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AUSTRALIAN ENERGY REGULATOR

Significant electricity prices

April to June 2026

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1 Obligation

The Australian Energy Regulator (AER) has an obligation under the National Electricity Rules (Rules) to monitor and report on significant price outcomes in the National Electricity Market (NEM).[1] The AER is also required to publish a Significant Price Reporting Guideline (guideline) outlining its approach for monitoring and reporting significant price outcomes under Rule 3.13.7.[2]

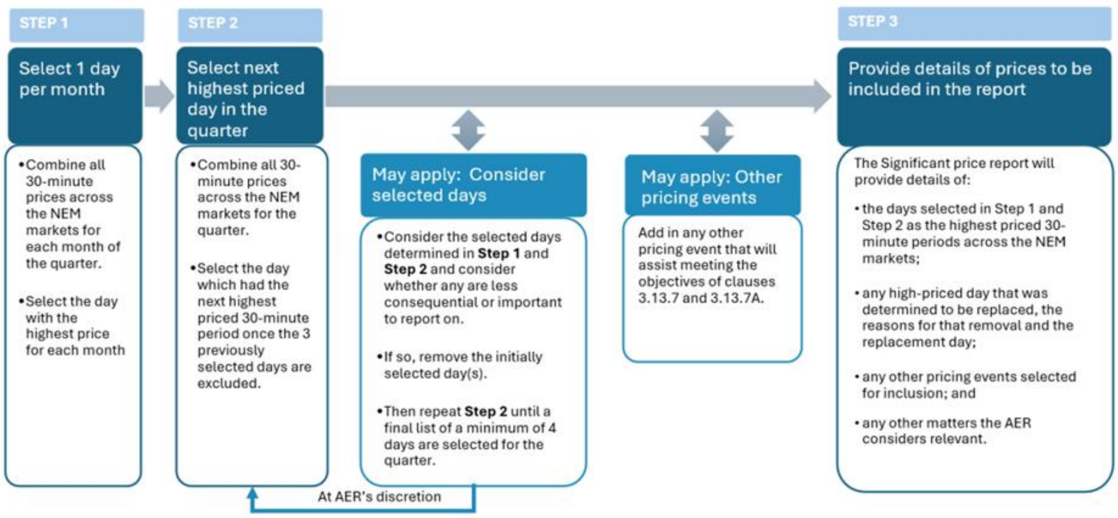
The guideline was updated in January 2026 with revised criteria for identifying significant price outcomes. Rather than applying a fixed price threshold, the AER now uses a principles-based approach to decide which outcomes to report on.[3] This approach involves:

1. identifying one day each month when the maximum 30-minute price in the NEM across all regions is highest and the next highest priced day in the calendar quarter;
2. considering whether other price outcomes in the quarter have more significance than the outcomes identified in Step 1; and
3. determining whether any other matter or pricing event should be reported because it would assist the AER to meet the objectives of clauses 3.13.7 and 3.13.7A of the Rules.

As a result of applying this methodology, a minimum of four days will be reported on as significant price outcomes each quarter.

In circumstances where the AER chooses other days than the highest for each month, and the next highest for the quarter to report on, the AER will provide reasons for the price outcomes it selects, and it will also include a table of all prices considered in the selection process.

Figure 1 Process to determine Significant price outcomes



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1 The AER also analyses trends in prices and other market events through our annual wholesale markets report, available from www.aer.gov.au/wholesale-markets/performance-reporting.

2 AER, Significant price reporting guidelines, Australian Energy Regulator, 2026, accessed 3 August 2026.

3 The 2025 review of the Significant price reporting guidelines identified $5,000 per MWh threshold as no longer fit for purpose. AER, 2025 review of the significant price reporting guidelines, Australian Energy Regulator, 2026, accessed 3 August 2026.

2 Summary

Significant price outcomes in the NEM during April to June 2026 were identified in Queensland, Tasmania and South Australia, across both energy and Frequency Control Ancillary Service (FCAS) markets. The outcomes were driven by local market and network conditions, including the availability of local generation, rather than sustained high prices across the quarter. Overall energy and FCAS prices were lower than in the same quarter last year.

The key drivers of these significant price outcomes were:

- a planned network outage required Queensland to supply its own local FCAS and technical limitations prevented some low-priced battery capacity from being enabled on one day.
- Basslink's control system constraints and the trade-off between energy and FCAS markets in Tasmania contributed to high FCAS and energy prices across two days. Tasmanian local FCAS costs still fell materially, from $9.8 million in Q1 2026 to $3.5 million this quarter.
- cold conditions which led to high demand, low wind generation, interconnector constraints and rebidding contributing to significant energy prices in South Australia over two days in June. This added $13 per MWh to the quarterly volume-weighted average price.

Significant price outcomes

Mild winter conditions and more low to mid-priced offers from new wind, solar and battery entrants contributed to lower electricity prices in April to June 2026 (Q2 2026). Quarterly volume-weighted average prices ranged from $60 per MWh in Victoria to $95 per MWh in South Australia. This was 42% to 64% lower than the same quarter in 2025. There were also fewer 30-minute prices above $3,000 per MWh, falling from 83 in Q2 2025 to 6 this quarter.

A total of 14 days were considered for the quarter (see Appendix A for price considerations). Across the days considered, the highest 30-minute prices ranged from:

- $251 per MWh to $20,300 per MWh in energy;
- $717 per MW to $3,768 per MW in FCAS.

We selected four days, covering five events, for detailed reporting. These events occurred in both energy and FCAS markets across Queensland, Tasmania and South Australia. The selected days were not chosen on price alone. They also reflected the AER's principles-based approach, including the market conditions and operational drivers behind each outcome.

A common feature of the selected events was that interconnector limitations reduced the affected region's access to lower priced energy or FCAS capacity from elsewhere in the NEM. Queensland, Tasmania and South Australia sit at the edges of the market. When interconnector flows are limited by network outages, constraints or operating limits, these regions can become more reliant on local generation and local FCAS providers, reducing access to lower-priced generation.

For FCAS prices in Tasmania and Queensland, network constraints affected interconnectors and increased local FCAS requirement. This was also a feature of the Tasmanian outcomes reported in Q1 2026.[4] Because there were fewer significant prices overall, Tasmanian local FCAS costs fell to $3.5 million this quarter, down from $9.8 million in Q1 2026. Queensland local FCAS costs were $3.2 million this quarter, up from $2 million in Q1 2026.

In South Australia, network constraints limited transfers across the Heywood interconnector and reduced access to lower-priced capacity from Victoria. At the same time, very low output from wind generators combined with a cascading reduction in the state of charge of batteries in South Australia, resulted in a number of high prices across the 2 days.

Rebidding contributed to the high prices across three days. In these events, participants withdrew low-priced capacity or shifted capacity from lower price bands to higher price bands for technical reasons and commercial reasons. This included batteries removing capacity as the state of charge of the units decreased and gas peakers shifting capacity to higher prices due to changes in forecasts from the Australian Energy Market Operator (AEMO). At times, very low amounts of high price capacity were needed, and as a result, small rebids by participants contributed to the high prices.

These rebids affected the availability of lower-priced capacity at the time it was needed, contributing to the dispatch of higher-priced offers. Further detail on the relevant rebids is provided in Appendix B to Appendix E.

The key drivers for each selected significant price day are detailed below (Table 1).

- **20 April in Queensland**: A planned line network outage created a risk of Queensland becoming electrically islanded, so Queensland had to supply its own FCAS. Low-priced capacity from batteries became unavailable due to technical limitations, causing a need for high-priced capacity. Minor rebidding also contributed to the high prices. Detailed analysis is in section 3.1.
- **31 May in Tasmania**: Basslink control system constraints meant Tasmania had to provide its own FCAS. Some units were unable to provide their offered FCAS due to constraints. AEMO’s dispatch engine optimised the FCAS and energy markets, to determine the least cost outcome. Detailed analysis is in section 3.2.
- **21 June in Tasmania**: High energy and FCAS prices were set by the trade-off between the FCAS and energy markets, system normal constraints (which included an emergency control scheme to address frequency) and network limitations. These conditions limited the availability of low-priced capacity. A minor rebid also contributed to the high prices. Detailed analysis is in section 3.3.
- **21 and 22 June in South Australia**: Cold weather drove high demand at the same time as significantly low wind and interconnector constraints limited the region’s access to low-priced capacity. Some rebidding contributed to the high prices, including batteries removing capacity as the state of charge of the units decreased and gas peakers shifting capacity to higher prices. Detailed analysis is in section 3.4.

4 AER, Significant price report - January to March 2026, Australian Energy Regulator, 2026, accessed 3 August 2026.

Table 1 Summary of high price drivers

Date	30-minute price (Energy $/MWh, FCAS $/MW)	High prices forecast	Network limitation	High demand or requirement	Low wind	Rebidding
20 April, Qld (FCAS)	$2,634	×	✓	✓	×	✓
31 May, Tas (FCAS)	$834	×	✓	×	×	×
21 June, Tas (Energy & FCAS)	$3,596 (Energy) $3,538 - $3,568 (FCAS)	×	✓	×	✓	✓
21 & 22 June, SA (Energy)	$3,836 - $20,300	✓	✓	✓	✓	✓

Source: AER analysis using NEM data.

Significant price outcomes for July to September will be covered in Q3 2026 Significant price report.

