Electricity Report

AUSTRALIAN ENERGY REGULATOR

21 – 27 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.

Spot market prices

Figure 1 shows the spot prices that occurred in each region during the week 21 to 27 July 2019.

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

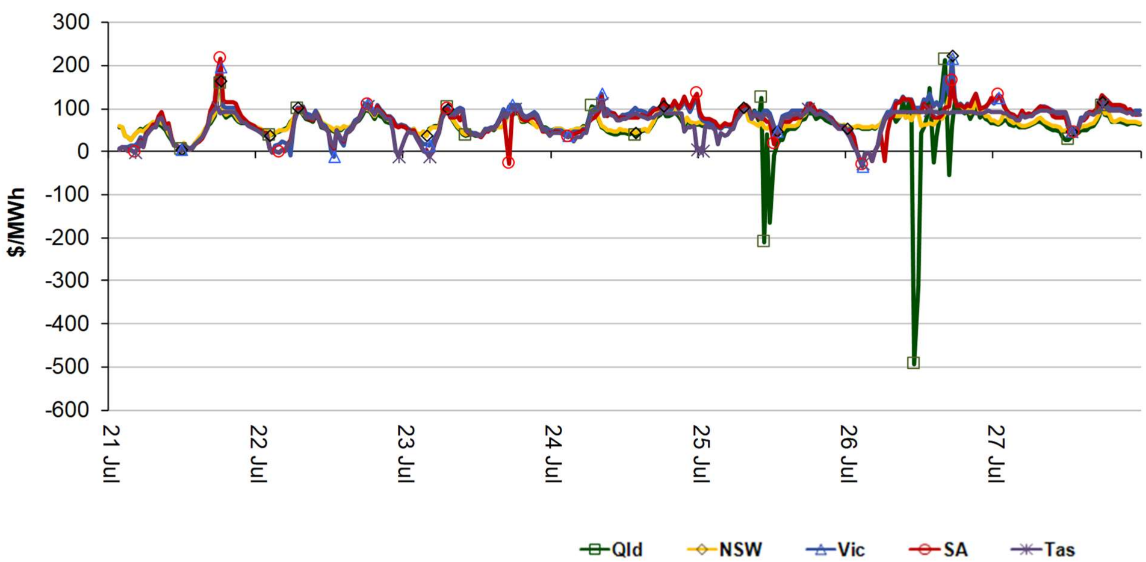


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

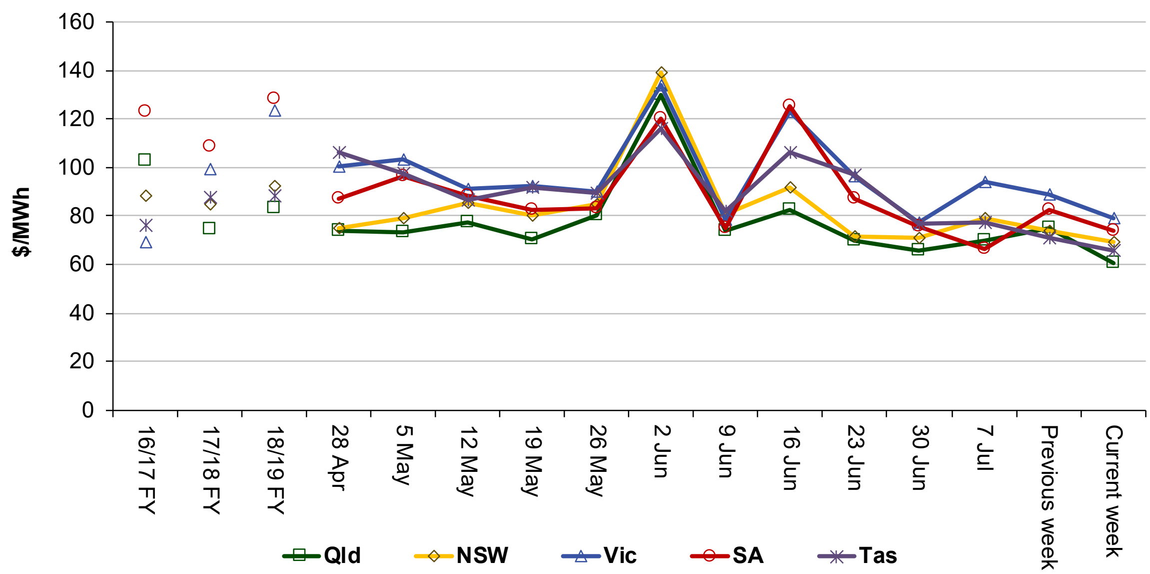


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	61	69	79	74	66
18-19 financial YTD	73	79	77	116	49
19-20 financial YTD	68	74	86	76	73

