# Electricity Report

AUSTRALIAN ENERGY REGULATOR

# 26 November - 2 December 2017

## 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 26 November - 2 December 2017.

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

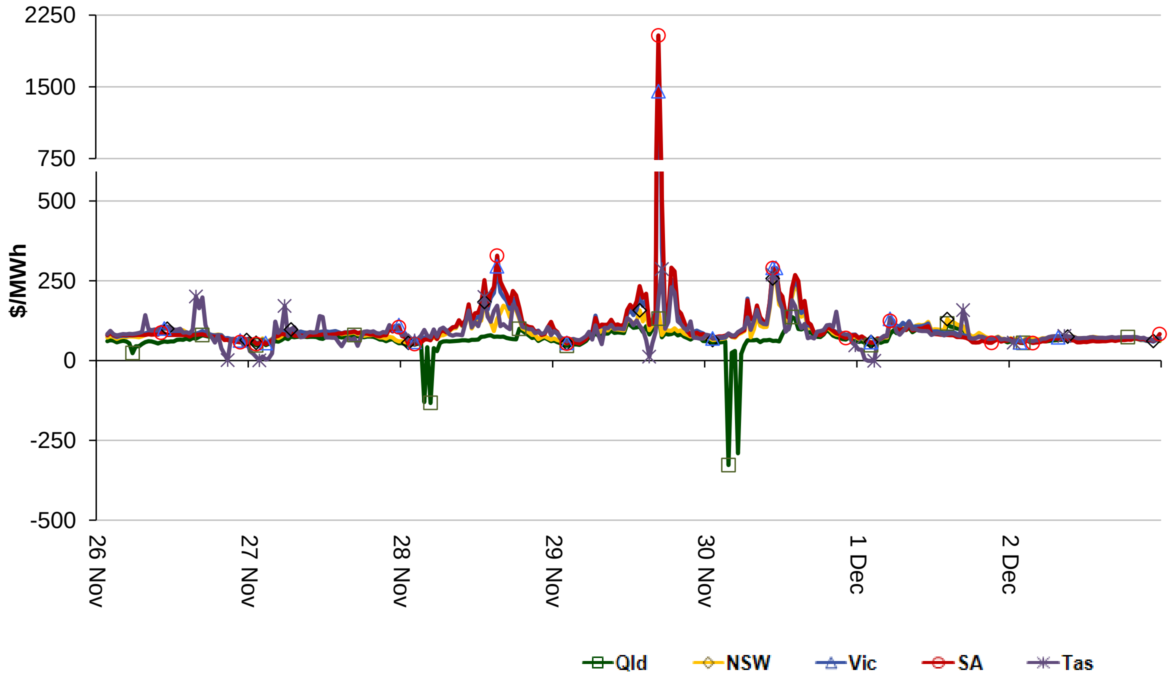
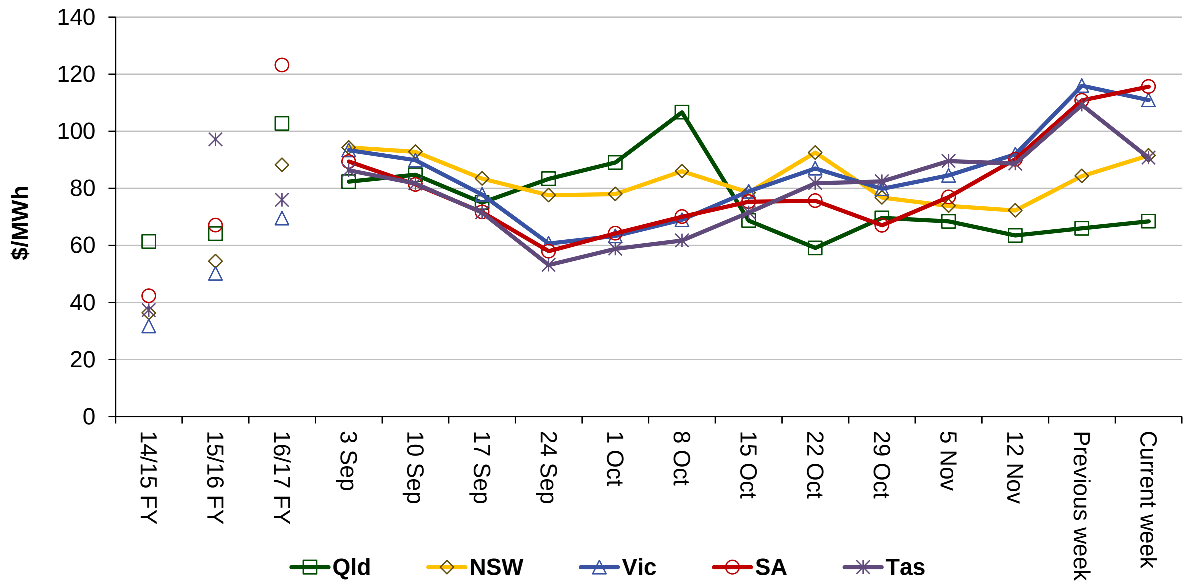



Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

### 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 | 68 | 92 | 111 | 116 | 91 |
| 16-17 financial YTD | 58 | 63 | 46 | 114 | 48 |
| 17-18 financial YTD | 78 | 90 | 97 | 96 | 91 |

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 230 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2016 of 273 counts and the average in 2015 of 133. 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

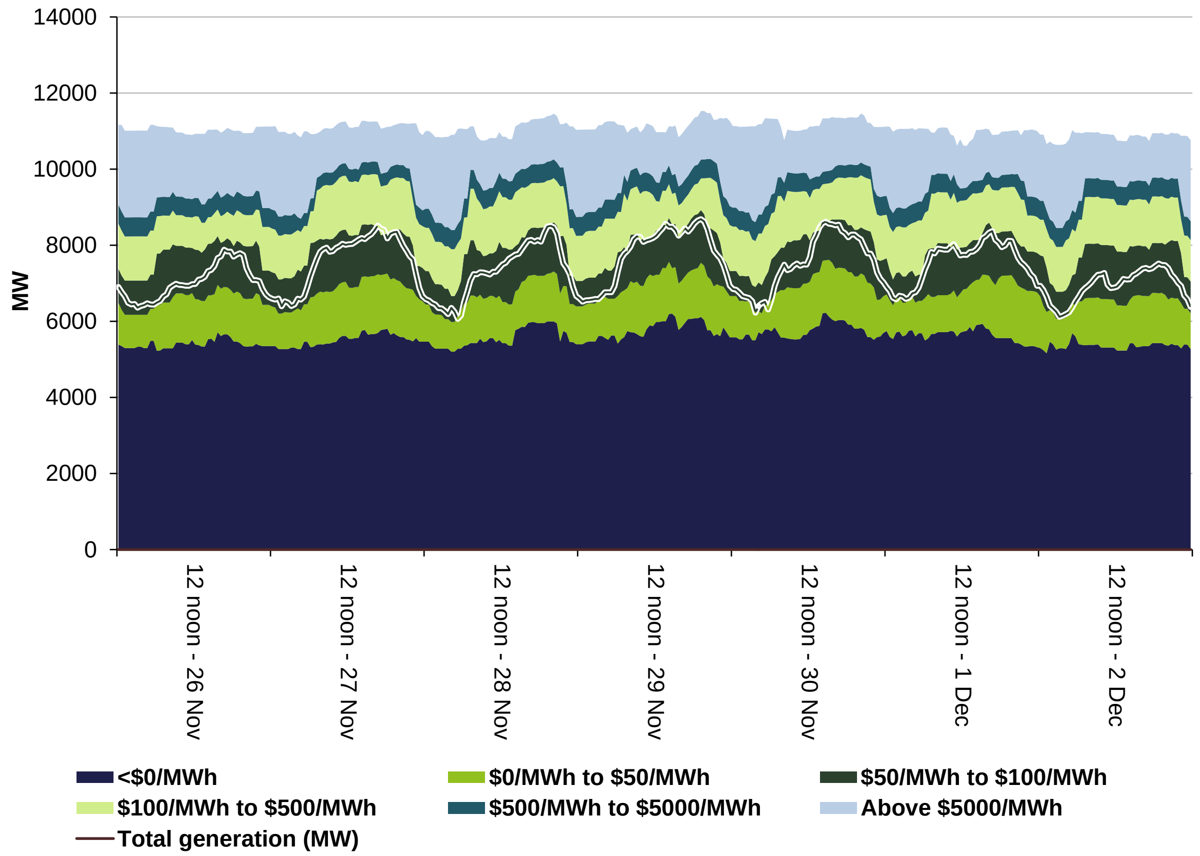
| | Availability | Demand | Network | Combination |
|---|---|---|---|---|
| % of total above forecast | 2 | 25 | 0 | 1 |
| % of total below forecast | 49 | 17 | 1 | 5 |

