Electricity prices above $5,000 per MWh

April to June 2023

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AUSTRALIAN ENERGY REGULATOR

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Contents

Obligation **1**

Summary **2**

1 4 May, South Australia **4**

1.1 Overview of market conditions 4

1.2 Rebidding contributed to the high prices 6

2 24, 25 and 30 May 2023, Queensland and NSW **7**

2.1 Overview of market conditions 7

2.2 Rebidding contributed to the high prices 10

3 12 June 2023, Queensland **14**

3.1 Overview of market conditions 14

3.2 Rebidding contributed to the high price 18

4 28 June 2023, South Australia **19**

4.1 Overview of market conditions 19

4.2 Rebidding contributed to the high price 21

Attachment A – Significant rebids, 4 May **22**

Attachment B – Significant rebids, 24 May **27**

Attachment C – Significant rebids, 30 May **30**

Attachment D – Significant rebids, 12 June **32**

Attachment E – Significant rebids, 28 June **33**

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/MWh, but with a market price cap over $15,000/MWh prices can occasionally exceed this reporting threshold.[3] This reporting framework is intended to pick up 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 spot price is the price for a trading interval. The 30-minute price is the average of 6 trading intervals.

[3] The market price cap in 2022/23 was $15,500 per MWh and in 2023/24 is $16,600 per MWh.

Summary

While average wholesale prices across the NEM from April to June 2023 were significantly below the levels from the same quarter in the 2022, there were still some short-term price events where prices exceeded $5,000 per MWh.[4] In all, 30-minute prices exceeded $5,000 per MWh 16 times over April to June 2023 – 6 times in Queensland, 5 in NSW and 5 in South Australia. This compares to 42 high prices over the same period last year, when 30-minute prices exceeded $5,000 per MWh 15 times in Queensland alone.

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

A common driver across all these high price events was that during the high prices, the relevant region was limited in its ability to import cheaper generation from a neighbouring region due to network outages or issues.

A second driver was the reduced supply of low-priced capacity. In South Australia, this was primarily due to low wind and low solar output. As South Australia has little base-load capacity, during hours of low renewable output it is dependent on imports from Victoria or more expensive gas generation. In NSW and Queensland, the reduced supply of low-priced capacity was due to:

- up to 3,500 MW of ongoing planned and unplanned baseload generator outages
- unit issues on the day that reduced the availability of low-priced black coal
- the closure of the Liddell Power Station in NSW at the end of April.

Common drivers of high price events

Date and region	Reduced supply	High demand	Network limitations	Technical rebids[5]	Commercial rebids[6]
4 May, SA	✓	✓	✓	✓	✓
24 May, Qld, NSW	✓	✓	✓	✓	×
25 May, Qld, NSW	✓	✓	✓	×	×
30 May, Qld, NSW	✓	✓	✓	✓	✓
12 June, Qld	✓	✓	✓	✓	✓
28 June, SA	✓	✓	✓	×	✓

[4] The AER's Wholesale Markets Quarterly Q2 2023 describes these broader market price dynamics from April to June 2023 in more detail.

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

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

Rebidding contributed to most of the high prices discussed in this report. On most occasions, these rebids were for technical reasons, such as units failing to start and plant issues. However, on other occasions, these rebids were for commercial reasons such as lower forecast prices or managing a constraint.

Weather is having a greater influence on the market as it transitions to renewable sources of generation. The market is increasingly competitive during the middle of the day when renewables output are high. However, particularly since the Liddell Power Station closure, supply and demand conditions are generally tighter during periods of high demand and low renewable output, particularly when this occurs at the same time as high levels of coal outages. Participants may try to take advantage of these tight market conditions by rebidding to withdraw capacity or by shifting capacity to high prices to exacerbate high prices. While this behaviour does not appear to be a key factor in the events covered in this report, we will continue to monitor trends in rebidding as part of our role in identifying whether there is effective competition in the NEM.

1. 4 May, South Australia

The wholesale price of electricity exceeded $5,000 per MWh for four 30-minute periods on the morning of 4 May 2023 in South Australia.

Table 1.1 Summary of the 30-minute high price events

Date	Time	Price ($ per MWh)
4 May	7 am	7,496
	7.30 am	7,736
	8 am	9,497
	8.30 am	9,819

A combination of factors drove the high prices:

- Cool morning temperatures of around 9°C drove high demand
- Low output from wind and solar generation resulted in limited amounts of low-priced capacity available
- Network limitations, which impacted the interconnectors, meant that South Australia had limited access to cheaper generation from Victoria
- Rebidding of capacity from below to above $5,000 per MWh
- Withdrawal of some low-priced capacity.

1.1 Overview of market conditions

In South Australia, prices exceeded $5,000 per MWh for four 30-minute periods on the morning of 4 May. Earlier that morning, AEMO had some concerns around lack of available capacity and issued a forecast Lack of Reserve (LOR1)[7] notice for the 7 am to 8 am period, however an actual LOR didn't eventuate.

From Table 1.2 we observe that:

- the 7 am and 7.30 am prices were forecast to exceed $5,000 per MWh, however, the actual prices were lower than expected due in part to actual demand being lower and actual availability being higher than forecast
- the 8 am and 8.30 am prices were not forecasted to exceed $5,000 per MWh, as actual demand was higher than forecast
- actual availability was higher than forecast at 8 am but lower than forecast at 8.30 am.

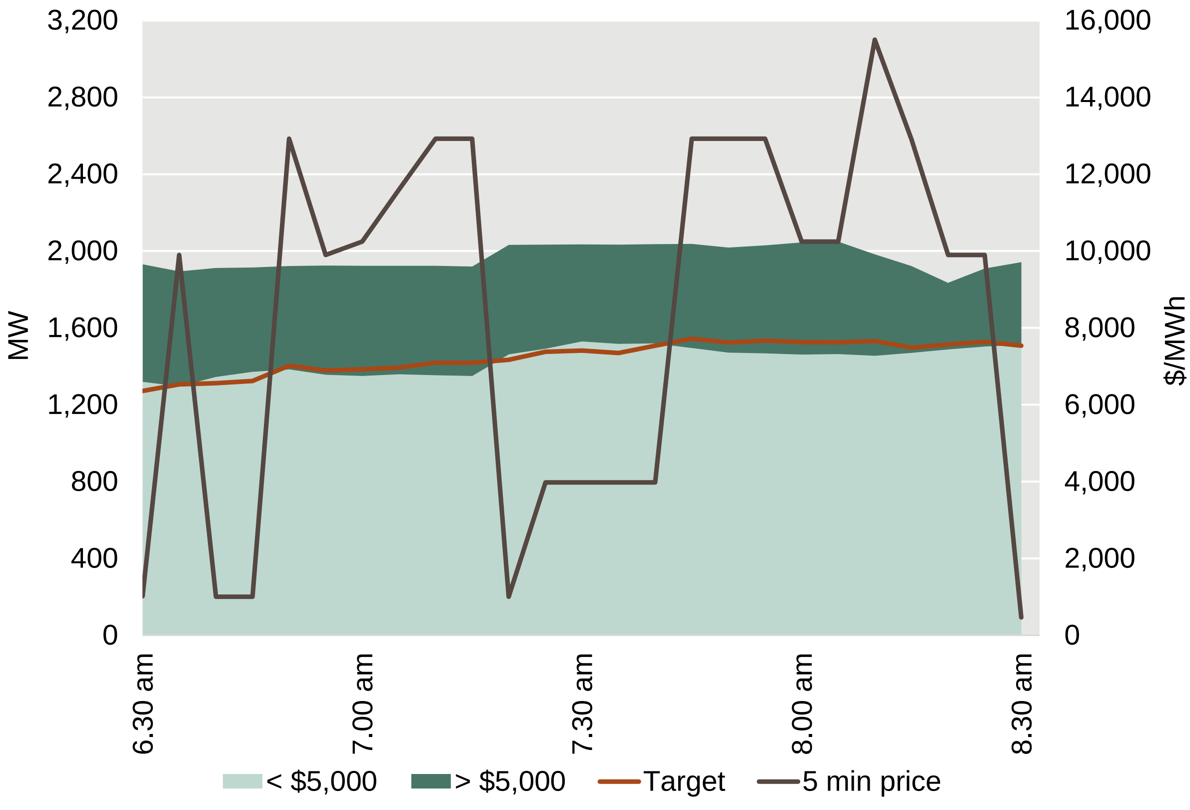
[7] AEMO LOR factsheet

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

Date	Time	Price ($ per MWh)		Demand (MW)		Availability (MW)	
		Actual	1 hr forecast	Actual	1 hr forecast	Actual	1 hr forecast
4 May	7 am	7,496	12,922	1,355	1,431	1,923	1,916
	7.30 am	7,736	12,922	1,441	1,497	1,978	1,884
	8 am	9,497	591	1,528	1,471	2,033	2,011
	8.30 am	9,819	591	1,547	1,461	1,940	2,090

Due to high demand, low wind and solar generation and limited imports from Victoria, between 10 MW and 76 MW of high-priced capacity was needed to meet demand (Figure 1.1), even though most capacity was offered below $5,000 per MWh.