3 Four significant price days in the quarter

3.1 FCAS price on 20 April, Queensland

While the price on 20 April was not the highest for April across the NEM, this day was selected for the following reasons:

- This was the highest 30-minute FCAS price in Queensland in the quarter; and
- This was the first opportunity to write about the Lower 1 second FCAS market (L1 sec) in the Queensland region in our Significant Price Report.[5]

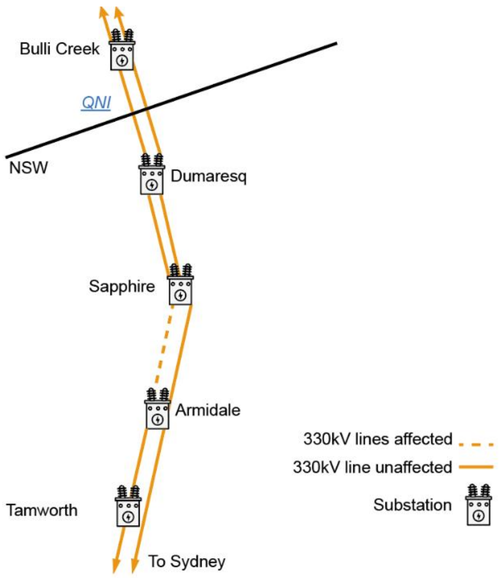
In Queensland, the L1 sec price reached $2,634 per MW for the 30-minute period ending 5.30 pm on 20 April. This was driven by a single 5-minute price of $15,800 per MW at 5.30 pm. All other 5-minute prices in the 30-minute period were below $1.84 per MW. The high 30-minute price at 5.30 pm was not forecast.

3.1.1 A planned network outage drove L1 sec requirement in Queensland

FCAS helps maintain power system frequency within the required operating standards.[6] Queensland is connected by two interconnectors, QNI and Terranora. Of these, only QNI can transfer FCAS.

From 14 to 24 April, a planned outage of the Armidale - Sapphire line south of QNI (Diagram 1) created a credible risk that Queensland could be synchronously separated from the NEM. Constraints managing the outage meant Queensland had to supply its own FCAS.

Diagram 1 Planned outage of the Armidale - Sapphire line



Source: AER analysis using NEM data.

5 The AER first reported on the L1 sec high prices that occurred in South Australia in the Electricity prices above $5,000 per MWh report – July to September 2025.

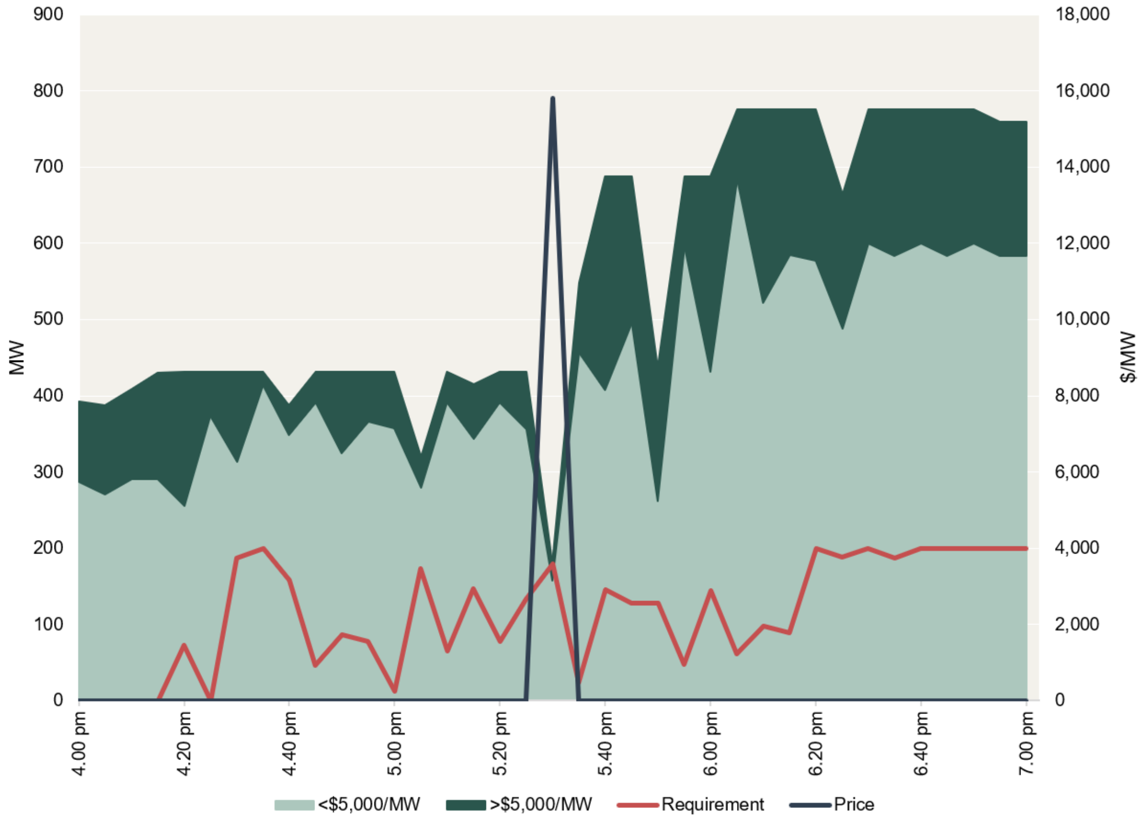
6 AEMO, Market ancillary services specification and FCAS verification tool, Australian Energy Market Operator, 2024, accessed 3 August 2026.

During the evening on 20 April, the L1 sec requirement increased to 200 MW and was 180 MW during the high-priced interval. At 5.30 pm, there was insufficient effective capacity (Box 1) below $5,000 per MW to meet the requirement, so 23 MW of high-priced capacity was needed. In the dispatch intervals immediately before and after 5.30 pm, there was enough low-priced capacity so more expensive capacity was not needed (Figure 2).

Box 1 Effective Capacity

Effective capacity is the amount of capacity that is available after accounting for technical limits, wind and solar forecasts, how long it takes a generator to increase or decrease generation, constraints and other operating conditions.

Figure 2 Effective capacity above and below $5,000 per MW, 20 April 2026



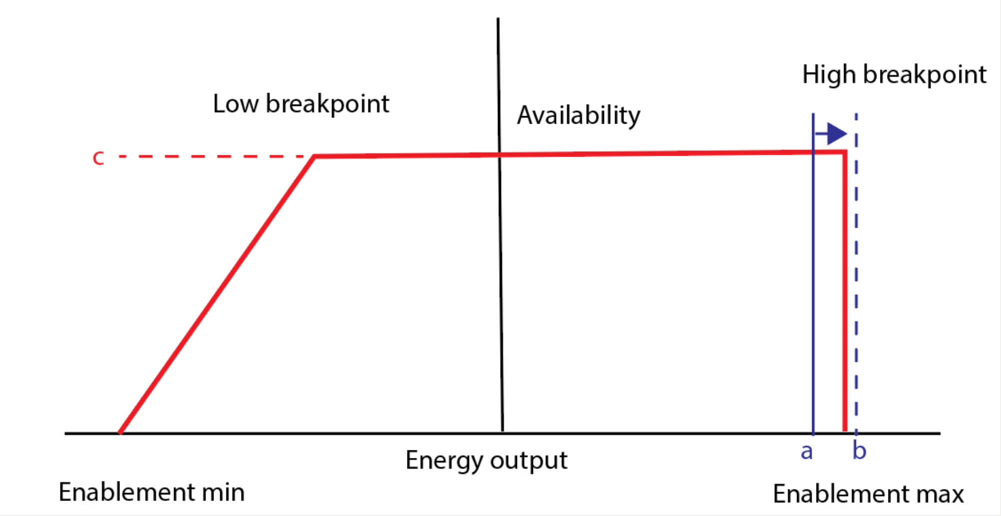
Source: AER analysis using NEM data.
Note: Capacity available below $5,000 per MW refers to effective capacity.

3.1.2 Some units were unable to provide their offered FCAS

At 5.30 pm, two units were generating too much in energy and could not be enabled in L1 sec which made 234 MW of low-priced FCAS capacity unavailable. This meant 23 MW of high-priced capacity was needed to meet the 180 MW requirement.

Neoen's Western Downs Battery offered 122 MW of low-priced L1 sec capacity for 5.30 pm but it could not be enabled to provide this as it was dispatching 255.57 MW into the energy market. This meant that the unit was 0.57 MW beyond its L1 sec enablement maximum which was set at 255 MW for this dispatch interval (Box 2). Because this exceeded its maximum enablement point of 255 MW, this placed the unit outside its trapezium, which sets the technical limits of what the maximum amount of FCAS in megawatts the unit is permitted to provide into the FCAS market. As a result, the unit was technically unable to provide L1 sec services.

Box 2 FCAS Trapezium of Western Downs Battery



The FCAS trapezium is a visual representation of a unit's technical limitations for providing generation and FCAS. The degree to which a participant is dispatched in the energy market impacts the amount of FCAS it can provide. If a participant is generating energy past its maximum enablement point, then it cannot provide FCAS, despite its offers, its 'effective' availability for FCAS is 0 MW.

a = 252.27 MW: the battery's energy dispatch at 5.25 pm, which was not a significant price. This was below the 255 MW maximum enablement point, so the battery remained within its FCAS operating range.

b = 255.57 MW: the battery's energy dispatch at 5.30 pm. This was 0.57 MW above the 255 MW maximum enablement point, so the battery moved outside its FCAS operating range and could not be enabled for L1 sec.

c = 140 MW: the max availability for L1 sec, of which 122 MW was low-priced.

At 5.23 pm, Akaysha Energy's Brendale Battery offered 112 MW of low-priced L1 sec capacity for 5.30 pm but could not be enabled to provide this as it was dispatching energy (205.22 MW) at a level greater than their L1 sec enablement maximum. This exceeded its maximum enablement point of 205 MW, placing the unit outside its trapezium. As a result, the unit was technically unable to provide capacity into the FCAS market.

A unit's technical limitations for providing generation and FCAS differ from the energy and FCAS trade-off discussed later (Box 5), where AEMO's dispatch engine simultaneously optimises the FCAS and energy markets.

3.1.3 Rebidding contributed to the high price

Rebidding for technical and commercial reasons contributed to the high price at 5.30 pm (Appendix B).

