Electricity spot prices above $5000/MWh

South Australia
8 February 2017

27 April 2017

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1 Obligation

The Australian Energy Regulator 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 energy markets, including the annual State of the energy market report, to assist participants and the wider community.

The AER is required to publish a report whenever the electricity spot price exceeds $5000/MWh in accordance with clause 3.13.7 (d) the National Electricity Rules.

The report:

- describes the significant factors contributing to the spot price exceeding $5000/MWh, including withdrawal of generation capacity and network availability;
- assesses whether rebidding contributed to the spot price exceeding $5000/MWh;
- identifies the marginal scheduled generating units; and
- identifies all units with offers for the trading interval equal to or greater than $5000/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 enforcement action.

2 Summary

On 8 February 2017, the spot price in South Australia exceeded $5000/MWh for five consecutive half hourly trading intervals, from 5.30 - 7.30 pm inclusive. Prices ranged between $9387/MWh and $13 440/MWh.

The cause of these high prices in South Australia can be attributed to two main factors: the dispatch of high priced electricity generation to satisfy electricity demand (5.30 pm, 6 pm and 7.30 pm) and action by the market operator to shed load (6.30 pm and 7 pm).

Temperatures in Adelaide reached 42 degrees, the highest for the 2016/17 summer until that day. This is around one degree higher than what had been forecast by the Bureau of Meteorology consistently in the preceding 48 hours. The hot weather resulted in high levels of demand.

Despite the conditions, forecasts prepared by the market operator, AEMO, did not anticipate the level of demand. Throughout the day, the market operators' forecasts predicted materially lower levels of demand and a greater contribution from wind generation than actually occurred.

From 5.25 pm, flows across Murraylink increased above its import limit resulting in the power system moving to an insecure state. AEMO must take all reasonable actions, including directing generators not currently operating or interrupting customers to return the power system to a secure operating state within 30 minutes.

Around 6 pm, without other alternatives, AEMO issued a direction to the South Australia transmission network service provider (ElectraNet) to shed 100 MW of load. ElectraNet in turn instructed the distribution network service provider SA Power Networks (SAPN), to shed 100 MW of customer load, based on established load shedding priorities. SAPN inadvertently shed around 300 MW of customer load for around 40 minutes as a result of an error in its load shedding systems. This error had no effect on the market price. Load shedding was necessary to return the power system to a secure state and reduce flows on the Murraylink interconnector to within limits. Under the National Electricity Rules, when load shedding occurs, prices are set at the market price cap ($14 000/MWh).

As stated in our latest Quarterly Compliance Report, released in March, we will be undertaking a compliance assessment of the load-shedding that occurred in the State on 8 February.

While events on the day are complex and some capacity was unavailable, difficulties in accurately forecasting demand contributed to the overall uncertainty of market outcomes. The lower demand forecasts and over-estimated wind generation resulted in lower price forecasts. Had the forecasts been more reflective of actual conditions it is likely that the potential shortage of supply may have been visible to the market earlier, allowing for a wider range of potential mitigation actions to have been considered. Since these events AEMO has commenced a number of initiatives to improve demand forecasting.

After load was fully restored at 7.08 pm and the market price cap removed, wholesale prices continued to be high reflecting the tight supply demand conditions.

While there was in the order of 115 MW of capacity withdrawn due to technical reasons, there was no significant rebidding by generators of capacity from low to high prices, which contributed to the high prices.

3 Analysis

To calculate the amount of electricity that must be supplied, or generated, AEMO collects information about: network capability and offers from market generators and calculates expected (forecast) demand from customers. Generator offers comprise the mega-watt (MW) capacities generators are willing to supply at a price point and the amount the generator can generate in total (generator availability). AEMO publishes regular forecasts of its assessment of the demand for electricity in each region of the market based on a range of external inputs such as temperature.

Market conditions are quite dynamic and to inform market participants AEMO also publishes aggregated expected and actual dispatch information, price and network loadings at five minute and 30 minute intervals for the remainder of the day. These forecasts form the basis for AEMO's recommendations with respect to interconnector capacity, transfers between regions, reserves and conditions that relate to power system security

The spot price exceeded $5000/MWh for the 5.30 - 7.30 pm trading intervals inclusively, reaching a maximum of $13 400/MWh. The spot price exceeding $5000/MWh can be attributed to two main factors: high priced electricity generation was required to satisfy electricity demand (5.30 pm, 6 pm and 7.30 pm) and the market operator (AEMO) intervened to require load shedding (6.30 pm and 7 pm). The analysis extends to other trading intervals as they are relevant to the conditions that occurred during the afternoon.

Actual demand in South Australia was around 300 MW higher than forecast for most of the trading intervals. Maximum temperature reached 42 degrees in Adelaide on the day. Very high temperatures often have a big impact on electricity demand as air conditioners are in greater use and must work harder to keep household temperatures down.

Table 1 shows the actual, four and 12 hour ahead forecasts for spot price and demand in South Australia from 3.30 - 7.30 pm. The intervals where the spot price exceeded $5000/MWh are in bold and the intervals where the price outcome was not determined by the market but instead by the market operator are in bold orange font.

Table 1: Actual and forecast demand for South Australia

Trading interval	Spot Price ($/MWh)			Demand (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
3.30 pm	2620	351	351	2677	2415	2283
4 pm	438	579	405	2802	2503	2383
4.30 pm	444	590	405	2910	2616	2472
5 pm	2482	353	440	2979	2706	2545
5.30 pm	**11 141**	**579**	**590**	**3007**	**2732**	**2625**
6 pm	**13 160**	**579**	**590**	**3046**	**2733**	**2660**

Trading interval	Spot Price ($/MWh)			Demand (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
6.30 pm	13 440	579	590	2946	2715	2685
7 pm	9387	1750	579	2876	2807	2666
7.30 pm	**13 400**	**13 100**	**579**	**3009**	**2791**	**2588**

3.1 Conditions on the day

This section explores the contributing factors that led to the market outcomes on the day. Electricity demand forecast accuracy, transmission network availability, South Australian generation availability, including wind forecast accuracy and the conditions that gave rise to load shedding are discussed further.

3.1.1 Demand forecasts

Table 2 shows actual demand and the difference between forecast (demand error) half hour, one, four and 12 hour ahead for all trading intervals from 3.30-7.30 pm. The 6.30-7 pm trading intervals are highlighted in orange as AEMO initiated a process to interrupt electricity supply to customers in South Australia, known as load shedding, at 6.03 pm. This is discussed in more detail in section 3.2. While AEMO only requested 100 MW, the actual reduction was over 300 MW.[1]

During this period, demand was higher than that forecast. The largest four hour ahead forecast error occurred just before load was shed at 6.03 pm during the 6 pm trading interval.