Figure 1.1 Capacity offered above and below $5,000 per MWh on 4 May



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

1.1.1 Cold temperatures drove high demand

South Australia had low temperatures of around 9°C at the time of high prices which drove the use of heating appliances and high demand. Demand increased by 242 MW from 6.35 am to 8.30 am.

1.1.2 Limited low-priced capacity due to low wind and solar

Wind and solar output, which is generally low-priced, was low due to calm and cloudy weather conditions.

Combined low-priced capacity for wind and solar ranged between 13 MW to 120 MW during times of the high prices. In comparison, later that morning it increased up to 370 MW. At the time, there was around 2,500 MW of wind and almost 480 MW of solar (maximum) capacity in South Australia.

1.1.3 Network issues limited access to cheaper generation from Victoria

There are two interconnectors between South Australia and Victoria, Heywood and Murraylink, which enable transfer of energy between the regions.

Heywood was flowing an average of 43 MW into South Australia during high prices, where its nominal capacity is 600 MW. This was a result of a constraint used to manage power system stability, limiting imports into South Australia and was forecast.

At the same time, a constraint to manage the possible voltage collapse of the Bendigo to Kerang 220kV line in Victoria was forcing flows at an average of 27 MW out of South Australia across Murraylink. Without this constraint, 220 MW could have potentially flowed towards South Australia and provided access to cheaper generation from Victoria.

1.2 Rebidding contributed to the high prices

Rebidding contributed to the high prices on 4 May (Attachment A – Significant rebids, 4 May) with between only 10 MW and 76 MW of high-priced capacity needed to meet demand. While some of the rebids were for technical reasons, others were in response to changing market conditions. Within 30 minutes of the first high price, AGL, Infigen, Engie and Neoen each rebid capacity from below to above $5,000 per MWh:

- Over several rebids from 6.06 am, AGL shifted between 52 MW and 114 MW of capacity at Barker Inlet from below $200 per MWh to $15,500 per MWh and set the 5-minute price 6 times. The rebids were a commercial response to changes in forecast demand and price.
- Over several rebids from 6.12 am, Infigen rebid between 24 MW and 35 MW at Lake Bonney battery, from below $1,000 per MWh to above $9,500 per MWh, due to change in forecast state of charge. The participant also withdrew 24 MW from below $1,000 per MWh for the 7.50 am interval.
- Over several rebids from 6.12 am, Engie also rebid a total of 12 MW at Dry Creek Station from below $5,000 per MWh to $13,126 per MWh, to manage a constraint affecting the Heywood interconnector.
- Over several rebids from 6.46 am, Neoen rebid a total of 30 MW of capacity at Hornsdale Power Reserve from below $5,000 per MWh to $9,000 per MWh and withdrew a total of 66 MW from below $5,000 per MWh, due to a change in forecast state of charge. The battery set the 5-minute price 5 times.

2. 24, 25 and 30 May 2023, Queensland and NSW

The wholesale price of electricity exceeded $5,000 per MWh for five 30-minute periods during the evenings of 24, 25 and 30 May in Queensland and NSW (Table 2.1). There was relative price alignment across Queensland and NSW during these high price periods, so our analysis treats these as one region.[8]

Table 2.1 Summary of 30-minute high price events

Date	Time	Queensland price ($ per MWh)	NSW price ($ per MWh)
24 May	6 pm	8,022	9,179
24 May	6.30 pm	5,969	6,954
25 May	6 pm	6,587	7,304
30 May	5.30 pm	5,187	5,453
30 May	6 pm	5,527	5,851

A combination of factors drove these high prices:

- High demand due to cold weather and ongoing generator outages contributed to relatively tight supply/demand conditions
- A planned network outage south of Sydney from the middle of May to early June limited the regions' access to cheaper generation from southern NSW and Victoria
- Mt Piper experienced boiler issues late in the afternoon of 24 May reducing its available capacity by around 420 MW on 24 and 25 May
- Rebidding contributed to the high prices on 24 and 30 May but not 25 May. All but one of these were for technical reasons.

High prices were not forecast on 24 or 30 May but were forecast for 25 May which had similar market conditions to the other 2 days.

2.1 Overview of market conditions

Colder than average May temperatures, around 3,600 MW of ongoing generator outages and the closure of Liddell a few weeks prior contributed to generally tight market conditions in Queensland and NSW during the evening peaks in May. On 25 and 30 May, a shortfall of spare capacity across Queensland and NSW triggered AEMO to issue a LOR1 for both regions during the high price periods.[9]

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[8] As the interconnector flows between Queensland and NSW were unconstrained during the high prices discussed in this report, the regions were price aligned and the same units set price across both regions. Therefore, our analysis considers them as one region and the same drivers drove the high prices in both regions.

[9] AEMO issues Lack of Reserve notices when the buffer between the forecast availability and forecast demand is insufficient to cover unplanned events. They do this to encourage generators to offer more supply and large consumers to reduce demand.

On all the high-priced days, a planned outage on a key transmission line south of Sydney limited access to cheaper priced generation located in southern NSW and Victoria. This outage started on 15 May and ended in early June.

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

- high prices were not forecast on 24 and 30 May but were forecast on 25 May
- actual combined demand was greater than forecast on 24 and 30 May but was lower than forecast on 25 May (but not sufficiently low to stop the high price)
- actual combined availability was lower than forecast for all the high-priced periods, by between 303 MW and 475 MW.

Table 2.2 Actual price, demand and availability compared to the 1 hour forecast

Date	30-min period	Price ($ per MWh)				Combined demand (MW)		Combined availability (MW)	
		Actual		1 hr forecast		Actual	1 hr forecast	Actual	1 hr forecast
		Qld	NSW	Qld	NSW				
24 May	6 pm	8,022	9,179	553	581	18,339	18,066	19,972	20,274
	6.30 pm	5,969	6,954	272	300	18,437	18,182	20,043	20,361
25 May	6 pm	6,587	7,304	13,304	14,800	17,856	18,121	20,070	20,529
30 May	5:30 pm	5,187	5,453	321	300	17,596	17,534	20,085	20,430
	6 pm	5,527	5,851	399	372	18,395	18,103	20,042	20,517

Even though most capacity was offered below $5,000 per MWh, some high-priced capacity was needed to meet demand during the evening:

- on 24 May, 26 MW to 172 MW of high-priced capacity was needed (Figure 2.2)
- on 25 May, 152 MW to 200 MW of high-priced capacity was needed (Figure 2.3)
- on 30 May, 152 MW to 200 MW of high-priced capacity was needed (Figure 2.4).

2.1.1 Demand was higher than forecast

Colder than average May temperatures drove relatively high demand in the second half of the month. During the evening peak when prices spiked on 24 and 30 May, actual demand was 62 MW to 292 MW higher than forecast one hour prior. On 25 May it was lower than forecast, but still relatively high.

2.1.2 Availability was lower than forecast

On top of the approximately 3,500 MW of planned baseload capacity unavailable in Queensland and NSW on the 3 days, actual availability was lower than forecast for all the high-priced periods by 300 MW to 475 MW (Table 2.2).

Available capacity was reduced by up to 420 MW by participants removing capacity for mainly technical reasons, which did affect price. The most significant was Mt Piper due to a boiler issue which reduced availability across all 3 days (section 2.2):

There was also a reduction in the availability of wind generation. Wind availability is impacted by its output in the preceding 5 minutes. Wind generation in southern NSW was reduced by up to 500 MW because of Snowy Hydro rebidding around 1,400 MW of capacity to the price floor at Tumut, which is also in southern NSW. This made wind generation in southern NSW more expensive than capacity at Tumut. As there was a planned outage on the Dapto to Kangaroo Valley transmission line between southern NSW and Sydney, this curtailed generation in southern NSW as it could not all get to Sydney (Section 2.1.3).

2.1.3 Planned network outages reduced access to cheaper generation from southern NSW and Victoria

Flows over the Victoria-NSW interconnector can be up to 1,600 MW. However, on all 3 days, flows over the interconnector were limited, and at times forced into Victoria to maintain system security.