Between 2.58 pm and 5.23 pm, AGL Energy moved a net total of 23 MW at its Wandoan Battery from low-price to $15,800 per MW. These rebids were based on the battery's change in capability for the 5.30 pm 5-minute interval.

This high-priced capacity was ultimately needed to meet the last 23 MW required for the 5.30 pm dispatch interval, which meant this unit set the price for this interval.

3.1.4 Impact on quarterly price and FCAS costs

This event contributed $237,000 to the $468,954 in L1 sec costs in Queensland across April to June.

3.2 FCAS price on 31 May, Tasmania

The day selected for analysis in May was 31 May. The local Raise 6 second (R6 sec) 30-minute price in Tasmania was $834 per MW at 7 pm, which was the highest 30-minute price in the month.

During the 7 pm 30-minute period, there was one 5-minute price of $4,955 per MW at 6.55 pm. All other 5-minute prices for this 30-minute period were under $25 per MW. The high price was not forecast.

The high price occurred because Basslink was unable to transfer FCAS which meant Tasmania had to provide its own. Constraints in the region limited the amount of offered FCAS capacity that was effectively available. AEMO's dispatch engine optimised the FCAS and energy markets, to determine the least cost outcome.

Although enough capacity was offered below $5,000 per MW, only about 58% of that capacity was effectively available once constraints were applied.

3.2.1 Basslink's "No-Go" zone and high local FCAS requirements

At 6.55 pm on this day, the metered flow on Basslink was 0 MW. This meant Basslink was in its "No-Go" zone (Box 3) and unable to transfer FCAS. A system normal constraint that was in place to cover the potential loss of the largest generator, at the time, bound and caused the requirement for R6 sec services to be set at 143 MW.

Box 3 Basslink's "No-Go" zone

Basslink has an operational "No-Go" zone (a restricted power transfer band typically between **+50 MW and -50 MW**, excluding absolute zero flow) because of its specific equipment design and control limitations when reversing power direction (i.e. from imports to exports or vice versa). This differs from some other interconnectors such as Murraylink and Terranora which use different converter configurations or operating parameters. This design feature prevents Basslink from transferring FCAS to and from the rest of the NEM when flows are within the "No-Go" zone range (i.e. when flows are between approximately -50 MW and +50 MW).[7] If Basslink is unable to transfer FCAS, Tasmania has to provide its own FCAS locally.

3.2.2 Some units were unable to provide their offered FCAS

Hydro Tasmania's load unit that only provides ancillary services was restricted during the high-priced interval under the Adaptive Under Frequency Load Shedding (AUFLS) scheme (Box 4). This constraint limited the unit's low-priced capacity that was available for the R6 sec service. Around 70 MW of capacity offered at 6.55 pm was unable to be dispatched and contributed to the high prices.

7 Australian Energy Market Operator, Constraint Formulation Guidelines, AEMO, 2025, accessed 3 August 2026.

Box 4 Adaptive Under Frequency Load Shedding scheme

FCAS normally responds to address frequency deviations in the power system and ensures it stays within the operating frequency tolerance band. In rare circumstances, when non-credible contingencies occur on the network which can have material impacts on frequency deviations, the AUFLS scheme is used as an emergency mechanism to return the frequency to normal operating bands.

3.2.3 Energy & FCAS Trade-off

On this occasion at 6.55 pm, AEMO's dispatch engine determined the cheapest outcome was to back off an offer of around -$1,000 per MWh from Hydro Tasmania's Liapootah, Catagunya, Wayatinah in energy, to provide more in raise services (Box 5). This option was cheaper than dispatching the next unit in R6 sec, which had an offer of over $20,000 per MW.

Box 5 Co-optimisation and Trade-off

AEMO's dispatch engine simultaneously optimises the FCAS and energy markets, for every dispatch interval, to determine the least cost outcome. This can lead to a trade-off between the FCAS and energy markets. For example, a generator's output may be reduced in energy so that it can provide additional raise ancillary services or vice versa. This can impact prices in both the energy and FCAS markets.

3.2.4 Rebidding did not contribute to this price

There were no significant rebids in R6 sec service for this event.

3.2.5 Impact on quarterly FCAS costs

This event did not have any significant impact to the quarterly FCAS costs in Tasmania. This event contributed $58,874 to the $2 million in R6 sec service costs across April to June.

3.3 Energy and FCAS prices on 21 June, Tasmania

The fourth highest price day of the quarter occurred on 21 June. Significant prices occurred in both South Australia and Tasmania on this day. This section discusses the drivers of prices in the energy and FCAS markets in Tasmania. The prices in South Australia have been combined with 22 June in section 3.4 as they were caused by similar drivers.

In Tasmania, 30-minute prices were above $3,500 per MWh in energy and above $3,500 per MW in FCAS. The affected FCAS markets were Raise Regulation (RReg) and Raise 60 second (R60 sec) at 6 pm and R6 sec at 10 pm. Each 30-minute price was driven by a single 5-minute price spike at or near the market price cap (Table 2). All other 5-minute prices in the relevant dispatch intervals were not significant.

Table 2 Significant prices on 21 June in Tasmania

30-minute Period	30-minute Price ($/MWh or $/MW)	5-minute interval/s	5-minute Price ($/MWh or $/MW)	Market
6 pm	3,596	6 pm	20,300	Energy
6 pm	3,568	6 pm	20,300	FCAS Raise Regulation
6 pm	3,538	6 pm	20,290	FCAS Raise 60 second
10 pm	3,553	9.35 pm	20,290	FCAS Raise 6 second

Source: AER analysis using NEM data.

None of the high prices were forecast. The main drivers were the trade-off between energy and FCAS markets, system normal constraints including an emergency frequency control scheme, Basslink in the “No-Go” zone and one minor rebid.

3.3.1 Significant prices in energy, raise regulation and raise 60 second at 6 pm

Prices at 6 pm were high because the energy and FCAS markets were co-optimised and system normal constraints limited how much low-priced capacity could be dispatched, and some offered FCAS capacity was not effectively available.

3.3.1.1 Trade-off between energy and FCAS set high prices

Similar to 31 May (section 3.2.3), the trade-off between the FCAS and energy markets (Box 5) impacted prices in both the energy and FCAS markets. For energy and RReg, the 6 pm price was driven by an offer of around $20,000 per MW in FCAS R60 sec services due to price co-optimisation.

3.3.1.2 Local requirements in FCAS

FCAS helps maintain power system frequency within the required operation standards (section 3.1.1). If a region is or is at risk of being electrically islanded, then it must provide its own local FCAS.

On 21 June, system normal constraints invoked by AEMO to maintain system security caused the local FCAS requirement in Tasmania to reach up to 66 MW at 6 pm. Up to 1 MW of high-priced capacity was needed to meet these requirements.

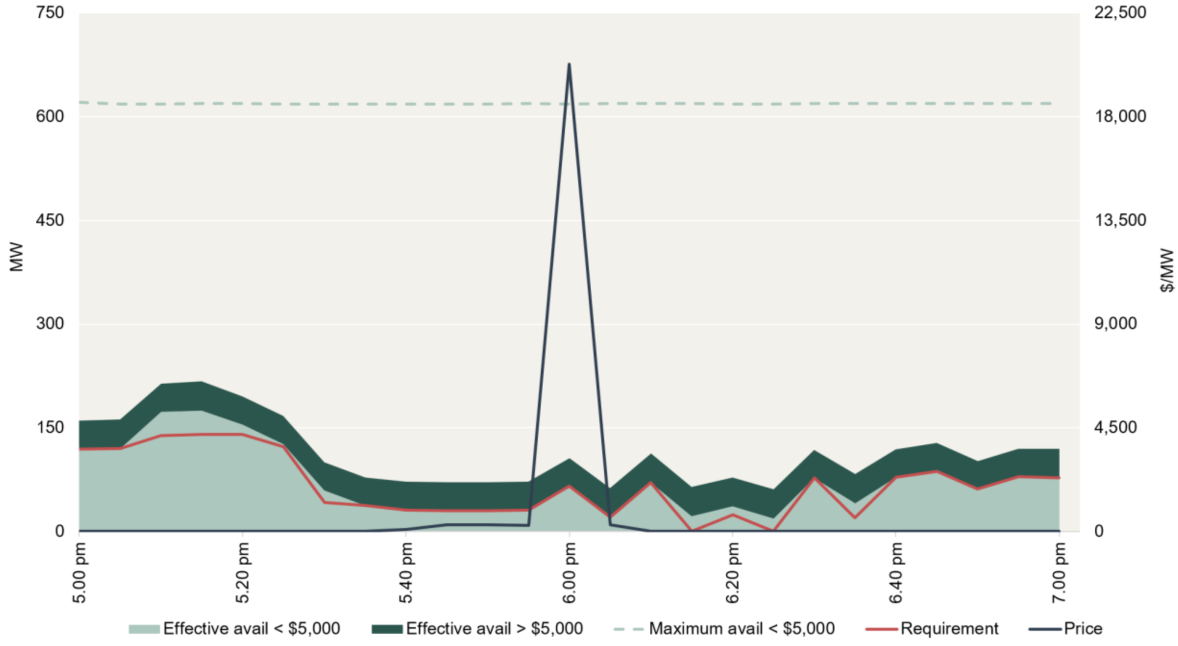
3.3.1.3 Low-priced generation unable to be dispatched at 6 pm

FCAS

Due to the trade-off between energy and FCAS markets (section 3.3.1.1), much of the capacity offered in FCAS was effectively unavailable during the high prices at 6 pm. Most units were dispatching at or near their capacity in energy and therefore could not be fully enabled in FCAS.

Though there was sufficient capacity offered below $5,000 per MW, only around 4% and 11% for the RReg and R60 sec services, respectively, was effectively available at 6 pm (Figure 3 with R60 sec as an example). As a result, high-priced capacity had to be enabled to meet the requirements in RReg and R60 sec services.

