Electricity Report

AUSTRALIAN ENERGY REGULATOR

3 - 9 September 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 3 – 9 September 2017.

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

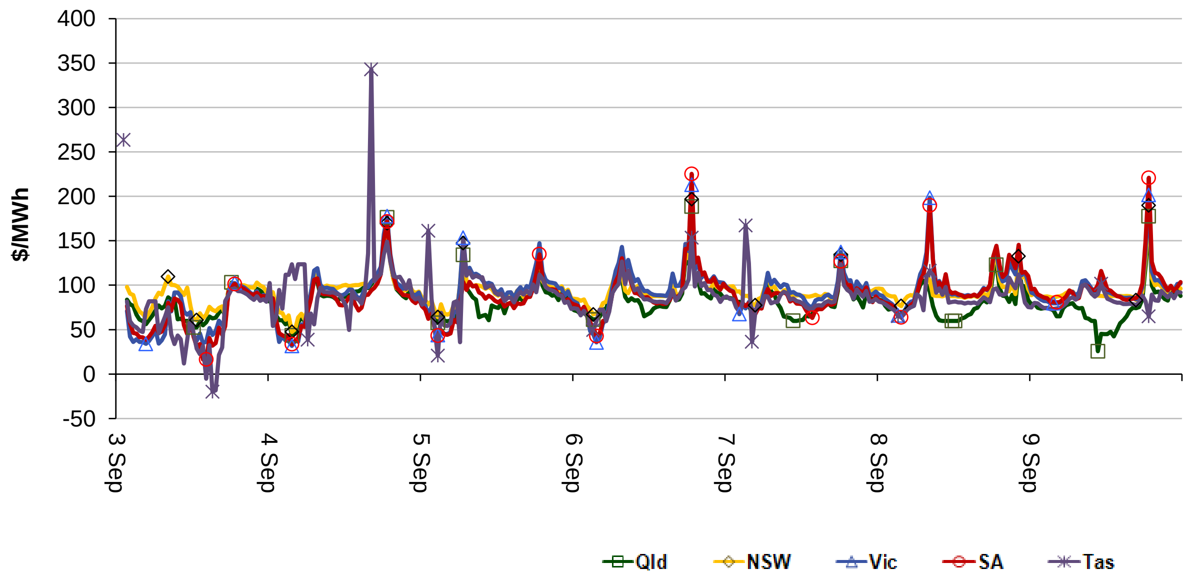


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

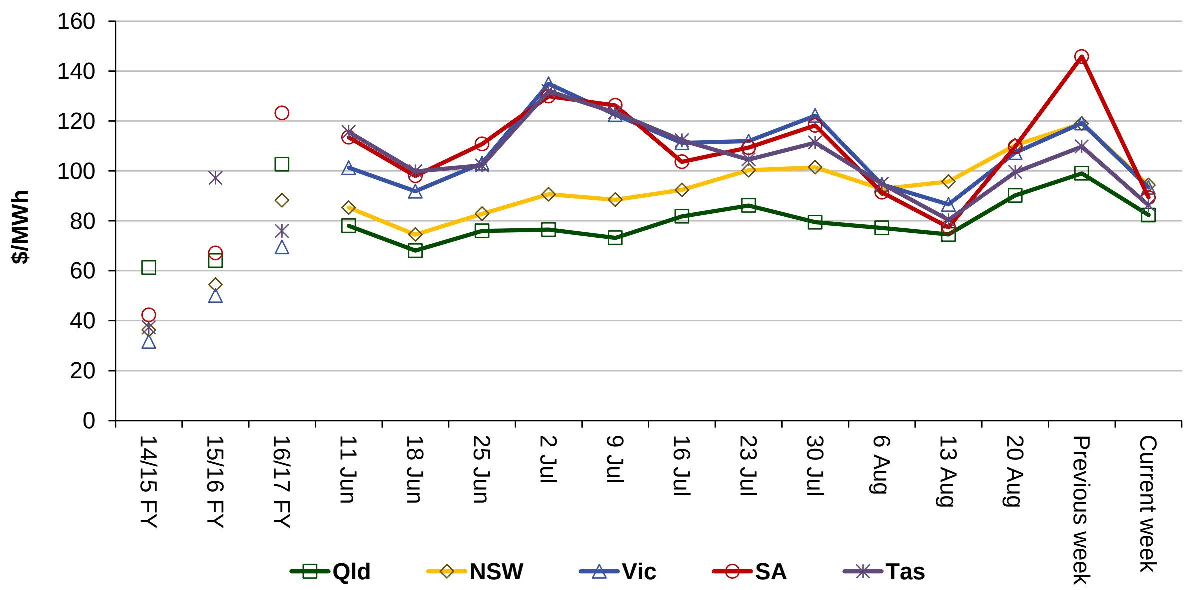


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	82	94	93	89	86
16-17 financial YTD	56	59	54	152	57
17-18 financial YTD	82	98	111	110	105

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 101 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	1	35	0	2
% of total below forecast	38	18	0	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

