Electricity Report

AUSTRALIAN ENERGY REGULATOR

# 4 – 10 September 2016

## 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 4 to 10 September 2016.

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

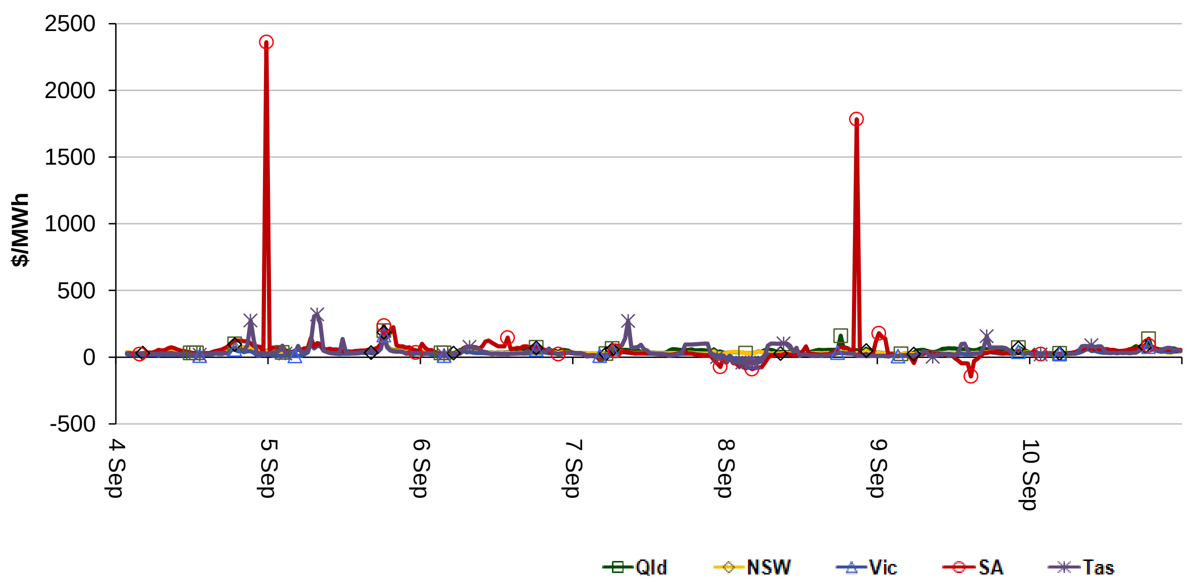
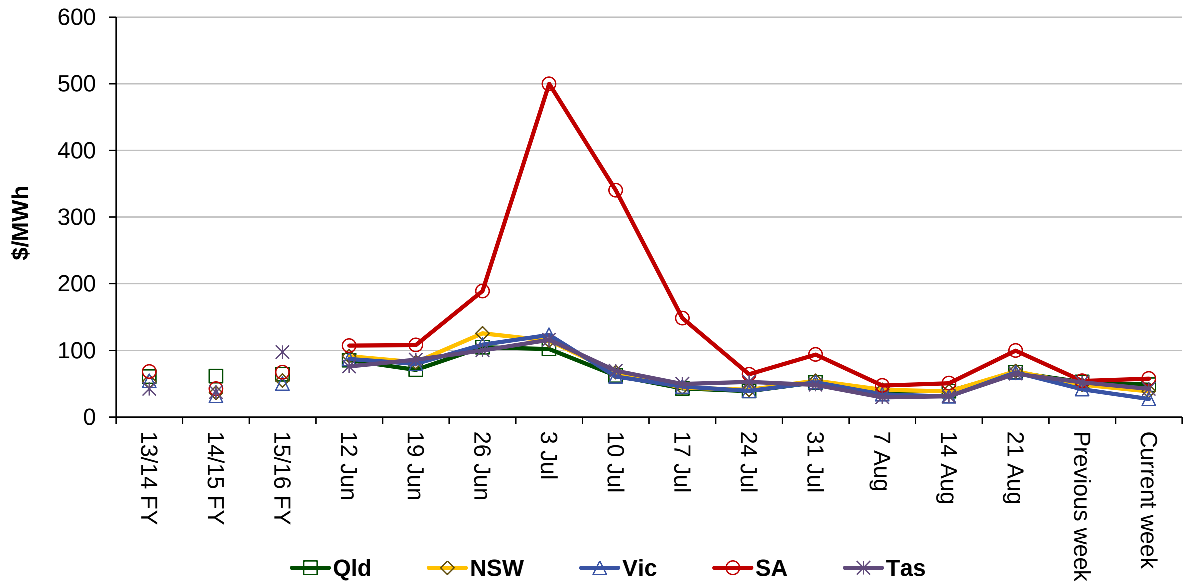



Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

### 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 | 48 | 39 | 27 | 58 | 42 |
| 15-16 financial YTD | 45 | 40 | 38 | 72 | 35 |
| 16-17 financial YTD | 56 | 58 | 54 | 151 | 57 |

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 264 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2015 of 133 counts and the average in 2014 of 71. 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

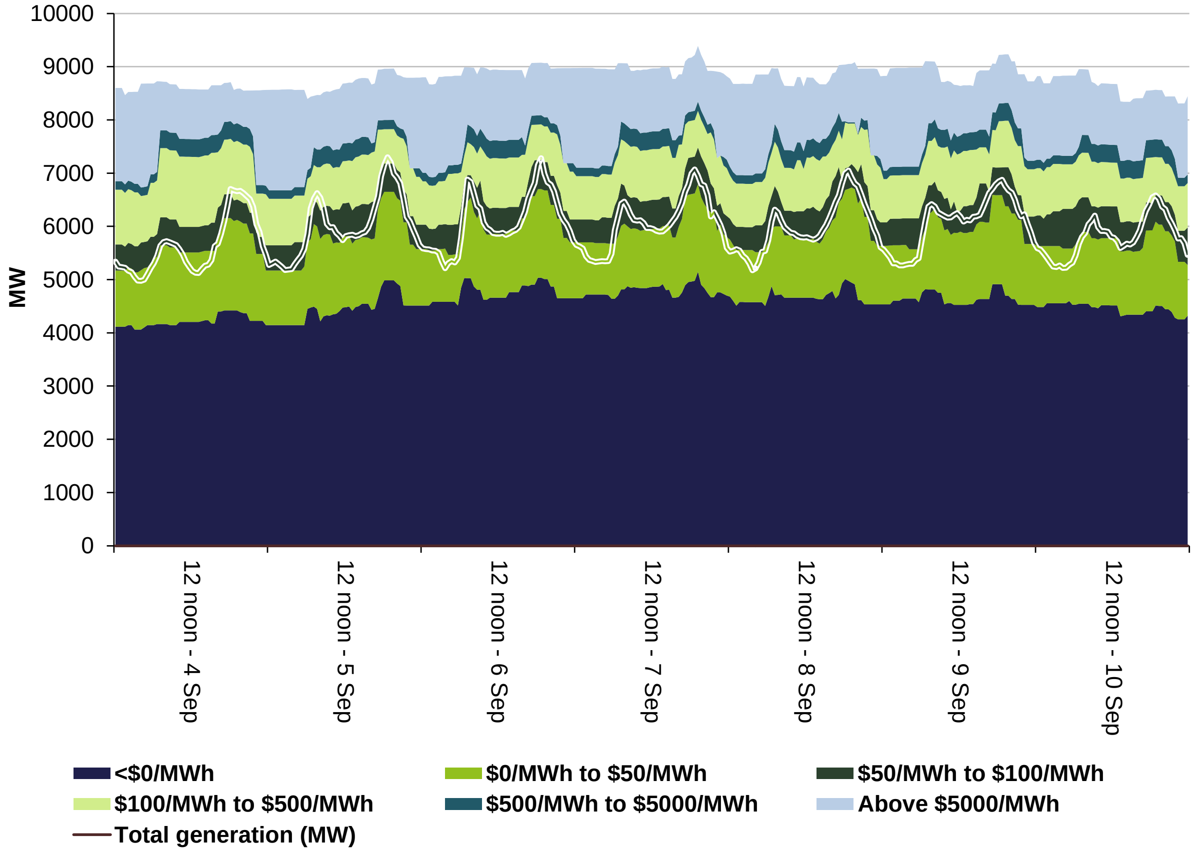
| | Availability | Demand | Network | Combination |
|---|---|---|---|---|
| % of total above forecast | 6 | 43 | 0 | 2 |
| % of total below forecast | 35 | 12 | 0 | 3 |

