Electricity prices above $5,000 per MWh

October to December 2025

February 2026

AUSTRALIAN
ENERGY
REGULATOR

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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 guideline outlining its approach for monitoring and reporting significant price outcomes under Rule 3.13.7 (guideline).

The inaugural guideline, which is applicable to this Q4 2025 report, was published in 2022 and commits to:

- reporting whenever the 30-minute price for wholesale electricity exceeds $5,000 per megawatt hour (MWh); or two consecutive 30-minute Frequency Control Ancillary Service (FCAS) prices exceed $5,000 per MW[2]; and
- describing the significant factors contributing to 30-minute prices exceeding $5,000 per MWh, considering market conditions, available generation capacity, network availability, as well as offer and rebidding behaviour.

In 2025, we conducted a review of the 2022 guideline which concluded the significant price outcome criteria of $5,000 per MWh was no longer fit for purpose. A revised guideline setting out a new significant price outcome criteria and approach was published in January 2026.[3]

This report is the last report that falls under the guideline published in 2022.[4] We will apply the revised significant price outcome criteria outlined in the 2026 guideline for reporting events from Q1 2026 onwards.[5]

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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] The 30-minute price is the average of six 5-minute intervals under the electricity rules.

[3] AER, Significant price reporting guidelines, January 2026.

[4] AER, Significant price reporting guidelines, September 2022

[5] AER, Significant price reporting guidelines, January 2026.

2 Executive Summary

During Q4 2025, 30-minute prices exceeded the reporting threshold of $5,000 per MWh three times. All high prices this quarter were in the New South Wales (NSW) energy market.

The 30-minute price for energy exceeded $5,000 per MWh on 25 and 26 November, and 19 December. This compares to seven times in the previous quarter and 23 times over the same period in 2024. The high prices were not forecast.

The common factors across the high prices this quarter were:

- A sudden increase in demand due to a significant reduction in rooftop solar generation
- Generating units were unable to start or ramp up quickly enough, and
- Network limitations that prevented cheaper generation from getting to load centres.

Temperatures on 19 December hit a seven-year record for Sydney of 42°C and 26 November experienced a high of 34°C.

Storms over parts of NSW, including greater Sydney, caused cloud cover during the middle of the day on 25 and 26 November, and in the early afternoon on 19 December. These weather patterns resulted in a sudden and unusual reduction in rooftop solar generation during peak solar generation times causing a significant increase in demand. Some generators with low-priced capacity were unable to start or ramp up quickly enough to help lower the price (section 3.1). For example, on 25 November, 1,700 MW of low-priced capacity was unable to be dispatched due to some units being limited by their offered ramp up rate.[6]

We did not observe any significant rebids of ramp rate offers or start up timings by generators during the relevant high price periods. However, we did identify significant ramp rate constraints for nine units across four market participants where their offered ramp up rates were close to the minimum allowed under the Rules (Table 3). All else being equal, if these ramp up rates offered were nearer to the maximum registered rate for each unit or were more aligned with the unit's technical capability, all high prices would likely not have occurred.

Planned network outages on the Canberra to Lower Tumut and the Avon to Marulan lines on 25 and 26 November, respectively, reduced the amount of low-priced generation that could flow from southern NSW and Victoria to the load centre in Sydney during the high prices. There were also network limitations due to system normal constraints on all the high price days (section 4).

Rebidding contributed to the high prices on 25 November only (section 5). These rebids included participants withdrawing low-priced capacity or moving capacity from low to high prices for technical and commercial reasons.

[6] Under the Rules, participants are required to offer the rate at which the output of their unit may vary up and down within five minutes (clause 3.8.3A(b)(1)). This is commonly referred to as a ramp rate offer.

Table 1 Common drivers of high energy prices

Date	High prices forecast	Network limitations	High demand	Low solar	Baseload outages	Rebidding
25 November, NSW	×	✓	✓	✓	×	✓
26 November, NSW	×	✓	✓	✓	×	×
19 December, NSW	×	✓	✓	✓	×	×

Source: AER analysis using NEM data.
Note: Baseload outages refer to planned or unplanned outages of coal-fired generators.