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 182 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	2	15	0	2
% of total below forecast	11	61	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

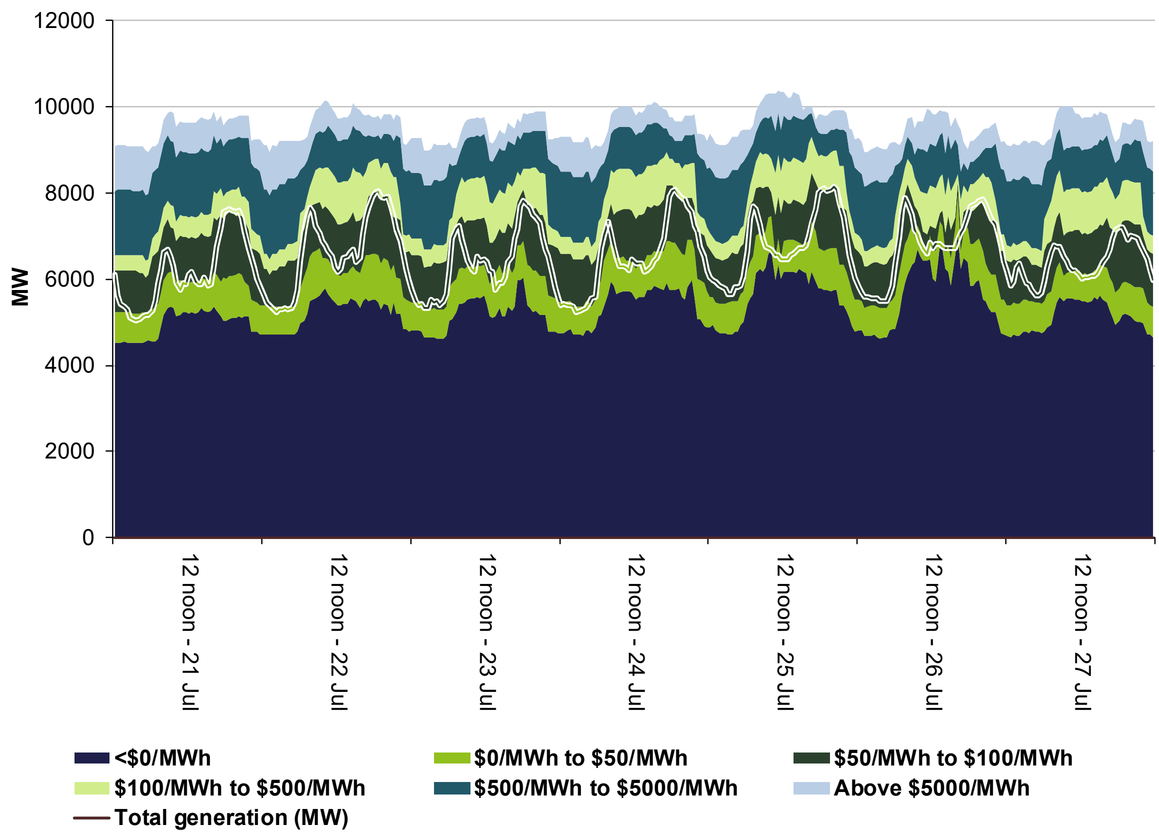


Figure 4: New South Wales generation and bidding patterns

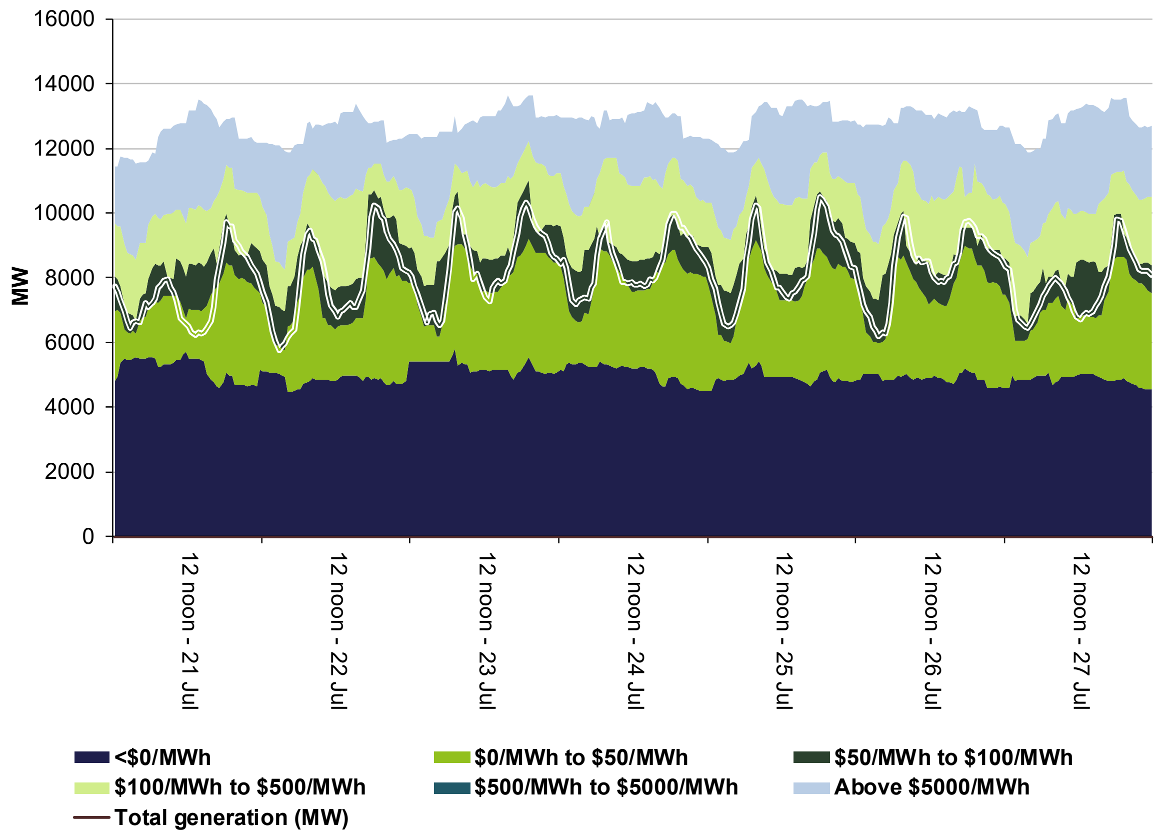


