Electricity prices above $5,000 per MWh

October to December 2023

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AUSTRALIAN ENERGY REGULATOR

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Obligation

The Australian Energy Regulator (AER) has an obligation under the National Electricity Rules (energy rules) to monitor and report on significant price outcomes in the National Energy Market (NEM). The energy rules require us to produce a guideline for how we report significant price events.[1] Our guideline commits us to reporting whenever the 30-minute price exceeds $5,000 per megawatt hour (MWh).[2]

30-minute prices rarely reach $5,000 per MWh, but with a market price cap over $16,600 per MWh prices can occasionally exceed this reporting threshold.[3] This reporting framework is intended to examine these outlier events.

This report describes 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.

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

[1] AER, Significant price reporting guidelines, September 2022.

[2] A trading interval is a 5-minute period, and the 5-minute price is the price for the trading interval. The 30-minute price is the average of the 5-minute prices for six intervals, ending on the half hour.

[3] The market price cap in in 2023–24 is $16,600 per MWh.

Summary

During the October to December 2023 quarter, 30-minute prices exceeded $5,000 per MWh 5 times – 3 times in South Australia and 2 times in Queensland. This compares to 10 high prices in the previous quarter and 5 high prices over the same period last year.

Generally, it requires a combination of factors to drive prices above $5,000 per MWh.

A common driver across the high price events was reduced access to cheaper generation from a neighbouring region due to network outages or network constraints to maintain system security.

In South Australia on 9 November, flows over the interconnectors were limited due to a planned network outage and a constraint to maintain system security. On 8 December, flows were limited to protect system security during severe storms in the region.

In Queensland in the last week of December, as temperatures climbed above 36 degrees, Queensland was importing cheaper generation from NSW to meet the very high demand. However, flows from NSW were limited by a constraint on the Bayswater to Liddell lines to maintain system security. The same dynamic of hot temperatures, high demand, and network constraints in NSW continued to contribute to price volatility in Queensland over January.

A second common driver of the high prices in the quarter was a reduced supply of low-priced capacity. In South Australia, this was primarily during periods of low wind and solar output. In Queensland, baseload outages contributed to tight market conditions during times of high demand.

Common drivers of high price events

Date and region	Reduced supply	High demand	Network limitations	Technical rebids[4]	Commercial rebids[5]
9 November, SA	✓	×	✓	✓	✓
8 December, SA	✓	×	✓	×	×
28 & 29 December, Qld	✓	✓	✓	✓	✓

Rebidding also contributed to some of the high prices discussed in this report. While most of these were for technical reasons, such as unit trips and other plant issues, some were for commercial reasons. The AER continues to monitor trends in rebidding as part of our role in identifying whether there is effective competition in the NEM.

[4] Technical rebids are those which are categorised as ‘P’ (plant) as defined in the AER’s Rebidding and Technical Parameters Guideline 2019

[5] Commercial rebids are those which are categorised as ‘F’ (financial) or ‘A’ (AEMO communications including demand and price forecasts, constraints, and directions).

1. 9 November, South Australia

The wholesale price of electricity exceeded $5,000 per MWh for one 30-minute period during the evening of 9 November in South Australia. The 30-minute price at 7 pm was $10,083 per MWh (Table 1.1). The high price was not forecast.

Table 1.1 Breakdown of the 30-minute high price

Date	Time	5-minute price ($ per MWh)
9 November	6.35 pm	346
	6.40 pm	450
	6.45 pm	16,600
	6.50 pm	16,600
	6.55 pm	16,600
	7 pm	9,900
7 pm average 30-minute price		**10,083**

A combination of factors drove these high prices:

- A planned network outage impacted the Heywood interconnector and reduced South Australia's access to cheaper generation from Victoria.
- Low output from wind generation in South Australia reduced the amount of low-priced capacity available.
- Rebidding of capacity for both technical and commercial reasons contributed to the high price.

1.1 Market conditions

We compared actual with forecast outcomes an hour prior (Table 1.2) and observed:

- the high price was not forecast
- actual demand was higher (95 MW) than forecast
- actual availability was lower (266 MW) than forecast.

