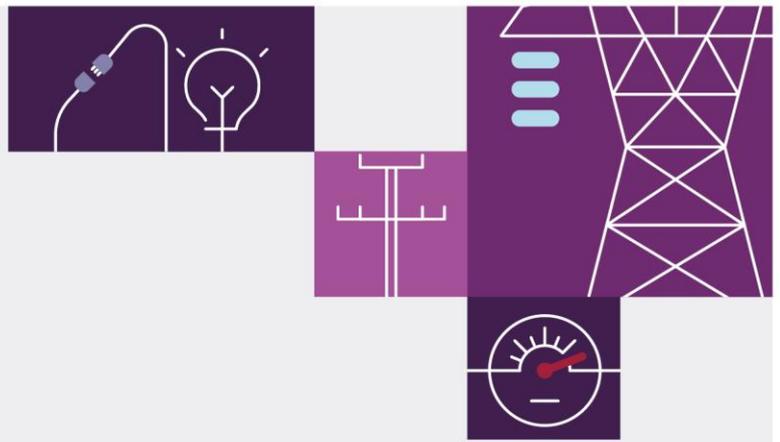


Quarterly Energy Dynamics Q2 2022

July 2022





Important notice

Purpose

AEMO has prepared this report to provide energy market participants and governments with information on the market dynamics, trends and outcomes during Q2 2022 (1 April to 30 June 2022). This quarterly report compares results for the quarter against other recent quarters, focusing on Q1 2022 and Q2 2021. Geographically, the report covers:

- The National Electricity Market (Queensland, New South Wales, the Australian Capital Territory, Victoria, South Australia and Tasmania).
- The Wholesale Electricity Market and domestic gas supply arrangements operating in Western Australia.
- The gas markets operating in Queensland, New South Wales, Victoria and South Australia.

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Version control

Version	Release date	Changes
1	29 July 2022	

Executive summary

East coast electricity and gas highlights

Prices rise to all-time highs with multiple market interventions required

- Wholesale spot prices in the National Electricity Market (NEM) and eastern Australian gas markets rose to unprecedented average levels in Q2 2022. The quarterly average NEM spot price of \$264 per megawatt-hour (MWh)¹ was more than double the previous high of \$130/MWh recorded in Q1 2019, and more than triple Q2 2021's average of \$85/MWh. Across the east coast gas markets, spot prices averaged \$28.40 per gigajoule (GJ), against a previous high of \$10.74/GJ in Q3 2021, and were up 246% on levels a year ago.
- Rising and volatile spot prices in electricity and gas markets triggered automatic application of administered price caps, commencing in the Victorian Declared Wholesale Gas Market (DWGM) from 30 May, and in the mainland NEM regions over 12-13 June. Separately, gas prices in the Short Term Trading Market (STTM) hubs of Sydney and Brisbane were also capped from 24 May to 7 June under the operation of Retailer of Last Resort (RoLR) provisions, after suspension of a trading participant retailer. Sydney STTM hub prices were also capped between 8 June and 14 June when high price thresholds were breached.
- As administered price capping commenced in the NEM, generation volumes offered into the spot market began to drop. Combined with a large number of prior outages, this led to shortfalls in actual and forecast reserves which triggered a range of interventions by AEMO to maintain power system reliability and security. 406 separate Lack of Reserve (LOR) conditions were declared by AEMO in Q2 2022, compared with 36 in Q1 2022 and 73 in Q2 2021. The scale of interventions needed to manage the extent of reserve shortfalls made operation of the market in accordance with the National Electricity Rules (NER) impossible and AEMO suspended operation of the NEM spot market in all regions between 15 June and 24 June, when full spot market operation recommenced.

International and local drivers underly wholesale gas and electricity price movements

- Key factors underlying the extraordinary rise in wholesale prices in Q2 included:
 - The impacts in local fuel markets of extremely high international prices for traded gas and thermal coal.
 - Reduced availability of coal-fired generation, due to scheduled maintenance as well as long- and short-duration forced outages, driving high levels of gas-fired generation, which both raised electricity prices and put pressure on local gas markets.
 - Physical fuel supply and hydrological constraints at a number of thermal and hydro generators which further limited their operational flexibility.
- East coast gas market prices reached parity with and even exceeded international liquefied natural gas (LNG) netback prices in May and June, as rising winter demand and aggregate gas supply limitations meant that local

¹ Wholesale electricity prices refer to the value of energy traded between participants in the NEM, and affect only one component of the retail energy bills that consumers pay. In addition to wholesale energy purchases, costs that retailers incur to supply electricity to consumers include transmission and distribution network charges, environmental costs and retail operating expenses. Uses the time-weighted average which is the simple average of regional wholesale electricity spot prices in the quarter. The Australian Energy Regulator (AER) reports the volume-weighted average spot price which is weighted against native demand.

markets effectively competed at the margin with gas demand for LNG export. Gas price rises were accelerated and made more volatile during periods of high gas-fired generation, as generators sought to purchase additional fuel supplies in the gas spot markets.

