Electricity Report

AUSTRALIAN ENERGY REGULATOR

22 – 28 November 2020

Weekly Summary

Weekly volume weighted average (VWA) prices ranged from $54/MWh in Victoria to $69/MWh in New South Wales and Tasmania. Quarter to date VWA prices were at least $23/MWh lower in all regions than the same time last year. Spot prices in Queensland, New South Wales and Tasmania exceeded $2000/MWh on several occasions due to generator rebidding, variations in forecast demand and co-optimisation between FCAS and energy markets.

On 23 November, transmission equipment at the Wodonga terminal station in Victoria tripped, resulting in 51 MW of local load being lost. Despite this, AEMO did not instruct load shedding and prices were not significantly affected.

Purpose

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 22 to 28 November 2020.

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

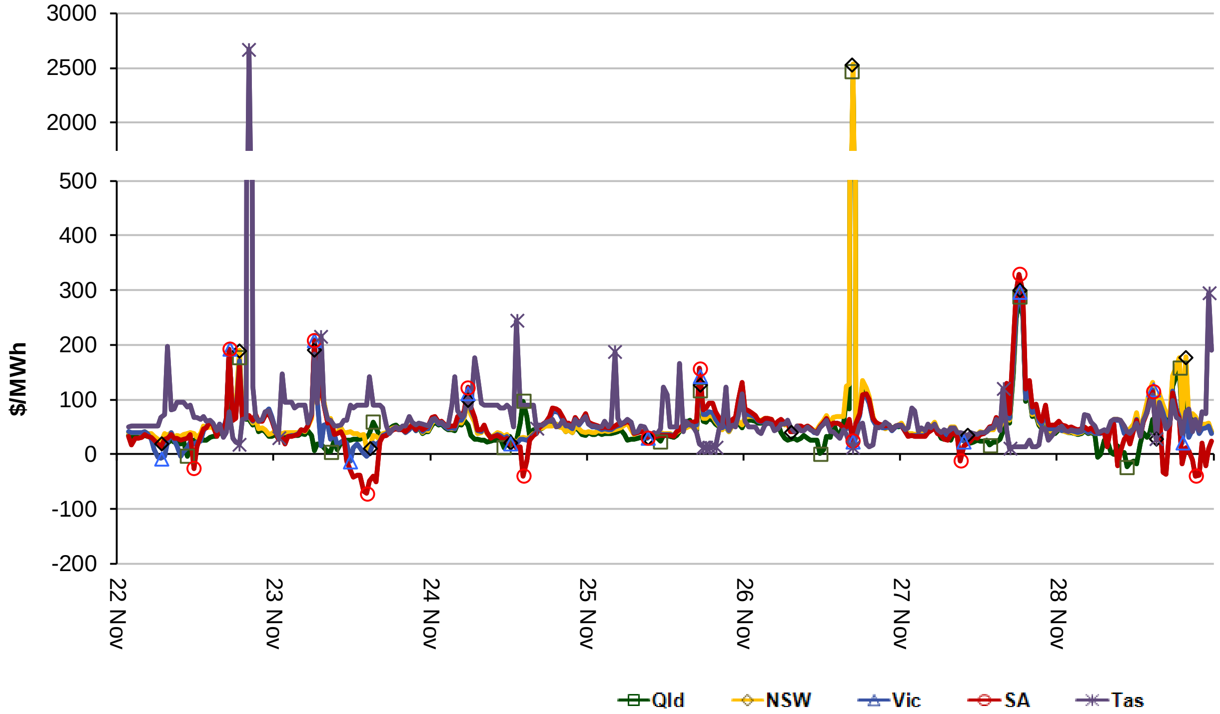


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

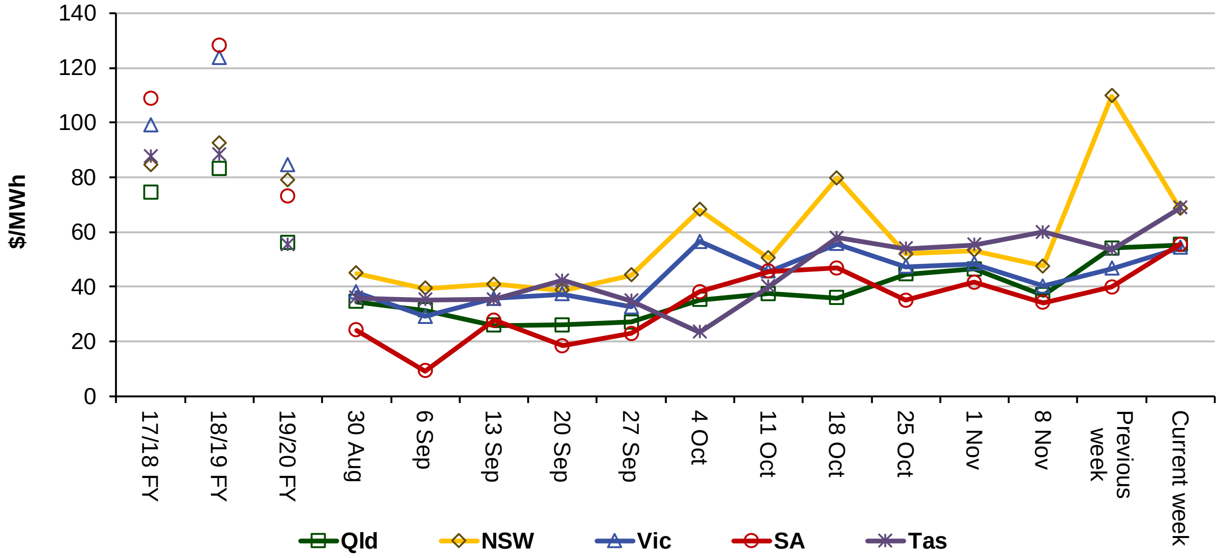


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	55	69	54	55	69
Q4 2019 (QTD)	70	88	88	65	89
Q4 2020 (QTD)	43	65	47	40	50
18-19 financial YTD	67	87	97	76	77
19-20 financial YTD	38	55	52	44	50

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 270 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2019 of 204 counts and the average in 2018 of 199. 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	26	0	1
% of total below forecast	20	38	0	13

