Electricity spot prices above $5,000/MWh

South Australia, 22 January 2021

16 March 2021

AUSTRALIAN ENERGY REGULATOR

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1 Obligation

The Australian Energy Regulator (AER) regulates energy markets and networks under national legislation and rules in eastern and southern Australia, as well as networks in the Northern Territory. Its functions include:

- monitoring wholesale electricity and gas markets to ensure energy businesses comply with the legislation and rules, and taking enforcement action where necessary;
- setting the amount of revenue that network businesses can recover from customers for using networks (electricity poles and wires and gas pipelines) that transport energy;
- regulating retail energy markets in Queensland, New South Wales, South Australia, Tasmania (electricity only), and the ACT;
- operating the Energy Made Easy website, which provides a retail price comparator and other information for energy consumers;
- publishing information on the performance of energy markets, including the annual State of the energy market report and biennial effective competition report, to assist stakeholders and the wider community.

The AER is required to publish a report whenever the electricity spot price exceeds $5,000 per megawatt hour ($/MWh) in accordance with clause 3.13.7 (d) of the National Electricity Rules.

The report:

- describes the significant factors contributing to the spot price exceeding $5,000/MWh, including withdrawal of generation capacity and network availability;
- assesses whether rebidding contributed to the spot price exceeding $5,000/MWh;
- identifies the marginal scheduled generating units; and
- identifies all units with offers for the trading interval equal to or greater than $5,000/MWh and compares these dispatch offers to relevant dispatch offers in previous trading intervals.

These reports are designed to examine market events and circumstances that contributed to wholesale market price outcomes and are not an indicator of potential compliance issues or enforcement action.

2 Summary

On 22 January 2021 the spot price in South Australia reached $5,031/MWh for the 4 am trading interval, driven by 2 dispatch intervals priced at the price cap. The high price was not forecast by AEMO, the market operator. Instead it was a result of 2 main factors:

- At 3.45 am Pelican Point power station tripped, meaning around 240 MW of capacity, priced below $100/MWh, was no longer available.
- Following the trip at Pelican Point, imports from Victoria were reduced by 240 MW. Imports were reduced to protect the power system in South Australia, in case the Heywood interconnector also tripped.

During the high priced period around 60% of capacity offered by participants in South Australia was priced below $5,000/MWh. Given the loss of supply from Pelican Point and reduced imports from neighbouring regions, around 450 MW of capacity had to be sourced locally. This could only be met by capacity priced at the cap for 2 dispatch intervals.

Pelican Point returned to service during the 4.30 am trading interval and continued to operate as expected for the remainder of the day.

Generator rebidding from prices below to above $5,000/MWh did not contribute to the 4 am price outcome. In fact, participants rebid capacity to the floor in response to the high priced dispatch intervals.

3 Analysis

On 22 January 2021 the spot price in South Australia reached $5,031/MWh for the 4 am trading interval. Pelican Point power station tripped, removing 240 MW of capacity from the market, all priced below $100/MWh.

3.1 Overview of actual and expected conditions

The spot price exceeded $5,000/MWh for the 4 am trading interval. The price was not forecast as it was due to an unplanned trip of the Pelican Point power station during the trading interval. Demand was close to forecast and at low levels due to the time of day. All other availability was close to forecast.

3.2 Supply

This section examines the supply side factors that had an effect on the high price outcomes.

3.2.1 Generation availability

Before Pelican Point tripped, the 4 other thermal units generating were 2 units at Torrens Island, Barkers Inlet and Ladbroke. Collectively, these thermal units, including Pelican Point, were dispatching around 550 MW of electricity, while wind was dispatching around 180 MW. Pelican Point was the largest thermal unit generating at the time.

When generating, thermal units also provide technical characteristics to a power system to help manage minor voltage and frequency fluctuations.[1] A constraint that manages the import limit into South Australia uses the number of thermal units that are currently generating locally to calculate the amount of electricity that South Australia can safely import without risking the stability of the power system.

To make up for the loss of Pelican Point's generation, at 3.45 am, units that were already generating received increased targets at their ramping limits. Peaking plant (that typically offer their capacity at the price cap) and batteries were also issued targets by the market operator to begin generating (Table 1).