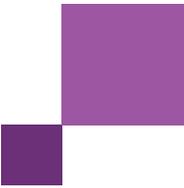
- These cost and availability factors caused very large shifts in generation offer prices in the NEM. Relative to Q2 2021, black coal-fired supply offered at prices under \$100/MWh reduced by over 2,700 megawatts (MW), over 20% of offered volumes, while for gas and hydro generators corresponding reductions were around 300 MW and 1,100 MW respectively. These shifts saw the incidence of NEM spot prices above \$100/MWh rise from only 14% of trading intervals in Q2 2021 to 86% of trading intervals in Q2 2022. The frequency of spot prices exceeding \$300/MWh rose from just 1% of intervals in Q2 2021 to 26% in Q2 2022.
- Forward electricity contract prices continued to rise strongly in response to spot market outcomes, with ASX electricity futures for Calendar Year (Cal) 2023 rising from \$49/MWh at the end of Q2 2021 and \$94/MWh at the end of Q1 2022 to average \$168/MWh by the end of the quarter.

Lower coal-fired output drives NEM supply shifts, while southern gas production increases

- Outages, bidding changes and fuel supply constraints saw black coal generation's average quarterly output down by 947 MW or 8.5% from Q2 2021 to its lowest Q2 output on record. Its share of NEM supply fell 4.8 percentage points to 43%. Gas-fired generation jumped in response to low coal-fired output and higher spot electricity prices, rising by an average of 472 MW or 27% on Q2 2021 to its highest Q2 average level since 2017. While seasonally lower than in Q1 2022, output from wind and grid-scale solar generation continued its significant annual growth, up by 664 MW or 21% on a year ago, driven by new capacity additions and commissioning, with the total NEM renewable supply share for Q2 2022 (including distributed photovoltaics [PV] and hydro) reaching 31.8%, up 3.7 percentage points on Q2 2021.
- NEM average operational demand grew by only 0.6% on Q2 2021, however a cold outbreak in late May and early June drove half-hourly operational demand in Queensland to a new Q2 record of 8,255 MW, and in Victoria to its highest Q2 level since 2011 at 8,158 MW, up by 492 MW (+6.4%) on Q2 2021.
- Gas demand rose slightly (+2 petajoules [PJ] or 0.5%) on Q2 2021, with significant increases in gas demand for power generation (+10 PJ) largely offset by lower industrial commercial and residential demands and a small drop in LNG export demand at Gladstone due to a processing train outage commencing in mid-June. Victorian gas production grew strongly (+17 PJ or 20%), with Longford achieving its highest Q2 production since 2017. Coupled with production decreases at Moomba (South Australia) and in Queensland, this saw Victorian gas supply to other states reach its highest level since Q4 2017, and a 7 PJ turnaround in net flows between Queensland and the southern regions, switching from 4 PJ south in Q2 2021 to 3 PJ northward in Q2 2022.

System management costs

- Costs for activation and dispatch of NEM Reliability and Emergency Reserve Trader (RERT) contracts during June, required on three occasions, were around \$86 million.
- System security direction costs in South Australia fell to \$6 million, their lowest level since Q2 2019.
- Participant compensation costs for losses incurred under administered pricing and market suspension and for operation under other AEMO directions in the NEM during June cannot yet be estimated, as claims are still being received and assessed.



Western Australia electricity and gas highlights

Balancing Price reaches four-year high

- The weighted average Balancing Price reached \$68/MWh this quarter, a four-year high and \$6/MWh (9%) above that of Q2 2021, despite average operational demand being similar, decreasing by 42 MW (2%).
- Increased balancing prices were driven by participant bidding behaviour, with a 33% decrease in volumes offered in the \$0 to \$50/MWh price band, and also a decrease in volumes offered at negative prices.

