# Electricity Report

AUSTRALIAN ENERGY REGULATOR

# 2 – 8 June 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 2 to 8 June 2019.

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

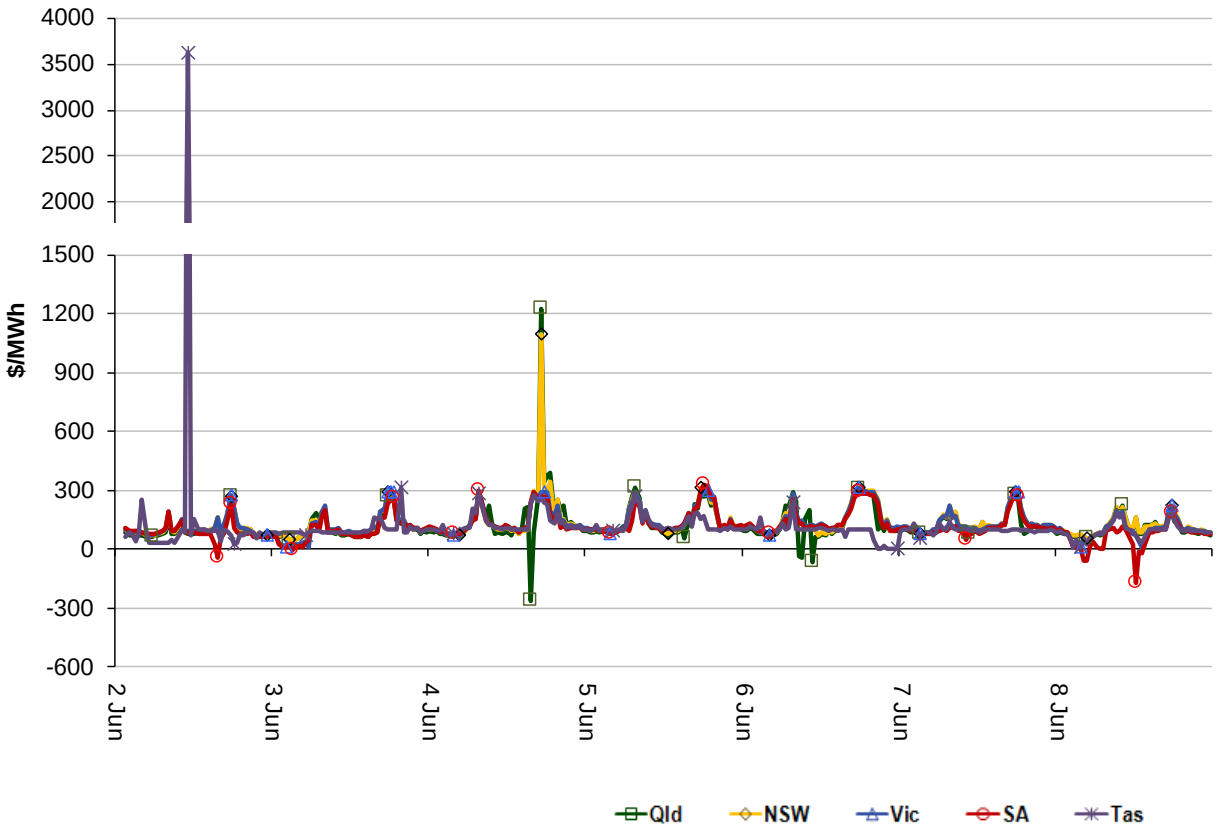
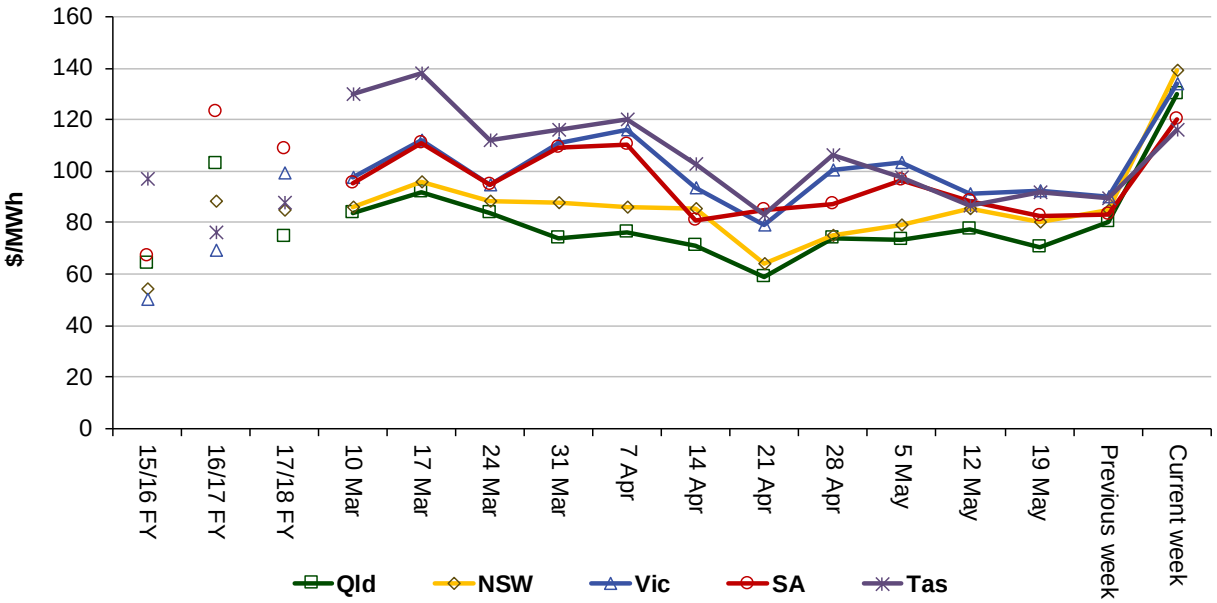



Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

### 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 | 130 | 139 | 134 | 120 | 116 |
| 17-18 financial YTD | 74 | 84 | 100 | 109 | 89 |
| 18-19 financial YTD | 84 | 93 | 126 | 131 | 88 |

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 216 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

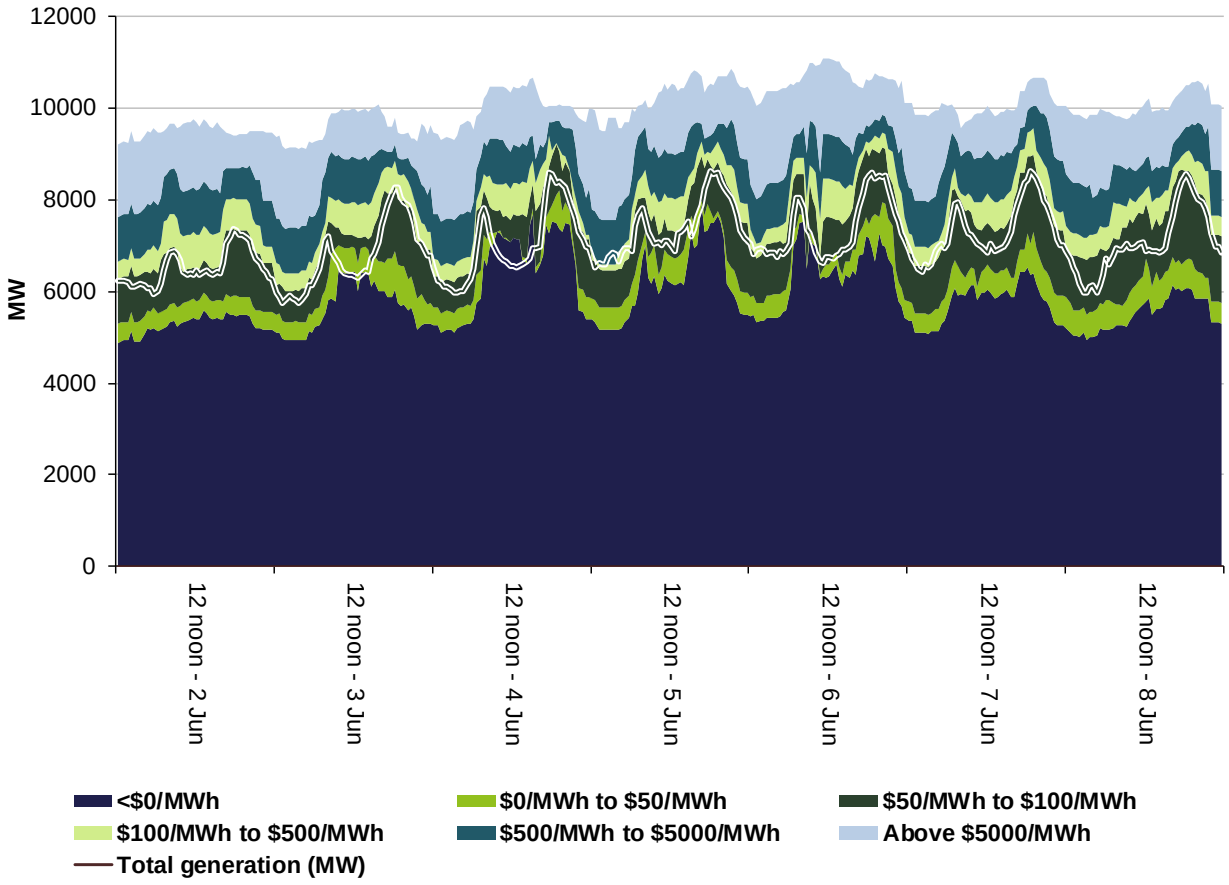
| | Availability | Demand | Network | Combination |
|---|---|---|---|---|
| % of total above forecast | 8 | 36 | 0 | 1 |
| % of total below forecast | 15 | 29 | 0 | 12 |