[1] Electranet is currently installing synchronous condensers in South Australia which will also provide these necessary characteristics traditionally provided by thermal units, reducing South Australia's reliance on thermal generation. https://www.electranet.com.au/what-we-do/projects/power-system-strength/ https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/Operability/2020/2020-System-Strength-and-Inertia-Report#:~:text=Procurement%20by%20ElectraNet%20of%20fast,that%20shortfall%20for%202022%2D23.

Table 1: Units given a start target following Pelican Point's trip

Station	Registered Capacity (MW)	Fuel Type	Target at 3.45 am (MW)
Angaston	50	Diesel	40
Lonsdale	21	Diesel	14
Port Stanvac	58	Diesel	65
Hornsdale Power Reserve	150	Battery	80
Dalrymple North	30	Battery	20
Lake Bonney BESS	25	Battery	25
Total	334		**244**

While the capacity that started (received a target) made up for the lost generation at Pelican Point, this capacity was either priced at the cap or could not set price as it was ramp constrained, technically constrained or at max capacity.

During the time prices were above $5,000/MWh, around 2,200 MW of generation was offered into the market out of around 5,000 MW installed in South Australia. The reduced availability was due to some older gas plant at Torrens Island and Osborne not offering their capacity along with low wind conditions and no solar, as the event was before dawn. It is typical behaviour that much of Torrens Island and Osborne were not offered, given the low demand conditions and time of day. Of the 1,750 MW of semi-scheduled wind installed, less than 200 MW was available due to calm weather conditions.

Figure 1 shows how much effective available capacity was offered above and below $5,000/MWh and how much local generation was targeted to meet demand in South Australia. Capacity that could not get dispatched during the high prices due to technical or ramp constraints has been removed from the stack. As a result, it was necessary to dispatch local generation priced close to the cap for 2 dispatch intervals.

Figure 1: Generation availability above and below $5,000/MWh, target and dispatch price