Figure 5: Victoria generation and bidding patterns

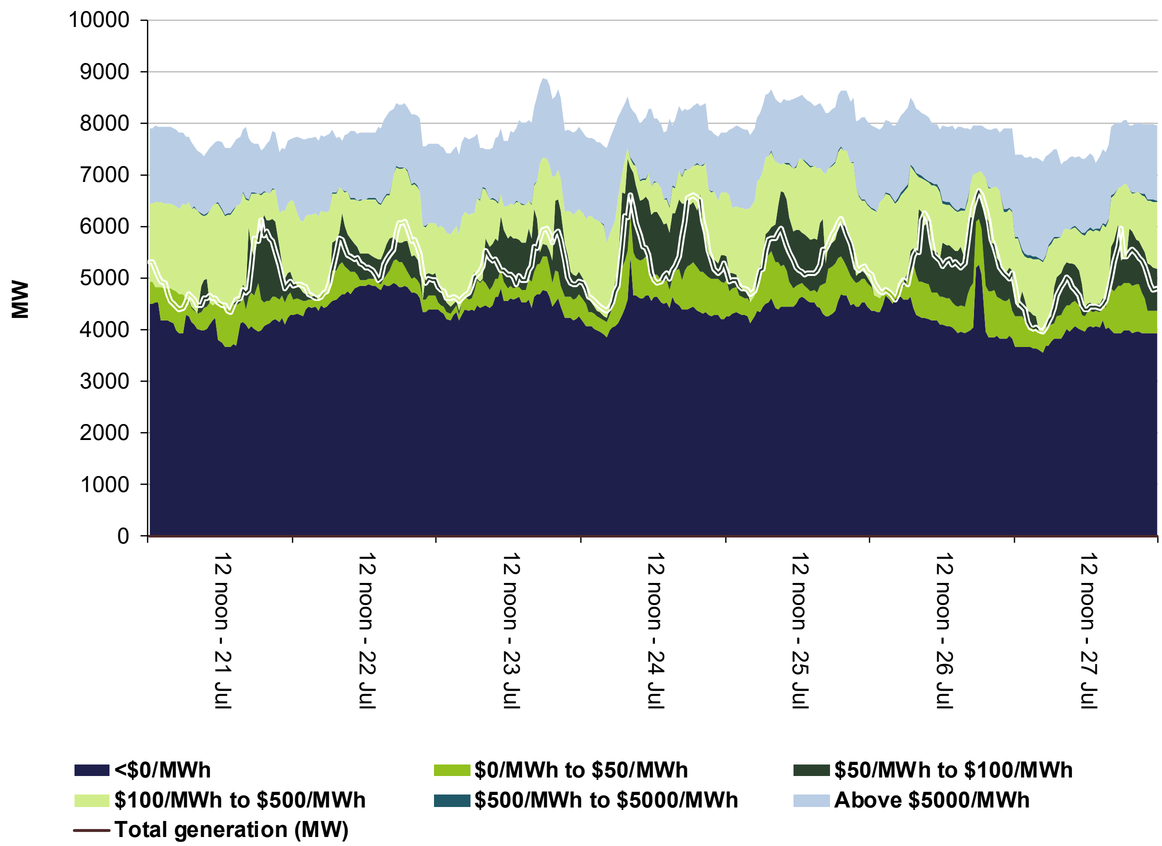


Figure 6: South Australia generation and bidding patterns