Figure 3 R60 sec capacity availability above and below $5,000 per MW, 21 June 6 pm



Source: AER analysis using NEM data.

Although Hydro Tasmania's Gordon generator offered up to 284 MW of low-priced FCAS capacity, it was generating at or near capacity in the energy market during the high-price period and therefore had no FCAS capacity effectively available (Table 3). Similarly, up to 140 MW at John Butters station could not be enabled for FCAS during the high-priced intervals, as they were dispatching mostly in energy. When FCAS requirements across RReg and R60 sec services increased to 66 MW at 6 pm, higher-priced capacity (around $20,290 per MW) was dispatched, contributing to the high FCAS prices.

Table 3 Maximum and effective availability across various units at 6 pm

Date	Participant	5-minute interval	FCAS Market	Maximum (offered) availability (MW)	Effective (actual) availability (MW)
21 June	Hydro Tasmania	6 pm	RReg	32 to 284	0 to 38
		6 pm	R60 sec	7 to 216	0 to 8

Note: Effective (actual) availability is the amount of generation a unit is able to provide after accounting for factors that limit output, such as a unit's FCAS bid trapezium or constraints on the unit.
Source: AER analysis using NEM data.

Energy

Overall, a total of 108 MW of low-priced generation was unable to be dispatched in energy at 6 pm, due to the trade-off between energy and FCAS markets (Table 4). This also impacted the effective availability of these units in FCAS (see FCAS). All else being equal, if these units were capable of dispatching all of their low-priced capacity, the high prices across energy and FCAS would likely not have occurred.

Table 4 Low-priced generation unable to be dispatched in energy at 6 pm

Date	Participant	Unit	Low-priced generation unable to dispatch (MW)*
21 June	Hydro Tasmania	Bastyan	9
	Hydro Tasmania	Cethana	46
	Hydro Tasmania	Devils Gate	9
	Hydro Tasmania	Poatina 110	40
	Hydro Tasmania	Tungatinah	4

Note: *The total MW of low-priced generation unable to be dispatched in the 5-minute interval at 6 pm.
Source: AER analysis using NEM data.

Around 65 MW of additional low-priced generation was trapped or stranded in FCAS (Box 6) and was unable to be dispatched in energy at 6 pm, mainly at Hydro Tasmania's Poatina 220 Power Station (Table 5). This also impacted the effective availability of these units in FCAS (see FCAS).

Box 6 Trapped and Stranded in FCAS

Units have limitations based on their technical ability (Box 2), when they fall outside of the limits, they are considered either trapped or stranded which impacts their generation targets.[8]

Trapped in FCAS occurs when a unit is generating at a level that intersects with its enablement min or max point in their FCAS trapezium. As a result, the unit is unable to receive an energy target that differs from the previous 5 minutes. A unit is considered stranded if it is generating at a limit above or below their FCAS trapezium and is therefore unable to provide FCAS. When a unit is trapped or stranded in FCAS, it is unable to set the price.

Table 5 Low-priced generation that was trapped or stranded in FCAS

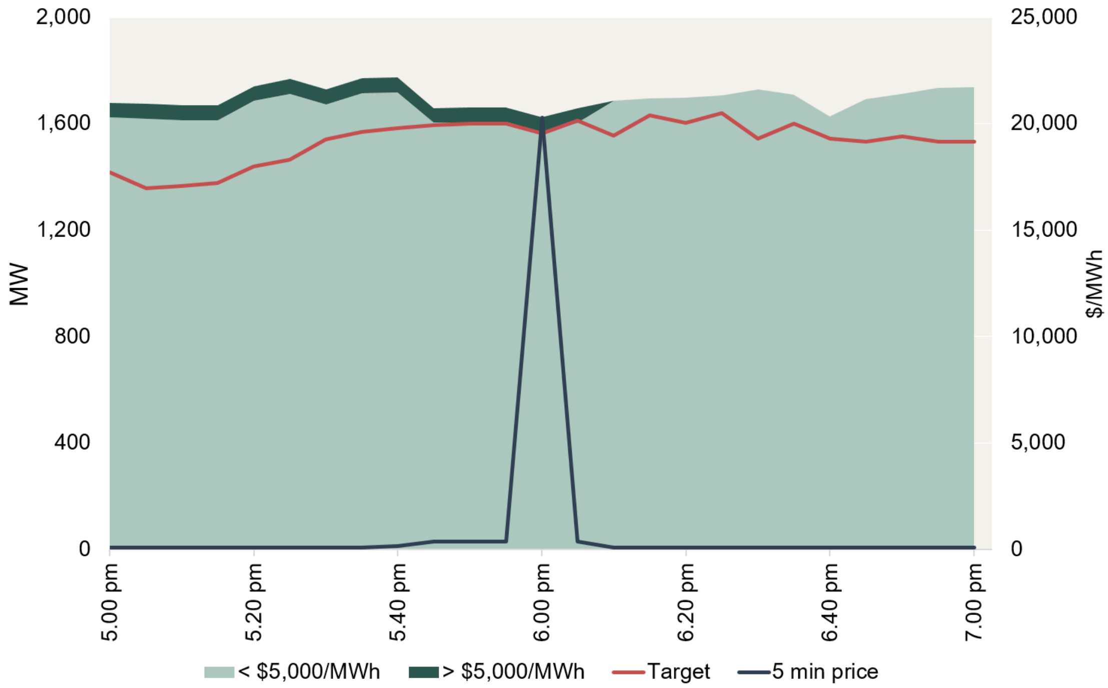
Date	Participant	Unit	Low-priced generation unable to dispatch (MW)*
21 June	Hydro Tasmania	Poatina 220	59
	Hydro Tasmania	Mackintosh	3
	Hydro Tasmania	John Butters	3

Note: *The MW of low-priced generation unable to be dispatched in the high-priced 5-minute interval at 6 pm.
Source: AER analysis using NEM data.

Though 97% of capacity in energy was offered below $5,000 per MWh, the 5-minute price in energy spiked to $20,300 per MWh at 6 pm (Figure 4).

8 Australian Energy Market Operator, FCAS Model in NEMDE – AEMO 3 June 2024, AEMO, 2024, accessed 3 August 2026.

Figure 4 Energy capacity offered above and below $5,000 per MWh, 21 June



Source: AER analysis using NEM data.
Note: Capacity available below $5,000 per MWh refers to effective capacity.

3.3.2 Significant price in R6 sec at 10 pm

Consistent with the price outcomes at 6 pm, the high price at 10 pm was a result of the trade-off between energy and FCAS markets (Box 5), limiting the low-priced capacity effectively available.

While there was sufficient capacity offered below $5,000 per MW, the capacity effectively available was limited to around 42% for R6 sec services for the 9.35 pm dispatch interval.[9] The most significant being Hydro Tasmania's Gordon generator, which offered up to 118 MW of low-priced FCAS capacity, was generating at or near capacity in the energy market during the high-price period and therefore had no FCAS capacity effectively available (Table 6). When FCAS requirements increased to 144 MW at 9.35 pm higher-priced capacity (around $20,290 per MW) was again dispatched, resulting in the high FCAS price.

Table 6 Maximum and effective availability across various units at 10 pm

Date	Participant	5-minute interval	FCAS Market	Maximum (offered) availability (MW)	Effective (actual) availability (MW)
21 June	Hydro Tasmania	9.35 pm	R6 sec	3 to 118	0 to 1

Note: Effective (actual) availability is the amount of generation a unit is able to provide after accounting for factors that limit output, such as a unit's FCAS bid trapezium or constraints on the unit.
Source: AER analysis using NEM data.

9 This also considers the capacity unavailable due to AUFLS constraint discussed below in section 3.3.3.

3.3.3 Other drivers specific to the FCAS R6 sec price at 9.35 pm

AUFLS Control Scheme contributed to high FCAS price

At the 9.35 pm interval, the requirement for FCAS reached up to 144 MW. Similar to 31 May (section 3.2.2 in May), the AUFLS control scheme (Box 4) was in place at the time and restricted Hydro Tasmania's load unit during the high-priced intervals. This constraint limited the unit's low-priced capacity that was available for the R6 sec service. Around 24 MW of low-priced capacity offered was unable to be dispatched and contributed to the high price.

Basslink's "No-Go" zone and high local FCAS requirements

From 9.35 pm, Basslink was in the "No-Go" zone (Box 3) and Tasmania had to provide its own local FCAS.[10] As a result, the local requirement for R6 sec services increased to 144 MW at 9.35 pm from 59 MW in the five minutes prior.

3.3.4 Rebidding

Though rebidding was not a main driver, removal of low-priced capacity in R60 sec services for technical reasons contributed to the high price at 6 pm on 21 June (Appendix C).

VIOTAS Australia removed 1 MW of low-priced capacity from its demand response unit, DRVIOT05, in a late rebid at 5.53 pm due to a change in plant conditions. This rebid contributed to the high price in R60 sec at 6 pm as only 1 MW of high-priced capacity was needed to meet the R60 sec requirement. DRVIOT05 also set the high price at the time.

There was no significant rebidding in the other FCAS markets.

3.3.5 Impact on quarterly prices and FCAS costs

The high prices in FCAS had a significant impact on the quarterly FCAS costs in Tasmania (Table 7).

Table 7 Contribution of FCAS costs to the total cost for the quarter

Time, FCAS Market	Contribution ($ and % of total cost)	Total cost for the quarter ($)
6 pm, RReg	84,583 (13%)	653,557
6 pm, R60 sec	111,484 (51%)	217,677
9.35 pm, R6 sec	244,003 (12%)	1,952,508

Source: AER analysis using NEM data.

The high price in energy added $1 per MWh to the quarterly volume-weighted average energy price for Tasmania of $87 per MWh.