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

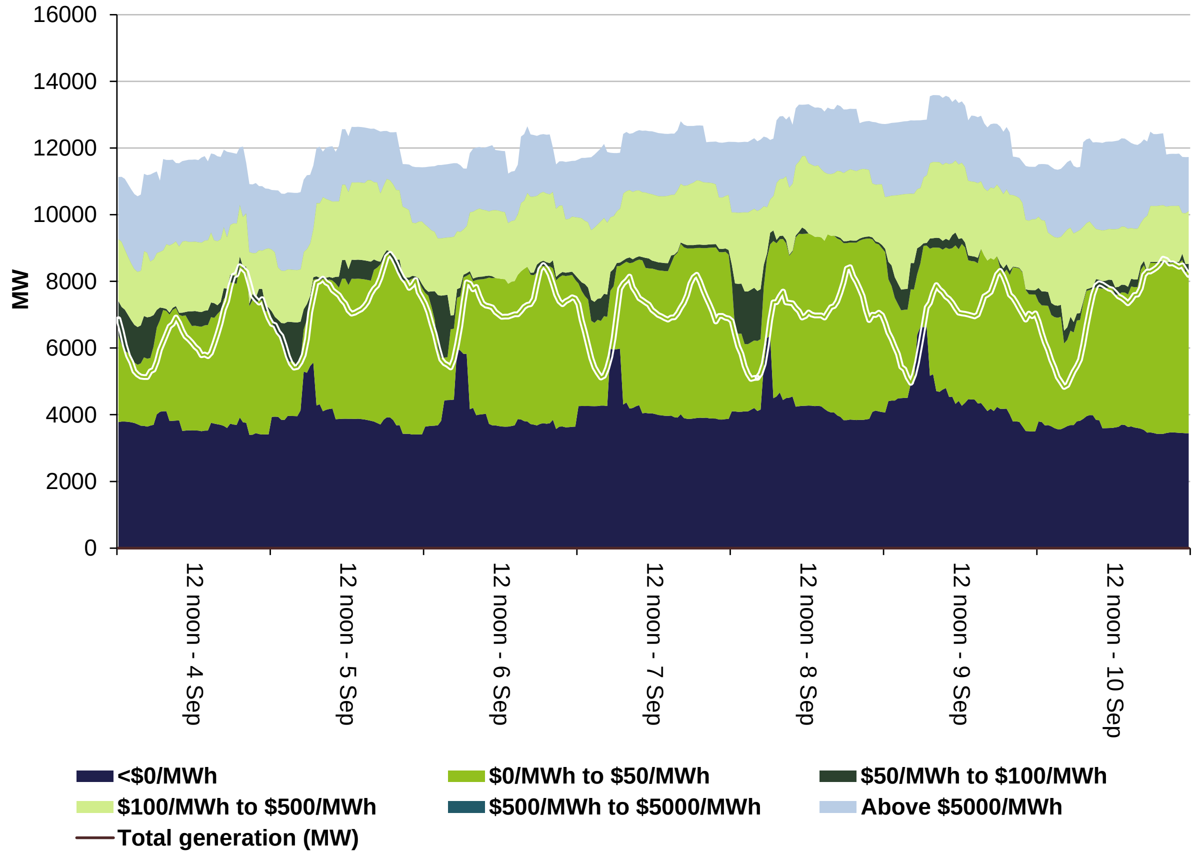
## Generation and bidding patterns

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.

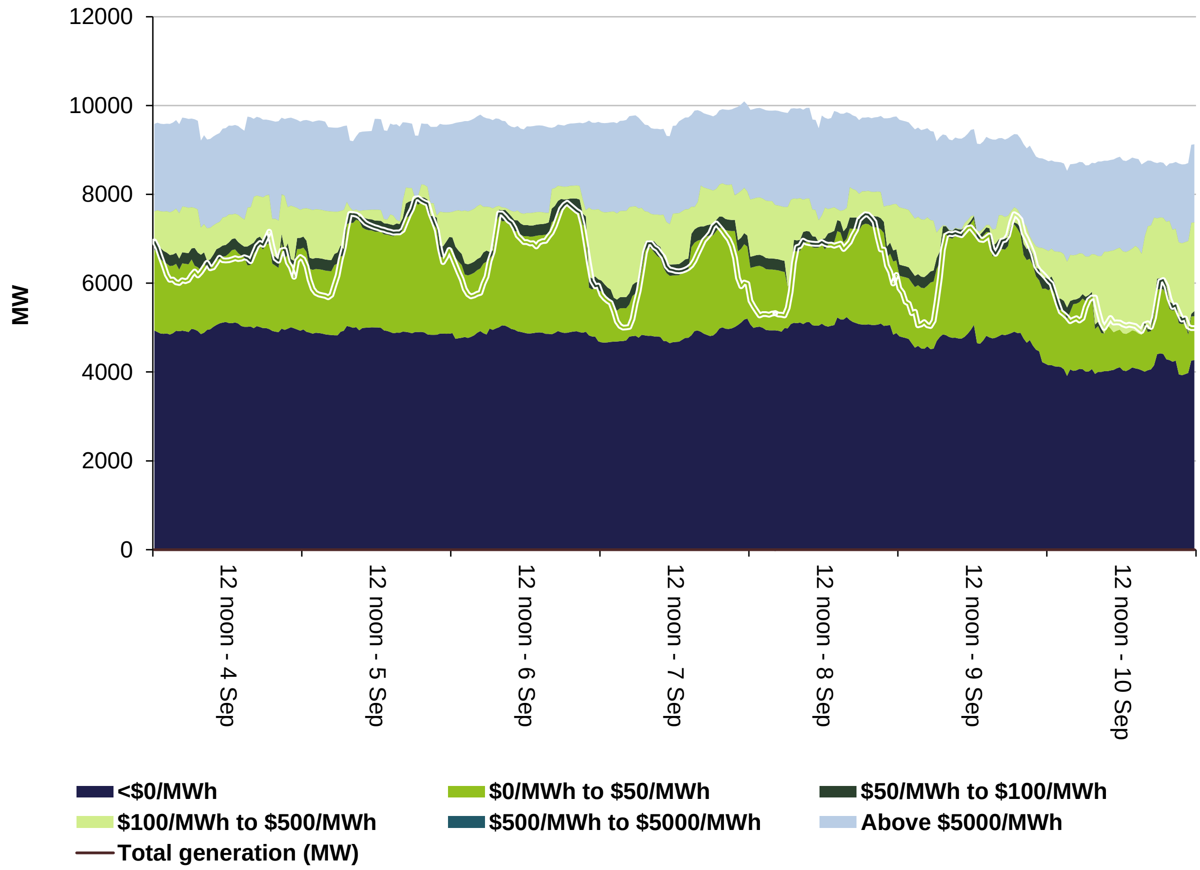
### Figure 3: Queensland generation and bidding patterns



