NEM market suspension and operational challenges in June 2022

August 2022

A market event and reviewable operating incident report for the National Electricity Market

Important notice

Purpose

AEMO has prepared this report to meet a number of reporting obligations arising out of a series of market and power system events in June 2022, under multiple provisions of the National Electricity Rules, using information available as at the date of publication.

Disclaimer

To inform its review and the findings expressed in this report, AEMO has collated information from its own observations, records and systems.

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Times

National Electricity Market time (Australian Eastern Standard Time [AEST]) is used in this report.

NER defined terms

This report uses many terms that are defined in the National Electricity Rules, which have the same meanings in this report.

Contact

If you have any questions or comments in relation to this report, please contact AEMO at system.incident@aemo.com.au.

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Incident classifications

Classification	Detail
Time and date of Incident	10 June 2022 to 24 June 2022
Region of incident	All NEM regions
Affected regions	All NEM regions
Event type	Market suspension, directions, power system not in a secure operating state for more than 30 minutes
Generation impact	Nil
Customer load impact	Nil
Associated reports	Nil

Abbreviations

Abbreviation	Term
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AEST	Australian Eastern Standard Time
APC	Administered price cap
APP	Administered price period
CPT	Cumulative price threshold
DWGM	Declared Wholesale Gas Market (Victoria)
FCAS	Frequency control ancillary services (defined in the NER as market ancillary services)
FOS	Frequency operating standard
GW	gigawatt
hrs	hours
Hz	hertz
LOR	Lack of reserve. LOR followed by a number indicates the level of the LOR condition, as defined in AEMO's Reserve Level Declaration Guidelines (https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power_system_ops/reserve-level-declaration-guidelines.pdf?la=en
MN	Market notice
MSPS	Market suspension pricing schedule
MW/MWh	megawatt/megawatt hour
NEM	National Electricity Market
NEMDE	National Electricity Market dispatch engine
NER	National Electricity Rules
OCD	Over-constrained dispatch
PASA	Projected assessment of system adequacy
QNI	Queensland – New South Wales Interconnector
RERT	Reliability and emergency reserve trader
STTM	Short Term Trading Market (for gas, at Adelaide, Brisbane and Sydney)
TI	trading interval (5-minutes)
VNI	Victoria – New South Wales Interconnector

Executive summary

This report relates to the series of events associated with low reserve conditions in the National Electricity Market (NEM) between 10 June 2022 and 24 June 2022, including operation of the Queensland – New South Wales Interconnector (QNI) in excess of secure limits on 13 June 2022, spot market suspension from 15 June 2022 to 24 June 2022, and multiple directions for reliability.

Event overview

In June 2022, a confluence of high commodity prices, domestic market price caps, planned and unplanned outages of scheduled generating plant, low output from semi-scheduled generation, and high winter demand conditions led to unprecedented challenges operating the NEM.

On Friday 10 June 2022, there were noticeable changes in generator bidding as the rolling sum of spot prices for the previous seven days in some NEM regions approached the cumulative price threshold (CPT), which would trigger an administered price cap (APC)[1].

A significant reduction in generation volumes offered to the market on 10 June 2022 saw the first actual lack of reserve (LOR) level 2 conditions[2] in this series of events. This necessitated the first reliability directions associated with this series of events.

On the evening of Sunday 12 June 2022, the CPT was exceeded for the Queensland region. The APC of $300/megawatt hour (MWh) was applied as required by the National Electricity Rules (NER), with price scaling applied to other regions during periods when energy was flowing towards Queensland.

During the evening of Monday 13 June 2022, the CPT was also exceeded for the New South Wales, Victoria and South Australia regions. The application of the APC in those regions coincided with reductions in the volume of generation offered to the market. AEMO intervened by directing generators to make generation capacity available to be dispatched for system reliability and implemented manual processes to manage capacity and energy limitations on generating facilities. Without these directions and other measures, such as outage cancellations and contracting for additional reserves, AEMO would have had to initiate significant customer load shedding, with forecast shortfalls at certain times up to around one third of NEM winter peak demand.

Over subsequent days, AEMO worked closely with generators, emergency reserve providers, network service providers and jurisdictions to manage system operations and maintain reliable supply to consumers. AEMO took steps available to it under the NER, such as deferral of network maintenance, generator directions and activation of emergency reserves, while working with jurisdictions and generators to facilitate fuel supply chain interventions and temporary relaxation of restrictions that limited generation capacity. Despite taking these actions, there were occasions when the market came very close to customer load shedding in mainland regions of the NEM, including one occasion on 13 June 2022 when flows on QNI exceeded secure limits for approximately 60 minutes. Supply-demand balance issues were also responsible for flows on the Victoria – New South Wales Interconnector (VNI) exceeding secure limits during two periods of under 30 minutes on 15 June 2022, and a low mainland frequency event on 17 June 2022.

[1] The APC is a safety net designed to facilitate continued electricity trading and supply during periods of sustained high prices.

[2] An LOR2 condition indicates potential for load shedding if a credible contingency event were to occur.

Through the efforts of all involved, involuntary customer load shedding was avoided.

Directed capacity reached close to 5 gigawatts (GW) on 14 and 15 June 2022, and the large number of constraints necessary to manage directions and supply limitations created issues for AEMO's automated systems and processes which became impossible to manage. Ultimately these issues resulted in AEMO suspending the market at 1400 hrs on 15 June 2022, with prices determined according to the published market suspension pricing schedule (MSPS).

AEMO continued to issue directions under market suspension, as well as activating the reliability and emergency reserve trader (RERT) mechanism in New South Wales and Queensland on three occasions in the suspension period[3]. The volumes and number of directions required progressively declined after 18 June 2022 as some large generating units returned to service, with all directions cancelled by 23 June 2022.

On 22 June 2022, AEMO, having briefed industry and jurisdictions, released its criteria and process for ending the market suspension. Following a staged process, normal dispatch pricing was resumed from 0400 on 23 June 2022, and the suspension was formally lifted at 1400 hrs on 24 June 2022.

Key findings

1. The confluence of high commodity prices, domestic gas market and subsequently NEM price caps, planned and unplanned outages of scheduled generating plant, low output from semi-scheduled generation, and high winter demand conditions led to unprecedented challenges operating the NEM.
2. On 13 June 2022 from 0630 hrs, the active power transfer on QNI exceeded the actual secure limit. AEMO had taken action to direct generation to increase output to resolve this issue, however as a result of the time it took for generation to ramp up and follow dispatch targets, the power system was not operating in a secure state for more than 30 minutes.
3. To a lesser extent and for a shorter time on 15 June 2022, the active power transfer on VNI exceeded the actual secure limit for two periods of less than 30 minutes. AEMO had taken action to direct generation to increase output in New South Wales to resolve this issue and the power system was returned to a secure operating state within 30 minutes.
4. The simultaneous suspension of all regional spot markets in the NEM at 1405 hrs on 15 June 2022 was necessary to return orderly operation of the NEM, and in particular the NEM dispatch systems.
5. Despite some irregular frequency outcomes, the frequency operating standard (FOS) was met throughout this period of events.
6. There were an unprecedented number of LOR conditions during this period. As described in Section 5.2, to manage this AEMO developed a set of criteria for issuing market notices which prioritised forecast and actual LOR2 and LOR3 conditions, for which AEMO anticipated a need to intervene in the market. On this basis, AEMO did not declare all LOR conditions during the period, but was able to meet the market notification requirements for potential interventions under NER clause 4.8.5A.
7. AEMO issued 483 direction-related participant notices during this period to maintain a reliable operating state. AEMO complied with NER clause 3.8.14 and followed its procedures in determining the appropriate mechanism to address the conditions of supply scarcity.

[3] AEMO has reported separately on RERT activations and costs. RERT reports covering this series of events are published at https://aemo.com.au/en/energy-systems/electricity/emergency-management/reliability-and-emergency-reserve-trader-rert/rert-reporting.

8. In these challenging circumstances, AEMO was satisfied overall with the timeliness and adequacy of participant responses and communication relating to AEMO directions, recognising the large number of directions for availability, the nature of the associated constraints, and in some cases rapidly changing plant limitations or operating conditions requiring additional manual steps or instructions.
9. AEMO's declaration of a manifestly incorrect input affecting a number of trading intervals on 23 June 2022 did not follow the applicable NER process, but was consistent with the objectives of the rules in the circumstances.
10. The strong collaboration between AEMO, the Australian Energy Market Commission (AEMC), Australian Energy Regulator (AER), generators, emergency reserve providers, network service providers and jurisdictions enabled this series of events to be effectively managed without involuntary customer load shedding. Supply reliability was maintained despite the acute energy and capacity limitations and market issues.

Recommendations and next steps

AEMO actions completed, underway or planned

- AEMO to prepare a plan for when regional cumulative prices reach the CPT to better enable the management of the transition to administered pricing.
- AEMO to identify tools and processes needed to cater for energy limitations.
- AEMO to continue actively engaging with the AEMC and industry with regard to reviews or rule change proposals relating to the APC, CPT and other market settings that influence the operation of the NEM[4]. AEMO is also conducting a review of gas market prices/parameters.
- AEMO is considering this series of events when developing the scope for the 2023 General Power System Risk Review.
- On 24 July 2022, AEMO completed an action to resolve a software error relating to frequency control ancillary services (FCAS) pricing under market suspension conditions when normal dispatch pricing is in effect.
- AEMO to review processes used for projecting supply adequacy over the medium term in light of this series of events. The review should identify processes, modelling and reporting that may assist for these types of circumstances, particularly when factors contributing to fuel constraints emerge.

Participant recommendations

- Participants ensure their submitted bids, projected assessment of system adequacy (PASA) availability and energy limits reflect operating conditions and are updated regularly, consistent with NER requirements in both short-term and medium-term PASA timelines.
- Participants ensure that operator training continues to cover bidding, operational and communication requirements during rare modes of market operation, such as during APP and market suspension.

[4] On 1 July 2022, the AEMC received a rule change request from Alinta Energy to amend the National Electricity Rules to increase the APC from $300/MWh to $600/MWh in every NEM region. See https://www.aemc.gov.au/rule-changes/amending-administered-price-cap#:~:text=Rule%20Change%3A%20Pending&text=On%201%20July%202022%20the,initiated%20this%20rule%20change%20request.

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1 Report objectives

This is AEMO's report into the series of related market and system events between 10 June and 24 June 2022 in the National Electricity Market (NEM). It is intended to provide an overview of the known facts relating to this series of events as at the date of publication, and to meet AEMO's incident and event reporting obligations under the following clauses of the National Electricity Rules (NER):

- 3.9.2B(g) – replacement of ancillary service prices in intervals determined to contain a manifestly incorrect input, following the resumption of market pricing on 23 June 2022.
- 3.13.6A(a) – the issue and impact of directions issued between 10 June and 23 June 2022, including AEMO's choice of supply scarcity mechanism under clause 3.8.14 and related procedures, but excluding the financial information under clause 3.13.6A(b).
- 3.14.3(c) – the adequacy of the provision and response of facilities or services during the market suspension period (15 to 24 June), and actions taken to restore or maintain power system security where applicable but excluding the financial information under clause 3.14.3(d).
- 3.14.4(g) – the reason for the spot market suspension and its effect on the operation of the spot market.
- 4.8.15(c) – the adequacy of the provision and response of facilities or services and actions taken to restore or maintain power system security for the reviewable operating incident relating to the Queensland – New South Wales Interconnector (QNI) on 13 June 2022, before the market suspension period.

Although noted in this report, AEMO's detailed reporting on the following events is undertaken separately:

- Reliability and emergency reserve trader (RERT) activations[5].
- Declaration of lack of reserve (LOR) conditions[6].
- Power system frequency performance[7].

The market suspension pricing schedule payments and related compensation payments – details of which are to be included in a market suspension report[8] – are not expected to be finalised until January 2023, after completion of all routine settlement revisions for the event period. AEMO will publish a supplementary report when full and final details of these amounts are available.

[5] RERT contacted, activation estimates and quarterly RERT report available at https://aemo.com.au/en/energy-systems/electricity/emergency-management/reliability-and-emergency-reserve-trader-rert/rert-reporting.

[6] LOR quarterly report available at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/power-system-operation/nem-lack-of-reserve-framework-quarterly-reports.

[7] Weekly and quarterly frequency reports available at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/ancillary-services/frequency-and-time-deviation-monitoring.

[8] NER clause 3.14.3(d).

2 Pre-event conditions leading into APP

Prior to 10 June 2022, the NEM had been experiencing a prolonged period of high electricity prices. Wholesale spot prices in the NEM and eastern Australian gas markets reached unprecedented average levels and regional markets were close to reaching the cumulative price threshold (CPT)[9] for many days leading up to 10 June 2022.

Key factors that resulted in high and volatile wholesale spot prices in the NEM are summarised in the section below.

2.1 Key factors influencing NEM regional prices

2.1.1 Fuel supply constraints

Leading up to 10 June 2022, black coal-fired generators reported difficulties sourcing sufficient volumes of coal to generate at desired output levels, principally due to under-deliveries from key suppliers[10,11]. Arranging alternative coal supplies can be logistically challenging or even infeasible at short notice. This increased reliance on other, often higher cost, generation sources.

Tight supply-demand balance in the east coast gas markets was also a limitation on fuel quantities available to gas-fired generators. As an extreme example, on 1 June AEMO invoked the Gas Supply Guarantee due to limits on gas supply available to generators and forecast LOR conditions in multiple NEM regions on 2 June. At other times, gas supply limits caused dual-fuelled peaking generators to run on limited reserves of high-cost liquid fuel.

2.1.2 Early onset of winter temperatures and associated high demands

Weather leading up to 10 June 2022 was dominated by exceptional rainfall in Queensland in May, and cold early winter conditions from late May into early June. A series of cold fronts in early June that extended as far as north Queensland caused an increase in heating demand across the NEM. This coincided with high demands in Queensland and Victoria and a rise in spot prices.

Cold winter conditions increased demand levels across the NEM between 7 June and 12 June 2022, with maximum NEM operational demands more than 1 gigawatt (GW) higher on average than in the preceding week. On 9 June 2022, a new record Q2 maximum demand of 8,255 megawatts (MW) was set in Queensland, surpassing the previous high in 2018 by 83 MW. In Victoria, early winter conditions led to the state reaching its highest Q2 maximum operational demand since 2011 when on 31 May 2022, Victoria's operational demand reached 8,158 MW. This was 492 MW higher than Q2 2021's maximum. On this day, several sites in Victoria recorded their coldest day in May on record.

2.1.3 Transmission network outages

Network outages affecting inter-regional transfers contributed materially to a number of extreme spot price events, lifting spot price volatility and overall NEM average prices leading up to 10 June 2022. Specifically, significant spot

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[9] The CPT is reached when the sum of uncapped spit prices in the previous seven days (2015 5-minute trading intervals) exceeds the CPT value, which was $1,359,100 for 2021-22.

[10] Origin 2022, Update on operating conditions and guidance, at https://www.originenergy.com.au/about/investors-media/update-on-operating-conditions-and-guidance/.

[11] EnergyAustralia 2022, Media update, at https://www.energyaustralia.com.au/about-us/media/news/media-update-18-june-2022.

price volatility events in Queensland from 7 June to 10 June 2022, which pushed regional cumulative prices towards the CPT, coincided with upgrade-related outage works on QNI that limited power transfers into Queensland.

2.1.4 Generation availability

Planned maintenance and unscheduled outages of large generation capacity[12] were at high levels in Q2, having approached 8 GW in early May. Capacity was progressively returned to service up to 7 June, but a total of 2.8 GW of further forced outages at large generating units then occurred from 9 June to 13 June (Bayswater 2 & 4 totalling 1,320 MW, Callide C 3 430 MW, Gladstone unit 4 280 MW, and Yallourn units 1 and 4 totalling 740 MW). In total, approximately 6.6 GW of large generation capacity, corresponding to about 20% of winter maximum NEM demand, was offline by 14 June 2022.

2.1.5 East coast gas market and thermal coal prices

Traded market prices for the NEM's major thermal generation fuels (gas and thermal coal) rose to unprecedented levels in the months leading up to 10 June 2022.

Although generators typically contract fuel supply in advance to match their expected output range, costs for purchasing additional fuel to support higher levels of generation, or for renewal of expiring contracts, can be strongly influenced by conditions in local and export markets for those fuels[13].

These changes in direct and opportunity costs of fuel were a principal driver of the observed changes in bidding behaviour from thermal generators in the NEM, which then directly impacted the level of wholesale electricity prices.

Gas prices started to increase in April, with the arrival of cooler weather and higher heating demand in the southern states. At the start of May, a step change in price was observed and by the middle of that month all east coast spot gas markets were trading in the range of $30-$50/gigajoule (GJ) (Figure 1). On 23 May 2022, AEMO suspended market participant Weston Energy from the Short Term Trading Market (STTM) and the Declared Wholesale Gas Market (DWGM), which saw the implementation of the retailer of last resort provisions that included an administered market scheduling state in the Sydney STTM and an administered price cap in the Brisbane STTM. After that event, gas prices increased in other markets and on 30 May 2022 the cumulative price threshold in the DWGM was exceeded, also triggering the administered price cap in that market.

As outlined in the STTM event reports covering this period[14], the initial administered market state in the Sydney STTM due to the Weston Energy failure caused some market participants to reduce their offer quantities into the Sydney hub to limit their exposure to this market when administered prices were lower than the cost of acquiring gas in other markets. Some participants who relied on the spot market for their gas supply had to reduce their demand or source gas by alternative means.

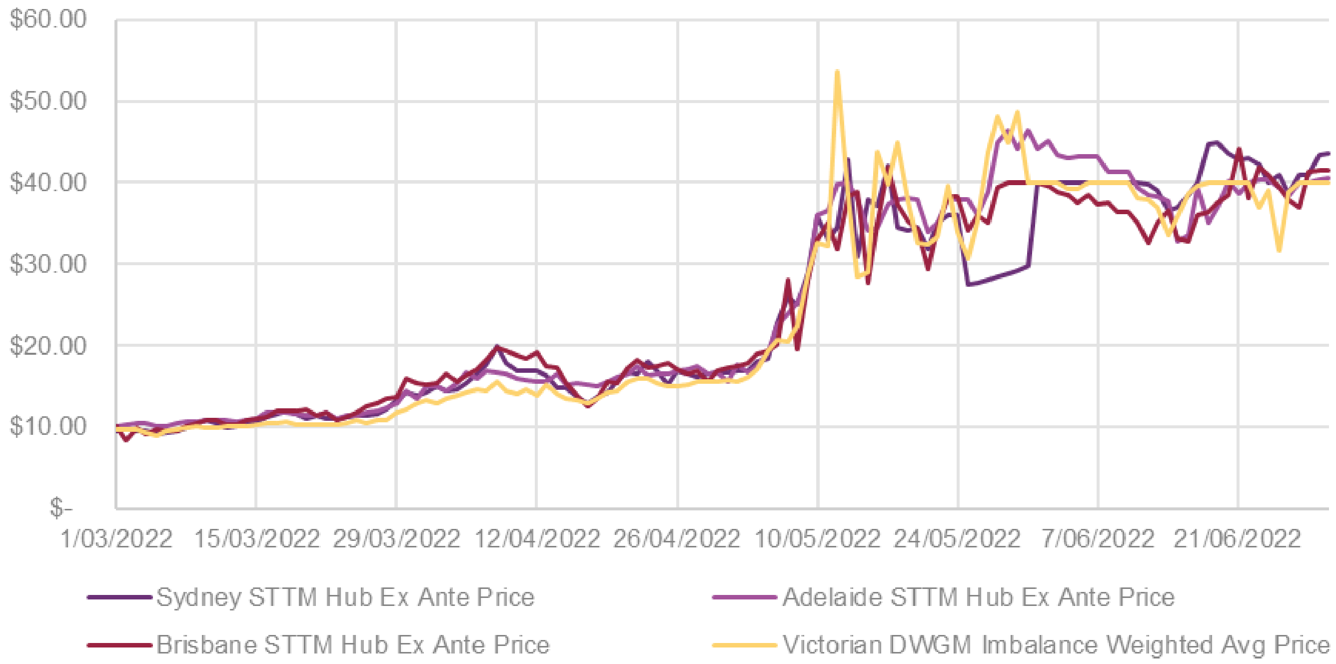
Gas supply was very tight during this period, as evidenced by the Sydney contingency gas trigger event on 25 May 2022 and AEMO's invoking of the Gas Supply Guarantee on 1 June 2022.

[12] NEM coal-fired and large gas fired units larger than 200 MW.

[13] EnergyAustralia 2022, Media update, at https://www.energyaustralia.com.au/about-us/media/news/media-update-22-june-2022.

[14] See https://aemo.com.au/energy-systems/gas/short-term-trading-market-sttm/sttm-events-and-reports.

Figure 1 **Gas prices in STTM and DWGM, March to June 2022**



2.2 Events leading into APP

Between 7 June and 12 June 2022, significant electricity spot price volatility around morning and evening peak demand times progressively increased Queensland's regional cumulative price from approximately $825,000 (corresponding to a weekly average spot price of $409/megawatt hour [MWh]) towards the CPT of $1,359,100 applicable for the 2021-22 financial year.