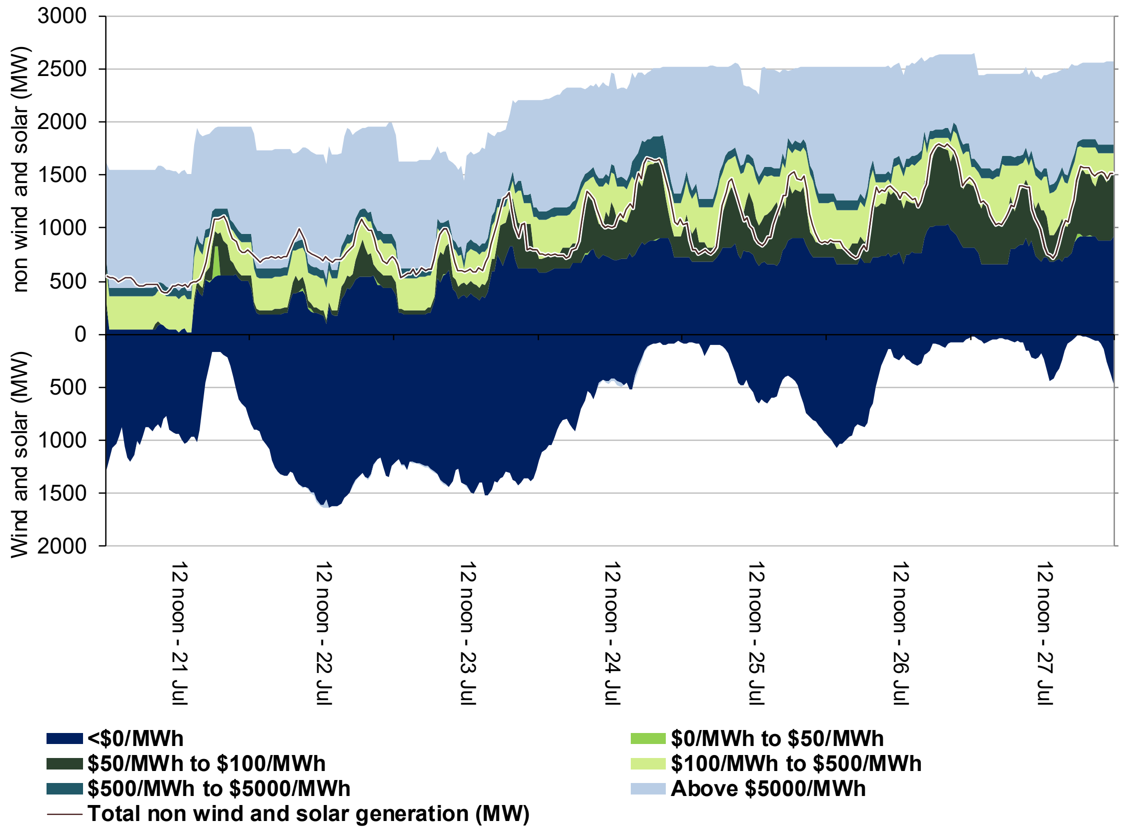
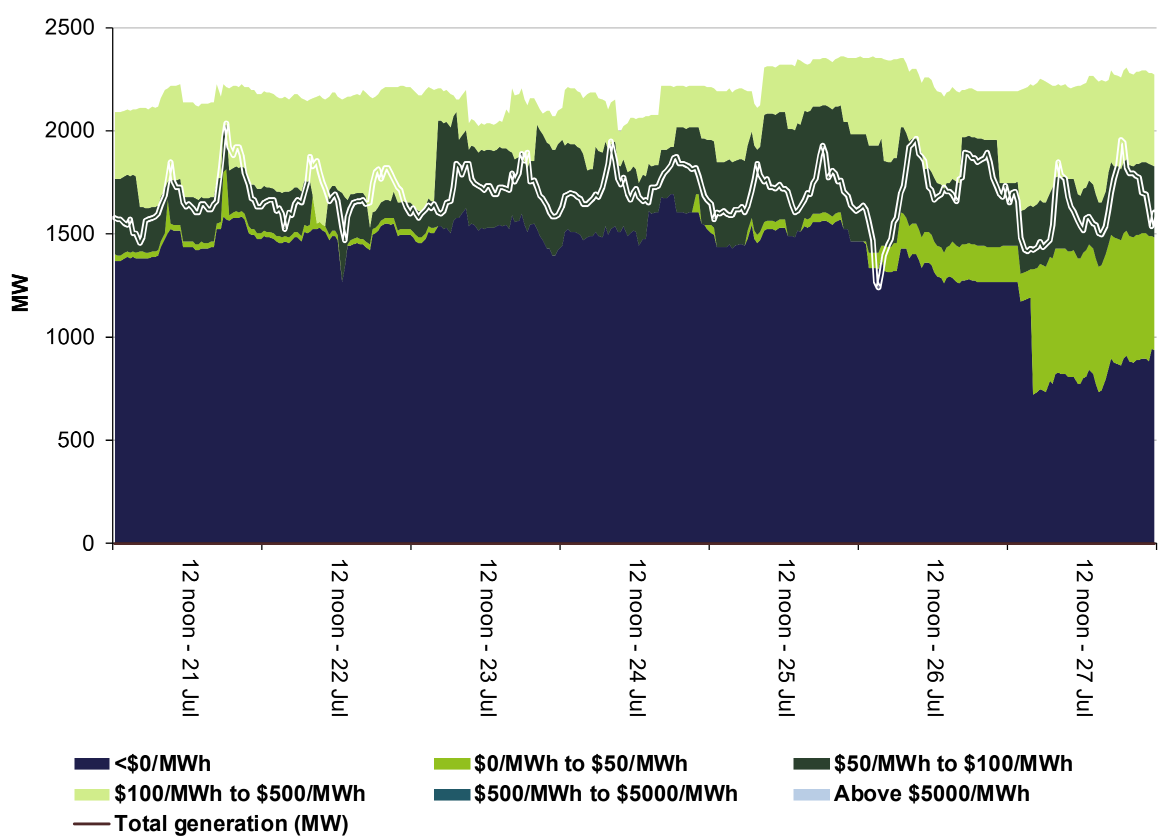


Figure 7: Tasmania generation and bidding patterns



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.