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

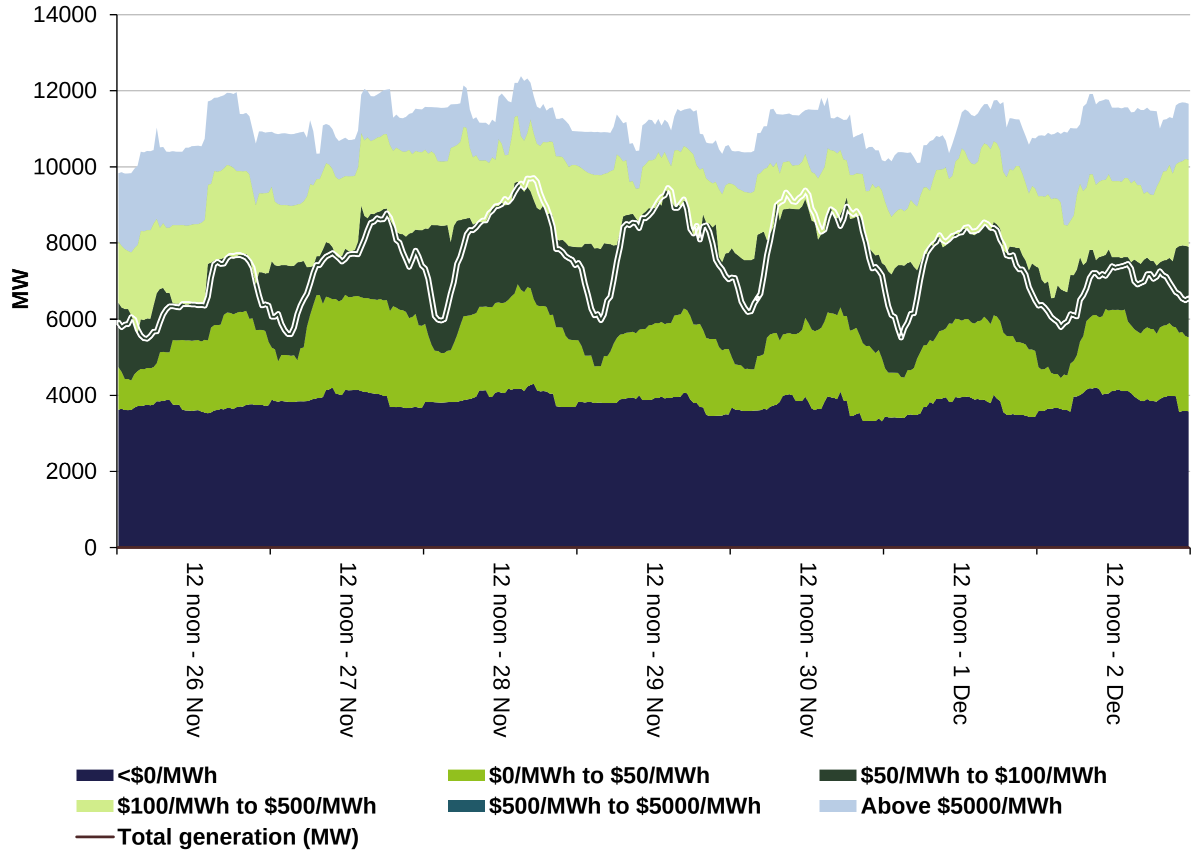
## Generation and bidding patterns

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.

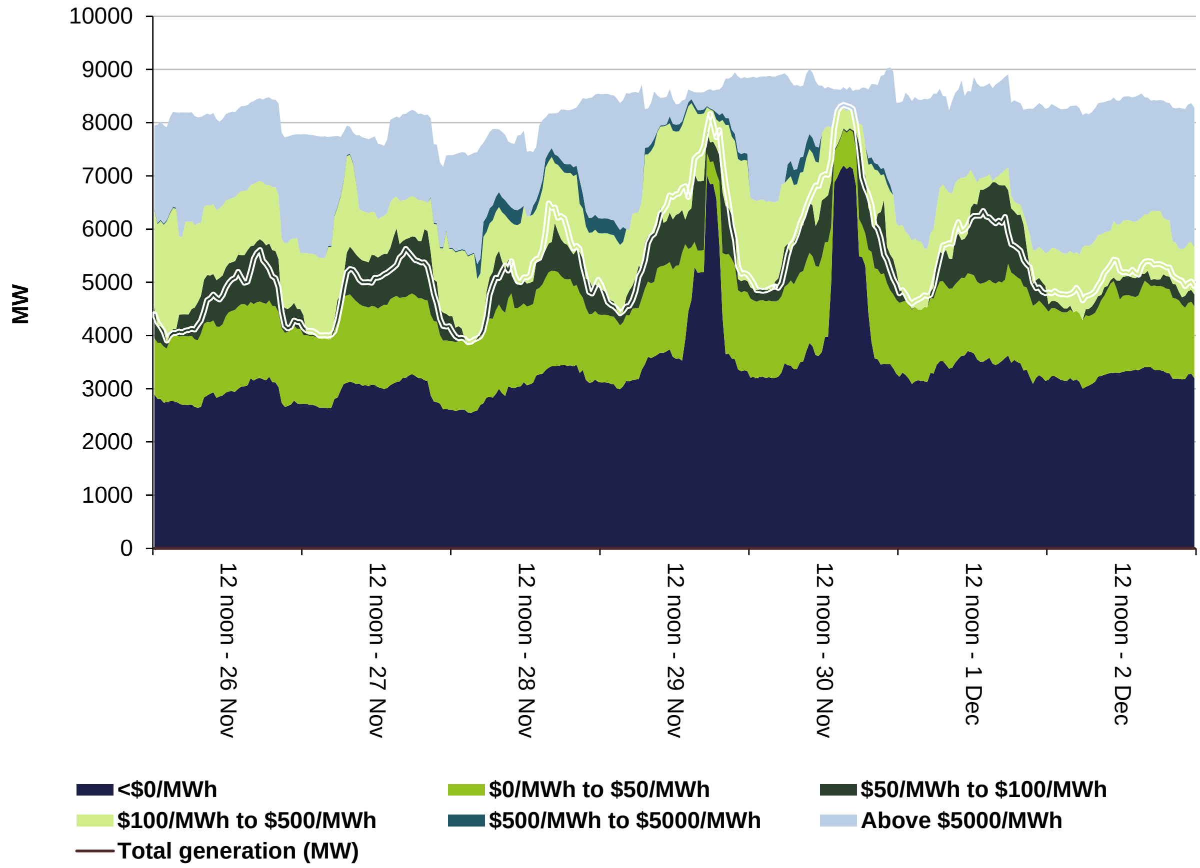
### Figure 3: Queensland generation and bidding patterns