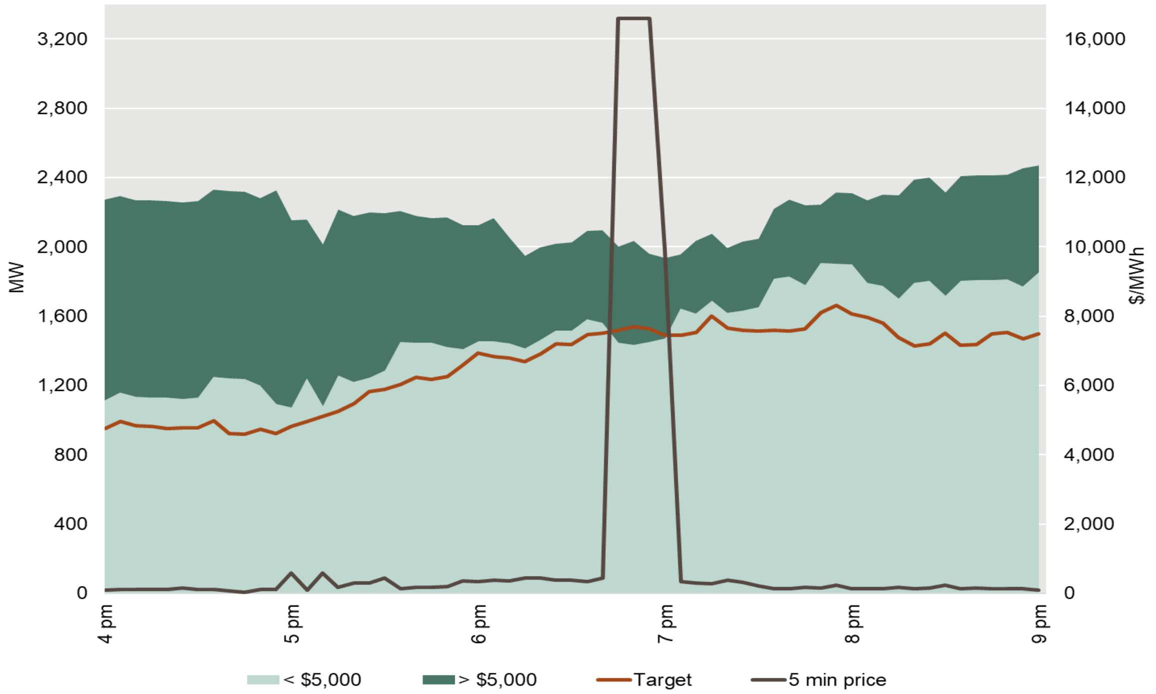
Table 1.2 Actual and forecast 30-minute price, demand and availability

Date	Time	Price ($/MWh)		Demand (MW)		Availability (MW)	
		Actual	1 hr forecast	Actual	1 hr forecast	Actual	1 hr forecast
9 November	7 pm	10,083	245	1,680	1,585	2,125	2,390

Between 18 and 106 MW of high-priced capacity was needed to meet demand during the high-priced 5-minute intervals (Figure 1.1). At the time, there was little capacity offered between $560 per MWh and $16,600 per MWh. This meant that small changes in demand or supply had a significant impact on price.

Between 24% to 29% of capacity was offered above $5,000 per MWh.

Figure 1.1 Capacity offered above and below $5,000 per MWh on 9 November 2023



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

1.1.1 A network outage limited access to cheaper generation

Network limitations reduced South Australia's ability to access cheaper generation from Victoria.

Flows over the Heywood interconnector were limited due to a planned network outage on the South-East to Tailem Bend line. The outage was planned to start at 5.35 pm on 8 November but was rescheduled to 5.35 pm on 9 November. Constraints managing the outage limited imports over Heywood to around 45 MW during the high-priced intervals, out of its nominal capacity of 600 MW.[6]

Flows over the Murraylink interconnector were limited between 6.35 pm and 7 pm by a system normal constraint to avoid a possible voltage collapse in the event of an outage on the Bendigo to Kerang line. This restricted imports over Murraylink, to between 89 MW and 140 MW during the high-priced intervals, out of its nominal capacity of 220 MW.[7]

1.1.2 Lower than average wind generation

Wind generation was lower than average, ranging between 287 MW and 322 MW during high priced 5-minute intervals, out of 2,500 MW installed.[8] It was also 120 MW lower than forecast an hour earlier. Wind speeds were low. Additionally, the output of several wind farms was limited due to the constraint on the South-East to Tailem Bend line. Wind generated capacity is offered at low prices, so the relatively low wind generation reduced the amount of low-priced capacity available in the region.

1.2 Rebidding contributed to the high prices

Two significant rebids, one for technical reasons and one for commercial reasons, contributed to the four high 5-minute prices. During these intervals, between 18 MW and 106 MW of high-priced capacity was needed to meet demand.