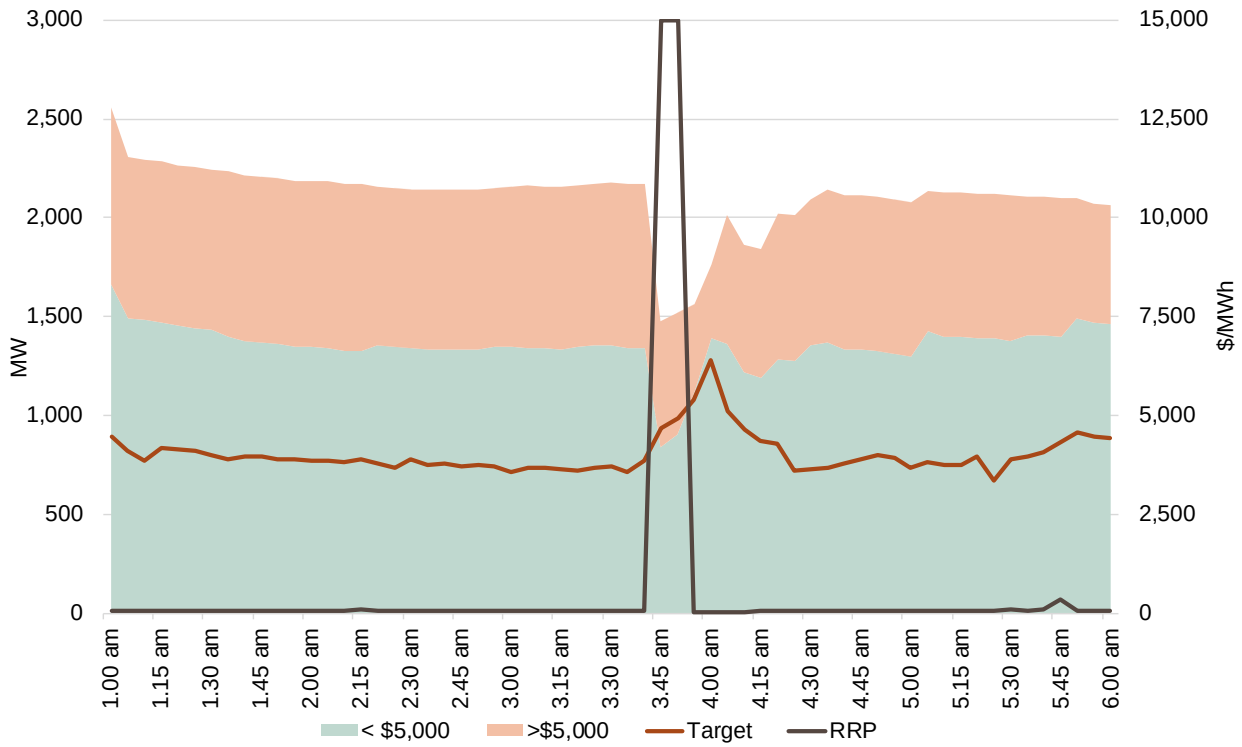
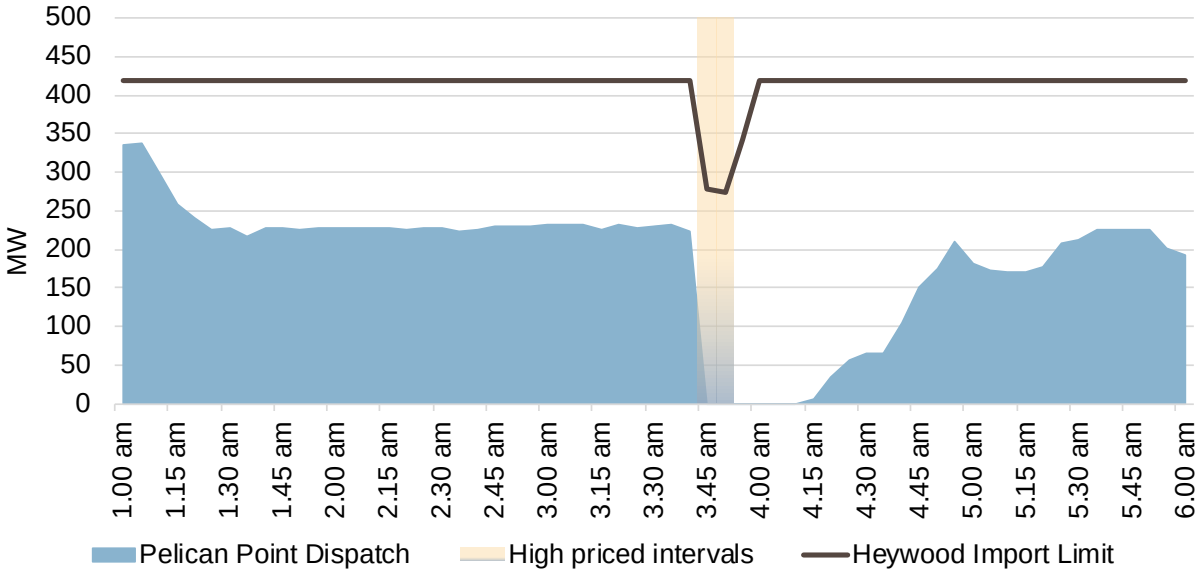


Figure 2 shows once Pelican Point stopped generating, the import limit into South Australia on the Heywood interconnector dropped by 240 MW, the same amount as Pelican Point's availability. The import limit was reduced because the constraint that set the limit used Pelican Point's generation (along with other inputs) to help determine the maximum amount of electricity that South Australia could safely import from Victoria, discussed further in the next section.

Figure 2: Pelican Point dispatch and the import limit into South Australia



3.2.2 Constraints and network availability

The regions of the National Electricity Market are connected via high voltage interconnectors, through which electricity is transferred. South Australia is connected to Victoria via two interconnectors, Heywood and Murraylink. Import and export limits control the maximum amount of electricity that can flow between regions across interconnectors. Constraints are mathematical equations that manage or "limit" flows on specific transmission lines (including interconnectors) for each five minute interval. The market operator, AEMO, manages the flow of electricity across the network using constraints to ensure that system security is maintained.

What is a constraint?

In optimising economic generation dispatch and interconnector flows, the National Electricity Market Dispatch Engine (NEMDE) formulates the maximum network capability for every five minute dispatch interval. These capabilities are used to form constraints that describe the maximum capability of each network element and include generator and interconnector coefficients.