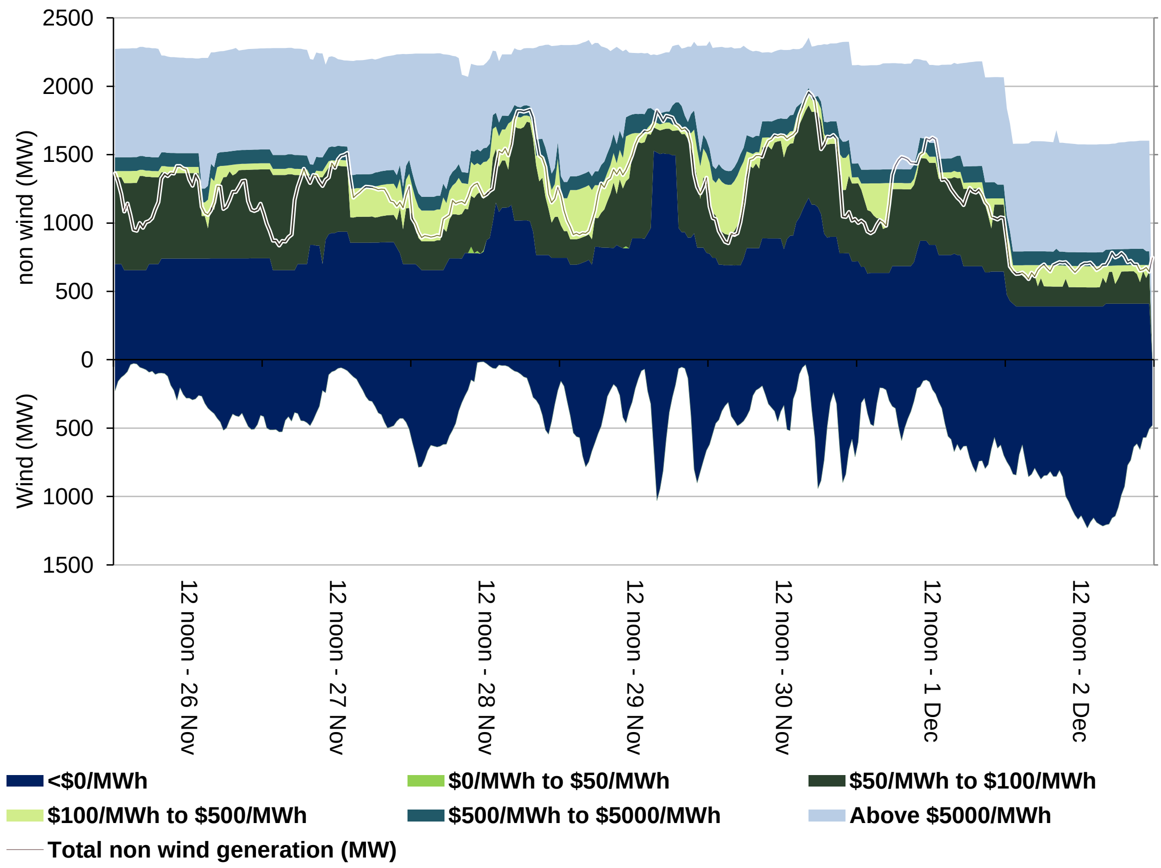
## Figure 4: New South Wales generation and bidding patterns