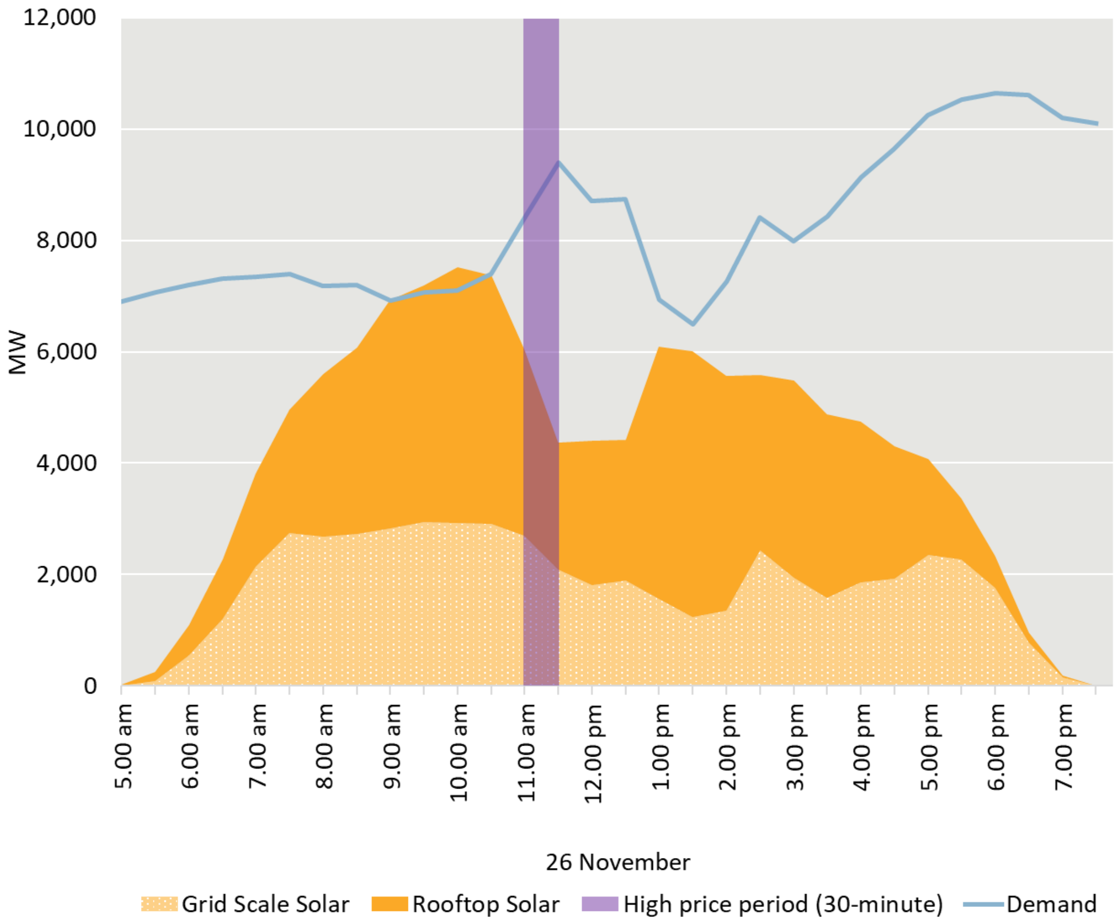
Coal-fired baseload outages this quarter averaged around 2,175 MW in NSW and was 15% higher than Q4 2024. There was a combination of both planned and unplanned coal-fired baseload outages during the high prices. They were known in advance and included in the initial forecasts.[7] We do not view these outages as a common driver for the high prices.

[7] Two units were on long term outages more than one month prior to the November high prices. A third unit went offline two days prior to 19 December.

3 A sudden reduction in rooftop solar generation increased demand

Fast-moving storms brought increased cloud cover over Sydney which caused a sharp drop in rooftop solar generation during the middle of the day on 25 and 26 November, and in the early afternoon on 19 December. This resulted in a sudden increase in demand in the hour before the high prices across all the high price days. For example, on 26 November, the sudden drop in rooftop solar generation resulted in demand increasing by around 2,000 MW (Figure 1, Table 2 and section 7). Temperatures on this day were as high as 34°C. Temperatures were also very high on 19 December, reaching a seven-year record for Sydney of 42°C.

Figure 1 Correlation between demand and rooftop solar generation



Source: AER analysis using NEM data.
Note: Figure 1 shows grid scale solar generation, rooftop solar generation and demand. Reduction of rooftop solar increases NEM demand. Reduction of grid scale solar does not affect demand, but rather, reduces the amount of low-priced supply available to meet demand.

A sudden fall in solar generation has two effects:

- the reduction of rooftop solar increases demand that needs to be met from the grid, and
- a reduction of grid scale solar must be replaced by higher-priced generation.

During the high price periods, the reduction in total solar generation compared to the previous hour was 1,520 MW on 25 November, 3,008 MW on 26 November, and 1,600 MW on 19 December (Table 2).

Table 2 Changes in demand and solar generation

Date	Demand (MW)		Rooftop solar (MW)		Grid solar (MW)	
	High price period	Change from 1 hour prior	High price period	Change from 1 hour prior	High price period	Change from 1 hour prior
25 November	7,236	↑ 1,538	4,178	↓ 1,209	2,145	↓ 311
26 November	9,400	↑ 2,004	2,285	↓ 2,183	2083	↓ 825
19 December	12,098	↑ 1,237	2,985	↓ 1,409	2,667	↓ 191

Source: AER analysis using NEM data.

Further information on the reduction in solar generation can be found in sections 7 and 8.

3.1 Some units were unable to start or ramp up quickly enough to lower the price

Following the sudden drop in solar generation, some units were unable to ramp up quickly enough to help meet demand and lower the price. This impacted the high-priced intervals on all the high price days. For example, on 25 November, units being unable to ramp up quickly enough meant that up to around 1,700 MW of low-priced capacity was unable to be dispatched, while only up to around 160 MW of high-priced capacity was needed (Figure 3).