Table 2: Actual and forecast demand for South Australia

Trading interval	Demand (MW)				
	Actual	Difference (Actual less Forecast)			
		1/2 hour forecast	1 hour forecast	4 hour forecast	12 hour forecast
3.30 pm	2677	48	150	262	395
4 pm	2802	84	88	299	420
4.30 pm	2910	103	114	294	438
5 pm	2979	107	115	273	434
5.30 pm	**3007**	**52**	**94**	**275**	**382**
6 pm	**3046**	**90**	**95**	**312**	**386**
6.30 pm	2946	-40	-12	232	261
7 pm	2876	-100	-77	69	211
7.30 pm	**3009**	**79**	**99**	**217**	**421**

1 AEMO notified the market of the direction to shedding load in a market notice. See Appendix D for a list of all Market Notices issued by AEMO that relate to this event.

Actual demand was between 69 MW and 312 MW higher than forecast four hours ahead. AEMO's demand forecasts are based on temperature forecasts provided by two external service providers. These were lower than what was actually occurring for most periods from midday. AEMO's report into events on the day shows that the temperature forecasts on which it relied failed to adequately correct for the actual temperature observation.[2] It appears that AEMO did not monitor the accuracy of the forecasts such that they might have been able to make corrective action.

The same AEMO report shows rooftop solar generation estimates were relatively accurate and did not contribute to the overall demand error.

The four hour ahead forecast has particular relevance on this occasion as it reflects the time needed for the additional generating unit at Pelican Point to be recalled. (see section 3.1.3).

Figure 1 shows actual demand (red line), the hour ahead demand forecast (heavy dashed blue line) and four hours ahead demand forecast (thin dashed blue line line).

The light shaded section of the graph highlights the trading intervals where the spot price exceeded $5000/MWh.

Figure 1 South Australia 30 minute actual vs forecast demand

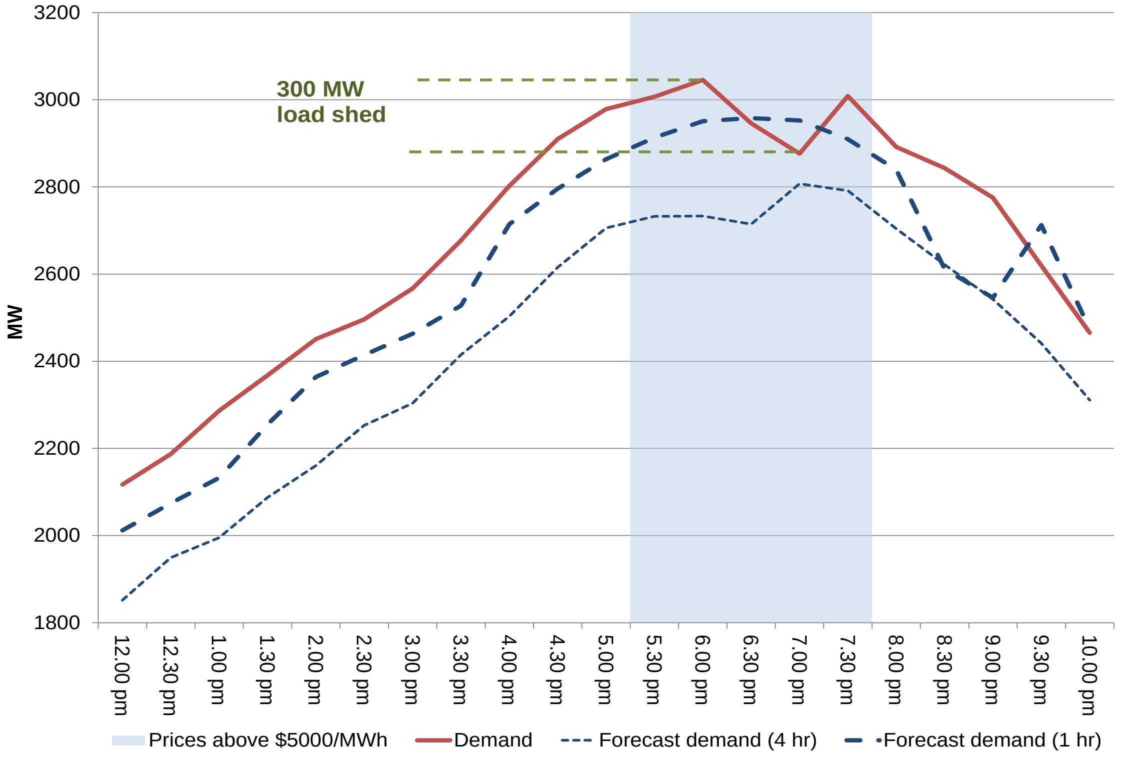


Figure 1 shows demand was continually higher than forecast for the period between midday and 10 pm except for when the load shedding occurred which brought demand down close the four hour forecast level.

Difficulties in accurately forecasting demand contributed to the overall uncertainty of market outcomes. The lower demand forecasts and over-estimated wind generation

2 System-Event-Report-South-Australia-8-February-2017.pdf

resulted in lower price forecasts. Had the forecasts been more reflective of actual conditions it is likely that the potential shortage of supply may have been visible to the market earlier, allowing for a wider range of potential mitigation actions to have been considered.

3.1.2 Network availability

This section examines the change in network capability.

Network constraints on the Murraylink interconnector limited imports from Victoria to South Australia to between 65 MW and 89 MW during the period 5.30 – 7.30 pm,.

Electricity was flowing into South Australia across the Heywood interconnector from Victoria at or close to its 600 MW maximum capability, as forecast.

Murraylink interconnector

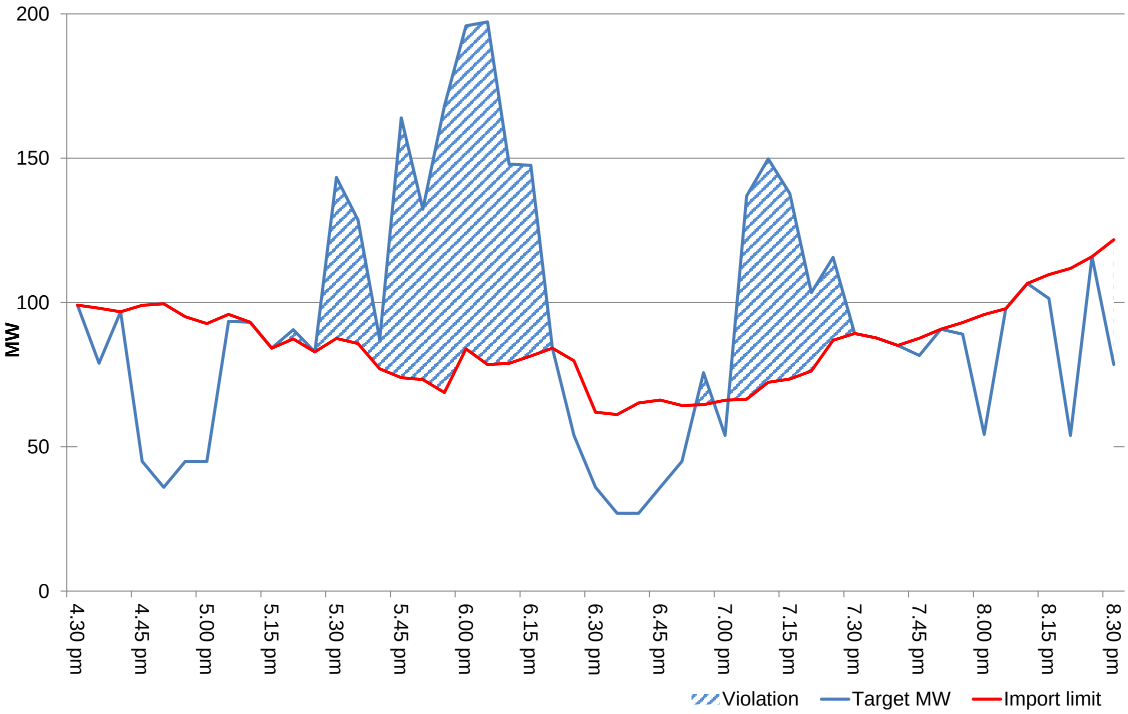
Table 3 shows the actual and forecast imports and import limit into South Australia on the Murraylink interconnector during the early evening. For the majority of the high price trading intervals, imports were lower than that forecast four hours ahead. Half hour and one hour ahead forecasts showed lower limits for Murraylink, further exacerbating the potential shortfall. For the 5.30 - 6.30 pm trading intervals imports exceeded the import limit into South Australia for more than 30 minutes, breaching power system security criteria, resulting in AEMO taking steps to address the breach.