- After being offline, gas-fired Pelican Point Power Station returned to service at around 3 pm but was unable to generate at levels it was anticipating by 6 pm. At 6.29 pm, its operator, Engie, withdrew 252 MW of low-priced capacity.
- At 6.39 pm, AGL Energy shifted 125 MW of low-priced capacity at Barker Inlet Power Station to the price cap in response to a change in forecast prices.

[6] AEMO, Interconnector Capabilities for the National Electricity Market, accessed 20 November 2023.

[7] AEMO, Interconnector Capabilities for the National Electricity Market, accessed 20 November 2023.

[8] Average wind dispatched over the quarter was 726 MW, while the maximum wind generation in the quarter was 1,894 MW.

2. 8 December, South Australia

The wholesale price of electricity exceeded $5,000 per MWh for two 30-minute periods in the middle of the day during severe weather on 8 December in South Australia. The 30-minute price was $5,393 per MWh at 11.30 am and $7,007 per MWh at midday (Table 2.1). The high prices were not forecast.

Table 2.1 Breakdown of 30-minute high prices

Date	Time	5-minute price ($/MWh)
8 December	11.05 am	450
	11.10 am	19
	11.15 am	101
	11.20 am	591
	11.25 am	15,600
	11.30 am	15,600
11.30 am average 30-minute price		**5,393**
	11.35 am	15,600
	11.40 am	12,922
	11.45 am	12,922
	11.50 am	380
	11.55 am	118
	midday	101
Midday average 30-minute price		**7,007**

A combination of factors drove these high prices:

- There were severe storms in the region.
- Network constraints to protect system security during the storms limited imports into South Australia over both the interconnectors and reduced South Australia's access to cheaper generation from Victoria.
- Wind generation was also limited to protect system security. This and low solar generation due to overcast weather reduced the amount of low-priced capacity available.

Rebidding did not contribute to the high 30-minute prices.

2.1 Market conditions

High prices were not forecast at any point and prices leading up to and following the high prices were mostly negative.

We compared actual with forecast outcomes an hour prior (Table 2.2) and observed:

- the high prices were not forecast; in fact, the midday price was forecast to be negative

- actual demand was lower (-81 MW) than forecast for the 30 minutes to 11.30 am and higher (136 MW) than forecast for the 30 minutes to midday
- actual availability was lower (-136 MW) than forecast for the 30 minutes to 11.30 am, and significantly lower (-428 MW) than forecast for the 30 minutes to midday.

Table 2.2 Actual and forecast 30-minute price, demand and availability

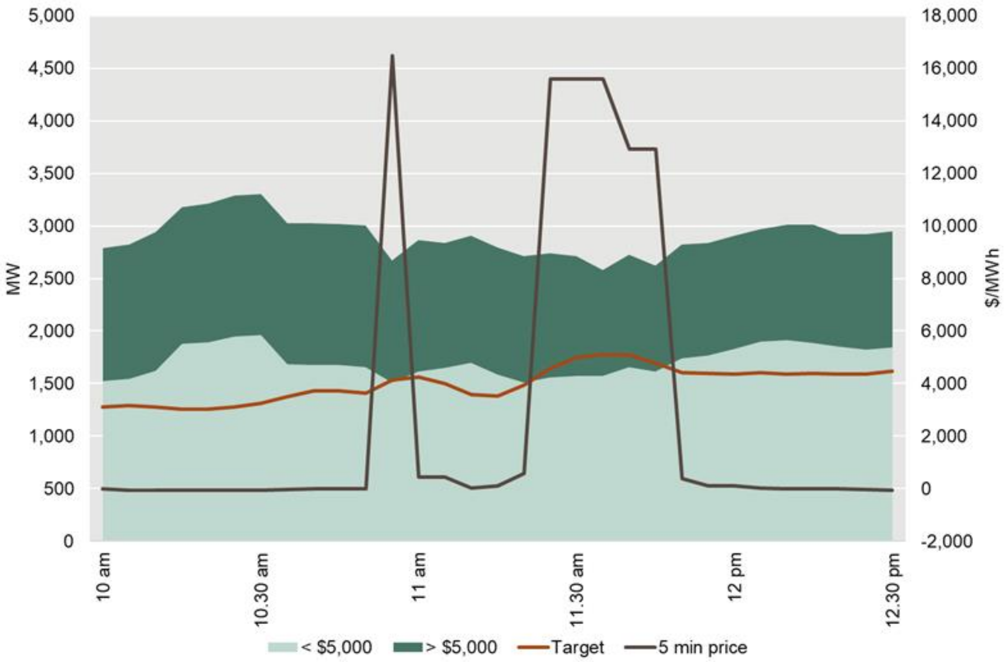
Date	Time	Price ($/MWh)		Demand (MW)		Availability (MW)	
		Actual	1 hr forecast	Actual	1 hr forecast	Actual	1 hr forecast
8 December	11.30 am	5,393	38	1,689	1,770	3,361	3,497
	12 pm	7,007	-52	1,783	1,647	3,299	3,727

