Electricity Report

AUSTRALIAN ENERGY REGULATOR

16 – 22 December 2018

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 16 - 22 December 2018.

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

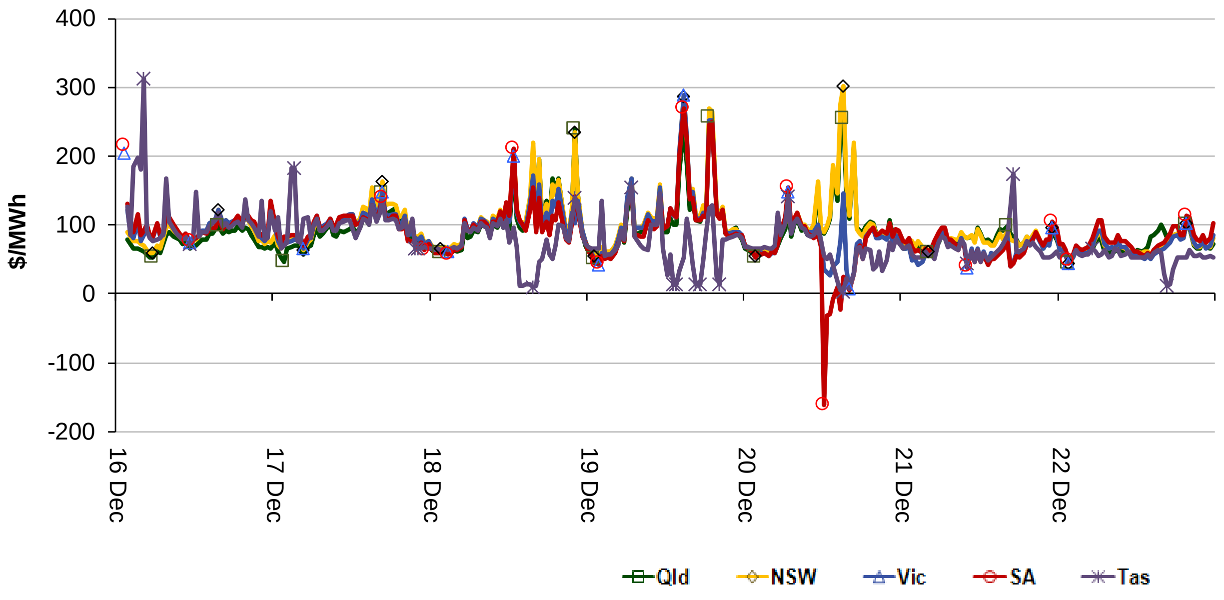


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

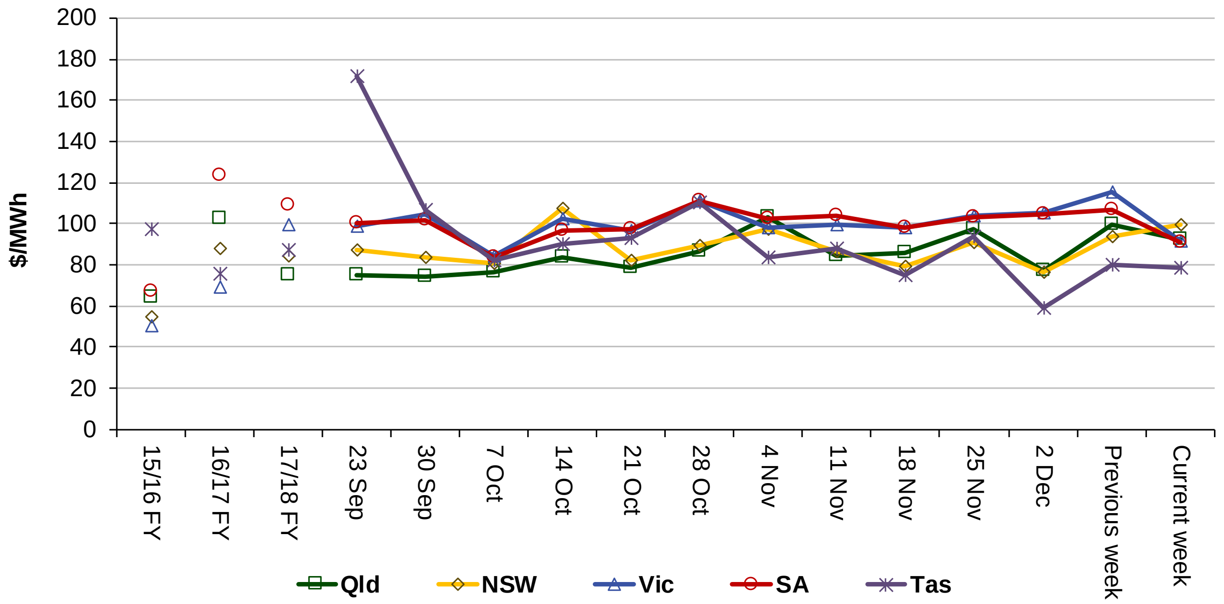


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	92	100	91	91	78
17-18 financial YTD	78	89	97	95	92
18-19 financial YTD	84	90	92	97	62