Table 3: Actual and forecast network capability of Murraylink interconnector

Trading interval	Imports (MW)					Import limit (MW)				
	Actual	1/2 hr forecast	1 hr forecast	4 hr forecast	12 hr forecast	Actual	1/2 hr forecast	1 hr forecast	4 hr forecast	12 hr forecast
3.30 pm	81	72	69	139	63	100	95	110	139	195
4 pm	80	86	88	125	113	119	86	88	125	187
4.30 pm	84	72	85	115	111	109	85	85	115	180
5 pm	58	72	85	116	146	97	81	85	116	173
5.30 pm	**98**	**76**	**86**	**118**	**169**	**89**	**76**	**86**	**118**	**169**
6 pm	**146**	**81**	**83**	**116**	**167**	**77**	**81**	**83**	**116**	**167**
6.30 pm	**111**	**85**	**92**	**132**	**170**	**77**	**85**	**92**	**132**	**170**
7 pm	**44**	**101**	**98**	**128**	**172**	**65**	**101**	**98**	**128**	**172**
7.30 pm	**122**	**86**	**115**	**138**	**180**	**77**	**86**	**115**	**138**	**180**

Figure 2 shows the import limit (red line), and flow across Murraylink (blue line) as well the violation amount that Murraylink was importing above its import limit (blue hatched area). The target flow should always be less than or at the limit of an interconnector as allowing interconnector flows to exceed their limits for extended periods poses a system security risk.

Figure 2: Murraylink import limit, flow and violation amount



From around 5.20 pm imports into South Australia began to exceed the import limit, thus putting the power system in an insecure state. As the violation continued for more than 30 minutes, AEMO took action to return the system to a secure state.[3] AEMO explored avenues to return the power system to a secure operating state as quickly as possible, in the end directing ElectraNet, the transmission network service provider to shed 100 MW of customer load at 6.03 pm. ElectraNet has an agreement with SAPN, the distribution network service provider to enact this function. The load shedding commenced at 6.10 pm.

While 100 MW was directed to be interrupted, around 300 MW was actually shed due to a software error in SAPN's load shedding system. SAPN have acknowledged this error. When a directed interruption to customers occurs, the market price is set at the market price cap, independent of the level of load shed. The power system was returned to a secure state by 6.15 pm and imports on Murraylink no longer exceeded its import limit by 6.20 pm.

The market price cap was applied and stayed in place until AEMO issued a direction to restore customer load, some 37 minutes later, at 6.40 pm.

The second hashed sector of the figure, starting around 7 pm, shows that Murraylink was again operating above its limits. However, as this was for a period less than 30 minutes, there was no requirement for further load shedding.

3.1.3 Generator offers and availability

South Australia has an installed generation capacity of 4556 MW of which 1596 MW is wind. The remaining 2960 MW is mainly gas fired. Generation is classified into three types, scheduled, semi-scheduled and non-scheduled. Scheduled and semi-scheduled

[3] National Energy Rules clause 4.2.6 (b)

must offer their supply availability into the market and are dispatched by AEMO. Non-scheduled generation are not dispatched by AEMO and do not offer into the market (see Appendix E).

Installed capacity isn't always the best indication of what may be available at any particular time, particularly during summer, when high ambient temperature conditions can materially affect a generators ability to perform to its nominal installed capacity. AEMO records each generators summer rating against regional bench mark summer conditions and for wind generators, it calculates, on the basis of probability, the most likely wind contribution during these conditions.[4] Furthermore generators are expected to update their capacity as their circumstances change as discussed in section 3.1.3.2.

Allowing for summer conditions and the mothballing of half of Pelican Point Power Station, AEMO's lists the total generator availability as 3626 MW if wind generation available at its full capacity and 2634 MW if the average wind availability is used.[5]

At the time of high prices there was around 2400 MW of supply offered by participants into the market, just below that expected given the conditions.

3.1.3.1 Scheduled and Semi Scheduled generator offers[6]

There was no significant rebidding of capacity from low to high prices which contributed to the high price trading intervals.

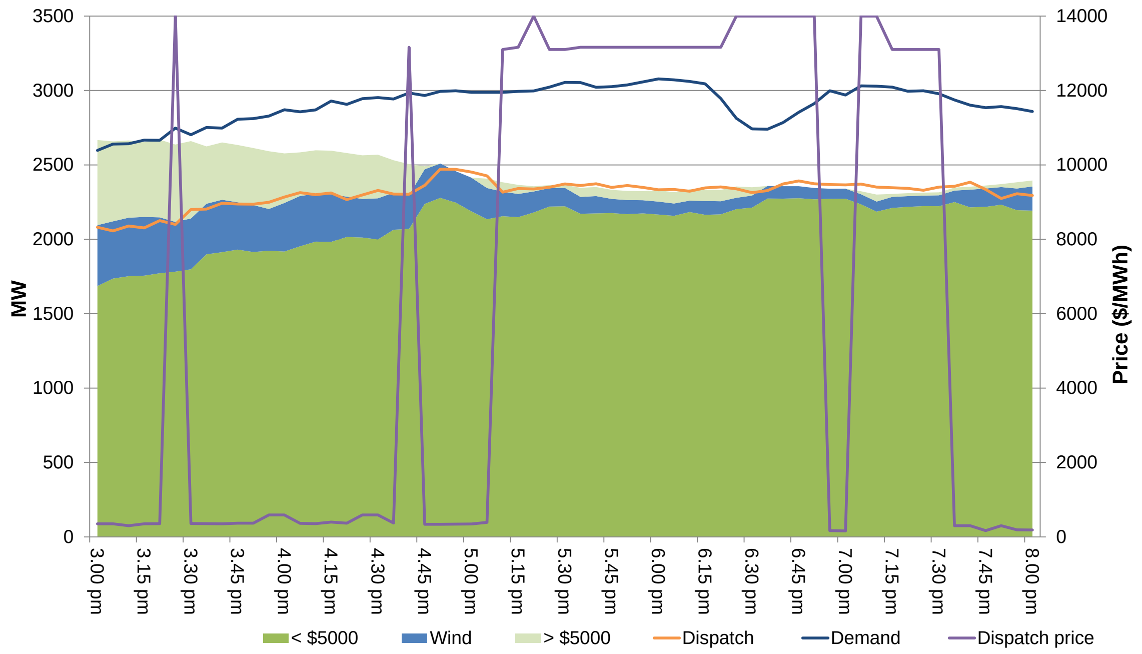
Figure 3 shows wind generation, supply capacity priced above and below $5000/MWh, 5-minute demand, dispatch and price.