Availability was lower than forecast at midday because wind and solar output was lower than forecast (section 2.1.2). In addition, at 11.35 am Origin removed 115 MW of capacity at Quarantine Power Station due to a technical issue, although because this capacity was priced at the price cap its removal did not contribute to the high price.

Between 82 MW and 203 MW of high-priced capacity was needed to meet demand (Figure 2.1). During the high-priced-intervals, there was little capacity offered between $1,000 per MWh and $9,900 per MWh. This meant that small changes in demand or supply had a significant impact on price.

Around 40% of capacity in South Australia was offered above $5,000 per MWh.

Figure 2.1 Capacity offered above and below $5,000 per MWh on 8 December 2023



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

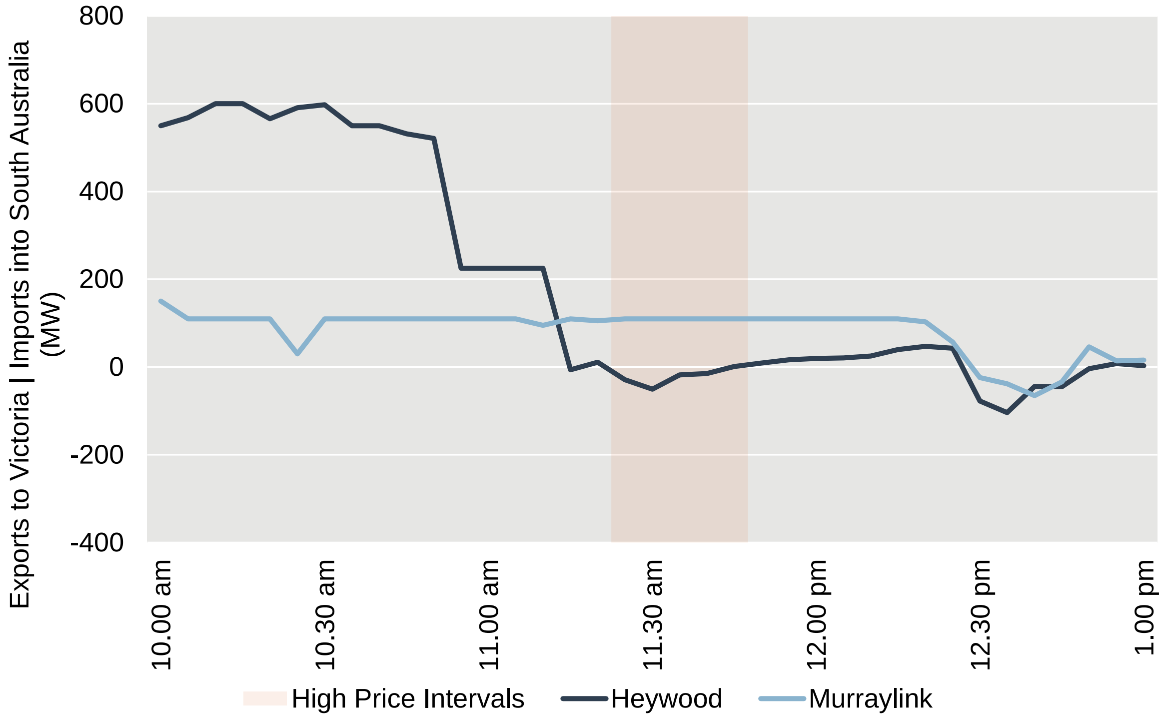
2.1.1 Network constraints limited access to cheaper generation

Severe weather warnings, with damaging winds, prompted AEMO to notify the market of numerous network constraints being invoked to maintain system security in South Australia. These constraints limited flows over both the Heywood and Murraylink interconnectors and reduced the region's ability to access cheaper generation from Victoria (Figure 2.2).[9]

Flows over Heywood were forecast to be 430 MW into South Australia an hour prior to the start of the 11.30 am period. Then at 10.50 am, constraints were invoked that limited imports into South Australia to 225 MW. At 11.15 am another constraint was invoked to manage the potential loss of the South East to Tailem Bend lines, which further reduced flows over the Heywood interconnector. Flows quickly swung from importing 225 MW to exporting 6 MW (Figure 2.2). AEMO cancelled the constraints at 2 pm.