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

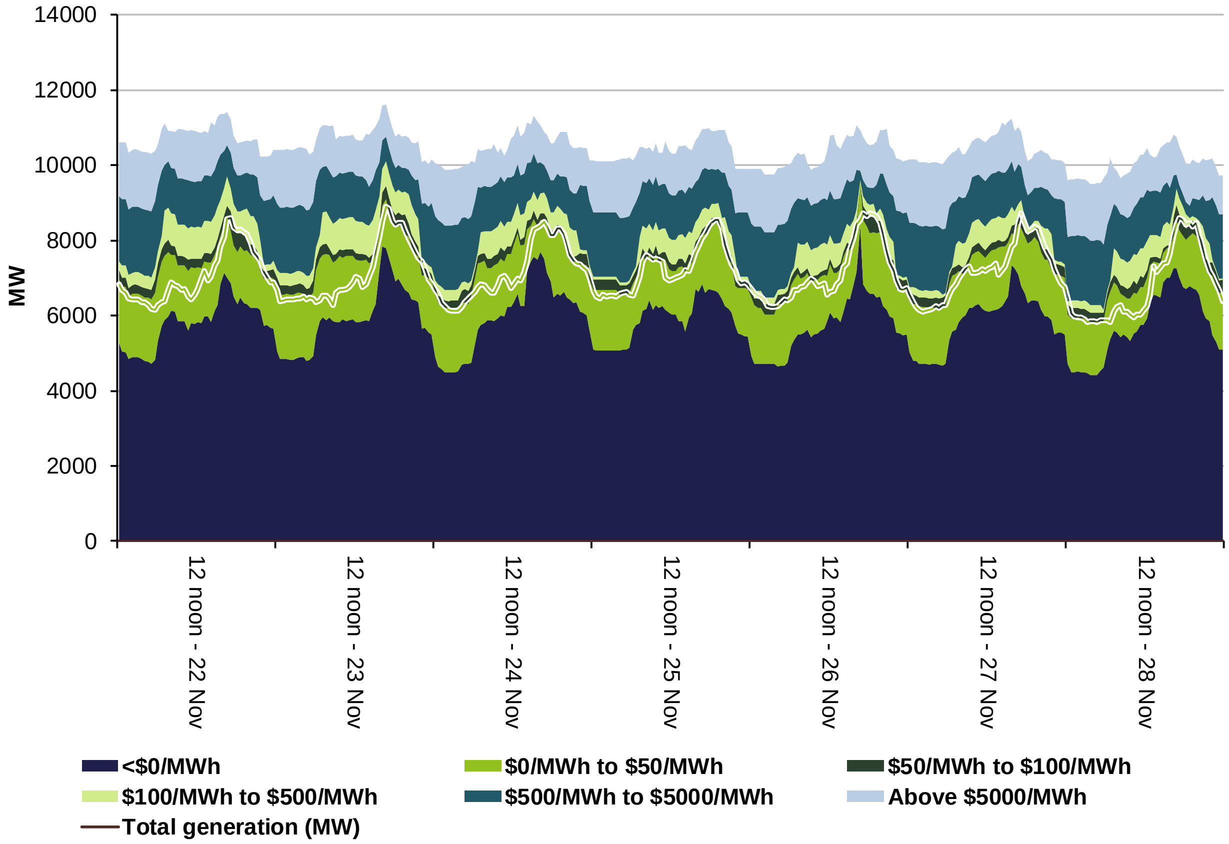


Figure 4: New South Wales generation and bidding patterns