Constraints contain a Left Hand Side (LHS) and a Right Hand Side (RHS). The RHS contains all of the inputs that cannot be varied by NEMDE. These inputs include demand and the rating of the relevant transmission line (i.e. how much energy the line can carry without damaging the line or causing unsafe conditions). The LHS contains all of the inputs that can be varied by NEMDE to deliver an outcome that satisfies the requirement of the RHS. These inputs include output from generators and flow on interconnectors. When the LHS equals the RHS then the constraint is binding.

3.2.2.1 Why did imports decrease across the Heywood Interconnector?

A constraint protecting the stability of the power system in South Australia was setting the import limit throughout the day. This constraint allows more imports into South Australia when more thermal units are operating locally. As discussed above, a thermal unit such as Pelican Point also provides technical characteristics which help support a stable power system.

When Pelican Point tripped it was the largest thermal plant on at the time. This increased the possibility for an unstable power system, especially if the Heywood interconnector also tripped. To mitigate this risk, imports into South Australia were reduced by 240 MW.

During the high priced trading interval both the Heywood and Murraylink interconnectors were importing into South Australia at their limit. The Murraylink interconnector operated close to its forecast limit, and was not affected by the trip at Pelican Point, so will be excluded from further discussion. The nominal import limit from Victoria to South Australia on Heywood is 600 MW. Although the same constraint was forecast to set the import limit on Heywood, the import limit was 289 MW lower than forecast 4 hours ahead (Table 2). This means the available supply of low priced generation into South Australia from neighbouring regions was materially reduced.

Table 2: Actual and forecast flows and limits across Heywood

Trading interval	Import flows (MW)			Import limit (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
4 am	236	525	354	294	525	354

3.2.2.2 Participants respond to high prices

In response to the high priced dispatch intervals, participants rebid capacity from prices above $370/MWh to the floor. By 3.55 am, fast start units such as Angaston and Snuggery were generating, more low priced thermal generation was on and the risk to power system security in South Australia had decreased. As a result, the import limit on Heywood increased and low priced generation from neighbouring regions set price in South Australia. Pelican Point slowly returned to service during the 4.30 am trading interval and continued to operate as expected for the remainder of the day.

The closing bids for all participants in South Australia with capacity priced at or above $5,000/MWh for the high-price periods are set out in *Appendix A: Closing bids*.

Rebidding into high price bands did not contribute to the high prices in South Australia. However any significant rebids are contained in *Appendix B: Significant rebids*.

The generators involved in setting the price during the high-price periods and how that price was determined by the market systems are detailed in *Appendix C: Price Setter.*

Australian Energy Regulator

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Appendix A: Closing bids

Figure A1 to A4 highlight the half hour closing bids for participants in South Australia with capacity priced at or above $5,000/MWh during the periods in which the spot price exceeded $5000/MWh. They also show generation output and the spot price.

Figure A1: AGL Energy (Barker Inlet, Dalrymple BESS, The Bluff wind farm, Hallett wind farm, North Brown Hill, Torrens Island) closing bids, dispatch and spot price