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 184 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2017 of 185 counts and the average in 2016 of 273. 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	27	0	1
% of total below forecast	16	38	0	10

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

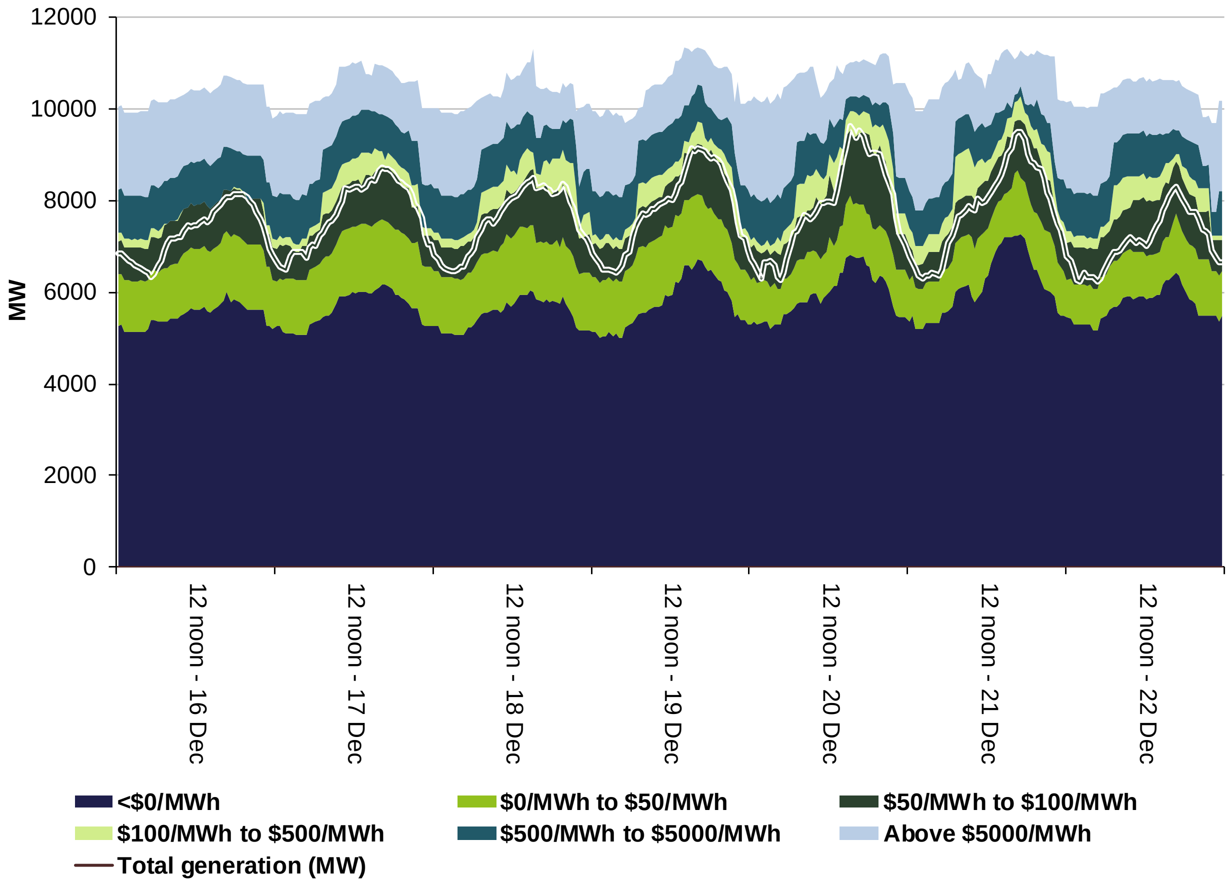


Figure 4: New South Wales generation and bidding patterns