Imports across Murraylink were also limited to 110 MW to keep the system secure.

Figure 2.2 Interconnector flows over Heywood and Murraylink



Source: AER analysis using NEM data.
Note: Using target flows (MW) for Heywood and Murraylink.

2.1.2 Limited output from wind and solar generation

Wind output was limited to maintain system security during the severe weather that day. A constraint reduced output from wind and solar farms in the north of the region by 500 MW to

[9] At 10.50 am, AEMO issued several market notices stating it had invoked constraints due to the severe weather warnings. Most relevant was the constraint on the South East to Tailem Bend lines, which limited flows over the Heywood interconnector. AEMO cancelled the constraints at 2 pm.

600 MW.[10] As a result, average wind output during the high price periods was reduced to around 800 MW out of 2,500 MW installed.

Average output for solar generation was around 120 MW during the high price periods, out of around 500 MW installed, largely due to the overcast conditions with the storms.

Normally, wind and solar capacity is offered at negative prices so lower renewable generation means less low-priced capacity is available.

2.2 Rebidding did not contribute to the high prices

Rebidding of capacity did not contribute to the high 30-minute prices.

[10] S^NIL_SA_NTH_N-2 was invoked to manage a possible voltage collapse in northern SA for the loss of Robertstown - Tungkillo 275kV line 1 and 2 and the Robertstown No.1 and No.2 synchronous condensers. It was invoked at 3.50 am and stayed in place throughout the high-price periods.

3. 28 and 29 December, Queensland

The wholesale price of electricity exceeded $5,000 per MWh for one 30-minute period on both 28 December and 29 December in Queensland (Table 3.1). The high prices were forecast on the morning of 28 December, but not forecast at all on 29 December.

Table 3.1 Breakdown of 30-minute high prices

Date	Time	5-minute price ($ per MWh)
28 December	6.35 pm	14,928
	6.40 pm	3,041
	6.45 pm	4,010
	6.50 pm	8,888
	6.55 pm	3,423
	7.00 pm	721
Average 30-minute price		**5,835**
29 December	6.05 pm	550
	6.10 pm	14,928
	6.15 pm	550
	6.20 pm	1,632
	6.25 pm	14,928
	6.30 pm	14,928
Average 30-minute price		**7,919**

A combination of factors drove these high prices:

- Hot temperatures and high humidity drove high demand, greater than forecast.
- Network constraints to maintain system security in NSW reduced Queensland's access to cheaper generation from NSW. There was also an outage of network equipment in NSW that forced flows into NSW.
- Wind generation was low and lower than forecast, so less low-priced capacity was available than anticipated.
- Rebidding for technical reasons contributed to the high prices.
- Ramp rate limitations on some generating units prevented capacity below $5,000 per MWh being dispatched in time.

3.1 Market conditions

We compared actual with forecast outcomes an hour prior (Table 3.2) and observed:

- even though the high price on 28 December was forecast that morning, neither high price was forecast an hour prior[11]
- actual demand was higher than forecast by 158 MW on 28 December and by 136 MW on 29 December
- actual availability was lower than forecast by 54 MW on 28 December and by 256 MW on 29 December.

Table 3.2 Actual price, demand and availability compared to the 1 hour forecast

Date	30-min period	Price ($ per MWh)		Demand (MW)		Availability (MW)	
		Actual	1 hr forecast	Actual	1 hr forecast	Actual	1 hr forecast
28 Dec	7 pm	5,835	721	9,506	9,348	10,469	10,523
29 Dec	6.30 pm	7,919	370	9,637	9,501	10,500	10,756

