Significant electricity prices

January to March 2026

May 2026

AUSTRALIAN ENERGY REGULATOR

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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.

This report is the first report that falls under the revised significant price outcome criteria outlined in the guideline published in January 2026.[2]

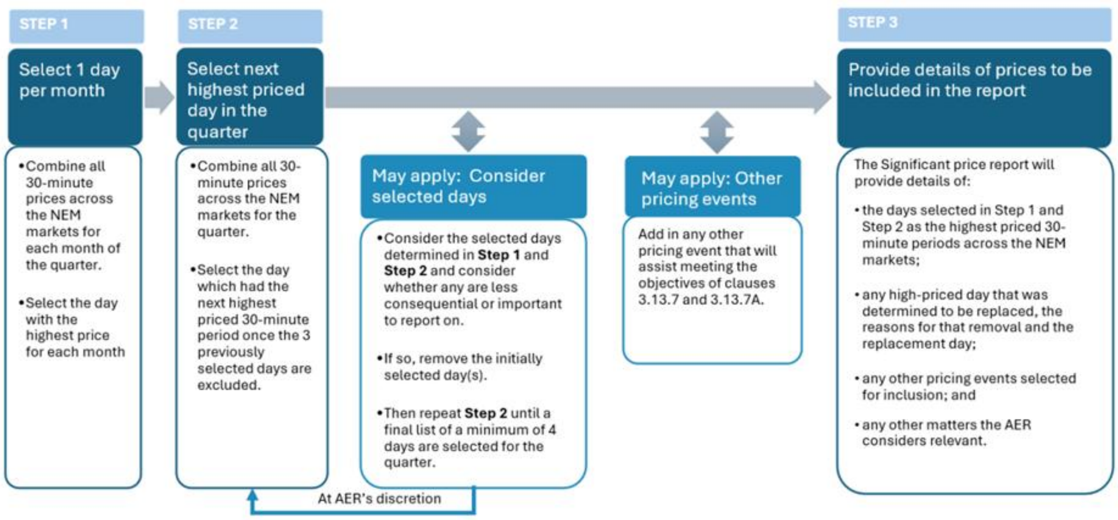
Instead of using a fixed price to determine a significant price outcome[3], the AER now applies a principles-based approach when selecting the price outcomes to report on by (Figure 1):

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 those in identified in Step 1 above; and
3. determining any other matter or pricing event that it considered will assist meeting 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



[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 22 May 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 22 May 2026.

Executive Summary

Significant price outcomes in the NEM during the January to March 2026 quarter were identified in Tasmania and South Australia in both energy and FCAS markets.

In Tasmania, all three significant price outcome days occurred when the Basslink interconnector was either offline or unable to transfer Frequency Controlled Ancillary Services (FCAS). When Basslink was offline, Tasmania needed to provide its own energy and FCAS locally. On other occasions, while Basslink was available for energy, it was unable to transfer FCAS for technical reasons, requiring Tasmania to supply FCAS locally.

These conditions were material because the main supplier of FCAS in Tasmania is also the main supplier of energy, creating trade-offs between energy and FCAS capability. Although there was enough low-priced capacity offered across these events, the availability of some generators was limited for technical reasons. While there was some rebidding in FCAS, it was significantly less than the low-priced capacity that was limited.

As a result, although the impact on Tasmania's quarterly volume-weighted average energy price was minimal, high Raise 6 second (R6 sec) FCAS prices contributed approximately $8 million in local costs, the highest quarterly cost for R6 sec services since at least 2010.

In South Australia, the other significant price outcomes occurred over two days under tight supply-demand conditions, including high demand during exceptional heat, low wind generation and network limitations, with rebidding also contributing to the prices. Prices above $5,000 per MWh increased the quarterly volume-weighted average energy price by $63 per MWh to $144 per MWh.

Significant price outcomes

A total of 16 days were considered in the quarter, including all prices over $5,000 per MWh (see Appendix E for price considerations). The highest 30-minute prices on these days ranged from:

- $336 per MWh on 25 March to $20,158 per MWh on 26 January for energy, both in South Australia.
- $809 per MW on 15 March to $6,843 per MW on 17 February for FCAS, both in Tasmania.

Using the new significant price outcome criteria, we determined five of these 16 days to be significant price outcomes for reporting (Table 1). This includes pricing outcomes below $5,000 per MWh that would not have been reported on under the previous threshold-based approach, demonstrating how the new principles-based framework captures significant events not reflected in extreme price levels alone.

The five significant price outcome days selected for the quarter occurred in both energy and FCAS markets in Tasmania and in energy in South Australia.

Overall, the significant price outcomes were driven by a number of factors (Table 1). A key theme was the need for Tasmania to supply its own FCAS and, on one occasion, energy.

Three of the five significant price days involved high R6 sec prices during periods when Basslink was unable to transfer FCAS, requiring Tasmania to meet its needs locally. On these occasions:

- Available providers for R6 sec in Tasmania were limited (primarily hydro and demand response) unlike the mainland which also has other generation options such as large-scale batteries.
- Hydro units were required in the energy market, reducing effective FCAS availability.
- While enough capacity was offered into the R6 sec market, there was not enough low-priced capacity available to meet local requirements and higher-priced capacity from demand response units was required

This combination of factors resulted in repeated high FCAS prices during the quarter.

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
12 January, Tas (Energy & FCAS)	$6,835 (Energy) $6,763 - $6,766 (FCAS)	×	✓	×	×	×
26-27 January, SA (Energy)	$3,704 - $20,158	✓	✓	✓	✓	✓
17 February, Tas (FCAS)	$6,764 - $6,843	×	×	✓	×	✓
3 March, Tas (FCAS)	$3,382	×	×	✓	×	×

Source: AER analysis using NEM data.

Rebidding was not a primary driver of significant price outcomes this quarter. Of the 55 significant 5-minute prices investigated for this report, only 14 were found to have rebids contributing to the high prices. Rebids for these intervals removed between 15 MW and 200 MW of low-priced capacity for a combination of technical and commercial reasons. Further details of the rebidding that contributed to the high prices can be found in Appendix A to Appendix D.

The details of each significant price day are summarised as follows:

- **12 January in Tasmania**: A sudden and unplanned outage of Basslink interconnector meant Tasmania had to provide its own energy and FCAS. To maintain system security, network constraints and control systems were implemented to manage the balance between demand and supply. Some rebidding contributed to the high prices. Detailed analysis is in section 1.1.
- **26 and 27 January in South Australia:** The high energy prices were driven by high demand due to hot temperatures, low wind generation, planned network limitations and some rebidding. These circumstances led to the Australian Energy Market Operator

(AEMO) declaring a low-level reserve shortfall in South Australia on one of the days.[4, 5] Detailed analysis is in section 1.2.

- **17 February in Tasmania:** High FCAS prices in Tasmania during the afternoon and evening were mostly driven by network limitations and control systems balancing demand and supply to protect the power system from collapsing. Some rebidding also contributed to the high prices. Detailed analysis is in section 1.3.
- **3 March in Tasmania:** Like 17 February, the high price was driven by network constraints and control systems balancing demand and supply to protect the power system from collapsing. Detailed analysis is in section 1.4.

[4] Market notice 133067: forecast LOR for South Australia. Market notice 133105: actual LOR in South Australia.

[5] AEMO, "LOR Factsheet", Australian Energy Market Operator, 2025, accessed 22 May 2026.

1 Five significant price days in the quarter

1.1 Energy and FCAS prices on 12 January, Tasmania

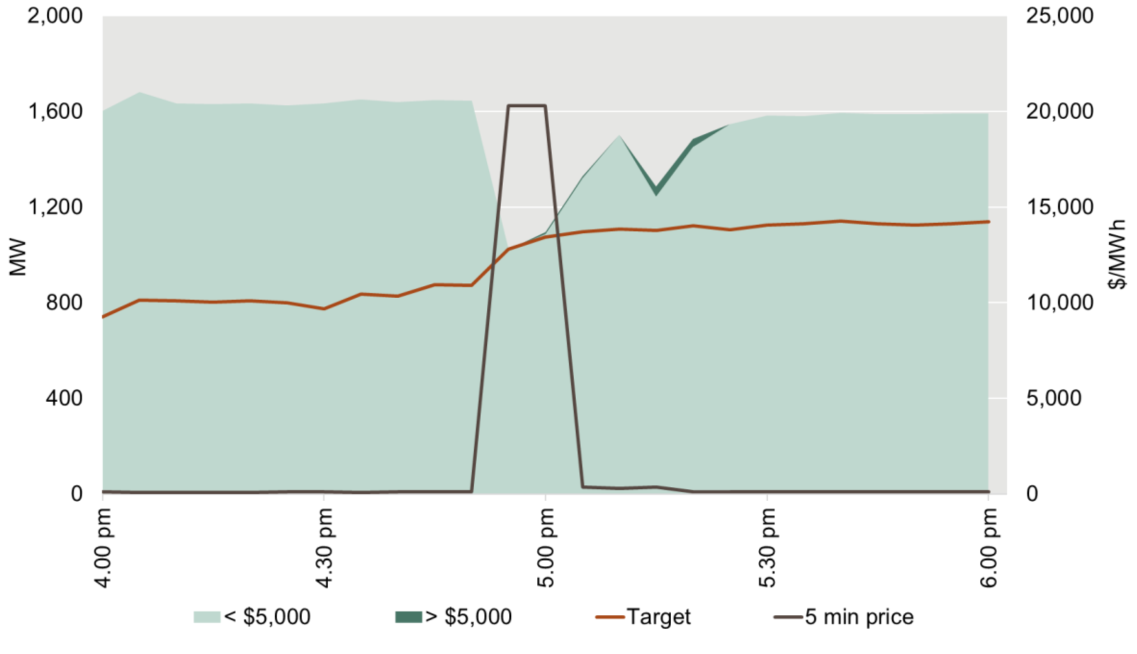
While the prices on 12 January were not the highest for January (section 1.2), this day was selected for the following reasons[6]:

- The outage of Basslink was sudden and unplanned;
- The high prices occurred for two 5-minute intervals only in energy and FCAS; and
- This was the first 30-minute FCAS above $5,000 per MWh in Tasmania in the quarter.