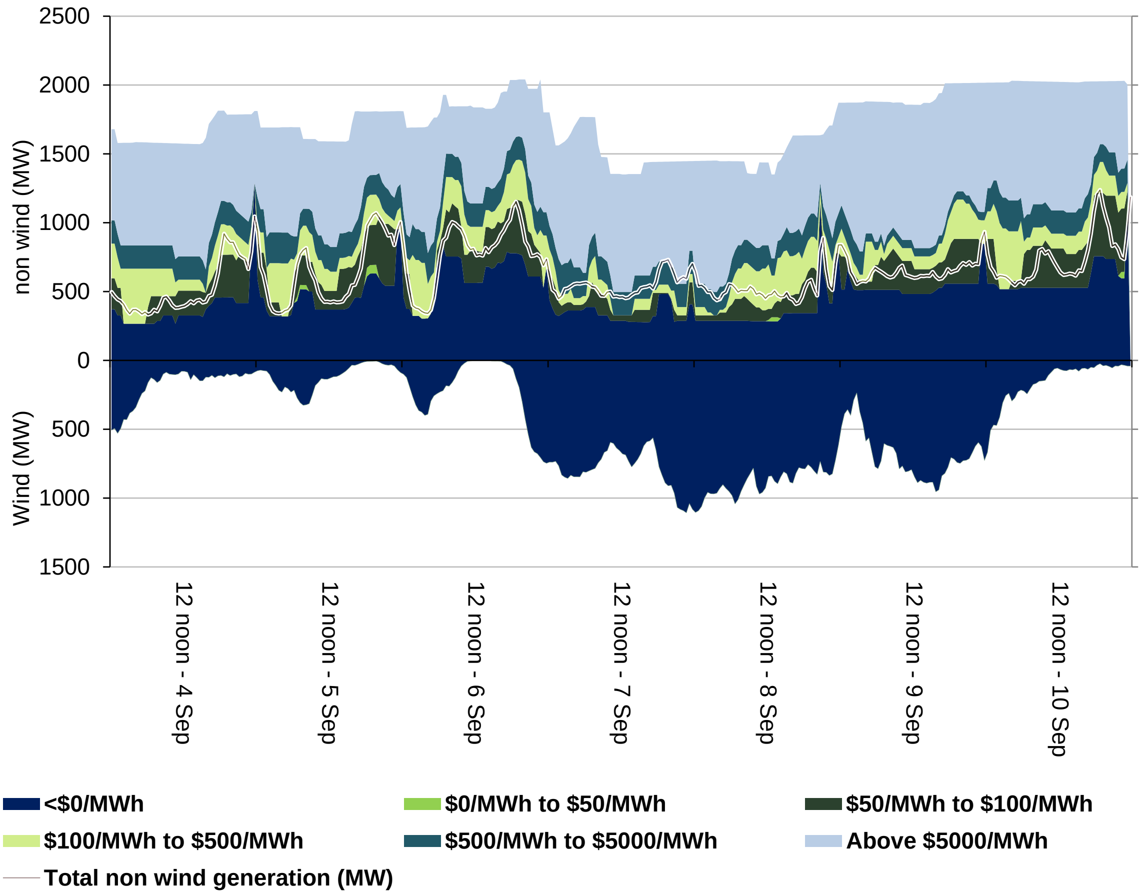
## Figure 4: New South Wales generation and bidding patterns