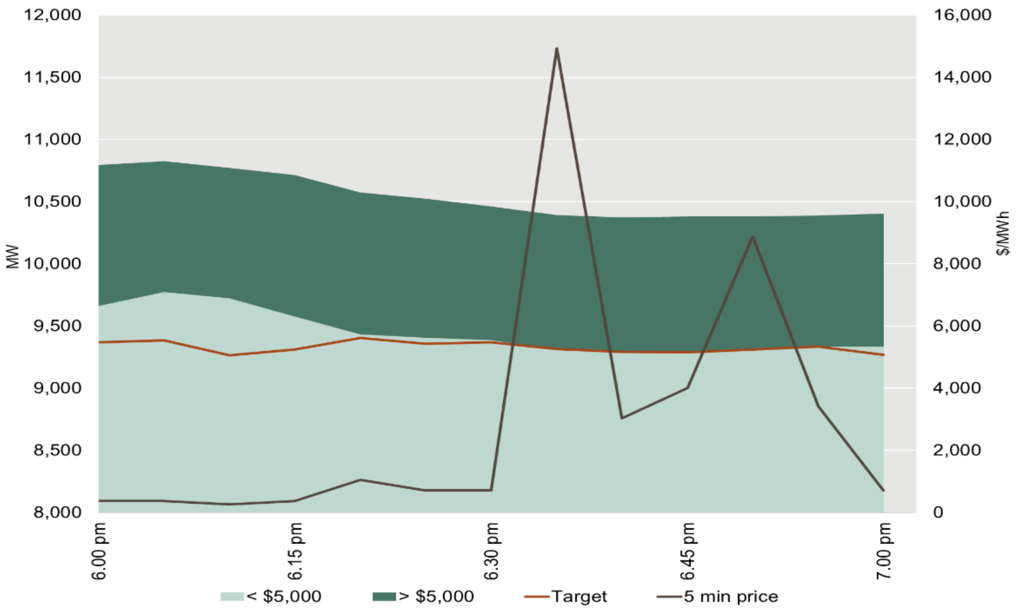
While 90% of capacity in Queensland was offered below $5,000 per MWh, some, and at times very little, high-priced capacity was needed to meet demand (Figure 3.1 and Figure 3.2):

- On 28 December, between as little as 6 MW was needed.[12]
- On 29 December, between 9 MW and 72 MW was needed.

[11] High prices were forecast earlier in the day but not an hour prior.

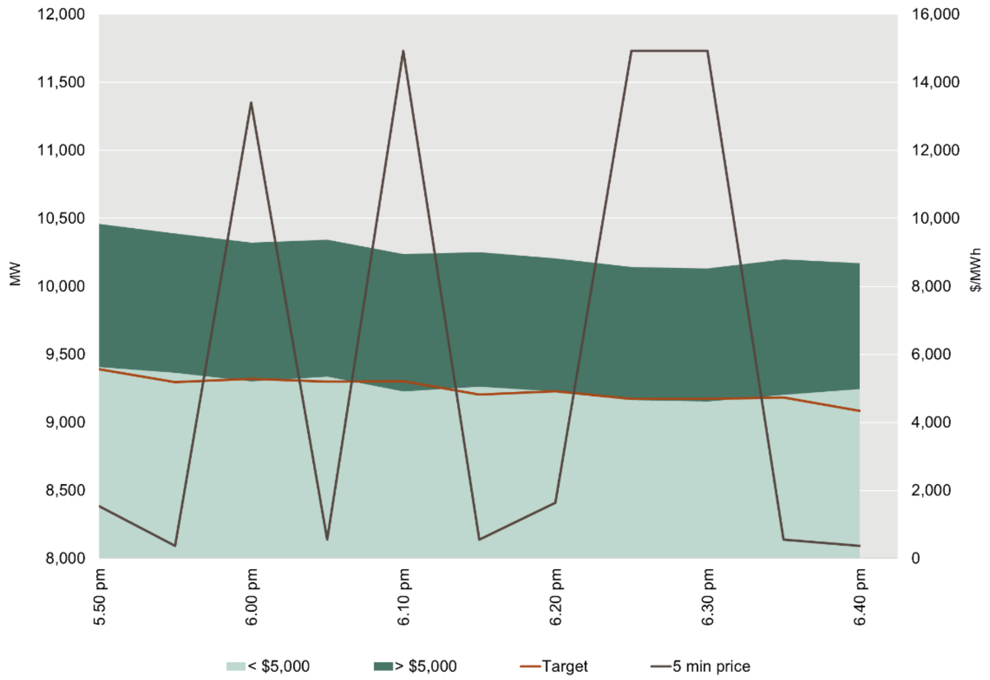
[12] During the second high 5-minute price on 28 December, no high-priced capacity was needed.

Figure 3.1 Capacity offered above and below $5,000 per MWh, 28 December



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

Figure 3.2 Capacity offered above and below $5,000 per MWh, 29 December



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

3.1.1 High temperatures drove high demand

High temperatures on both days, with Brisbane maximums of 36°C and 38°C respectively, exacerbated by high humidity drove high demand. Demand during the high prices was only 550 MW below the Queensland record and up to 158 MW higher than forecast.