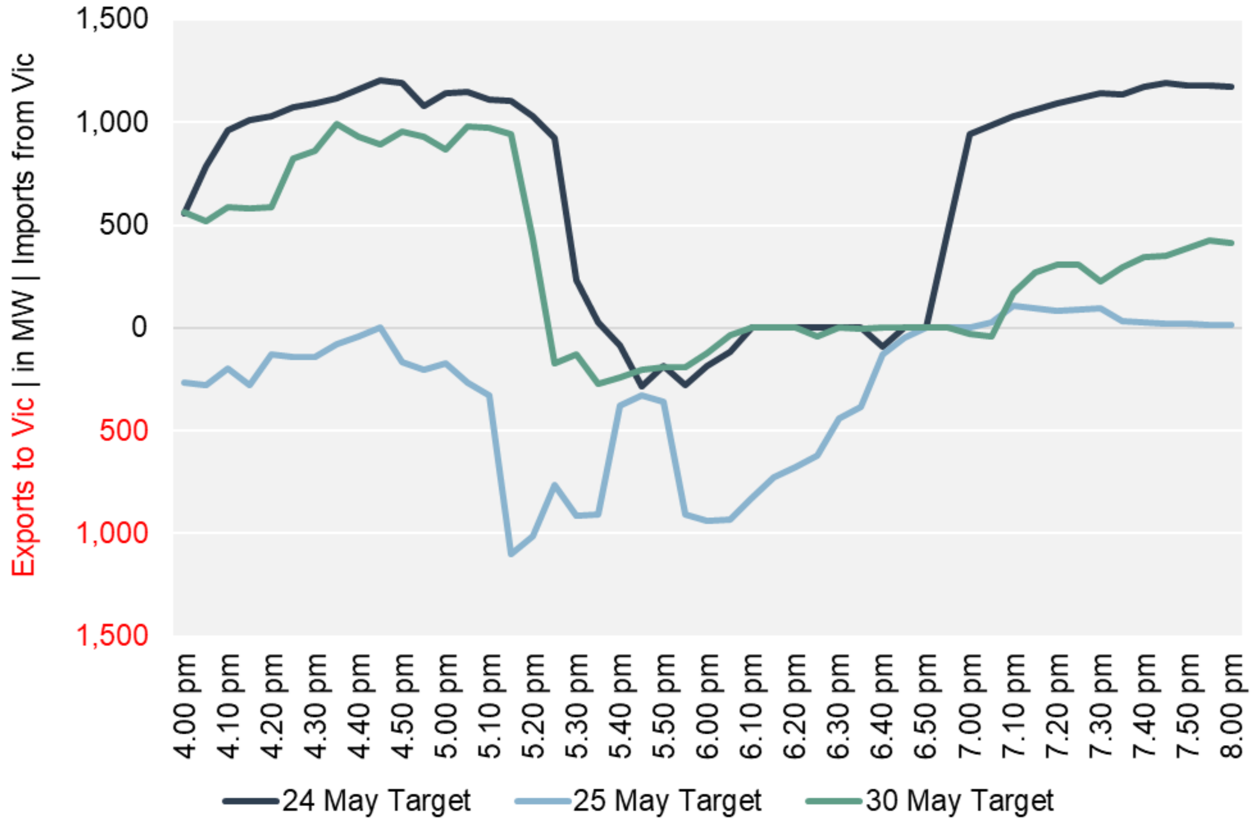
This was due to the planned outage of the Dapto to Kangaroo Valley line in NSW. This is a key transmission line between generation in southern NSW and Victoria and Sydney. This reduced Queensland and NSW’s access to cheaper generation from southern NSW and Victoria.

To maintain system security, excess low-priced capacity in southern NSW that could not make it to Sydney because of the line outage was forced into Victoria (Figure 2.1). AEMO's constraint report highlights the Dapto to Kangaroo Valley line outage as one of the top 10 constraint impacts for the month.[10]

- On 24 May, interconnector flows into NSW (which prior to this event were above 1,000 MW) were forced into Victoria up to 280 MW. Interconnector flows were later reduced to 0 MW in both directions as a constraint was invoked to stop forced flows into Victoria.
- On 25 May, between 326 MW to 935 MW was again forced from NSW into Victoria at the time of the high prices. One of the Tumut to Upper Tumut Lines was also out until 6 pm.
- On 30 May, up to 270 MW was forced from NSW into Victoria.

[10] AEMO, ‘Monthly Constraint Report, May 2023’, p6

Figure 2.1 Victoria-NSW interconnector target flows



2.2 Rebidding contributed to the high prices

Rebidding of capacity by participants contributed to the high prices on 24 May and 30 May. On 30 May one of these was for commercial reasons. Rebidding did not contribute to the high prices on 25 May.

24 May

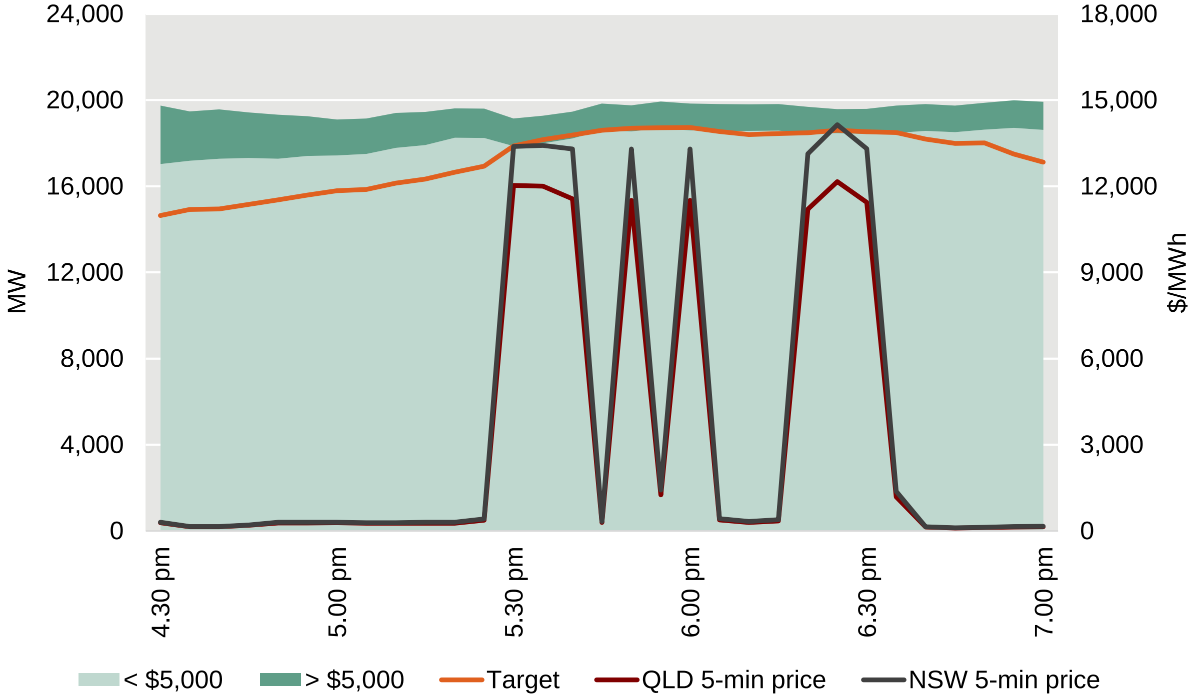
During the 7 high-priced intervals at 5.35 pm, 5.40 pm, 5.50 pm, 6 pm, 6.20 pm, 6.25 pm and 6.30 pm, between 26 MW to 172 MW of high-priced capacity was required to meet demand (Figure 2.2).

In NSW, the following rebids reduced the total amount of low-priced capacity available during these intervals by up to 525 MW:

- at 5.18 pm, EnergyAustralia removed between 190 MW of low-priced capacity from Mt Piper then at 5.36 pm it removed a further 230 MW due to boiler issues, reducing the amount of available capacity by 420 MW across the latter high-price intervals.
- at 5.20 pm, Infigen Energy also removed 81 MW of low-priced capacity from Smithfield gas power station from the first 2 high-priced intervals, due to a change in plant availability.

Meanwhile in Queensland at 5.22 pm, Yabulu gas power station shifted 42 MW from $0 per MWh to the cap due to unexpected plant limits, reducing low-priced capacity offered for the first high-priced interval.

Figure 2.2 Effective availability, target and price in Queensland and NSW, 24 May



Source: AER analysis using NEM data.

25 May

High prices on 25 May were forecast the day before (from 12.30 pm). Actual prices were high but lower than forecast an hour prior. Only around 10% of capacity was offered at high prices, but demand was sufficiently high enough that some of this high-priced capacity was needed. During the 3 high-priced intervals at 5.40 pm, 5.45 pm and 5.50 pm, between 152 MW to 200 MW of high-priced capacity was required to meet demand (Figure 2.3).