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

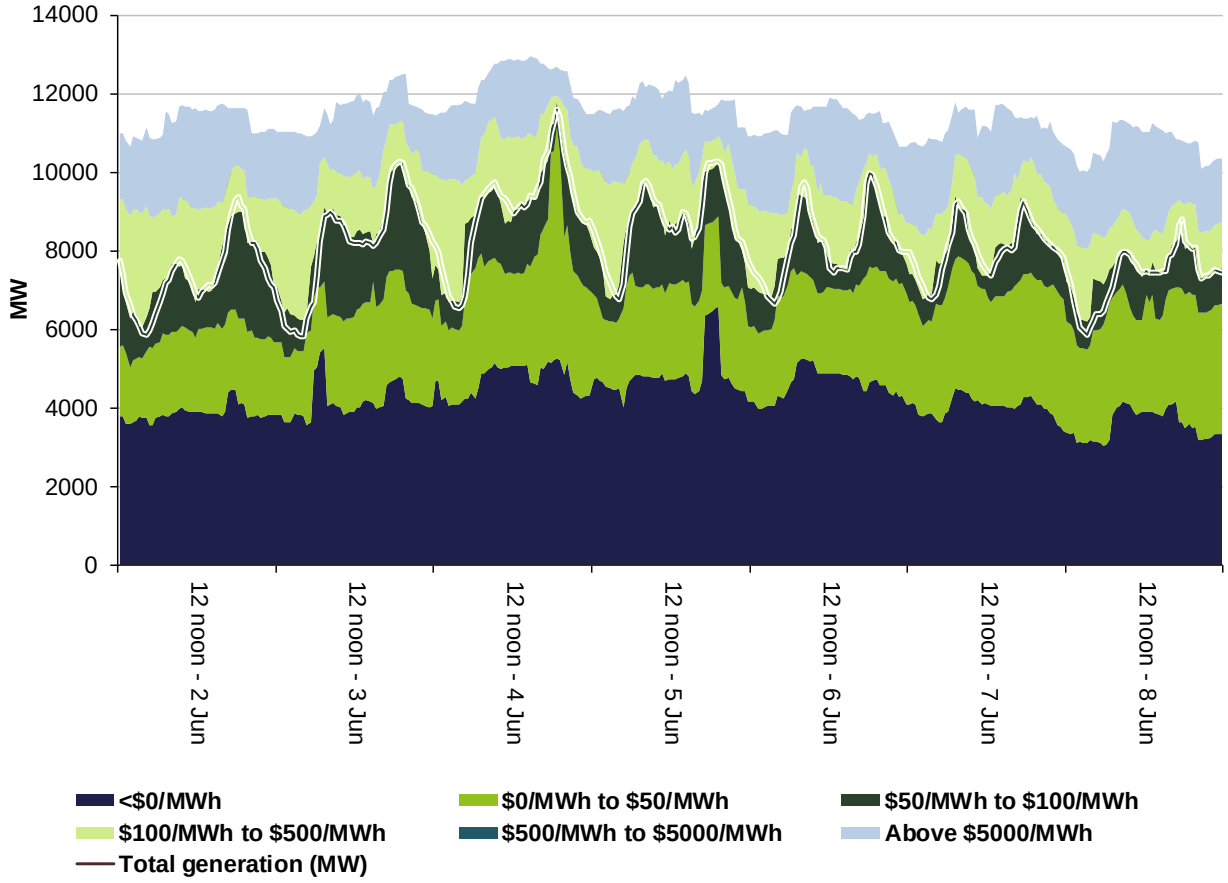
## Generation and bidding patterns

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.