We did not observe any significant rebids of ramp rate offers or start up timings by generators in the relevant periods. However, we did identify significant ramp rate constraints for nine units across four market participants where their offered ramp up rates were close to the minimum allowed under the Rules (Table 3). All else being equal, if these ramp up rates offered were nearer to the maximum registered rate for each unit or were more aligned with the unit's technical capability, all high prices would likely not have occurred.

The AER has previously considered this issue and submitted a rule change request to the Australian Energy Market Commission (AEMC) proposing a requirement for generators to submit ramp rates that reflect the technical /maximum capabilities of generating plant, rather than using the ramp rates to achieve commercial objectives.[8, 9] The AER will continue monitoring this issue and, where applicable, consider it in future reports.

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[8] AER, AEMC rule change - Generator ramp rates and dispatch inflexibility bidding, 5 February 2015

[9] AEMC, Generator ramp rates and dispatch inflexibility in bidding, 19 March 2015

Table 3 Ramp up rates of significant ramp rate constrained generation on 25 and 26 November, and 19 December per 5-minutes

Participant	Unit	Offered ramp rate per unit	Minimum up ramp rate per unit	Maximum up ramp rate per unit
Delta Electricity	Vales Point unit 6	15 to 30	15	125
Origin Energy	Eraring unit 1, 2 and 3	15 to 25	15	100
EnergyAustralia	Mount Piper unit 1 and 2	25	15	125
AGL Energy	Bayswater unit 1, 2 and 3	20	15	660 to 685

Source: AER analysis using NEM data.
Note: There were also other units that were ramp rate limited but were less significant contributors (Table).

Some units were also unable to start up quickly enough to meet the sudden increase in demand and lower the price. For example, on 26 November, units unable to start up quickly enough meant that up to 412 MW of low-priced capacity was unable to be dispatched while only around 312 MW of high-priced capacity was needed (Figure 3). If the units were able to start up quickly enough, the high prices on 25 and 26 November would likely not have occurred. This did not impact 19 December.

Further information on this can be found in sections 7 and 8, and in Figure 3.

4 Network limitations

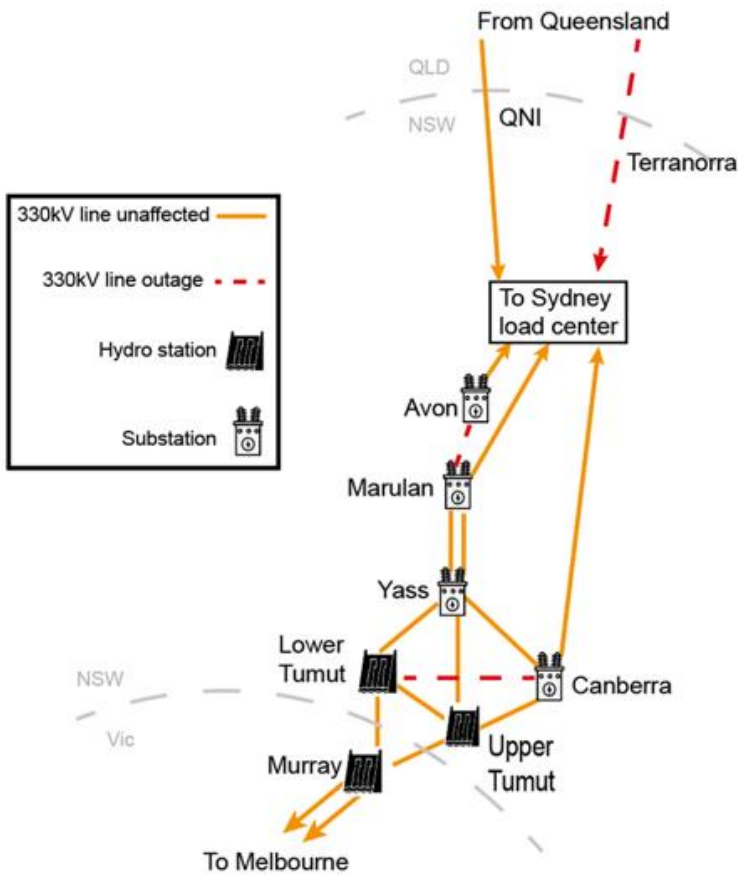
Planned network outages and system normal constraints in the southern NSW area limited NSW's ability to access low-priced capacity from Queensland and Victoria. Flows on the Queensland – NSW (QNI) and Directlink (Terranora) interconnectors were well below their nominal capacity due to a system normal constraint in place to prevent overloading and to maintain system security. Low-priced generation in southern NSW could not make it to the Sydney load centres and had to be forced into Victoria at times due to the outages.

Constraints used to manage these outages and system normal constraints together prevented up to 2,780 MW of low-priced capacity from making it to market during the high-price periods, which was 17 times the amount of high-priced capacity that was needed to be dispatched.

4.1 Canberra to Lower Tumut and Avon to Marulan lines

On 25 and 26 November, planned network outages on the Canberra to Lower Tumut and Avon to Marulan lines, respectively, limited the amount of low-priced capacity from Victoria and southern NSW that could reach key load centres including Sydney (Figure 2).