On 12 January, the energy price in Tasmania reached $6,835 per MWh at 5 pm (Figure 2). At the same time, prices in four of Tasmania's FCAS markets reached up to $6,766 per MW - R6 sec, Raise 60 second (R60 sec), Raise 5 minute (R5 min) and Raise Regulation (RReg). The high prices were not forecast.

The high prices occurred due to the Basslink interconnector (the only interconnector between Victoria and Tasmania) suddenly going on an unplanned outage. The sudden loss of Basslink meant Tasmania had to provide its own energy and FCAS. To manage power system security, a constraint was implemented to balance demand and supply, setting the high price in energy.

Figure 2 Energy capacity offered above and below $5,000 per MWh, 12 January



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

[6] AER, Significant price reporting guidelines, Australian Energy Regulator, 2026, accessed 22 May 2026.

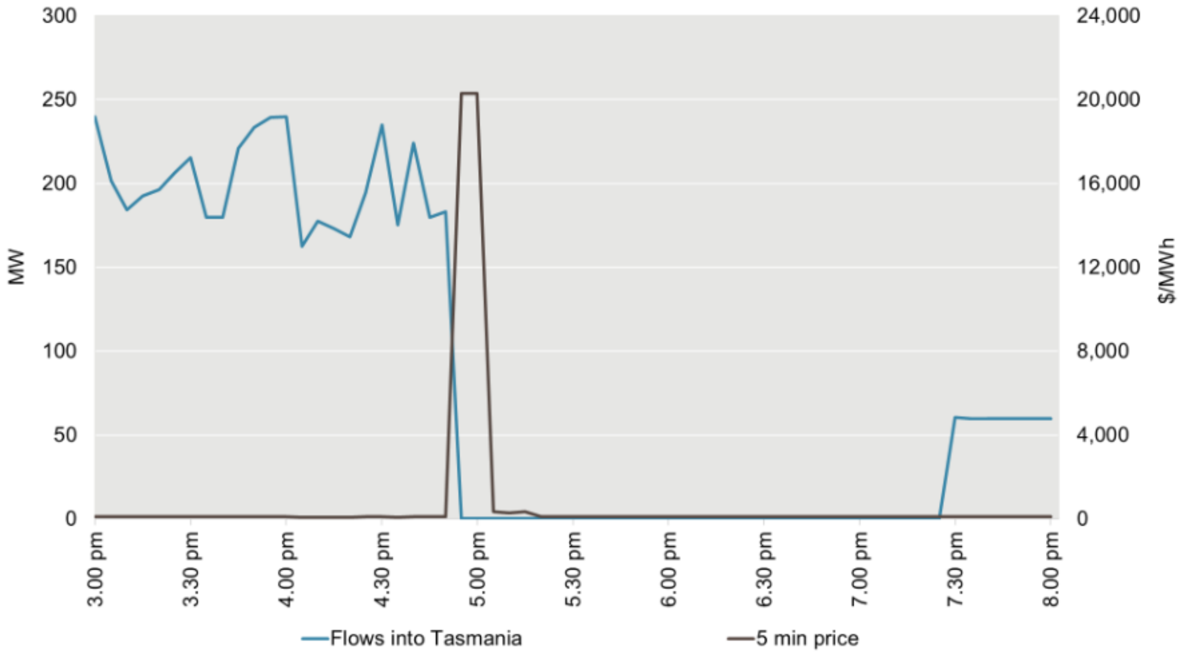
1.1.1 Network limitations

At 4.51 pm, the Basslink interconnector was taken offline for an unplanned outage when it was importing around 180 MW into Tasmania (Figure 3). This caused flows into Tasmania to suddenly drop to 0 MW.

We contacted APA regarding the unplanned outage. APA advised that Basslink had to be electrically isolated due to operational challenges. Basslink subsequently returned to service at 7.30 pm after the operational challenges had been resolved. We have considered APA's explanations for the unplanned outage and are satisfied with its response.

Due to the loss of Basslink, energy and FCAS was unable to be transferred from the mainland and Tasmania needed to provide its own energy and FCAS during this period.

Figure 3 Flows into Tasmania on Basslink and Dispatch Price, 12 January



Source: AER analysis using NEM data.

1.1.2 Generation ramp up constrained

Hydro Tasmania's stations were ramp up rate limited. AEMO can only ramp up units at their offered ramp rates (Table 2), which during the high prices was not enough to provide additional low-priced capacity that could have helped avoid the high prices. 494 MW and 450 MW of low-priced generation was ramp up constrained and unable to be dispatched in energy for 4.55 pm and 5 pm, respectively. This also impacted the effective availability of these units in FCAS (see section 1.1.7). All else being equal, if these units were capable of ramping up near their maximum rates, all high prices across energy and FCAS would likely not have occurred.

Table 2 Low-priced generation that was ramp up constrained on 12 January

Date	Participant	Unit	Low-priced generation unable to dispatch (MW)*
12 January	Hydro Tasmania	Bastyan	75
	Hydro Tasmania	Devils Gate	59
	Hydro Tasmania	John Butters	20
	Hydro Tasmania	Lemonthyme/Wilmot	28
	Hydro Tasmania	Mackintosh	83
	Hydro Tasmania	Meadowbank	33
	Hydro Tasmania	Trevallyn	47
	Hydro Tasmania	Tribute	87
	Hydro Tasmania	Tungatinah	82

Source: AER analysis using NEM data.
Note: *The maximum MW of low-priced generation unable to be dispatched in a high-priced 5-minute interval on the day.

1.1.3 Generation start up constrained

Hydro Tasmania's Bell Bay Three Power Station unit 1 and 2 and Tamar Valley GT Open Cycle Gas Turbine (OCGT) were unable to start up quickly enough to meet demand and provide low-priced capacity that could have helped avoid the high prices (Table 3). Between 63 MW and 80 MW of low-priced generation was unable to be dispatched in energy for 4.55 pm and 5 pm, respectively. This also impacted the effective availability of these units in FCAS (see section 1.1.7).

Table 3 Low-priced generation that was start up constrained on 12 January

Date	Participant	Unit	Low-priced generation unable to dispatch (MW)*
12 January	Hydro Tasmania	Bell Bay Three Unit 1	25
	Hydro Tasmania	Bell Bay Three Unit 2	25
	Hydro Tasmania	Tamar Valley GT OCGT	30

Source: AER analysis using NEM data.
Note: *The maximum MW of low-priced generation unable to be dispatched in a high-priced 5-minute interval on the day.

1.1.4 Generation trapped or stranded in FCAS

At Hydro Tasmania's Liapootah, Catagunya, Wayatinah Power Station, 53 MW was unable to be dispatched due to the interactions between the FCAS and energy markets (section 1.1.7). Between 79 MW and 85 MW of low-priced generation from hydro stations was unable to be dispatched in energy for 4.55 pm and 5 pm, respectively (Table 4). This also impacted the effective availability of these units in FCAS (see section 1.1.7).

Table 4 Low-priced generation that was trapped or stranded in FCAS on 12 January

Date	Participant	Unit	Low-priced generation unable to dispatch (MW)*
12 January	Hydro Tasmania	Liapootah, Catagunya, Wayatinah	53
	Hydro Tasmania	Cethana	1
	Hydro Tasmania	John Butters	1
	Hydro Tasmania	Gordon	24
	Hydro Tasmania	Devils Gate	7

Source: AER analysis using NEM data.
Note: *The maximum MW of low-priced generation unable to be dispatched in a high-priced 5-minute interval on the day.

1.1.5 System security constraint and energy-FCAS trade-off set high prices

The 5-minute high energy price at 4.55 pm was set by a constraint in place to manage the balance between supply and demand in Tasmania. This constraint was needed for power system security following the sudden loss of generation from Victoria due to Basslink being taken offline.

The market operator'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 may be reduced in providing raise ancillary services so it can provide additional energy or vice versa. This can impact prices in both the energy and FCAS markets. This is what occurred for the 5-minute high energy price at 5 pm, when the price was set by an offer of around $20,000 per MW in FCAS raise services.

1.1.6 AUFLS Control Scheme contributed to high FCAS prices

For the 4.55 pm and 5 pm intervals, there were high prices in four of Tasmania's FCAS markets (R6 sec, R60 sec, R5 min and RReg). The requirement for FCAS reached up to 101 MW during both intervals across the four services. The average enablement for the R6 sec service in Tasmania during Q1 2026 was 74 MW.