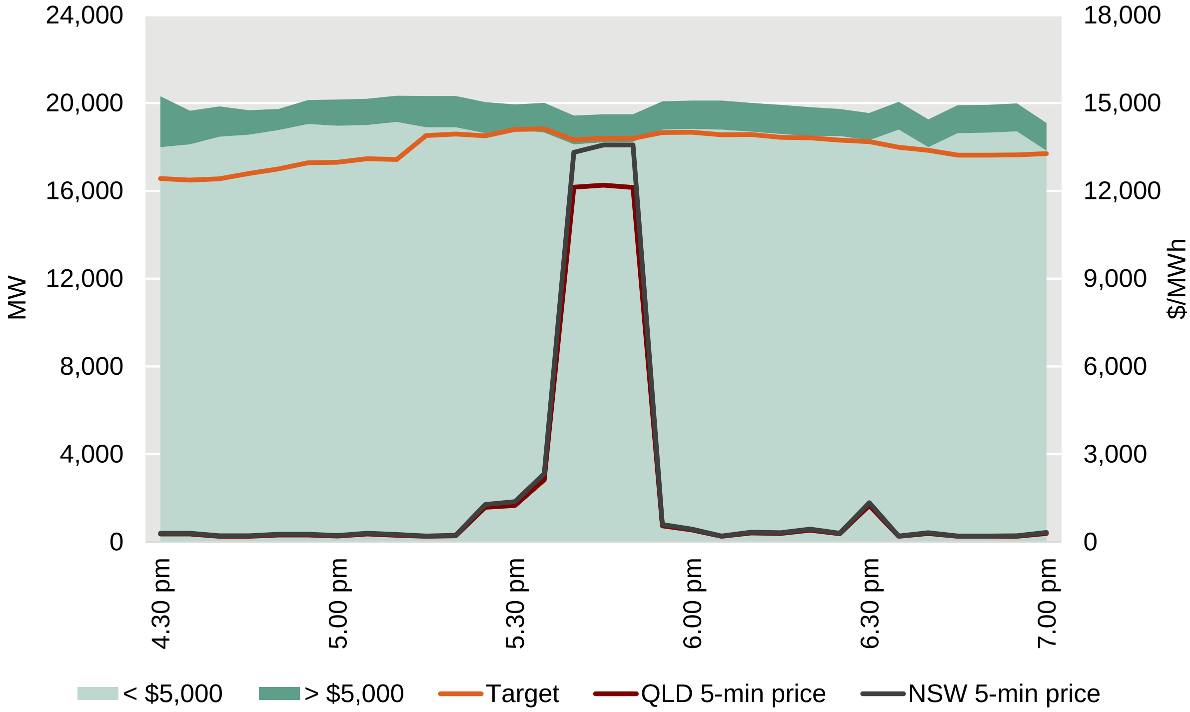
There were no significant rebids in either Queensland or NSW.

Demand response offered 20 MW of low-priced 'capacity' into the market in the hour leading up to the high prices. While the volumes were not enough to lower the price, demand response is a growing segment of the market.[11]

[11] The wholesale demand response mechanism allows demand side participation in the wholesale electricity market at any time, however, most likely at times of high electricity prices and electricity supply scarcity. Demand Response Service Providers classify and aggregate the demand response capability of large market loads for dispatch through the NEM's standard bidding and scheduling processes.

The DRSP receive payment for the dispatched response, measured in Mega-Watt hours (MWh) against a baseline estimate, at the electricity spot price.

Figure 2.3 Effective availability, target and price in Queensland and NSW, 25 May



Source: AER analysis using NEM data.

30 May

During the 4 high-priced intervals at 5.25 pm, 5.30 pm, 5.35 pm and 5.55 pm, between 19 MW to 166 MW of high-priced capacity was required to meet demand (Figure 2.4).

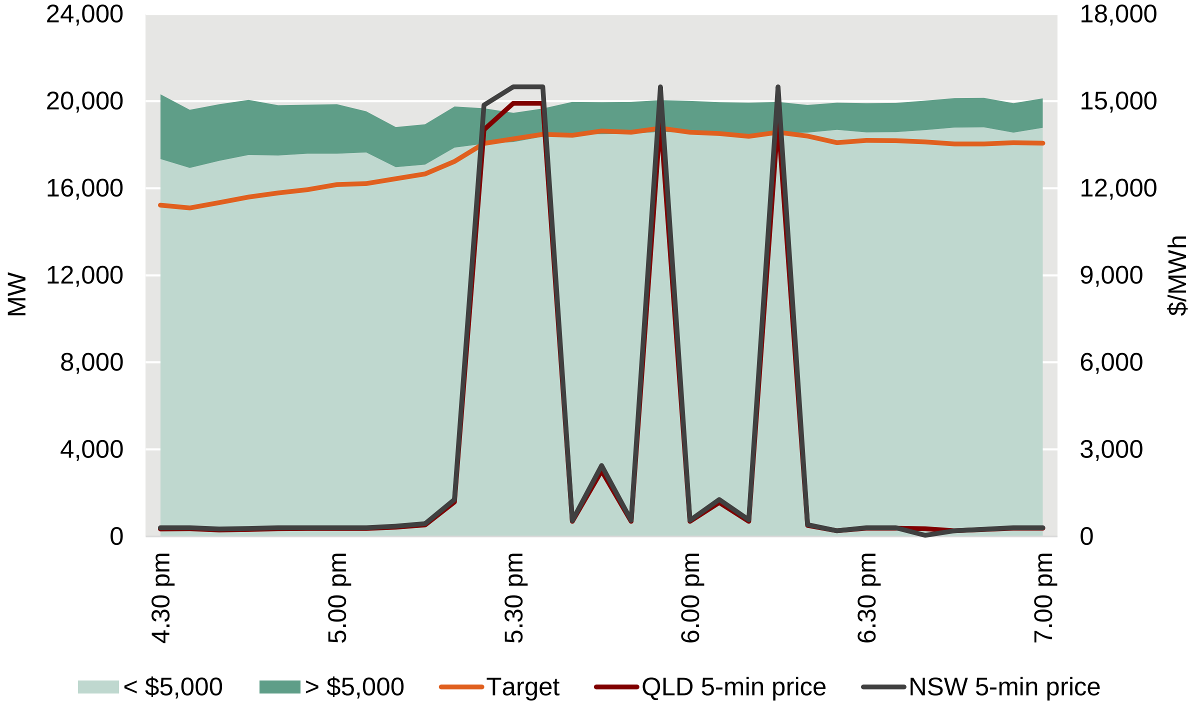
In NSW, the following rebids reduced the total amount of low-priced capacity available by 460 MW. These were mostly for technical reasons:

- at 2 pm, Infigen Energy removed 120 MW of Smithfield's low-priced capacity due to lower forecast prices
- at 3.53 pm, Snowy Hydro removed 89 MW of Upper Tumut's lowed priced capacity due to plant issues (for 2 of the high-priced intervals).
- at 4.24 pm, EnergyAustralia removed 250 MW of Mt Piper's low-priced capacity due to coal mill issues.

In Queensland, the following rebids reduced the total amount of low-priced capacity available by a further 270 MW:

- at 3.49 pm, CS Energy removed 60 MW of low-priced capacity from Gladstone for emissions testing
- at 5.13 pm, Alinta Energy removed 177 MW of low-priced capacity from Braemar A as it failed to start
- at the same time, Ergon Energy removed 37 MW of low-priced capacity from Barcaldine power station because the unit failed to start (impacting 2 of the high-priced intervals).

Figure 2.4 Effective availability, target and price in Queensland and NSW, 30 May



Source: AER analysis using NEM data.

3. 12 June 2023, Queensland

The wholesale price of electricity exceeded $5,000 per MWh for a 30-minute period during the evening on 12 June 2023 in Queensland. The 30-minute price to 5.30 pm was $5,111 per MWh. The high price was not forecast.

Table 3.1 Breakdown of 30-minute high price event

Date	Time	Queensland 5-minute price ($ per MWh)
12 June	5.05 pm	555
	5.10 pm	11,640
	5.15 pm	2,304
	5.20 pm	14,930
	5.25 pm	619
	5.30 pm	619

A combination of factors drove these high prices:

- Loss of available generation in Queensland due to 2 units tripping
- Constraints on the interconnectors between NSW and Queensland limited access to cheaper generation from NSW
- Wind generation was low, below 140 MW
- Technical limitations on some generating units prevented capacity below $5,000 per MWh being dispatched in time
- FCAS co-optimisation for the one of the high-priced dispatch intervals
- Rebidding contributed to high-priced outcomes.