4 AEMO generator information page http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information

5 These figures are 9.4% of the installed capacity during summer, and 7.0% during winter, based on AEMO's analysis of historical wind output over summer 2011-12 to 2015-16, and winter 2011 - 2015.

6 https://www.aemo.com.au/media/Files/Other/Registration%202014/Registration%20Final/PARTICIPANT_CATEGORIES_IN_THE_NEM_final.pdf

Figure 3 South Australia closing offers, wind output and 5 minute generation, price, and demand



Supply from local generation was around 2400 MW, with wind generation accounting for around 200 MW. Figure 3 shows all the generation in South Australia that was offered into the market was being fully dispatched (orange line is on or above the total capacity available). The remaining power to meet demand (blue line) was being sourced from interstate across the Murraylink and Heywood interconnectors (difference between the blue and orange lines). It also shows how wind generation started to reduce from around 3 pm to only around 200 MW by 5 pm. Capacity priced greater than $13 000/MWh had to be dispatched to meet demand from 5.10 pm until 6.20 pm. At that point AEMO intervened, the Market Price Cap was set until 6.55 pm, this is discussed in greater detail in section 3.2.

Figure 3 also shows that imports from neighbouring regions made a significant contribution in meeting demand in South Australia.

3.1.3.2 Unavailable generation

At the time of high prices there was 470 MW of capacity not able to be dispatched. 355 MW was due to long term outages which were accounted for in the forecast systems and 115 MW was rebid unavailable during the afternoon.

Table 4 lists the major changes to capacity from generators that were unavailable for the high priced periods and their cause.

Table 4: Generation unavailable

Generating unit	Unavailable capacity (MW)	Time rebid	Reason
Pelican Point Gas turbine unit 2	235	-	Mothballed – require four hours to start

Generating unit	Unavailable capacity (MW)	Time rebid	Reason
Torrens Island A1	120	-	Long term outage – boiler tube leak
Port Lincoln	55	3.53 pm	Rebid unavailable due to technical issues in the network
Torrens Island A3 and B1 and B2	40	Various from 3 pm	Rebid unavailable due to unexpected plant issues
Quarantine 4	20	5.20 pm	Rebid unavailable to manage fuel/line-pack

Pelican Point Power Station comprises two 160 MW gas turbines and a secondary 158 MW steam turbine that recovers waste heat from the gas generation for a total of almost 470 MW. Pelican Point can be configured to operate with one gas turbine and half the steam turbine for a total of 235 MW. Pelican Point has nominally mothballed part of the station (235 MW capacity of combined gas and steam generation) since 2014 based on commercial drivers on the understanding that, if required given four hours notice, it could return to service. Pelican Point has rarely operated at full capacity over the past two years.[7]-[8] The AER is assessing whether generator reporting obligations regarding declaring availability on the day was consistent with the Rules.

Torrens Island unit A1 was offline due to a forced outage following a plant failure on 6 February 2017.

By around 4.50 pm two other generators: Torrens Island and Port Lincoln reduced their available capacity by 40 and 55 MW respectively and after 5.15 pm Quarantine 4 reduced its available capacity by 20 MW, making a total of 115 MW withdrawn as a result of unexpected plant issues, some of which related to the high ambient temperatures, and issues in the transmission network.

Details of the rebids can be found in Appendix A.

3.1.3.3 Wind generation in South Australia

The level of generation from semi-scheduled and non-scheduled wind generators is forecast in a system known as the Australian Wind Energy Forecasting System (AWEFS). Forecasts from this system are produced regularly throughout the day by AEMO on both a 5 minute resolution for the next hour, and on a half hourly resolution for the remainder of the trading day.

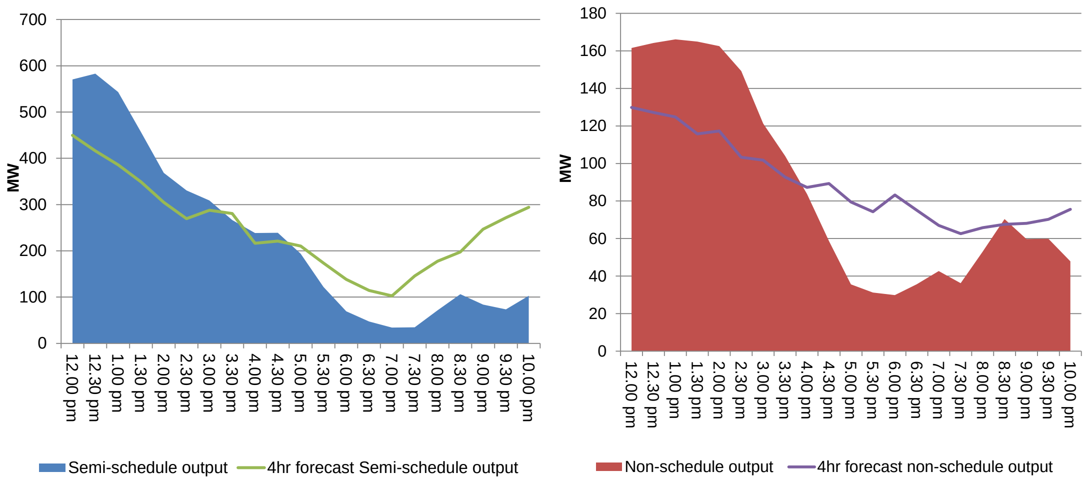
During the evening peak the output of wind generators in South Australia was up to 137 MW lower than what was forecast earlier in the day. 111 MW was related to semi-scheduled wind and the remaining 26 MW was related to non-scheduled wind. The lower than forecast semi-scheduled wind output is reflected in the reduction in generation availability. The lower than forecast non-scheduled wind output is reflected as an increase in demand, contributing the demand forecast error as discussed in section 3.1.1.