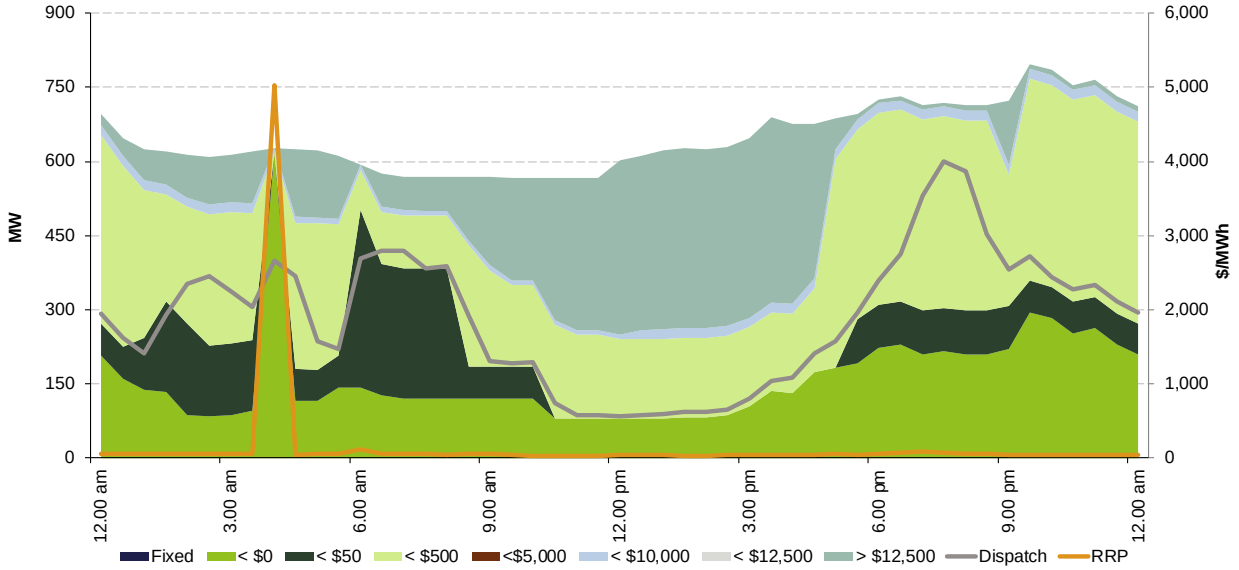


Figure A2: EnergyAustralia (Hallett, Waterloo wind farm) closing bids, dispatch and spot price

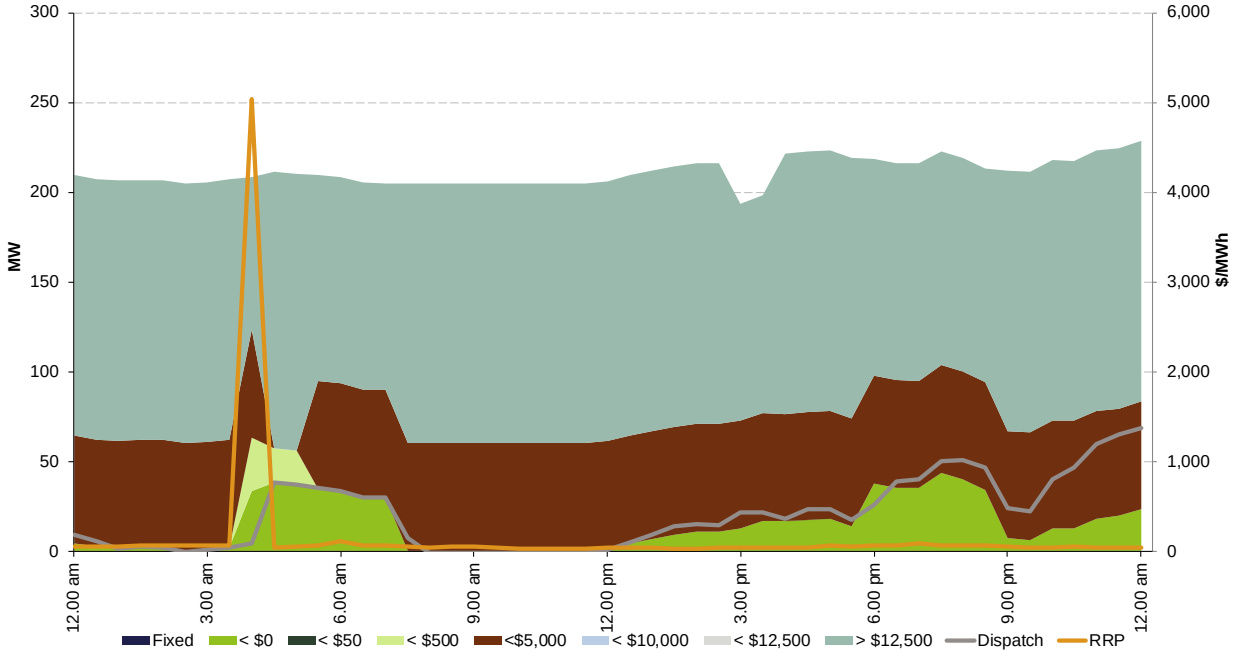


Figure A3: Engie (Dry Creek, Mintaro, Pelican Point, Port Lincoln, Snuggery, Willogoleche wind farm) closing bids, dispatch and spot price