3.1.2 Network constraints to maintain system security reduced access to cheaper generation from NSW

During the high-priced periods, the Queensland to NSW interconnector (QNI) was importing an average of 323 MW into Queensland on 28 December and an average of 449 MW on 29 December, out of a northbound capacity of 700 MW.[13] These reduced flows were mostly due to a constraint on the Bayswater to Liddell lines to maintain system security in NSW. The constraint limited flows into Queensland as a preventative measure, to avoid the possible overload of either of the two Bayswater to Liddell lines, in the event the other one failed. The Bayswater to Liddell constraint bound significantly more often from mid-December through to early February, than in previous months, with increased flows north to meet Queensland demand.

The same dynamic of hot temperatures, high demand, and the network constraint on the Bayswater to Liddell lines, continued to contribute to price volatility in Queensland over January.

Terranora, the other Queensland to NSW interconnector, was constrained by an ongoing outage of the Lismore static VAR compensator in NSW on both dates. On 29 December, the interconnector was further impacted by a constraint in NSW to avoid the possible overloading the Lismore to Dunoon power lines in the event one of them failed. To maintain system security, flows were forced into NSW on average by 97 MW on 28 December and 23 MW on 29 December, reaching 198 MW during the 6.35 pm interval on 28 December.

3.1.3 Wind generation was low and lower than forecast

Average wind output during the high-priced period was 108 MW on 28 December and 40 MW on 29 December, out of a total of 831 MW of registered wind capacity in Queensland. Wind output was less than forecast an hour earlier by 39 MW on 28 December and 43 MW on 29 December. Most wind is offered at negative prices, which would have helped mitigate the high-price events.

3.1.4 Loss of base load generation at Gladstone and Tarong North

In Queensland, baseload outages contributed to tight market conditions during times of high demand.

Gladstone Power Station, 28 December

On 28 December, CS Energy's Gladstone unit 2 went on a planned outage to rectify a tube leak which had been limiting its available capacity to 140 MW, half of its registered capacity. This brought the total base load outages across Queensland to 1,120 MW (both units at Callide C had been offline long-term).

At 4.12 pm, Gladstone unit 1 tripped while attempting to come online after a month-long outage. It was unable to generate as much as it expected, and CS Energy withdrew 170 MW

[13] At the time of the high price event, the limit for QNI flows from NSW to Queensland was 700 MW as AEMO was in the process of testing new limits following the upgrade. AEMO Market notice 105482.

of low-priced capacity. At around 5 pm the unit began generating again but had further problems and at 6.05 pm, CS Energy withdrew another 30 MW.

At 6.35 pm when only 6 MW of high-priced capacity was needed, Gladstone unit 1 had around 15 MW of capacity priced at the price floor that was unable to be dispatched because it could not ramp up fast enough.

At 5.41 pm, CS Energy withdrew 15 MW of capacity from Gladstone unit 3 due to fabric filter issues.

Tarong North Power Station, 29 December

On 29 December, Stanwell's Tarong North unit had offered around 440 MW below $5,000 per MWh before it tripped around 3.30 pm. Around 4.30 pm Stanwell revised its return to service times effectively reducing its capacity by 203 MW for the 6.30 pm 30-minute period.

Tarong North ramp rate limitations also prevented capacity below $5,000 per MWh being dispatched in time. At 6.10 pm, around 72 MW of high-priced capacity was needed. Because Tarong North could not ramp up fast enough it had 158 MW of capacity priced below $5,000/MWh that was unable to be dispatched in time to avoid the high price. This also impacted the 6.25 pm and 6.30 pm intervals when only 9 MW and 21 MW of high-priced capacity was needed to meet demand.

Other technical issues, 29 December

At 4.06 pm, Genuity withdrew 10 MW from Millmerran Power Station in relation to its boiler. At 5.29 pm, Stanwell Corporation withdrew 70 MW from one of its Tarong Power Station units to manage emissions. And at 6.05 pm CS Energy withdrew 10 MW at Gladstone Power Station due to condenser issues. These technical rebids removed a combined total of 90 MW of low priced capacity from the high-priced intervals.

3.2 Rebidding contributed to the high prices

As well as the technical rebids discussed above, a rebid for commercial reasons also contributed to the high price at 6.50 pm on 28 December.

On 28 December, in a late rebid at 6.36 pm, Bouldercombe battery in Queensland shifted 20 MW of capacity from a low price to $10,389 per MWh, due to a change in its state of charge. The formulation of the constraint on the Bayswater to Liddell lines (section 3.1.2) meant it was cheaper to back-off negatively priced generation in NSW, resulting in a price of $8,888 per MWh, than to increase generation in Queensland. This was because the next available megawatt in Queensland was from Bouldercombe priced at $10,389 per MWh.