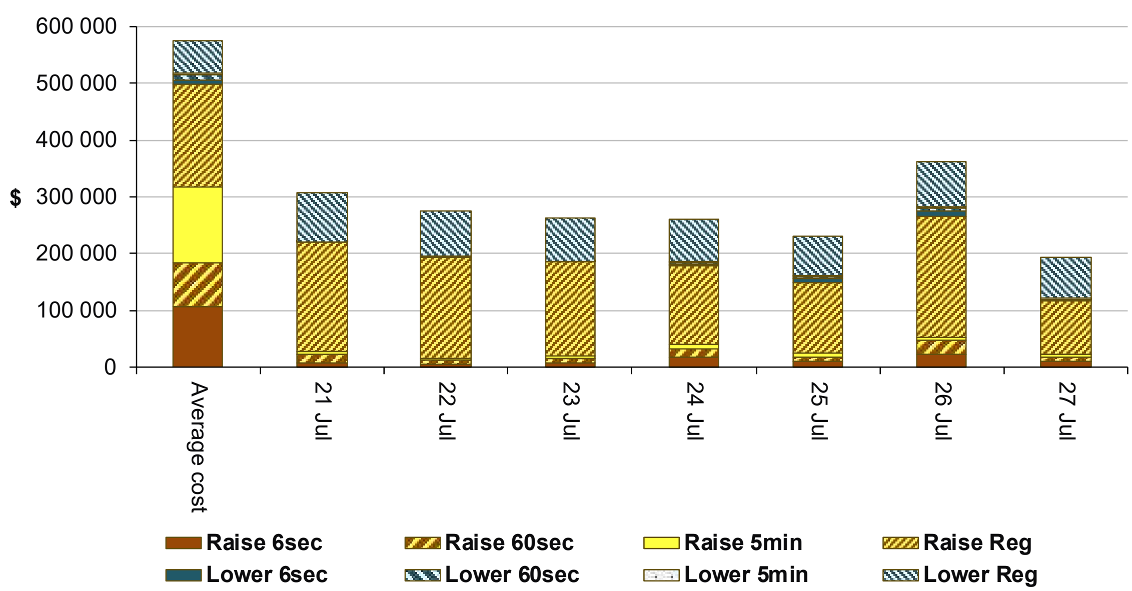
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $1 739 500 or less than 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $149 500 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



Detailed market analysis of significant price events

Queensland

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

Thursday, 25 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
11 am	-211.43	59.93	66.42	5390	5471	5450	10 322	10 359	10 364
Midday	-165.55	59.02	58.61	5298	5378	5374	10 358	10 346	10 345

For both the 11 am and midday trading intervals, demand and availability were close to forecast. Within four hours of the commencement of the 11 am trading interval, more than 1200 MW of capacity was rebid from above $0/MWh to the price floor. Similarly for the midday trading interval, more than 700 MW of capacity was rebid down to the price floor. See Table 4 for rebid details. As a result, the dispatch price dropped to the price floor at 10.35 am and stayed below $0/MWh for another three dispatch intervals during the 11 am trading interval. The dispatch price dropped to the price floor once during the midday trading interval at 11.40 am when demand in Queensland decreased by 76 MW.

Table 4: Significant rebids, 25 July

Submitted time	Effective trading interval	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
9.12 am	11 am, midday	CS Energy	Callide B	390	>0	-1000	0912A intra regional constraint
9.33 am	11 am	CS Energy	Gladstone	400	>54	-1000	0932A intra regional constraint
10.08 am	11 am	Alinta Energy	Braemar A	173	201	-1000	1005~A~change in price 5PD~
10.11 am	11 am, midday	Stanwell	Tarong	180	>68	-1000	1011A manage constraint Q>>CPPW_WOSP_WOGP_2
10.28 am	11 am, midday	Stanwell	Tarong North	70	>0	-1000	1027A manage unit loading variability on constraint Q>>CPPW_WOSP_WOGP_2
11.14 am	midday	Stanwell	Stanwell	90	49	-1000	1113A manage constraint Q>>CPPW_WOSP_WOGP_2

Friday, 26 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
11.30 am	-492.59	182.68	232.56	5612	5644	5677	9938	9635	9840
Midday	-311.97	169.96	227.00	5650	5580	5650	9945	9626	9822

For the 11.30 am trading interval, demand was close to forecast while availability was 303 MW more than forecast, both four hours prior. The increased availability was mostly due to Stanwell adding 130 MW of capacity at Tarong Power Station, priced at the floor. Within four hours of dispatch, more than 800 MW of capacity was rebid from above $0/MWh to the price floor. See Table 6 for rebid details. As a result, the dispatch price dropped close to or at the price floor for three dispatch intervals.