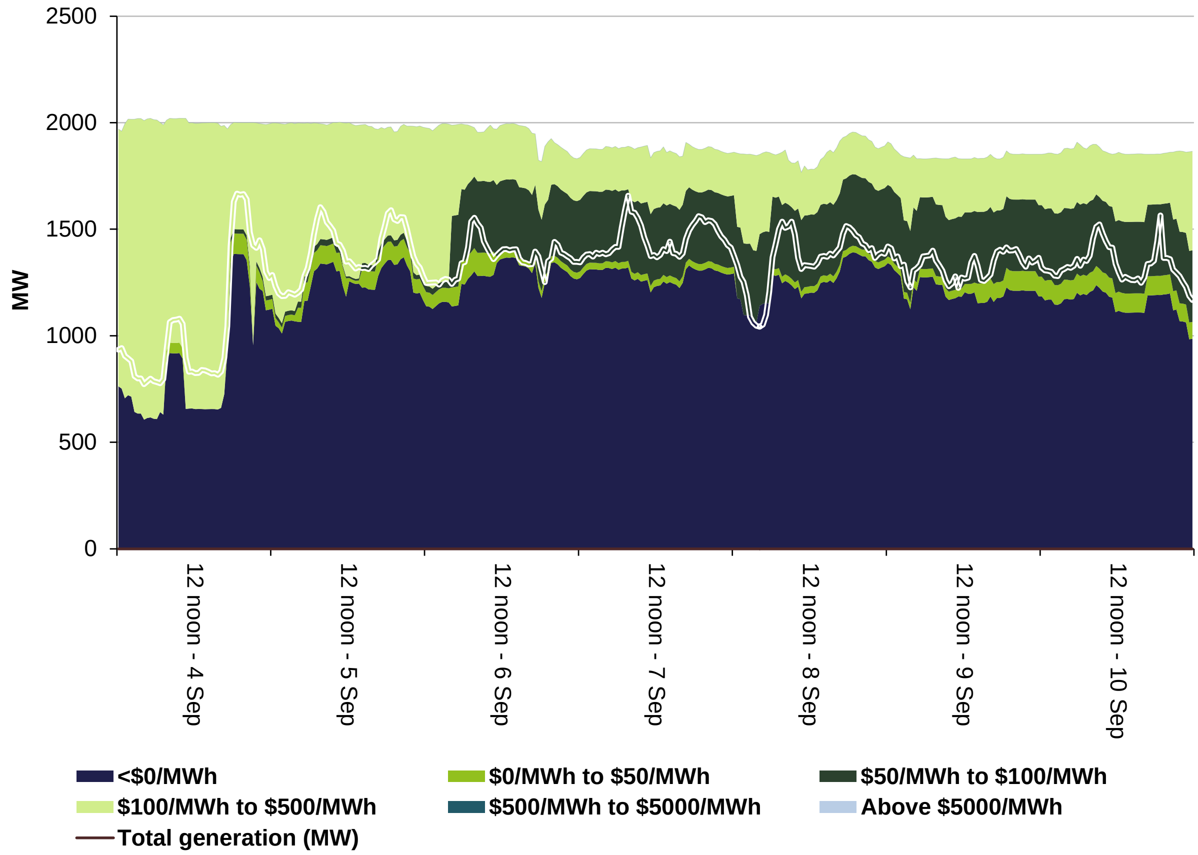

## Figure 5: Victoria generation and bidding patterns



## 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.

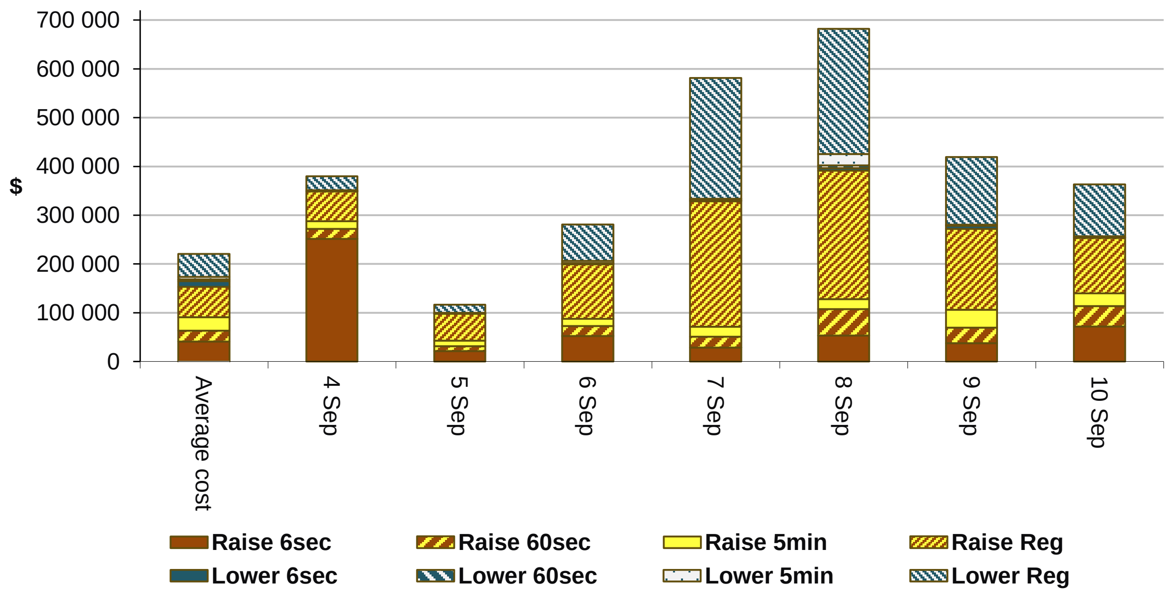
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $2 420 000 or around 2 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $402 000 or around 5 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 4 September, in Tasmania, the Raise 6 second service price was above $7800/MW for two dispatch intervals. This was a result of the co-optimisation of the energy and FCAS markets.

On 6 September, in Tasmania, the price of both Raise and Lower Regulation services exceeded $2500/MW and the Raise 6 Second service exceeded $4500/MW for the 5.50 pm dispatch interval. At this time Basslink was in the "no-go" zone and FCAS had to be sourced locally. The high prices were a result of the co-optimisation of the energy and FCAS markets.

A planned outage at Heywood in Victoria, which ran from 6 to 10 September, created a single contingency which could, if it occurred, separate South Australia from the rest of the NEM. AEMO invoked constraints that required 35 MW of regulation services from within South Australia. These imposition of these constraints cost around $1.5m.

# Detailed market analysis of significant price events

## 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 $58/MWh and above $250/MWh and there was one occasion where the spot price was below -$100/MWh.

**Monday, 5 September**

### 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 |
| Midnight | 2361.27 | 50.96 | 43.80 | 1656 | 1609 | 1562 | 1875 | 1863 | 1880 |

Conditions at the time saw demand and availability close to forecast four hours ahead.

At 11:35 pm demand increased by 212 MW due to hot water load, and wind generation decreased by 38 MW. With lower priced generation being either fully dispatched or stranded, the dispatch price increased from $33/MWh at 11.30 pm to $14 000/MWh at 11.35 pm. In response to the high price, participants rebid capacity from high to low prices. The price fell to $48/MWh at 11.40 pm and stayed low for the remainder of the trading interval.