FCAS normally responds to address frequency deviations in the power system and returns the frequency to the operating frequency tolerance band. In rare circumstances, when non-credible contingencies occur on the network, the Adaptive Under Frequency Load Shedding (AUFLS) scheme is used as an emergency mechanism to protect the power system from collapse when supply cannot meet demand and frequency drops sharply.[7]

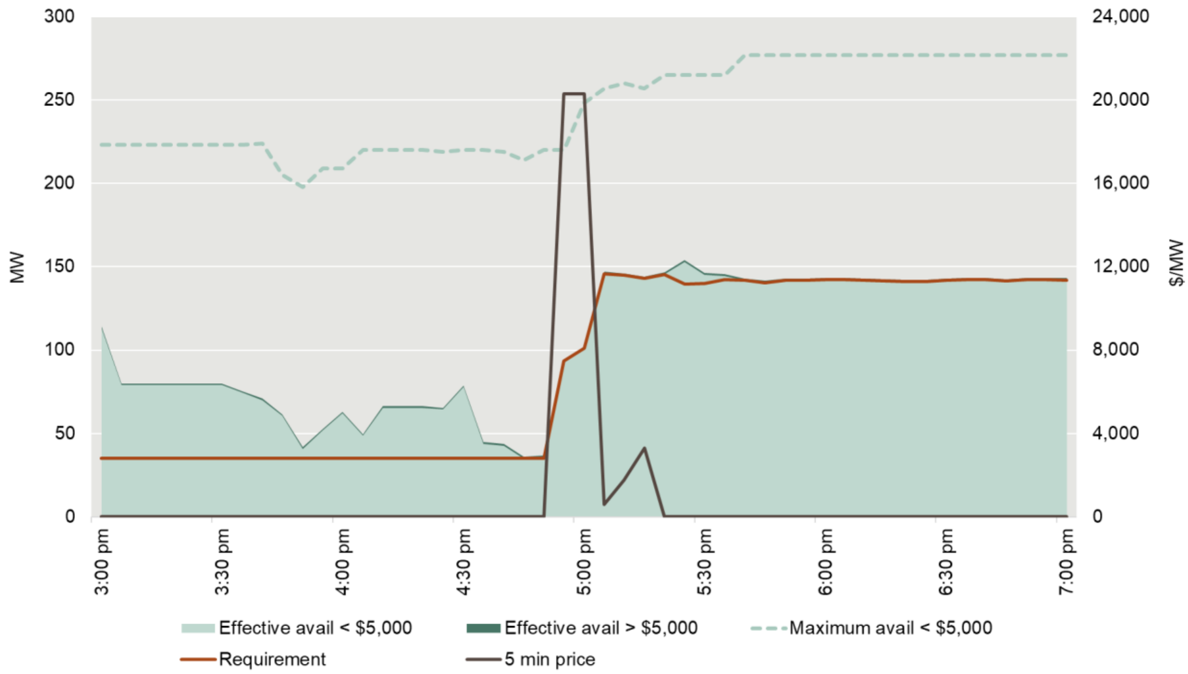
To rebalance supply and demand, Hydro Tasmania's load unit, ASTHYD1, was restricted during the high-priced intervals under the AUFLS scheme. This constraint limited the unit's low-priced capacity that was available for the R6 sec service. Around 13 MW of capacity offered for each interval was unable to be dispatched and contributed to the high prices.

[7] AEMO, Fact Sheet: Frequency Control, Australian Energy Market Operator, 2025, accessed 22 May 2026.

1.1.7 Some units were unable to provide their offered FCAS

Due to the trade-off between energy and FCAS markets (section 1.1.5), much of the capacity offered in FCAS was effectively unavailable (Figure 4). Most of these units were dispatching at (or near) their capacity in energy, and some units were dispatching at or near 0 MW in energy as they were starting up or ramp rate limited, therefore could not be fully enabled in FCAS.

Figure 4 R6 sec capacity availability above and below $5,000 per MW, 12 January



Source: AER analysis using NEM data.

Hydro Tasmania's units offered up to 243 MW of capacity across the R6 sec, R60 sec and R5 min services. However, during the high-priced periods, some units had only 1 MW to 20 MW of effective availability, while others had no effective availability (Table 5 to Table 7).

Table 5 Maximum and effective FCAS availability for R6 sec service, 12 January

Date	Participant	Unit	FCAS Service	Maximum (offered) availability (MW)	Effective (actual) availability (MW)
12 January	Hydro Tasmania	Cethana	R6 sec	10	0.21
		Devils Gate	R6 sec	8	0
		Gordon	R6 sec	63	0
		John Butters	R6 sec	37	7.32
		Lemonthyme/Wilmot	R6 sec	1	0
		Liapootah / Wayatinah / Catagunya	R6 sec	5	0
		Tribute	R6 sec	9	0
		Tungatinah	R6 sec	10	0

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.

Table 6 Maximum and effective FCAS availability for R60 sec service, 12 January

Date	Participant	Unit	FCAS Service	Maximum (offered) availability (MW)	Effective (actual) availability (MW)
12 January	Hydro Tasmania	Cethana	R60 sec	39	0
		Devils Gate	R60 sec	48	4.62
		Gordon	R60 sec	212	0
		John Butters	R60 sec	89	14.11
		Lemonthyme/Wilmot	R60 sec	7	0
		Liapootah / Wayatinah / Catagunya	R60 sec	19	0
		Poatina 110kV	R60 sec	6	0
		Poatina 220kV	R60 sec	12	2.18
		Tribute	R60 sec	43	0
		Tungatinah	R60 sec	42	0

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.

Table 7 Maximum and effective FCAS availability for R5 min service, 12 January

Date	Participant	Unit	FCAS Service	Maximum (offered) availability (MW)	Effective (actual) availability (MW)
12 January	Hydro Tasmania	Cethana	R5 min	97	0
		Devils Gate	R5 min	62	6
		Gordon	R5 min	243	0
		John Butters	R5 min	143	19.6
		Lemonthyme/Wilmot	R5 min	29	0
		Liapootah / Wayatinah / Catagunya	R5 min	18	0
		Poatina 110kV	R5 min	58	0
		Poatina 220kV	R5 min	120	0
		Tribute	R5 min	83	0

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.

1.1.8 Rebidding

Removal of low-priced capacity in the raise services for commercial and technical reasons contributed to the high prices at 4.55 pm and 5 pm (Appendix A).

With multiple rebids between 3.08 pm and 4.08 pm, VIOTAS Australia removed a net of 15 MW of low-priced capacity from its demand response unit, DRVIOT05, across three of the four raise services due to a change in plant conditions. These rebids contributed to the high prices at 4.55 pm and 5 pm. This unit also set the price for both intervals as its remaining high-priced capacity was needed to meet the requirement. We contacted VIOTAS Australia for further information regarding their FCAS rebids and plant conditions.

1.1.9 Impact on quarterly price and FCAS costs

This event added $2 per MWh to the quarterly volume-weighted average energy price for Tasmania. This event, in combination with the other FCAS high prices in Tasmania this quarter, contributed to the $8.2 million in R6 sec service costs across January to March. This is the highest quarterly Tasmanian local costs for this service since at least 2010.

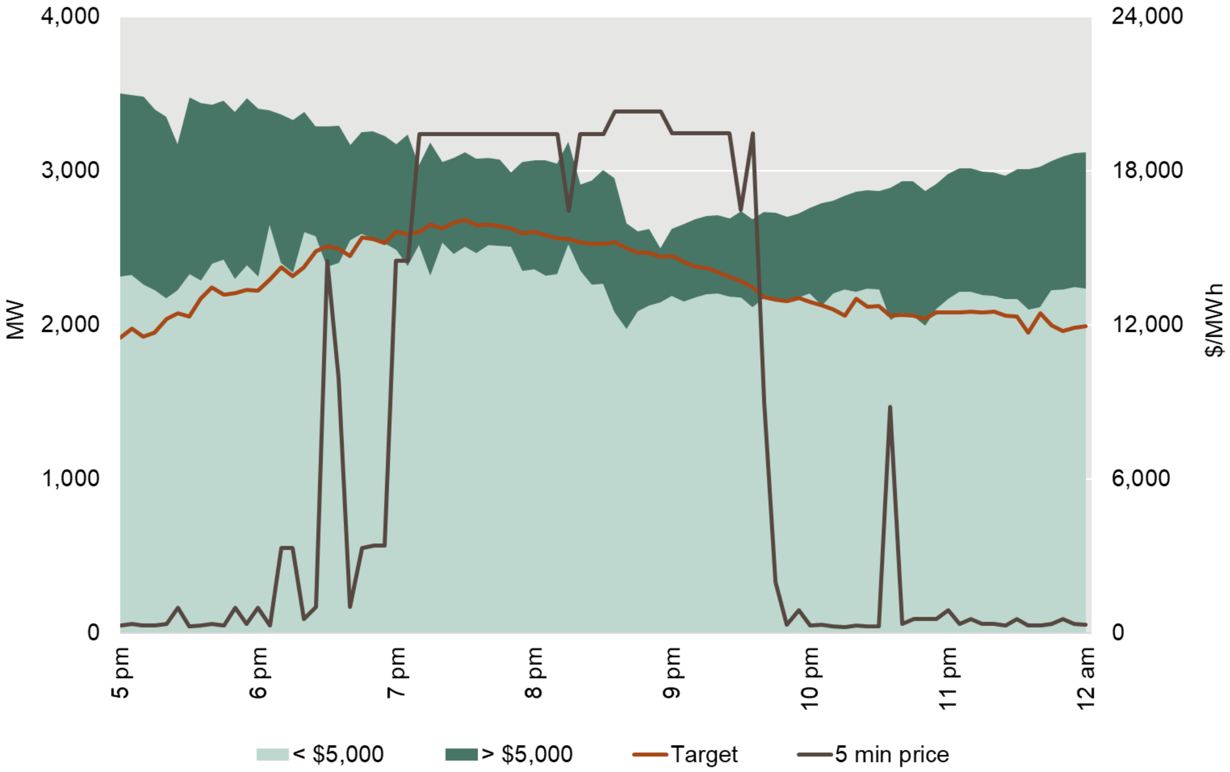
1.2 Energy prices on 26 and 27 January, South Australia

As noted above, the highest priced day of January and the quarter occurred on 26 January. However, 12 January was instead selected as the first day to report on for January due to its unique drivers. The significant prices on 26 and 27 January have been selected as the fourth and fifth days to report on in detail.