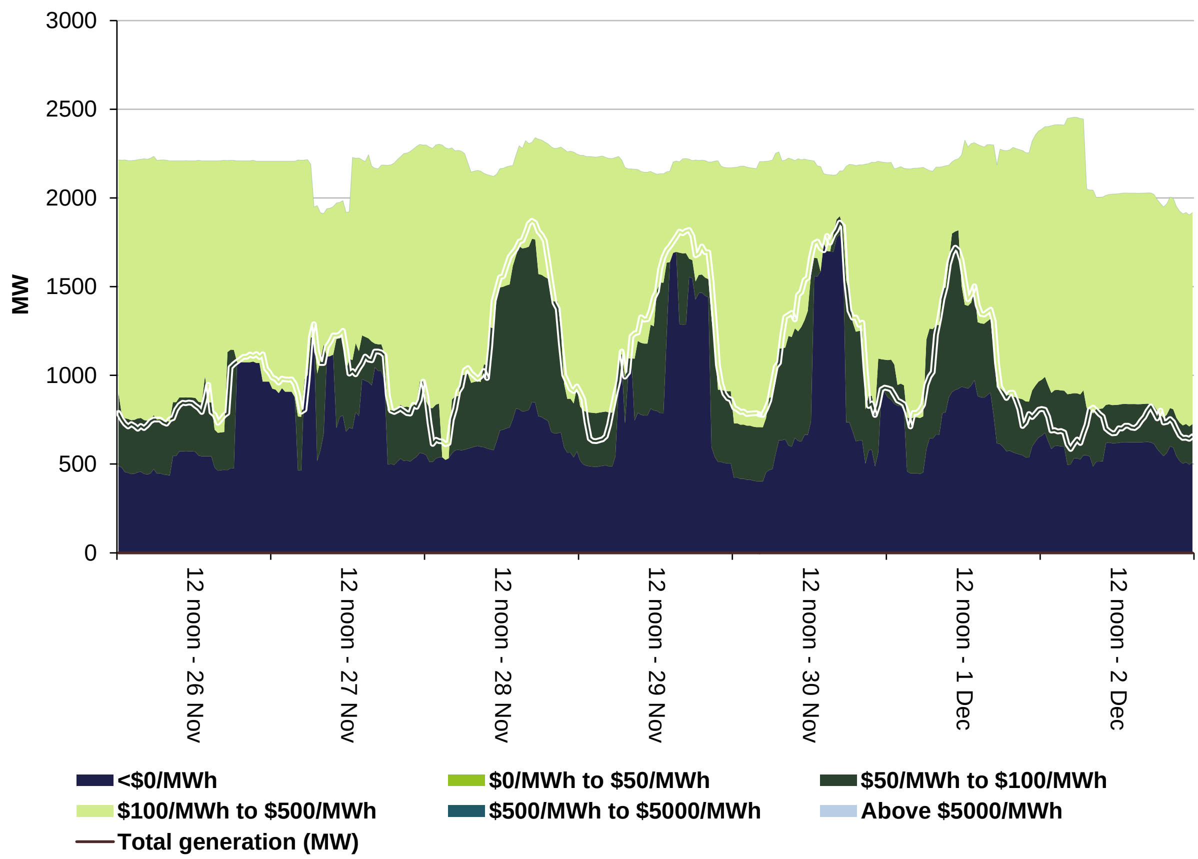

## Figure 5: Victoria generation and bidding patterns



## 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.

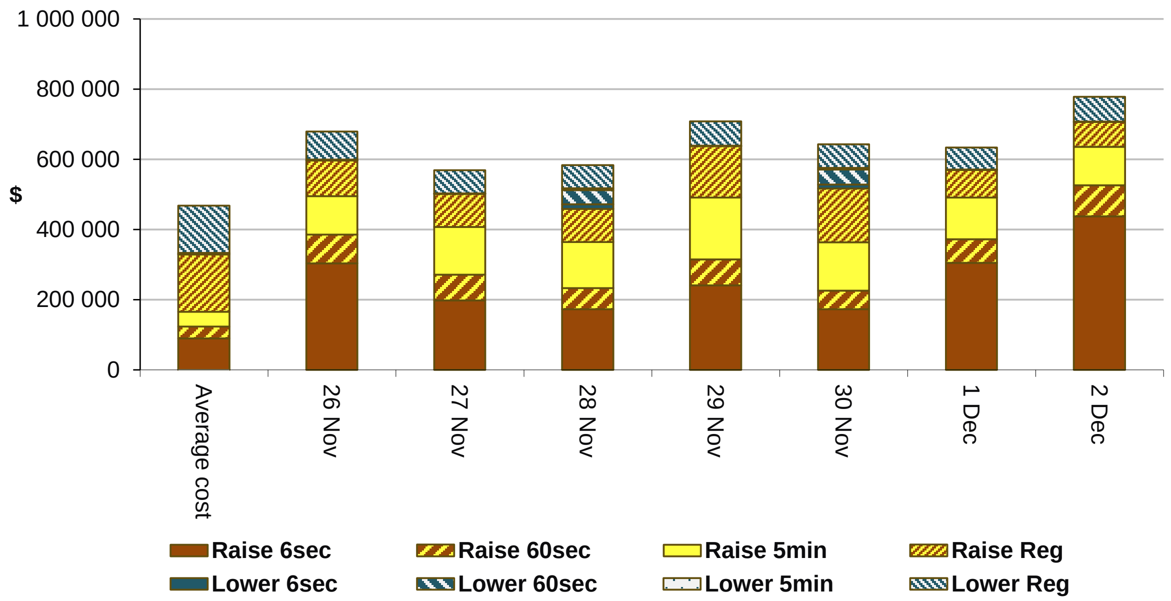
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $3 510 000 or around one per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $1 084 000 or around seven 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.