3.1 Overview of market conditions

In Queensland, prices exceeded $5,000 per MWh for one 30-minute period during the evening of 12 June 2023.

From

Table 3.2 we observe that:

- the high price was not forecast 1 hour earlier
- while demand was close to forecast, availability was 187 MW less than forecast 1 hour earlier.

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

Date	Time	Price ($ per MWh)		Demand (MW)		Availability (MW)	
		Actual	1 hr forecast	Actual	1 hr forecast	Actual	1 hr forecast
12 June	**5.30 pm**	5,111	550	7,578	7,570	8,473	8,660

3.1.1 Low temperatures in Queensland drove high demand

Queensland had a run of days that were colder than the June average at the time of the high price event.

Demand for the 2 high-priced 5-minute intervals saw a demand increases of 81 and 178 MW from the preceding intervals and more expensive generation was needed to meet this increase.

3.1.2 Loss of base load generation on the day

On-going base load outages in Queensland on the morning of 12 June were 1,850 MW. At 12.35 pm CS Energy's Kogan Creek unit tripped and removed 762 MW of capacity from the market. Then at 4.05 pm, InterGen's Millmerran unit 2 also tripped and removed a further 435 MW of capacity over two rebids (Attachment D – Significant rebids, 12 June). These two unplanned outages brought the total of unavailable base load capacity to 3,020 MW.

3.1.3 Limited access to cheaper generation from NSW

During the high-priced intervals, the Queensland to NSW interconnector (QNI) was importing 524 MW, which was around half its nominal capacity. This reduced limit was mostly due to a contingency constraint to avoid overloading Bayswater to Liddell power lines in NSW.

Terranora, the other Queensland to NSW interconnector, was constrained by an outage of the Lismore static VAR compensator in NSW. To maintain system security, flows of around 100 MW were forced into NSW.

While the limits on the interconnectors did not contribute to the high price at 5.10 pm because the dispatch engine found a cheaper option by co-optimising the price between the energy and FCAS markets, they did contribute to the high price at 5.20 pm.

3.1.4 Low wind and solar generation

Wind generation was 127 and 139 MW during the high-priced intervals, out of a total of 831 MW of registered wind capacity in Queensland. Given the time of day, there was little solar generation.

3.1.5 Energy FCAS trade-off sets the price

The market operator's dispatch engine simultaneously optimises the FCAS markets and the energy market, 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 the prices in both the energy and FCAS markets.

With no available capacity for the 5.10 pm interval between $300 and $13,749 per MWh, the NEM dispatch engine found the cheapest NEM solution was to co-optimise between the energy and FCAS markets, resulting in the price of $11,639 per MWh.

The dispatch engine did not find such co-optimisation opportunity for the 5.20 pm interval, and higher priced capacity in Queensland had to be dispatched. It came from Wivenhoe, which set the price at $14,930 per MWh.

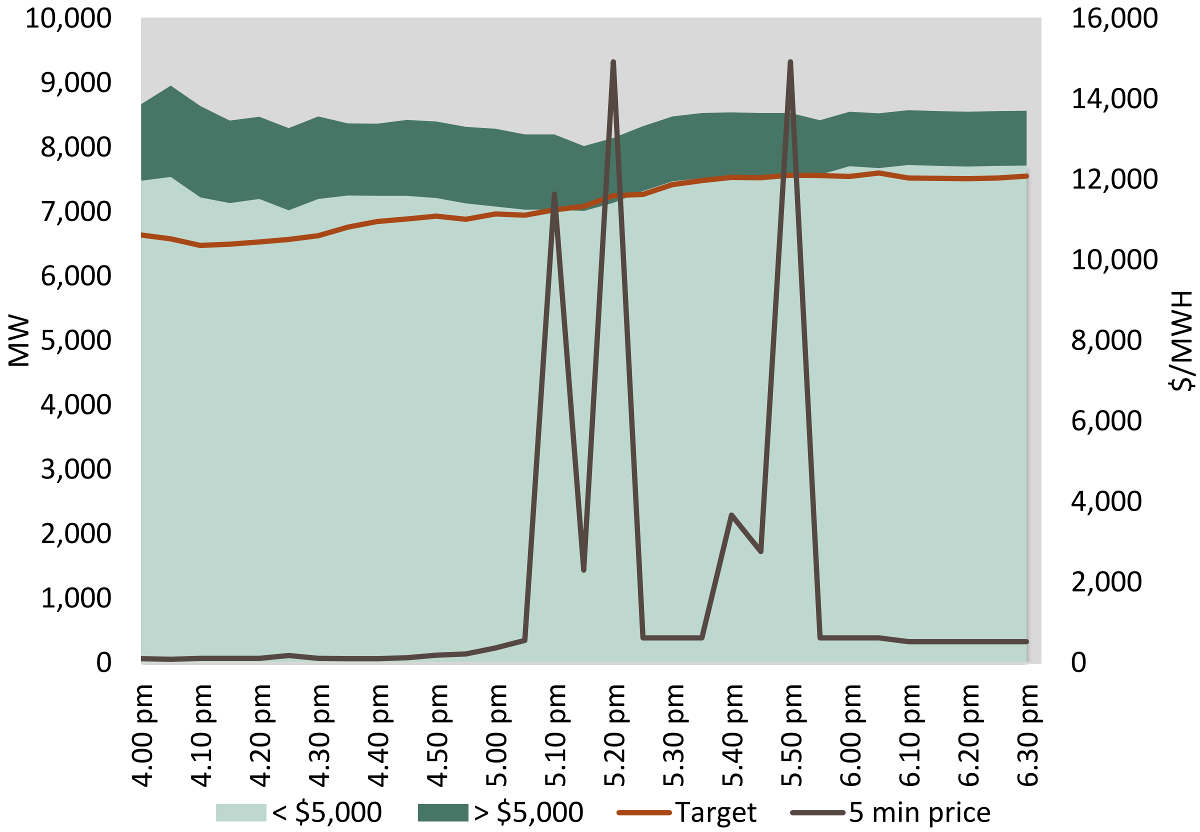
3.1.6 Low-priced capacity unable to be dispatched in time

Demand for the two high-priced 5-minute intervals saw substantial increases of 81 and 178 MW from the preceding intervals. However, some generators were unable to ramp up generation fast enough.

Some only started their plants after the 5.10 pm high price, and some were needed to provide FCAS. These factors resulted in some low-priced capacity unable to make it to market.

Between 12% and 14% of Queensland capacity was offered above $5,000 per MWh during high-priced intervals. No generation was offered between $700 and $14,000 per MWh (Figure 3.1).

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



Source: AER analysis using NEM data

3.2 Rebidding contributed to the high price

Rebidding for technical reasons and a commercial rebid made in error contributed to the high price. The technical rebids reflected the change in availability of the two units that tripped (section 3.1.2).

QGC Sales inadvertently rebid its Condamine unit unavailable for 5.15 pm and 5.20 pm. They were intending to commit the unit to market, but accidentally removed 90 MW of capacity priced at the floor. Given that close to 48 MW of capacity priced above $5,000 per MWh was needed for 5.20 pm, the rebid contributed to the high price for the interval. Having realised its error, QGC Sales almost immediately rebid the unit to its previously available capacity which took effect from 5.25 pm and the price fell to $619 per MWh.

4. 28 June 2023, South Australia

The wholesale price of electricity exceeded $5,000 per MWh for the 30-minute period to 8 am on 28 June in South Australia (Table 4.1). The 30-minute price to 8 am was $5,953 per MWh.

Table 4.1 Breakdown of 30-minute high price event

Date	Time	SA 5-minute price ($ per MWh)
28 June	7.35 am	999
	7.40 am	999
	7.45 am	999
	7.50 am	9,900
	7.55 am	12,922
	8 am	9,900

A combination of factors drove this high price event:

- Low output from wind generation reduced the amount of low-priced capacity available as it typically offers at negative prices
- Planned network outages impacted the Heywood and Murraylink interconnectors meaning that South Australia had limited access to cheaper generation from Victoria
- Rebidding of capacity from low to high prices contributed to higher prices.

4.1 Overview of market conditions

In South Australia, prices exceeded $5,000 per MWh for one 30-minute period during the morning on 28 June.