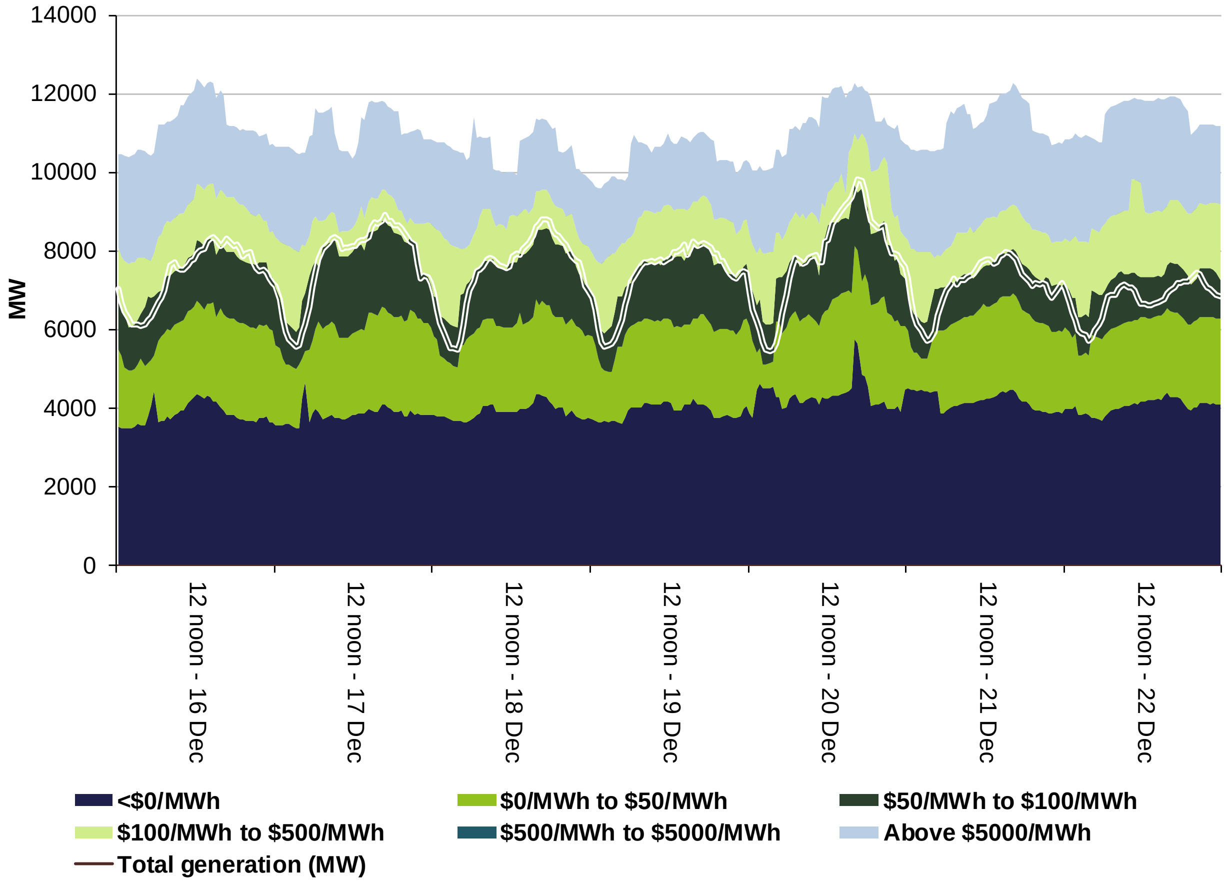


Figure 5: Victoria generation and bidding patterns

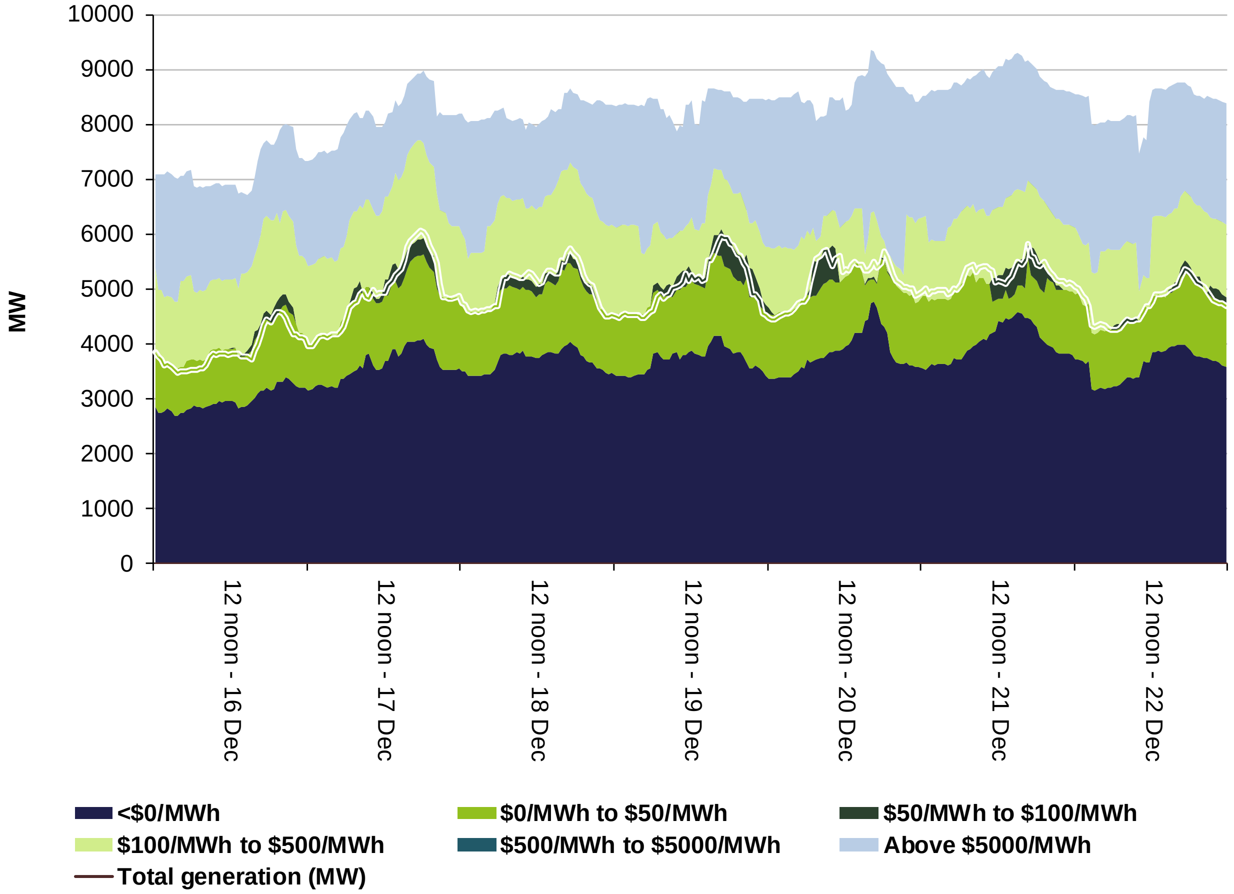


Figure 6: South Australia generation and bidding patterns