Table 6: Significant rebids, 26 July, 11.30 am

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
8.40 am		AGL Energy	Yabulu	160	-1000	2307	0830~A~050 chg in AEMO PD~54 PD price decrease QLD by avg $80/MWh in the 08:00 - 08:30 PDS for the PE 09:00 - 12:00
9.32 am		Stanwell Corporation	Stanwell	80	57	-1000	0930A manage constraint Q>>CPPW_WOSP_WOGP_2
9.32 am		Stanwell Corporation	Tarong	110	>56	-1000	0930A manage constraint Q>>CPPW_WOSP_WOGP_2
10.15 am		CS Energy	Callide B	320	>0	-1000	1015A intra regional constraint
10.23 am		Stanwell Corporation	Tarong	130	N/A	-1000	1022P plant HP bypass work complete
10.33 am		CS Energy	Gladstone	480	>54	-1000	1033A intra regional constraint Q>>CPPW_WOSP_WOGP_2

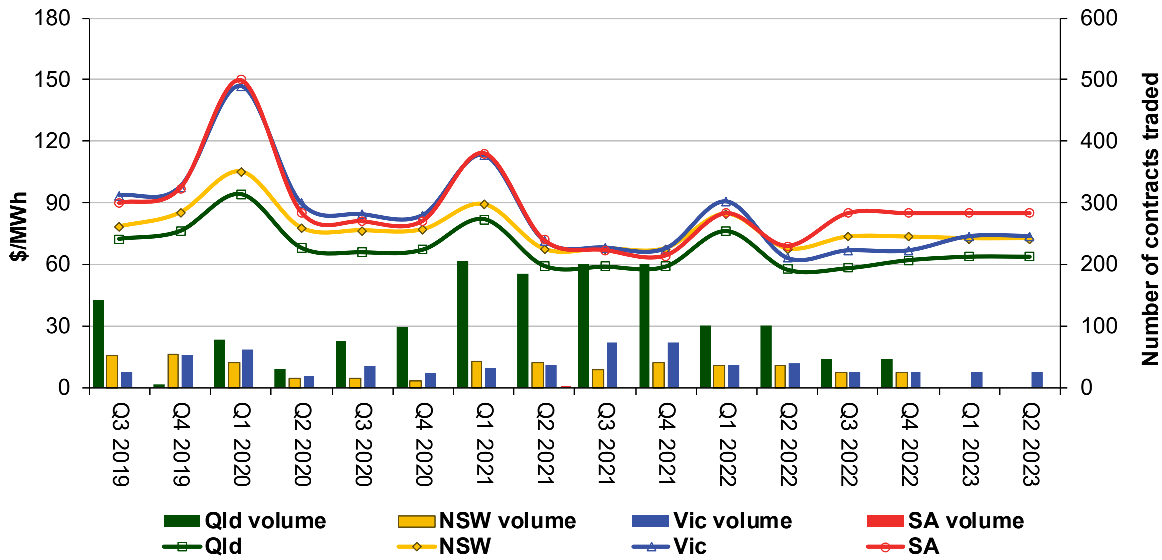
For the midday trading interval, demand was 70 MW more than forecast while availability was 319 MW more than forecast, both four hours prior. Increased availability was again due to additional capacity offered by Stanwell at Tarong Power Station.

Energy consumption by pump loads must be offset by an increase in generation. Starting at 11.25 am, CS Energy rebid 245 MW of load at Wivenhoe Pump 2 to start pumping, due to an intra-regional constraint. However CS Energy withdrew this load from the market, effective 11.55 am, due to technical issues. This meant Pump 2 went from pumping 245 MW at 11.50 am to 0 MW at 11.55 am and resulted in a decrease in Queensland generation. With more expensive generation ramp-down constrained and unable to set price at the time, the dispatch price dropped to the price floor at both the 11.55 am and 12.00 pm dispatch 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