Figure 2 Network diagram



Source: AER analysis using NEM data.

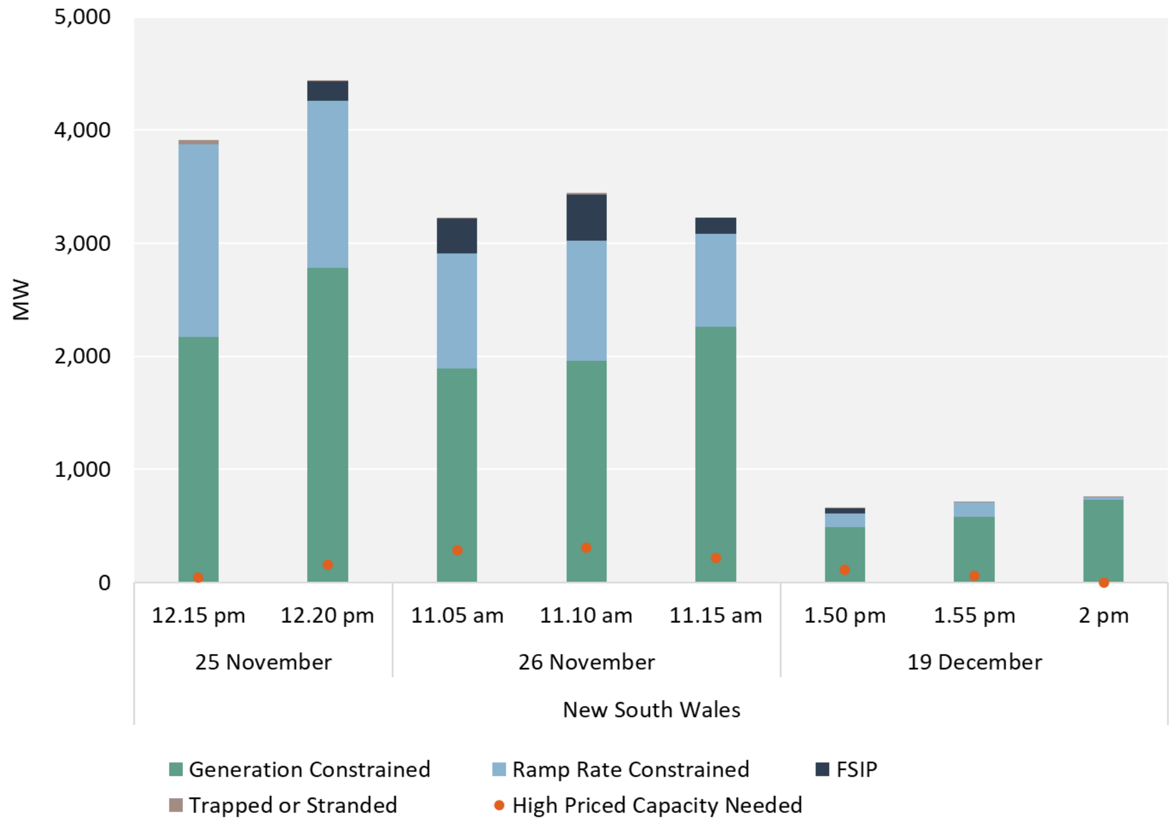
The Canberra to Lower Tumut line outage started on 17 November and ended on 28 November and contributed to the high price on 25 November.

The Avon to Marulan line outage started on 25 November and ended on 6 December and contributed to the high price on 26 November.

The location of the outages meant that up to 2,245 MW of low-priced capacity in southern NSW was unable to make it to market during the high prices. For all the high-priced intervals, the amount of low-priced capacity behind the constraint (green bar in Figure 3) was more than the high-priced capacity that was ultimately needed to meet demand (red dots in Figure 3).

On 19 December, there were no network line outages, but system normal constraints contributed to the high price.[10]

Figure 3 Low-priced capacity unable to be dispatched due to network constraints, ramp rates and start up limitations



Source: AER analysis using NEM data.
Note: High price capacity needed refers to the amount of capacity priced over $5,000 per MWh dispatched (MW) during intervals when a high-priced offer set the price. The red dot is the amount of high-priced capacity that was needed to meet demand. The blue bars are the amount of capacity that could not be dispatched because the generator was unable to ramp up faster. Fast start inflexibility profile (FSIP) relates to how quickly a unit can start up.

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[10] "System normal" constraints do not relate to outages, but are in place to protect system security, e.g. reducing generation to prevent overloading a line.

4.2 Terranora

A planned outage of Terranora's three Directlink cables reduced flows to around 0 MW compared to its nominal capacity of 210 MW and contributed to the high price on 25 November (Figure 2). This outage started in the morning of 25 November around 6 am and ended the same day at around 4 pm.

4.3 System normal constraints

On 25 and 26 November, a system normal constraint was used to avoid overloading the Uralla to Tamworth line, contributing to the high prices. This constraint limited imports into NSW on the QNI to around 600 MW on 25 November, and to around 780 MW on 26 November, compared to its nominal capacity of 1,400 MW.