**Thursday, 8 September**

### 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 |
| 9 pm | 1783.47 | 49.99 | 59.99 | 1578 | 1524 | 1449 | 2369 | 2522 | 2492 |

Conditions at the time saw demand 54 MW higher than forecast four hours ahead. Availability was 153 MW lower than forecast four hours ahead as a result of lower than forecast wind generation. Planned outages affecting the Heywood interconnector which had been in place since September 4, meant that South Australian regulation FCAS constraints were invoked.

With low-priced generation un-accessible because of FCAS co-optimisation, the dispatch price increased from $60/MWh at 8.30 pm to $14 000/MWh at 8.35 pm.

In response to the high prices participants rebid capacity to the price floor and the dispatch price fell to negative prices from 8.45 pm for the remainder of the trading interval.

**Thursday, 9 September**

### 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 |
| 3 pm | -144.15 | 5.56 | -45.00 | 1111 | 1148 | 1129 | 2755 | 2759 | 2759 |

Conditions at the time saw demand and availability close to forecast four hours ahead.

The spot price in South Australia was negative from 12.30 pm until 4.00 pm. During this time wind generation in South Australia was around 850 MW to 900 MW with approximately 220 MW being exported into Victoria each half hour. While the majority of negative prices were not forecast, low prices were expected for the majority of the day.

## Tasmania

There were four occasions where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $42/MWh and above $250/MWh.

**Sunday, 4 September**

### 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 |
| 9.30 pm | 274.35 | 38.01 | 36.08 | 1156 | 1098 | 1092 | 2000 | 2002 | 2025 |

Conditions at the time saw demand around 60 MW higher than forecast while availability was close to forecast.