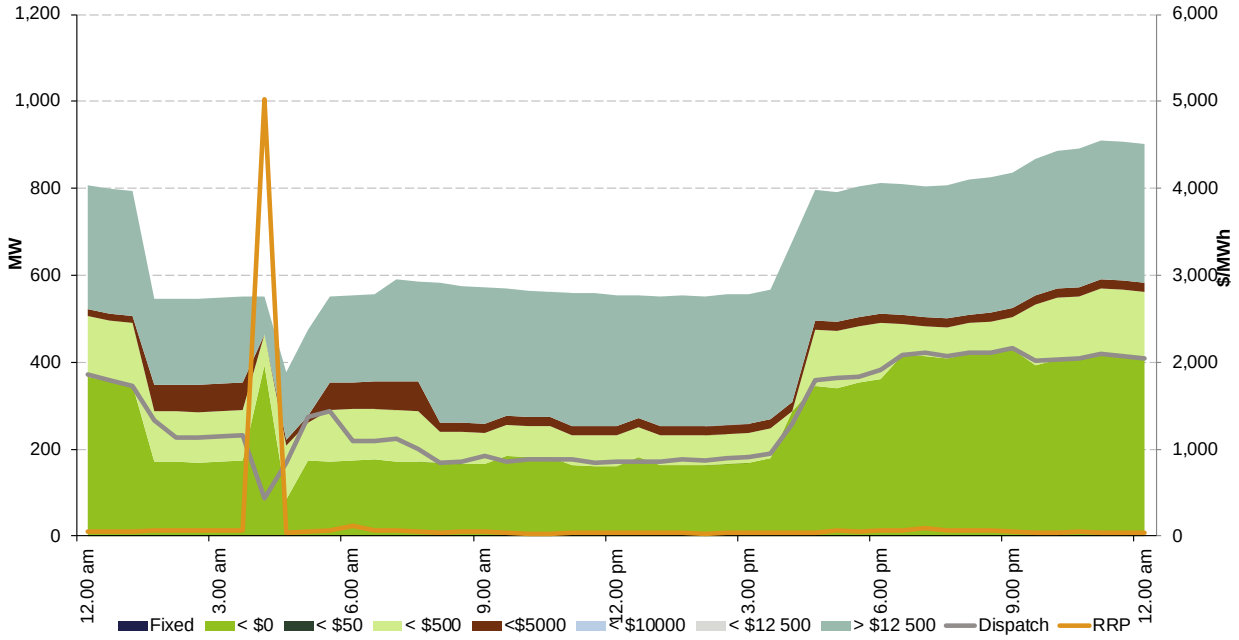
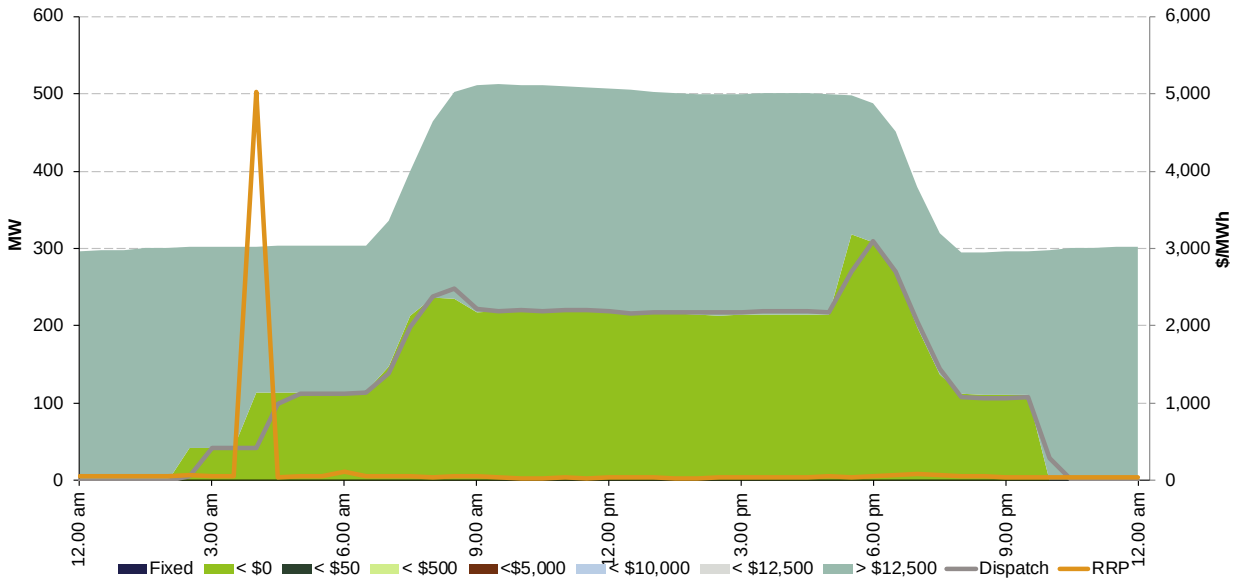