On 19 December, a system normal network constraint was used to avoid overloading the Bannaby to Sydney West line, contributing to the high prices. This meant up to around 730 MW of low-priced capacity in southern NSW was unable to make it to market, during the high prices. Further information on this can be found in section 8.

5 Rebidding contributed to the high price on 25 November

Rebidding contributed to the high prices on 25 November. These rebids included participants withdrawing low-priced capacity or moving capacity from low to high prices for either technical or commercial reasons.

The amount of high-priced capacity needed to meet demand on 25 November was up to 162 MW. AGL Energy shifted 250 MW of capacity at Bayswater from low to high prices due to a change in forecast prices. Iberdrola at Bodangora Wind Farm and Ironbark Energy at Gunnedah Solar Farm together removed 221 MW of low-priced capacity due to a change in plant availability due to high winds and a planned outage, respectively, although there was only 192 MW available prior to rebidding.

Details of participant rebidding are included in the individual high price day section in section 7 and in Appendix A).

6 Impact of prices above $5,000 per MWh

6.1 Contributions to average volume weighted prices

The three high prices in NSW drove up the quarterly volume-weighted average (VWA) price by $7 per MWh.

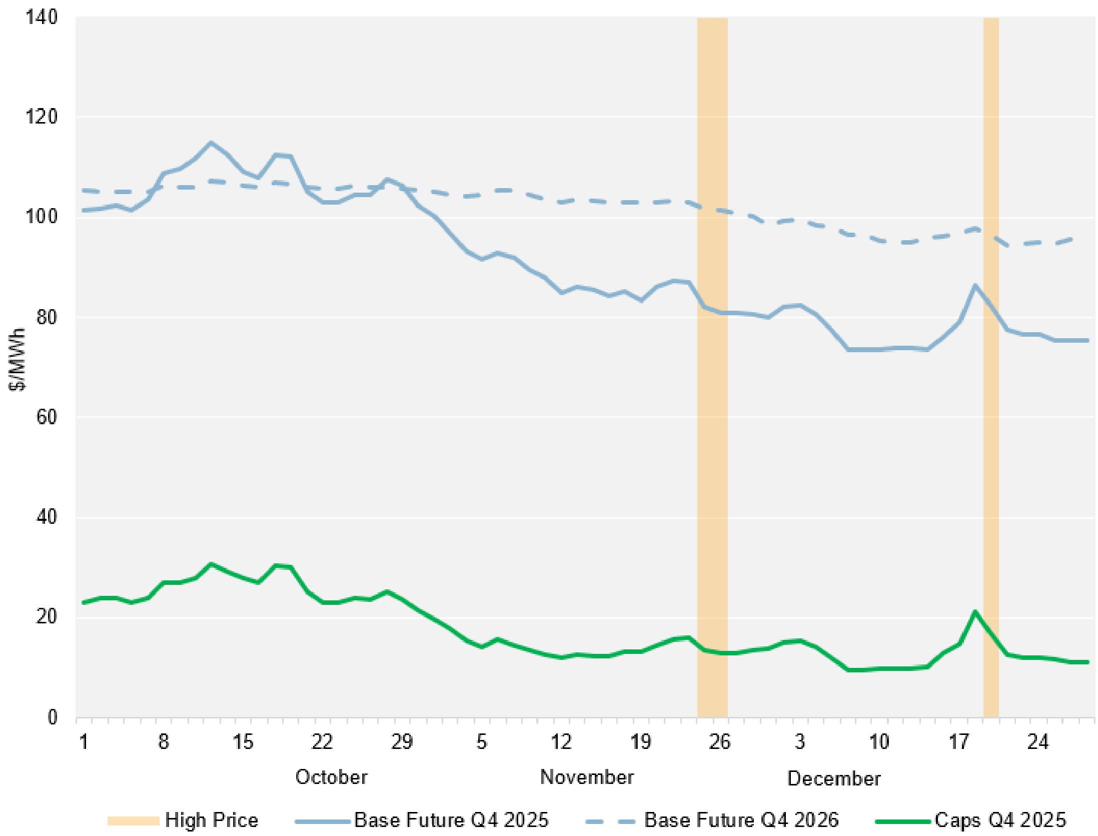
6.2 Impact on future contract prices

Generators and retailers enter futures contracts to secure the price of electricity in the future. The price of these futures contracts will depend on the supply and demand in the contract market, which can be driven by a number of factors including demand, weather conditions, generation outages and fuel availability.

In NSW, the high energy prices appear to have had little impact on the future contract prices, with contract prices increasing in the days prior and decreasing after (Figure 4). The contract prices continued to fall suggesting that the three high prices had little long-term impact on base future prices.

When looking at the entire quarter, Q4 2025 base futures closed $26 per MWh (26%) lower than where it started at the beginning of the quarter (Figure 4). Similarly, Q4 2025 caps were $12 per MWh (51%) lower. Q4 2026 base futures were $9 per MWh (9%) lower than where it started at the beginning of the quarter.