7 The unit operated briefly in Q1 2015.

8 Engie released a statement to the market saying “There is no commercial rationale to operate the second Pelican Point unit in the current market environment in SA for a small number of days across the year”.: http://engie.com.au/media/UploadedDocuments/News/Pelican%20Point%20Second%20Unit%20-%20Media%20statement.pdf

Figure 4 shows actual wind output (filled areas) and the four hour ahead forecast output (solid lines) for both semi-scheduled and non-scheduled wind.

Figure 4: Semi-scheduled and non-scheduled four hour forecast and actual generation



For both semi-scheduled and non-scheduled wind generators, the actual wind generation started higher than forecast earlier in the day and dropped off at a faster rate than forecast later in the afternoon. This can be seen in the steepness of the reduction in the solid sections compared to the steepness of the line and contributed to the forecast error. This error compounded the overall forecast errors that lead to load shedding and caused high prices.

3.1.4 Lack of Reserve (LOR)

AEMO is required to monitor the level of reserve, or spare capacity, within each region of the NEM. Reserves are defined as the difference between the volume of electricity that can be made available to consumers, either by local generation or through the network from other regions of the NEM, and the regional customer demand at that time.

Reserves are an indicator of the supply demand balance and an important tool to communicate with the market potential and actual shortfalls. This is achieved through the release of LOR notices by AEMO. Forecast LOR notices are designed to elicit a market response from generators to increase their declared available capacity or retailers to reduce demand to address any forecast reserve shortfalls. Actual LOR notices are also issued when the thresholds are actually triggered.

There are three reserve thresholds which relate to managing power system security following a defined number of unplanned failures of either transmission or generating equipment (credible contingencies). An example of a credible contingency would be the failure of a large generator or the failure of a transmission line that would reduce interconnector capacity.

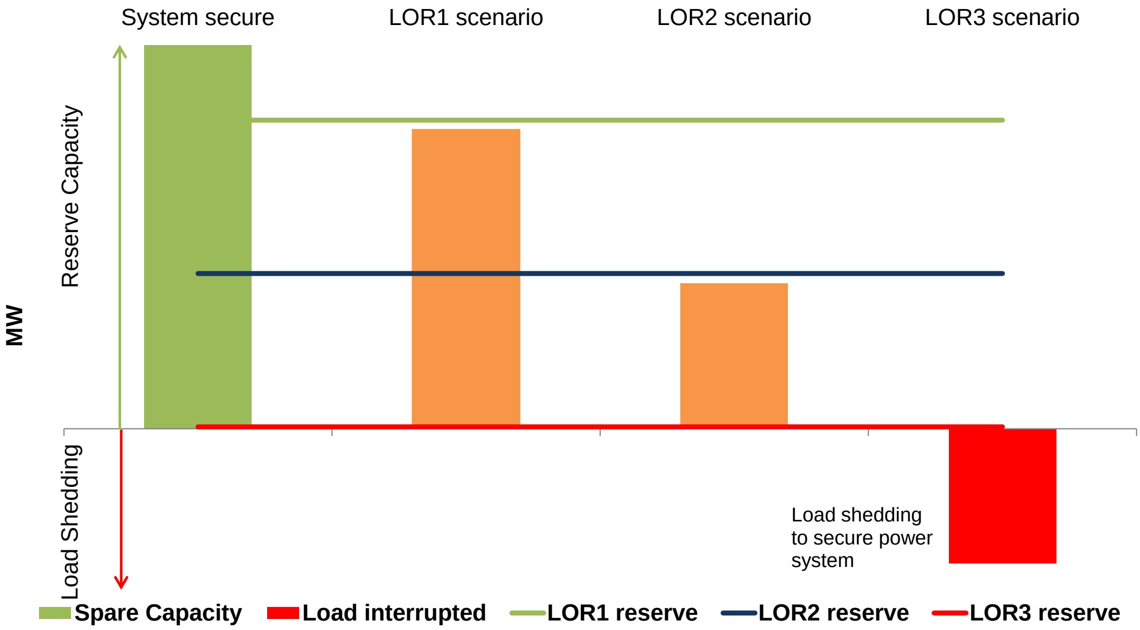
The three LOR levels are broadly categorised as follows: [9]

9 These definitions have been simplified for the sake of readability. An interactive glossary of electricity market terms

- An LOR1 is declared when AEMO considers load shedding is likely to occur after two single credible contingencies.
- An LOR2 is declared when AEMO considers load shedding is likely to occur after a single credible contingency.
- An LOR3 is declared when customer(s) load would be, or is, shed in order to maintain the security of the power system.

Figure 5 shows the four possible spare capacity and the lack of reserve threshold situations graphically.

Figure 5: Spare capacity and lack of reserve



Assuming that the horizontal axis line represents a situation when supply equals demand, then excess generating capacity (above the x axis) amounts to spare or reserve capacity. As discussed above, the three reserve levels are shown as three horizontal lines, reserve requirements for LOR1 in green, for LOR2 in blue and where there are no reserves and all capacity is being used to meet demand, LOR3, in red.

The solid green and amber blocks represent spare capacity. As the spare capacity drops below a reserve line (the horizontal lines) either by a reduction in available capacity or an increase in demand, a new reserve condition exists. AEMO monitors this situation continuously and issues LOR notices to inform participants.

When there is insufficient capacity to meet demand load must be shed (customers interrupted) and an LOR3 is issued, as occurred on this day.

Details of the LOR market notices issued by AEMO can be found in Appendix D.

In summary:

can be found on the AEMO website at: https://www.aemo.com.au/Datasource/Archives/Archive1767#

- At 3.18 pm, AEMO issued a forecast LOR1 notice for South Australia for the period 4.30 - 7 pm. The reserve level required for the afternoon was 400 MW and the minimum reserve available at the time was 277 MW
- An actual LOR1 notice was issued around an hour later at 4.13 pm.
- An actual LOR2 notice was issued at 5.13 pm.
- An actual LOR3 notice was issued 6.11 pm.

Forecast LOR2 or LOR3 notices were not published which may have provided some notice to the market that there was a likelihood of insufficient supply to meet forecast demand. This was primarily because inaccuracy in the forecast results which meant that the LOR2 and LOR3 reserve report thresholds were not triggered.

3.2 Market Outcomes

Spot prices in the wholesale market are expected to significantly increase at times when demand is high and the margin between demand and available generation (reserves) is low. When the market operator cannot satisfy the reserve requirements and intervention in the market is required, two options are available:

- directing additional resources to enter the market which results in "what-if" pricing, or
- reducing demand to manage a supply shortage through load shedding which results in the price being set to the market price cap.

On this occasion the inability to source additional generation, in the required timeframe, resulted in AEMO instructing load shedding for around 40 minutes.