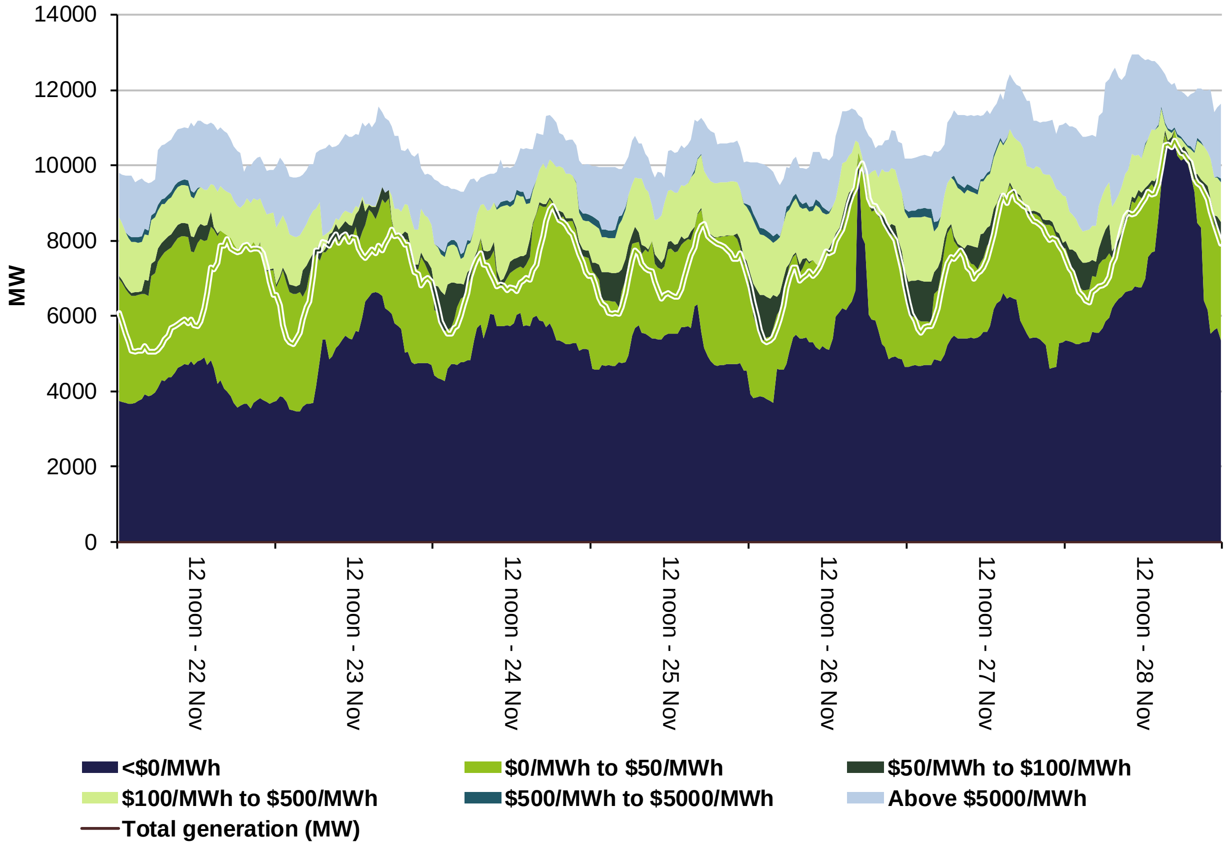


Figure 5: Victoria generation and bidding patterns

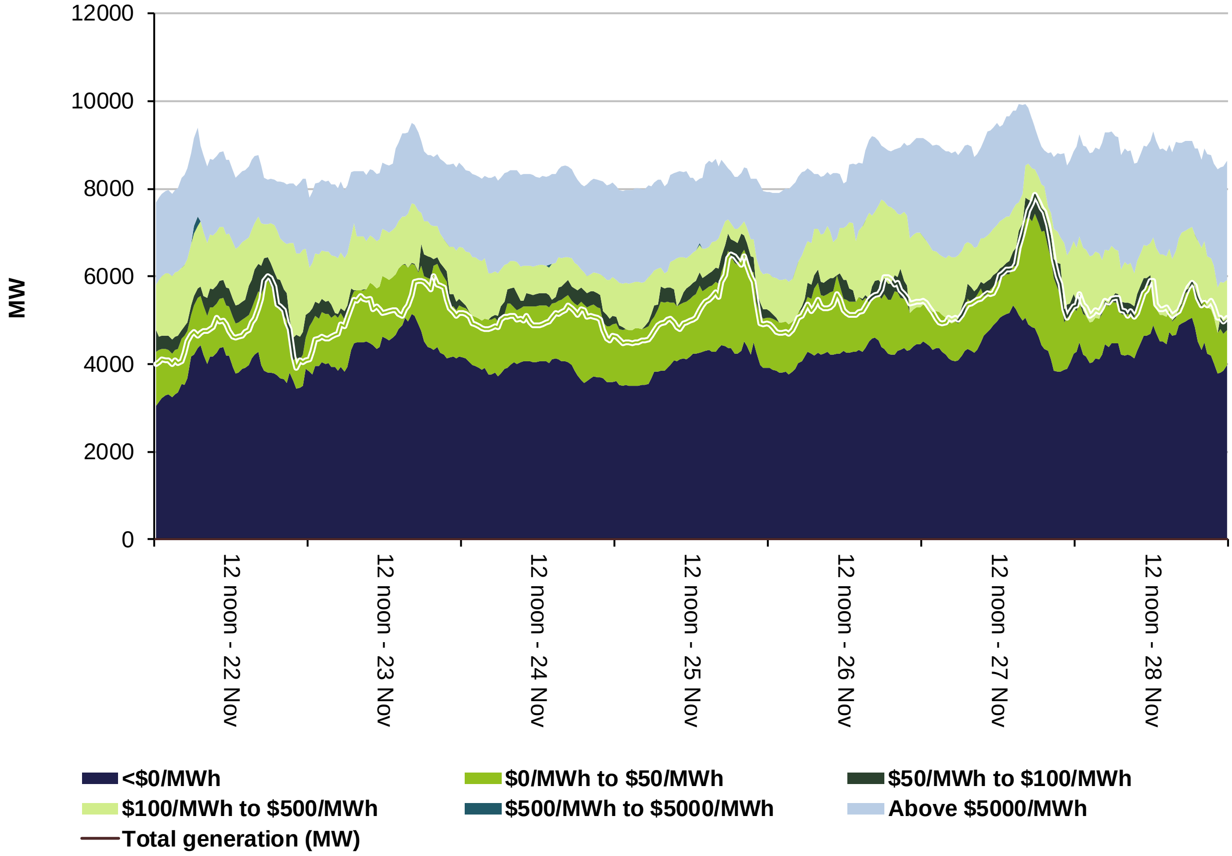