At 8.48 pm, effective from 9.05 pm, Hydrotas rebid 154 MW of capacity from less than $50/MWh to $274/MWh. The reason given was “2046A FCAS REQUIREMENT > FORECAST: TAS R6”. With no capacity priced between $29/MWh and $274/MWh and low-priced generation either trapped or stranded in FCAS or fully dispatched the price increased from $51/MWh at 9 pm to $274/MWh at 9.05 pm and stayed at that price for the rest of the trading interval.

**Monday, 5 September**

### 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 |
| 7.30 am | 307.15 | 386.41 | 31.85 | 1342 | 1257 | 1257 | 1998 | 2000 | 1993 |
| 8 am | 319.29 | 51.65 | 37.84 | 1369 | 1291 | 1288 | 1995 | 2000 | 1991 |

The price at 7.30 am was close to that forecast four hours ahead.

At 8 am demand was around 80 MW higher than forecast and availability was close to forecast four hours ahead.

With no capacity priced between $55/MWh and $274/MWh, the higher than forecast demand led to the higher than forecast spot price at 8 am, with dispatch prices ranging from $274/MWh to $365/MWh.

### Wednesday, 7 September

### Table 8: Price, Demand and Availability

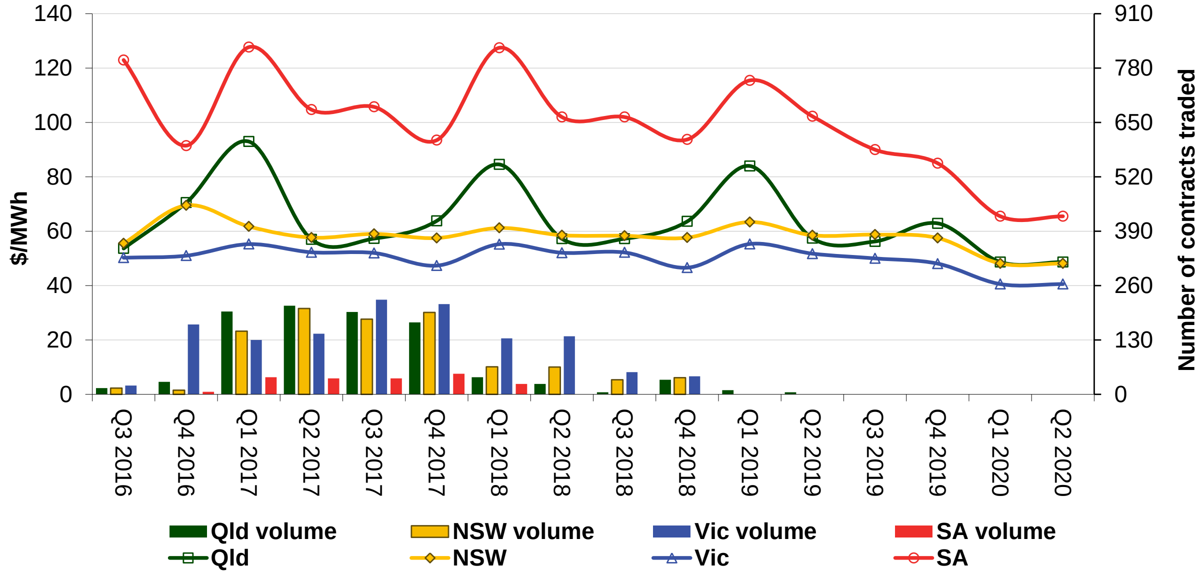
| Time | Price ($/MWh) | | | Demand (MW) | | | Availability (MW) | | |
|---|---|---|---|---|---|---|---|---|---|
| | Actual | 4 hr forecast | 12 hr forecast | Actual | 4 hr forecast | 12 hr forecast | Actual | 4 hr forecast | 12 hr forecast |
| 9:00 AM | 271.60 | 271.82 | 271.82 | 1376 | 1342 | 1319 | 1876 | 1880 | 1889 |

The price was close to that forecast four 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.