Had the forecasts reflected the actual demand more closely forecast LOR2 or 3 notices would have informed the market of the potential shortfall. A response from these participants may have provided the market operator with a wider range of alternative actions to maintain system security including: directing Engie to operate additional generation at Pelican Point Power Station.[10]

At 6.03 pm, AEMO issued a direction to ElectraNet to shed 100 MW of load. The load shedding was complete at 6.20 pm, however 200 MW of extra load was inadvertently interrupted. SAPN, who is responsible for implementing the load shedding, acknowledged that the extra load interrupted was as a result of an error in the load shedding software.[11]

The Market Price Cap (MPC) was applied to the South Australia region and the 5 minute price was set at $14 000/MWh for the 6.25 pm to 6.50 pm dispatch intervals.

Table 5 summaries the sequence of events and comments on the impact of these factors that lead up to AEMO issuing a direction, load shedding and the price being set to the MPC.[12]

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10 Only half of Pelican Point power station has been in service since April 2015 but the plant could be made fully available under special arrangements with AEMO given four hours prior notice.

11 http://www.sapowernetworks.com.au/centric/corporate/media_releases.jsp

12 Some of times and details have been have been gathered from the AEMO report on this event. https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2017/System-Event-

Table 5: Sequence of events

Time	Event	Comments
3.18 pm	Forecast LOR1 from 4.30 - 7 pm	Forecast a shortage of 277 MW to cope with two unplanned failures.
4.13 pm	Actual LOR1 from 4 - 7 pm	Short 164 MW of spare capacity to cope with two unplanned failures
5.13 pm	Actual LOR2 from 5 - 7 pm	Short 86 MW of spare capacity to cope with a single unplanned failure
5.25 pm	Imports across Murraylink exceeded safe limits	Power system no longer in a secure operating state
5.39 pm	AEMO contacts Engie to enquire about the availability of Pelican Point gas turbine two.	Engie do not have the extra gas and even if it could get gas, it would be four hours before they could get to minimum load.
6.03 pm	Actual LOR3 from 6 - 7.30 pm	No spare capacity to ride through any unforeseen event.
6.03 pm	AEMO direct Electranet to shed 100 MW of load	Electranet instruct SA Power Networks to shed 100 MW of residential load.
6.20 pm	Load shedding complete	Load remains interrupted until AEMO direct load restoration. SAPN sheds 300 MW of customer load due to software error.
6.20 pm	Imports across Murray link reduced to within safe operating thresholds.	System returned to a secure operating state
6.25 pm	Market price cap in place from the 6.25 pm dispatch interval	Each 5 minute price is set to $14 000/MWh until the direction has ceased
6.30 pm	AEMO directs ElectraNet to restore 100 MW of load	Electranet instruct SA Power Networks to restore 100 MW of load
6.40 pm	AEMO directs Electranet to restore all load	All affected customers power starts to return
6.49 pm	AEMO confirms with ElectraNet that SAPN are restoring load.	The direction is no longer in place.
6.50 pm	Market price cap is removed	Normal market bid stack pricing resumes
7 pm	LOR3 is cancelled	Sufficient spare capacity is available to cope with a single unplanned failure
7.08 pm	Customer load is fully restored	

Australian Energy Regulator

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Appendix A: 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 capacity involved, the change in the price of the capacity was being offered and the rebid reason.

Table 6: Energy rebids during the high price period

Submit time	Effected high price trading intervals	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
3.09 pm	5.30–7.30		AGL Energy	Torrens Island B2	20	N/A	14 000	1506~P~030 increase in avail cap~301 plant limit lifted 20 MW
3.53 pm	5.30–7.30		Engie	Port Lincoln	-55	14 000	N/A	1552P units oos – control signal fault
4.24 pm	5.30–7.30 pm		AGL Energy	Torrens Island A3	-10	<300	N/A	1624~P~020 reduction in avail cap~203 plant failure 10MW
4.48 pm	5.30-7 pm		AGL Energy	Torrens Island B1	-20	<350	N/A	1648~P~010 unexpected/plant limits~vaccuum limits
4.53 pm	5.30-7 pm		AGL Energy	Torrens Island B1	-30	125	N/A	1652~P~010 unexpected/plant limits~vacuum limits
4.53 pm	7.30 pm		AGL Energy	Torrens Island B1	-50	<350	N/A	1652~P~010 unexpected/plant limits~vacuum limits
5.20 pm	6–7.30 pm		Origin	Quarantine QPS4	-20	14 000	N/A	1716P management of fuel and linepack sl
5.48 pm	6–6.30pm	5.55 pm	AGL Energy	Torrens Island B4	-10	125	N/A	1748~P~020 reduction in avail cap~206 unexp ambient temp effects 10MW

Submit time	Effected high price trading intervals	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
6.41 pm	7.30 pm	7.05 pm	AGL Energy	Torrens Island	-5	-1000	N/A	1840~P~020 reduction in avail cap~206 unexp ambient temp effects 5MW
7.00 pm	7.30 pm	7.10 pm	AGL Energy	Torrens Island	-20	-1000	N/A	1900~P~020 reduction in avail cap~203 plant failure 20MW

Appendix B: Price setter

The following table identifies for the trading intervals in which the spot price exceeded $5000/MWh, each five minute dispatch interval price and the generating units involved in setting the energy price. This information is published by AEMO.[13] The 30-minute spot price is the average of the six dispatch interval prices. Italicised prices are either affected by intervention pricing or exceeded the market price cap (MPC). While the dispatch process will determine a lower price, these prices are set at the MPC ($14 000/MWh) for settlement purposes.

Table 7: Price setter for the 5.30 pm trading interval

DI	Dispatch Price ($/MWh)	Participant	Unit	Service	Offer price ($/MWh)	Marginal change	Contribution
17:05	$388.05	Snowy Hydro	MURRAY	Energy	$290.00	1.34	$388.60
17:10	$13 100.02	Engie	DRYCGT1	Energy	$13 100.02	1.00	$13 100.02
17:15	$13 160.01	Origin Energy	QPS1	Energy	$13 160.01	0.31	$4079.60
		Origin Energy	QPS2	Energy	$13 160.01	0.34	$4474.40
		Origin Energy	QPS3	Energy	$13 160.01	0.34	$4474.40
17:20	$14 000.00	Origin Energy	OSB-AG	Energy	$14 000.00	1.00	$14 000.00
17:25	$13 100.02	Engie	DRYCGT1	Energy	$13 100.02	1.00	$13 100.02
17:30	$13 100.02	Engie	DRYCGT1	Energy	$13 100.02	1.00	$13 100.02
Spot price		**$11 141/MWh**					

Table 8: Price setter for 6 pm trading interval

DI	Dispatch Price ($/MWh)	Participant	Unit	Service	Offer price ($/MWh)	Marginal change	Contribution
17:35	$13 160.01	Origin Energy	QPS2	Energy	$13 160.01	1.00	$13 160.01
17:40	$13 160.01	Origin Energy	QPS2	Energy	$13 160.01	1.00	$13 160.01
17:45	$13 160.01	Origin Energy	QPS2	Energy	$13 160.01	1.00	$13 160.01
17:50	$13 160.01	Origin Energy	QPS2	Energy	$13 160.01	1.00	$13 160.01
17:55	$13 160.01	Origin Energy	QPS2	Energy	$13 160.01	1.00	$13 160.01
18:00	$13 160.01	Origin Energy	QPS2	Energy	$13 160.01	1.00	$13 160.01
Spot price		**$13 160/MWh**					