Figure 4 Base futures and caps closing settlement prices



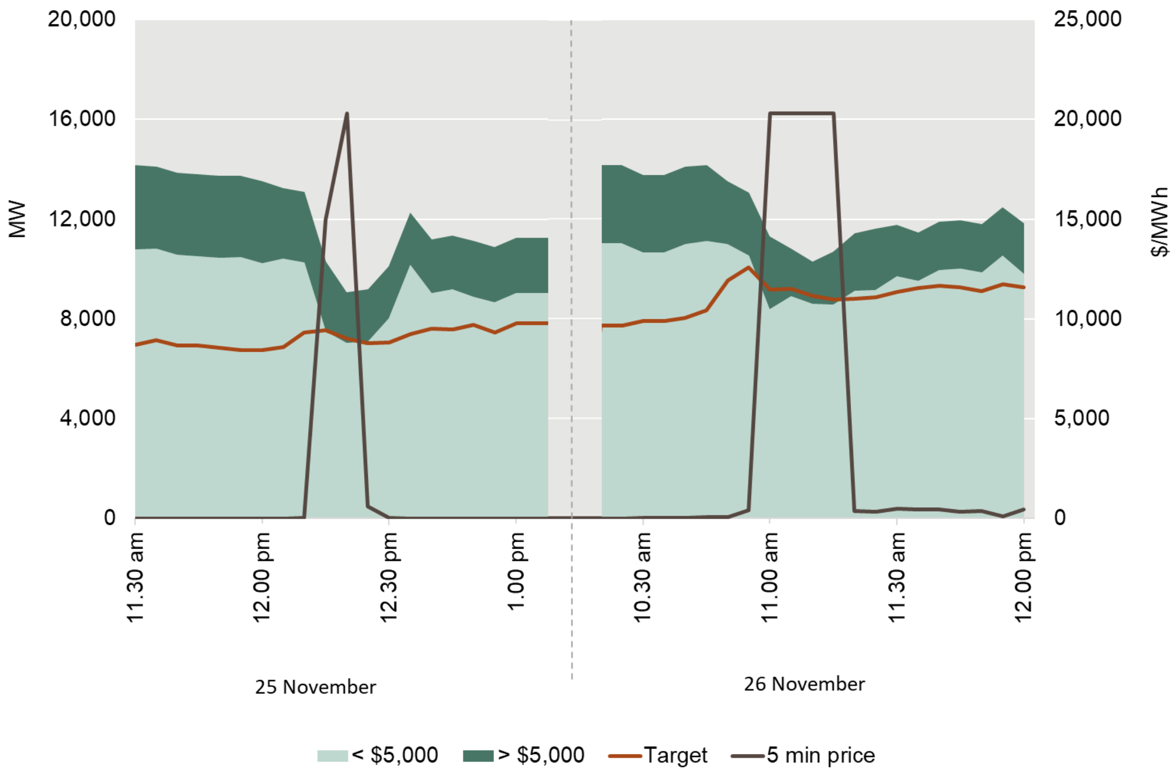
Source: AER analysis using ASX and NEM data.

7 25 and 26 November, NSW

On 25 and 26 November, the 30-minute price in NSW reached $5,984 per MWh at 12.30 pm and $10,342 per MWh at 11.30 am, respectively. The high prices were not forecast.

Around 79% of capacity in the region was offered below $5,000 per MWh during the high prices on both days (Figure 5). Between 46 MW and 312 MW of high-priced capacity was required to meet demand on 25 and 26 November.

Figure 5 Capacity offered above and below $5,000 per MWh, 25 and 26 November



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

7.1 Limited solar generation

There was a significant reduction in low-priced renewable generation from rooftop solar and grid scale solar during the high price intervals. The sudden drop in rooftop solar generation was due to cloud cover from storms while grid scale solar was limited due to network constraints (section 4).

- On 25 November:
  - Rooftop solar generation dropped from over 5,380 MW at 11.30 am to around 4,180 MW at 12.30 pm when the high prices occurred. This was 78% of the maximum rooftop solar generation on the day which also happened to be at 11.30 am.

- Grid scale solar generation dropped from over 2,450 MW at 11.30 am to around 2,145 MW at 12.30 pm when the high prices occurred. This was 63% of the maximum grid scale solar generation on the day which was at 8 am.

- On 26 November:
    - Rooftop solar generation dropped from over 4,460 MW at 10.30 am to around 2,285 MW at 11.30 am when the high prices occurred. This was 48% of the maximum rooftop solar generation on the day which was at 1.30 pm.
    - Grid scale solar generation dropped from over 2,900 MW at 10.30 am to around 2,083 MW at 11.30 am when the high prices occurred. This was 71% of the maximum grid scale solar generation on the day which was at 9.30 am.

7.2 High demand

The increase in demand for both days was mainly due to the sudden reduction in rooftop solar generation due to cloud cover from storms (section 7.1).

On 25 November at 12.30 pm, demand was 7,236 MW which was 1,538 MW more than the previous hour and 547 MW higher than forecast.

On 26 November, demand was 9,400 MW at 11.30 am which was 2,004 MW more than the previous hour and 2,429 MW higher than forecast.