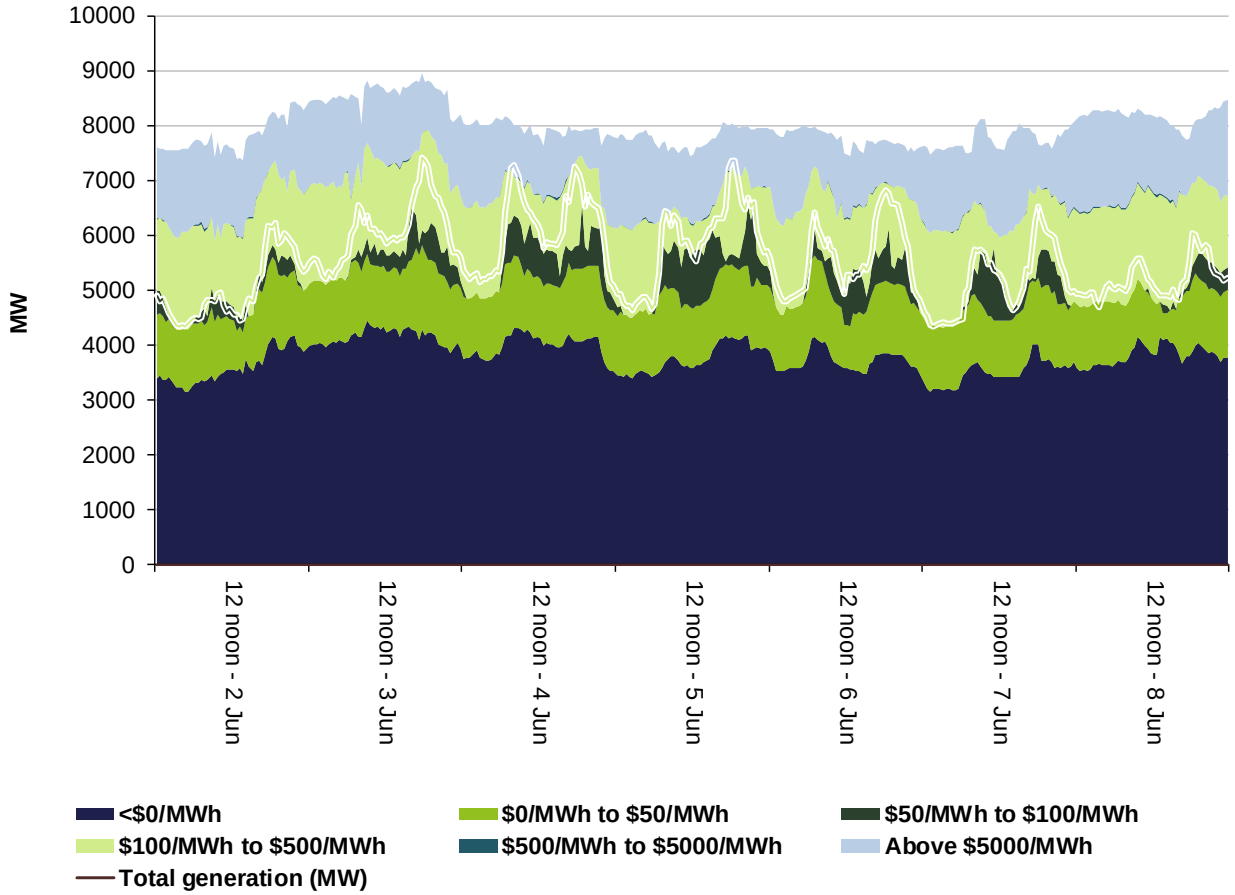
### Figure 3: Queensland generation and bidding patterns