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

Table 9: Price setter for 6.30 pm trading interval

DI	Dispatch Price ($/MWh)	Participant	Unit	Service	Offer price ($/MWh)	Marginal change	Contribution
18:05	$13 160.01	Origin Energy	QPS2	Energy	$13 160.01	1.00	$13 160.01
18:10	$13 160.01	Origin Energy	QPS2	Energy	$13 160.01	0.50	$6580.01
		Origin Energy	QPS4	Energy	$13 160.01	0.50	$6580.01
18:15	$13 160.01	Origin Energy	QPS2	Energy	$13 160.01	0.50	$6580.01
		Origin Energy	QPS4	Energy	$13 160.01	0.50	$6580.01
18:20	$13 160.01	Origin Energy	QPS1	Energy	$13 160.01	0.23	$3026.80
		Origin Energy	QPS2	Energy	$13 160.01	0.26	$3421.60
		Origin Energy	QPS3	Energy	$13 160.01	0.26	$3421.60
		Origin Energy	QPS4	Energy	$13 160.01	0.26	$3421.60
18:25	*$158.66*	AGL Hydro	MCKAY1	Energy	$129.86	1.22	$158.43
18:30	*$128.00*	Hydro Tasmania	REECE1	Raise reg	$15.00	1.00	$15.00
		AGL (SA)	TORRB1	Energy	$124.99	0.47	$58.75
		AGL (SA)	TORRB1	Raise reg	$11.99	-0.47	-$5.64
		AGL (SA)	TORRB3	Energy	$124.99	0.53	$66.24
		AGL (SA)	TORRB3	Raise reg	$11.99	-0.53	-$6.35
Spot price		**$13 440/MWh**					

Table 10: Price setter for 7 pm trading interval

DI	Dispatch Price ($/MWh)	Participant	Unit	Service	Offer price ($/MWh)	Marginal change	Contribution
18:35	*$126.34*	Snowy Hydro	UPPTUMUT	Energy	$103.00	1.23	$126.69
18:40	*$147.41*	AGL Hydro	MCKAY1	Energy	$129.86	1.14	$148.04
18:45	*$140.34*	Hydro Tasmania	GORDON	Energy	$107.15	1.31	$140.37
			BASSLINK	Energy	$0.01	1.19	$0.01
18:50	*$154.73*	AGL Hydro	MCKAY1	Energy	$129.86	1.19	$154.53
18:55	$166.30	AGL Hydro	MCKAY1	Energy	$129.86	1.28	$166.22
19:00	$157.99	AGL Hydro	MCKAY1	Energy	$129.86	1.22	$158.43
Spot price		**$9387/MWh**					

Table 11: Price setter for 7.30 pm trading interval

DI	Dispatch Price ($/MWh)	Participant	Unit	Service	Offer price ($/MWh)	Marginal change	Contribution
19:05	*$2 100 000*	Demand supply balance			$2 100 000	1.00	$2 100 000
19:10	$13 999.99	Snowy Hydro	PTSTAN1	Energy	$13 999.99	1.00	$13 999.99
19:15	$13 100.02	Engie	DRYCGT1	Energy	$13 100.02	1.00	$13 100.02
19:20	$13 100.02	Engie	DRYCGT1	Energy	$13 100.02	1.00	$13 100.02
19:25	$13 100.02	Engie	DRYCGT1	Energy	$13 100.02	1.00	$13 100.02
19:30	$13 100.02	Engie	DRYCGT1	Energy	$13 100.02	1.00	$13 100.02
Spot price		**$13 400/MWh**					

Appendix C: Closing bids

Figures C1 and C2 highlight the half hour closing bids for participants in South Australia with significant capacity priced at or above $5000/MWh during the periods in which the spot price exceeded $5000/MWh. They also show generation output and the spot price.

Figure C1 - Engie (Pelican Point, Mintaro, Dry Creek, Port Lincoln, Snuggery) closing bid prices, dispatch and spot price

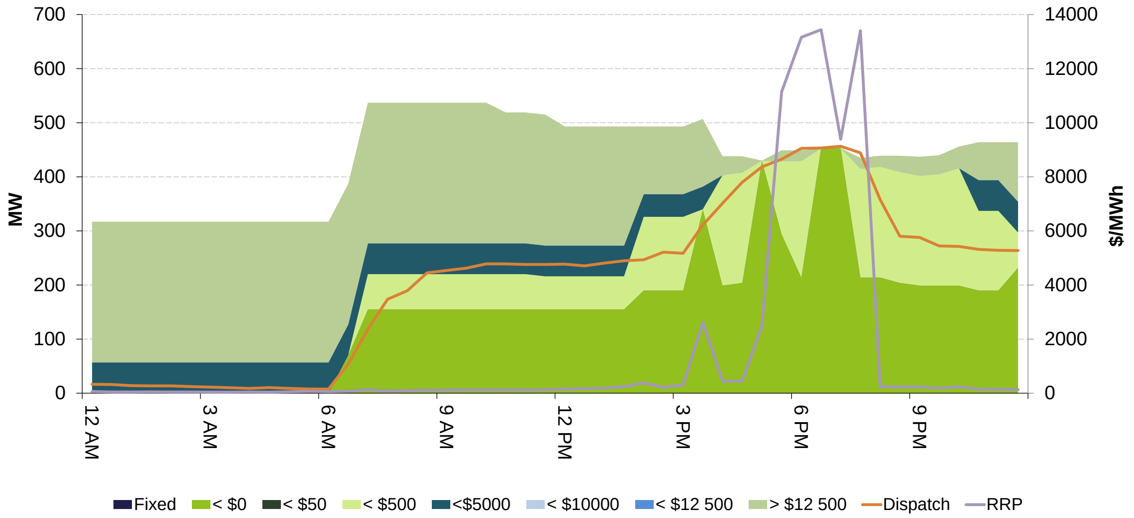
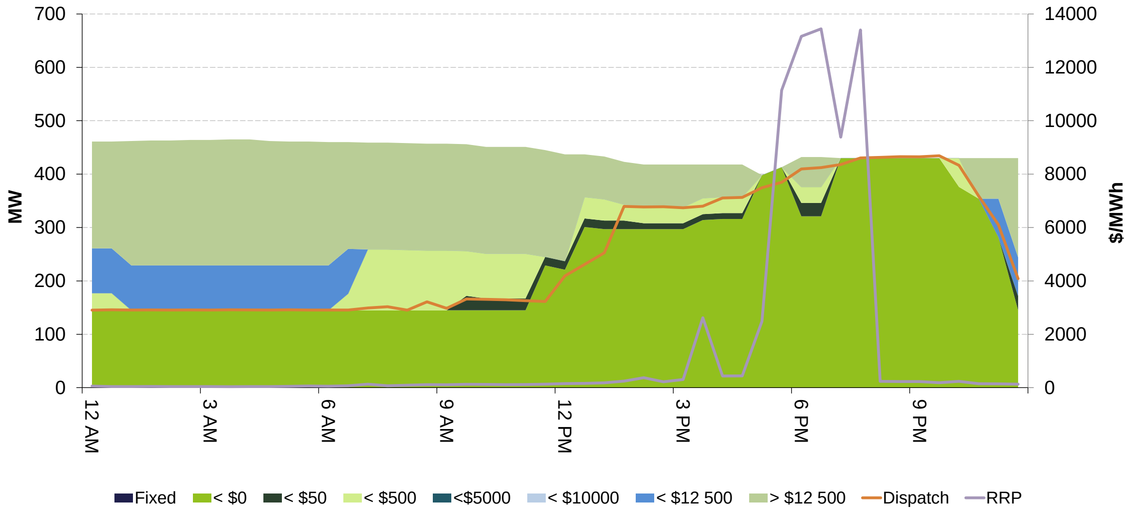