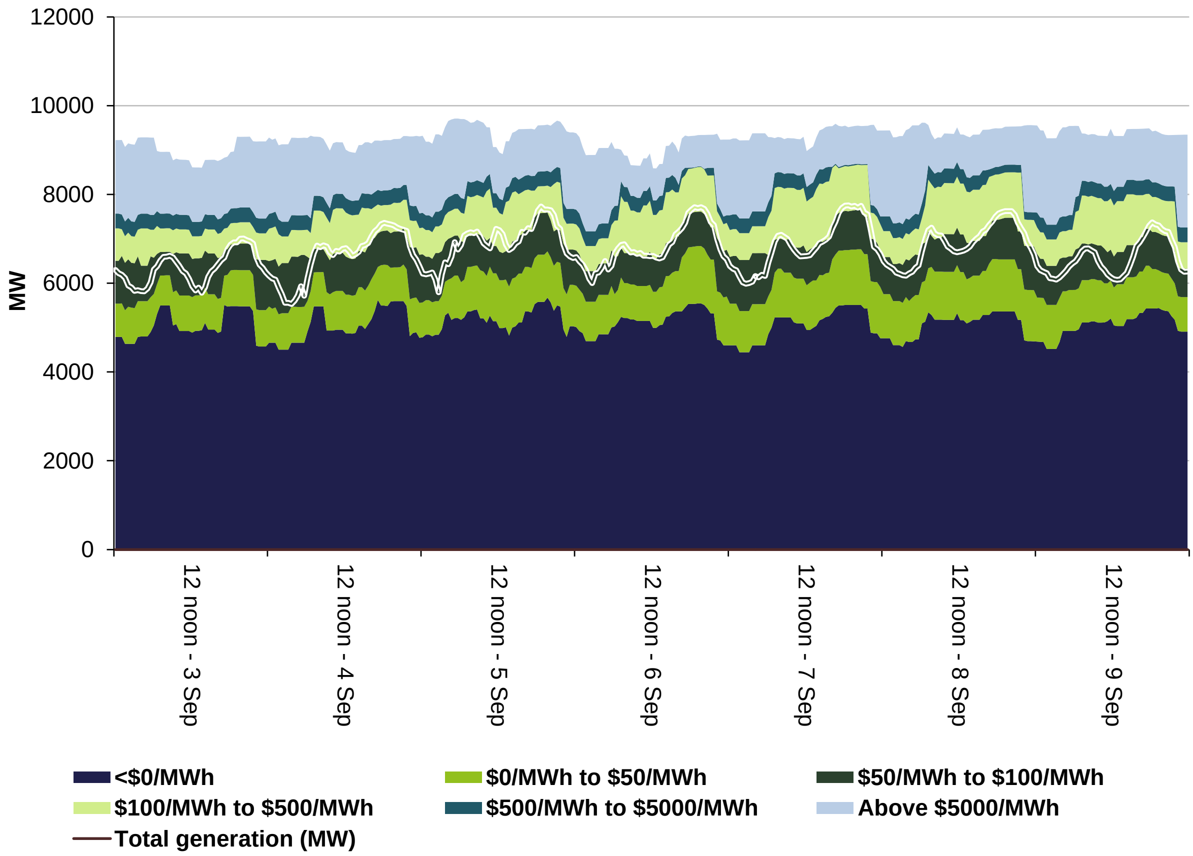


Figure 4: New South Wales generation and bidding patterns