7.3 Network limitations

As discussed in section 4, planned network outages and system normal constraints contributed to the high prices as follows:

- On 25 November:
    - a planned network outage on the Lower Tumut to Canberra line prevented between 867 MW and 2,245 MW of low-priced capacity in southern NSW from making it to market.
    - a planned outage of all three Directlink cables on Terranora reduced flows to around 0 MW from Queensland into NSW compared to its nominal capacity of 210 MW.
    - a system normal constraint, to avoid overloading of the Uralla to Tamworth line in northern NSW, limited imports into NSW on the QNI to around 600 MW compared to its nominal capacity of 1,400 MW.
- On 26 November:
    - a planned outage on the Avon to Marulan line prevented between 1,596 MW and 2,193 MW of low-priced capacity from making it to market (Figure 2).
    - a system normal constraint, to avoid overloading of the Uralla to Tamworth line in northern NSW, limited imports into NSW on the QNI to around 780 MW and also limited Terranora to around 65 MW.

7.4 Generation ramp up constrained

Generation units at Delta Electricity’s Vales Point, Origin Energy’s Eraring, AGL Energy’s Bayswater, EnergyAustralia’s Mt Piper and Tallawarra, and Snowy Hydro’s Upper Tumut stations were ramp up rate limited. AEMO can only ramp up units at their offered ramp rates (Table 3 shows those significantly constrained), which during the high prices was not enough to provide additional low-priced capacity that could have helped avoid the high prices (Table 4).

Table 4 Low-priced generation that was ramp-up constrained on 25 and 26 November

Date	Participant	Unit	Low-priced generation unable to dispatch (MW)*
25 November	Delta Electricity	Vales Point	240
	Origin Energy	Eraring	374
	AGL Energy	Bayswater	116
	EnergyAustralia	Mt Piper	795
	EnergyAustralia	Tallawarra**	179
26 November	Delta Electricity	Vales Point	88
	Origin Energy	Eraring	229
	EnergyAustralia	Mt Piper	703
	Snowy Hydro	Upper Tumut**	143

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. ** These units were less significant contributors, as the amount of low-priced generation constrained for Upper Tumut could not make it to the key load centre and Tallawarra was just starting up.

7.5 Generation start-up constrained

Gas generation units at Snowy Hydro's Colongra, Origin Energy's Uranquinty and EnergyAustralia's Tallawarra stations were unable to start up quickly enough to meet the sudden increase in demand and provide low-priced capacity that could have helped avoid the high prices (Table 5). The low-priced generation that was unable to be dispatched contributed to one high-priced 5-minute interval on 25 November, and two high-priced 5-minute intervals on 26 November.

Table 5 Low-priced generation that was start-up constrained on 25 and 26 November

Date	Participant	Unit	Low-priced generation unable to dispatch (MW)*
25 November	Snowy Hydro	Colongra	170
26 November	Origin Energy	Uranquinty	252
	EnergyAustralia	Tallawarra	160

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.

7.6 Rebidding

Between 46 MW and 162 MW of high-priced capacity was required on 25 November. Rebidding occurred due to technical or commercial reasons (i.e. change in forecast prices) which also included late rebids (section 7.6.1 and Appendix A).

There was no rebidding that contributed to the high prices on 26 November.

7.6.1 25 November

At 10.58 am, Ironbark Energy removed all of Gunnedah Solar Farm's capacity due to a planned outage. Of its 110 MW offered maximum capacity, this unit had 105 MW available prior to rebidding, all of which was offered at -$10 per MWh. Therefore, the impact of this rebid was the removal of 105 MW of low-priced capacity. This contributed to the high price at 12.15 pm.

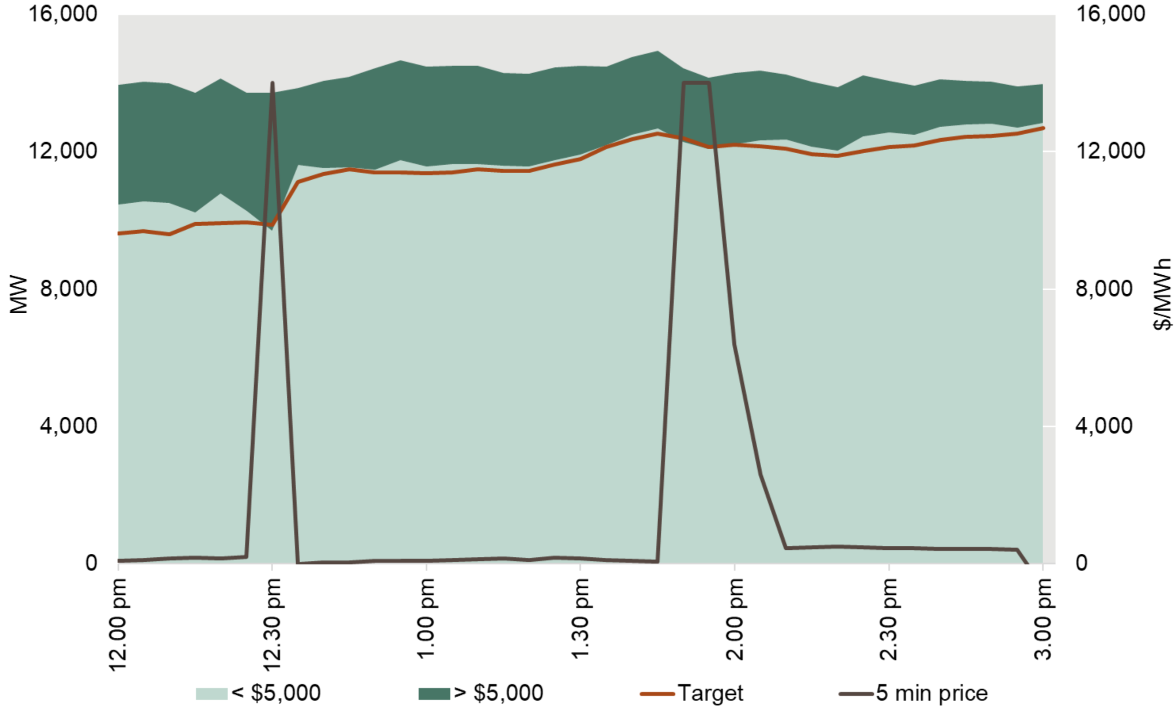
At 11.54 am, Iberdrola rebid to remove all of Bodangora Wind Farm's capacity due to high winds. Of its 111 MW offered maximum capacity, this unit had 87 MW available prior to rebidding, all of which was offered at -$1,000 per MWh. Therefore, the impact of this rebid was the removal of 87 MW of low-priced capacity. This contributed to the high price at 12.15 pm.