Across 26 and 27 January, the 30-minute price for energy exceeded $3,000 per MWh on 10 occasions. The 30-minute prices ranged from $3,704 per MWh to $20,158 per MWh (Figure 5 and Figure 6).

High prices on 26 January were forecast from the day prior and AEMO forecast a low-level reserve in South Australia for 6.30 pm to 9 pm, with an actual shortfall occurring from 8.30 pm to 9.45 pm on 26 January.[8, 9] The prices on 27 January were not forecast.

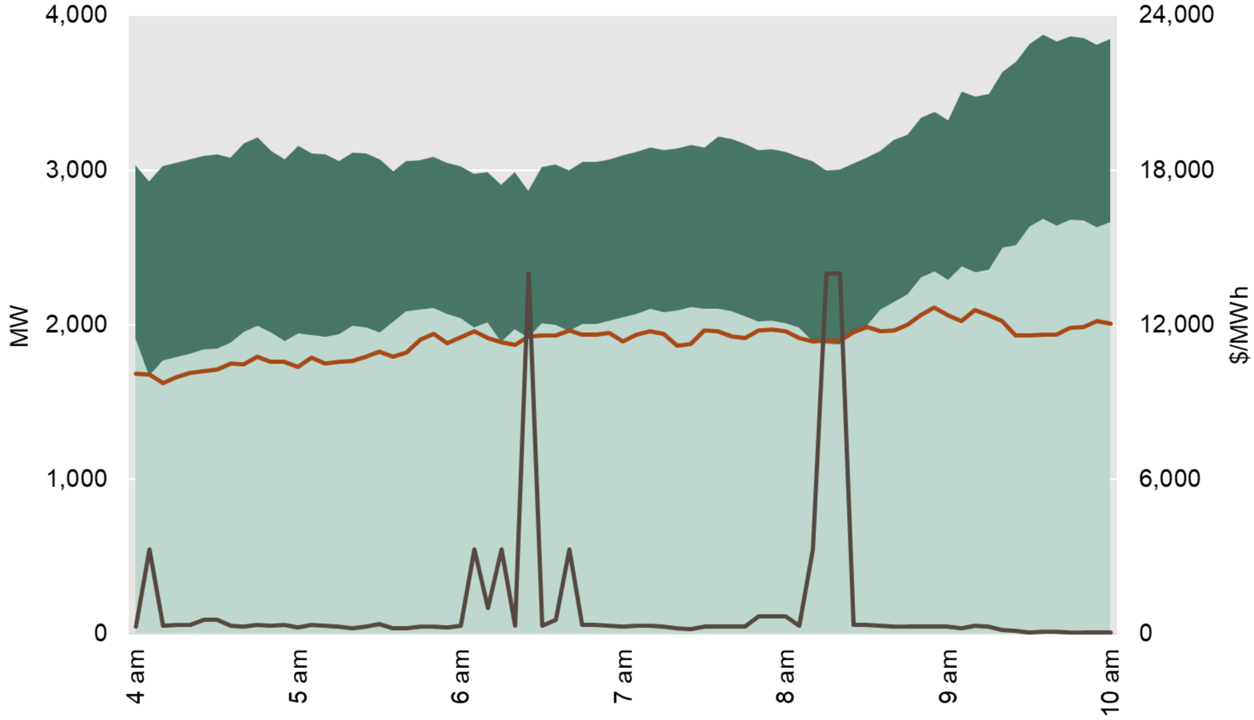
Figure 5 Capacity offered above and below $5,000 per MWh, 26 January



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

[8] Market notice 133067: forecast LOR for South Australia. Market notice 133105: actual LOR in South Australia.
[9] AEMO, "LOR Factsheet", Australian Energy Market Operator, 2025, accessed 22 May 2026.

Figure 6 Capacity offered above and below $5,000 per MWh, 27 January



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

1.2.1 High demand driven by hot temperatures

South Australia experienced exceptionally high temperatures on 26 and 27 January with some sites across the region breaking historical record temperatures for January.[10]

On 26 January, parts of Adelaide recorded temperatures in excess of 44°C. During the evening peak, electricity demand in South Australia exceeded 3,100 MW, which is within 300 MW of the record for South Australia and significantly higher than the previous week's average of around 1,900 MW during the same evening period.

Temperatures remained elevated throughout the evening of 26 January and continued into the morning of 27 January. Houses could not cool down overnight during the long run of heat and air conditioner usage remained high. At 8.30 am, when the price was $5,388 per MWh demand exceeded 2,500 MW. This was almost double the average demand of 1,300 MW recorded during the same morning period the previous week.

During the high-priced periods, actual demand was up to 160 MW higher than forecast one hour prior, while availability was lower than forecast by up to 460 MW. Due to the low availability of cheaper priced generation, up to 527 MW of high-priced capacity was needed.

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[10] Bureau of Meteorology, South Australia in January 2026, BOM website, 2026, accessed 22 May 2026.

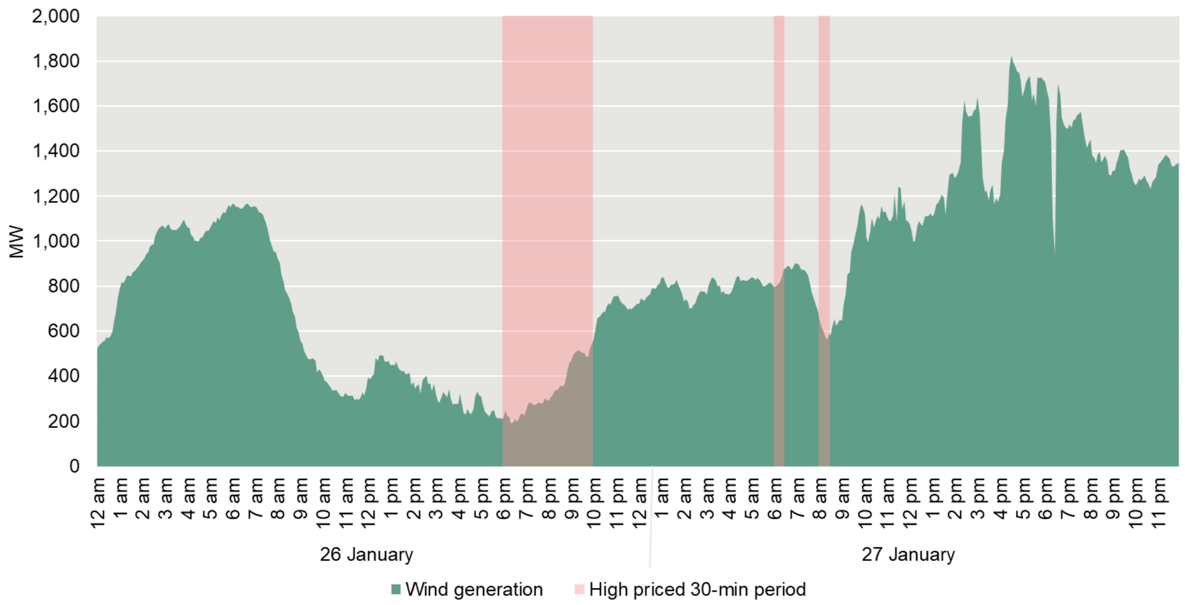
1.2.2 Low wind output

At the time of the high prices on 26 January, wind output was very low due to calm conditions in South Australia. Wind averaged around 337 MW (Figure 7) out of 2,766 MW registered capacity, which equates to around 12% of the installed capacity in South Australia. During the same evening period across the week prior, the average wind generation was around 1,000 MW. 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.

On 27 January at 6.30 am, wind generation averaged around 820 MW and the price was $3,704 per MWh. Later that morning, at 8.30 am wind generation dropped to around 600 MW from around 880 MW one hour prior. The price for this 30-minute period was $5,388 per MWh.

Although temperatures remained high throughout 27 January, wind generation increased later in the evening and was around 1,000 MW higher than the previous day. This additional wind generation on 27 January exceeded the high-priced capacity required on the previous evening and helped keep prices low.