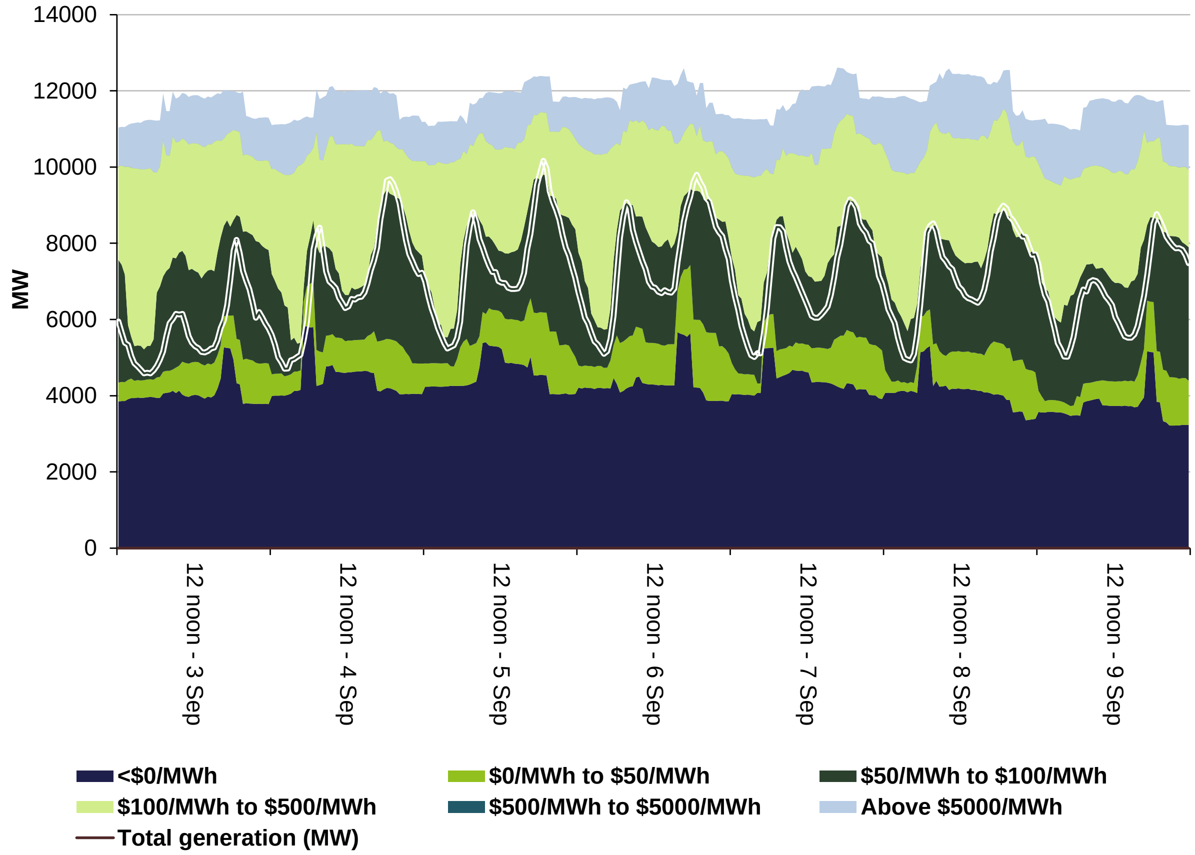


Figure 5: Victoria generation and bidding patterns