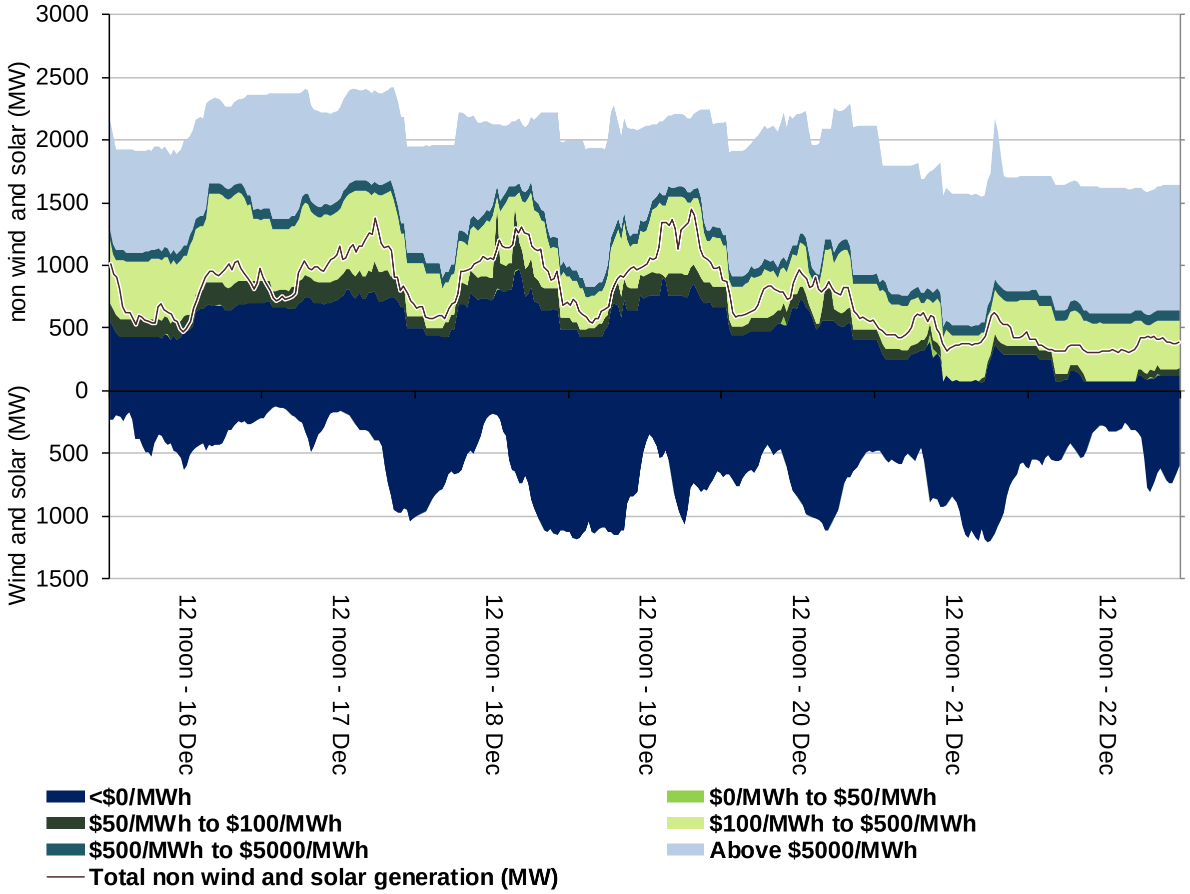
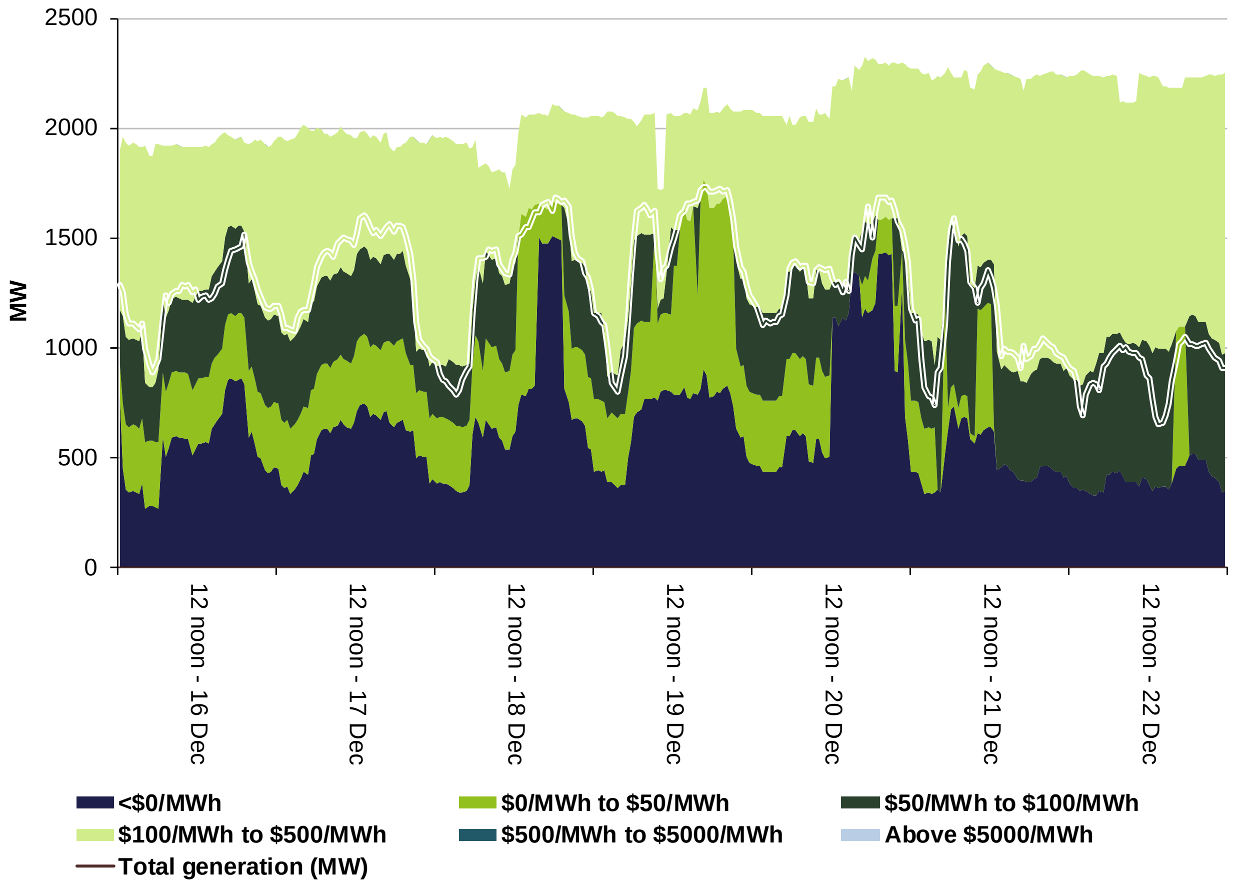


Figure 7: Tasmania generation and bidding patterns



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.