Figure 6: South Australia generation and bidding patterns

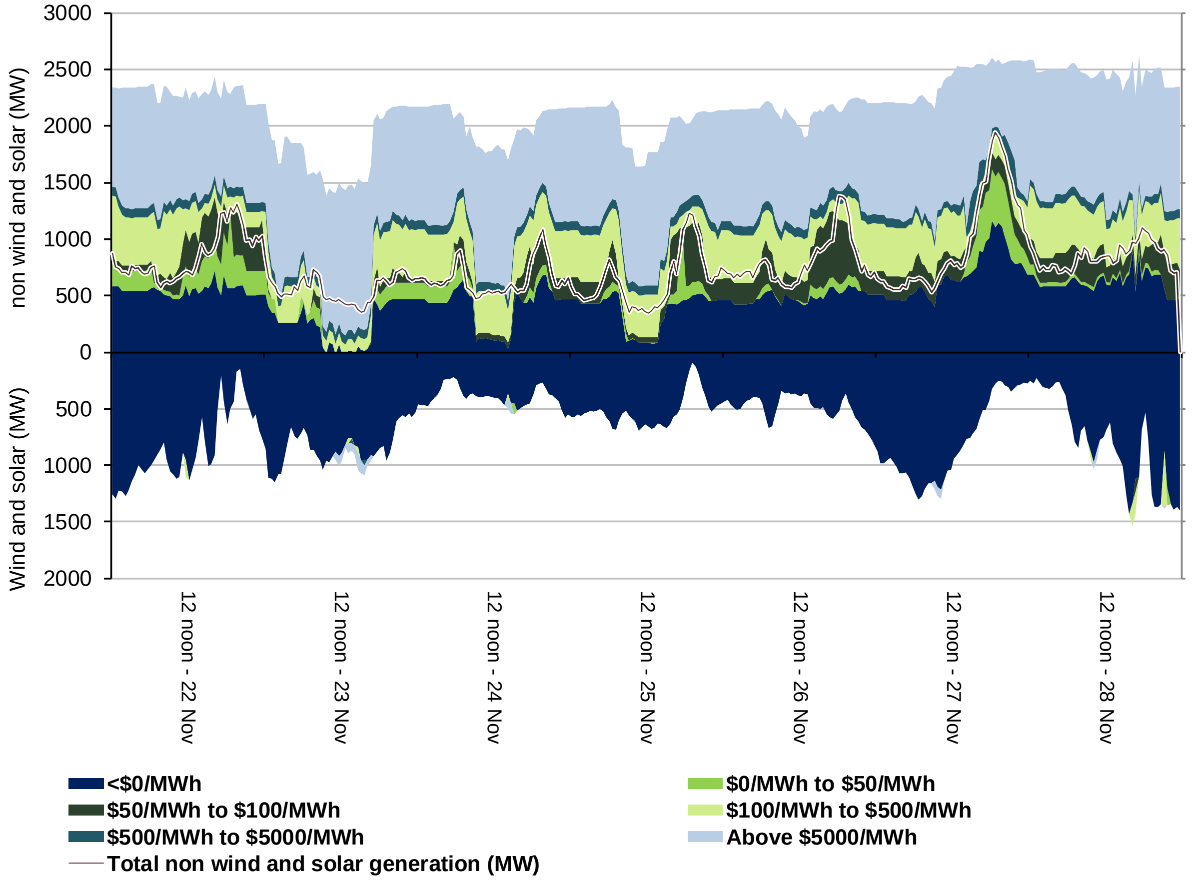