Figure 7 Wind generation on 26 January and 27 January



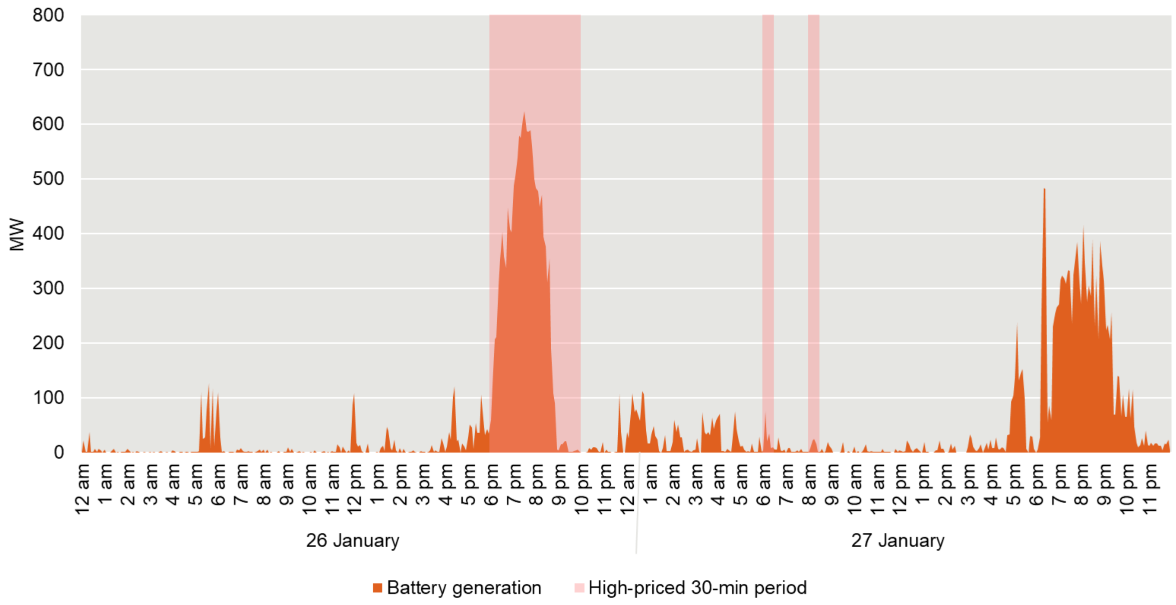
Source: AER analysis using NEM data.

1.2.3 Batteries

During the high prices on 26 January, batteries in the region provided substantial generation (Figure 8). However, battery offers started to be removed from around 7.50 pm with participants generally citing state of charge. 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. By 8.55 pm, battery offers were less than 100 MW, falling from an average of 839 MW offered at the beginning of the high prices.

Batteries commonly charge in the middle of the day to take advantage of the cheaper prices. When the high prices occurred at 6.30 am and 8.30 am the following morning on 27 January, there was very little battery capacity offered. This limited battery availability during these periods with increased reliance on more expensive generation such as gas.

Figure 8 Battery generation on 26 January and 27 January



Source: AER analysis using NEM data.

1.2.4 Network limitations

Interconnector flows into South Australia from Victoria were limited due to system normal constraints that were invoked to maintain system security. For one 30-minute period, 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. This limited South Australia's access to importing low-priced capacity from Victoria.

On 26 January:

- Murraylink's flows were reduced to 0 MW out of its 220 MW nominal capacity for the duration of the high prices until 9.40 pm. This was due to a constraint managing an outage of the New South Wales Murraylink runback scheme.
- Heywood flows were around 500 MW out of its 650 MW nominal capacity due to a system normal constraint.

On 27 January:

- Murraylink flows were forced counter-price at around 70 MW from South Australia into Victoria at 6.30 am due to a planned outage of the Rowville to South Morang line. At 8.30 am, flows into South Australia on Murraylink were limited to 44 MW by a system normal constraint.
- Heywood flows were around 580 MW for both the 6.30 am and 8.30 am high-priced periods and were also limited by a system normal constraint.

1.2.5 Rebidding

Rebidding for commercial and technical reasons contributed to some of the high prices on 26 January and 27 January (Appendix B and Appendix C).

1.2.5.1 26 January

Between 10 MW and 527 MW of high-priced capacity was needed to meet demand.

The requirement for high-priced capacity was mostly driven by the tight supply conditions detailed above. However, for some of the high prices, when smaller amounts of high-priced capacity were required, rebidding for technical and commercial reasons also contributed to some high price intervals.

In the two hours before the high prices, Neoen shifted between 130 MW and 200 MW of capacity from low to high prices at Blyth battery due to a change in forecast state of charge. This contributed to the high prices at 6.10 pm, 6.15 pm, 6.30 pm and 6.35 pm.

At 7.18 pm, Vena Energy removed 40 MW of low-priced capacity at Tailem Bend battery due to a change in forecast prices. This contributed to high prices at 8.15 pm.

1.2.5.2 27 January

Between 5 MW to 28 MW of high-priced capacity was needed to meet demand.

Across multiple rebids between 6.08 am and 8.13 am, Epic Energy removed up to 100 MW of low-price capacity at Mannum battery due to state of charge management. This contributed to the high prices at 6.25 am, 8.15 am and 8.20 am.

At 7.12 am, Neoen shifted 59 MW from above $3,000 per MWh (34 MW of which was priced above $14,000 per MWh) to below $1,000 per MWh at Hornsdale battery in response to volatile market prices. Across multiple rebids, most in the late rebidding period at 8.02 am and 8.07 am, this 59 MW of low-priced capacity was then withdrawn due to the unit's state of energy approaching lower operational limits. This contributed to the high prices at 8.15 am and 8.20 am.

At 8.01 am, AGL shifted up to 60 MW from low to high prices across three units at Torrens Island station due to a change in forecast prices. This contributed to the high prices at 6.25 am, 8.15 am and 8.20 am.

1.2.6 Impact on quarterly volume-weighted average price

Energy prices above $5,000 per MWh added $63 to South Australia's quarterly volume-weighted average price of $144 per MWh. Across the same period the previous year, high prices added only $16 to the quarterly volume-weighted average price of $98 per MWh.

1.2.7 Impact on contract prices

The high price periods in South Australia drove an increase in the Q1 2026 base future prices for South Australia. The base future prices for Q1 2026 increased by $20 per MWh following the high prices on 26 and 27 January. However, the sustained high prices had no material impact on base future prices for Q2 2026 or Q1 2027.

The price of Q1 2026 cap contracts increased significantly from $25 per MWh to $56 per MWh, correlating to the high price periods. There was no change to the Q2 2026 cap contracts, but the Q1 2027 cap contracts rose by $2 per MWh, to $33 per MWh.

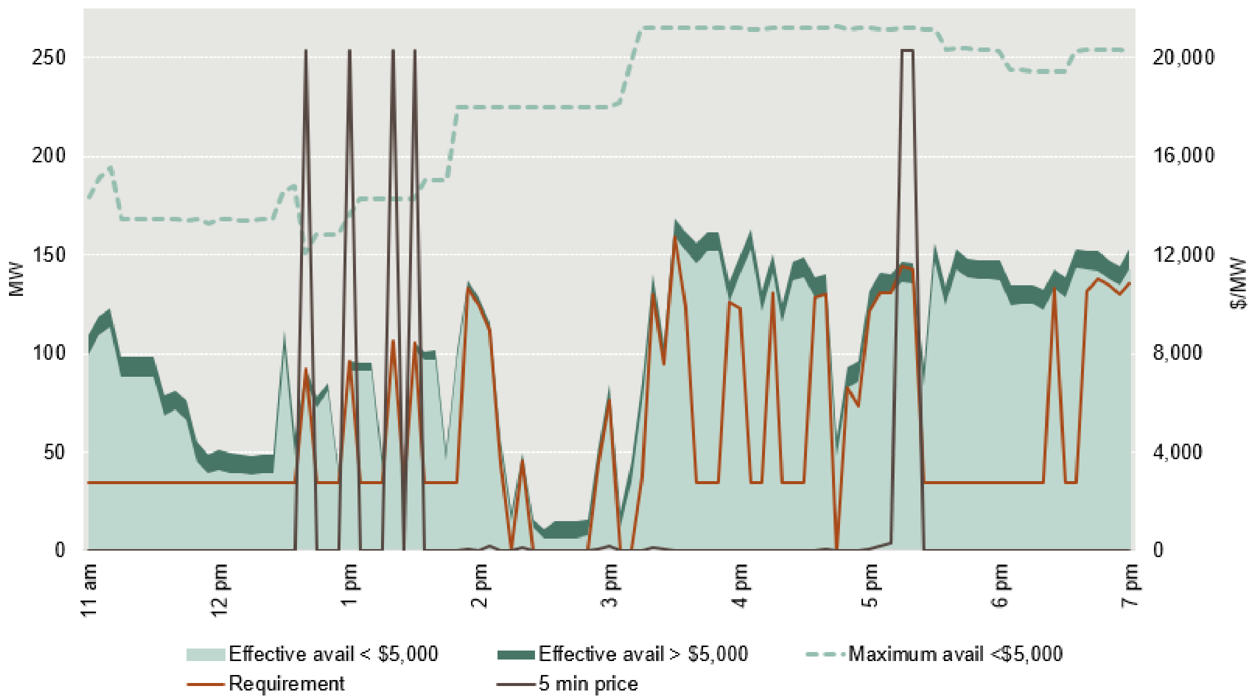
1.3 FCAS prices on 17 February, Tasmania

The highest priced day in February occurred on 17 February in Tasmania with high prices in the local R6 sec service at 1 pm, 1.30 pm and 5.30 pm. The 30-minute prices ranged from $6,764 per MW at 1 pm to $6,843 per MW at 5.30 pm. The price at 5.30 pm was the highest price recorded in the FCAS market for the quarter.