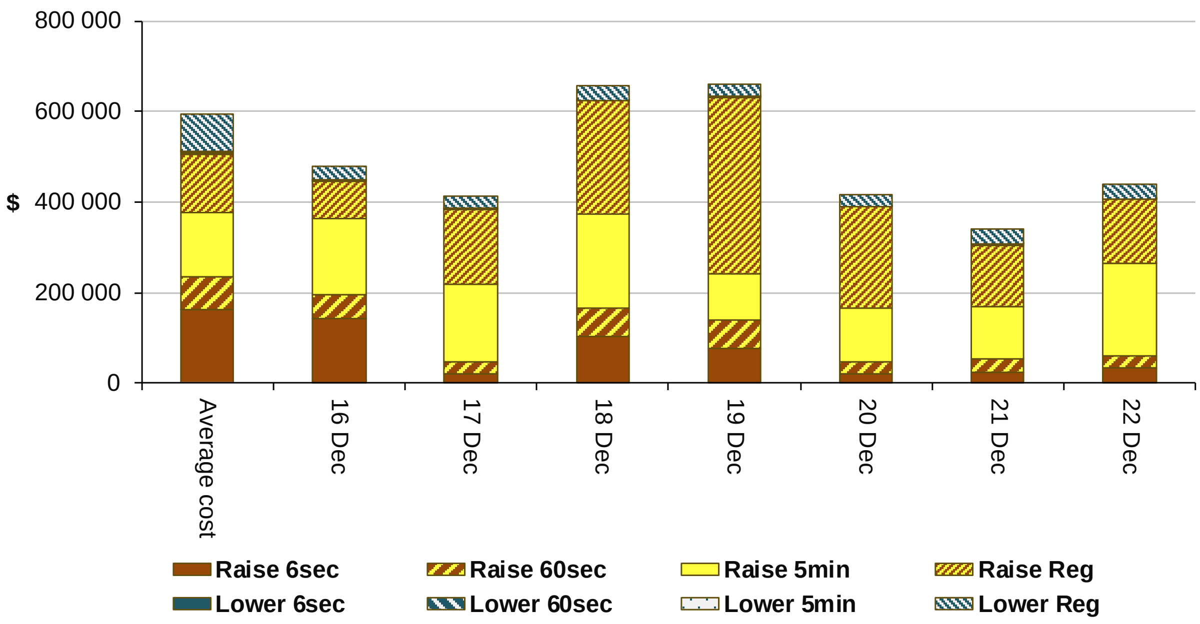
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $2 965 000 or less than 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $436 500 or around 3 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

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 $100/MWh and above $250/MWh.

Thursday, 20 December

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
3.30 pm	302.26	131.57	111.88	11 316	10 166	10 504	12 092	12 185	12 552

Prices in New South Wales and Queensland were aligned for this trading interval and is discussed collectively for this analysis. Demand and availability in Queensland were both close to forecast.

Demand in New South Wales was 1150 MW higher than forecast while availability was close to forecast, four hours prior. With no capacity offered between $130/MWh and $280/MWh across New South Wales and Queensland the higher than forecast demand saw the dispatch price set around $300/MWh for the entire trading interval.

Victoria

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

Wednesday, 19 December

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
3 pm	290.00	93.40	290.00	5789	5334	5580	8417	8474	8411

Prices in New South Wales, Victoria and South Australia were aligned for this trading interval and is discussed collectively for this analysis. The price in New South Wales didn't exceed our reporting threshold as it had a higher weekly average than the other two regions.

Demand in Victoria and New South Wales was 455 MW and 514 MW higher than forecast respectively. This saw dispatch prices at around $290/MWh in the three regions for the entire trading interval.

South Australia

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

Thursday, 20 December

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	-161.39	60.64	58.99	912	866	911	3073	3011	3063

Demand was 46 MW higher than forecast and availability was 62 MW higher than forecast, four hours prior.

There were negative dispatch prices in South Australia for the 12.20 pm and 12.30 pm dispatch intervals.

In both instances, a system normal constraint reduce exports to Victoria by 20 MW while demand also decreased. There were only two generation units in South Australia with offers between -$1000/MWh and $80/MWh at the time. With these units being ramp-down constrained and unable to set price, the dispatch prices fell to -$152/MWh and the price floor for the two intervals.