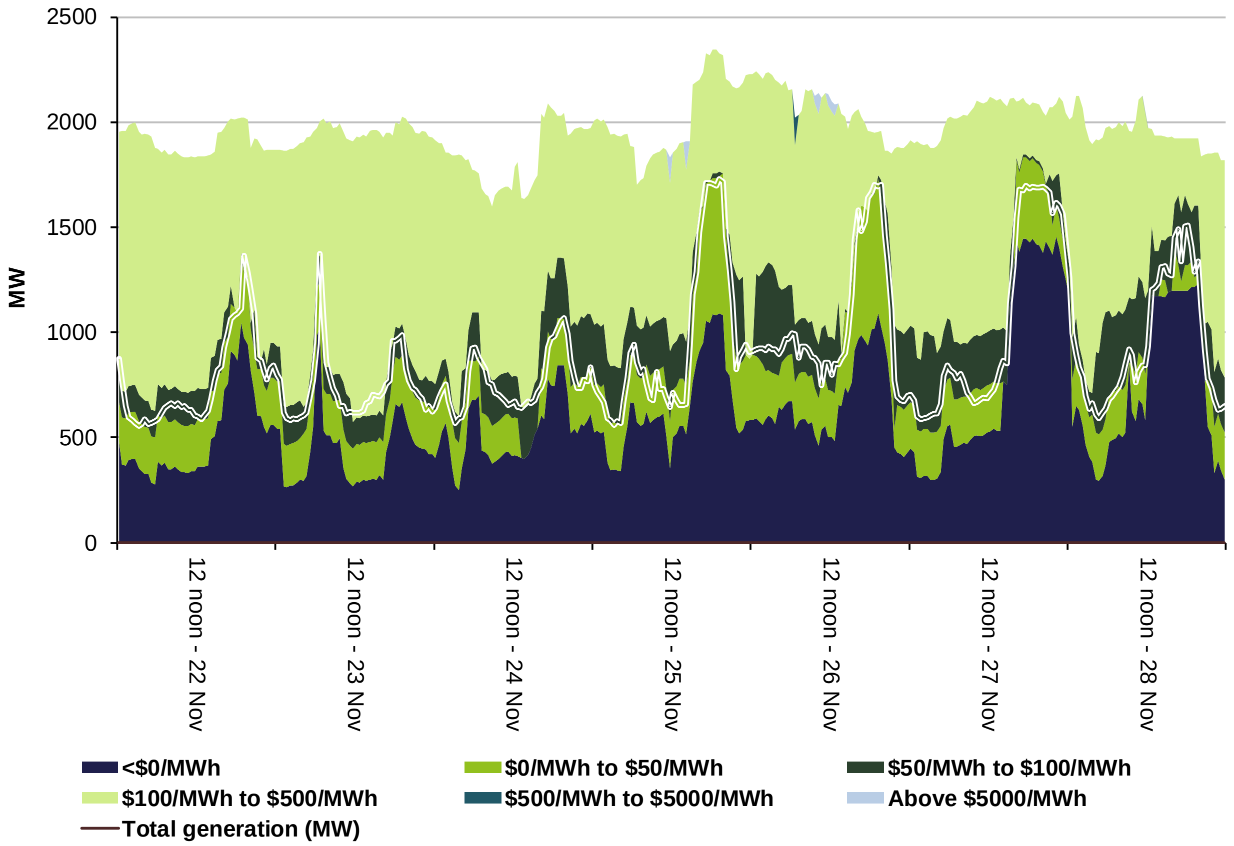


Figure 7: Tasmania generation and bidding patterns



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.