From Table 4.2 we observe that, compared to forecasts one hour prior:

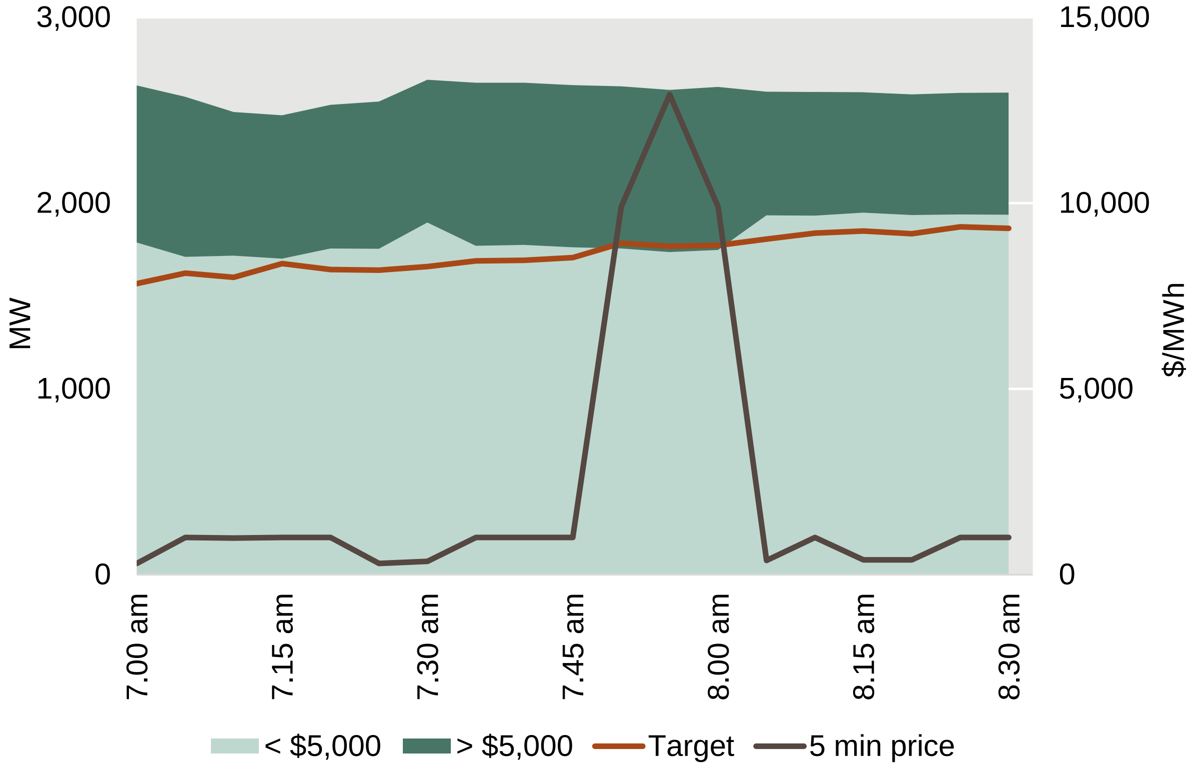
- high prices were not forecast
- actual demand was lower than forecast (~55 MW)
- actual availability was lower than forecast (~96 MW).

Table 4.2 Actual price, demand and availability compared to the 1 hour forecast

Date	Time	Price ($ per MWh)		Demand (MW)		Availability (MW)	
		Actual	1 hr forecast	Actual	1 hr forecast	Actual	1 hr forecast
28 June	8 am	5,953	999	1,778	1,832	2,641	2,737

Due to low wind generation, limited imports from Victoria, and rebidding of low-priced capacity, between 25 MW and 30 MW of high-priced capacity was needed to meet demand for 3 5-minute intervals (Figure 4.1). During the high priced intervals, around a third of capacity was offered above $5,000 per MWh and no capacity was offered between around $1,000 per MWh and $9,900 per MWh.

Figure 4.1 Capacity offered above and below $5,000 per MWh on 28 June



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

4.1.1 Limited output from wind generation

Average wind output was low at 115 MW out of around 2,500 MW installed. This was nearly half the volume forecast one hour prior and explains why availability was lower than forecast.

4.1.2 Network outages limited access to cheaper generation

The Heywood and Murraylink interconnectors were limited due to planned network outages for high voltage equipment maintenance. These outages limited imports over Heywood to 43 MW and Murraylink to 0 MW, out of their nominal capacities of 600 MW and 220 MW, respectively.[12]

As a result of the planned network outages, South Australia could not access enough cheaper generation from Victoria to prevent the high price.

[12] AEMO, Interconnector Capabilities for the National Electricity Market, accessed 8 August 2023.

4.2 Rebidding contributed to the high price

Rebidding of capacity from low to high prices contributed to the high price. Only between 25 MW and 30 MW of high-priced capacity was needed to meet demand which was less than the capacity rebid by participants.

Rebids by Engie at Snuggery and AGL Energy at Torrens Island resulted in 195 MW of lower-priced capacity being shifted to above $13,000 per MWh. The reasons related to constraints on the Heywood interconnector.

Attachment A – Significant rebids, 4 May

Below are tables with significant rebids for the high prices covered in this report. Only the 5-minute periods with a high price are included.

4 May 2023

6.35 am (10 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
6.06 am	6.15 am	AGL Energy	Barker Inlet	4	176	15,500	050 Chg in AEMO PD~50 PD DEMAND_AND_NONSCHEDGEN change SA by -100MW for PD 05:31 from PE 06:00
6.12 am	6.20 am	Infigen Energy	Lake Bonney BESS1	24	-1,000	9,900	Change in forecast SOC
6.18 am	6.25 am	AGL Energy	Barker Inlet	48	0	15,500	050 Chg in AEMO PD~50 PD (05:31-06:01) Demand change [SA] [62MW avg] for PE 07:00-07:30

6.50 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
6.06 am		AGL Energy	Barker Inlet	4	176	15,500	050 Chg in AEMO PD~50 PD DEMAND_AND_NONSCHEDGEN change SA by -100MW for PD 05:31 from PE 06:00
6.12 am		Engie	Dry Creek	12	4,609	13,126	Constraint Management: #R027594_001_RAMP_F-SL
6.18 am	6.25 am	AGL Energy	Barker Inlet	48	0	15,500	050 Chg in AEMO PD~50 PD (05:31-06:01) Demand change [SA] [62MW avg] for PE 07:00-07:30

6.55 am (22 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
6.06 am		AGL Energy	Barker Inlet PS	4	176	15,500	050 Chg in AEMO PD~50 PD DEMAND_AND_NONSCHEDGEN change SA by -100MW for PD 05:31 from PE 06:00
6.12 am		Engie	Dry Creek	12	4,609	13,126	Constraint Management: #R027594_001_RAMP_F-SL
6.18 am		AGL Energy	Barker Inlet	48	0	15,500	050 Chg in AEMO PD~50 PD (05:31-06:01) Demand change [SA] [62MW avg] for PE 07:00-07:30
6.46 am	6.55 am	Neoen	Hornsdale Power Reserve	30	3,983	9,900	Change in forecast SOC

7 am (35 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
6.06 am		AGL Energy	Barker Inlet	4	176	15,500	050 Chg in AEMO PD~50 PD DEMAND_AND_NONSCHEDGEN change SA by -100MW for PD 05:31 from PE 06:00
6.12 am		Engie	Dry Creek	12	4,609	13,126	Constraint Management: #R027594_001_RAMP_F-SL
6.18 am		AGL Energy	Barker Inlet	48	0	15,500	050 Chg in AEMO PD~50 PD (05:31-06:01) Demand change [SA] [62MW avg] for PE 07:00-07:30
6.46 am	6.55 am	Neoen	Hornsdale Power Reserve	30	3,983	9,900	Change in forecast SOC

7.05 am (34 of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
6.06 am		AGL Energy	Barker Inlet	33	176	15,500	050 Chg in AEMO PD~50 PD DEMAND_AND_NONSCHEDGEN change SA by -100MW for PD 05:31 from PE 06:00
6.12 am		Engie	Dry Creek	12	4,609	13,126	Constraint Management: #R027594_001_RAMP_F-SL
6.18 am		AGL Energy	Barker Inlet	48	0	15,500	050 Chg in AEMO PD~50 PD (05:31-06:01) Demand change [SA] [62MW avg] for PE 07:00-07:30
6.46 am	6.55 am	Neoen	Hornsdale Power Reserve	30	3,983	9,900	Change in forecast SOC

7.10 am (65 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
6.06 am		AGL Energy	Barker Inlet	33	176	15,500	050 Chg in AEMO PD~50 PD DEMAND_AND_NONSCHEDGEN change SA by -100MW for PD 05:31 from PE 06:00
6.12 am		Engie	Dry Creek	12	4,609	13,126	Constraint Management: #R027594_001_RAMP_F-SL
6.18 am		AGL Energy	Barker Inlet	48	0	15,500	050 Chg in AEMO PD~50 PD (05:31-06:01) Demand change [SA] [62MW avg] for PE 07:00-07:30
6.46 am	6.55 am	Neoen	Hornsdale Power Reserve	30	3,983	9,900	Change in forecast SOC