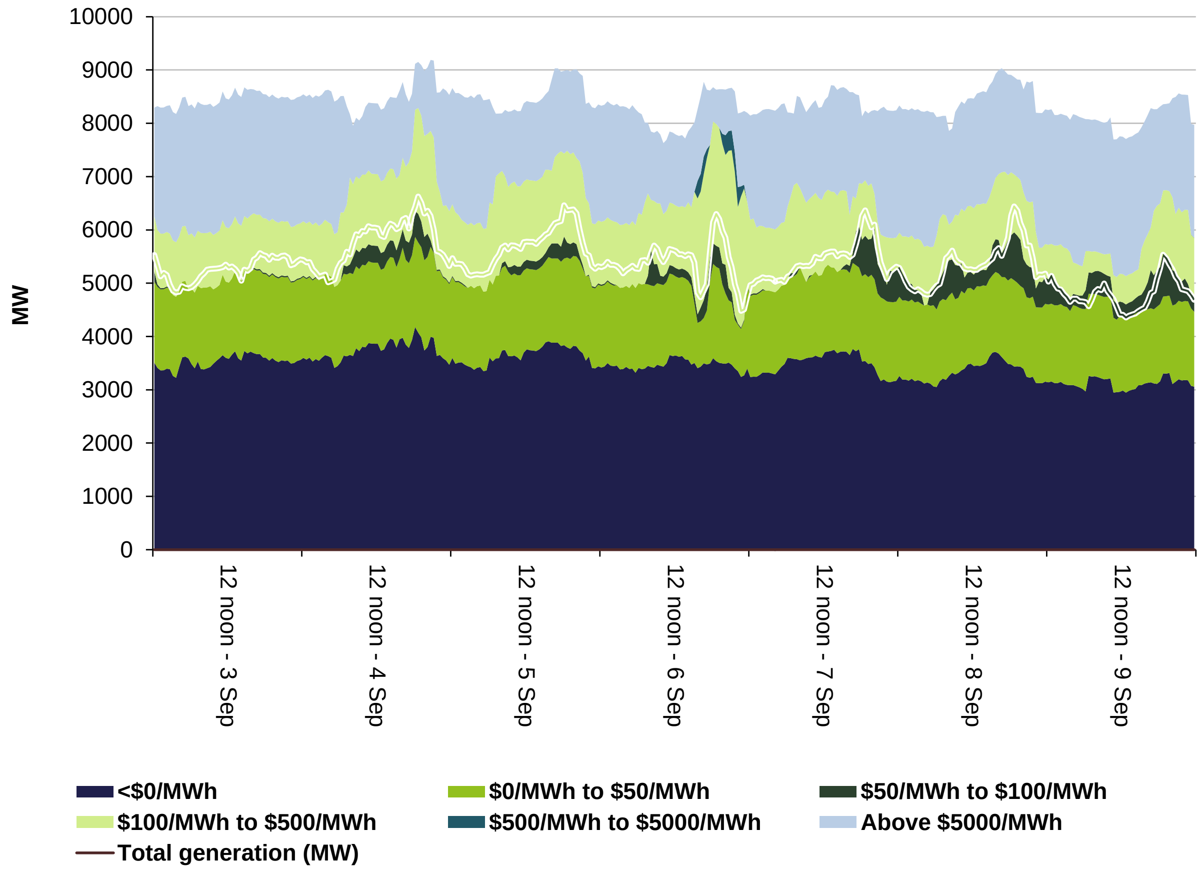


Figure 6: South Australia generation and bidding patterns