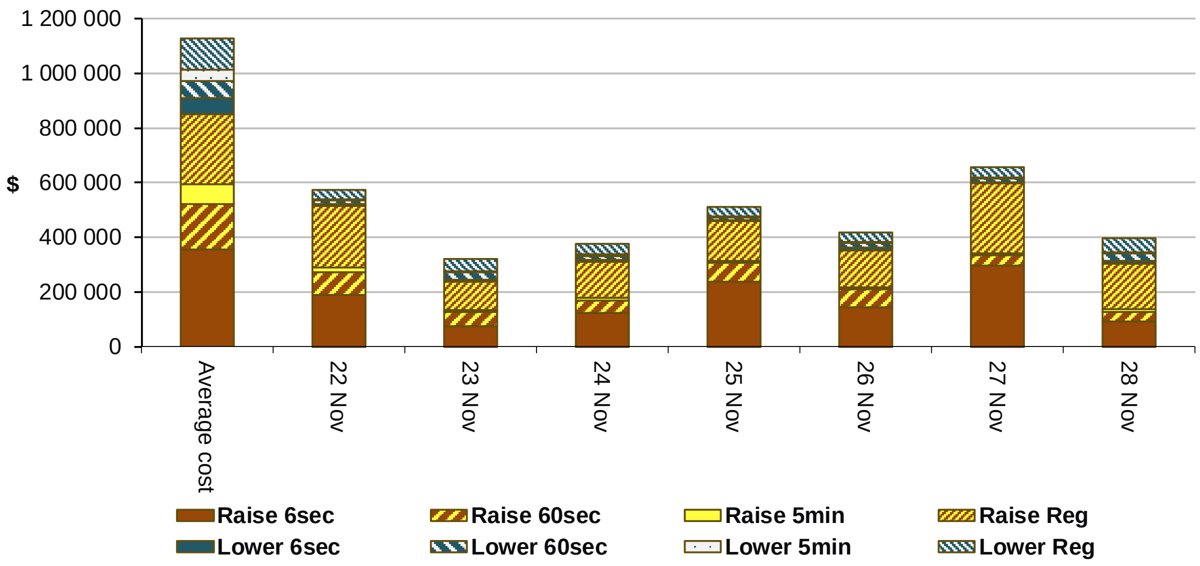
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $2,650,500 or around 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $600,500 or less than 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



Detailed market analysis of significant price events

Mainland

There were three occasions where the Mainland spot price was greater than three times the New South Wales weekly average price of $69/MWh and above $250/MWh. The New South Wales price is used as a proxy for the NEM.

Friday, 27 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
6 pm	264.05	65.19	98.2	27 580	26 971	26 722	34 277	35 064	34 713
6.30 pm	299.99	66.51	132.09	27 337	26 720	26 386	33 493	34 594	34 230
7 pm	264.96	97.88	131.08	27 007	26 382	26 140	33 363	34 158	33 967

Prices were aligned across mainland regions and will be treated as one region, though Queensland did not breach our reporting thresholds for the 6 pm trading interval. For the 6 pm to 7 pm trading intervals, demand was over 600 MW higher than forecast while availability was up to 1101 MW lower than forecast, four hours prior. Lower than forecast availability was due to lower than forecast wind generation and rebids removing or shifting capacity.

Table 4: Significant rebids

Time	Participant	Station	Amount (MW)	From ($/MWh)	To ($/MWh)	Reason
1.46 pm	InterGen	Millmerran	42	-1000	N/A	Condensate polisher inlet temperature limitation
3.11 pm	CleanCo	Swanbank E	350	-1000	N/A	Fixed load required for commissioning
3.22 pm	Infigen	SA Temporary Generator	80	-1000	N/A	Changes in forecast prices
3.34 pm	Origin Energy	Eraring	>100	<35	15,000	Plant reasons
3.52 pm	AGL Energy	Torrens Island	50	0	11,449	Changes in forecasting
4 pm	KSF Project Nominees	Kiamal Solar Farm	150	-1000	15,000	Technical reasons
4.01 pm	Callide Power Trading	Callide C	406	<27	N/A	Unit trip
4.12 pm	AGL	Bayswater	150	<50	N/A	Technical issues
4.30 pm	AGL	Liddell	70	<0	N/A	Technical issues
5.40 pm	Origin Energy	Darling Downs Power Station	33	<31	N/A	Ambient conditions

Due to the combination of higher than forecast demand and lower than forecast availability, prices were above forecast for each trading interval.

Queensland

There was one occasion where the spot price in Queensland was greater than three times the Queensland weekly average price of $55/MWh and above $250/MWh.

Thursday, 26 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	2467.39	67	64.35	7940	7660	7652	10 976	10 826	10 831

Prices were aligned across Queensland and New South Wales and will be treated as one region.

Demand was collectively 937 MW higher than forecast and availability was 261 MW higher than forecast, four hours prior. Higher than forecast availability was due to higher than forecast solar and wind generation, most priced below $0/MWh and participants adding over 350 MW of capacity across various price bands due to either plant reasons or changes in forecasting.