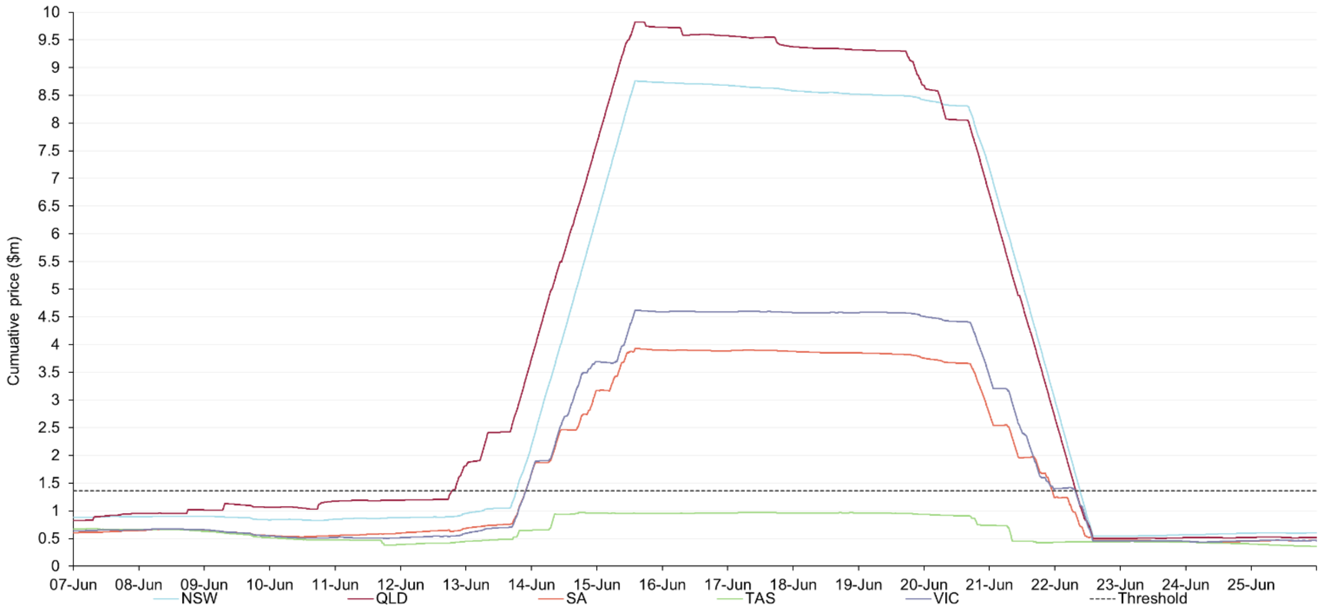
On Friday 10 June 2022, there were noticeable changes in generator bidding as the rolling sum of spot prices for the previous seven days in some NEM regions approached the cumulative price threshold (CPT). On this day, AEMO observed the first withdrawal of capacity leading to actual LOR level 2 (LOR2) conditions, indicating the potential for load shedding if a credible contingency event were to occur. At 1821 hrs on Friday 10 June 2022, AEMO issued market notice (MN) 96921 informing the market of an actual LOR2 condition in the Queensland region from 1800 hrs. The notice also confirmed that AEMO was seeking an immediate market response to resolve this LOR condition. There had been no forecast LOR2 or LOR3 conditions for this timeframe leading up to the actual LOR2 condition arising. The absence of an immediate market response necessitated the first reliability directions associated with this series of events (MN 96924).

Further price volatility in Queensland on 12 June saw the regional cumulative price exceed the CPT in the trading interval ending at 1850 hrs. This marked the start of an administered price period (APP) in the region, with the administered price cap (APC) of $300/MWh in place.

Shortly after Queensland's APP began, reductions in generation capacity offered to the market led to extremely high underlying dispatch prices in Queensland (which were then capped by the APC in that region) and subsequently in other mainland NEM regions.

Many of the extreme dispatch prices occurring outside Queensland over 12 to 13 June 2022 were also capped under the NER's "price scaling" provisions applying under administered pricing[15], however they contributed to rises in cumulative prices for those regions, which are calculated from the uncapped dispatch prices. Consequently, as shown in Figure 2, cumulative prices breached the CPT in New South Wales, South Australia and Victoria on the evening of 13 June 2022 in the trading intervals ending at 1830 hrs, 2155 hrs, and 2200 hrs respectively, triggering APPs in each of those regions.

Figure 2 Regional cumulative prices 7 June to 25 June 2022



[15] If an adjoining region is exporting energy across a regulated interconnector to a region where the price is capped at the APC, then under NER 3.14.2 "price scaling" is applied to also cap the price in that exporting region to a level reflecting the importing region's administered price with an adjustment for interconnector losses.

3 Summary of key events and structure of this report

Key events during this period are summarised below, and a detailed timeline is in Appendix 0. Trading interval (TI) times refer to the 5-minute trading interval ending at that time.

Table 1 Summary of key events

Date	Event
10 June 2022	• TI 1805 actual LOR2 condition arises • First directions for reliability issued - for 260 MW generation capacity to be made available from TI 1845
12 June 2022	• TI 1855 Queensland APP commenced and spot price capped at the APC* • 260 MW generation capacity directed to be made available
13 June 2022	• 0630 – 0730 hrs exceedance of QNI secure limit, power system not in a secure operating state based on post-incident analysis. Refer to Section 6.2 of this report for more details. • TI 1835 New South Wales APP commenced • TI 2200 South Australia APP commenced • TI 2205 Victoria APP commenced • 3544 MW generation capacity directed to be made available
14 June 2022	• 1805 – 2105 hrs in response to a forecast LOR2 condition (MN 97365), AEMO instructed the dispatch of approximately 300 MW of RERT in New South Wales • 4868 MW generation capacity directed to be made available
15 June 2022	• 0500 – 0530 hrs and 0630 – 0700 hrs the flow on VNI into NSW went above the secure limit for two periods of up to 30 minutes (see Section 6.2 of this report for more details) • TI 1405 spot market suspended with market suspension pricing schedule (MSPS) applied in all regions • 1730 – 2330 hrs in response to a forecast LOR3 condition (MN 97776), AEMO instructed the dispatch of approximately 489 MW of RERT in NSW at 1730 hrs which was forecast to apply until 2330 hrs (MN 97793) • 1800 – 2330 hrs in response to forecast LOR2 and LOR3 conditions AEMO instructed the dispatch of approx. 51 MW of RERT in Queensland • 4945 MW generation capacity directed to be made available
17-18 June 2022	• 2000 hrs 17 June – 0410 hrs 18 June 2022 in response to a forecast LOR2 condition AEMO instructed the dispatch of approximately 463 MW of RERT in New South Wales • 2528 MW generation capacity directed to be made available on 17 June • 4568 MW generation capacity directed to be made available on 18 June
19-21 June 2022	• 2686 MW generation capacity directed to be made available on 19 June • 1426 MW generation capacity directed to be made available on 20 June • 1058 MW generation capacity directed to be made available on 21 June
22 June 2022	• TI 0400 APP ended in South Australia and did not restart • 899 MW generation capacity directed to be made available
23 June 2022	• TI 0400 APP ended in New South Wales, Queensland and Victoria and did not restart • TI 0400 AEMO declared MSPS ended, and dispatch pricing resumed in all regions
24 June 2022	TI 1400 market suspension ends, spot market resumed in all regions from TI 1405

* An APP ends at the end of each NEM trading day at 0400 hrs and recommences immediately for the next trading day if the CPT is still exceeded at that time.

There is a more detailed sequence of key events over the period in Appendix A1.

The remaining sections of this report contain AEMO's detailed analysis of the market and power system events over the period from 10 to 24 June 2022, and are structured as follows:

- Section 4 outlines the supply and demand position, including transmission and generation outages, operational demand, and variable renewable energy resources for semi-scheduled generation.
- Section 0 covers available reserves and the actions AEMO took to address relevant LOR conditions, including the issue of directions and RERT activation.
- Section 0 reports on power system security incidents.
- Section 0 reports on the spot market suspension, including the reasons for suspension and its effect on spot market operation.
- Section 8 summarises the report's conclusions.
- Section 9 lists recommended actions for AEMO and market participants, and next steps.
- Appendix A1 summaries key events in sequence.
- Appendix A2 lists transmission outages that occurred or were cancelled in the period from 10 June to 24 June 2022.

4 Supply and demand

4.1 Changes in transmission network and generator outages

Table 8Table 8 in Appendix 0 details the transmission network outages from 10 June 2022 to 24 June 2022 and the impact they had on reserves. To minimise outage impacts on reserves, many network outages were withdrawn or labelled unlikely to proceed (UTP). Table 9 in Appendix 00 summarises the transmission network outages that were withdrawn or labelled unlikely to proceed (UTP) from 10 June 2022 to 24 June 2022.

Approximately 6,000 MW of generation capacity was out of service due to planned and unplanned outages at the time of the market suspension on 15 June 2022. Around 2,500 MW of generation was brought back online during the suspension period. On 23 June, approximately 3,500 MW of generation capacity remained out of service as a result of planned and unplanned outages.

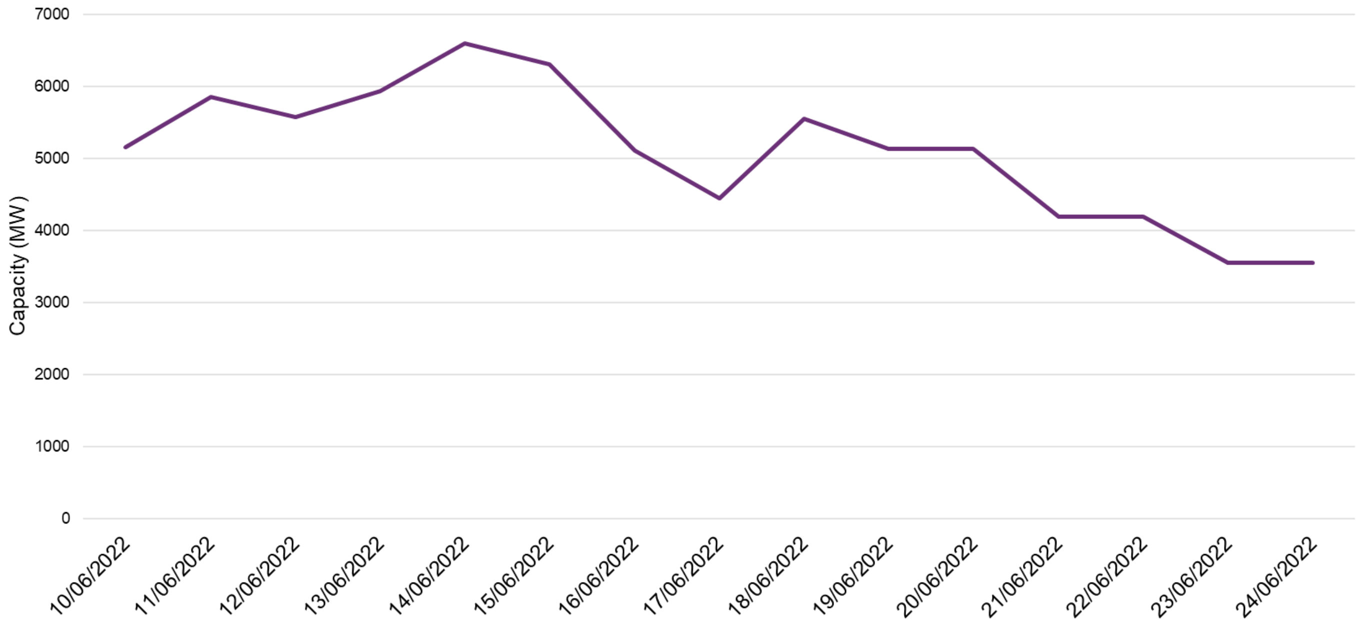
Table 2 summarises changes in physically available generation capacity of large generating units due to outages over the period from 10 June 2022 to 24 June 2022, and Figure 3 shows the total NEM generation unavailable due to planned and unplanned outages.

Table 2 Summary of changes in available generation capacity associated with planned/unplanned outages, 10 June 2022 to 24 June 2022

Date	Generator capacity change*				
	NEM	QLD	SA	NSW	VIC
10 June 2022	-700	-700	0	0	0
11 June 2022	+280	+280	0	0	0
12 June 2022	-360	0	0	0	-360
13 June 2022	-660	-280	0	0	-380
14 June 2022	+280	+280	0	0	0
15 June 2022	+1,206	+846	0	0	+360
16 June 2022	+660	0	0	+660	0
17 June 2022	-1,070	-1,070	0	0	0
18 June 2022	+426	+426	0	0	0
19 June 2022	+660	0	0	+660	0
20 June 2022	+280	+280	0	0	0
21 June 2022	0	0	0	0	0
22 June 2022	+644	+644	0	0	0
23 June 2022	0	0	0	0	0
24 June 2022	0	0	0	0	0

*Capacity returning to service is positive, capacity being de-committed is negative.

Figure 3 Total NEM generation capacity unavailable due to planned/unplanned outages, 10 June 2022 to 24 June 2022



4.2 Operational forecasting

4.2.1 Prevailing weather conditions

A series of cold fronts brought cold air to south-eastern Australia from Wednesday 8 June to Sunday 12 June 2022 as a slow-moving high-pressure system established south-west of the Great Australian Bight. This system pushed cool, dry air over eastern and northern parts of Australia, resulting in cooler than average days and nights. Minimum temperatures were as much as 4-8ºC below average for far northern New South Wales and much of Queensland, with some isolated locations in Queensland recording minimum temperatures as much as 10ºC below average.

The last in the series of cold fronts moved over the Tasman Sea on Monday 13 June with several locations falling to near 0ºC including through western Sydney and west of Brisbane. However, as the high started shifting east it began to direct more onshore flow onto the east coast, and that meant a gradual return of moisture to the lower atmosphere. This resulted in a gradual increase in temperatures over the following few days with both maximum and minimum temperatures returning to near average for northern and eastern parts of the country, which led to operational demands near winter averages in New South Wales and Queensland.

4.2.2 Peak operational demand

During winter the level of daily peak operational demand is mainly driven by the extent of residential heating and lighting under cold conditions and the operating levels of commercial and large industrial loads.

Table 3 shows the day ahead peak operational demand forecast and how this compared to actual demand at the time of daily peak for the four mainland NEM regions and the NEM total during the period 10 June to 24 June 2022.

The day ahead demand forecasts produced by AEMO project what demand would be, given available model inputs, and do not try to capture commercial demand response, or interventions by AEMO, network service providers, or the market. During the period 10 June to 24 June 2022 combinations of demand-side mechanisms were activated which resulted in actual demand deviating from the day ahead forecast. The major sources of variability which can cause actual operational demand to deviate from the day ahead forecast include:

- Weather variability and behavioural changes:
  - Differences between forecast weather and actual observations. For example, during winter if actual temperatures are lower than forecast, actual operational demand may be higher than forecast.
  - Differences between forecast distributed photovoltaic (PV) generation and actual generation. There is an inverse relationship between distributed PV generation and measured operational demand.
  - Behavioural changes in electricity consumption under certain conditions. For example, increased working from home arrangements due to COVID-19 have increased the weather sensitivity of demand.
- Commercial response:
  - Large industrial loads and other commercially sensitive loads reducing their electricity consumption in response to high electricity market prices reduces operational demand.
  - Non-scheduled generation reducing output in response to low electricity market prices increases operational demand.
- Security and intervention:
  - Activation of RERT or involuntary load shedding instructed by AEMO reduces operational demand.
  - Controlled demand management from distribution network service providers reduces operational demand.
  - Voluntarily electricity reductions from end-use customers following requests to conserve electricity reduces operational demand.

Table 3 Daily peak operational demand actuals and day-ahead forecasts (MW) for 10 June to 24 June 2022

Date	NEM		QLD		SA		NSW		VIC		TAS	
	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual
10 June 2022	30,774	30,059	7,788	7,978	2,143	2,071	12,065	11,345	7,351	7,188	1,648	1,610
11 June 2022	29,111	28,754	7,512	7,603	1,924	1,983	11,367	10,817	6,890	6,880	1,537	1,547
12 June 2022	28,988	28,510	7,382	7,862	2,013	1,928	11,140	10,655	6,965	6,572	1,608	1,594
13 June 2022	29,591	29,352	7,668	7,849	2,057	2,040	11,062	11,166	6,990	6,799	1,573	1,604
14 June 2022	30,469	31,285	7,808	7,761	2,077	2,168	11,688	12,141	7,445	7,707	1,710	1,705
15 June 2022	30,078	30,028	7,511	7,551	2,023	2,082	11,496	11,390	7,570	7,524	1,632	1,599
16 June 2022	29,865	29,269	7,366	7,506	2,008	2,065	11,614	10,979	7,285	7,234	1,569	1,577
17 June 2022	28,459	28,677	7,368	7,388	2,016	2,010	10,811	10,856	6,935	7,078	1,595	1,616
18 June 2022	26,996	27,167	7,151	7,139	1,816	1,897	10,167	10,206	6,442	6,539	1,483	1,477
19 June 2022	28,010	27,945	7,348	7,254	1,943	2,016	10,573	10,478	6,626	6,803	1,470	1,483
20 June 2022	29,209	29,558	7,628	7,620	2,080	2,172	11,033	11,233	7,098	7,220	1,528	1,475
21 June 2022	29,316	29,635	7,478	7,493	2,157	2,137	10,988	11,254	7,195	7,335	1,525	1,508
22 June 2022	29,683	29,587	7,457	7,452	2,023	1,984	11,455	11,478	7,162	7,308	1,549	1,564
23 June 2022	29,120	28,679	7,470	7,232	1,939	1,948	11,405	11,268	6,995	7,022	1,533	1,526
24 June 2022	28,400	27,759	7,171	7,019	1,986	1,910	10,783	10,540	6,927	6,842	1,547	1,525

Operational demand observations before and during administered pricing

Prior to commencement of APPs, in general operational demand profiles followed normal winter patterns. Cold weather drove elevated demands, particularly in New South Wales and Queensland, while intermittent cloud cover and widespread rainfall resulted in elevated and variable daytime demands due to volatility in distributed PV generation. High market prices resulted in commercial demand response from large industrial and commercially sensitive loads which were regularly reducing their consumption, resulting in demand reductions across the daily peaks compared to the forecast.

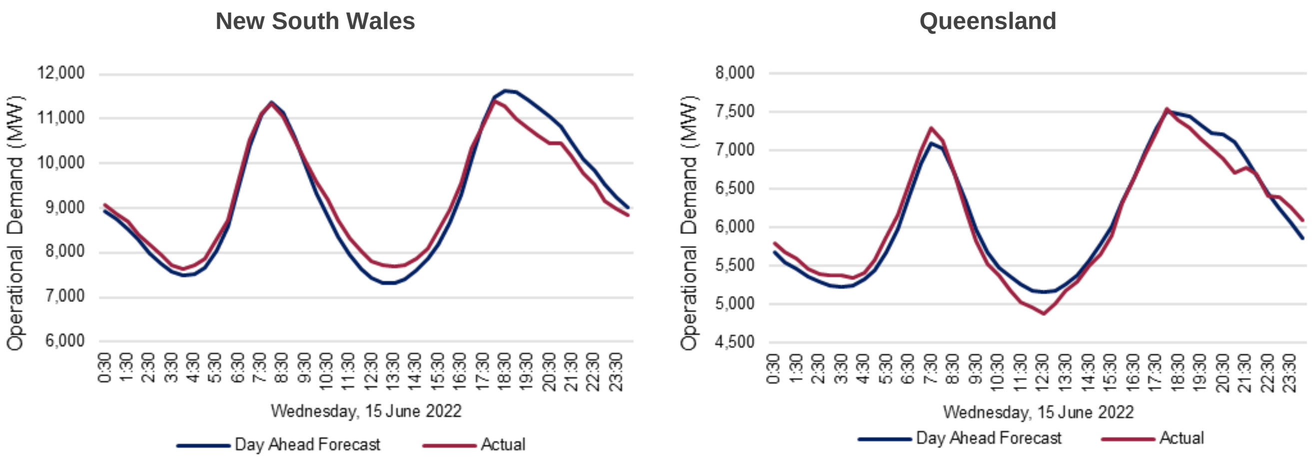
For example, on 10 June 2022, load reductions of approximately 630 MW were observed across New South Wales and Victoria at the evening peak, accounting for most of the demand forecast deviation across the NEM. This activity continued in New South Wales on 12 and 13 June where approximately 300 MW of load reductions contributed to the peak forecast deviations seen in Table 3 above.

During the APP, the capped market prices reduced short-term incentives for load to self-curtail for commercial reasons, resulting in less price elasticity. This resulted in additional demand from commercial and industrial consumers which may have otherwise responded to high prices. Instead, day ahead forecast deviations throughout this period were mainly a result of the exercise of RERT contracts, demand management from distribution network service providers, and voluntary reductions from end-use customers in response to requests from jurisdictions and AEMO. This was most active during the period 14 June to 18 June 2022 and resulted in large reductions in operational demand compared to the forecast.