Figure A4: Origin (Ladbroke, Osborne and Quarantine) closing bids, dispatch and spot price



Appendix B: Significant rebids

The rebidding tables highlight the relevant rebids submitted by generators that impacted on market outcomes during the time of high prices. It details the time the rebid was submitted and used by the dispatch process, the maximum capacity involved, the change in the price of the capacity being offered, and the rebid reason.

Table 3: South Australia significant rebids for 4 am trading interval

Submit time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
3.41 am	3.50 am	Neoen	Hornsdale Power Reserve	63	1,015	-1,000	0341 A change in forecast prices
3.41 am	3.50 am	Infigen	Lake Bonney BESS	25	10,000	-1,000	0341~A~change in forecast prices~~
3.44 am	3.55 am	Snowy	Angaston	40	>376	-1,000	03:44:05 A unforecast change to market - reason to follow
3.44 am	3.55 am	Snowy	Lonsdale	21	15,000	-1,000	03:44:05 A unforecast change to market - reason to follow
3.44 am	3.55 am	Snowy	Port Stanvac	65	>381	-1,000	03:44:05 A unforecast change to market - reason to follow
3.44 am	3.55 am	Engie	Dry Creek	137	>390	-1,000	0340~A~response to MPC event. sl.~~
3.44 am	3.55 am	Engie	Snuggery	15	1,750	-1,000	0340~A~response to MPC event. sl.~~
3.47 am	3.55 am	AGL	Barkers Inlet	56	15,000	-1,000	0335~A~040 chg in aemo disp~45 price increase vs pd SA $14938~
3.47 am	3.55 am	AGL	Torrens	320	>0	-1,000	0335~A~040 chg in AEMO disp~45 price increase vs pd SA $14938~

Appendix C: Price setter

The following tables identify for the trading interval in which the spot price exceeded $5,000/MWh, each 5 minute dispatch interval price and the generating units involved in setting the energy price. This information is published by AEMO.[2] The 30-minute spot price is the average of the 6 dispatch interval prices.

Table 4: South Australia price setter 4 am

DI	Dispatch Price ($/MWh)	Participant	Unit	Service	Offer price ($/MWh)	Marginal change	Contribution
3:35 am	$61	AGL (SA)	BARKIPS1	Energy	$61	$1	$61
3:40 am	$62	AGL (SA)	TORRB1	Energy	$62	$0.50	$31
		AGL (SA)	TORRB4	Energy	$62	$0.50	$31
3:45 am	$15,000	Snowy Hydro	LONSDALE	Energy	$15,000	$1	$15,000
3:50 am	$15,000	Snowy Hydro	ANGAST1	Energy	$15,000	$0.31	$4,650
		Snowy Hydro	LONSDALE	Energy	$15,000	$0.13	$1,950
		AGL (SA)	BARKIPS1	Energy	$15,000	$0.56	$8,400
3:55 am	$34.25	Callide Power	CPP_3	Energy	$26.51	$0.73	$19.35
		Callide Power	CPP_4	Energy	$26.51	$0.41	$10.87
		CleanCo	W/HOE#1	Raise 5	$0.87	$1.14	$0.99
		CS Energy	GSTONE3	Raise 6	$1.73	$1.14	$1.97
		Delta Electricity	VP6	Raise 60	$1	$1.14	$1.14
4:00 am	$29.01	Snowy Hydro	MURRAY	Energy	$28.96	$1	$28.96
Spot Price		**$5,031/MWh**					

[2] Details on how the price is determined can be found at www.aemo.com.au