10 See Australian Energy Market Operator, Constraint Formulation Guidelines, AEMO, 2025, accessed 3 August 2026.

3.4 Energy prices on 21 & 22 June, South Australia

The highest priced day of June and the quarter occurred on 22 June in South Australia. As discussed in section 3.3, the next highest priced day for the quarter was on 21 June which occurred in South Australia and Tasmania. As the prices in South Australia on 21 June had similar drivers to 22 June, we have combined the two days together in this section.

Across 21 and 22 June, the 30-minute price for energy exceeded $3,000 per MWh on five occasions. The 30-minute prices ranged from $3,836 per MWh to $20,300 per MWh (Table 8).

Table 8 Significant prices on 21 and 22 June in South Australia

Date	Time	Price ($/MWh)
21 June	8 pm	8,689
	8.30 pm	4,323
22 June	7.30 am	12,713
	8 am	20,300
	8.30 am	3,836

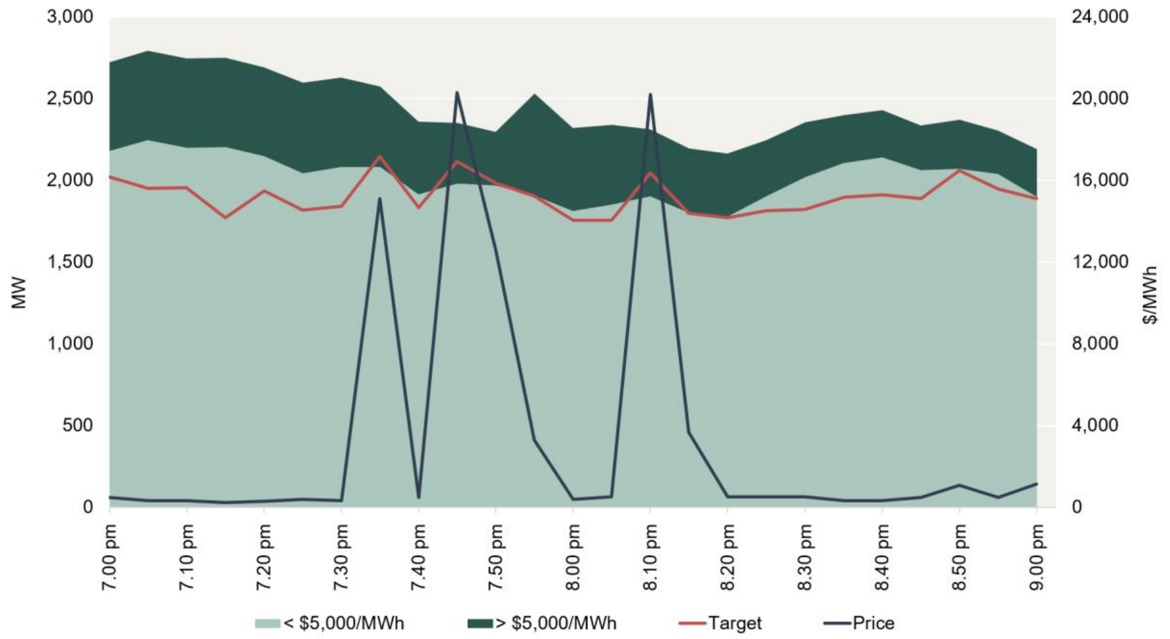
The high prices on 21 June were not forecast. The high prices on 22 June were forecast in the hour before they occurred. Reserve shortfalls were indicated in Pre-Dispatch Projected Assessment of System Adequacy (PDPASA) but AEMO considered the condition would be transient and did not declare forecast reserve conditions.[11] [12] No actual reserve shortfalls occurred during these periods.

Across both days, high prices occurred when high demand coincided with low wind generation and network limitations that reduced South Australia's access to lower-priced imports. Additionally, batteries removed capacity in the lead up to the high prices as they ran out of charge. These conditions increased reliance on higher-priced local generation, with capacity offered above $5,000 per MWh required to meet demand during the highest-priced dispatch intervals (Figure 5 and Figure 6).

11 AEMO, AEMO Electricity Market Notice 144305, Australian Energy Market Operator, 2026, accessed 3 August 2026

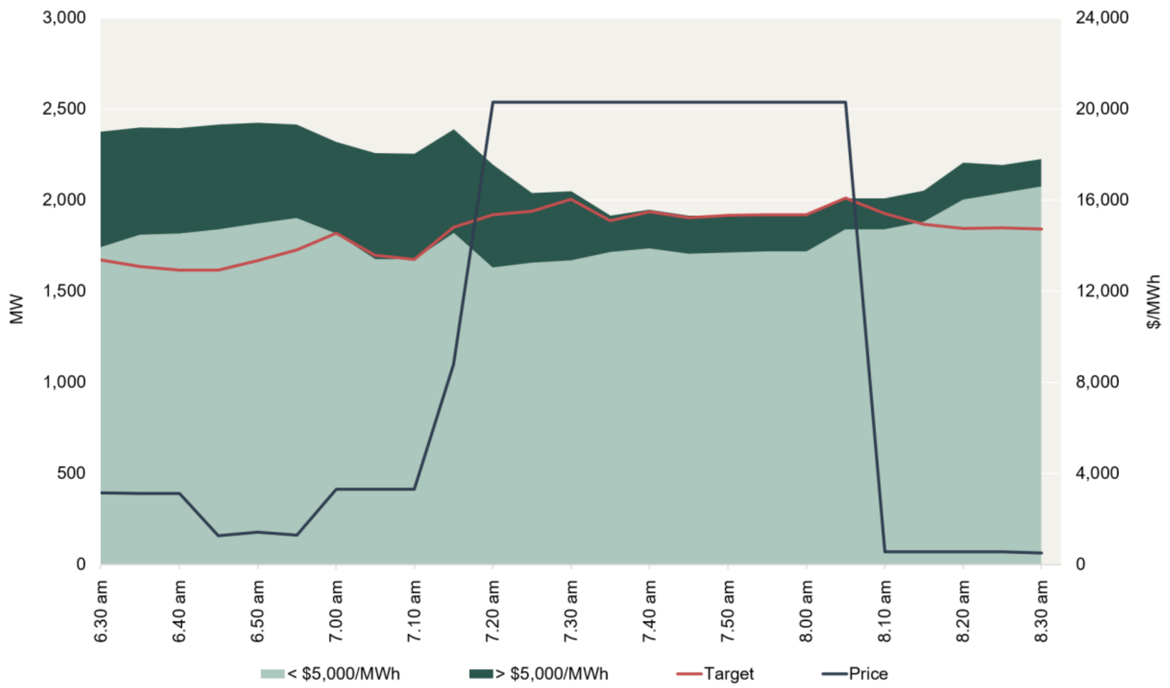
12 AEMO, AEMO Electricity Market Notice 144315, Australian Energy Market Operator, 2026, accessed 3 August 2026

Figure 5 Capacity offered above and below $5,000 per MWh, 21 June



Source: AER analysis using NEM data.
Note: Capacity available below $5,000 per MWh refers to effective capacity.

Figure 6 Capacity offered above and below $5,000 per MWh, 22 June



Source: AER analysis using NEM data.
Note: Capacity available below $5,000 per MWh refers to effective capacity.

3.4.1 High demand driven by cold temperatures

South Australia experienced colder temperatures ranging from 4°C to 15°C on 21 and 22 June, resulting in higher than usual electricity demand.

Across 21 and 22 June, demand was 37 MW to 429 MW above the average for the same periods in the previous week. Demand reached 2,188 MW on the morning of 22 June, equivalent to 83% of South Australia's winter record demand of 2,626 MW.

During the high-priced periods, demand was up to 64 MW above forecast and generation availability was up to 473 MW below forecast, requiring up to 335 MW of high-priced capacity to meet demand.

3.4.2 Low wind output

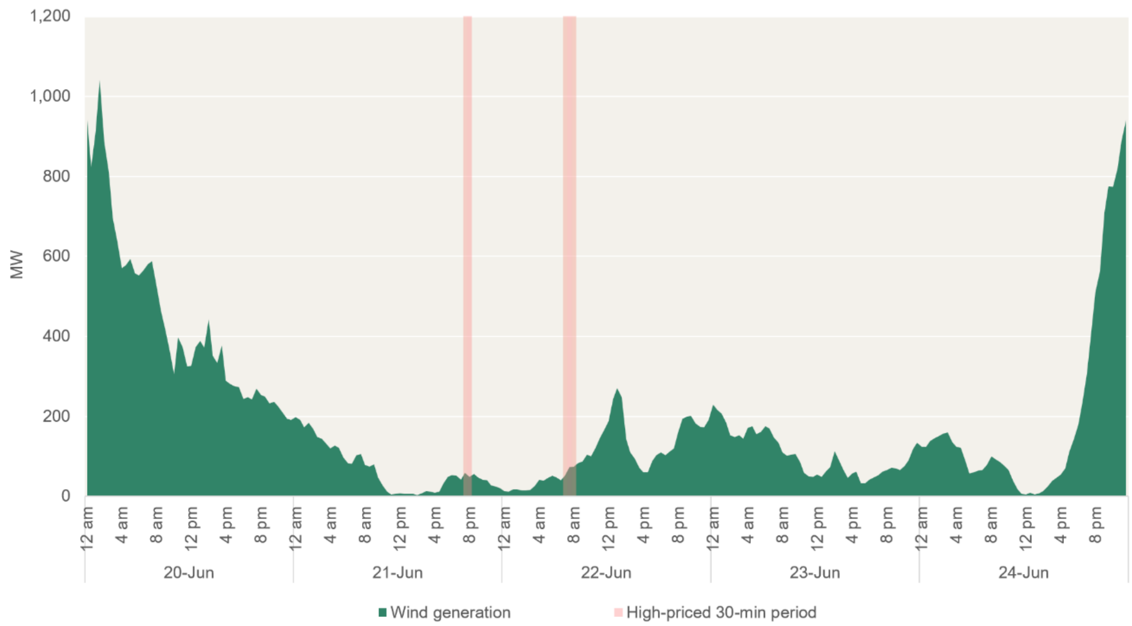
South Australia experienced a wind lull on 21 and 22 June, with wind output averaging 85 MW out of 2,766 MW of registered wind capacity (Figure 7). At its lowest point, total wind generation was 3 MW at 2.30 pm on 21 June.