During this period the largest reductions were often observed after the actual demand peak in Table 3 above. For example, on 14 June 2022, the daily peak was almost 500 MW above the day ahead forecast due to colder than forecast daytime temperatures, with demand reducing after the peak when RERT was activated.

The impact of these intervention processes on the New South Wales and Queensland evening peak demands on 15 June 2022 is illustrated in Figure 4.

Figure 4 Peak operational demand day-ahead forecast and actuals (MW) in New South Wales and Queensland on 15 June 2022



4.2.3 Semi-scheduled generation

The regional semi-scheduled wind and solar generation levels are shown against their 24-hour ahead unconstrained intermittent generation forecasts (UIGF) for the period 10 June to 24 June 2022 in Figure 5 and

Figure 6. These figures show the absolute generation level (MW) and how this compares as a percentage of the total installed capacity in the regions. At this forecast horizon, the UIGF is driven by numerical weather prediction (NWP) models which resolve the broad patterns and trends in wind levels; short-term variability and ramping in actual generation is generally not captured until nearer-term forecast horizons.

Figure 5 Semi-scheduled wind generation normalised by regional capacity for 10 to 24 June 2022

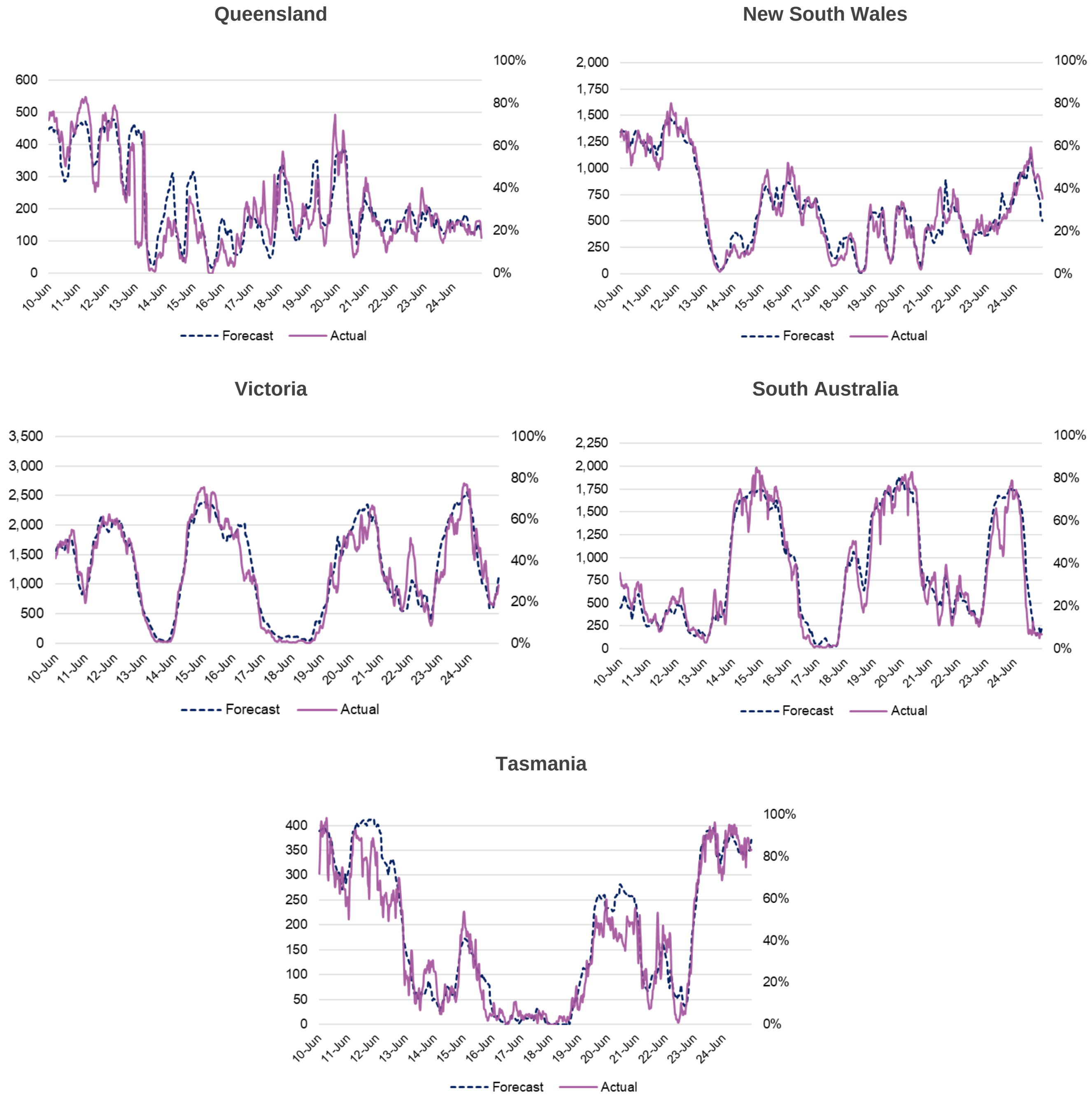
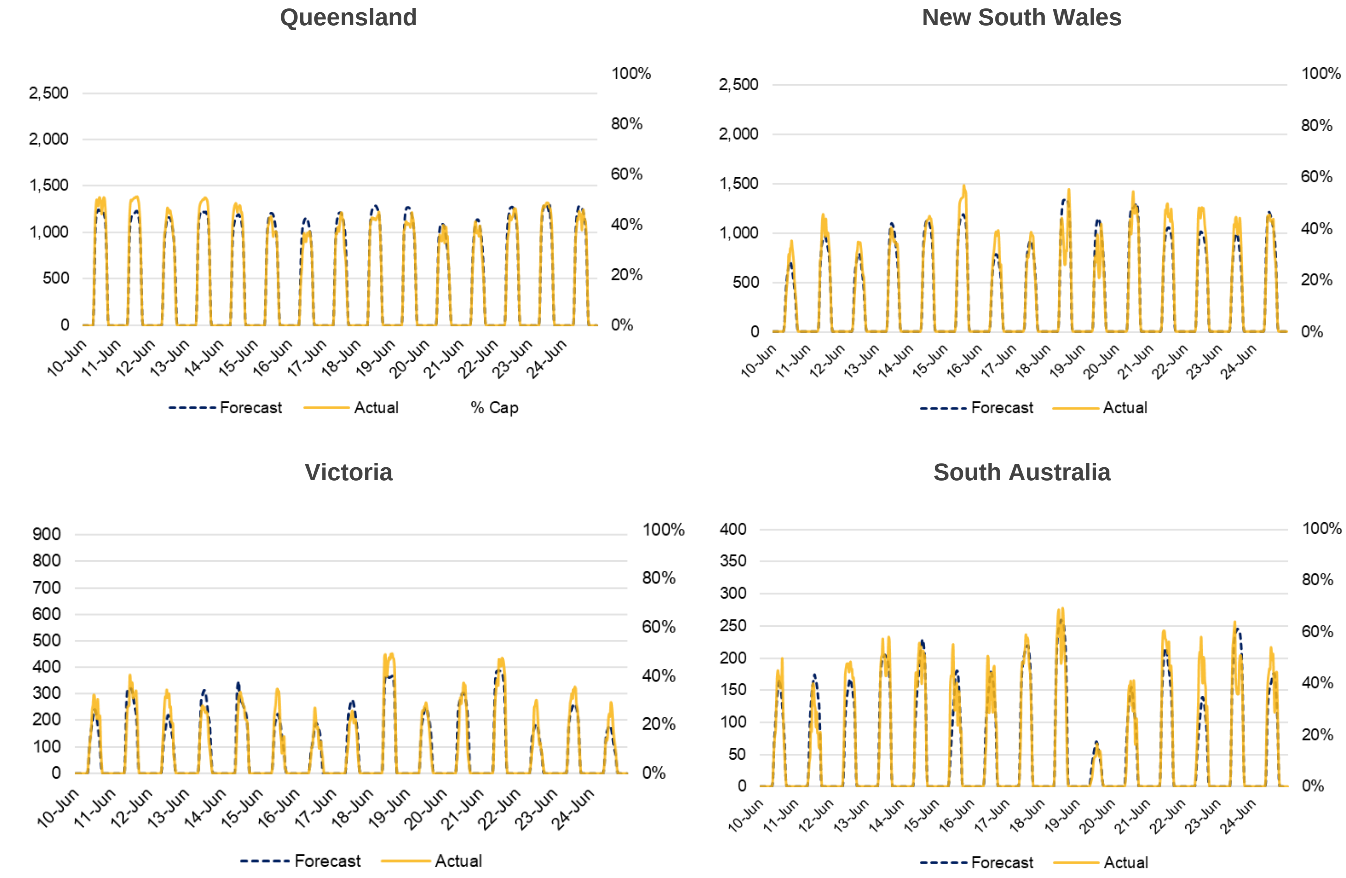


Figure 6 Semi-scheduled solar generation normalised by regional capacity for 10 to 24 June 2022



In Queensland and New South Wales, wind generation levels were highest at the beginning of the period, peaking on 11 June at 83% and 80% of installed capacity in those regions respectively. Wind conditions in the eastern NEM settled from 13 June, which resulted in average wind generation levels of 23% during the period 13 June to 24 June 2022 in both Queensland and New South Wales and intermittently approaching 0% in both regions. Victoria, South Australia, and Tasmania fluctuated between periods of very high and very low wind generation. Following similar patterns, these regions reached highs of 77%, 85% and 98% respectively and lows of 0%, including sustained periods of very low wind generation on 13 June and 17 June to 19 June 2022 in Victoria.

As expected in winter, the availability of grid-scale solar generation was near annual minimum levels, reflected in maximum daytime generation levels of 49%, 51%, 57% and 69% across the event period in Victoria, Queensland, New South Wales, and South Australia respectively, while Tasmania has no semi-scheduled solar generation installed. Solar output was also highly variable at times due to intermittent cloud cover, and minimal during the morning and evening demand peak periods.

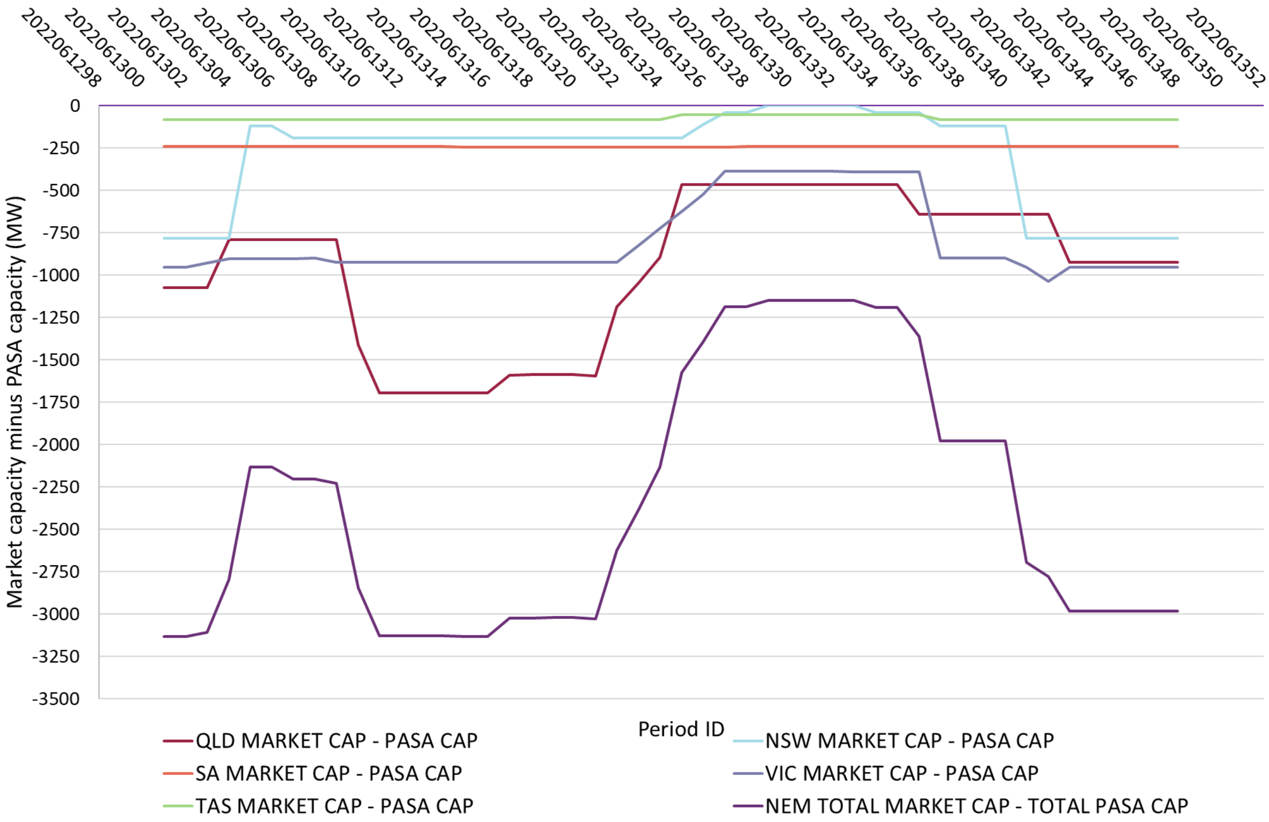
5 Reserves

5.1 Generator availability

After the commencement of APPs, several generators rebid their energy volumes offered to the market, significantly reducing the generation capacity available for dispatch. This directly led to a deep actual LOR2 condition on 13 June 2022[16], which necessitated the issuing of directions by AEMO to maintain reliability, as described in Sections 5.2 and 5.3. Figure 7 shows the total market capacity minus the pre-dispatch projected assessment of system adequacy (PASA) availability for each region and the NEM as a whole on 13 June 2022. This illustrates the volume of generation capacity that was technically available[17] but not offered to the market.

While the Tasmania region was not subject to the APC, it was also not subject to price scaling under the NER because it is not connected to the mainland regions by a regulated interconnector. This meant that northward export flows from Tasmania on Basslink (which would have provided additional reserves) attracted a large accumulation of negative residues. Basslink subsequently (on 14 June 2022) reduced its available export capacity to zero.

Figure 7 NEM regional total market capacity minus total PASA capacity on 13 June 2022 (during APP)

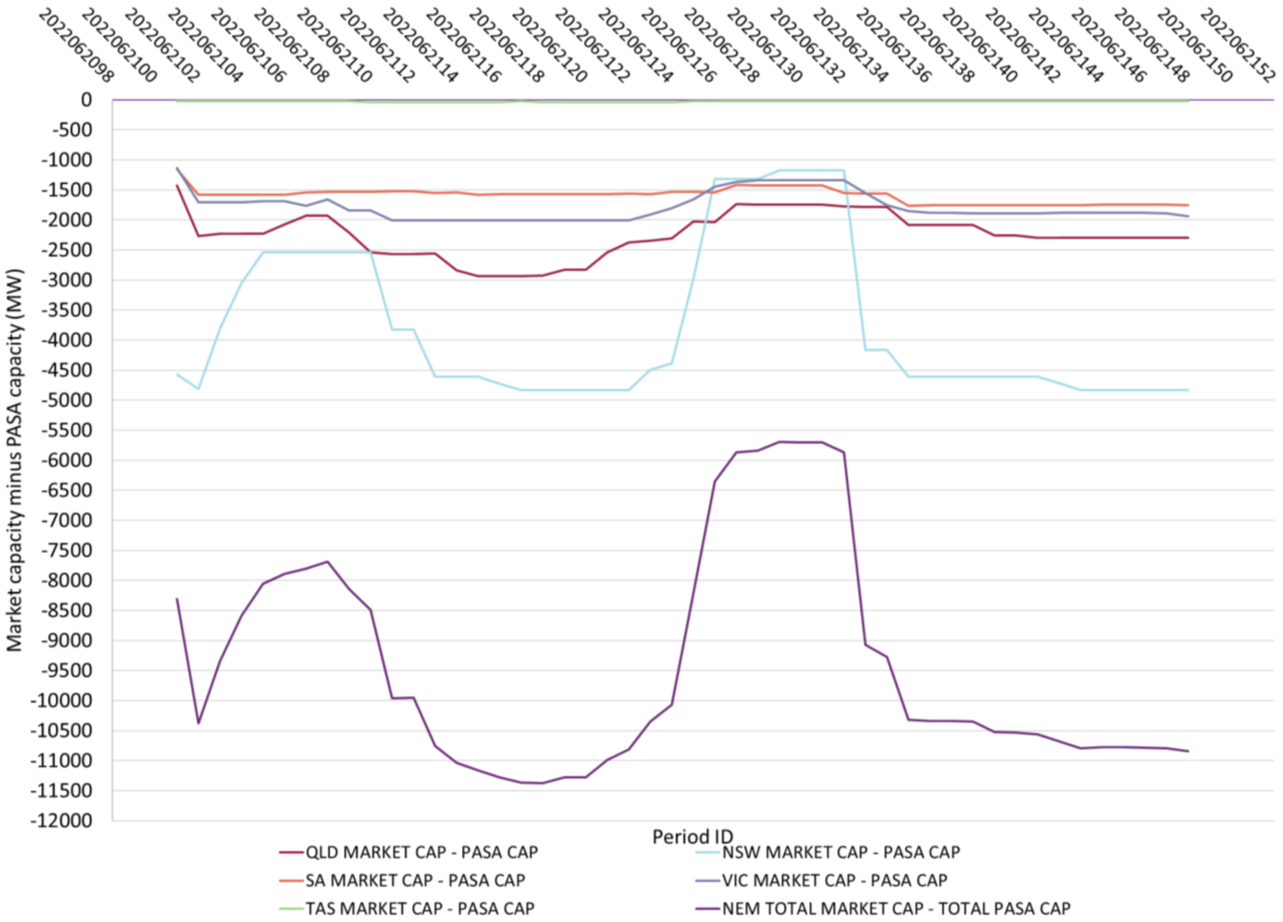


[16] The actual LOR level 2 condition was declared with a capacity reserve requirement of 487 MW and a minimum capacity reserve available of 190 MW – see MN 97019.

[17] Or could be made available on less than 24 hours' notice.

During the market suspension and under the market suspension pricing schedule (MSPS), reduced generation volumes continued to be offered to the market, as illustrated in Figure 8. For example, on 21 June, during the market suspension, between approximately 6 GW and 11 GW of technically available generation capacity across the NEM was not commercially offered to the market – significantly more than the 1-3 GW on 13 June during the APP. This necessitated frequent capacity availability directions from AEMO to maintain reliability throughout the suspension period, as described in Section 5.3.

Figure 8 NEM regional total market capacity minus total PASA capacity on 21 June 2022 (during market suspension)



5.1.1 Energy limited plant

Coal supply constraints in New South Wales

Reduced coal production at local mines and reduced deliveries from remote mines meant that a number of major power stations in New South Wales experienced very low coal stocks and implemented energy limits for their generation. The daily energy limits at these stations varied depending upon the levels of coal stockpiles and daily deliveries, which were frequently unpredictable. Raising the energy limit for a given day could mean that a lower limit would be necessary for the following day, requiring dispatch decisions to be made based on anticipated power system conditions. For example, on one occasion AEMO scheduled additional energy-limited coal generation when supply was tight due to lower forecast wind generation for the following day, on the basis that the forecast wind generation was significantly higher for the day after that.

Gas supply constraints

Tight supply-demand balance in the east coast gas markets also limited the fuel available for gas generators, particularly impacting participants without contracted gas supplies. As discussed in Section 2, on 1 June 2022, AEMO invoked the Gas Supply Guarantee when forecast limits on gas supply available to generators resulted in widespread forecast LOR conditions for four NEM regions on 2 June 2022. At other times gas supply limits required dual-fuelled peaking generators to run on limited reserves of high-cost liquid fuel.

The Victorian DWGM was subject to a $40 per GJ price cap from 30 May that resulted in market participants reducing gas supply offers into the DWGM. Some generators that were reliant on purchases from the DWGM needed to operate some stations with back up diesel to supplement their gas supply. Delays in restoring diesel storages on site led to risks of temporary unavailability if they had operated at a high level on the previous day.

Energy limits in PASA

Figure 9, Figure 10 and Figure 11 show the submitted aggregate energy limits for the Queensland, New South Wales and Victoria regions in medium-term PASA (MT PASA). Since early July, the energy limits submitted by participants have been repeatedly revised down, better reflecting the levels of fuel availability and other operational challenges advised by participants. Energy limits in the periods leading up to and during the market suspension, however, are believed to have been significantly tighter than the limits that were forecast for that time.