At 4.45 pm, an unplanned constraint on the Victoria-NSW interconnector reduced flows into NSW by over 490 MW, limiting availability of low-priced generation from Victoria. Additionally, demand increased by over 150 MW while available capacity fell by over 220 MW, partially driven by a unit trip at Braemer unit 3 which removed 110 MW from the price floor. With several generators start-up constrained and unable to set price, prices reached over $14,600/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 $69/MWh and above $250/MWh.

Thursday, 26 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	2533.74	70.13	67.90	10 785	10 128	9897	11 298	11 187	11 335

Prices were aligned across Queensland and New South Wales and will be treated as one region. See Queensland section for analysis.

Tasmania

There were two occasions where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $69/MWh and above $250/MWh.

Sunday, 22 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
8.30 pm	2671.93	72.54	74.68	1054	1128	1135	1893	1940	1948

Demand and availability were close to forecast four hours prior. FCAS constraints relating to potential generator losses in Tasmania violated at the start of the trading interval. This saw energy and FCAS markets co-optimise, resulting in prices reaching the price cap for one dispatch interval.

Saturday, 28 November

Table 8: Price, Demand and Availability

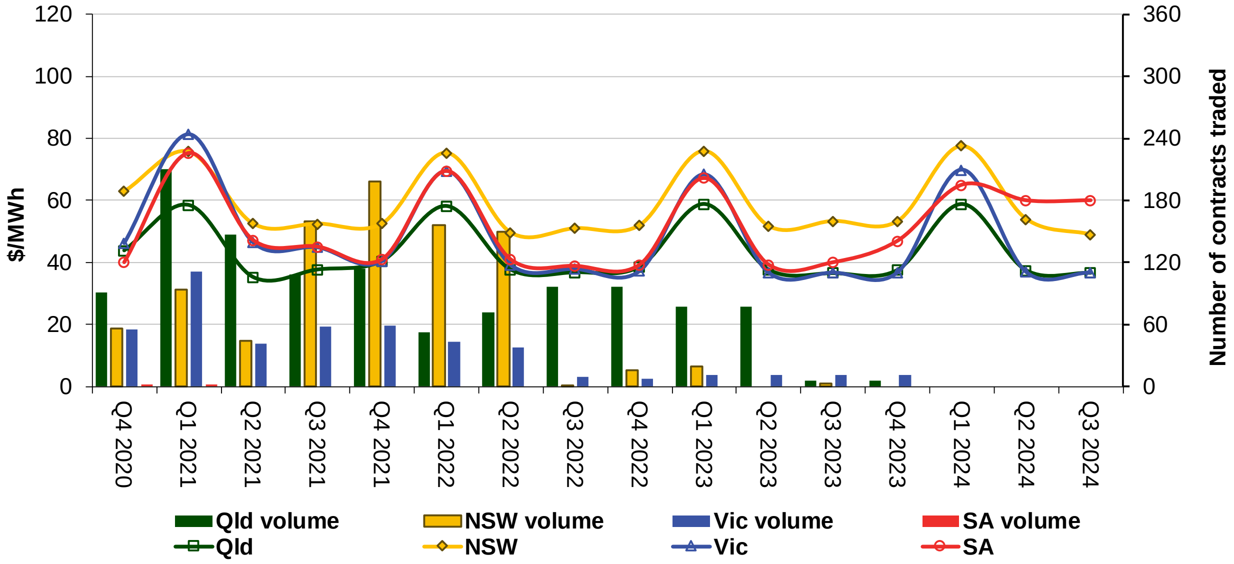
Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
11.30 pm	294.47	63.15	65.36	1035	1029	1046	1818	1818	1842

Demand was close to forecast and availability was as forecast, four hours prior. Rebids from 8.47 pm onwards by HydroTas at John Butters, Liap, Cata, Waya and Tungatinah shifted over 200 MW from below -$1/MWh to $399/MWh due to changes in forecast prices. The start of the trading interval saw prices close to forecast, however with no capacity between $85/MWh and $399/MWh, small changes in demand or availability could result in large fluctuations in price. At 11.15 pm, a small decrease in availability saw prices rise to $399/MWh where they remained for the rest of the trading interval.

