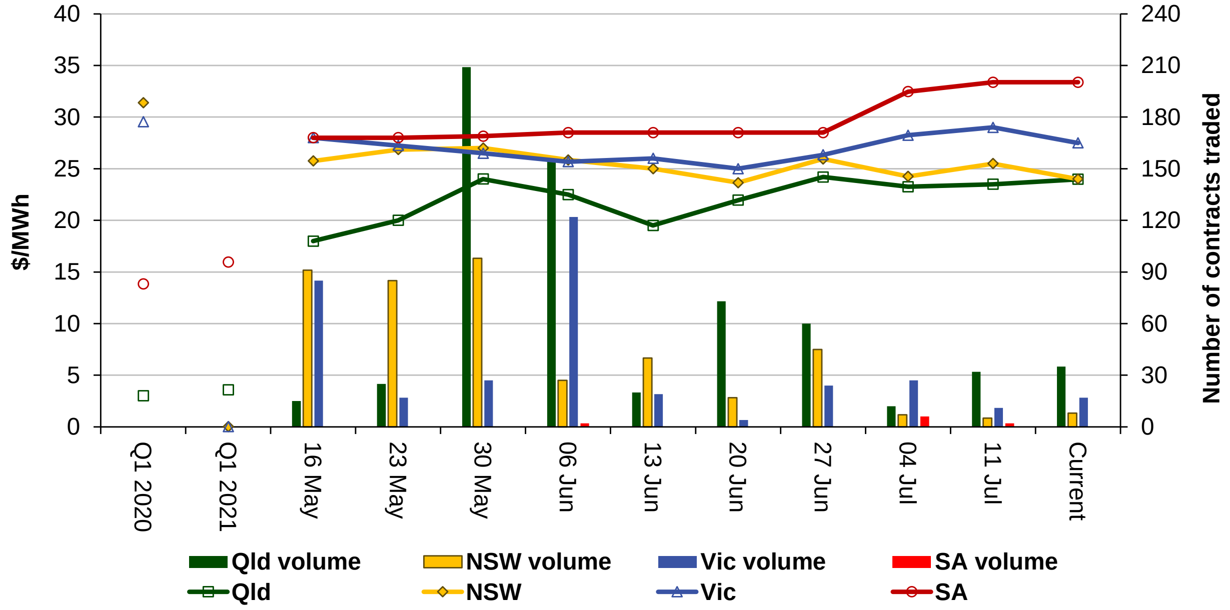


Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

Source. ASXEnergy.com.au

Figure 11 shows how the price for each regional Q1 2022 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing Q1 2021 and Q1 2020 prices are also shown.

Figure 11: Price of Q1 2022 cap contracts over the past 10 weeks (and the past 2 years)



Source. ASXEnergy.com.au

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

Australian Energy Regulator
August 2021