7.15 am (69 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
6.06 am		AGL Energy	Barker Inlet	33	176	15,500	050 Chg in AEMO PD~50 PD DEMAND_AND_NONSCHEDGEN change SA by -100MW for PD 05:31 from PE 06:00
6.12 am		Engie	Dry Creek	12	4,609	13,126	Constraint Management: #R027594_001_RAMP_F-SL
6.18 am		AGL Energy	Barker Inlet PS	48	0	15,500	050 Chg in AEMO PD~50 PD (05:31-06:01) Demand change [SA] [62MW avg] for PE 07:00-07:30
6.46 am	6.55 am	Neoen	Hornsdale Power Reserve	30	3,983	9,900	Change in forecast SOC

7.45 am (48 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
6.12 am		Engie	Dry Creek	12	4,609	13,126	Constraint Management: #R027594_001_RAMP_F-SL
6.46 am		AGL Energy	Barker Inlet	54	176	15,500	050 Chg in AEMO PD~50 PD (06:31) DEMAND_AND_NONSCHEDGN change [SA] [72MWavg] for PE 08:00 and 08:30
7.14 am	7.20 am	AGL Energy	Barker Inlet PS	24	0	15,500	050 Chg in AEMO PD~51 PD (06:31-07:01) Demand change [SA] [84MWavg] for PE 08:00-08:30
7.27 am	7.35 am	AGL Energy	Barker Inlet	36	0	15,500	050 Chg in AEMO PD~54 PD (06:31-07:01) price change [SA] $8173avg for PE 08:00 and 08:30
7.31 am	7.40 am	Infigen Energy	Lake Bonney BESS1	24	<996	12,936	Change in forecast SOC

7.50 am (52 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
6.12 am		Engie	Dry Creek	12	4,609	13,126	Constraint Management: #R027594_001_RAMP_F-SL
6.46 am		AGL Energy	Barker Inlet	54	176	15,500	050 Chg in AEMO PD~50 PD (06:31) DEMAND_AND_NONSCHEDGN change [SA] [72MWavg] for PE 08:00 and 08:30
7.14 am		AGL Energy	Barker Inlet	24	0	15,500	050 Chg in AEMO PD~51 PD (06:31-07:01) Demand change [SA] [84MWavg] for PE 08:00-08:30
7.27 am	7.35 am	AGL Energy	Barker Inlet	36	0	15,500	050 Chg in AEMO PD~54 PD (06:31-07:01) price change [SA] $8173avg for PE 08:00 and 08:30

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
7.41 am	7.50 am	Infigen Energy	Lake Bonney BESS1	-24	996	N/A	Updated SOC close to limit

7.55 am (66 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
6.12 am		Engie	Dry Creek	12	4,609	13,126	Constraint Management: #R027594_001_RAMP_F-SL
6.46 am		AGL Energy	Barker Inlet	54	176	15,500	050 Chg in AEMO PD~50 PD (06:31) DEMAND_AND_NONSCHEDGN change [SA] [72MWavg] for PE 08:00 and 08:30

8 am (65 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
6.46 am		AGL Energy	Barker Inlet	54	176	15,500	050 Chg in AEMO PD~50 PD (06:31) DEMAND_AND_NONSCHEDGN change [SA] [72MWavg] for PE 08:00 and 08:30
7.14 am		AGL Energy	Barker Inlet	24	0	15,500	050 Chg in AEMO PD~51 PD (06:31-07:01) Demand change [SA] [84MWavg] for PE 08:00-08:30
7.27 am	7.35 am	AGL Energy	Barker Inlet	36	0	15,500	050 Chg in AEMO PD~54 PD (06:31-07:01) price change [SA] $8173avg for PE 08:00 and 08:30
7.31 am	7.40 am	Infigen Energy	Lake Bonney BESS1	24	<996	12,936	Change in forecast SOC

8.05 am (62 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
6.12 am		Engie	Dry Creek	12	4,609	13,126	Constraint Management: #R027594_001_RAMP_F-SL
6.46 am		AGL Energy	Barker Inlet PS	50	176	15,500	050 Chg in AEMO PD~50 PD (06:31) DEMAND_AND_NONSCHEDGN change [SA] [72MWavg] for PE 08:00 and 08:30
7.01 am		Neoen	Hornsdale Power Reserve	-21	3,983	N/A	Change in forecast SOC
7.06 am		Neoen	Hornsdale Power Reserve	-28	<3,983	N/A	Change in forecast SOC
7.14 am		AGL Energy	Barker Inlet PS	24	0	15,500	050 Chg in AEMO PD~51 PD (06:31-07:01) Demand change [SA] [84MWavg] for PE 08:00-08:30

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
7.27 am		AGL Energy	Barker Inlet PS	36	0	15,500	050 Chg in AEMO PD~54 PD (06:31-07:01) price change [SA] $8173avg for PE 08:00 and 08:30
7.41 am	7.50 am	Infigen Energy	Lake Bonney BESS1	5	996	12,936	Updated SOC close to limit

8.10 am (76 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
6.12 am		Engie	Dry Creek	12	4,609	13,126	Constraint Management: #R027594_001_RAMP_F-SL
7.26 am		Neoen	Hornsdale Power Reserve	-8	3,983	N/A	Change in forecast SOC
7.06 am		Neoen	Hornsdale Power Reserve	-28	<3,983	N/A	Change in forecast SOC
7.36 am	7.45 am	Infigen Energy	Lake Bonney BESS1	6	996	12,936	Change in forecast SOC

8.15 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
7.01 am		Neoen	Hornsdale Power Reserve	-21	3,983	N/A	Change in forecast SOC
7.06 am		Neoen	Hornsdale Power Reserve	-28	<3,983	N/A	Change in forecast SOC
7.14 am		AGL Energy	Barker Inlet	24	0	15,500	050 Chg in AEMO PD~51 PD (06:31-07:01) Demand change [SA] [84MWavg] for PE 08:00-08:30
7.27 am		AGL Energy	Barker Inlet	36	0	15,500	050 Chg in AEMO PD~54 PD (06:31-07:01) price change [SA] $8173avg for PE 08:00 and 08:30
7.31 am		Infigen Energy	Lake Bonney BESS1	24	996	12,936	Change in forecast SOC
7.36 am		Neoen	Hornsdale Power Reserve	-17	1,004	N/A	Change in forecast SOC

Attachment B – Significant rebids, 24 May

The below table shows significant rebids for the 5.40, 5.50, 6.00, 6.20, 6.25 and 6.30 pm 5-minute dispatch intervals which required 26 MW to 172 MW of high-priced-capacity.

24 May 2023

5.35 pm (172 MW of high-priced capacity was needed)

NSW

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
5.18 pm	5.25 pm	EnergyAustralia	Mt Piper	-190	<140	N/A	adj avail roc1 boiler stability issue SL
5.20 pm	5.30 pm	Infigen Energy	Smithfield	-81	-1,062	N/A	Change in plant availability SL

Queensland

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
5.22 pm	5.30 pm	AGL Energy	Yabulu	42	0	15,500	010 Unexpected/plant limits~108 load/ramp variation

NSW

5.40 pm (164 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
5.18 pm	5.25 pm	EnergyAustralia	Mt Piper	-190	<140	N/A	adj avail roc1 boiler stability issue SL
5.20 pm	5.30 pm	Infigen Energy	Smithfield	-81	-1,062	N/A	Change in plant availability SL

5.50 pm (146 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
5.18 pm	5.25 pm	EnergyAustralia	Mt Piper	-190	<140	N/A	adj avail roc1 boiler stability issue SL
5.36 pm	5.45 pm	EnergyAustralia	Mt Piper	-230	0	N/A	adj avail roc1 boiler/coal limit SL

6 pm (94 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
5.18 pm	5.25 pm	EnergyAustralia	Mt Piper	-190	<140	N/A	adj avail roc1 boiler stability issue SL
5.36 pm	5.45 pm	EnergyAustralia	Mt Piper	-230	0	N/A	adj avail roc1 boiler/coal limit SL
5.51 pm	6.00 pm	EnergyAustralia	Mt Piper	-25	-1,000	N/A	adj avail roc1 coal qual/feeder/boiler issue SL