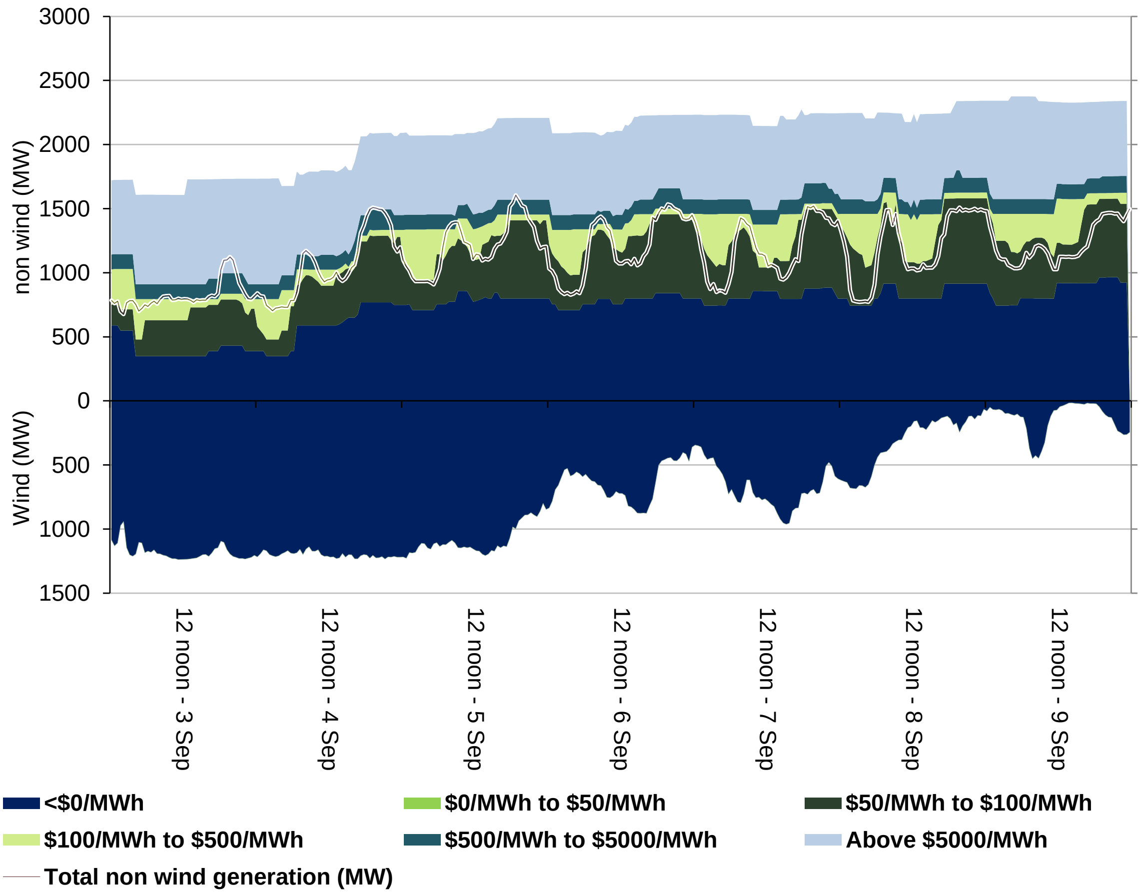
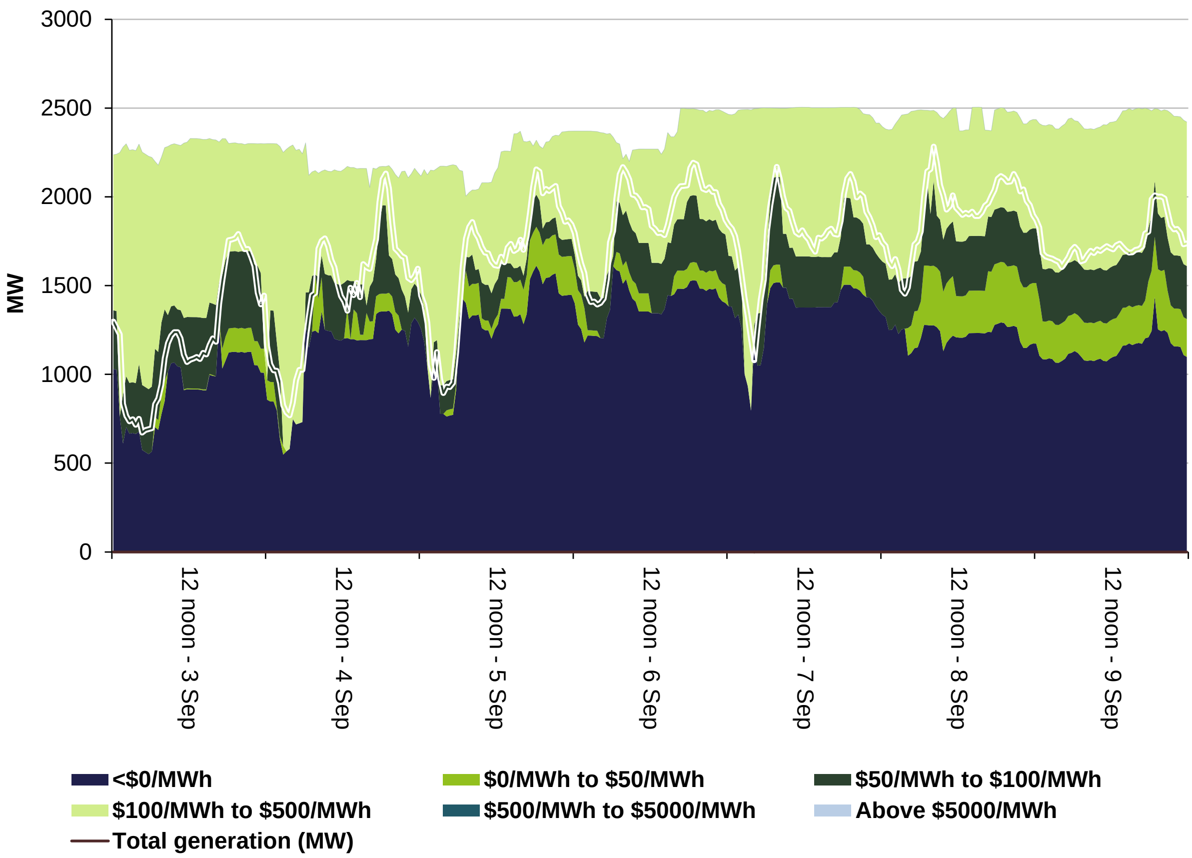