### Tuesday, 28 November

### 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 am | -129.87 | 53.68 | 53.32 | 5340 | 5303 | 5303 | 10 845 | 10 895 | 10 845 |
| 5 am | -132.71 | 15.90 | 13.80 | 5449 | 5410 | 5431 | 10 855 | 10 895 | 10 895 |

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

From 3.40 am, in preparation for an outage between Armidale to Bulli Creek, a ramping constraint reduced exports from Queensland to New South Wales. Queensland exports across QNI reduced by around 390 MW across the 3.40 am and 3.45 am trading intervals. With higher priced generation ramp down constrained or trapped in FCAS the dispatch price decreased to -$12/MWh and -$918/MWh respectively.

At 3.37 am, effective from 3.45 am, CS Energy rebid 240 MW of load capacity at one of the Wivenhoe pumps available. The reason given was ‘0337P WATER MANAGEMENT-SL’. As a result, pump 1 received a target of 240 MW at 3.50 am, which led to a similar increase in generation and caused the dispatch price to increase to $57/MWh.

At 4.41 am, effective from 4.50 am, CS Energy effectively reversed the previous rebid and removed 240 MW of load capacity from Wivenhoe pump 1. This led to a similar decrease in generation and with higher priced generation ramp down constrained the dispatch price decreased to the floor and resulted in the lower than forecast spot price for the 5 am trading interval.

### Thursday, 30 November

### 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 |
| 4 am | -327.52 | 52.24 | 51.84 | 5346 | 5310 | 5253 | 11 079 | 11 054 | 10 968 |
| 5.30 am | -290.55 | 13.80 | 13.80 | 5662 | 5581 | 5510 | 11 290 | 11 361 | 11 395 |

For the 4 am trading interval demand and availability were close to that forecast four hours prior.

From 3.35 am, in preparation for an outage between Armidale to Bulli Creek, a ramping constraint reduced exports from Queensland to New South Wales. From 3.35 am to 3.45 am Queensland exports across QNI reduced by around 590 MW. With higher priced generation ramp down constrained or trapped in FCAS the dispatch price decreased to -$13/MWh at 3.35 am and then the floor at 3.40 am and 3.45 am.

At 3.36 am, effective from 3.50 am CS Energy rebid 240 MW of load capacity at one of the Wivenhoe pumps available. The reason given was '0336P FUEL MANAGEMENT-MANAGE SPLITYARD CREEK LEVEL-SL'. As a result, pump 1 received a target of 240 MW at 3.50 pm, which saw a similar increase in generation and caused the dispatch price to increase to $57/MWh.

For the 5.30 am trading interval demand was around 80 MW higher and availability was 70 MW lower than forecast four hours prior.

At 5.08 am, effective from 5.20 am, CS Energy effectively reversed the previous rebid and removed 240 MW of load capacity from Wivenhoe pump 1. This saw a similar decrease in generation and with higher priced generation ramp down constrained or trapped in FCAS the dispatch price decreased to the floor and resulted in the lower than forecast spot price for the 5.30 am trading interval.

## Victoria

There were two occasions where the spot price in Victoria was greater than three times the Victoria weekly average price of $111/MWh and above $250/MWh.

**Wednesday, 29 November**

### 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 |
| 5 pm | 1450.46 | 435.49 | 273.64 | 8661 | 8392 | 7887 | 8549 | 8627 | 8601 |
| 5.30 pm | 353.38 | 435.49 | 198.36 | 8546 | 8212 | 7728 | 8581 | 8605 | 8621 |

Conditions for the 5 pm trading interval saw demand around 270 MW higher than forecast while availability was around 80 MW less than forecast four hours prior.

For the entire trading interval Victoria and South Australia were acting as one region.