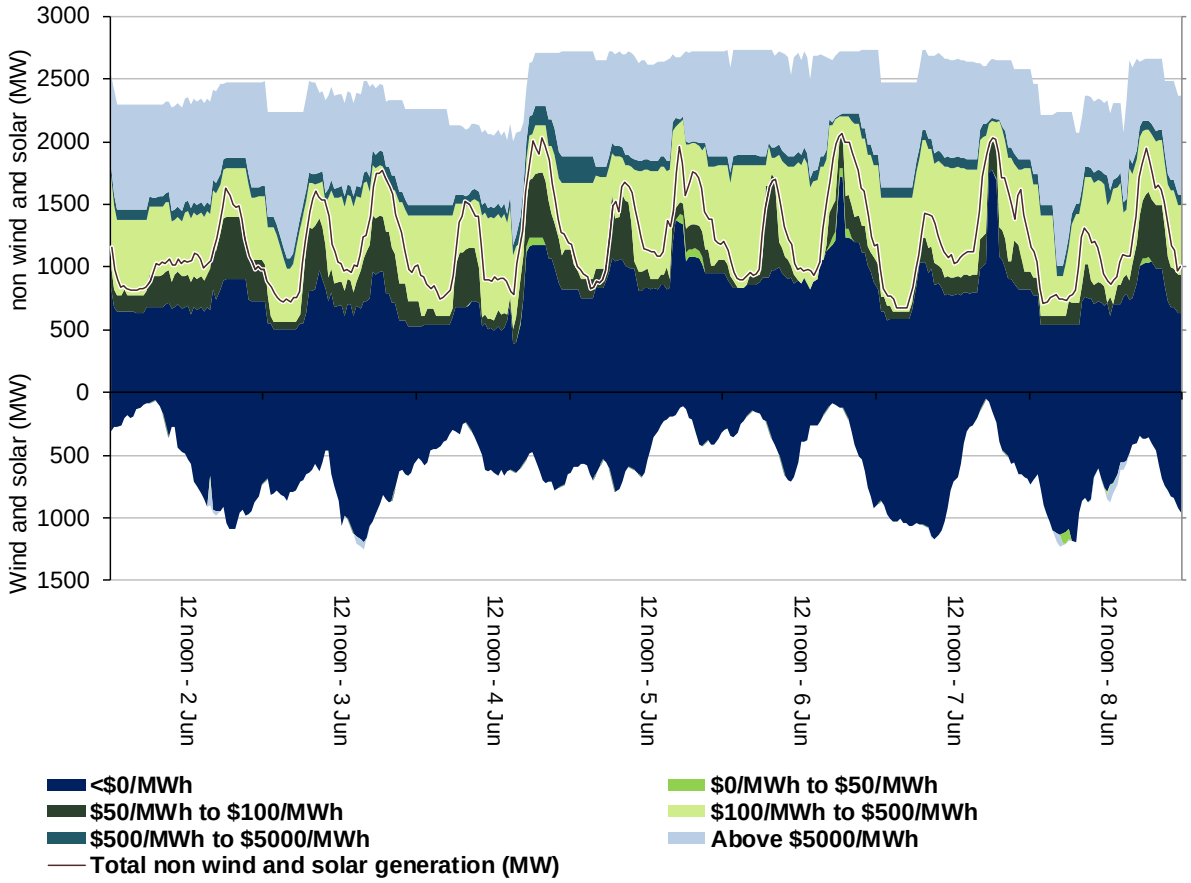
## Figure 4: New South Wales generation and bidding patterns