Figure 9 Queensland aggregated MT PASA energy limits as submitted weekly

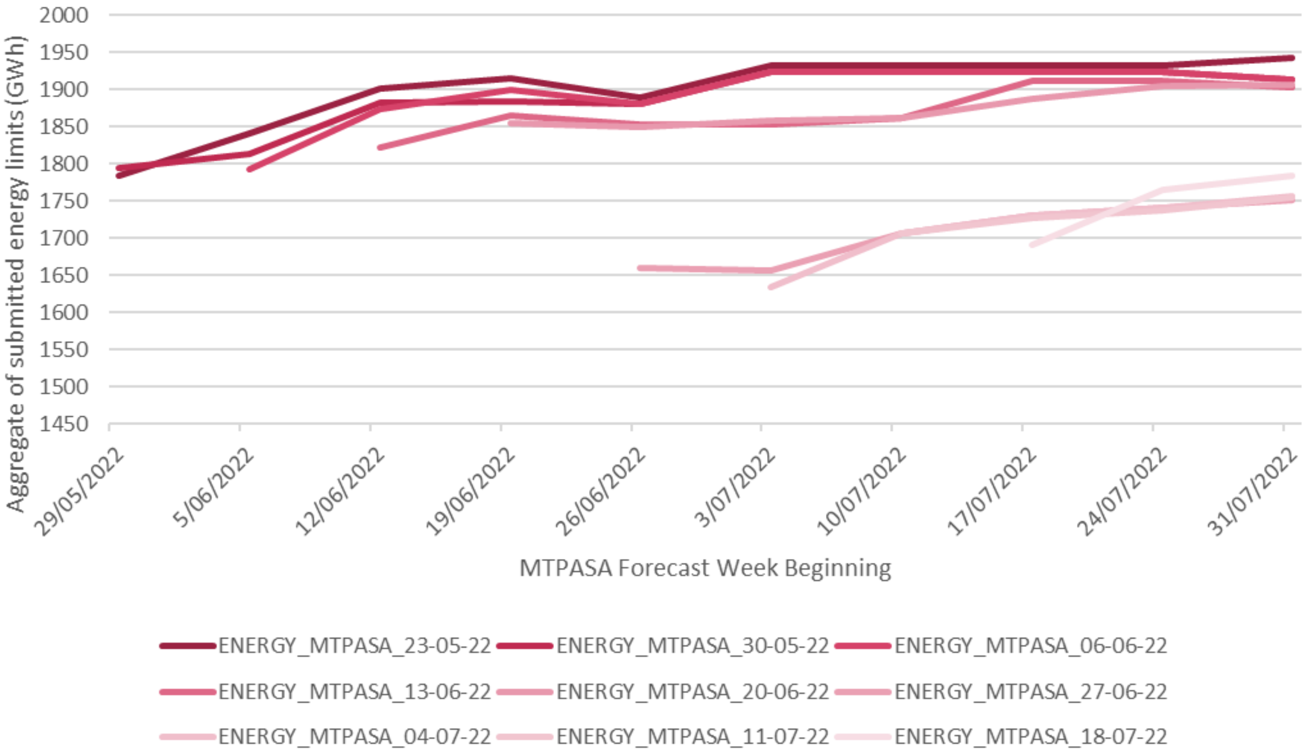


Figure 10 New South Wales aggregated MT PASA energy limits as submitted weekly

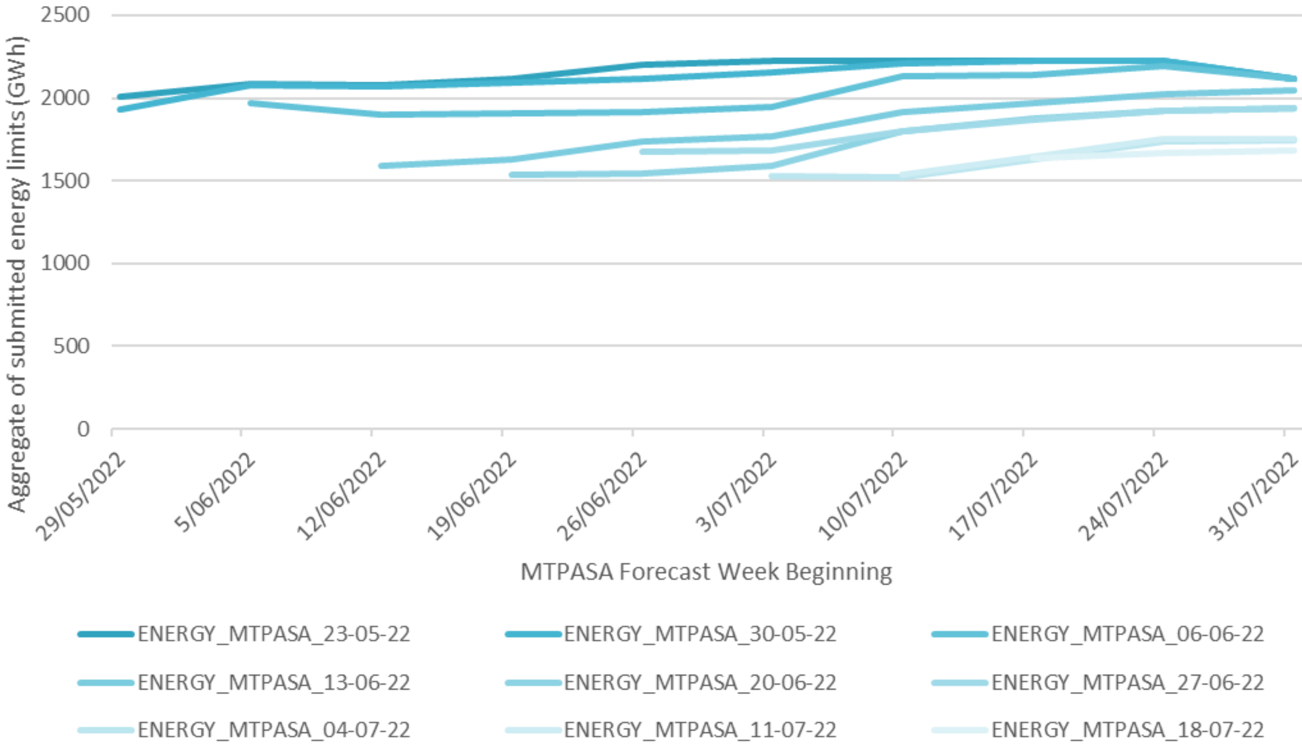
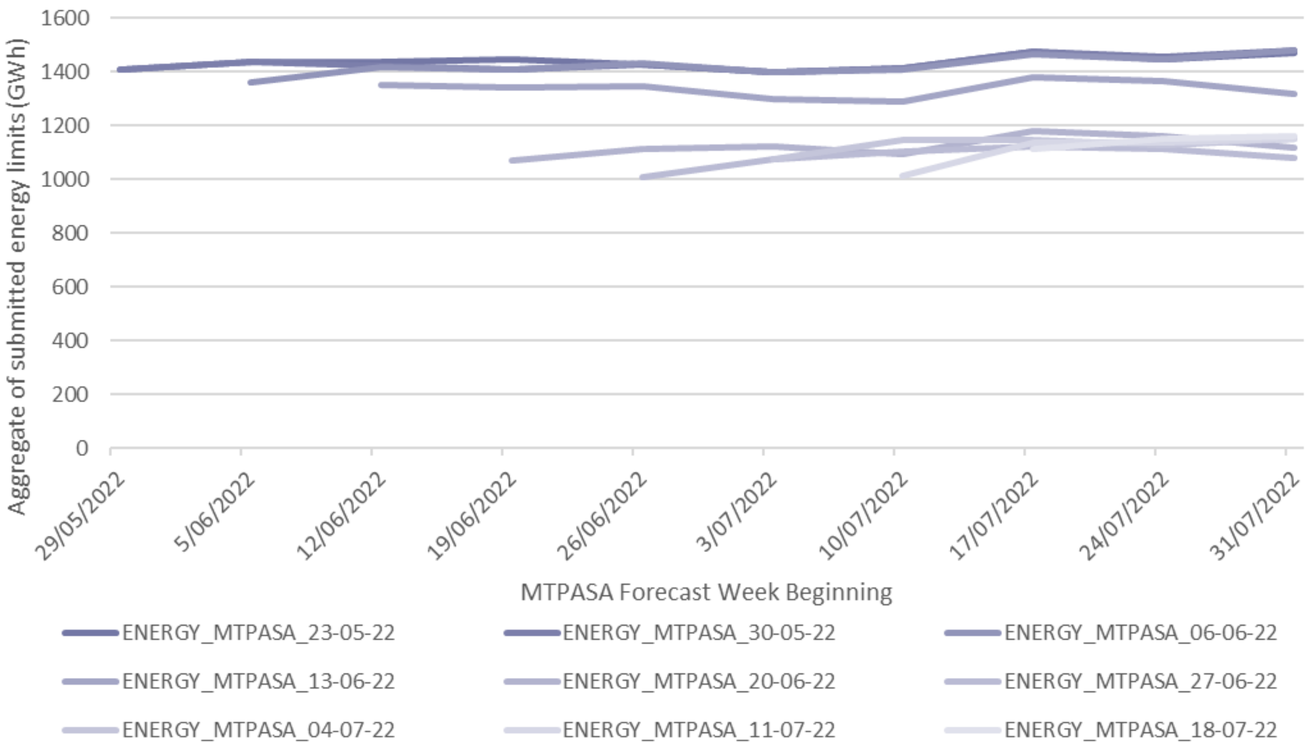


Figure 11 Victoria aggregated MT PASA energy limits as submitted weekly



5.2 Lack of Reserve (LOR) conditions

Figure 12 and Figure 13 show the number of forecast and actual LOR conditions that were declared during administered pricing and during the market suspension, respectively. Full details of individual LOR conditions are in Table 7 in Appendix A1.

The counting of forecast and actual LOR conditions was based on existing established declaration count principles. However, adjustments had to be made to manage the unusually long continuous LOR conditions of varying severity that occurred during the event period. Additional counting principles were therefore added to capture the LOR conditions that lasted longer than six hours as multiple LOR conditions. Hence, an increased number of LOR conditions in Figure 13 also represents longer duration LOR conditions.

The number of forecast LOR condition notices issued by AEMO increased substantially after the commencement of administered pricing in all mainland regions. To cope with the very high number of LOR conditions occurring during the market suspension period, AEMO prioritised the issue of LOR2 and LOR3 market notices above LOR1 notices and reduced the frequency of issue. However, AEMO was still able to meet the market notification requirements for potential interventions due to LOR conditions under NER clause 4.8.5A.

A more detailed explanation of the LOR count principles and adjustments is provided in AEMO's lack of reserve framework report for the quarter ending 30 June 2022[18].

Following commencement of APPs from 12 June 2022, the reductions in the volume of generation offered to the market resulted in actual LOR conditions that had not been forecast in the short term or pre-dispatch PASA. In response to actual LOR2 conditions, AEMO directed units to make capacity available and follow dispatch targets – this is further detailed in Section 5.3. AEMO continued to publish forecast LOR conditions to encourage a response from the market to provide additional capacity. Demand response reserves were also contracted under RERT and later activated in response to forecast LOR2 and LOR3 conditions – RERT activations are outlined in Section 5.4.

As detailed in Section 5.3, after the spot market was suspended on 15 June 2022, AEMO was directing many units for availability (capacity availability directions) and was managing generation dispatch on a rolling day ahead basis. Therefore, the forecast LOR conditions published during the market suspension period were not necessarily representative of reserve conditions, given that AEMO was manually directing generation on a day ahead basis.

Figure 13 indicates that the duration of actual LOR conditions increased during the market suspension. During some periods of low reserves, actual LOR2 conditions were prolonged by hydro pumps operating under direction from AEMO to improve the reserve outlook for future periods, on the basis that demand from pumping loads could be reduced if there were any material adverse changes in reserve conditions while they were operating.

[18] At https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/power-system-operation/nem-lack-of-reserve-framework-quarterly-reports.

Figure 12 Pre-market suspension forecast and actual LORs (10 June – 14 June 2022)

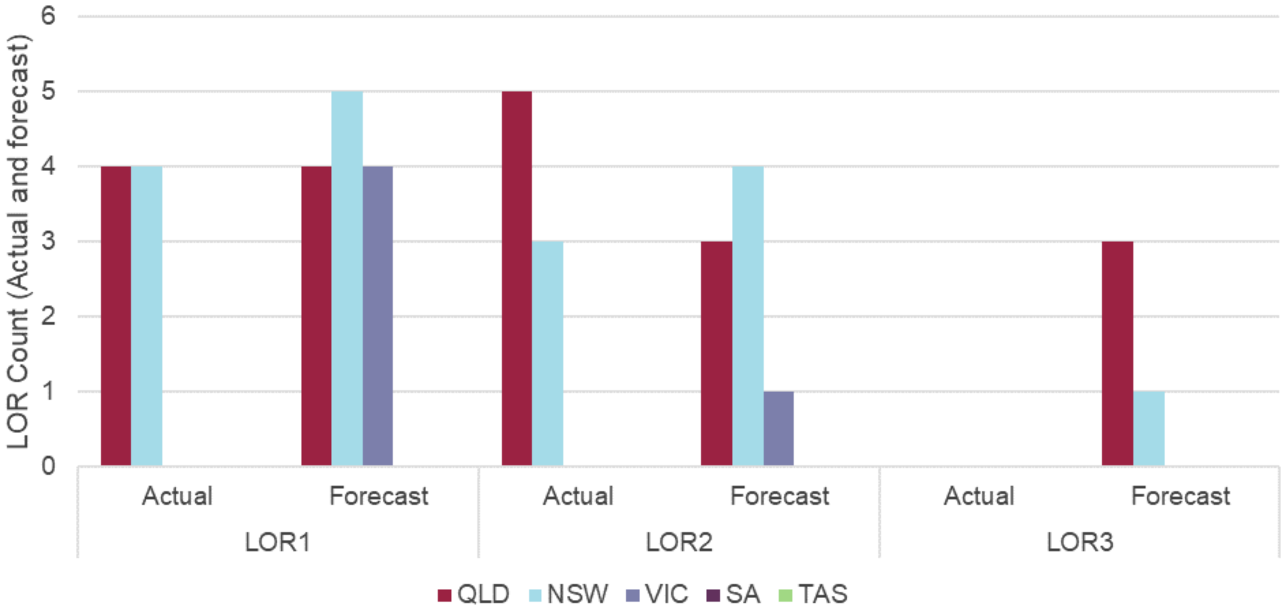
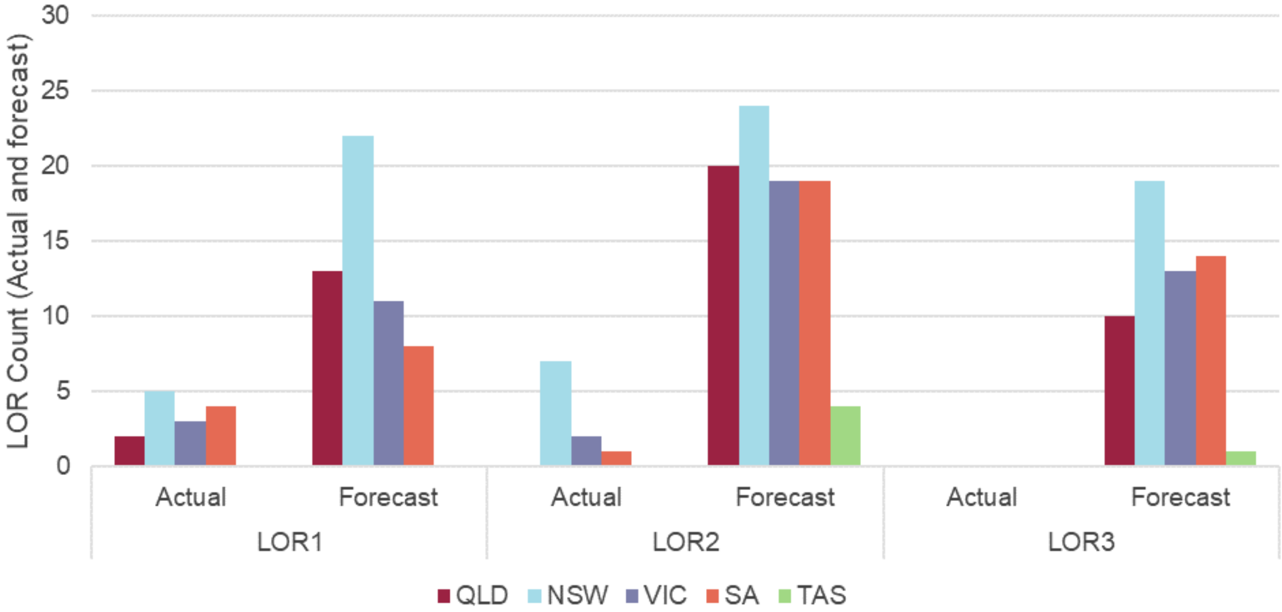


Figure 13 Market suspension forecast and actual LORs (15 June – 24 June 2022)



5.3 Directions

AEMO issued a large number of directions between 10 June and 24 June 2022 to manage actual and forecast LOR conditions in the circumstances described in the earlier sections of this report. For these purposes, directions were issued to market participants in respect of scheduled generation, scheduled load (hydro pumps in this case) and market network services. This section addresses the reporting requirements of NER clause 3.13.6A(a) in respect of these directions. The financial information under clause 3.13.6A(b) has yet to be finalised and will be included in a supplementary report.

Table 4 summarises the total directed generation and number of direction-related participant notices issued for each day between 10 June and 24 June 2022. Figure 14 shows the total net directed capacity in the NEM over this period. Full details of individual directions are included in Appendix A1.

Prior to the market suspension on 15 June 2022, as shown in Table 4 and Figure 14, AEMO had to direct units to make capacity available and follow dispatch targets for reliability reasons in response to actual LOR2 conditions.

During the market suspension, to address the challenges described in Section 7.2 that contributed to the suspension decision, AEMO was directing many units for availability (capacity availability directions) and managing generation dispatch on a rolling 24-hour lookahead basis. As a result, the number of directions issued rose during the market suspension. Capacity availability directions were coupled with the use of constraints implemented in the NEM dispatch engine (NEMDE) to manually control generation dispatch during the market suspension. Initially, unit constraints were entered into NEMDE to control how generating units were dispatched based on their bid availability, but it became apparent that NEMDE would override these and dispatch the relevant units to address a network constraint violation or lack of reserve condition. Subsequently, from around 16 June in most cases, non-conformance constraints[19] in NEMDE were used to control generation dispatch.

To implement this management strategy, AEMO had daily communications with energy constrained scheduled generators to understand physical fuel constraints and associated unit energy limits that could impact future capacity availability. AEMO had a day ahead scheduling team, which endeavoured to indicate to generators the likelihood of directions for the next day by early afternoon the previous day for fuel management and procurement purposes.

As shown in Table 4, initially the directions issued were primarily to generators in the Queensland region, then moving to New South Wales, South Australia and Victoria respectively on 14, 15 and 16 June 2022, with a peak of almost 5,000 MW of directed capacity across the NEM on 15 June 2022. The daily maximum number of direction-related participant notices issued (110) occurred on 17 June 2022.

Following the resumption of dispatch pricing on 23 June 2022, all outstanding directions were cancelled (see Figure 14) and no further directions were issued for the remainder of the suspension period ending at 1400 hrs on 24 June 2022.

The following general observations can be made in relation to directions issued over the event period:

- Where possible, AEMO sought a market response before issuing directions. Several LOR conditions were not forecast, however, and the latest time for intervention was when the actual LOR conditions were identified. In those situations, there was no time to request a market response before issuing directions.
- AEMO was not able to assess changes in dispatch outcomes due to the very large number of intervention constraints over the extended period of the event, which meant the information available from the central dispatch process was not usable for this assessment[20].

[19] Non-conformance is a condition where a dispatched unit fails to follow a dispatch target. AEMO applies a non-conformance constraint equation when a defined threshold is exceeded (refer to Dispatch Operating Procedure (SO_OP3705)). The RHS of the non-conformance constraint equation is set to the last telemetered value of generation, consumption or transfer, i.e. the initial value for the new dispatch interval. The non-conformance constraint equation will remain in place until the participant advises AEMO that they are capable of following dispatch instructions. Non-conformance constraint equations operate to ensure that dispatch of all other scheduled units is consistent with the operation of scheduled and semi-scheduled generators that are temporarily unable to follow dispatch instructions. The general form is: Generator target = last telemetered value.

[20] For more information, see AEMO, Affected Participant Compensation Fact Sheet - NEM – June 2022, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-events-and-reports.