For the 5 pm dispatch interval there was no available capacity priced between $605/MWh and $14 000/MWh in Victoria and $596/MWh and $10 578/MWh in South Australia. In Victoria multiple constraints bound which resulted in lower priced generation being ramped down constrained. At the same time, low priced wind generation decreased by around 70 MW in South Australia and demand increased by 40 MW from both regions.

With cheaper priced generation taking longer than five minutes to start or trapped in FCAS the dispatch price increased to $10 578/MWh in South Australia and $7312/MWh in Victoria.

The 5.30 pm trading interval was close to that forecast four hours ahead.

## 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 $116/MWh and above $250/MWh.

**Wednesday, 29 November**

**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 pm | 2036.87 | 548.40 | 326.67 | 2460 | 2508 | 2335 | 3050 | 2442 | 2513 |
| 5.30 pm | 510.18 | 551.66 | 243.15 | 2449 | 2521 | 2342 | 2819 | 2409 | 2500 |

The higher than forecast price for the 5 pm trading interval is explained in the Victorian section above.

The 5.30 pm trading interval was close to that forecast four hours ahead.

## Tasmania

There was one occasion where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $91/MWh and above $250/MWh.

**Wednesday, 29 November**

**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 |
| 5.30 pm | 286.49 | 136.63 | 177.78 | 1104 | 1019 | 1069 | 2218 | 2225 | 2267 |

Conditions at the time saw demand 85 MW higher than forecast while availability was close to that forecast four hours prior.

In the four hours leading up to the start of the trading interval 44 MW was rebid from -$75/MWh to $349/MWh.

For the majority of the trading interval there was no capacity priced between $74/MWh and $220/MWh and small amounts of low priced generation was trapped in FCAS or being limited by system normal constraints.

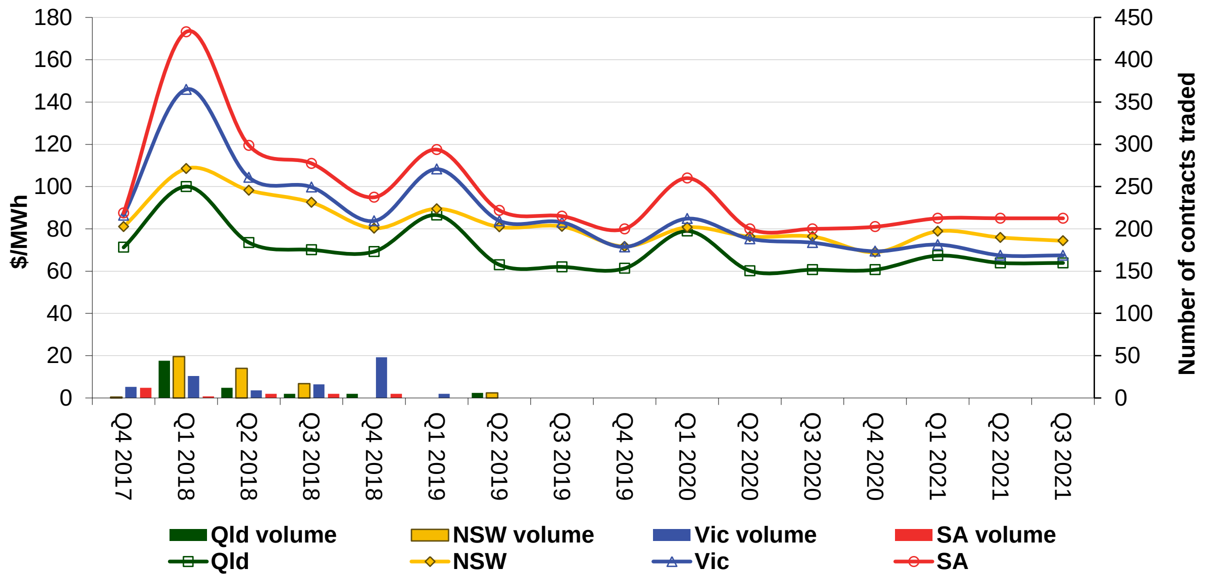
The higher than forecast demand, rebidding and limitations on lower priced generation led to the price being co-optimised with the FCAS market for the majority of the trading interval and the dispatch priced varied between $172/MWh to $349/MWh.

## Financial markets

The high volume of trades in Figure 9, 10 and 11 are due to options on calendar year base load expiring on Monday 20 November 2017.

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.