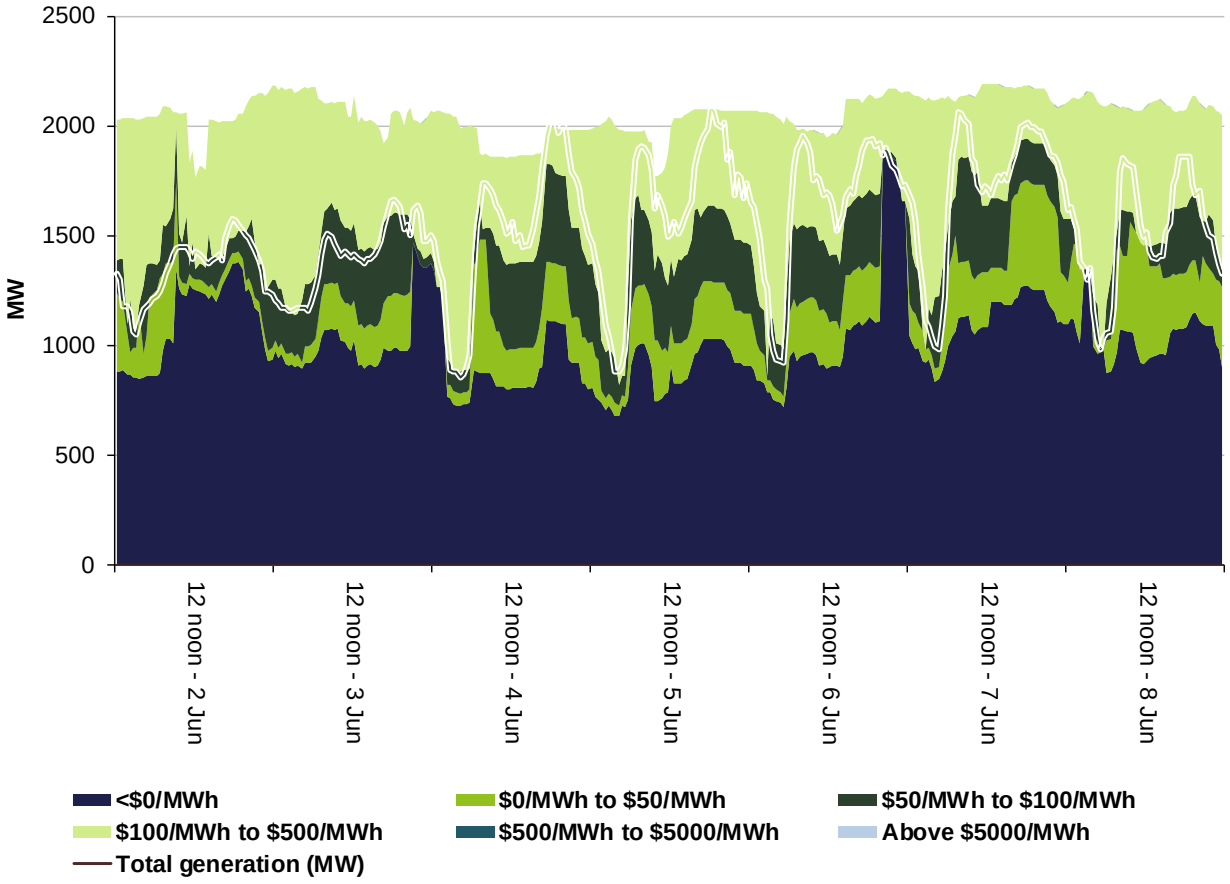

## Figure 5: Victoria generation and bidding patterns



## 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.

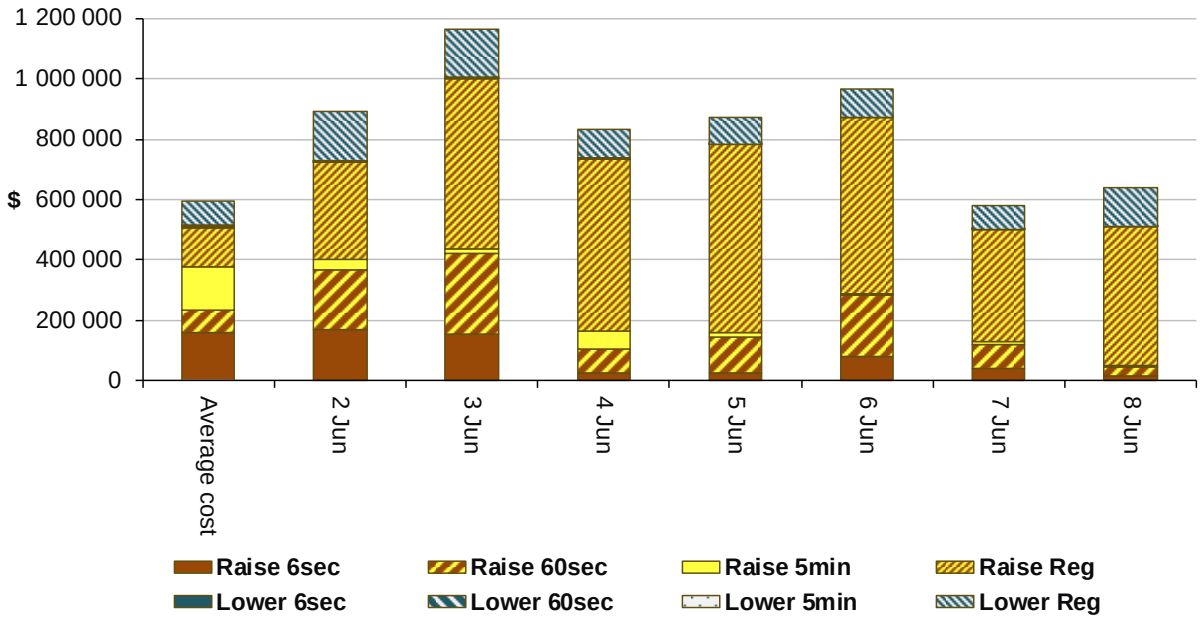
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $5 487 000 or around 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $455 000 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

## Queensland

There was one occasion where the spot price in Queensland was greater than three times the Queensland weekly average price of $130/MWh and above $250/MWh and there was one occasion where the spot price was below -$100/MWh.

**Tuesday, 4 June**

### 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 pm | -261.30 | 101.48 | 93.99 | 6520 | 6582 | 6617 | 10 325 | 10 269 | 10 242 |
| 5.30 pm | 1223.28 | 280.15 | 281.79 | 7763 | 7669 | 7667 | 9846 | 9903 | 9835 |

For the 4 pm trading interval, demand and availability were close to forecast. There was a planned outage of the Woolooga to Palmwoods line which was forcing flows from Queensland into New South Wales counter price. At 3.40 pm, AEMO invoked a constraint to manage the negative residues which reduced exports into New South Wales by 220 MW. This meant generation in Queensland was backed off and unable to set price, and the price went to the price floor for two dispatch intervals.

For 5.30 pm trading interval demand and availability were close to forecast and the outage was still in place. At 5.30 pm the energy and FCAS markets were co-optimised with negatively priced generation being backed off. As a result the dispatch price reached $5776/MWh for one dispatch interval.

## New South Wales

There was one occasion where the spot price in New South Wales was greater than three times the New South Wales weekly average price of $139/MWh and above $250/MWh.

**Tuesday, 4 June**

### 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 |
| 5.30 pm | 1095.59 | 299.60 | 299.60 | 11 573 | 11 134 | 10 896 | 12 658 | 12 629 | 12 769 |

Demand was around 440 MW higher than forecast and availability was 29 MW higher than forecast, four hours prior. The price was aligned with the Queensland price and is discussed in the Queensland section.