- AEMO issued directions based on a manually determined schedule of generation dispatch, that was implemented using constraints applied to the central dispatch process. The schedule was informed by information from market participants and incorporated a number of priority considerations to minimise the number and cost of directions required to meet operational requirements. Considerations included:
  - Utilisation of higher northward flows on Basslink where possible subject to Tasmanian generation and implications for dam storage levels.
  - Generation start times, ramp rates and minimum run times.
  - Increasing scheduled output of units operating below maximum availability.
  - Minimising impacts on energy limited plant having regard to issues like current and anticipated fuel supply and storage levels, back-up fuel sources, and the ability to schedule pumping or charging at periods of lower reserve impact.
- AEMO used the following approaches to set spot prices:
  - During the APP, prior to market suspension, prices were initially determined using the processes for pricing in the event of intervention by AEMO in NER 3.9.3 and application of the administered price cap in NER 3.14.2. For reasons described in Section 7.1, this became impractical as the event continued.
  - During market suspension, AEMO applied the market suspension pricing schedule in accordance with the provisions of NER 3.14.5.
- Given the challenging circumstances that required a very large number of directions to make generation available and follow targets, AEMO was satisfied overall with the timeliness and adequacy of participant responses and communication relating to AEMO directions, recognising the large number of directions for availability, the nature of the associated constraints, and in some cases rapidly changing plant limitations or operating conditions requiring additional manual steps or instructions.
- AEMO complied with NER clause 3.8.14 and followed its procedures in determining the appropriate mechanism to address the conditions of supply scarcity.

Table 4 MW directed capacity and number of direction related participant notices issued per day

	MW directed capacity per day*					Number of direction-related participant notices per day				
Date	QLD	NSW	VIC	SA	NEM total	QLD	NSW	VIC	SA	NEM total
10/06/2022	260	0	0	0	260	2	0	0	0	2
11/06/2022	0	0	0	0	0	0	0	0	0	0
12/06/2022	260	0	0	0	260	4	0	0	0	4
13/06/2022	3,010	534	0	0	3,544	31	6	0	0	37
14/06/2022	695	3,465	0	708	4,668	9	14	0	7	30
15/06/2022	550	2,507	1,047	841	4,945	10	20	10	8	48
16/06/2022	140	1,168	914	1,149	3,849	4	13	11	16	46
17/06/2022	424	1,224	520	360	2,728	30	20	26	33	110
18/06/2022	640	2,884	563	0	4,565	9	37	20	3	71
19/06/2022	680	1,500	0	500	2,680	4	10	0	2	16
20/06/2022	0	1,160	0	266	1,426	3	12	0	10	25
21/06/2022	0	0	735	350	1,085	12	12	4	2	30
22/06/2022	343	171	0	385	899	4	8	0	13	26
23/06/2022	0	0	0	0	0	1	13	17	6	38 (cancellation of directions)

* Note MW of NEM directed capacity per day is simply the total of the MW capacity directed each day and is not adjusted for the same unit being directed multiple times in one 24-hour period, nor does it account for any cancelled directions in the same period. Capacity volumes include generation and market network service providers.

Figure 14 Total net directed capacity in the NEM (MW) from 10 June 2022 to 24 June 2022*

* Note the total net directed capacity presented in Figure 14 is the total net position of directions taking account of the capacity of MWs under direction at that time and cancelled directions. Figures have been adjusted to avoid any double counting of directed generator capacity.

5.4 Reliability and Emergency Reserve Trader

To maintain power system reliability and system security, based on a number of forecast LOR2 and LOR3 conditions, even after directions to generators it was necessary to procure short notice reserves for four periods in New South Wales and Queensland between 10 June and 24 June 2022. A summary of the RERT that was dispatched/activated from 10 June to 24 June 2022 is given in Table 5. Further details, including the reporting information required under the NER, are available on AEMO's RERT reporting page[21].

Table 5 Summary of RERT activated from 10 June 2022 to 24 June 2022

RERT activation time	RERT MW dispatched	Region	Description	RERT dispatch Market Notices
14/06/2022: 1805 - 2105 hrs	300	NSW	In response to a forecast LOR2 condition (MN 97365) AEMO instructed the dispatch of approx. 300 MW of RERT at 1805 hrs which was forecast to apply until 2105 hrs.	RERT dispatch MN 97376
15/06/2022: 1730 - 2330 hrs	489	NSW	In response to a forecast LOR3 condition (MN 97776) AEMO instructed the dispatch of approx. 489 MW of RERT at 1730 hrs which was forecast to apply until 2330 hrs.	RERT dispatch MN 97793
15/06/2022: 1800 - 2330 hrs	51	QLD	In response to forecast LOR2 and LOR3 conditions (LOR 2 MN 97773) AEMO instructed the dispatch of approx. 51 MW of RERT at 1800 hrs which was forecast to apply until 2330 hrs.	RERT dispatch MN 97801
17/06/2022 2000 hrs - 18/06/2022 0410 hrs	463	NSW	In response to a forecast LOR2 condition (MN 98272) AEMO instructed the dispatch of approx. 263 MW of RERT at 2000 hrs which was forecast to apply until 2330 hrs. The instructed dispatch was later increased by 200 MW of RERT which was forecast to apply until 0410 hrs on 18/06/2022.	RERT dispatch MN 98386 Update to RERT dispatch MN 98426

[21] See https://aemo.com.au/en/energy-systems/electricity/emergency-management/reliability-and-emergency-reserve-trader-rert/rert-reporting.

6 Power system security

AEMO is responsible for power system security in the NEM. This means AEMO must use reasonable endeavours to operate the power system in a secure operating state to the extent practicable and take all reasonable actions to return the power system to a secure state as soon as practical following a contingency event in accordance with the NER[22].

Incidents where the power system is not in a secure operating state for more than 30 minutes are defined as reviewable operating incidents under NER clause 4.8.15(a)(1)(v).

During the event period, in particular after the APC was applied and later while the spot markets in each region were suspended, there were several instances of constraint violations. Following further post-event analysis, AEMO has concluded that the power system remained in a secure operating state throughout the event period, except during the following times:

- **13 June 2022, 0630 - 0730 hrs:** the flow on QNI into Queensland exceeded the secure limit for greater than 30 minutes.
- **15 June 2022, 0500 – 0530 hrs and 0630 – 0700 hrs:** the flow on the Victoria – New South Wales Interconnector (VNI) exceeded the secure limit for less than 30 minutes.

AEMO also investigated whether power system frequency during the period exceeded limits specified in the frequency operating standard (FOS), which would also be a reviewable operating incident under NER clause 4.8.15(a)(1)(iii). While technically the FOS appears to have been met, AEMO considered that a sustained low frequency event that occurred on 17 June 2022 was sufficiently significant to warrant discussion in this report.

This section of the report covers AEMO's analysis of these matters.

In addition, on 23 June 2022 there were persistent voltage oscillations in the South Australian network which were unrelated to the circumstances surrounding this series of events. AEMO plans to prepare a separate incident report on this event.

6.1 Security of QNI

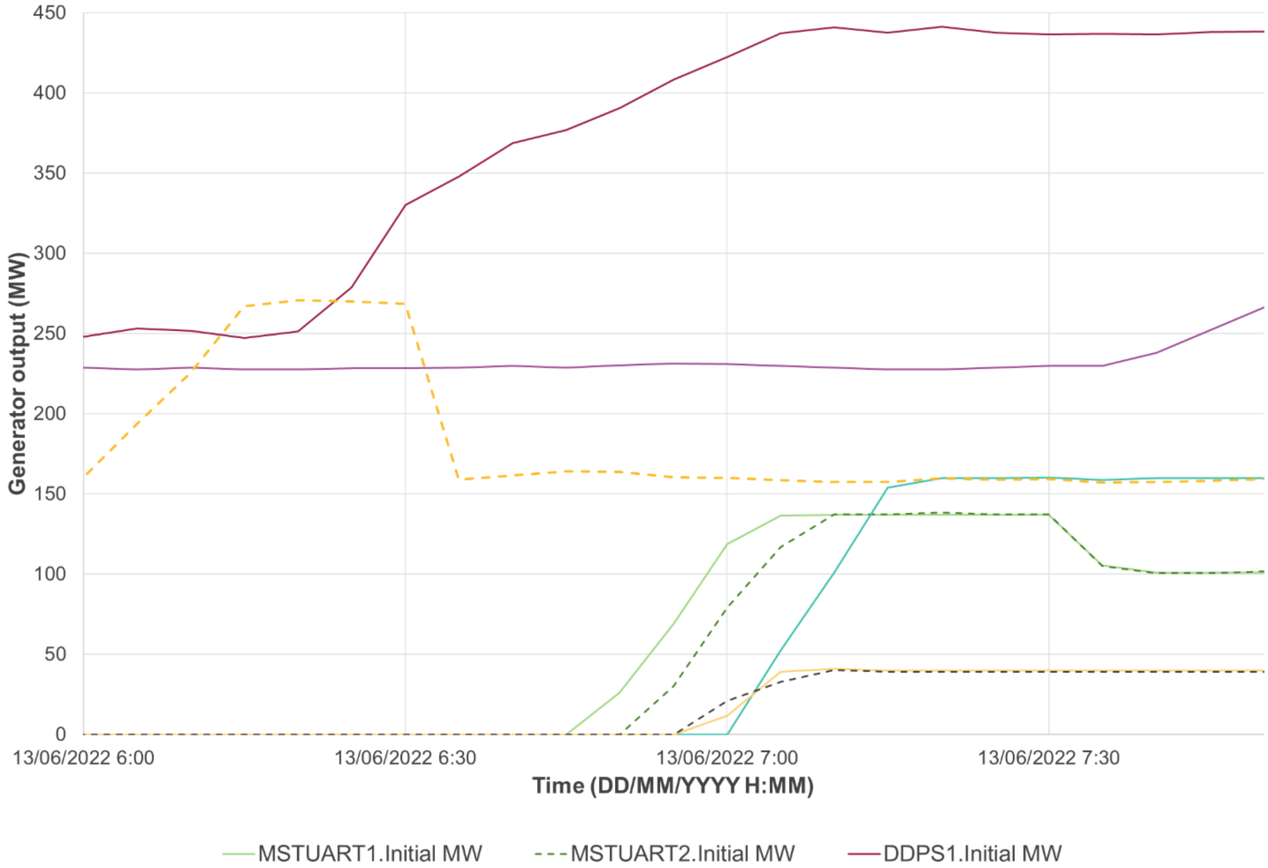
At 0620 hrs on 13 June 2022, AEMO issued MN 97019 informing the market of an actual LOR2 condition in the Queensland region from 0600 hrs. The notice also confirmed that AEMO was seeking an immediate market response to resolve this LOR condition. There were no forecast LOR conditions for this period leading up to the actual LOR2 condition. AEMO directed units in the Queensland region to make additional capacity available and follow dispatch targets, as outlined in Table 6.

[22] Refer to AEMO's functions in section 49 of the National Electricity Law and the power system security principles and responsibilities in clauses 4.2.6, 4.3.1 and 4.3.2 of the NER.

Table 6 AEMO directions in response to the actual LOR2 condition in Queensland on 13 June 2022

Generating unit	Time directed	Capacity directed to be made available and follow targets
Mount Stuart 1 and Mount Stuart 2	0600	138 MW each unit (276 MW total)
Darling Downs Power Station	0605	190 MW
Oakey Power Station 1	0650	160 MW
Roma No.7 and Roma No.8	0705	36 MW each unit (72 MW total)
Stanwell No.4	0705	130 MW
Wivenhoe 1	0730	110 MW
Total	-	938 MW

Figure 15 Power output of directed generators on 13 June 2022



Note: Darling Downs Power Station, Stanwell No.4 and Wivenhoe were generating prior to being directed by AEMO.

As shown in Table 6, between 0600 hrs and 0730 hrs AEMO issued directions for a total of 938 MW of additional generation capacity to be available and follow dispatch targets. As shown in Figure 15, the directed generators responded by increasing their generation in line with dispatch targets (or in the case of Wivenhoe unit 1, maintaining generation above 110 MW). Due to the directed generators' start times, ramp rates and the staggered timing of directions, many of the generators did not start ramping up their outputs until around 0655 hrs, with Stanwell unit 4 being the last to increase its output at around 0740 hrs.

As a result, at approximately 0628 hrs on 13 June 2022, based on the sum of northerly flows on QNI and the Directlink interconnector and generation levels at Kogan Creek (being the largest credible contingency event at the time), the secure limit set by the constraint N^^Q_LS_VC_B1 was exceeded. This constraint limits the combined northerly flows on QNI and the Directlink Direct Current (DC) Interconnector and generation at Kogan Creek when the Lismore Static VAR Compensator (SVC) is out of service to avoid voltage collapse following the loss of the Kogan Creek generator. System security constraints are designed to keep the power system in a satisfactory operating state (under NER clause 4.2.2) should the relevent credible contingency event occur, accounting for current power system operating conditions.

As there were no forecast LOR conditions for this period prior to the actual LOR 2 condition, AEMO was not able to predict this constraint violation. As Figure 7 in Section 5.1 shows, leading up to 0600 hrs on 13 June 2022, there was a significant reduction in the volume of generation offered to the NEM, which contributed in large part to the actual LOR2 condition that occurred from 0600 hrs.

By the time of the constraint violation, AEMO had already directed additional generation online in Queensland, so it was expected that the flow from New South Wales to Queensland on QNI would progressively reduce and allow for the power system to be resecured as soon as practical. Additionally, to increase the limit of the N^^Q_LS_VC_B1 constraint, AEMO requested that Transgrid switch out the Armidale No.2 reactor and the Tamworth No.2 and No.1 reactors, and switch in the Armidale No.6 capacitor and the Tamworth No.3 capacitor. These actions increased the system voltage around Tamworth and Armidale and increased the N^^Q_LS_VC_B1 constraint limit by approximately 200 MW.

Despite these actions and the directions issued, AEMO's SCADA systems indicated that the N^^Q_LS_VC_B1 constraint had violated[23] for over 30 minutes.

AEMO underook post event analysis using half-hourly system snapshots to determine the maximum northerly QNI flow possible while maintaining system security for the the loss of the Kogan Creek generator.

As shown by the dashed line in Figure 16, the actual QNI secure limit calculated through post event analysis was slightly higher during this event than the QNI secure limit calculated by NEMDE as it does not include the statistical or operating margins of the constraint[24].

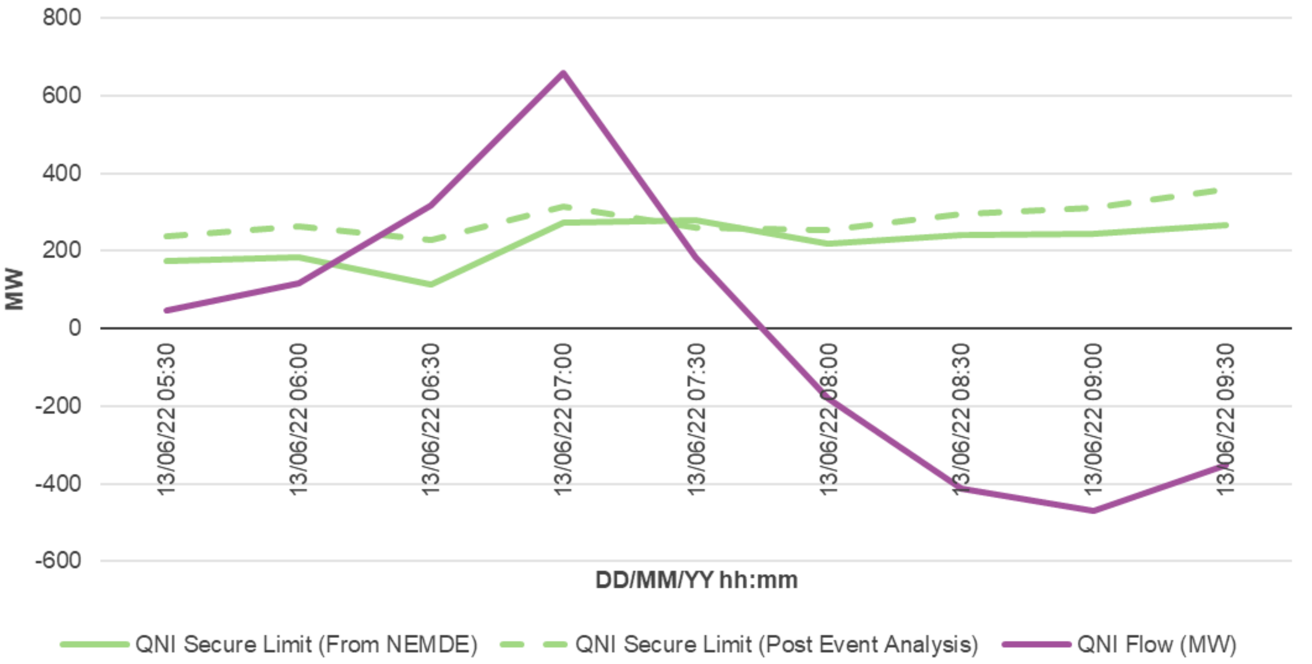
Figure 16 also confirms that the N^^Q_LS_VC_B1 constraint violated this higher limit from 0630 hrs and that the power system was insecure for more than 30 minutes. The QNI flow exceeded its actual secure limit by a maximum of 387 MW at 0700 hrs. After 0700 hrs, the generators in Queensland that had been directed by AEMO started to increase their output, thereby reducing the constraint violation[25]. By 0730 hrs, sufficient units in Queensland had ramped up generation to stop the constraint violation. Therefore, the post event analysis conducted by AEMO concluded that the N^^Q_LS_VC_B1 constraint violated for approximately 60 minutes and the power system was not in a secure operating state during that time.

[23] A constraint equation violates when its left-hand side (the market variables in NEMDE) exceeds the right-hand side (everything else which makes up the constraint equation (e.g line ratings, generator MVAr, on/off plant status)). A constraint equation violates when NEMDE is unable to satisfy all constraint equations simultaneously. The dispatch engine will not be able to target the summation of the left-hand side terms below the right-hand side value. A violating constraint equation indicates a potentially insecure power system.

[24] Constraint equations have both operational and statistical margins. The ability of the constraint equation in NEMDE to maintain the flow on an interconnector or transmission element to within the true limit is dependent on a number of factors including modelling approximations, control limitations, and short-term variations in loads and generator outputs. AEMO determines the operating margins to be applied to constraint equations to manage these approximations and errors – the operating margin for the N^^Q_LS_VC_B1 constraint is 45 MW. The statistical margin of a constraint relates to the percentage of critical cases that have less restrictive limits than predicted by the limit equation and the percentage of critical cases that have more restrictive limits. The secure limit calculated through post event analysis does not include the operating margin or the statistical margin of the constraint.

[25] QNI flow into Queensland appears on the left-hand side of this constraint, therefore reducing QNI flow into Queensland reduces this constraint's LHS term.

Figure 16 N^^Q_LS_VC_B1 post event analysis: QNI flow secure limits



In accordance with clause 4.2.6 of the NER, AEMO must use reasonable endeavours to adjust operating conditions where possible after a significant change in power system conditions, with a view to returning to a secure operating state as soon as practical and within 30 minutes. AEMO took action to direct Queensland generation and instruct the switching of reactors to alleviate the actual LOR2 condition and the N^^Q_LS_VC_B1 constraint violation promptly. The only remaining option available to restore power system security would have been to instruct manual load shedding in the Queensland region. This would have taken approximately 15 minutes to take effect and was not expected to materially reduce the time to resolve the QNI constraint violation, as directed generation increases were expected to bridge the deficit. Load shedding was therefore not considered to be a necessary response in the circumstances at the time.

6.2 Security of VNI

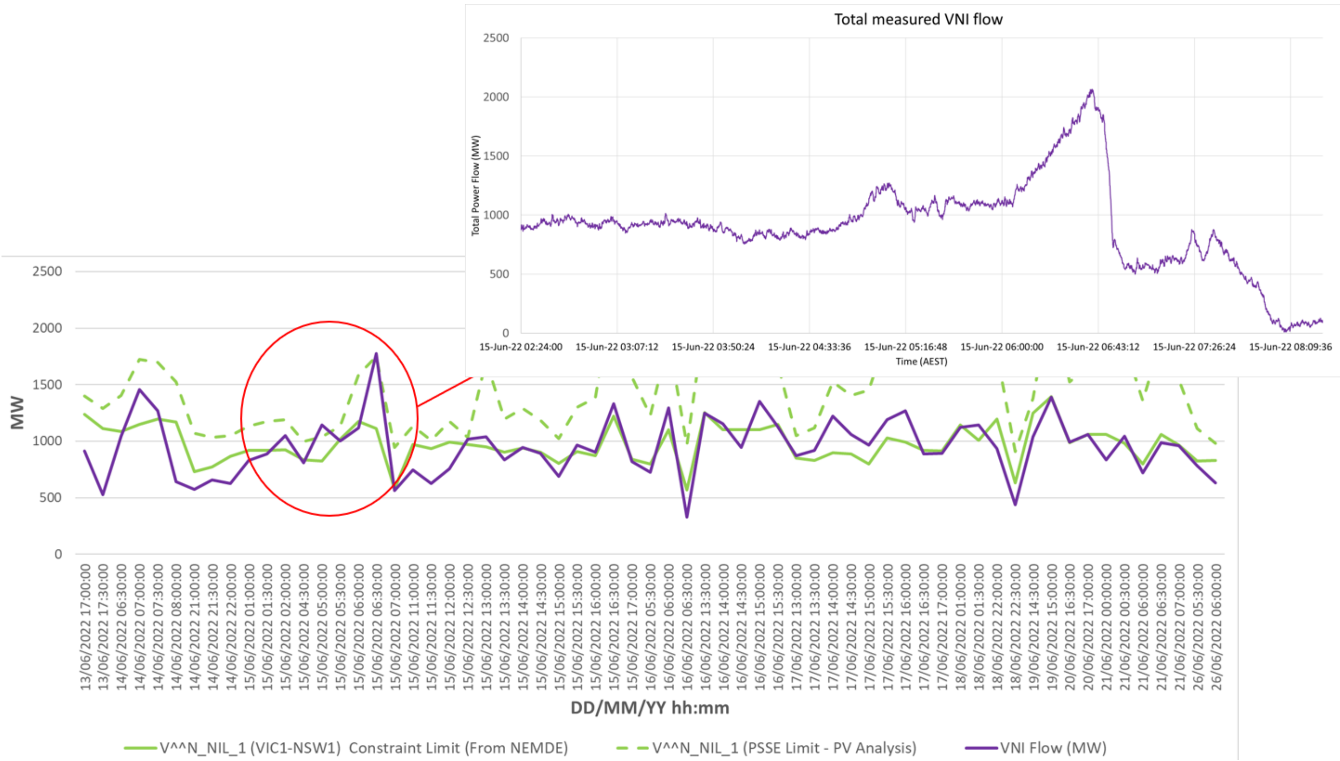
From 14 June to 22 June 2022, there were multiple periods during which the flow on the AC lines connecting Victoria to New South Wales exceeded the secure limit set by the constraint V^^N_NIL_1[26] as calculated by NEMDE. Subsequently, AEMO undertook post event analysis using half-hourly system snapshots to determine the maximum northerly VNI flows possible during these times while maintaining power system security for the loss of the Alcoa Portland (APD) pot lines.