Tasmania

There was one occasion where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $78/MWh and above $250/MWh.

Sunday, 16 December

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
4.30 am	313.56	70.28	66.78	901	953	952	1919	1951	2005

Demand was 50 MW lower than forecast and availability was 32 MW lower than forecast, four hours prior.

Hydro Tasmania rebid a total of 125 MW of capacity across Gordon and Poatina from $67/MWh to $288/MWh, effective 4.05 am due to Basslink flow greater than forecast. With cheaper priced generation in Tasmania ramp-up constrained, prices rose to around $290/MWh for the 4.05 am and 4.15 am dispatch intervals.

At 4.10 am, Basslink was exporting in the “no go zone” and unable to transfer FCAS services from the mainland. This caused a 102 MW increase in local raise 6 second requirement and there was insufficient local raise 6 second effective availability at the time. As a result, energy dispatch price at 4.10 am was co-optimised with raise 6 second market, increasing to $1086/MWh.

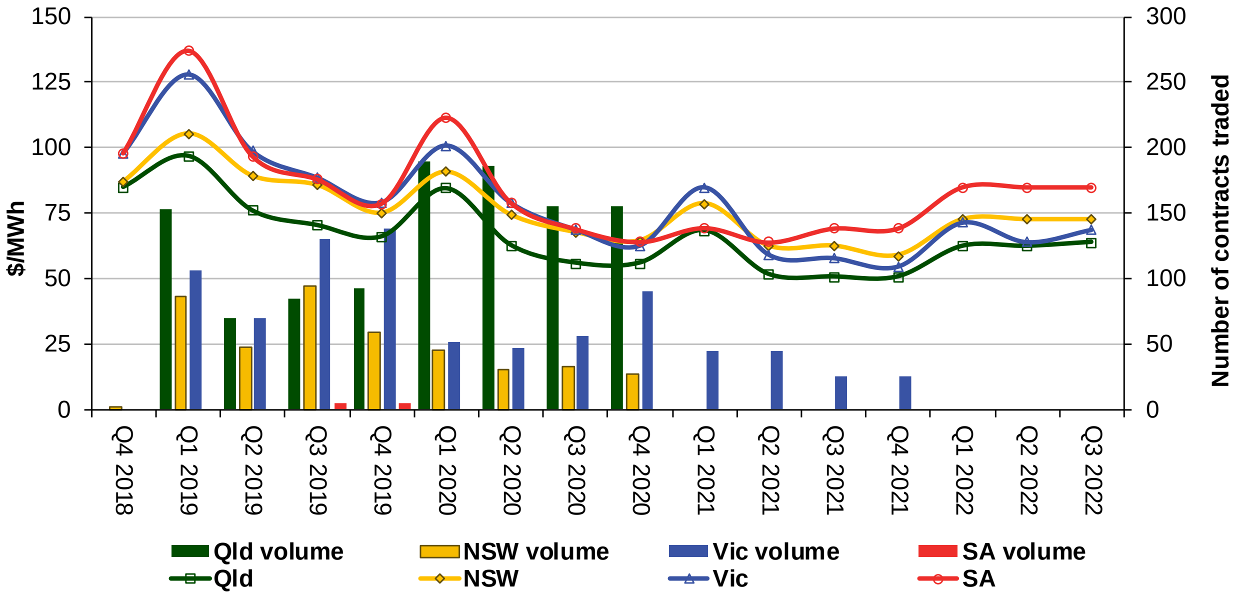
The dispatch price fell to around $70/MWh from 4.20 am onwards when Basslink became unconstrained and cheaper priced generation from the mainland was able to set price in Tasmania.

Financial markets

The high volume of trades in Figure 10 is a result of the conversion of base load options to base future contracts on Monday 19 November 2018.

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.