Appendix A – Significant rebid, November

This table details rebids that contributed to the high prices on 9 November 2023 in South Australia. Only the 5-minute intervals with a high price are included.

6.45 pm (72 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
6.29 pm		Engie	Pelican Point	-252	<298	N/A	Update OOS Profile. sl
6.39 pm	6.45 pm	AGL Energy	Barker Inlet	125	<176	16,600	040 Chg in AEMO DISP~44 Price change vs PD [SA] [$450.02 dp v pd 354.53 1900]

6.50 pm (106 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
6.29 pm		Engie	Pelican Point	-252	<298	N/A	Update OOS Profile. sl
6.39 pm		AGL Energy	Barker Inlet	125	<176	16,600	040 Chg in AEMO DISP~44 Price change vs PD [SA] [$450.02 dp v pd 354.53 1900]

6.55 pm (75 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
6.29 pm		Engie	Pelican Point	-252	<298	N/A	Update OOS Profile. sl
6.39 pm		AGL Energy	Barker Inlet	125	<176	16,600	040 Chg in AEMO DISP~44 Price change vs PD [SA] [$450.02 dp v pd 354.53 1900]

7.00 pm (18 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
6.29 pm		Engie	Pelican Point	-252	<298	N/A	Update OOS Profile. sl
6.39 pm		AGL Energy	Barker Inlet	125	<176	16,600	040 Chg in AEMO DISP~44 Price change vs PD [SA] [$450.02 dp v pd 354.53 1900]

Appendix B – Significant rebids, 28 and 29 December

These tables details rebids that contributed to the high prices on 28 and 29 December 2023 in Queensland. Only the 5-minute intervals with a high price and where rebidding contributed to the high price are included.

28 December

6.35 pm (6 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
9.48 am		CS Energy	Gladstone	-140	-1,000	N/A	Boiler - Tube Leak - SL
4.12 pm		CS Energy	Gladstone	-170	<371	N/A	Unit commitment-Unit RTS revised-SL
5.41 pm		CS Energy	Gladstone	-15	371	N/A	Emissions -Fabric filter-SL
6.05 pm	6.15 pm	CS Energy	Gladstone	-30	-1,000	N/A	Unit commitment-Rebid to match Scada-SL

6.50 pm (There was a high price, but no high priced capacity was dispatched)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
9.48 am		CS Energy	Gladstone	-140	-1,000	N/A	Boiler - Tube Leak - SL
4.12 pm		CS Energy	Gladstone	-170	<371	N/A	Unit commitment-Unit RTS revised-SL
5.41 pm		CS Energy	Gladstone	-15	371	N/A	Emissions -Fabric filter-SL
6.05 pm	6.15 pm	CS Energy	Gladstone	-30	-1,000	N/A	Unit commitment-Rebid to match Scada-SL
6.36 pm	6.45 pm	Bouldercombe Battery	Bouldercombe Battery	20	441	10,389	Change in forecast state of charge

29 December

6.10 pm (73 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
4.36 pm		Stanwell Corporation	Tarong North	-93	-1,000	N/A	Revised RTS SL
4.53 pm		Stanwell Corporation	Tarong North	-110	-1,000	N/A	Revised RTS SL
5.29 pm		Stanwell Corporation	Tarong	-70	<550	N/A	Manage emissions SL

6.25 pm (9 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
4.06 pm		Genuity	Millmerran	-10	-1,000	N/A	Boiler Water/Steam Limitation
4.36 pm		Stanwell Corporation	Tarong North	-93	-1,000	N/A	Revised RTS SL
4.53 pm		Stanwell Corporation	Tarong North	-110	-1,000	N/A	Revised RTS SL
5.29 pm		Stanwell Corporation	Tarong	-70	<550	N/A	Manage emissions SL
6.05 pm	6.15 pm	CS Energy	Gladstone	-10	371	N/A	Condenser -Back Pressure-SL

6.30 pm (21 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
4.06 pm		Genuity	Millmerran	-10	-1,000	N/A	Boiler Water/Steam Limitation
4.36 pm		Stanwell Corporation	Tarong North	-93	-1,000	N/A	Revised RTS SL
4.53 pm		Stanwell Corporation	Tarong North	-110	-1,000	N/A	Revised RTS SL
5.29 pm		Stanwell Corporation	Tarong	-70	<550	N/A	Manage emissions SL
6.05 pm	6.15 pm	CS Energy	Gladstone	-10	371	N/A	Condenser -Back Pressure-SL