On 21 June, average wind generation was around 54 MW from 8 pm to 8.30 pm when the energy price reached $8,689 per MWh and $4,323 per MWh, respectively. Wind continued to remain very low throughout the evening and into the next morning.

On 22 June, average wind generation was around 66 MW from 7.30 am to 8.30 am when the energy price varied from $3,836 per MWh to $20,300 per MWh.

Low wind generation, combined with high demand, contributed to higher electricity prices as more expensive generation such as gas and batteries was required to meet demand.

Figure 7 Wind generation on 21 June and 22 June



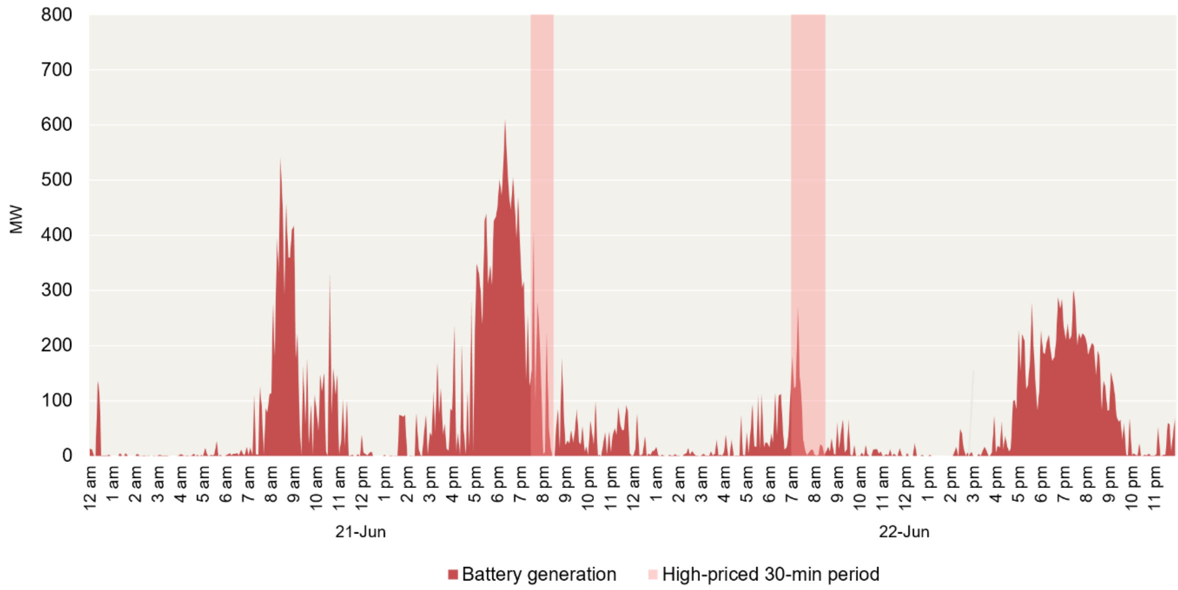
Source: AER analysis using NEM data.

3.4.3 Batteries

During the evening peak on 21 June, batteries in the region provided substantial generation (Figure 8). However, batteries started to remove capacity from around 7.35 pm with participants generally citing change in state of charge forecast. State of charge refers to the amount of energy remaining in a battery, which limits how much electricity it can supply at any given time. During the high price intervals between 7.35 pm to 8.30 pm, battery offers varied from 119 MW to 572 MW, falling from an average of 759 MW offered during the previous hour.

Batteries commonly charge in the middle of the day or overnight to take advantage of the cheaper renewable generation. Due to extremely low wind conditions on 21 and 22 June (section 3.4.2), batteries had little opportunity to recharge overnight from renewables. When the high prices occurred at 7.30 am and 8 am on 22 June, total offers from batteries dropped sharply from 326 MW to 1 MW and eventually there was no capacity offered at 8.05 am and 8.10 am.

Figure 8 Battery generation on 21 June and 22 June



Source: AER analysis using NEM data.

3.4.4 Network limitations

South Australia had limited access to imports during the high-priced periods due to system normal constraints affecting both interconnectors. Heywood imports into South Australia were restricted, while Murraylink flows were forced counter-price (i.e. when high-priced generation in one region is forced into a region with lower-priced generation) into Victoria. While South Australia mostly remained a net importer from Victoria, the reduced Heywood imports and counter-price Murraylink flows limited access to lower-priced generation from Victoria during periods of tight local supply conditions.

On 21 June:

- Heywood's flows into South Australia were around 212 MW and 406 MW out of its 650 MW nominal capacity at 8 pm and 8.30 pm, respectively. Flows varied from 44 MW to 553 MW during the high price intervals due to the system normal constraints.
- Murraylink's flows were forced counter-price at around 141 MW and 135 MW at 8 pm and 8.30 pm from South Australia into Victoria due to the same constraints.

On 22 June:

- Heywood's flows were around 139 MW and 328 MW at 7.30 am and 8 am, respectively. At 8.05 am, system normal constraints were still in place, and imports were limited to 397 MW at the time of the high price. At 8.10 am, the constraints changed and imports increased to around 605 MW, coinciding with a decline in regional prices.
- Murraylink's flows continued to be forced counter-price into Victoria during the high prices of 7.30 am and 8 am. Murraylink exported approximately 225 MW from South Australia to Victoria at 8:05 am.

3.4.5 Rebidding

Rebidding for commercial and technical reasons contributed to some high prices on 21 and 22 June. On 21 June, between 12 MW and 142 MW of high-priced capacity was needed to meet demand during the high prices at 8 pm and 8.30 pm. On 22 June, between 30 MW to 335 MW of high-priced capacity was needed to meet demand. The rebidding reasons across these events were due to battery state of charge, changes in pre-dispatch (e.g. forecast prices, availability), capability changes, and technical reasons.

21 June

Rebids from Gas Power Stations:

Engie shifted 44 MW from $8,809 per MWh to $20,300 per MWh at Dry Creek unit 1 due to a change in forecast price. This rebid contributed to the high price at 7.50 pm when 16 MW of high price capacity was needed.

Rebids from Batteries:

At 7.01 pm, Zen Energy removed 111 MW of capacity priced under $5,000 per MWh at Templers Battery for availability adjustment due to five-minute dispatch price. This rebid contributed to the high price at 7.35 pm when 66 MW of high price capacity was needed.

From 7.02 pm across multiple rebids, Neoen removed 144 MW of low-priced capacity from Blyth Battery due to a lower than forecast state of charge. This contributed to the high price at 7.45 pm when 133 MW high-priced capacity was needed.

For the high price at 7.50 pm when 16 MW of high-priced capacity was needed:

- AGL removed 50 MW of low-priced capacity from Torrens Island Battery due to a capability change in energy and FCAS.
- Vena Energy removed 35 MW of low-priced capacity at Tailem Bend 2 Hybrid Renewable Power Station due to a change in forecast price.

- Iberdrola removed 22 MW low-priced capacity from Lake Bonney Battery due to a change in forecast price.
- Neoen removed 54 MW low-priced capacity at Blyth Battery due to its state of charge.

For the high price at 7.55 pm when 27 MW of high-priced capacity was needed:

- Vena Energy removed the remaining 6 MW from Tailem Bend 2 Hybrid Renewable Power Station due to external price forecast.
- Epic Energy shifted 66 MW at Mannum Battery to prices over $3,000 per MWh and removed 17 MW from low price due to a state of charge management.
- Neoen removed all 134 MW of low-priced capacity at Blyth Battery for the state of charge being lower than forecast. Neoen also removed 26 MW from $3,275 per MWh at Hornsdale Power Reserve citing state of energy approaching lower operational limit and set the price for 7.55 pm.

For the high price at 8.15 pm when 12 MW of high-priced capacity above $3,000 per MWh was needed:

- Epic Energy removed 100 MW from low-prices at Mannum Battery and added 7 MW to prices over $3,000 per MWh.
- Neoen removed 20 MW at Hornsdale Power Reserve and at 8.07 pm, removed 54 MW at Blyth Battery from below $3,000 per MWh citing state of energy approaching lower operational limit and, change in state of charge forecast respectively.
- Vena Energy shifted 41 MW from $840 per MWh to high-prices at Tailem Bend 2 Hybrid Renewable Power Station due to a change in forecast prices.
- AGL removed 150 MW from low prices at its Torrens Island Battery and added 55 MW at high prices due to capability changes in energy and FCAS.

22 June

Rebids from Gas Power Stations:

At 5.56 am, Origin shifted 51 MW from low to high prices at Quarantine unit 5 citing constraint management. Origin also removed 9 MW of low-priced capacity from Quarantine unit 3 at 6.27 am due to technical reasons. This contributed to the high price of 7.15 am.

At 6.18 am, AGL rebid from low to high prices due to pre-dispatch changes and shifted 55 MW at Barker Inlet and 100 MW at Torrens Island power station unit 2. These rebids contributed to the high prices from 7.05 am to 7.15 am when 30 MW to 90 MW of capacity over $3,000 per MWh and $5,000 per MWh was needed.

Rebids from Batteries:

Neoen shifted 75 MW and 69 MW from low to high prices at Hornsdale Power Reserve at 6.17 am and 6.27 am and set the price for 7.05 am and 7.10 am.