As shown in Figure 17, the VNI secure limit calculated through post event analysis was slightly higher during this period than the VNI limit calculated by NEMDE as it does not include the statistical or operating margins of the

[26] This constraint limits the northerly flow on the VNI lines into New South Wales to prevent voltage collapse in the Murray region following the loss of both APD potlines.

constraint[27]. Figure 17, which has a resolution of 30 minutes, shows that the VNI flow exceeded its actual secure limit for two periods of up to 30 minutes on 15 June 2022 at 0500 hrs and 0630 hrs. Based on the half-hourly system snapshots, the VNI flow exceeded the secure limit by a maximum of 108 MW at 0500 hrs. Figure 17 also shows the measured VNI power flow on 15 June 2022. The measured VNI power flow data with a timestep of 4 seconds indicates that the secure limit was likely breached for close to but less than 30 minutes at both 0500 hrs and 0630 hrs.

Figure 17 V^^N_NIL_1 post event analysis: VNI flow secure limits



There were multiple forecast LOR2 and LOR3 conditions in New South Wales in short-term and pre-dispatch PASA leading up to the morning of 15 June 2022. In response to this, AEMO directed a significant number of generating units in New South Wales on 14 June 2022 and the morning of 15 June 2022. As a result, there were no actual LOR conditions during the morning of 15 June 2022. After 0640 hrs on 15 June 2022, the flows on VNI reduced sharply due to AEMO's actions to issue directions.

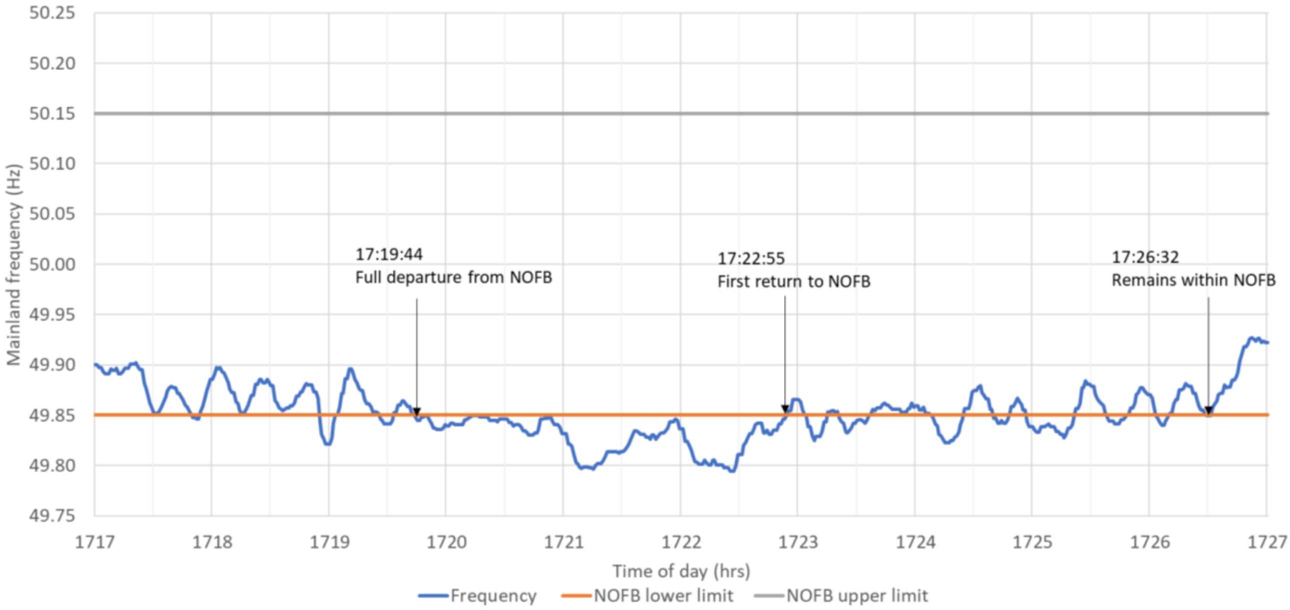
[27] Constraint equations have both operational and statistical margins. The ability of the constraint equation in NEMDE to maintain the flow on an interconnector or transmission element to within the true limit is dependent on a number of factors including modelling approximations, control limitations, and short-term variations in loads and generator outputs. AEMO determines the operating margins to be applied to constraint equations to manage these approximations and errors – the operating margin for the V^^N_NIL_1 constraint is 50 MW. The statistical margin of a constraint relates to the percentage of critical cases that have less restrictive limits than predicted by the limit equation and the percentage of critical cases that have more restrictive limits. The secure limit calculated through post event analysis does not include the operating margin or the statistical margin of the constraint.

6.3 Frequency performance

Based on its review of frequency performance during the period of 10 June to 25 June 2022[28], AEMO has not identified any clear breaches of the FOS. There were, however, periods where frequency behaviour was outside typical operating levels.

The most significant event occurred at around 1720 hrs on 17 June 2022, when a sustained low frequency event occurred. The minimum frequency reached during this time was 49.79 hertz (Hz) at 1721 hrs. The NEM mainland frequency trace shown in Figure 18 was sourced from a network phasor measurement unit (PMU) in Sydney, however no significant difference between measurements in other mainland regions was apparent.

Figure 18 Mainland system frequency on 17 June 2022



NOFB: normal operating frequency band.

In Table A.2 of the FOS[29], the following relevant requirements are set out:

Except as a result of a contingency event or a load event, system frequency:

a) *shall be maintained within the applicable normal operating frequency excursion band, and*

b) *shall not be outside of the applicable normal operating frequency band for more than 5 minutes on any occasion and not for more than 1% of the time over any 30-day period.*

These requirements appear to have been met during the frequency event shown above. Assuming 17:19:44 as the start of the event[30], frequency never exceeded the normal operating frequency excursion band (49.75 Hz), and frequency did not remain outside the normal operating frequency band (49.85 Hz) for more than 5 minutes

[28] AEMO's quarterly frequency and time deviation monitoring report covering this period is published at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/ancillary-services/frequency-and-time-deviation-monitoring.

[29] AEMO notes that the AEMC Reliability Panel is currently conducting a review of the FOS, which provides an opportunity for further consideration of FOS requirements (https://www.aemc.gov.au/sites/default/files/2020-01/Frequency%20operating%20standard%20-%20effective%201%20January%202020%20-%20TYPO%20corrected%2019DEC2019.PDF).

[30] 17:18:55 could also possibly be treated as the start of the event, however frequency quickly returned to within the NOFB at this point and remained there until 17:19:44, where it departed and remained outside the NOFB. In any case, the same conclusions are met with either starting point.

continuously as frequency returns within the NOFB 191 seconds later at 17:22:55. However, it is clear that frequency did not return and then remain within the NOFB, with a number of short excursions until approximately 17:26:32, which is 408 seconds overall (almost 7 minutes) after the start of the event. Therefore, while this event did not technically exceed FOS limits, it appears inconsistent with the intent of the FOS[31] and warranted further investigation.

The key causes of this low frequency event appear to be:

- A significant increase in NEM demand, and demand forecasts being lower than actual demand during the period of the frequency event.
- A shortage of generation available to provide frequency response and in particular regulation services (note Section 5.1 on general availability of generation).
- The frequency event not being deep enough to trigger much of the available contingency frequency control ancillary services (FCAS) response employing switching controllers.

AEMO has not found any evidence of a contingency event (such as a generator or transmission line trip) during the relevant time period.

Figure 19 shows the change in demand from 1700 hrs to 1735 hrs on 17 June. It is clear that at this time there was a long (but steady) increase in demand. For example, total system demand increased by approximately 900 MW over the 15 minutes between 1715 hrs and 1730 hrs, when the low frequency event occurred. A significant contributor to this increase in grid demand was the evening ramp down of solar generation. Rapidly increasing demand presents a challenge for frequency control, as any under-forecasting or delay in generation ramping will manifest as low frequency. Indeed, it appears that the demand forecasts under-estimated the ramp up in demand, as shown in Figure 20.

[31] AEMO notes that the AEMC Reliability Panel is currently conducting a review of the FOS, which provides an opportunity for further consideration of FOS requirements (https://www.aemc.gov.au/sites/default/files/2020-01/Frequency%20operating%20standard%20-%20effective%201%20January%202020%20-%20TYPO%20corrected%2019DEC2019.PDF).

Figure 19 5-minute demand recorded on 17 June 2022

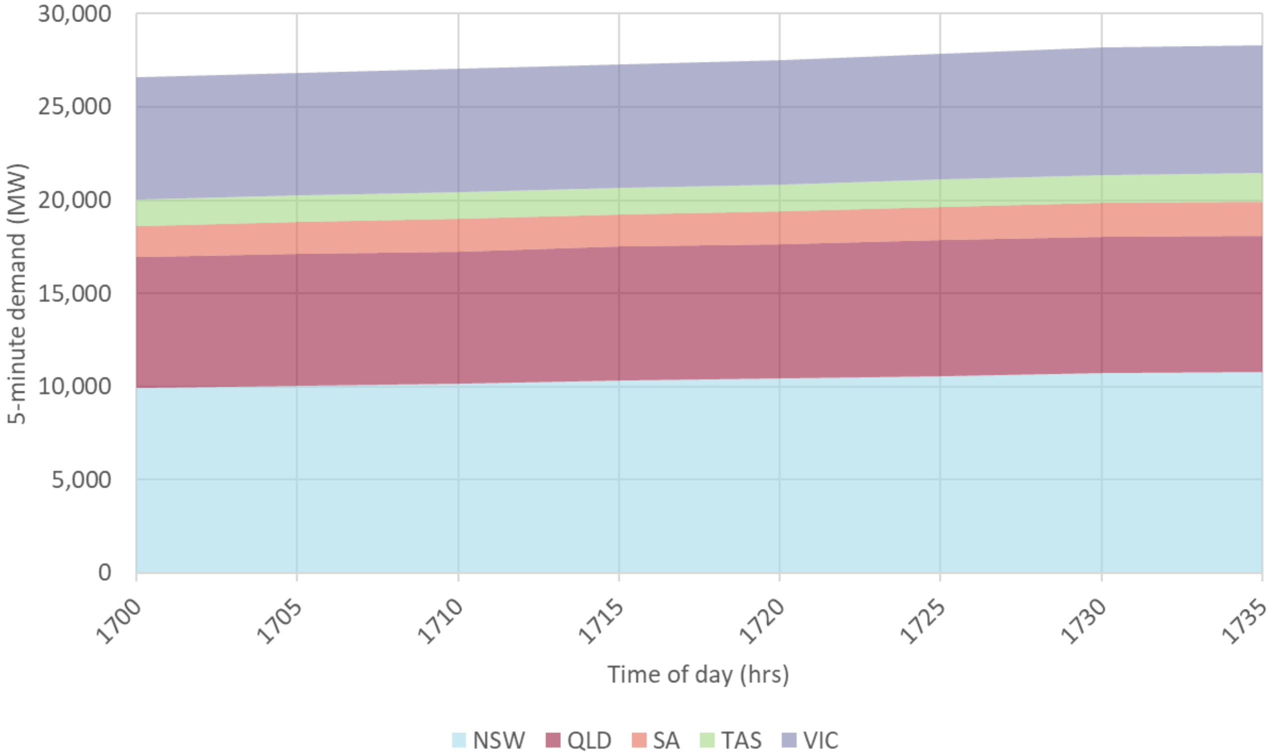
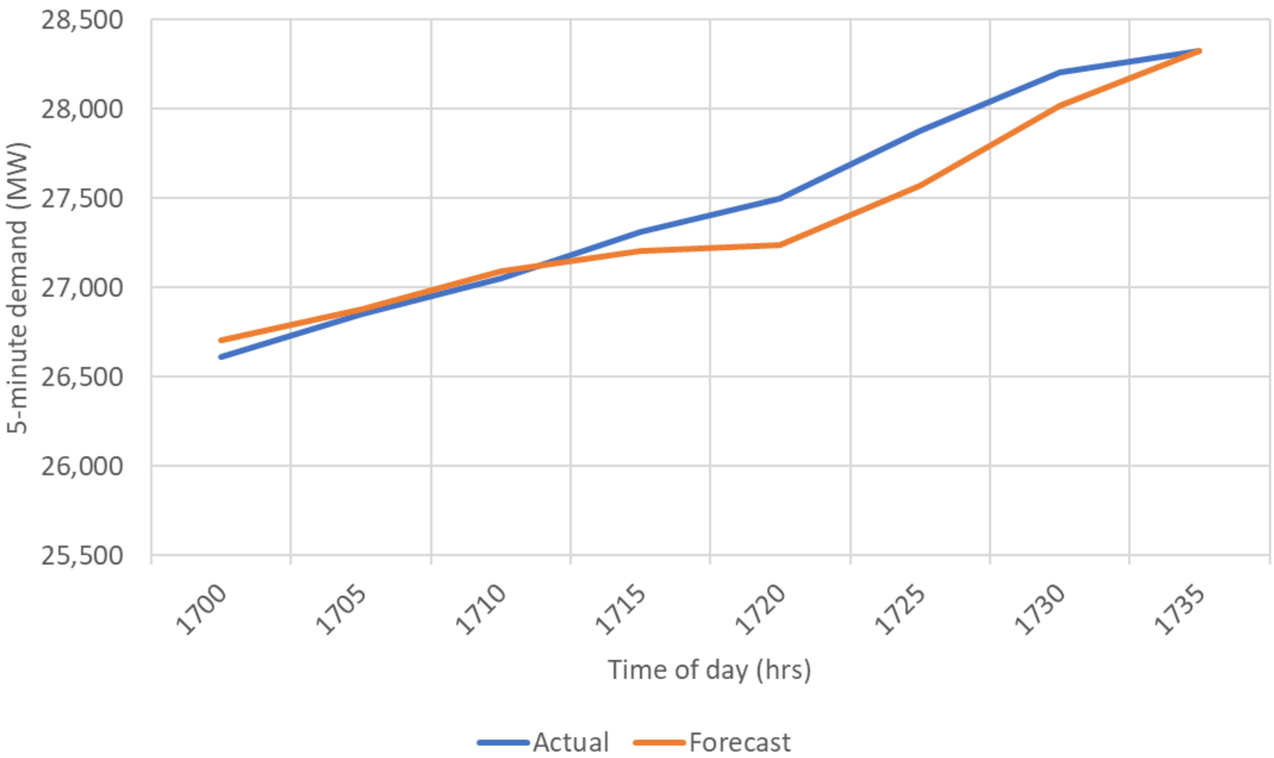


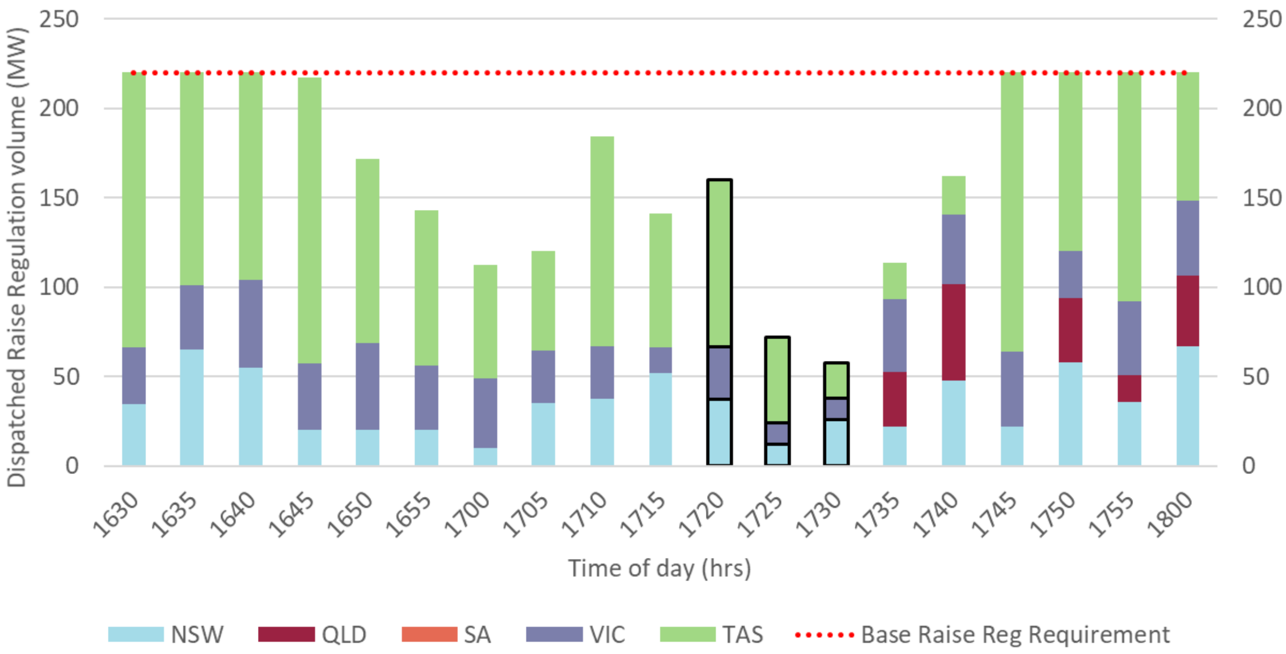
Figure 20 5-minute forecast system vs actual demand on 17 June 2022



As mentioned above, a contributing factor to the prolonged low frequency event was a lack of regulation FCAS, with raise regulation being relevant for low frequency. AEMO normally dispatches at least 220 MW of raise regulation FCAS, but this amount was not available for dispatch during the frequency event, resulting in violating regulation constraints and as little as 58 MW dispatched during the TI ending 1730 hrs.

As shown in Figure 21, resources adequate for meeting the normal 220 MW minimum were not re-established until the 1745 hrs trading interval. With only 60 MW to 160 MW available during the frequency event, AEMO's automatic generation control system did not have the resources to provide as much of an influence on frequency restoration as it usually would. AEMO will be further investigating the causes of the inadequate available volumes of regulation FCAS during this period, but it appears likely to be primarily related to lack of generator availability.

Figure 21 Raise Regulation FCAS dispatch on 17 June 2022



AEMO is also conducting an FCAS performance assessment and is in the process of acquiring and analysing FCAS recorder data from facilities enabled for contingency FCAS. The following are preliminary observations from this analysis process:

- A significant portion of the facilities enabled at the time employ switching controllers (approximately 20%, 30%, and 50% in fast, slow and delayed raise contingency FCAS respectively). Switching controllers in the mainland are allocated trigger points between 49.8 Hz and 49.6 Hz. As the frequency only just reached the very upper bound of this range, most of the switching controllers would not have been triggered.
- Initial analysis points to a significant primary frequency response across many facilities; indeed without primary frequency response this is likely to have been a significantly larger frequency event.
- A few facilities may have under-delivered FCAS, or not delivered any frequency response. AEMO is investigating these matters and will take further action where appropriate according to its usual FCAS compliance procedures.

7 Market suspension

7.1 Market operation before suspension

As described in Section 2.1.4, commencement of the APP in Queensland coincided with reductions in offered generation availability leading to actual and forecast LOR conditions, necessitating AEMO directions for reliability. These reductions in availability also led to uncapped dispatch prices rising to very high levels in both Queensland and other NEM regions. These prices were capped at the APC ($300/MWh) in Queensland, while in other mainland regions the “price scaling” provisions of NER 3.14.2 frequently operated to cap spot prices at levels below $300/MWh. However, the high underlying uncapped dispatch prices continued to drive cumulative prices upward in all regions, with the CPT being breached in New South Wales, South Australia and Victoria on 13 June 2022.