The high prices were not forecast and occurred mainly due to a few system normal constraints which included a control scheme for balancing demand and supply, and the trade-off between the energy and FCAS markets.

Though there was sufficient capacity offered below $5,000 per MW, the capacity effectively available was limited to around 55% due to the constraints, during the high-priced intervals. As a result, high-priced capacity had to be enabled to meet the R6 sec requirement (Figure 9).

Figure 9 R6 sec capacity availability above and below $5,000 per MW, 17 February



Source: AER analysis using NEM data.

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

Basslink has a control system which prevents it from transferring FCAS services when flows are within the "No-Go" zone range (i.e. when flows are between approximately -50 MW and +50 MW).[11] If Basslink is unable to transfer FCAS, Tasmania has to provide its own FCAS locally, which is typically managed by system normal constraints. In this case, a contingency R6 sec constraint was in place to cover the loss of the largest generator in the region.

On this day, the metered flows on Basslink during all six high-priced 5-minute intervals were within the "No-Go" zone range. For example, for the 5.15 pm and 5.20 pm intervals, the

[11] Australian Energy Market Operator, Constraint Formulation Guidelines, AEMO, 2025, accessed 22 May 2026.

metered flows on Basslink were 48 MW and 0 MW, respectively. This meant Basslink was in its “No-Go” zone and unable to transfer FCAS. A system normal constraint was invoked to cover the potential loss of the largest generator at the time. This caused the requirement for R6 sec services to fluctuate between 35 MW and 144 MW in the 30-minute lead up to 5.30 pm.

1.3.2 Some units were unable to provide their offered FCAS

Similar to 12 January (section 1.1.7), some units were unable to be enabled in FCAS due to the energy and FCAS trade-off.

Hydro Tasmania’s Gordon hydro generator unit typically offers most of its capacity at low prices. It had 144 MW out of the total 576 MW registered for R6 sec services in Tasmania.

At 5.15 pm, it was the largest generator in the region and was generating at (or near) its capacity in the energy market to meet Tasmanian demand. However, this meant that Gordon could not be enabled in R6 sec service and reduced the amount of R6 sec capacity effectively available to the minimum when the requirement increased suddenly to 144 MW at 5.15 pm. Consequently, another unit with high-priced capacity ($20,290 per MW) was dispatched to meet the 144 MW requirement and contributed to the high price at 5.30 pm.

Similarly, 61 MW at Hydro Tasmania’s Devils Gate station and 86 MW at Mackintosh station could not be enabled for FCAS at 1.20 pm and 1.30 pm, respectively, as they were dispatching mostly in energy, contributing to the high price at 1.30 pm.

1.3.3 AUFLS Control Scheme

Like 12 January (section 1.1.6), to restore supply and demand balance, the load unit, ASTHYD1, was constrained under the AUFLS scheme during the high prices. This limited the low-priced effective capacity that was available for R6 sec services. Around 65 MW of low-priced capacity offered was constrained and unable to make it to market, contributing to the high prices.

1.3.4 Rebidding contributed to some of the high prices

Rebidding by removal of low-priced capacity in R6 sec services for technical reasons contributed to the high prices at 1 pm and 1.30 pm on 17 February (Appendix D).

VIOTAS Australia removed 36 MW of low-priced capacity from its demand response unit, DRVIOT05, in the lead up to the high prices at 1 pm and 1.30 pm due to a change in plant conditions. These rebids contributed to the high prices at 12.40pm, 1 pm, 1.20 pm and 1.30 pm, as only up to 7 MW of high-priced capacity was needed to meet the R6 sec requirement. DRVIOT05 also set all the high prices at those times. As noted in section 1.1.8, we contacted VIOTAS Australia for further information regarding these rebids.

Rebidding did not contribute to the high price at 5.30 pm on this day.

1.4 FCAS price on 3 March, Tasmania

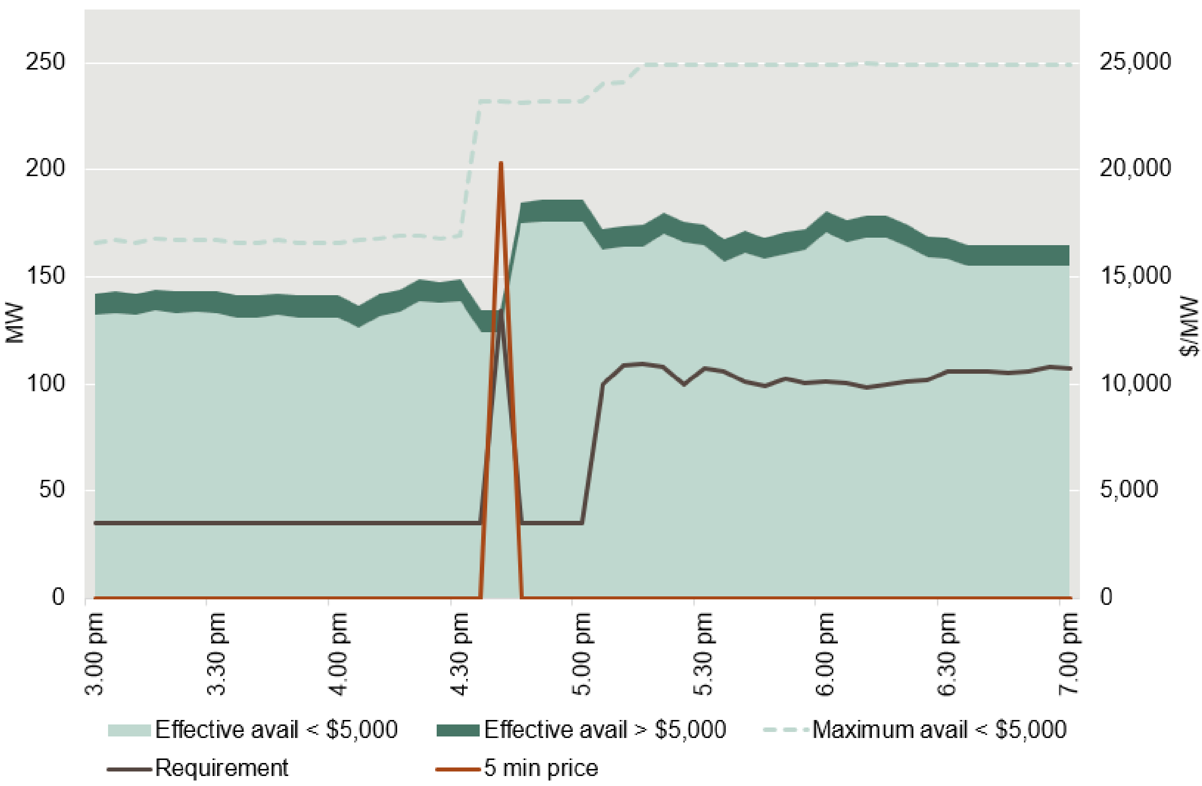
The highest priced day for the final month of Q1 2026 was 3 March. The local R6 sec 30-minute price in Tasmania was $3,382 per MW at 5 pm.

During the 5 pm 30-minute period, there was one 5-minute price of $20,290 per MW at 4.40 pm. All other 5-minute prices for this interval were $0.38 per MW. The high price at 4.40 pm was not forecast.

Similar to 17 February (section 1.3), the high prices occurred mainly due to a few system normal constraints which included a control scheme for balancing demand and supply, and trade-off between the energy and FCAS markets.

There was enough low-priced capacity offered to meet demand (Figure 10), however the constraints meant that some low-priced capacity was unable to make it to market. This resulted in high-priced capacity being enabled.

Figure 10 R6 sec capacity availability above and below $5,000 per MW



Source: AER analysis using NEM data.

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

As mentioned earlier, when Basslink is in the "No-Go" zone, it is unable to transfer FCAS and Tasmania has to provide its own local FCAS (section 1.3.1).[12]

At 4.40 pm, the metered flows on the Basslink dropped from -99 MW in the previous 5-minutes to -49 MW and Basslink entered its "No-Go" zone. This caused the requirement for R6 sec services to suddenly increase from 35 MW in the five minutes prior to 134 MW.

1.4.2 Some units were unable to provide their offered FCAS

Similar to 17 February (section 1.3), Hydro Tasmania's Gordon hydro generator had 144 MW out of the total 576 MW of capacity registered for R6 sec services in Tasmania.

At 4.40 pm, it was the largest generator in the region and was generating at (or near) its capacity in the energy market to meet Tasmanian demand. However, this meant that Gordon could not be enabled in R6 sec service and reduced the amount of FCAS R6 sec capacity effectively available when the requirement increased to 134 MW at 4.40 pm.

Consequently, another unit with high-priced capacity ($20,290 per MW) was dispatched to meet the requirement and contributed to the high price at 5 pm.

1.4.3 AUFLS Control Scheme

Similar to 12 January and 17 February (sections 1.1.6 and 1.3.3), to restore supply and demand balance, the load unit, ASTHYD1, was constrained under the AUFLS scheme, further limiting the low-priced effective capacity that was available for the R6 sec service during the high prices. Around 45 MW of low-priced capacity offered was constrained and unable to make it to market, contributing to the high prices.

1.4.4 Rebidding did not contribute to this price

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

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[12] See Australian Energy Market Operator, Constraint Formulation Guidelines, AEMO, 2025, accessed 22 May 2026.