For the high price at 7.15 am when 30 MW of high-priced capacity was needed:

- Epic Energy shifted 30 MW from low to high prices at Mannum Battery due to pre-dispatch changes resulting in changes to economic conditions.
- Zen Energy removed 111 MW of low-price capacity at Templers Battery due to availability adjustment due to 5-minute dispatch price.
- Neoen removed 75 MW from Hornsdale Power Reserve due to the state of energy approaching low limits.

3.4.6 Impact on quarterly volume-weighted average price

On 21 and 22 June, energy prices above $5,000 per MWh added $13 to South Australia's quarterly volume-weighted average price of $95 per MWh. Across the same period the previous year, high prices added $46 to the quarterly volume-weighted average price of $166 per MWh.

3.4.7 Impact on contract prices

The high price periods in South Australia drove an increase in the Q2 2026 base future prices for South Australia. The base future prices for Q2 2026 increased by $11.50 per MWh following the high prices on 21 and 22 June. However, these high prices had no material impact on base future prices for Q3 2026 or Q2 2027.

The price of Q2 2026 cap contracts increased from $5.50 per MWh to $15 per MWh, correlating to the high price periods.

A Significant prices tables

We considered 14 days this quarter and selected four days, covering five events, for detailed reporting. The selected events were chosen using the Significant Price Reporting Guideline and the AER's principles-based approach. The selection considered price level, market conditions, operational drivers, and the value of explaining the event to market participants and the public. In particular, we:

- applied a principles-based approach for the month of April, resulting in 20 April being selected as the most interesting, unusual and consequential day of the month;
- selected the highest-priced days for May (31) and June (22); and
- included 21 June for its connection to the events of 22 June in South Australia, along with coinciding with high prices in Tasmania.

The review considered each high-priced day, but the detailed analysis focuses on the material dispatch intervals. Where prices were below $5,000 per MWh, the AER applied an appropriate threshold to assess whether high-priced capacity was material. The relevant thresholds are identified in the rebidding appendices.

Table A.1 below provides details of the significant price days selected as the highest priced 30-minute periods across the NEM markets and the reasons for selection.

Table A.2 further below provides the 11 other pricing outcomes that were considered but not selected for April to June as significant price outcomes including reasons for exclusion.

Table A.1 Details of significant price days selected for April to June

	Date, Time	Region	Market	Highest 30-min price ($/MWh Energy, $/MW FCAS)	Reasons for inclusion or exclusion
Day for April (not the highest price day)	20 April, 5.30 pm	Queensland	FCAS	2,634	20 April was not the highest day for the month. However, it was selected as the significant price outcome day for April as circumstances were more compelling than the highest price day of the month (11 April). A planned Sapphire–Armidale line network outage created a risk of Queensland becoming electrically islanded, so a local FCAS requirement was set. There was sufficient capacity offered in the L1 sec FCAS market to meet the local requirement for the 5.30 pm dispatch interval, however two units were also dispatching into

	Date, Time	Region	Market	Highest 30-min price ($/MWh Energy, $/MW FCAS)	Reasons for inclusion or exclusion
					the energy market at a level that technically prevented both from providing their offered capacity into the ancillary market.
Day for May (highest price day)	31 May, 7 pm	Tasmania	FCAS	834	31 May was selected to report as it was the highest price of the month. We also considered it relevant to provide additional insights into Tasmanian FCAS prices and the market supply dynamics contributing to high prices. During this event, high FCAS price in Tasmania was experienced in the evening driven by Basslink being in “No-Go” zone, control system issues and the trade-off between energy and FCAS. There was sufficient capacity offered in the R6 sec FCAS market to meet the local requirement, however few units were also dispatching into the energy market at a level that technically prevented them from providing their offered capacity into the ancillary market.
Fourth day	21 June, 6 pm, 10 pm	Tasmania	Energy FCAS	3,596 (Energy) 3,568 (RReg) 3,538 (R60 sec) 3,553 (R6 sec)	The energy price in Tasmania on 21 June is the next highest energy price in Q2, following the energy high prices in South Australia on 21 and 22 June. This day is interesting since it had high prices in both energy and FCAS markets. During this event, the prices exceeded $3,500 per MW(h) at 6 pm and 10 pm. The price spikes were driven by the trade-off between energy and FCAS, units being trapped or stranded, capacity effectively unavailable in FCAS, control system issues and network limitations.

	Date, Time	Region	Market	Highest 30-min price ($/MWh Energy, $/MW FCAS)	Reasons for inclusion or exclusion
Day for June (highest price days)	21 June, 8 pm, 8.30 pm	South Australia	Energy	8,689	On 21 June, high prices occurred during the evening peak. High prices were not forecast. This event was driven by elevated demand due to cold weather, very low wind generation, network limitations and some rebidding. It was the second highest price day of the month and the quarter.
	22 June, 7.30 am - 8.30 am	South Australia	Energy	20,300	On 22 June during the morning peak, energy price reached the market cap, and it was the highest price of the month and the quarter. High prices occurred due to continuing conditions from the previous day. Drivers included high demand due to very cold morning, low wind generation, network limitations and some rebidding.

Table A.2 Other pricing outcomes considered but not selected for April to June for detailed reporting. The table explains why each event was excluded including where the drivers were similar to selected events, the price outcome as less material, or a preliminary review did not identify a need for further analysis.

Table A.2 Other pricing outcomes considered but not selected for April to June

Month	Day	Time	Region, Market	Price ($/MWh Energy, $/MW FCAS)	Reasons for exclusion
April	11	3 pm	Tas, FCAS	3,768	Highest price in the month. 11 April was not selected as the first significant price day. Instead, 20 April (second highest price day) was selected. 11 April is similar to previous significant prices that occurred earlier in the year with analysis included within the [Quarter 1 2026 Significant Price report](), released on 28 May 2026.
	13	1 pm	SA, Energy	269	A preliminary scan did not identify cause to review further. There was low wind generation as well as low rooftop solar generation. Demand was higher than average for the time of day.
	14	11.30 am	SA, Energy	265	A preliminary scan did not identify cause to review further. There was low wind and rooftop solar generation. Demand was higher than average for the time of day.
	15	12.30 am, 1 am	SA, Energy	251 - 297	A preliminary scan did not identify cause to review further. There was low wind generation at the time.
May	18	12.30 pm	NSW, Qld, Vic, Energy	268 - 289	A preliminary scan did not identify cause to review further. There was low wind, rooftop solar and grid solar generation at the time. Demand was higher than average for the time of day as it was cold. There was price alignment, between the 3 regions.

Month	Day	Time	Region, Market	Price ($/MWh Energy, $/MW FCAS)	Reasons for exclusion
May	18	3.30 pm	Tas, FCAS	717	Like the selected day for May (31 May), high R6 sec FCAS price in Tasmania was driven by control system issues and the trade-off between energy and FCAS. Given the very similar nature of drivers and the fact this was not the highest-priced day for the month, it was excluded.
	26	6.30 am	SA, Energy	274	A preliminary scan did not identify cause to review further. There was low wind and network limitations.
	30	2.30 am	Tas, FCAS	750	Like the selected day for May (31 May), high R6 sec FCAS price in Tasmania was driven by control system issues and the trade-off between energy and FCAS. Given the very similar nature of drivers and the fact this was not the highest-priced day for the month, it was excluded.
June	14	6.30 am	Tas, FCAS	3,470	High R6 sec FCAS prices in Tasmania on 14 and 23 June were driven by Basslink being in "No-Go" zone and unable to transfer FCAS, the AUFLS control scheme limited R6 sec enablement, and generator effective availability. Given the very similar nature of drivers and the fact this was not the highest priced day for the month, it was excluded.
	23	2.30 pm	Tas, FCAS	3,384	High R6 sec FCAS prices in Tasmania on 14 and 23 June were driven by Basslink being in "No-Go" zone and unable to transfer FCAS, the AUFLS control scheme limited R6 sec enablement, and generator effective availability. Given the very similar nature of drivers and the fact this was not the highest priced day for the month, it was excluded.

Month	Day	Time	Region, Market	Price ($/MWh Energy, $/MW FCAS)	Reasons for exclusion
June	24	7 am	SA, Energy	675	Excluded because the drivers were similar to 21 and 22 June and the price outcome was less material. The 5-minute prices did not exceed $844 per MWh and the price was not forecast. The price was driven by ongoing low wind generation and limited flow over the interconnectors for planned network outage and system normal constraints.

B Significant rebids 20 April, Queensland

For the 5.30 pm dispatch interval 23 MW of high-priced capacity was needed. The rebids of AGL, which shifted capacity from low to high prices at its Wandoan battery therefore contributed to the high price outcomes.[13]

5.30 pm

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MW)	Price to ($/MW)	Rebid reason
2.58 pm		AGL Energy	Wandoan Battery	31	0.04	15,800	P Capability Change ENERGY, FCAS
5.08 pm	5.15 pm	AGL Energy	Wandoan Battery	16	0.04	15,800	P Capability Change ENERGY, FCAS
5.23 pm	5.30 pm	AGL Energy	Wandoan Battery	24	15,800	N/A	P Capability change ENERGY, FCAS

13 High-priced capacity has been defined as dispatched capacity above $5,000 per MWh. When the 5-minute price has been lower than $5,000 per MWh, the threshold has been set to $3,000 per MWh. These occurrences have been marked with ⊗.

C Significant rebids 21 June, Tasmania

For the 6 pm dispatch interval, 1 MW of high-priced capacity was needed, therefore the rebid by VIOTAS had an impact on price outcomes.

6 pm – R60 sec

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MW)	Price to ($/MW)	Rebid reason
5.53 pm	6 pm	VIOTAS Australia	DRVIOT05	1	0.36	N/A[14]	Change in plant conditions

[14] N/A indicates that the rebid 'from' or 'to' price is not available, as the rebid involved capacity being added or removed rather than shifted between price bands.