With all mainland regions in APPs, further reductions in offered generation availability were observed across the NEM, leading to more widespread LOR conditions (Section 5.2) and increasingly extensive directions being required to maintain system reliability (Section 5.3). Underlying uncapped dispatch prices rose to extreme levels in many trading intervals. Between commencement of APP in Queensland on 12 June and suspension of the spot market on 15 June, around 70% of uncapped trading interval prices in Queensland and New South Wales exceeded $10,000/MWh, and around 30% in South Australia and Victoria. With directions active, as well as RERT activation in some periods to maintain system reliability (Section 5.4), AEMO used intervention pricing, a requirement under the NER[32] which seeks to calculate the dispatch prices that would have eventuated in the absence of intervention, to set the uncapped prices for all regions. These are commonly referred to as “what-if” prices. However, a number of issues, discussed below, made it impractical to determine intervention prices as the event continued and the number of directions increased.

The reduced level of market generation offers following APP commencement meant that in many intervals the “what-if” dispatch prices calculated under this methodology reached the market price cap of $15,100/MWh, occurring in 56% of intervals for New South Wales between commencement of the first APP and suspension of the spot market. This resulted either because load shedding would have been required in the absence of reliability directions or RERT activation, or because nearly all generation offered as available would have been dispatched into its highest price bands.

As a result, as shown in Figure 2 in Section 2.2, cumulative prices in all regions except Tasmania continued to rise steeply, exceeding $8 million in New South Wales and $9.7 million in Queensland by the time of market suspension, and reaching around $4 million in South Australia and $4.6 million in Victoria. As long as the dynamic of reduced market-offered generation volume requiring AEMO directions to run continued, there was no prospect of uncapped dispatch prices falling and cumulative prices returning to levels below the CPT.

As outlined in Section 5.3, levels of direction being undertaken during this period covered over 3.5 GW of generation on 13 June and 4.7 GW on 14 June and over 30 participant-specific direction notices per day. The process of formulating these directions was a largely manual one undertaken by control room staff supported by AEMO operational planning resources, guided by a range of information sources including PASA reserve projections, market pre-dispatch forecasts, and information on generator capabilities and limitations obtained

[32] NER clause 3.9.3

through direct contact with market participants. Physical implementation of directions and market dispatch itself continued to rely on use of market systems and NEMDE, being effected through volumetric direction constraints entered by control room staff and submission of participant offers reflecting the availability directions issued by AEMO.

An additional and emerging complication of market operation in this period was that NEMDE could not find a feasible dispatch solution in some intervals without breaching one or more constraints – known as "over-constrained dispatch" (OCD). Compliance with NER rules 3.8 and 3.9 (central dispatch and pricing) requires that instances of OCD in dispatch must be resolved to establish a dispatch price, either through an automated "constraint relaxation re-run" procedure in NEMDE itself[33], or if that fails through offline manual resolution of conflicting constraints.

Normally, AEMO may need to establish dispatch prices through manual resolution of OCD in one or two intervals per year. In the 12 months prior to the June 2022 events, no manual resolution had been required. Due in part to the number and volume of reliability directions following commencement of APPs and the need for these directions to be formulated via essentially manual processes, and in part to the low reserve margins applying over this period, the number of unresolved OCD intervals requiring manual resolution reached around 200 in three days. Manual resolution of this number of constraints was not feasible, and consequently it was not possible to reliably establish a dispatch price for these intervals.

In practice, the inability to determine dispatch prices in NEMDE had little effect on spot prices because they would have been above the APC. However, as required by the NER, the uncapped prices had to be used in the calculation of the cumulative price. Additionally, the 'what-if' run is used for the determination of changes in dispatch outcomes due to directions. These two issues led AEMO to determine it was not practical to operate central dispatch and determine spot prices in accordance with NER 3.8 and 3.9.

A further issue that emerged in this period was the effect of administered pricing in mainland regions, specifically Victoria, on flows across the non-regulated Basslink interconnector. Tasmania's cumulative price remained below the CPT and the non-regulated status of Basslink meant that price scaling did not operate to limit Tasmanian spot prices when energy flows were northward into the price-capped Victorian region. This meant that large negative settlement residues could accrue on northward Basslink flows if uncapped dispatch prices in Tasmania reached very high levels while Basslink was exporting to the mainland. This occurred for several hours on the morning of 14 June, following which the operator of Basslink made the interconnector unavailable for northward flows when the APC (or associated price scaling) was limiting the higher underlying Victorian spot price to a level below the Tasmanian spot price.

The spot market in Tasmania was not subject to the APC during this period. However, many of the issues occurring in other regions affected the ability to operate the market in Tasmania. In particular, the spot price in Tasmania was being calculated using the 'what-if' price and difficulties with OCD had the potential to impact Tasmanian spot prices in the same way as other regions.

[33] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Congestion-Information/2016/Over-Constrained-Dispatch-Rerun-Process.pdf.

7.2 Declaration of market suspension

As described above, operation of the spot market was severely impacted by the circumstances arising under administered pricing.

The underlying drivers of some generators' reduced market availability, linked to capped spot prices and high underlying costs, appeared unlikely to be resolved quickly. Critical energy shortages at a number of coal- and gas-fired generators, alongside additional directions for pumped hydro to ensure capacity was available for extended periods of peak demand, further complicated the formulation of directions. As the cumulative price in all mainland regions continued to rise due to extremely high underlying dispatch prices (shown in Figure 2 in Section 2.2), there was no near-term prospect of exit from administered pricing.

Important features of the wider market processes such as PASA and pre-dispatch projections, which are integral to participants making well-informed market offers reflecting constraints such as limited fuel or water availability, and to AEMO in assessing reserves and reliability, were compromised by the extent of directions required and the fact these could not all be adequately represented in these projections well ahead of dispatch time. This in turn increased the level and complexity of directions required, reinforcing the original problem.

In essence dispatch was moving from being a market-based process – with directions only where needed to address specific issues – to a centralised volumetric scheduling exercise with market systems being increasingly used to implement this scheduling rather than determining least-cost economic dispatch and associated spot market prices as contemplated in the NER.

The extent of:

- ongoing reductions in market offer volumes,
- LOR conditions and forecasts triggering the need for widespread reliability directions,
- essentially manual processes and interventions required to formulate and implement these multiple and ongoing directions and affect them through market systems,
- unresolved OCD intervals caused by conflicting constraints in which a dispatch price could not be calculated in accordance with the NER, and
- extremely high underlying dispatch prices with no obvious prospect of cumulative prices returning to levels below the CPT allowing exit from administered pricing

all led AEMO to conclude that the spot market was becoming increasingly challenging to operate in accordance with the NER and in important respects it was no longer possible to do so.

AEMO cannot, and did not, suspend the spot market solely because underlying prices had reached the market price cap, or due to the APC or individual market interventions. However, NER clause 3.14.3(a) contemplates that AEMO may suspend the spot market if it determines that it has become impossible to operate in accordance with the rules.

AEMO's system operating procedure SO_OP_3706 Market Suspension and Systems Failure[34] provides guidance on thresholds for suspending the spot market. The procedure indicates the threshold will be met if it is necessary to dispatch generation, load or market network services using manual dispatch instructions with a cumulative

[34] See section 6.2 of the procedure. AEMO's public system operating procedures are available at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/power-system-operation/power-system-operating-procedures.

effect on at least 20% of the predicted regional load, but also confirms that AEMO can also determine that spot market operation in accordance with the rules has become impossible in any other circumstances. Although the directions issued by AEMO on 13 June and 14 June 2022 did not all require manual dispatch instructions as such, it is worth noting that the level of manually-implemented directions impacted 3.5 GW and 4.7 GW of supply on 13 June and 14 June respectively in the combined Queensland and New South Wales regions, compared with combined average June load of around 15 GW.

In all the circumstances at the time, AEMO concluded that it was necessary to suspend the spot market because it had become impossible to operate in accordance with the NER, and declared the suspension for all regions with effect from the trading interval ending 1405 hrs on 15 June 2022 (see MN 97705 issued at 1401 hrs).

7.3 Pricing during market suspension and market impacts

NER clause 3.14.5(b) requires that if AEMO determines it is not practical to operate central dispatch and determine prices in accordance with NER 3.8 and 3.9, then AEMO must set spot prices and ancillary service prices in suspended regions using the current MSPS. The MSPS is updated and published weekly and 14 days in advance, in accordance with NER clause 3.14.5(e) and AEMO's market suspension pricing methodology[35].

A key factor in AEMO's decision to suspend the spot market was the impossibility of continuing to operate central dispatch and determine prices in accordance with NER 3.8 and 3.9, for reasons set out in the previous two sections of this report. Consequently, AEMO set spot prices and ancillary service prices from the commencement of market suspension using the then-current MSPS.

Similar price scaling to that used for APP also applies to the MSPS (refer NER clause 3.14.5(f))[36], with the intent of avoiding the accumulation of significant negative inter-regional settlement residues where energy flows across regulated interconnectors towards a region or regions with MSPS pricing. The price scaling design uses either the cleared interconnector flow or the "what-if" interconnector flow if intervention pricing is being used. Under the conditions leading up to market suspension, the high levels of directions resulted in a large difference between the physical and "what-if" dispatch outcomes and the results were unusable. The rules also restrict application of price scaling to regulated interconnectors (that is, excluding Basslink). AEMO will review these aspects of price scaling to establish whether alternative designs or policy considerations are appropriate.

7.4 Resumption of the spot market

Section 5.3 details how AEMO continued to manage market dispatch through the period of suspension using availability directions based on a rolling 24-hour lookahead and control of directed generation dispatch through NEMDE constraints.

Return of generating units from outage and improved visibility of availability and energy limitations allowed more effective scheduling and direction of generation to meet demand.

With central dispatch no longer determining spot market or dispatch prices under NER 3.9, prices from the MSPS also became the basis for cumulative price calculation. As these schedule prices are capped at $300/MWh in

[35] See AEMO Guide to Market Suspension in the NEM – Pricing during Market Suspension at https://aemo.com.au/en/energy-systems/electricity/emergency-management/guide-to-market-suspension-in-the-nem.

[36] The price scaling principle applies under the NER to the market price cap and floor, the administered price cap and floor, and MSPS prices.

accordance with the Market Suspension Pricing Methodology, regional cumulative prices stabilised and then commenced declining as extreme prices more than one week old progressively dropped out of the rolling cumulative price determination. South Australia's administered price period ended at 0400 hrs on 22 June, and APPs in the other mainland regions ended at 0400 hrs on 23 June 2022.

During this period, AEMO developed assessment criteria and a staged process for resumption of normal spot market operation. These comprised:

- Assessment of recent dispatch and pre-dispatch solutions to determine if pricing via NEMDE would operate effectively, in particular that any incidence of unresolved OCD intervals was at manageable levels. This would enable resumption of market-based dispatch and pricing while still operating under suspension.
- Following the resumption of dispatch pricing, dispatch and pricing outcomes would be monitored over a period of at least 24 hours, with a decision to end the suspension to be made based on satisfaction of the following three criteria:
  – Market-based dispatch and pricing would continue to operate effectively with manageable incidence of any unresolved OCD intervals requiring manual intervention.
  – The ongoing volume and complexity of directions falling to a level that could be reasonably managed.
  – Confidence that if market suspension were lifted then the conditions that led to suspension would be unlikely to recur within 24 hours, in particular reserve outlooks remaining manageable.

AEMO briefed stakeholders on these criteria. With all mainland regions' APPs ended by 0400 hrs on 23 June and parallel runs for the preceding 24 hours having indicated that market-based dispatch pricing could operate effectively, NEMDE dispatch prices replaced use of the MSPS from trading interval ending (TI) 0405 hrs on 23 June 2022.

Market dispatch price outcomes, direction levels, and reserve outlooks met AEMO's criteria in the 24 hours following resumption of market-based pricing, with the exception of a software issue described below in relation to published ancillary service prices, which was rectified on 23 June. Accordingly, at around 1000 hrs on 24 June (MN 99369) AEMO notified market participants that the spot market suspension would formally end in all NEM regions from 1400 hrs that day[37].

Manifestly incorrect inputs and replacement of ancillary service prices on 23 June 2022

Shortly after recommencement of market-based dispatch pricing on 23 June, AEMO became aware that the regional prices ("RRP") for all market ancillary services (FCAS) were being published via market systems with zero values, although NEMDE itself was correctly determining ancillary service prices, which were also being published as the "raw output price" (ROP) for each service. This issue was later found to be the result of a software issue, which manifested while the suspension condition remained in place but the MSPS was no longer the source for published FCAS prices. The ROP is the price before any modifications (such as intervention pricing, price caps or scaling). For the intervals in question on the morning of 23 June, the APP had ended, as had the MSPS, therefore there were no modifications between ROP and RRP. However, the application that reads the ROP values from the NEMDE output and writes them to the market database as RRP did not work as

[37] This 4-hour notice of resumption exceeded the minimum notice periods for resumption of the spot market under AEMO's power system operating procedure SO_OP_3706 – Market Suspension and Systems Failure

intended where the suspension condition remained in place but the prices came from the dispatch pricing regime rather than the MSPS. The issue did not affect published energy spot prices.

AEMO informed the market at 0711 hrs (MN 99063) that the published FCAS prices were incorrect, and AEMO was urgently investigating the problem. While the cause remained under investigation, AEMO was also seeking a way in which the published “RRP” regional FCAS prices could be substituted by the ROP prices that were correctly determined by NEMDE. AEMO was also concerned that if FCAS prices became more volatile but ancillary service prices were zero, FCAS offers could start to be withdrawn, leading to potential system security issues.

By 0830 hrs, AEMO had identified the cause of the issue as an underlying software setup error and was working on a temporary solution to effectively overwrite the FCAS RRP values with the ROP. Under NER clause 3.9.2B, AEMO may correct already-published prices resulting from a “manifestly incorrect input” (MII), but only within 30 minutes of their publication. An ‘input’ is defined in 3.9.2B(a) as ‘*any value that is used by the dispatch algorithm including … software setup*’. Relying on this definition, AEMO issued MN 99065 at 0830 hrs, advising the market that MIIs were currently applying to the published FCAS prices, and they would be substituted with the published ROPs from at least the trading interval ending at 0805 hrs. An automated solution to perform this substitution was implemented from the trading interval ending 0905 hrs. AEMO again confirmed in MN 99070, published at 1314 hrs, that the ROP values would be substituted for all FCAS prices between the trading intervals ending at 0805 hrs and 0900 hrs. This was a manual process, which was subsequently completed and confirmed by MN 99457 issued on 24 June.

Noting that the correct ancillary service prices had in fact been determined by the dispatch algorithm (as ROP), as required by NER clause 3.9.2A(a), AEMO continued to consider whether the RRP FCAS prices published between 0400 hrs and 0800 hrs on 23 June could or should also be substituted. AEMO later concluded that there was no basis in the NER to do so, and confirmed this at 1458 hrs in MN 99093.

Later on 23 June, AEMO identified, tested and implemented a permanent fix for the software error that affected the publication of FCAS prices on 23 June, such that a similar issue is unlikely to recur.

AEMO notes that NER clause 3.9.2B contemplates that trading intervals affected by a MII will be identified by automated procedures published by AEMO, and that the replacement prices for affected intervals should be the corresponding prices for the last ‘correct’ interval. In this incident:

- The MII in this incident was not (and could not have been) detected by the automated procedures, but AEMO nevertheless considered it prudent to act on the issue by manually declaring a MII.
- The last ‘correct’ interval price for each FCAS service would have been (depending on interpretation) either zero or an MSPS price, neither of which was appropriate, in particular given that a correct dispatch price was available and visible to market participants.

AEMO therefore concludes that it did not follow the processes set out in clause 3.9.2B, however, its MII determination and consequent actions were consistent with the principles and objectives expressed in that clause.

8 Conclusions

This report has outlined the NEM power system operating conditions and incidents and market events between 10 June and 24 June 2022, including multiple market interventions to maintain reliable supply, the NEM-wide market suspension on 15 June 2022, and resumption on 24 June 2022. It is intended to meet a number of NER reporting requirements in relation to the intervention events (specifically directions), market suspension and power system operating incidents.

AEMO has concluded that:

1. The confluence of high commodity prices, domestic gas market and subsequently NEM price caps, planned and unplanned outages of scheduled generating plant, low output from semi-scheduled generation, and high winter demand conditions led to unprecedented challenges operating the NEM.
2. On 13 June 2022 from 0630 hrs, the active power transfer on QNI exceeded the actual secure limit. AEMO had taken action to direct generation to increase output to resolve this issue, however as a result of the time it took for generation to ramp up and follow dispatch targets, the power system was not operating in a secure state for more than 30 minutes.
3. To a lesser extent and for a shorter time on 15 June 2022, the active power transfer on VNI exceeded the actual secure limit for two periods of less than 30 minutes. AEMO had taken action to direct generation to increase output in New South Wales to resolve this issue and the power system was returned to a secure operating state within 30 minutes.
4. The simultaneous suspension of all regional spot markets in the NEM from the trading interval ending at 1405 hrs on 15 June 2022 was necessary because operation in accordance with the rules had become impossible.
5. Despite some irregular frequency outcomes, the FOS was met throughout this period of events.
6. There were an unprecedented number of LOR conditions during this period. As described in Section 5.2, to manage this AEMO developed a set of criteria for issuing market notices which prioritised forecast and actual LOR2 and LOR3 conditions, for which AEMO anticipated a need to intervene in the market. On this basis, AEMO did not declare all LOR conditions during the period, but was able to meet the market notification requirements for potential interventions under NER clause 4.8.5A.
7. AEMO issued 483 direction-related participant notices during this period to maintain a reliable operating state. AEMO complied with NER clause 3.8.14 and followed its procedures in determining the appropriate mechanism to address the conditions of supply scarcity.
8. In these challenging circumstances, AEMO was satisfied overall with the timeliness and adequacy of participant responses and communication relating to AEMO directions, recognising the large number of directions for availability, the nature of the associated constraints, and in some cases rapidly changing plant limitations or operating conditions requiring additional manual steps or instructions.
9. AEMO's declaration of a manifestly incorrect input affecting a number of trading intervals on 23 June 2022 did not follow the applicable NER process, but was consistent with the objectives of the rules in the circumstances.
10. The strong collaboration between AEMO, the Australian Energy Market Commission (AEMC), Australian Energy Regulator (AER), generators, emergency reserve providers, network service providers and jurisdictions enabled this series of events to be effectively managed without involuntary customer load shedding. Supply reliability was maintained despite the acute energy and capacity limitations and market issues.

9 Recommendations and next steps

As a result of this investigation, AEMO has identified a number of issues and potential opportunities to improve processes with a view to enhancing the operation of the NEM and security of the NEM power system.

9.1 AEMO actions completed, underway or planned

- AEMO to prepare a plan for when regional cumulative prices reach the CPT to better enable the management of the transition to administered pricing.
- AEMO to identify tools and processes needed to cater for energy limitations.
- AEMO to continue actively engaging with the AEMC and industry with regard to reviews or rule change proposals relating to the APC, CPT and other market settings that influence the operation of the NEM[38]. AEMO is also conducting a review of gas market prices / parameters.
- AEMO is considering this series of events when developing the scope for the 2023 General Power System Risk Review.
- On 24 July 2022, AEMO completed an action to resolve a software error relating to FCAS pricing under market suspension conditions when normal dispatch pricing is in effect.
- AEMO to review processes used for projecting supply adequacy over the medium-term in light of this series of events. The review should identify processes, modelling and reporting that may assist for these types of circumstances, particularly when factors contributing to fuel constraints emerge.

9.2 Participant recommendations

- Participants ensure their submitted bids, PASA availability and energy limits reflect operating conditions and are updated regularly, consistent with NER requirements in both short-term and medium-term PASA timelines.
- Participants ensure that operator training continues to cover bidding, operational and communication requirements during rare modes of market operation, such as during APP and market suspension.

9.3 Next steps

AEMO will issue a supplementary report covering the financial reporting requirements specified in NER 3.14.3(c)-(d) and 3.14.4(f)-(g) when final details of those payments and recovery amounts are available. At this stage, AEMO has determined provisional market suspension compensation payments and recovery amounts under NER clauses 3.14.5A and 3.15.8A respectively, together with provisional compensation for participants directed to make energy available before the suspension commenced on 15 June 2022 under clause 3.15.7[39]. A number of

[38] On 1 July 2022, the AEMC received a rule change request from Alinta Energy to amend the National Electricity Rules to increase the APC from $300/MWh to $600/MWh in every NEM region. See https://www.aemc.gov.au/rule-changes/amending-administered-price-cap#:~:text=Rule%20Change%3A%20Pending&text=On%201%20July%202022%20the,initiated%20this%20rule%20change%20request.

[39] AEMO's "June 2022 Compensation Update" series, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-events-and-reports, will update the market on estimated compensation amounts and payment timing as information becomes available.

directed participants and market suspension compensation claimants have claimed additional compensation in accordance with the NER. These claims will be assessed by independent experts and are expected to be determined by the final routine revision statements for the period, in January 2023.