## South Australia

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

**Saturday, 8 June**

### 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 |
| 12.30 pm | -171.80 | 56.37 | 57.26 | 928 | 939 | 922 | 3170 | 3071 | 3053 |

Demand was close to forecast while availability was around 100 MW higher than forecast.

There was little capacity available in South Australia priced between $77/MWh and the price floor meaning small changes in demand, generation or interconnector flows could have a large effect on price.

At 12.10 pm there was a 31 MW decrease in demand and the price fell to the price floor. In response participants rebid capacity from the floor to above $0/MWh. This coupled with a 34 MW increase in demand saw the price increase to $101/MWh at 12.15 pm

## Tasmania

There was one occasion where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $116/MWh and above $250/MWh.

**Sunday, 2 June**

### Table 6: Price, Demand and Availability

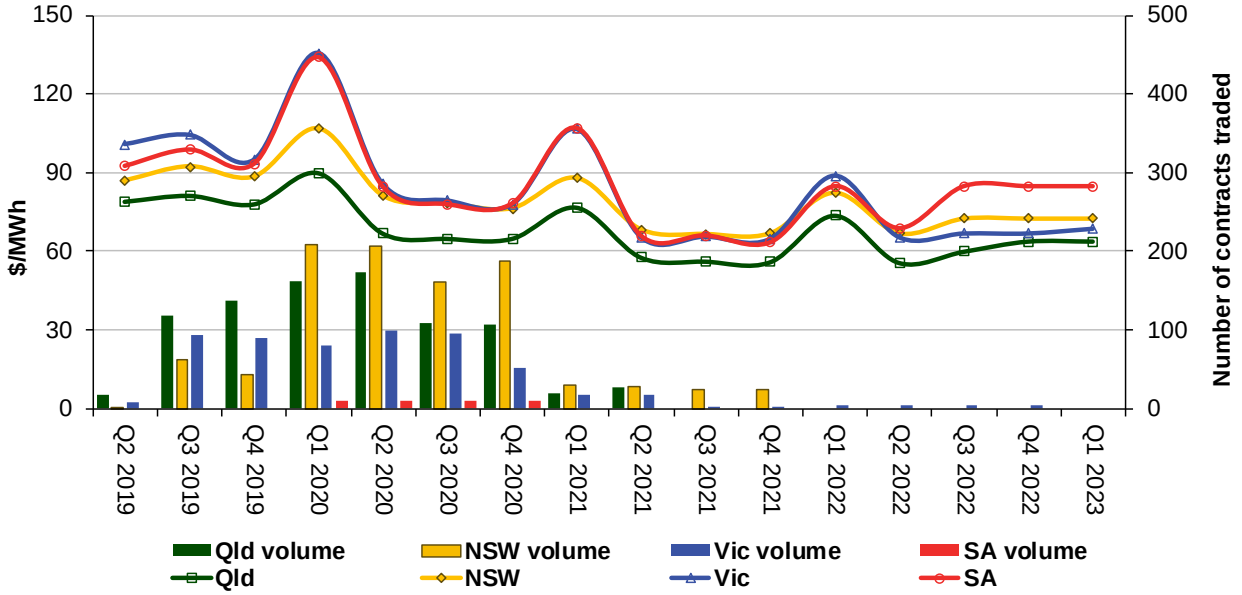
| Time | Price ($/MWh) | | | Demand (MW) | | | Availability (MW) | | |
|---|---|---|---|---|---|---|---|---|---|
| | Actual | 4 hr forecast | 12 hr forecast | Actual | 4 hr forecast | 12 hr forecast | Actual | 4 hr forecast | 12 hr forecast |
| 11.30 am | 3631.07 | 88.53 | 89.78 | 1365 | 1302 | 1290 | 1953 | 1821 | 1820 |

At around 4 am Basslink tripped and was out of service for the remainder of the day, leaving Tasmania to supply its own energy and FCAS. Effective from 11.25 am Hydro Tasmania rebid capacity at Gordon and Reece in energy and FCAS. This led to multiple violations of FCAS constraints and the price for energy went to the price cap at 11.25 am and to $6918/MWh at 11.30 am when the energy and FCAS markets were co-optimised.