Appendix A – Significant rebids 12 January, Tasmania

4.55 pm (1 MW of high-priced capacity[13] was needed) – R6, R60 and R5

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MW)	Price to ($/MW)	Rebid reason
3.08 pm		VIOTAS Australia	DRVIOT05	1	0.36	N/A	Change in plant conditions
3.43 pm		VIOTAS Australia	DRVIOT05	16	0.36	N/A	Change in plant conditions
3.58 pm		VIOTAS Australia	DRVIOT05	2	N/A	0.36	Change in plant conditions

5 pm (1 MW of high-priced capacity was needed) – R6, R60 and R5

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MW)	Price to ($/MW)	Rebid reason
3.08 pm		VIOTAS Australia	DRVIOT05	1	0.36	N/A	Change in plant conditions
3.43 pm		VIOTAS Australia	DRVIOT05	16	0.36	N/A	Change in plant conditions
4.04 pm		VIOTAS Australia	DRVIOT05	3	N/A	0.36	Change in plant conditions
4.08 pm		VIOTAS Australia	DRVIOT05	1	0.36	N/A	Change in plant conditions

[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 ⊗.

Appendix B – Significant rebids 26 January, South Australia

6.10 pm (95 MW of high-priced capacity was needed)⊗

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
6.04 pm	6.10 pm	Neoen	Blyth Battery	200	268	>9,610	Change in SOC Forecast

6.15 pm (95 MW of high-priced capacity was needed)⊗

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
3.39 pm		Neoen	Blyth Battery	130	<971	>9,610	SOC lower than Forecast
5.59 pm	6.05 pm	Neoen	Blyth Battery	69	>9,610	120	SOC lower than Forecast
6.04 pm	6.10 pm	Neoen	Blyth Battery	69	120	>9,610	Change in SOC Forecast

6.30 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
4.29 pm		Neoen	Blyth Battery	200	<971	>9,610	Change in SOC Forecast

6.35 pm (92 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
5.09 pm		Neoen	Blyth Battery	200	<971	>9,610	Change in SOC Forecast

8.15 pm (33 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid Reason
7.18 pm		Vena Energy	Tailem Bend Battery	40	899	N/A	Sa1 5min Pd Rrp For 1925 ($3300.0) Published At 1915 Is $11199.0 Lower Than 5min Pd Rrp Published At 1910 ($14499.0)

Appendix C – Significant rebids 27 January, South Australia

6.25 am (5 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
6.08 am	6.15 am	Epic Energy	Mannum Battery	100	3,120	N/A	Soc Management - Update Availability. SI
6.08 am	6.15 am	AGL Energy	Torrens Island	45	138	20,300	Chg In Aemo Disp~45 Price Change Vs Pd [Sa] [$999.43 Disp V Pe 0630 $170.44]

8.15 am (20 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
6.38 am		Epic Energy	Mannum Battery	33	3,120	N/A	Soc Management - Update Availability. SI
6.42 am		Epic Energy	Mannum Battery	11	3,120	N/A	Soc Management - Update Availability. SI
6.47 am		Epic Energy	Mannum Battery	10	3,120	N/A	Soc Management - Update Availability. SI
6.52 am		Epic Energy	Mannum Battery	1	N/A	3,120	Soc Management - Update Availability. SI
6.57 am		Epic Energy	Mannum Battery	3	3,120	N/A	Soc Management - Update Availability. SI
7.03 am		Epic Energy	Mannum Battery	3	3,120	N/A	Soc Management - Update Availability. SI
7.08 am		Epic Energy	Mannum Battery	3	3,120	N/A	Soc Management - Update Availability. SI
7.12 am		Epic Energy	Mannum Battery	2	3,120	N/A	Soc Management - Update Availability. SI
7.12 am		Neoen	Hornsdale Battery	59	>3,382	<995	Volatile Market Prices
7.12 am		Neoen	Hornsdale Battery	3	N/A	<995	Volatile Market Prices
7.17 am		Neoen	Hornsdale Battery	1	995	N/A	Soe Approaching

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
							Lower Operational Limits Set By Asset Operator For 2026-01-27 07:25 Causing Limited Availability For Product Gen Energy
7.27 am		Epic Energy	Mannum Battery	4	3,120	N/A	SOC management - update availability. SL
7.32 am		Neoen	Hornsdale Battery	1	995	N/A	SOE approaching lower operational limits set by asset operator for 2026-01-27 07:40 causing limited availability for product gen energy
7.33 am		Epic Energy	Mannum Battery	3	3,120	N/A	SOC management - update availability. SL
7.42 am		Epic Energy	Mannum Battery	3	3,120	N/A	SOC management - update availability. SL
7.47 am		Epic Energy	Mannum Battery	3	3,120	N/A	SOC management - update availability. SL
7.47 am	7.55 am	Neoen	Hornsdale Battery	1	995	N/A	SOE approaching lower operational limits set by asset operator for 2026-01-27 07:55 causing limited availability for product gen energy
7.58 am		Epic Energy	Mannum Battery	23	3,120	N/A	SOC management - update availability. SL
8.01 am	8.10 am	AGL	Torrens Island	60	138	20,300	040 Chg in AEMO DISP~45 Price change vs PD [SA] $330.00 vs $138.04 0830
8.02 am	8.10 am	Neoen	Hornsdale Battery	28	<995	N/A	SOE approaching

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
							lower operational limits set by asset operator for 2026-01
8.07 am	8.15 am	Neoen	Hornsdale Battery	31	359	N/A	SOE approaching lower operational limits set by asset operator for 2026-01-27 08:15 causing limited availability for product gen energy
8.08 am		Epic Energy	Mannum Battery	10	N/A	3,120	SOC management - update availability. SL

8.20 am (28 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
6.38 am		Epic Energy	Mannum Battery	33	3,120	N/A	SOC management - update availability. SL
6.42 am		Epic Energy	Mannum Battery	11	3,120	N/A	SOC management - update availability. SL
6.47 am		Epic Energy	Mannum Battery	10	3,120	N/A	SOC management - update availability. SL
6.52 am		Epic Energy	Mannum Battery	1	N/A	3,120	SOC management - update availability. SL
6.57 am		Epic Energy	Mannum Battery	3	3,120	N/A	SOC management - update availability. SL
7.03 am		Epic Energy	Mannum Battery	3	3,120	N/A	SOC management - update availability. SL
7.08 am		Epic Energy	Mannum Battery	3	3,120	N/A	SOC management - update availability. SL
7.12 am		Epic Energy	Mannum Battery	2	3,120	N/A	SOC management - update availability. SL
7.12 am		Neoen	Hornsdale Battery	59	>3,382	<995	Volatile Market Prices

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
7.12 am		Neoen	Hornsdale Battery	3	N/A	<995	Volatile Market Prices
7.27 am		Epic Energy	Mannum Battery	4	3,120	N/A	SOC management - update availability. SL
7.27 am		Neoen	Hornsdale Battery	3	995	N/A	SOE approaching lower operational limits set by asset operator for 2026-01-27 07:35 causing limited availability for product gen energy
7.33 am		Epic Energy	Mannum Battery	3	3,120	N/A	SOC management - update availability. SL
7.37 am		Neoen	Hornsdale Battery	1	N/A	995	SOE approaching lower operational limits set by asset operator for 2026-01-27 07:45 causing limited availability for product gen energy
7.42 am		Epic Energy	Mannum Battery	3	3,120	N/A	SOC management - update availability. SL
7.47 am		Epic Energy	Mannum Battery	3	3,120	N/A	SOC management - update availability. SL
7.47 am	7.55 am	Neoen	Hornsdale Battery	3	N/A	995	SOE approaching lower operational limits set by asset operator for 2026-01-27 07:55 causing limited availability for product gen energy
7.58 am	8.05 am	Epic Energy	Mannum Battery	3	3,120	N/A	SOC management - update availability. SL
8.01 am	8.10 am	AGL	Torrens Island	60	138	20,300	040 Chg in AEMO DISP~45 Price change vs PD [SA]

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
							$330.00 vs $138.04 0830
8.02 am	8.10 am	Neoen	Hornsdale Battery	4	995	N/A	SOE approaching lower operational limits set by asset operator for 2026-01-27 08:10 causing limited availability for product gen energy
8.03 am	8.10 am	Epic Energy	Mannum Battery	20	3,120	N/A	SOC management - update availability. SL
8.07 am	8.15 am	Neoen	Hornsdale Battery	41	<995	N/A	SOE approaching lower operational limits set by asset operator for 2026-01-27 08:15 causing limited availability for product gen energy
8.12 am	8.20 am	Neoen	Hornsdale Battery	18	359	N/A	SOE approaching lower operational limits set by asset operator for 2026-01-27 08:20 causing limited availability for product gen energy
8.13 am	8.20 am	Epic Energy	Mannum Battery	8	N/A	3,120	SOC management - update availability. SL

Appendix D – Significant rebids 17 February, Tasmania

12.40 pm (7 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MW)	Price to ($/MW)	Rebid reason
12.13 pm	12.20 pm	VIOTAS Australia	DRVIOT05	1	N/A	0.36	Change in plant conditions
12.23 pm	12.30 pm	VIOTAS Australia	DRVIOT05	2	0.36	N/A	Change in plant conditions
12.28 pm	12.35 pm	VIOTAS Australia	DRVIOT05	1	0.36	N/A	Change in plant conditions
12.33 pm	12.40 pm	VIOTAS Australia	DRVIOT05	34	0.36	N/A	Change in plant conditions