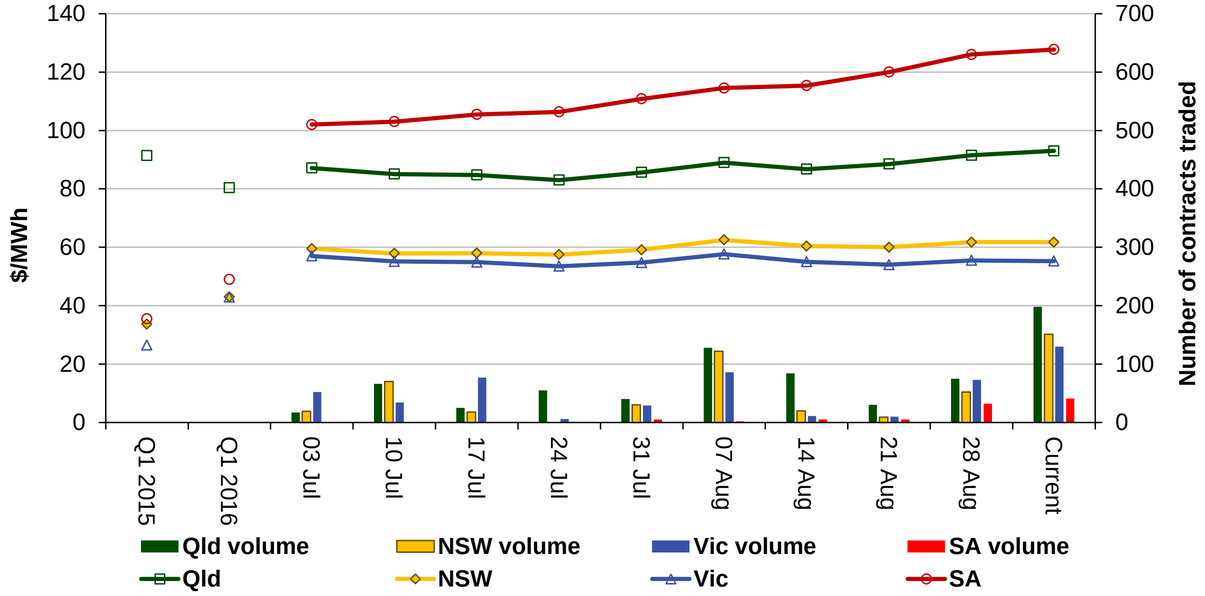
### Figure 9: Quarterly base future prices Q3 2016 – Q2 2020




Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional quarter 1 2017 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2015 and quarter 1 2016 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 2017 base contracts over the past 10 weeks (and the past 2 years)



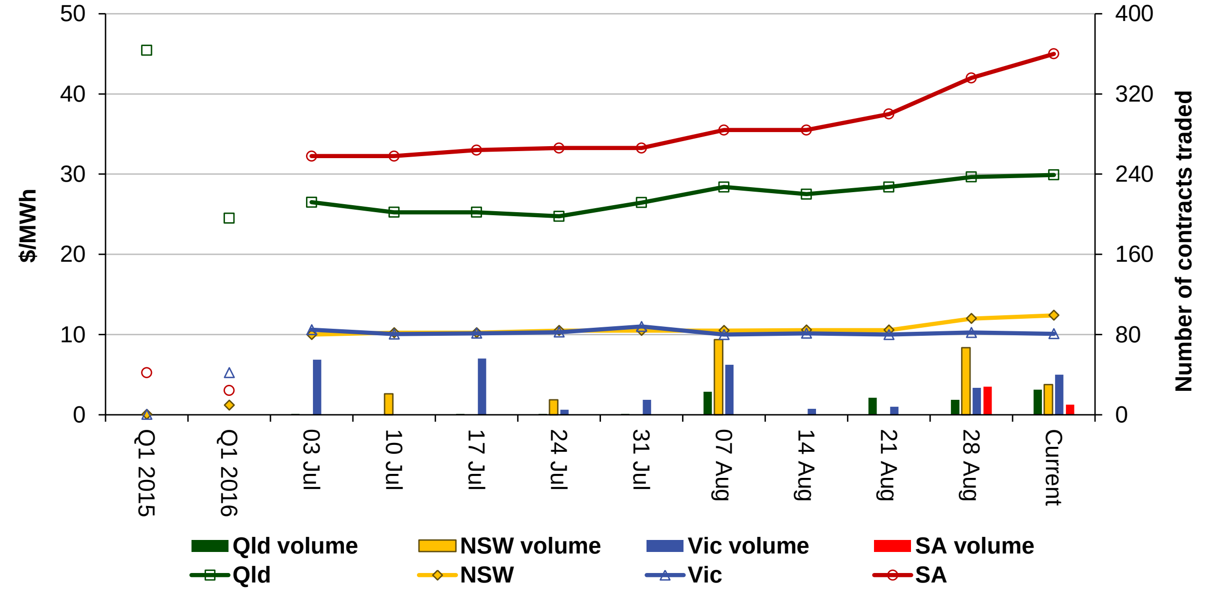

Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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 2017 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2015 and quarter 1 2016 prices are also shown.

## Figure 11: Price of Q1 2017 cap contracts over the past 10 weeks (and the past 2 years)




Source. ASXEnergy.com.au

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