Figure 7: Tasmania generation and bidding patterns



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.

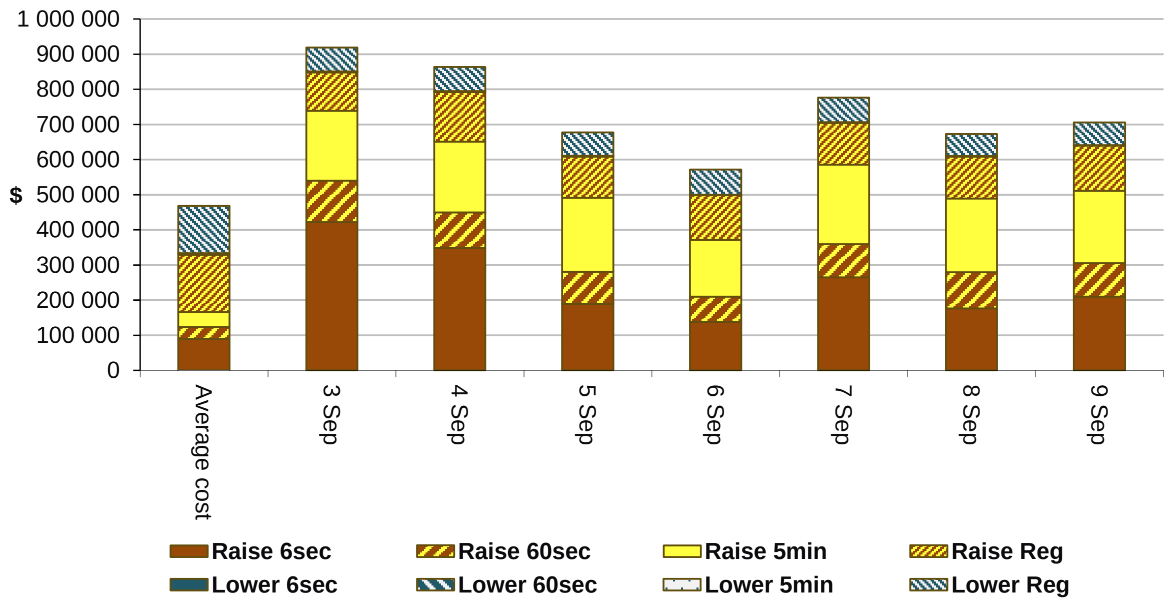
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $4 032 000 or around one per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $1 154 000 or around six 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



The higher than average daily costs of FCAS were a result of an increase in local requirements for raise 6 services in Tasmania and an increase in global prices for the majority of services.

The increase in global prices is a result of a change in offers by HydroTas at a number of its power station in raise services from 1 August 2017. HydroTas shifted the majority of their raise regulation capacity from prices less than $30/MW to prices between $30 - $50/MW.

Detailed market analysis of significant price events

Tasmania

There were two occasions where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $86/MWh and above $250/MWhs.

Sunday, 3 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
1.30 am	263.43	68.33	82.00	1018	981	990	2250	2203	2199

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

From 1.05 am to 1.25 am between 50-90 MW of flow was being forced from Tasmania to Victoria by a system normal constraint which manages transient stability on the network. Forecasts four hours prior had flows from Victoria to Tasmania at around 100 MW.