Figure C2 – Origin Energy (Ladbroke Grove, Osborne, Quarantine) closing bid prices, dispatch and spot price



Appendix D: Relevant Market Notices

The following market notices notified the market of the regulation requirement for South Australia.

Market Notice	Type	Date of issue	Last Changed
57276	Reserve notice	8/02/2017 15:18	8/02/2017 15:18
Reason			
AEMO ELECTRICITY MARKET NOTICE Forecast Lack Of Reserve Level 1 (LOR1) in the South Australia Region - PDPASA AEMO declares a Forecast LOR1 condition for the South Australia Region. From 1630 hrs to 1900 hrs 8/2/17 The contingency capacity reserve required is 400 MW The minimum reserve available is 277 MW Manager NEM Real Time Operations			

Market Notice	Type	Date of issue	Last Changed
57277	Reserve notice	8/02/2017 16:13	8/02/2017 16:13
Reason			
AEMO ELECTRICITY MARKET NOTICE Actual Lack Of Reserve Level 1 (LOR1) in the SA Region. An Actual LOR1 condition has been declared for the SA Region. From 1600 hrs to 1900 hrs 08/02/2017 The contingency capacity reserve required is 400 MW The minimum reserve available is 236 MW Manager NEM Real Time Operations			

Market Notice	Type	Date of issue	Last Changed
57279	Reserve notice	8/02/2017 17:13	8/02/2017 17:13
Reason			
AEMO ELECTRICITY MARKET NOTICE Actual Lack Of Reserve Level 2 (LOR2) in the South Australia Region An Actual LOR2 condition has been declared for the South Australia region from 1700 hrs. The Actual LOR2 condition is forecast to exist until 1900 hrs The contingency capacity reserve required is 200MW The minimum reserve available is 114 MW AEMO is seeking a market response. AEMO does not intend to intervene through a AEMO intervention event. Manager NEM Real Time Operations			

Market Notice	Type	Date of issue	Last Changed
57282	Reserve Notice	8/02/2017 18:11	8/02/2017 18:11

Reason

AEMO ELECTRICITY MARKET NOTICE

Actual Lack Of Reserve Level 3 (LOR3) in the South Australia Region - Wednesday, 8 February 2017.

Under the NER Cl 4.8.4(d), AEMO considers that Customer load is actually being interrupted in order to maintain or restore the security of the power system in South Australia Region.

An Actual LOR3 condition has been declared for the South Australia region from 1803 hrs.

The Actual LOR3 condition is forecast to exist until 1930 hrs

The maximum load is being interrupted is 100 MW at 1803 hrs Wednesday, 8 February 2017

Manager NEM Real Time Operations

Market Notice	Type	Date of issue	Last Changed
57283	Market intervention	8/02/2017 19:38	8/02/2017 19:38

Reason

AEMO ELECTRICITY PARTICIPANT NOTICE.

Section 116 National Electricity Law direction - ElectraNet

In accordance with Section 116 National Electricity Law AEMO is issuing a direction to ElectraNet to take the following action.

The Section 116 National Electricity Law direction to shed 100 MW load will be according to the priority load shedding schedule for the South Australia region.

The Section 116 National Electricity Law direction is issued at 1803 hrs and is expected to stay in place until 1900 hrs

Manager NEM Real Time Operations

Market Notice	Type	Date of issue	Last Changed
57284	Market intervention	8/02/2017 19:38	8/02/2017 19:38

Reason

AEMO ELECTRICITY PARTICIPANT NOTICE.

Section 116 National Electricity Law direction - ElectraNet

Refer to AEMO Participant notice 57283

In accordance with Section 116 National Electricity Law AEMO is issuing a direction to ElectraNet to take the following action.

The Section 116 National Electricity Law direction is to restore all load according to the priority load shedding schedule for the South Australia region.

The Section 116 National Electricity Law direction is issued at 1830 hrs.

Manager NEM Real Time Operations

Appendix E: Generation Capacity

To operate a generator in the National Energy Market you must register with AEMO and provide it with the generators registered capacity which is the nominal megawatt capacity. This represents the maximum continuous output from the generator.

Under the Rules generation must be classified as scheduled, semi-scheduled or non-scheduled. AEMO's definitions of these are:

Scheduled generation refers to any generating system with an aggregate nameplate capacity of 30 MW or more, unless AEMO approves its classification as semi-scheduled or non-scheduled.

Semi-scheduled generation refers to any generating system with intermittent output (such as wind or run-of-river hydro) with an aggregate nameplate capacity of 30 MW or more, unless AEMO approves its classification as scheduled or non-scheduled. A semi-scheduled classification gives AEMO the power to limit generation output that may exceed network capabilities, but reduces the participating generator's requirement to provide information.

Non-scheduled generation refers to generating systems with an aggregate nameplate capacity of less than 30 MW, unless AEMO approves its classification as scheduled or semi-scheduled.

Generating systems greater than 30 MW must be classified as non-scheduled if:

- the primary purpose of the generating unit is for local use and the aggregate sent-out generation rarely exceeds 30 MW
- it is not practicable for the generating unit to participate in central dispatch

A generating unit with a nameplate rating between 5 MW and 30 MW may also be exempted by AEMO if it exports less than 20 GWh into the grid in a year or extenuating circumstances apply.

In South Australia of the 4556 MW installed at the time, there was 2933 MW of scheduled, 1189 MW of semi-scheduled (all wind at this point in time) and 416 MW of non- scheduled generation

Changes in actual generator availability

The actual generator availability at any point in time can differ from its registered capacity for a number of reasons including:

- Outages
- Reduction in thermal efficiency when temperatures increases

For thermal efficiency AEMO uses historical data to determine a reference temperature associated for a one in 10 year demand level. In South Australia that temperature level is 43 degrees. AEMO then ask generators to provide the capacity of their plant given that reference temperature, this is their summer rating, and is a more accurate level of the likely generation capacity available.