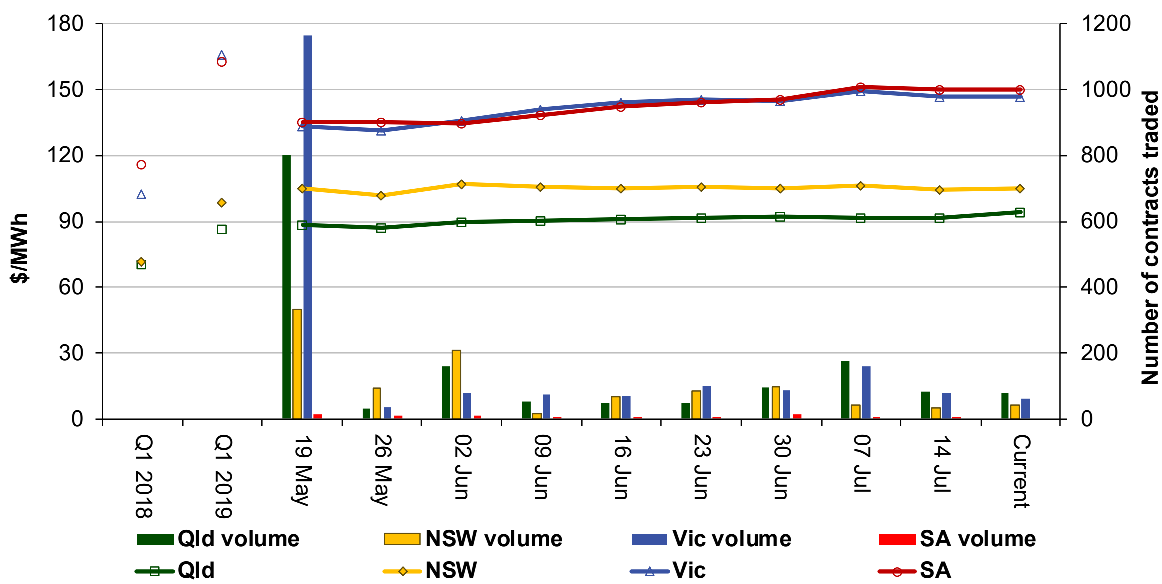


Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional quarter 1 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 for the week starting 19 May 2019 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)



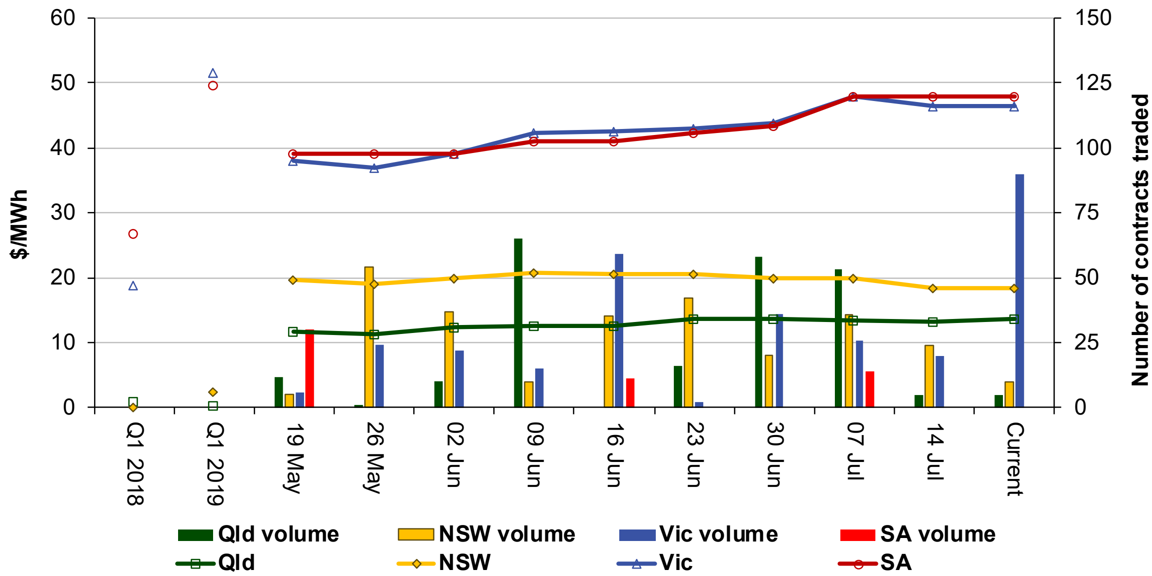
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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

Australian Energy Regulator
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