At 12.59 am, effective from 1.05 am, HydroTas rebid 74 MW of capacity at Cethana priced at -$1/MWh to $349/MWh. The reason related to lake levels being greater than forecast. This combined with co-optimisation of the energy and FCAS markets saw the dispatch price at 1.05 am increase from $82/MWh to $349/MWh. Prices remained around this level until 1.30 pm when flows were no longer being forced into Victoria.

Monday, 4 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
4.30 pm	342.65	90.74	90.66	1396	1227	1197	2084	2195	2191

Conditions at the time saw demand around 170 MW higher than forecast while availability was around 110 MW lower than forecast four hours prior. Flows on Basslink were being forced into Victoria but less than was forecast four hours ahead.

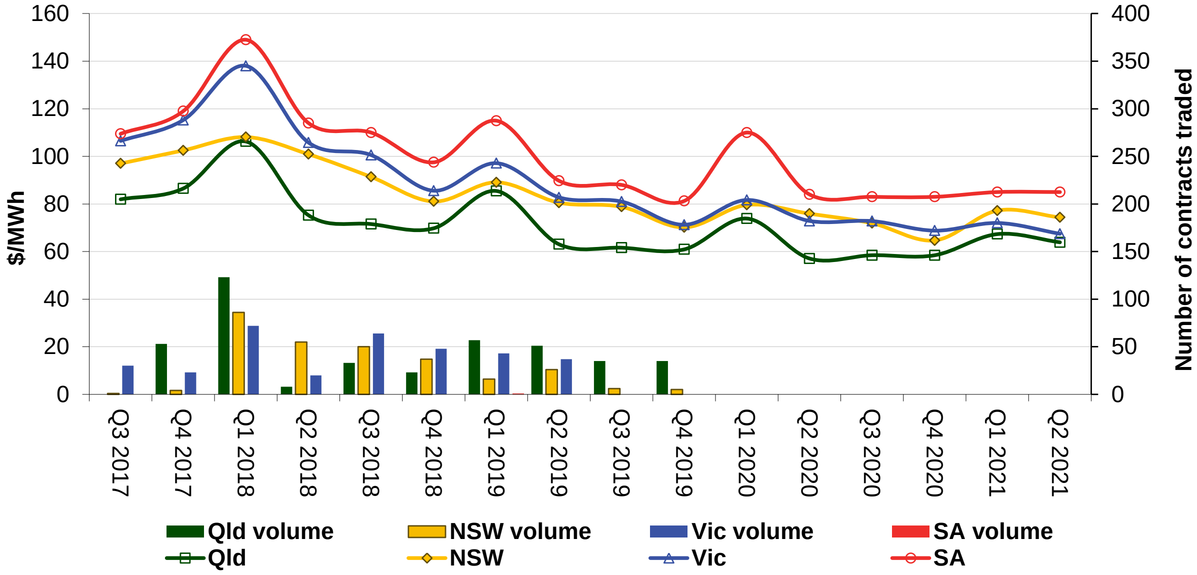
Over two rebids at 3.32 pm and 3.58 pm (all effective from 4.05 pm), HydroTas shifted a total of 391 MW of capacity at Gordon, Tribute and Tungatinah from $91/MWh to $349/MWh. The reasons for the rebids related to Gordons targets being different than expected and flows across Basslink being greater than forecast.

These rebids, combined with the energy price being co-optimised with FCAS markets saw the dispatch increase to $468/MWh at 4.05 pm and remained around this level until 4.25 pm when exports were no longer being forced across Basslink.

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.