At 12.13 pm, AGL Energy rebid 250 MW of capacity at Bayswater from $36 per MWh to the market price cap due to a change in forecast prices (commercial reason) and set the high price at 12.20 pm.

8 19 December, NSW

The 30-minute price in NSW reached $5,773 per MWh at 2 pm on 19 December. The high price was not forecast. Around 85% of capacity was offered below $5,000 per MWh during the high prices (Figure 6). Between 1 MW and 110 MW of high-priced capacity was required to meet demand on 19 December.

Figure 6 Capacity offered above and below $5,000 per MWh, 19 December



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

8.1 Limited solar generation

As discussed in section 3 and section 7.1, there was also a significant reduction in low-priced renewable generation from rooftop solar and grid scale solar during the high price intervals on 19 December.

- Rooftop solar generation dropped from over 4,390 MW at 1 pm to 2,985 MW at 2 pm when the high prices occurred. This was 54% of the maximum generation on the day which was at 11.30 am.
- Grid scale solar generation dropped from over 2,850 MW at 1 pm to 2,667 MW at 2 pm when the high prices occurred. This was 76% of the maximum generation on the day which was at 8.30 am.

8.2 High demand

The increase in demand on this day was mainly due to the sudden reduction in rooftop solar generation due to cloud cover and, to a lesser extent, from storms (section 8.1). Demand was high due to high temperatures on the day.

On 19 December, Sydney recorded its highest temperature for December 2025 at 42°C. Average demand throughout the day was high. During the high prices demand was above 12,000 MW which was 1,237 MW more than the previous hour and 1,440 MW higher than forecast one hour prior.

8.3 Network limitations

A system normal constraint used to avoid overloading the Bannaby to Sydney West line limited flows into NSW on the QNI to around 560 MW, compared to its nominal capacity of 1,400 MW. This meant between 491 MW and 729 MW of low-priced capacity could not make it to market during the high prices.

8.4 Generation ramp up constrained

AGL Energy's Bayswater unit 1 and Origin Energy's Eraring unit 2 were already running but were unable to ramp up quickly enough to meet the sudden increase in demand to mitigate the high prices. Between 27 MW and 131 MW from AGL Energy's Bayswater unit 1 and another 5 MW from Origin Energy's Eraring unit 2 could not be dispatched due to ramp up rate limitations.

Both Origin Energy and AGL Energy offered their capacity with ramp up rates close to the minimum allowed under the Rules (Table 3). If the relevant units' ramp up rates were near their maximum registered rates or were more aligned to the unit's technical ability, the high prices on 19 December would likely not have occurred.

8.5 Generation start-up constrained

EnergyAustralia's Tallawarra unit B were unable to start up quickly enough to meet the sudden increase in demand to help avoid the high prices. The unit was unable to dispatch 46 MW of low-priced generation for one of the three high price intervals.

9 Appendix A – Significant rebids 25 November, NSW

12.15 pm (46 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MW)	Price to ($/MW)	Rebid reason
10.58 am		Ironbark Energy	Gunnedah Solar Farm	110*	-10	N/A	Planned outage
11.54 am	12 pm	Iberdrola	Bodangora Wind Farm	111**	-1,000	N/A	Change in plant availability -high winds SL

Note: *While they bid 110 MW, they had only 105 MW available before the outages.
**While they bid 111 MW, they had only 87 MW available before the outages.

12.20 pm (162 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	AGL Energy	Bayswater	250	<100	20,300	040 Chg in AEMO DISP~Price change vs PD [NSW] [$14974.54 DISP vs -$23.50 30MPD PE 12:30]