1 pm (4 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MW)	Price to ($/MW)	Rebid reason
12.33 pm	12.40 pm	VIOTAS Australia	DRVIOT05	1	0.36	N/A	Change in plant conditions
12.38 pm	12.45 pm	VIOTAS Australia	DRVIOT05	15	0.36	N/A	Change in plant conditions
12.43 pm	12.50 pm	VIOTAS Australia	DRVIOT05	20	0.36	N/A	Change in plant conditions

1.20 pm (4 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MW)	Price to ($/MW)	Rebid reason
12.28 pm		VIOTAS Australia	DRVIOT05	1	N/A	0.36	Change in plant conditions
12.33 pm		VIOTAS Australia	DRVIOT05	3	0.36	N/A	Change in plant conditions
12.38 pm		VIOTAS Australia	DRVIOT05	14	0.36	N/A	Change in plant conditions
12.43 pm		VIOTAS Australia	DRVIOT05	17	0.36	N/A	Change in plant conditions
12.48 pm	12.55 pm	VIOTAS Australia	DRVIOT05	3	0.36	N/A	Change in plant conditions

1.30 pm (4 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MW)	Price to ($/MW)	Rebid reason
12.33 pm		VIOTAS Australia	DRVIOT05	1	0.36	N/A	Change in plant conditions
12.38 pm		VIOTAS Australia	DRVIOT05	13	0.36	N/A	Change in plant conditions
12.43 pm		VIOTAS Australia	DRVIOT05	20	0.36	N/A	Change in plant conditions
12.48 pm		VIOTAS Australia	DRVIOT05	2	0.36	N/A	Change in plant conditions

Appendix E – Significant prices tables

We considered 16 days in our review this quarter and determined five to be significant price days for reporting. In accordance with the approach outlined in sections 2.2 and 2.3 of the guidelines, we selected the significant price outcomes by:

- applying a principles-based approach for the month of January, resulting in 12 January being selected as the most interesting, unusual and consequential day of the month;
- choosing 26 January, the highest-priced day of the month, as the fourth day for the quarter;
- including 27 January for its connection to the events of 26 January, and
- selecting the highest-priced days for February (17) and March (3).

While entire high-priced days have been reviewed, analysis has been targeted for material intervals within the day. When price was below $5,000 per MWh, an appropriate price threshold was applied to determine the amount of high-priced capacity needed. This is highlighted within the relevant rebidding appendices.

Table 8 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 9 further below provides the 11 other pricing outcomes that were considered but not selected for January to March as significant price outcomes including reasons for exclusion.

Table 8 Details of significant price days selected for January to March

	Date, Time	Region	Market	Highest 30-min price ($/MWh Energy, $/MW FCAS)	Reasons for inclusion or exclusion
Day for January (not the highest price day)	12 January 5 pm	Tasmania	Energy, FCAS	6,835 (Energy) 6,763 (R5 min) 6,764 (R60 sec, R6 sec) 6,766 (RReg)	12 January was not the highest day for the month however it was selected as the significant price outcome day for January as it was more unique and interesting than the highest price day of the month (26 January). On 12 January, Basslink, was taken offline due to operational challenges. This meant imports into Tasmania fell suddenly from 180 MW to 0 MW. Generation in Tasmania could not start up or ramp up quickly enough to make up for the loss of imports, and a large amount of

	Date, Time	Region	Market	Highest 30-min price ($/MWh Energy, $/MW FCAS)	Reasons for inclusion or exclusion
					low-priced generation was trapped/stranded in FCAS. High energy prices were set due to the trade-off between energy and FCAS and a constraint managing the balance between demand and supply. At the same time, there were high FCAS prices in Tasmania.
Day for February (highest price day)	17 February 1 pm 1.30 pm 5.30 pm	Tasmania	FCAS	6,843	17 February was selected to report as it was the highest price of the month. We also considered it relevant to provide additional insights into Tamanian FCAS prices and the market supply dynamics contributing to high prices. During this event, high FCAS prices in Tasmania were experienced in the afternoon and evening driven by control system issues, the trade-off between energy and FCAS, units being trapped/stranded and some generator rebidding.
Day for March (highest price day)	3 March 5 pm	Tasmania	FCAS	$3,382	3 March was selected to report as it was the highest price of the month. We also considered it relevant to provide additional insights into Tamanian FCAS prices and the market supply dynamics contributing to high prices. During this event, the local R6 sec 30-minute price exceeded $3,000 per MW at 5 pm. Similar to 17 February, this price spike was driven by

	Date, Time	Region	Market	Highest 30-min price ($/MWh Energy, $/MW FCAS)	Reasons for inclusion or exclusion
					system normal constraints and the trade-off between energy and FCAS markets.
Fourth day	26 January 6.30 pm - 10.30 pm	South Australia	Energy	20,158	While 26 January was the highest-price day of January it was not initially selected to report on. Instead, it was selected as the fourth day to report on for the quarter as it was the highest price in the quarter. On 26 January, high prices occurred during the evening peak. High prices were forecast, and an actual lack of reserves (level 1) was declared by AEMO. This event was driven by high demand due to hot weather, low wind generation, planned network limitations and some rebidding.
Fifth day	27 January 6.30 am 8.30 am	South Australia	Energy	5,388	We determined it appropriate to also report on the 27 January high prices due to its relationship to 26 January. On 27 January, high prices occurred during the morning peak due to continuing conditions from the previous day. Drivers included high morning demand due to persisting hot temperatures, low wind generation, planned network limitations and some rebidding.

Table 9 below provides details of 11 other pricing outcomes that occurred in the quarter that were analysed but not selected for detailed reporting. The table also provides reasons for their exclusion.

Table 9 Other pricing outcomes considered but not selected for January to March

Month	Day	Time	Region, Market	Price ($/MWh)	Reasons for exclusion
January	6	7.30 pm 8 pm 8.30 pm	SA, Energy	3,845 - 14,578	6 January was not selected as the fourth significant price day. Instead, the 26 January (highest price day) and 27 January were selected as the fourth and fifth days. Also, 6 January high prices occurred during evening peak demand and were driven by similar conditions to events covered in recent high price reports. See Q4 2024 and Q1 2025 for recent reports detailing high prices in South Australia driven by low wind, high demand and network limitations.[14, 15]
	10	7-7.30 pm	NSW, Energy	6,952 - 11,862	High prices occurred during evening peak demand and were driven by similar factors to those covered in recent high price reports. See Q2 2025 and Q4 2025 for recent reports detailing high prices in NSW related to high demand, low wind generation, planned network limitations and rebidding.[16, 17]
	15	7 pm	Qld, Energy	5,142	Like 10 January, this high price occurred during the evening peak and, similar to other high price events reported on recently, was driven by generator outages and rebidding. See Q1 2024 and

[14] AER, Prices above $5,000/MWh - October to December 2024, Australian Energy Regulator, 2025, accessed 22 May 2026.

[15] AER, Prices above $5,000/MWh - January to March 2025, Australian Energy Regulator, 2025, accessed 22 May 2026.

[16] AER, Prices above $5,000/MWh – April to June 2025, Australian Energy Regulator, 2025, accessed 22 May 2026.

[17] AER, Prices above $5,000/MWh – October to December 2025, Australian Energy Regulator, 2026 accessed 22 May 2026.

Month	Day	Time	Region, Market	Price ($/MWh)	Reasons for exclusion
					Q2 2025 for recent reports detailing high prices in Queensland related to generator outages and rebidding.[18, 19]
February	7	5.30 am	SA, Energy	3,984	This price occurred during the morning peak. It was the fifth highest price day of the month driven by planned network limitations and generator rebidding. It was excluded on the basis that it was like other events recently reported on and not the highest priced day.
	23	6.30 pm, 7 pm, 9.30 pm	Tas, FCAS	4,716 – 6,792	Like the selected day for February (17 February), high R6 sec FCAS prices in Tasmania on 23, 26 and 27 February were driven by control system issues, the trade-off between energy and FCAS, generator availability and units being trapped/stranded. Given the very similar nature of drivers and the fact these were not the highest-priced days for the month it was excluded.
	26	6 am, 9 am	Tas, FCAS	3,382 – 6,764	
	27	4.30 am	Tas, FCAS	6,766	
March	1	3 pm	SA, Energy	345	On 1 March, prices just above $300 per MWh at 3 pm were forecast. No significant rebids were identified. The event was excluded for those reasons.
	15	4 pm	Tas, FCAS	809	Prices above $800/MWh at 4 pm were not forecast. As this price was lower than the 3 March and driven by similar factors it was excluded.
	24	1.30 am	SA, Energy	401	This 30-minute price was just above $400/MWh was forecast. This was

[18] AER, Prices above $5,000/MWh - January to March 2024, Australian Energy Regulator, 2024, accessed 22 May 2026.

[19] AER, Prices above $5,000/MWh – October to December 2025, Australian Energy Regulator, 2026, accessed 22 May 2026.

Month	Day	Time	Region, Market	Price ($/MWh)	Reasons for exclusion
					caused by one 5-minute price spike to $1,000 per MWh due to a unit failing to start and excluded on that basis. These factors were not considered significant to pricing outcomes.
	25	5 am	SA, Energy	336	The event was excluded on the basis that it wasn't the highest price and, even though the price was not forecast, wind output was low at the time.