6.20 pm (26 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
5.18 pm	5.25 pm	EnergyAustralia	Mt Piper	-190	<140	N/A	adj avail roc1 boiler stability issue SL
5.36 pm	5.45 pm	EnergyAustralia	Mt Piper	-230	0	N/A	adj avail roc1 boiler/coal limit SL
5.51 pm	6.00 pm	EnergyAustralia	Mt Piper	-25	-1,000	N/A	adj avail roc1 coal qual/feeder/boiler issue SL
5.53 pm	6.00 pm	EnergyAustralia	Mt Piper	20	N/A	-1,000	adj avail roc1 coal/feeder/boiler SL
5.58 pm	6.05 pm	EnergyAustralia	Mt Piper	105	N/A	<0	adj avail match output feeder/coal limit ROc1 SL
6.03 pm	6.10 pm	EnergyAustralia	Mt Piper	30	N/A	0	adj avail revised coal/mill/feeder limit SL

6.25 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
5.18 pm	5.25 pm	EnergyAustralia	Mt Piper	-190	<140	N/A	adj avail roc1 boiler stability issue SL
5.36 pm	5.45 pm	EnergyAustralia	Mt Piper	-230	0	N/A	adj avail roc1 boiler/coal limit SL
5.51 pm	6.00 pm	EnergyAustralia	Mt Piper	-25	-1,000	N/A	adj avail roc1 coal qual/feeder/boiler issue SL
5.53 pm	6.00 pm	EnergyAustralia	Mt Piper	20	N/A	-1,000	adj avail roc1 coal/feeder/boiler SL
5.58 pm	6.05 pm	EnergyAustralia	Mt Piper	105	N/A	<0	adj avail match output feeder/coal limit ROc1 SL
6.03 pm	6.10 pm	EnergyAustralia	Mt Piper	30	N/A	0	adj avail revised coal/mill/feeder limit SL
6.17 pm	6.25 pm	EnergyAustralia	Mt Piper	-30	0	N/A	adj avail revised mill/coal limit SL

6.30 pm (100 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
5.18 pm	5.25 pm	EnergyAustralia	Mt Piper	-190	<140	N/A	adj avail roc1 boiler stability issue SL
5.36 pm	5.45 pm	EnergyAustralia	Mt Piper	-230	0	N/A	adj avail roc1 boiler/coal limit SL
5.51 pm	6.00 pm	EnergyAustralia	Mt Piper	-25	-1,000	N/A	adj avail roc1 coal qual/feeder/boiler issue SL
5.53 pm	6.00 pm	EnergyAustralia	Mt Piper	20	N/A	-1,000	adj avail roc1 coal/feeder/boiler SL
5.58 pm	6.05 pm	EnergyAustralia	Mt Piper	105	N/A	<0	adj avail match output feeder/coal limit ROc1 SL
6.03 pm	6.10 pm	EnergyAustralia	Mt Piper	30	N/A	0	adj avail revised coal/mill/feeder limit SL
6.17 pm	6.25 pm	EnergyAustralia	Mt Piper	-30	0	N/A	adj avail revised mill/coal limit SL

Attachment C – Significant rebids, 30 May

The below table shows significant rebids for the 5.25, 5.30, 5.35 and 5.55 pm 5-minute dispatch intervals which required 19 MW to 166 MW of high-priced-capacity.

5.25 pm (19 MW of high-priced capacity was needed)

NSW

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
2.12 pm		Infigen Energy	Smithfield	-120	-1,062	N/A	NSW1 RRP 30PD@14:02 for 17:30 is $306.49 lower than 30PD@13:32 ($354.54 vs $661.03) SL
4.24 pm		EnergyAustralia	Mt Piper	-250	-1,000	N/A	Adj Energy avail and FCAS trap/avail due to mill issue SL

Queensland

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
3.49 pm		CS Energy	Gladstone	-60	<371	N/A	Testing-Stack Emission -SL
5.13 pm	5.20 pm	Ergon Energy	Barcaldine	-37	-940	N/A	1709P unit failed to start. delayed start
5.13 pm	5.20 pm	Alinta Energy	Braemar A	-177	<288	N/A	revised unit availability: unit did not start during start up sequence. SL.

5.30 pm (146 MW of high-priced capacity was needed)

NSW

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
2.12 pm		Infigen Energy	Smithfield	-120	-1,062	N/A	NSW1 RRP 30PD@14:02 for 17:30 is $306.49 lower than 30PD@13:32 ($354.54 vs $661.03) SL
4.24 pm		EnergyAustralia	Mt Piper	-250	-1,000	N/A	Adj Energy avail and FCAS trap/avail due to mill issue SL

Queensland

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
3.49 pm		CS Energy	Gladstone	-60	<371	N/A	Testing-Stack Emission -SL
5.13 pm	5.20 pm	Ergon Energy	Barcaldine	-37	-940	N/A	1709P unit failed to start. delayed start
5.13 pm	5.20 pm	Alinta Energy	Braemar A	-177	<288	N/A	revised unit availability: unit did not start during start up sequence. SL.

5.35 pm (112 MW of high-priced capacity was needed)

NSW

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
2.12 pm		Infigen Energy	Smithfield	-80	-1,062	N/A	nsw1 rrp 30pd@14:02 for 17:30 is $306.49 lower than 30pd@13:32 ($354.54 vs $661.03) sl
3.53 pm		Snowy Hydro	Upper Tumut	-89	300	N/A	15:53:00 p update capability parameters for change to outage plan/plant conditions
3.54 pm		Infigen Energy	Smithfield	-40	-1,062	N/A	nsw1 rrp 30pd@15:32 for 19:00 is $300.66 lower than 30pd@14:33 ($304.15 vs $604.81) sl
5.16 pm	5.25 pm	EnergyAustralia	Mt Piper	-250	-1,000	N/A	adj avail revised coal/mill limit sl

Queensland

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
4.18 pm		CS Energy	Gladstone	-60	<371	N/A	Testing-Stack Emission SL
5.27 pm	5.35 pm	Alinta Energy	Braemar A	-177	<288	N/A	revised unit availability SL

5.55 pm (166 MW of high-priced capacity was needed)

NSW

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
2.12 pm		Infigen Energy	Smithfield	-80	-1,062	N/A	nsw1 rrp 30pd@14:02 for 17:30 is $306.49 lower than 30pd@13:32 ($354.54 vs $661.03) sl
3.53 pm		Snowy Hydro	Upper Tumut	-89	300	N/A	15:53:00 p update capability parameters for change to outage plan/plant conditions
3.54 pm		Infigen Energy	Smithfield	-40	-1,062	N/A	nsw1 rrp 30pd@15:32 for 19:00 is $300.66 lower than 30pd@14:33 ($304.15 vs $604.81) sl
5.16 pm	5.25 pm	EnergyAustralia	Mt Piper	-250	-1,000	N/A	adj avail revised coal/mill limit sl

Queensland

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
4.18 pm		CS Energy	Gladstone	-60	<371	N/A	Testing-Stack Emission -SL
5.34 pm	5.40 pm	Alinta Energy	Braemar A	-177	<288	N/A	Unit did not start during start sequence. SL.

Attachment D – Significant rebids, 12 June

The below table shows significant rebids for the 5.10 pm and 5.20 pm 5-minute dispatch intervals which required 0 MW and 48 MW of high-priced-capacity.

5.10 pm (0 MW of high-priced capacity was needed – co-optimisation)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
1.15 pm		CS Energy	Kogan Creek	-762	<19	N/A	13:00:21 P Unit trip - rebid energy contFCAS and regFCAS to zero - AT
3.09 pm		Intergen	Millmerran	-115	-1,000	N/A	P Fuel/Mill/CV Limitation
4.09 pm		Intergen	Millmerran	-320	-1,000	N/A	P Unit outage

5.20 pm (48 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
1.25 pm		CS Energy	Kogan Creek	-762	<19	N/A	13:20:13 P Unit trip - rebid energy contFCAS and regFCAS to zero - AT
3.09 pm		Intergen	Millmerran	-115	-1,000	N/A	P Fuel/Mill/CV Limitation
4.09 pm		Intergen	Millmerran	-320	-1,000	N/A	P Unit outage
5.08 pm	5.15 pm	QGC Sales	Condamine	-90	-1,000	N/A	Market change - commit unit - SL

Attachment E – Significant rebids, 28 June

The below table shows significant rebids for the 7.50, 7.55 and 8 am 5-minute dispatch intervals which required 29 MW, 30 MW and 25 MW of high-priced-capacity.

Significant rebids for 7.50, 7.55 and 8 am

Submitted time	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
6 am	Engie	Snuggery	65	4,664	13,281	Constraint Management: V:S_600_HY_TEST. SL
6.53 am	AGL Energy	Torrens Island	130	176	15,500	050 Chg in AEMO PD ~ Manage Heywood Ramping Constraint for I-HYSE