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 Q4 2020 – Q3 2024

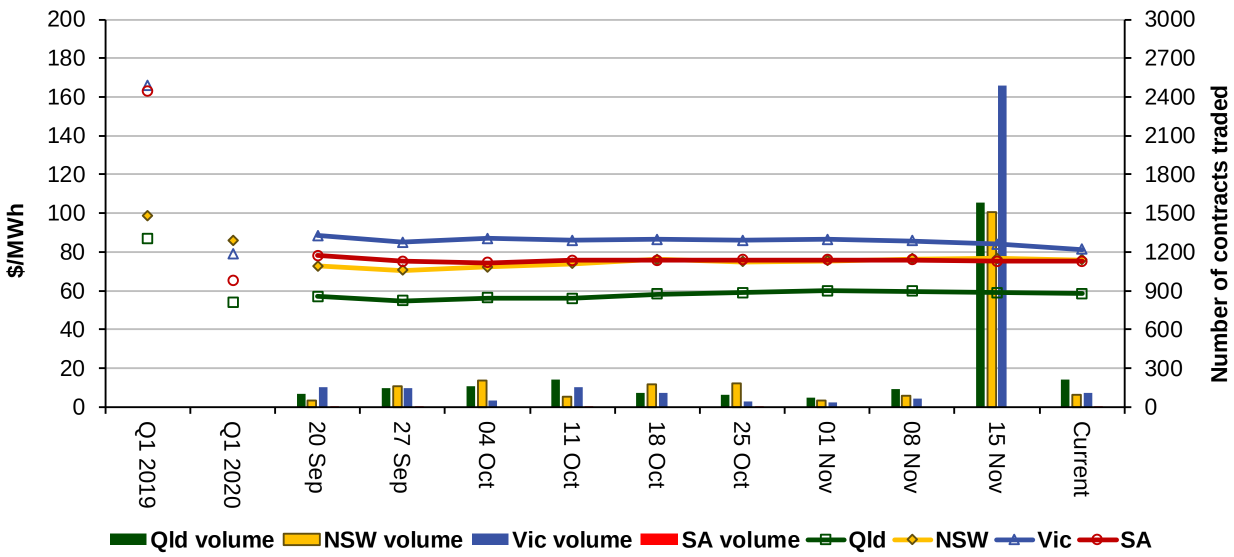


Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional Q1 2021 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing Q1 2020 and Q 1 2019 prices are also shown. The AER notes that data for South Australia is less reliable due to very low numbers of trades.

The high volume of trades in Figure 10 is a result of the conversion of base load options to base future contracts on 19 November 2020.

Figure 10: Price of Q1 2021 base contracts over the past 10 weeks (and the past 2 years)

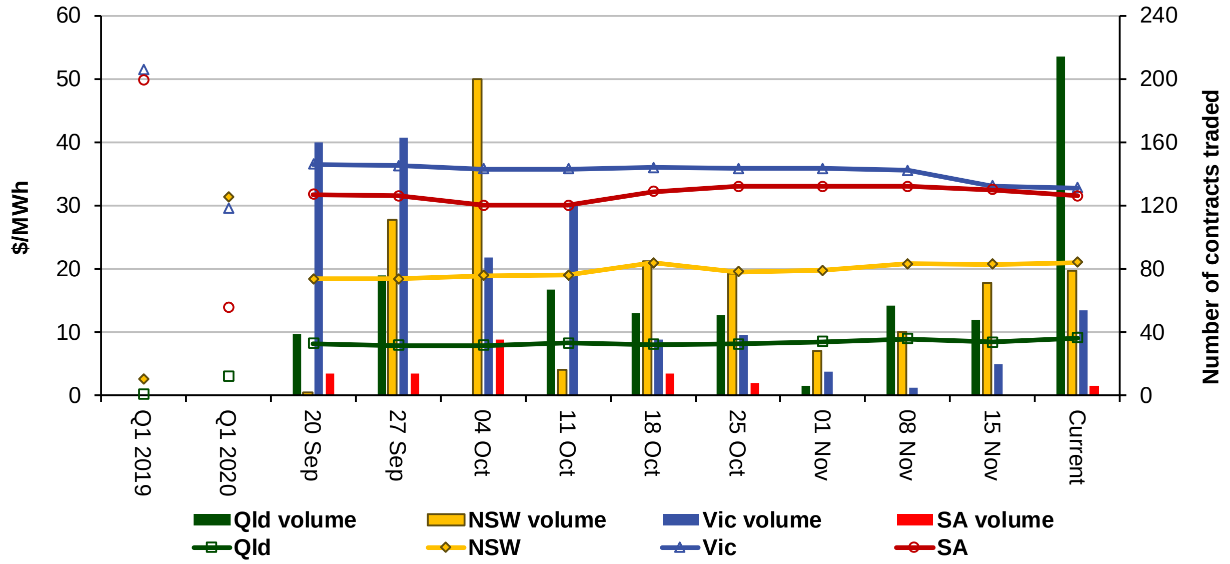


Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

Source. ASXEnergy.com.au

Figure 11 shows how the price for each regional Q1 2021 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing Q1 2020 and Q1 2019 prices are also shown.

Figure 11: Price of Q1 2021 cap contracts over the past 10 weeks (and the past 2 years)



Source. ASXEnergy.com.au

Prices of other financial products (including longer-term price trends) are available in the [Industry Statistics](#) section of our website.

Australian Energy Regulator
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