D Significant rebids 21 June, South Australia

The tables below predominantly highlight low-priced capacity being withdrawn from batteries as their state of charge decreased in the lead up to the significant price events. Each table includes the amount of high-priced capacity that was ultimately needed to be dispatched to meet demand, at these times.

7.35 pm (66 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
7.01 pm	7.10 pm	Zen Energy	Templers Battery	111	≤3,041	N/A	Availability adj due to 5-Min DP SL

7.45 pm (133 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
7.02 pm		Neoen	Blyth Battery	10	254	N/A	Change in SOC forecast
7.07 pm		Neoen	Blyth Battery	2	254	N/A	Change in SOC forecast
7.12 pm	7.20 pm	Neoen	Blyth Battery	44	254	N/A	Change in SOC forecast
7.17 pm	7.25 pm	Neoen	Blyth Battery	3	254	N/A	Change in SOC forecast
7.22 pm	7.30 pm	Neoen	Blyth Battery	19	254	N/A	SOC lower than forecast
7.27 pm	7.35 pm	Neoen	Blyth Battery	12	254	N/A	SOC lower than forecast
7.32 pm	7.40 pm	Neoen	Blyth Battery	44	≤254	N/A	Change in SOC forecast
7.32 pm	7.40 pm	Neoen	Blyth Battery	10	≤254	9,610	Change in SOC forecast
7.37 pm	7.45 pm	Neoen	Blyth Battery	10	9,610	N/A	Change in SOC forecast

7.50 pm (16 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
7.19 pm		AGL	Torrens Island Battery	50	302	N/A	Capability Change (PD) ENERGY, LOWER1SEC, LOWER5MIN, LOWER60SEC, LOWER6SEC, LOWERREG, RAISE1SEC, RAISE5MIN, RAISE60SEC, RAISE6SEC, RAISEREG
7.28 pm	7.35 pm	Vena Energy	Tailem Bend 2 Hybrid Renewable Power Station	41	840	N/A	SA1 5MIN PD RRP for 2000 ($360.55) published at 1925 is $207.65 higher than 30MIN PD RRP published at 1901 ($152.9) - Time of alert: 1928
7.32 pm	7.40 pm	Iberdrola	Lake Bonney Battery	22	940	N/A	SA1 lower_reg 5PD@2026-06-21 19:35:00 AEST for 2026-06-21 19:40:00 AEST is 0.37 vs 5PD@2026-06-21 19:30:00 AEST for 2026-06-21 19:40:00 AEST is 1.97
7.34 pm		Engie	Dry Creek	44	8,809	20,300	AEMO 5MPD vs 30MPD - Region Price Decrease $360 DI1940. SL.
7.37 pm	7.45 pm	Neoen	Blyth Battery	54	≤254	N/A	SOC lower than forecast

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
7.38 pm	7.45 pm	Vena Energy	Tailem Bend 2 Hybrid Renewable Power Station	24	N/A	840	SA1 30MIN PD RRP for 2000 ($324.77) published at 1931 IS $171.87 higher than 30MIN PD RRP published at 1901 ($152.9) - Time of alert: 1938
7.43 pm	7.50 pm	Vena Energy	Tailem Bend 2 Hybrid Renewable Power Station	18	840	N/A	SA1 5MIN PD RRP for 2000 ($513.47) published at 1940 IS $360.58 higher than 30MIN PD RRP published at 1901 ($152.9) - Time of alert: 1943

7.55 pm (27 MW of high-priced capacity was needed)⊗

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
7.12 pm		Neoen	Blyth Battery	51	254	N/A	Changes in SOC forecast
7.17 pm		Neoen	Blyth Battery	14	N/A	254	Changes in SOC forecast
7.22 pm	7.30 pm	Neoen	Blyth Battery	34	254	N/A	SOC Lower than forecast
7.27 pm	7.35 pm	Neoen	Blyth Battery	8	N/A	254	SOC Lower than forecast
7.32 pm	7.40 pm	Neoen	Blyth Battery	12	N/A	254	Changes in SOC forecast
7.37 pm	7.45 pm	Neoen	Blyth Battery	81	254	N/A	Changes in SOC forecast
7.37 pm	7.45 pm	Neoen	Blyth Battery	2	≤254	19,707	SOC Lower than forecast
7.38 pm	7.45 pm	Epic Energy	Mannum Battery	36	248	N/A	SOC management - update availability. SL

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
7.43 pm	7.50 pm	Vena Energy	Tailem Bend 2 Hybrid Renewable Power Station	35	840	N/A	SA1 5MIN PD RRP for 2000 ($513.47) published at 1940 IS $360.58 higher than 30MIN PD RRP published at 1901 ($152.9) - Time of alert: 1943
7.43 pm	7.50 pm	Epic Energy	Mannum Battery	28	N/A	470	SOC management - update availability. SL
7.48 pm	7.55 pm	Vena Energy	Tailem Bend 2 Hybrid Renewable Power Station	6	840	N/A	Due to external price forecast - SL
7.48 pm	7.55 pm	Epic Energy	Mannum Battery	17	<470	N/A	SOC management - update availability. SL
7.48 pm	7.55 pm	Epic Energy	Mannum Battery	66	<470	>3,120	SOC management - update availability. SL
7.48 pm	7.55 pm	Neoen	Hornsdale Power Reserve	26	3,275	N/A	SOE approaching lower operational limits set by asset operator for 2026-06-21 19:55 causing limited availability for product gen energy

8.15 pm (12 MW of high-priced capacity was needed)⊗

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
6.23 pm		Epic Energy	Mannum Battery	52	248	N/A	Forecasted change SA1 RRP at 2026-06-21T18:30:00 from existing forecast resulting in a change in economic conditions. SL
6.28 pm		Epic Energy	Mannum Battery	46	248	N/A	Forecasted change SA1 RRP at 2026-06-21T18:35:00 from existing forecast resulting in a change in economic conditions. SL
6.33 pm		Epic Energy	Mannum Battery	7	N/A	248	Forecasted change SA1 RRP at 2026-06-21T18:40:00 from existing forecast resulting in a change in economic conditions. SL
6.38 pm		Epic Energy	Mannum Battery	9	248	N/A	Forecasted change SA1 RRP at 2026-06-21T18:45:00 from existing forecast resulting in a change in economic conditions. SL
7.52 pm	8 pm	AGL	Torrens Island Battery	150	≤302	N/A	Chg in AEMO DISP~44 Price change vs PD [SA] [$3,290.00 disp vs $324.77 30MPD PE 2000]
7.53 pm	8 pm	Neoen	Hornsdale Power Reserve	20	359	N/A	SOE approaching lower operational limits set by asset operator for 2026-06-21 20:00 causing limited availability for product gen energy

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
8.03 pm	8.10 pm	Vena Energy	Tailem Bend 2 Hybrid Renewable Power Station	41	840	20,300	SA1 5MIN PD RRP for 2030 ($499.38) published at 2000 IS $321.61 higher than 30MIN PD RRP published at 1931 ($177.77) - Time of alert: 2003
8.07 pm	8.15 pm	Neoen	Blyth Battery	54	≤254	N/A	Changes in SOC forecast
8.08 pm	8.15 pm	Epic Energy	Mannum Battery	7	N/A	3,120	SOC management - update availability. SL
8.08 pm	8.15 pm	Vena Energy	Tailem Bend 2 Hybrid Renewable Power Station	41	20,300	8,800	Responding to MPC prices

E Significant rebids 22 June, South Australia

The tables below highlight low-priced capacity being withdrawn including from batteries as their state of charge decreased in the lead up to the significant price events. Each table includes the amount of high-priced capacity that was ultimately needed to be dispatched to meet demand, at these times.

7.05 am and 7.10 am (90 MW and 82 MW of high-priced capacity was needed) ⊗

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
6.17 am		Neoen	Hornsdale Power Reserve	75	359	3,275	SOE approaching lower operational limits set by asset operator for 2026-06-22 07:20 causing limited availability for product gen energy
6.18 am		AGL	Barker Inlet Power Station	55	101	20,300	Change in AEMO PD~54 PD (06:01) available generation change [SA] 116MW avg for PE 07:00 - 07:30 - SL
6.18 am		AGL	Torrens Island	100	≤138	20,300	Change in AEMO PD~54 PD (06:01) available generation change [SA] 116MW avg for PE 07:00 - 07:30 - SL
6.27 am		Neoen	Hornsdale Power Reserve	69	359	3,275	SOE approaching lower operational limits set by asset operator for 2026-06-22 07:25 causing limited availability for product gen energy

7.15 am (30 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
5.56 am		Origin	Quarantine	51	70	20,300	Constraint management - CA_SYDS_59488 2A3_1 SL
6.18 am		AGL	Barker Inlet Power Station	55	101	20,300	Change in AEMO PD~54 PD (06:01) available generation change [SA] 116MW avg for PE 07:00 - 07:30 - SL
6.18 am		AGL	Torrens Island	100	≤138	20,300	Change in AEMO PD~54 PD (06:01) available generation change [SA] 116MW avg for PE 07:00 - 07:30 - SL
6.27 am		Origin	Quarantine	9	-1,000	N/A	Change in avail - high lube oil temp limitation revised SL
6.47 am		Epic Energy	Mannum Battery	30	470	19,190	Forecasted change SA1 P5min 2026-06-22 06:50 from previous forecast resulting in a change in economic conditions
6.56 am	7.05 am	Zen Energy	Templers Battery	15	3,041	N/A	Availability adj due to 5-MIN DP SL
7.01 am	7.10 am	Zen Energy	Templers Battery	96	≤3,041	N/A	Availability adj due to 5-MIN DP SL
7.07 am	7.15 am	Neoen	Hornsdale Power Reserve	75	3,275	N/A	SOE approaching lower operational limits set by asset operator for 2026-06-22 07:15 causing limited availability for product gen energy