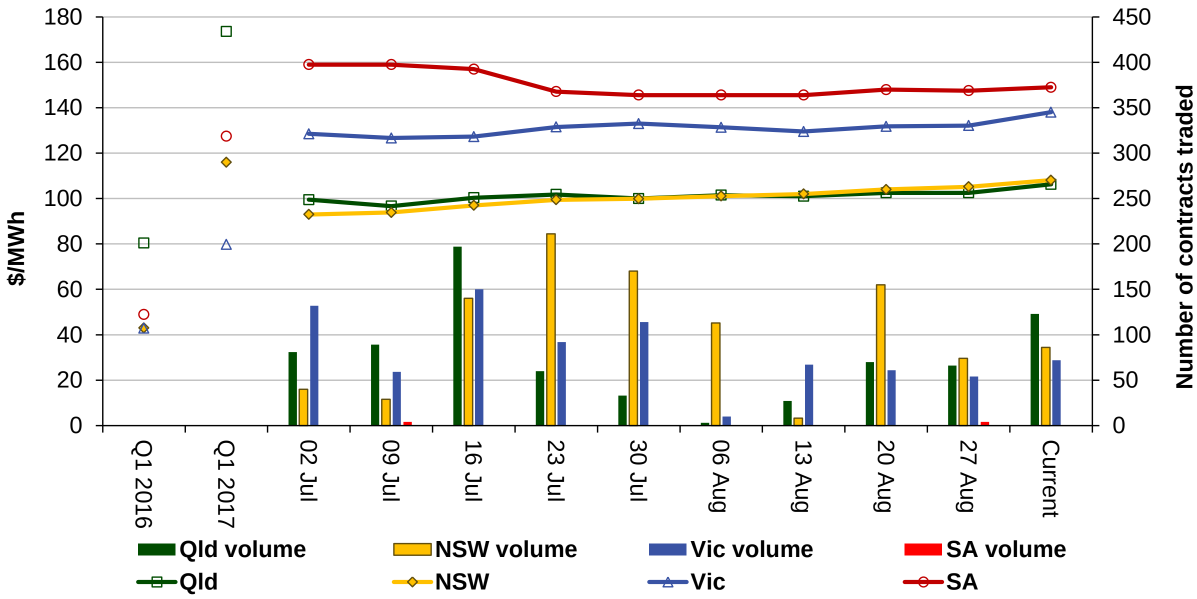
Figure 9: Quarterly base future prices Q3 2017 – Q2 2021



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)



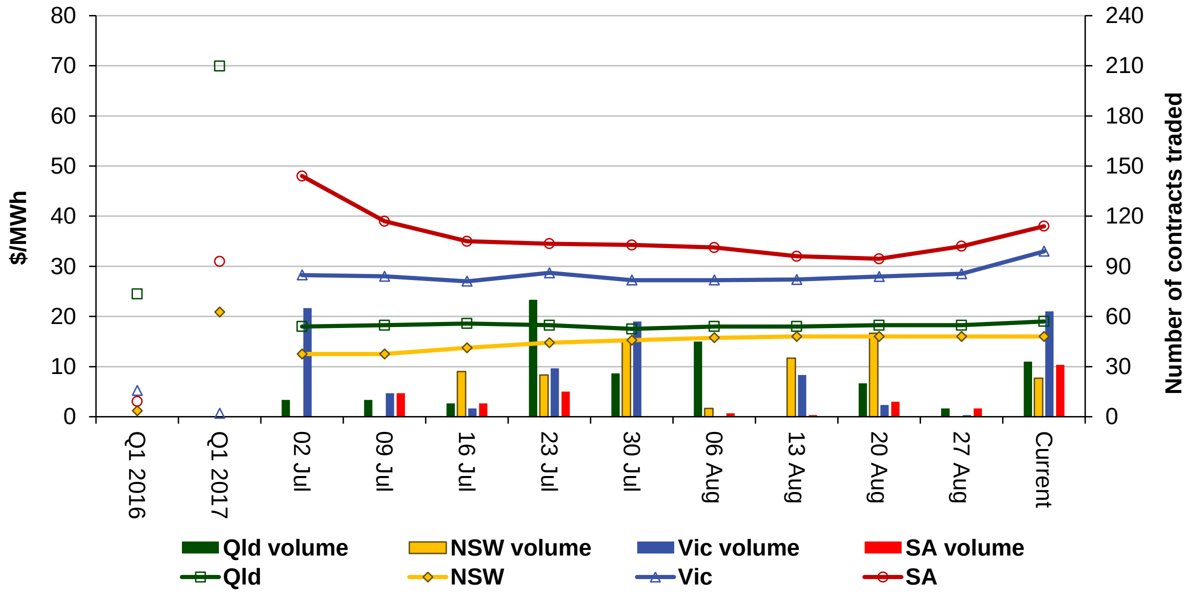
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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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