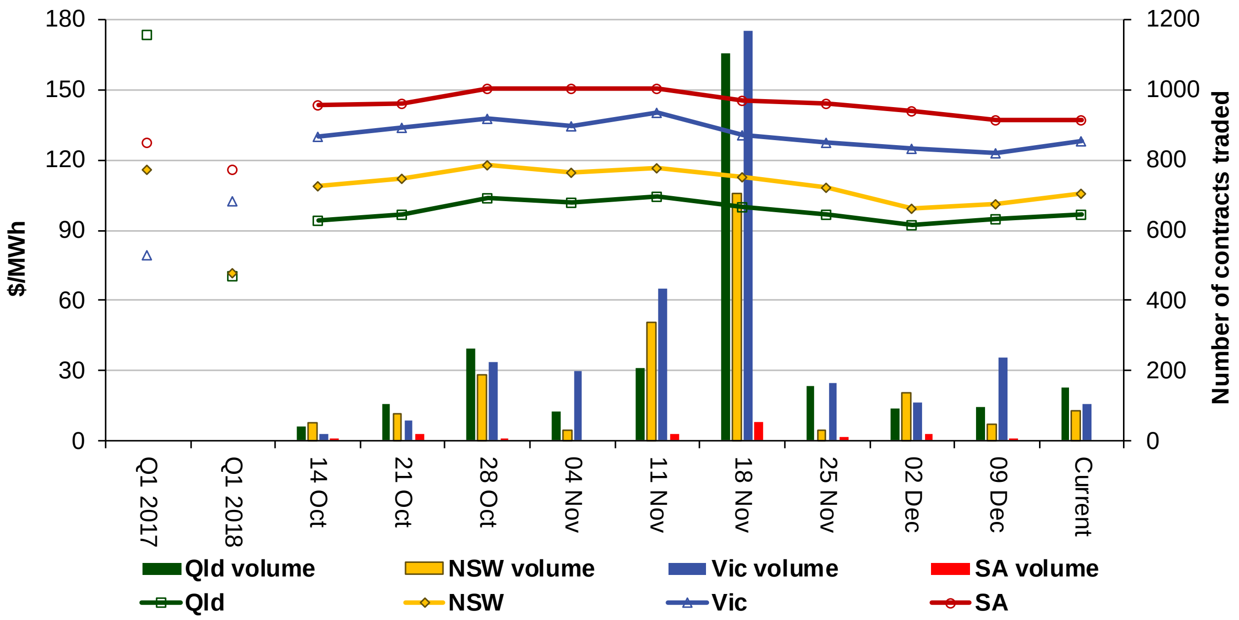
Figure 9: Quarterly base future prices Q4 2018 – Q3 2022



Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional Q1 2019 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2017 and quarter 1 2018 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 2019 base contracts over the past 10 weeks (and the past 2 years)



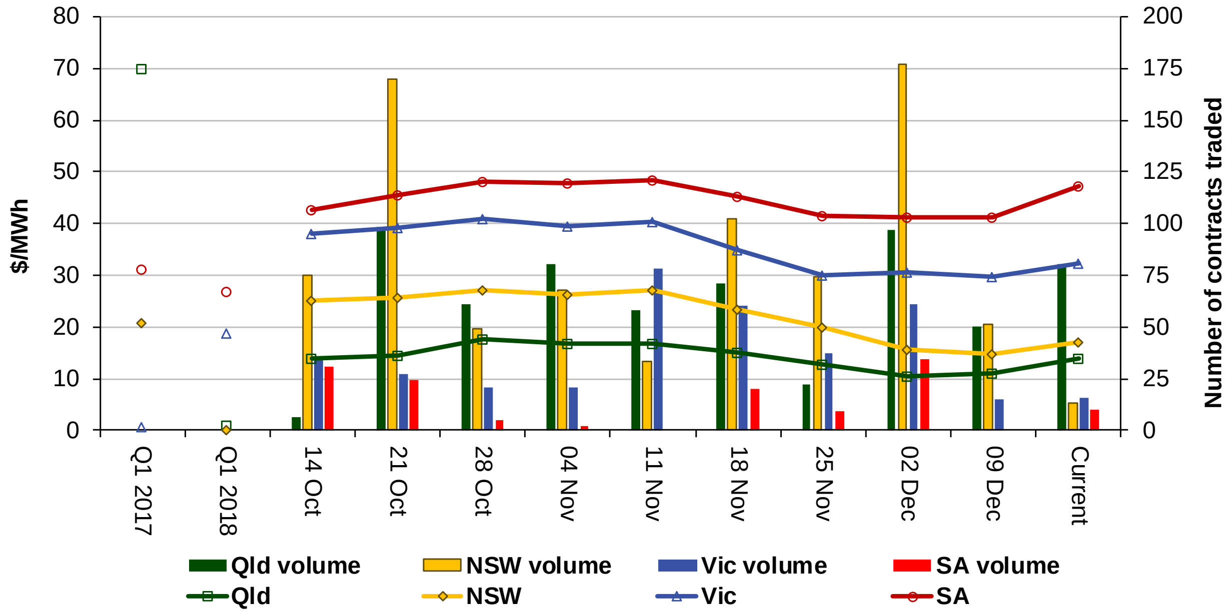
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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 2019 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2017 and quarter 1 2018 prices are also shown.

Figure 11: Price of Q1 2019 cap contracts over the past 10 weeks (and the past 2 years)



Source. ASXEnergy.com.au

Australian Energy Regulator
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