AEMO will also prepare a separate incident report under NER 4.8.15 in relation to oscillations that occurred in the South Australian network on 23 June 2022, which were unrelated to the operational challenges covered by this report.

A1. Sequence of key events

Table 7 outlines the key events that form part of the market suspension and other incidents that occurred in the period from 10 June 2022 to 24 June 2022.

Table 7 Sequence of key events 10 June 2022 to 24 June 2022

Date/time	Event	Description	Note
10/06/2022	Number of direction-related Participant notices issued on 10/06/2022 – 2 Capacity of generation in MW's directed to be made available and follow dispatch targets on 10/06/2022 – 260 MW* Cumulative MW capacity of generation under direction at 2359 hrs on 10/06/2022 - 0 MW		
0830 - 0900	Actual LOR1 condition NSW region	The capacity reserve requirement is 1400 MW The minimum capacity reserve available is 1267 MW	Market Notice (MN) 96902 and 96913 – First actual LOR condition during this incident
1800 - 1900	Actual LOR2 condition QLD region*	The capacity reserve requirement is 524 MW The minimum capacity reserve available is 311 MW	MN 96921 and 96927
1900 - 2000	Actual LOR1 condition QLD region	The capacity reserve requirement is 961 MW The minimum capacity reserve available is 888 MW	MN 96928 and 96929
1845 - 1900	Direction to maintain a reliable Operating State -QLD region	Direction issued to Origin Energy Limited – Mt Stuart Unit 1 and Unit 2 at 1845 hrs 10/06/2022 – each unit to make 130 MW of additional capacity available (total 260 MW). The Direction was issued in response to an Actual LOR2*. See Section 5.2 for details of LOR conditions.	MN 96924 and 96925
11/06/2022	Number of direction related Participant notices issued on 11/06/2022 – 0 Capacity of generation in MW's directed to be made available and follow dispatch targets on 11/06/2022– 0 MW* Cumulative MW capacity of generation under direction at 2359 hrs on 11/06/2022 - 0 MW		
2229	Non-credible contingency - Tas region	Palmerston - St Marys tee Avoca 110 kV Line tripped and Mussleroe Wind Farm reduced output by approximately 135 MW.	9MW load was lost (2229 hrs - ongoing) MN 96964
12/06/2022	Number of direction related Participant notices issued on 12/06/2022 – 4 Capacity of generation in MW's directed to be made available and follow dispatch targets on 12/06/2022– 260 MW* Cumulative MW capacity of generation under direction at 2359 hrs on 12/06/2022 - 0 MW		
1855 - ongoing	Administered Price Period Declared in QLD Region	AEMO determined that the rolling sum of the uncapped spot prices for the QLD1 region over the previous 2016 trading intervals has exceeded the cumulative price threshold (CPT) of $1,359,100. As the CPT had been exceeded, an administered price cap (APC) of 300 $/MWh was applied to all trading intervals (during this administered price period). This APC was applied to spot prices and to all market ancillary service prices in the QLD1 region.	MN 96986
2030 - 2130	Actual LOR2 condition QLD region	The capacity reserve requirement is 487 MW The minimum capacity reserve available is 403 MW	MN 96992 and 96997
13/06/2022	Number of direction related Participant notices issued on 13/06/2022 – 37 Capacity of generation in MW's directed to be made available and follow dispatch targets on 13/06/2022– 3544 MW* Cumulative MW capacity of generation under direction at 2359 hrs on 13/06/2022 - 1892 MW		
0530 - 0800	Actual LOR1 condition QLD region	The forecast capacity reserve requirement is 914 MW The minimum capacity reserve available is 596 MW	Market Notice 97016 and 97040

Date/time	Event	Description	Note
Approx. 0628 - 0730	QNI 1-NSW1 not in a secure operating state	The flow on QNI into QLD went above the secure limit which violated the N^^Q_LS_VC_B13 constraint. QNI remained insecure for approximately 1 hour.	See Section 6.1 for details
0600 - 0800	Actual LOR2 condition QLD region	The capacity reserve requirement is 487 MW The minimum capacity reserve available is 190 MW	Market Notice 97019 and 97039
1730 - 1930	Forecast LOR3 condition QLD region	The maximum load (other than interruptible loads) forecast to be interrupted is 513 MW	Multiple Market Notices starting with 97035 and ending with 97139
1700 - 2030	First Actual LOR in NSW: Actual LOR1 condition NSW region	The capacity reserve requirement is 1430 MW The minimum capacity reserve available is 860 MW	MN 97132 and 97167
1730 - 2000	Actual LOR2 condition NSW region	The capacity reserve requirement is 730 MW The minimum capacity reserve available is 411 MW	Market Notice 97136 and 97166
1810 - 2000	First direction in NSW: Direction To Maintain A Reliable Operating State – NSW Region	Direction issued to Snowy Hydro Limited – Colongra Unit 1 & 2 & 3 at 0600 hrs make 178 MW of additional capacity available. The Direction was issued in response to an Actual LOR2	Market Notices 97143 and 97157
QLD1 = 0405 - ongoing **NSW1 = 1835 - ongoing** **SA1 = 2200 - ongoing** **VIC1 = 2205 - ongoing**	Administered price cap applied to additional regions: ADMINISTERED PRICE PERIOD DECLARED in QLD, NSW, SA and VIC.	AEMO determined that the rolling sum of the uncapped spot prices for the NSW, SA and VIC regions over the previous 2016 trading intervals has exceeded the cumulative price threshold (CPT) of $1,359,100. As the CPT had been exceeded, an administered price cap (APC) of 300 $/MWh was applied to all trading intervals (during this administered price period). The APC was now also applied to spot prices and to all market ancillary service prices in the NSW1, SA1 and VIC1 regions (in addition to QLD1).	Market Notices 97011, 97146, 97170 and 97171
14/06/2022	Number of direction related Participant notices issued on 14/06/2022 – 30 Capacity of generation in MW's directed to be made available and follow dispatch targets on 14/06/2022– 4868 MW* Cumulative MW capacity of generation under direction at 2359 hrs on 14/06/2022 - 5197 MW		
1120 - 1200 - Osborne PS **1120 - 1400 - Quarantine PS**	First Direction for system security: NEL 116 Direction for system security – SA region	Direction issued to Origin Energy Electricity Ltd - Osborne Power Station to remain synchronised at 1130 hrs and to Quarantine Power Station Unit 5 to synchronise at 1200 hrs follow dispatch targets.	MN 97245,97250,97258
1805 - 2105	300 MW of RERT dispatched in NSW	In response to a forecast LOR2 condition (MN 97365), AEMO instructed the dispatch of approx.. 300 MW of RERT at 1805 hrs which was forecast to apply until 2105 hrs.	MN 97376
15/06/2022	Number of direction related Participant notices issued on 15/06/2022 – 48 Capacity of generation in MW's directed to be made available and follow dispatch targets on 15/06/2022– 4945 MW* Cumulative MW capacity of generation under direction at 2359 hrs on 15/06/2022 - 7804 MW		
Approx. 0500 – 0530 and 0630 - 0700	VNI not in secure operating state	The flow on VNI into NSW went above the secure limit which violated the V^^N_NIL_1 constraint. VNI remained insecure for two periods of under 30 minutes.	Please see Section 6.2 of this report for more details

Date/time	Event	Description	Note
1405 - ongoing	Declaration of Electricity Market Suspension	AEMO declared the spot market suspended in New South Wales, Queensland, South Australia, Tasmania and Victoria and confirmed that prices would be determined by the MSPS. Suspension made under NER clause 3.14.3(a)(3) because it had become impossible to operate the spot market in accordance with the provisions of the Rules.	MN 97705 See Section 7.2 for details
1730 - 2330	489 MW of RERT dispatched in NSW	In response to a forecast LOR3 condition (MN 97776), AEMO instructed the dispatch of approx.. 489 MW of RERT at 1730 hrs which was forecast to apply until 2330 hrs.	MN 97793
1800 - 2330	51 MW of RERT dispatched in QLD	In response to forecast LOR2 and LOR3 conditions (LOR2 MN 97773) AEMO instructed the dispatch of approx. 51 MW of RERT at 1800 hrs which was forecast to apply until 2330 hrs.	MN 97801
16/06/2022	Number of direction related Participant notices issued on 16/06/2022 – 46 Capacity of generation in MW's directed to be made available and follow dispatch targets on 16/06/2022– 3849 MW* Cumulative MW capacity of generation under direction at 2359 hrs on 16/06/2022 - 7571 MW		
17/06/2022	Number of direction related Participant notices issued on 17/06/2022 – 110 Capacity of generation in MW's directed to be made available and follow dispatch targets on 17/06/2022– 2528 MW* Cumulative MW capacity of generation under direction at 2359 hrs on 17/06/2022 - 6452 MW		
	Peak number of direction related notices issued on 17/06/2022	Peak number of direction related participant notices issued on 17/06/2022, with AEMO issuing 110 direction related participant notices in this 24 hour period. (direction related participant notices being directions, cancellation of direction and update to direction notice)	
1722	Frequency event	NEM min frequency 49.79 Hz (remained below 49.85 Hz for 191 sec), RREG constraint violation Qld and SA were contributing 0 MW in RREG because they were fully loaded supplying to other regions Network Energy constraint applied to Qld gens to move back into trapezium.	See Section 6.3 for details
2000 – 18/06/2022 0410	463 MW of RERT dispatched in NSW	In response to a forecast LOR2 condition (MN 98272) AEMO instructed the dispatch of approx. 263 MW of RERT at 2000 hrs which was forecast to apply until 2330 hrs. The instructed dispatch was later increased by 200 MW of RERT which was forecast to apply until 0410 hrs on 18/06/2022.	MN 98386, 98426
18/06/2022	Number of direction related Participant notices issued on 18/06/2022 – 71 Capacity of generation in MW's directed to be made available and follow dispatch targets on 18/06/2022– 4565 MW* Cumulative MW capacity of generation under direction at 2359 hrs on 18/06/2022 - 6931 MW		
19/06/2022	Number of direction related Participant notices issued on 19/06/2022 – 16 Capacity of generation in MW's directed to be made available and follow dispatch targets on 19/06/2022– 2680 MW* Cumulative MW capacity of generation under direction at 2359 hrs on 19/06/2022 - 8111 MW		
20/06/2022	Number of direction related Participant notices issued on 20/06/2022 – 25 Capacity of generation in MW's directed to be made available and follow dispatch targets on 20/06/2022– 1426 MW* Cumulative MW capacity of generation under direction at 2359 hrs on 20/06/2022 - 9443 MW		
21/06/2022	Number of direction related Participant notices issued on 21/06/2022 – 30 Capacity of generation in MW's directed to be made available and follow dispatch targets on 21/06/2022– 1058 MW* Cumulative MW capacity of generation under direction at 2359 hrs on 21/06/2022 - 9673 MW		
22/06/2022	Number of direction related Participant notices issued on 22/06/2022 – 26		

Date/time	Event	Description	Note
	Capacity of generation in MW's directed to be made available and follow dispatch targets on 22/06/2022– 899 MW* Cumulative MW capacity of generation under direction at 2359 hrs on 22/06/2022 - 8174 MW		
0400	Administered price period ended in SA region	The administered price period declared for the SA region ended at 0400 hrs.	MN 98780
23/06/2022	Number of direction related Participant notices issued on 21/06/2022 – 38 (cancellation of directions) Capacity of generation in MW's directed to be made available and follow dispatch targets on 21/06/2022– 0 MW* Cumulative MW capacity of generation under direction at 2359 hrs on 21/06/2022 - 257 MW		
Approx. 0200 - 0600	Persistent voltage oscillations in SA	There were persistent voltage oscillations in the SA network which were unrelated to the circumstances surrounding this series of events. AEMO plans to prepare a separate incident report on this event.	
0400	Administered price period ended in NSW, QLD and VIC regions	The administered price period declared for these regions ended at 0400 hrs.	MN 99047, 99048 and 99049
0400 - 0800	Market Suspension – FCAS prices	AEMO had been publishing zero FCAS prices for all services in all regions of the NEM from 0400 hrs after reverting to dispatch pricing during the market suspension. AEMO determined that there is no basis on which the published ancillary service prices for TI 0405 to TI 0800 on 23 June 2022 can be substituted, and accordingly the published ancillary service prices for those TIs in all regions will stand.	MN 99063, 99065, 99070 and 99093
24/06/2022	-		
1000	Declaration of electricity market resumption	AEMO declared that the suspension of the spot market in New South Wales, Queensland, South Australia, Tasmania and Victoria is ended at 1400 hrs on 24 June 2022.	MN 99369

* Capacity of generation in MW directed to be made available and follow dispatch targets is the total of the MW capacity directed each day and is not adjusted for the same unit being directed multiple times in one 24-hour period nor does it account for any cancelled directions in the same period.

A2. Transmission network outage summary

Table 8 Transmission outages from 10 June to 24 June 2022

Region	Equipment out of service	Start date/time	End date/time	Recall	Impact to reserve
NSW	Lismore SVC	2/02/2022 1658 hrs	30/09/2022 1658 hrs	No recall	Reduces QNI capacity by 40 MW Directlink must flow South (QLD to NSW) depending on operating conditions
QLD	Woolooga – Palmwoods 810 275 kV line	5/04/2022 0715 hrs	22/06/2022 1810 hrs	336 hrs	Constrains around 500 – 600 MW during mid-morning to early afternoon (outside of peak periods)
QLD	Charters Towers- Millchester and Charters Towers- Clare South 66 kV lines	12/05/2022 1038 hrs	15/06/2022 1715 hrs	No recall	5 MW reduction in generation
QLD	Woree – Walkamin 8902 275 kV line	24/05/2022 0700 hrs	15/06/2022 1539 hrs	144 hrs	System strength constraints may limit generation but did not bind due to sufficient synchronous generation.
QLD	Nebo – Broadsound 8846 275 kV line	30/05/2022 0700 hrs	29/06/2022 1700 hrs	No recall	System strength constraints limit generation up to 36 MW at times.
QLD	Millmerran – Middle Ridge 9907 330 kV line	15/06/2022 0900 hrs	21/06/2022 1524 hrs	2 hrs	Voltage stability constraints on QNI did not bind
QLD	Charters Towers Bus 1 66 kV	16/06/2022 1030 hrs	26/07/2022 1630 hrs	No recall	5 MW reduction in generation
QLD	Wandoan South – Wandoan BESS	21/06/2022 0701 hrs	21/06/2022 1417 hrs	2 hrs	Wandoan BESS constrained to 0 MW (nominal 100 MW) but no LOR conditions at the time
Vic	South Morang - Dederang no.1 and 2 capacitors	1/03/2022 0531 hrs	31/10/2022 1730 hrs	No recall	Can limit transfer between NSW and VIC up to 100 MW
SA	Para No.2 SVC	4-Jan-22	1-Aug-23	No recall	Reduces SA to VIC Heywood interconnector transfer limit by 130 MW (from 550 MW to 420 MW)
TAS	Gordon C752 220 kV CB	16/06/2022 1300 hrs	16/06/2022 1911 hrs	30 mins	Constrains Gordon generation to < 250 MW, however, generator availability was < 250 MW during this period so no impact.

Table 9 Transmission outages that were cancelled (labelled UTP or withdrawn) from 10 June to 24 June 2022

Region	Equipment out of service	Start date/time	End date/time	Recall	Impact to reserve	Time outage was made UTP or withdrawn
NSW	Dapto-Kangaroo Valley TL 18	14/06/2022 0700 hrs	14/06/2022 1700 hrs	4 hrs	Reduces VNI capacity by 205 MW	13/06/2022 1452 hrs
NSW	Dapto-Kangaroo Valley TL 18	15/06/2022 0700 hrs	15/06/2022 1700 hrs	4 hrs	Reduces VNI capacity by 205 MW	14/06/2022 1236 hrs
NSW	Wagga-Yanco TL 994	15/06/2022 0700 hrs	15/06/2022 1700 hrs	2 hrs	Constrains Murraylink from SA to Vic	14/06/2022 1433 hrs

Region	Equipment out of service	Start date/time	End date/time	Recall	Impact to reserve	Time outage was made UTP or withdrawn
NSW	Bayswater-Regentville TL 31	15/06/2022 0730 hrs	15/06/2022 1700 hrs	2 hrs	Reduces QNI capacity by 120 MW	14/06/2022 1434 hrs
NSW	Lower Tumut-Canberra TL 07	15/06/2022 0800 hrs	15/06/2022 1700 hrs	18 mins	Constrains VNI by up to 75MW and constrains NSW-Snowy generation	14/06/2022 1403 hrs
NSW	Dapto-Kangaroo Valley TL 18	16/06/2022 0700 hrs	16/06/2022 1700 hrs	4 hrs	Reduces VNI capacity by 205 MW	15/06/2022 1144 hrs
NSW	Wagga-Yanco TL 994	16/06/2022 0700 hrs	16/06/2022 1700 hrs	2 hrs	Constrains Murraylink from SA to Vic	15/06/2022 1145 hrs
NSW	Bayswater-Sydney West TL 32	16/06/2022 0730 hrs	16/06/2022 1700 hrs	2 hrs	Reduces QNI capacity by 120 MW	15/06/2022 1146 hrs
NSW	Dapto-Kangaroo Valley TL 18	17/06/2022 0700 hrs	17/06/2022 1700 hrs	4 hrs	Reduces VNI capacity by 205 MW	16/06/2022 1011 hrs
NSW	Bayswater-Sydney West TL 32	17/06/2022 0730 hrs	17/06/2022 1700 hrs	2 hrs	Reduces QNI capacity by 120 MW	16/06/2022 1012 hrs
NSW	Wallerawang-Sydney South TL 76	18/06/2022 0600 hrs	18/06/2022 1800 hrs	2 hrs	Potentially constrains Bayswater, Liddell, Mt Piper and QNI and Directlink	17/06/2022 1303 hrs
NSW	Ingleburn-Sydney South TL 78	19/06/2022 0600 hrs	19/06/2022 1800 hrs	2 hrs	Potentially constrains Bayswater, Liddell, Mt Piper and QNI and Directlink	17/06/2022 1305 hrs
NSW	Stockdil-Canberra TL 3C	19/06/2022 0800 hrs	19/06/2022 1700 hrs	1 hr	Constrains NSW-Snowy generation	17/06/2022 1306 hrs
NSW	Dapto-Kangaroo Valley TL 18	20/06/2022 0600 hrs	25/06/2022 1600 hrs	4 hrs	Reduces VNI capacity by 205 MW	17/06/2022 1309 hrs
Vic	DDTS-SMTS 1 330 kV line	15/06/2022 0630 hrs	16/06/2022 1830 hrs	12 hrs	Restricts VNI (Vic import restricted approx. by ~ 700 MW)	14/06/2022 1313 hrs
Vic	Terang 1 220kV BUS	16/06/2022 0700 hrs	16/06/2022 1700 hrs	2 hrs	This outage causes TGTS to be in a single contingency from 220 kV. Any interruption of supply at TGTS has potential for an impact on the gas supply capacity within the Declared Transmission System (DTS) gas network in Victoria.	16/06/2022 0446 hrs
Vic	Heywood S East 1 275kV LINE	17/06/2022 0800 hrs	21/06/2022 1830 hrs	48 hrs	Restricts HIC~ 50 MW Vic-SA and 250 MW SA-Vic	15/06/2022 1415 hrs
Vic	Terang 1 220kV BUS	17/06/2022 0700 hrs	17/06/2022 1700 hrs	2 hrs	This outage causes TGTS to be in a single contingency from 220 kV. Any interruption of supply at TGTS has potential for an impact on the gas supply capacity within the DTS gas network in Victoria.	16/06/2022 1027 hrs
Vic	South Morang Rowville 3 500kV LINE	17/06/2022 0630 hrs	17/06/2022 1700 hrs	4 hrs	This outage has impact on Victorian Generation and interconnectors.	16/06/2022 1029 hrs

Region	Equipment out of service	Start date/time	End date/time	Recall	Impact to reserve	Time outage was made UTP or withdrawn
Vic	Ballart220-Berrybank 220kV LINE	20/06/2022 0700 hrs	20/06/2022 1730 hrs	2 hrs	This outage causes TGTS to be in a single contingency from 220 kV. Any interruption of supply at TGTS has potential for an impact on the gas supply capacity within the DTS gas network in Victoria.	19/06/2022 1838 hrs
Vic	Altona220 Laverton North 1 Gen Trans 220KV CB	20/06/2022 0830 hrs	23/06/2022 0900 hrs	26 hrs	Takes Laverton North 1 OOS. This is a generator requested outage. Outage withdrawn.	17/06/2022 1235 hrs
SA	South East – Heywood 1 275 kV line	18/06/2022 0800 hrs	24/06/2022 1130 hrs	no recall	Reduced SA to VIC Heywood interconnector transfer limit (no hard limit, but restriction from 550 MW to < -200 MW was observed in STPASA forecast). Outage withdrawn.	16/06/2022 0745 hrs