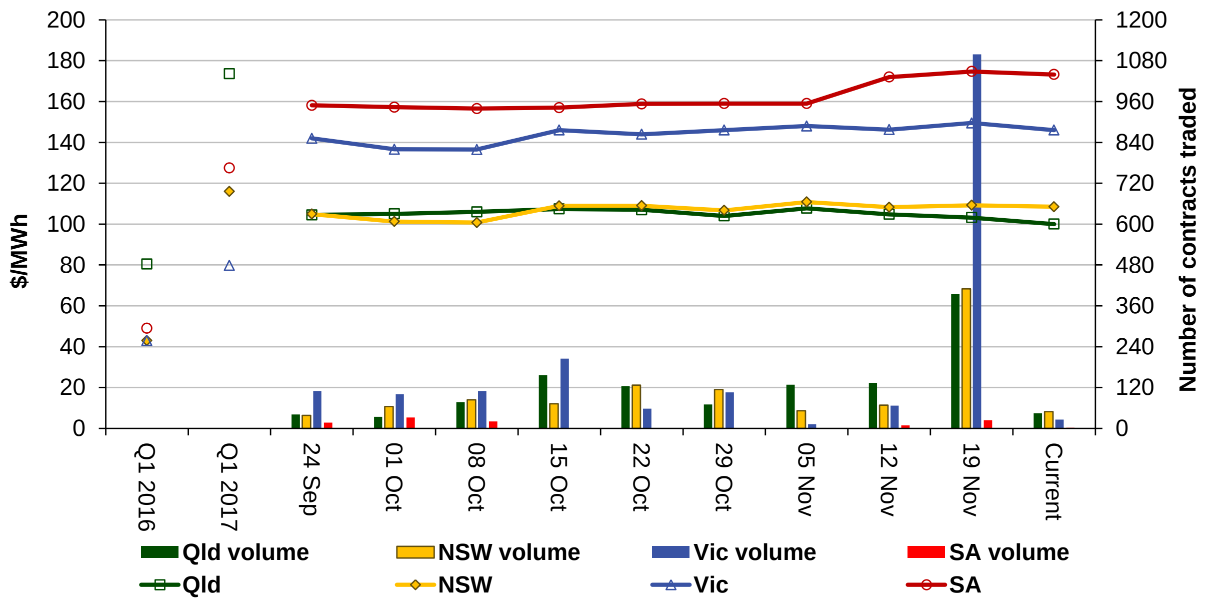
## Figure 9: Quarterly base future prices Q4 2017 – Q3 2021




Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional Q1 2018 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2016 and quarter 1 2017 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 2018 base contracts over the past 10 weeks (and the past 2 years)



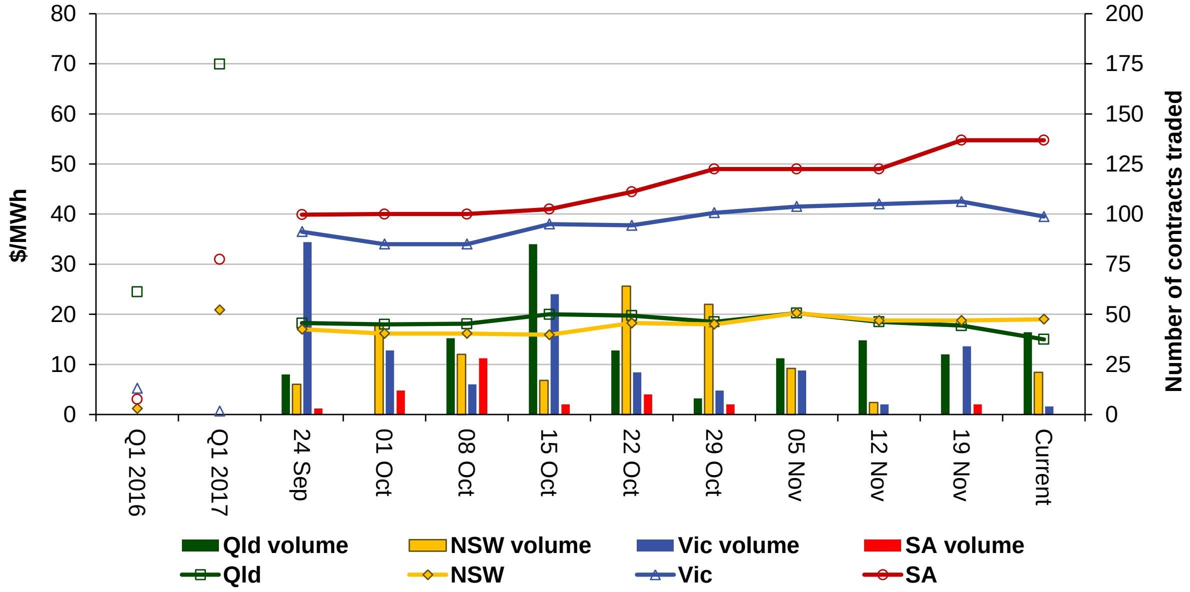

Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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 2018 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2016 and quarter 1 2017 prices are also shown.

## Figure 11: Price of Q1 2018 cap contracts over the past 10 weeks (and the past 2 years)




Source. ASXEnergy.com.au

**Australian Energy Regulator**
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