## 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.

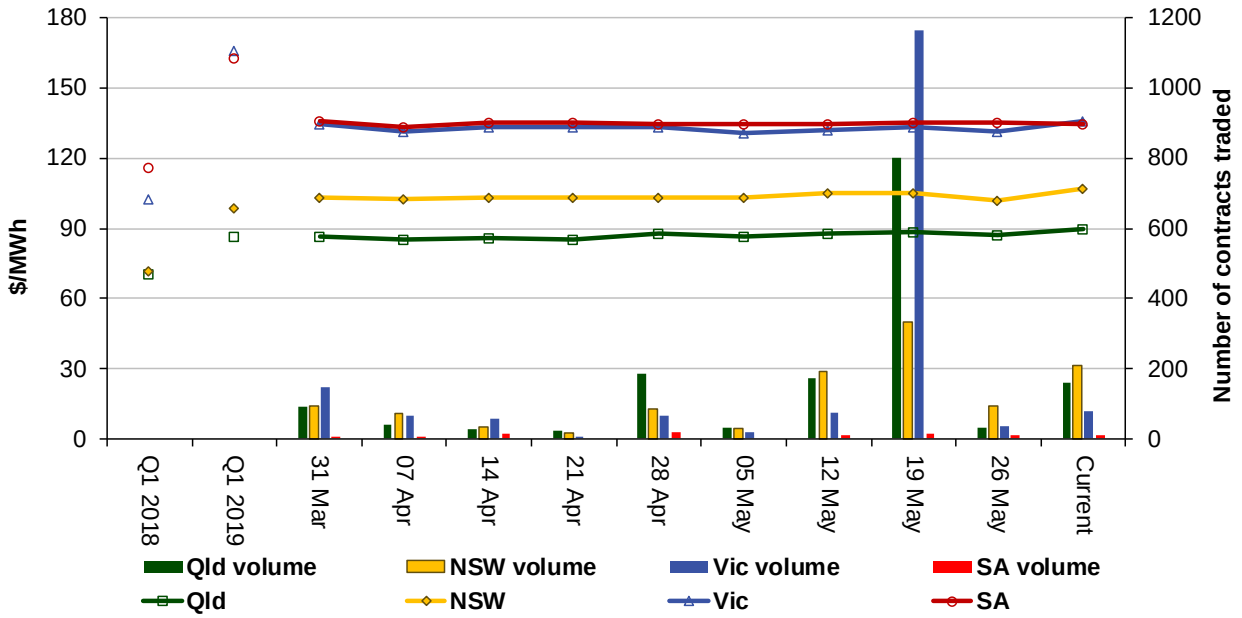
### Figure 9: Quarterly base future prices Q2 2019 – Q1 2023




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.

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



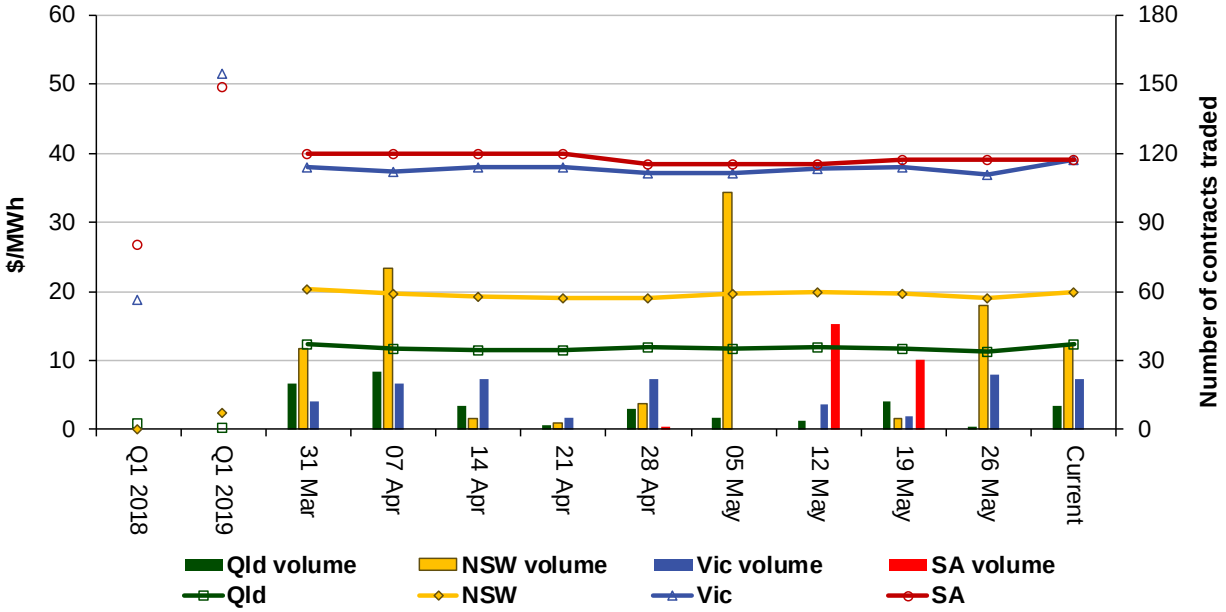

Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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