Coal-fired generation decreased while gas and renewables increased

- Coal-fired generation decreased by an average 117 MW (12%) compared to Q2 2021, particularly towards the end of the quarter due to a change in bidding behaviour, resulting in gas-fired generation overtaking coal to be the primary fuel towards the end of the quarter.
- Gas, solar and wind generation increased at all times of day, with distributed PV continuing to grow, increasing by 46 MW (28%) on average compared to Q2 2021. This increase was due to an estimated 386 MW (22%) of additional PV capacity installed in the South West Interconnected System (SWIS) since Q2 2021.
- Wind generation increased by an average of 79 MW (27%) in Q2 2022. This increase was mostly attributable to the effects of Cyclone Seroja in Q2 2021, with a 90% decrease in GIA (Generator Interim Access) Wind constraints compared to Q2 2021, falling from an average 40 MW to 4 MW.

Market events and AEMO reporting

The eastern Australian energy markets in Q2 2022 were significantly affected from late May onwards by price volatility and other market events triggering:

- The application of administered price caps, first in the gas markets and subsequently in regions of the NEM.
- Notices of threats to gas system security.
- Extensive NEM Lack of Reserve (LOR) forecasts.
- A range of market interventions by AEMO. Interventions in the NEM included numerous directions to market participants in order to maintain system reliability and security, activation of emergency reserves under the Reliability and Emergency Reserve Trader (RERT) arrangements, and culminated in suspension of the NEM spot market between 15 June and 24 June 2022.

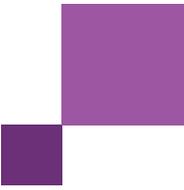
These episodes were the ultimate result of unprecedented wholesale price rises in the eastern Australian electricity and gas markets from early in the quarter, driven by a range of factors which are discussed in this report.

Consequent to its regulatory reporting obligations, AEMO has published or is currently preparing a series of detailed reports covering these market interventions and related events², as summarised below.

Report	Timeframe
NEM	
Reliability and Emergency Reserve Trader (RERT) 5 business day reports for 14/06/22, 15/06/22 and 17-18/06/22	21/06/22, 22/06/22 and 24/06/22
RERT 20 business day reports for 13/06/22, 14/06/22, 15/06/22 and 17-18/06/22	11/07/22
Lack of Reserve (LOR) quarterly report	End July 2022
RERT quarterly report	Mid-August 2022
Frequency performance reporting	Mid-August 2022
Reviewable operating incident report, incorporating directions and market suspension reporting (excluding compensation), covering the period 10 June 2022 to 24 June 2022	Mid-August 2022 (current target) Note: Compensation reporting will be covered in a subsequent report.
Gas markets	
Victorian Declared Wholesale Gas Market (DWGM) intervention reports	20/06/22, 1/07/22
Short Term Trading Market (STTM) contingency gas report	6/07/22
STTM – Events following the retail market participant suspension May/June	20/07/22, 26/7/22

This Quarterly Energy Dynamics (QED) report provides an overview of wholesale electricity and gas market outcomes and drivers across the entire quarter. Readers should refer to the published and forthcoming reports summarised above for further details of the specific interventions made by AEMO and the circumstances underlying them.

² AEMO, June 2022 series of events and reports: <https://aemo.com.au/newsroom/news-updates/june-2022-series-of-events-and-reports>



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1 NEM market dynamics

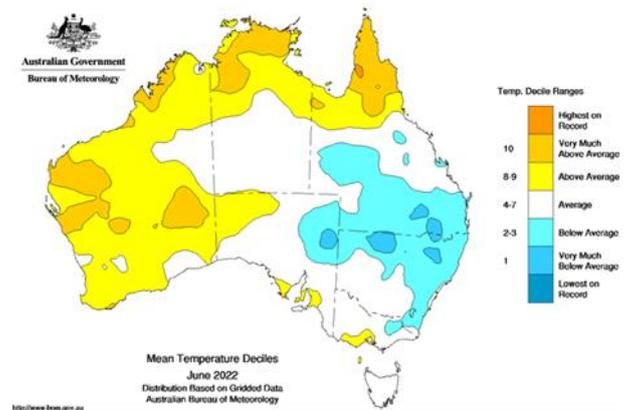
1.1 Electricity demand

1.1.1 Weather

During the quarter, the weather was dominated by exceptional rainfall in Queensland in May, followed by a very cold start to winter with many east coast cities experiencing their coldest start to June in decades.

Queensland experienced its wettest May since 1989, as well as its second highest May minimum temperatures³. This was abruptly followed by very cold weather in late May and early June, with some sites in Victoria experiencing their coldest May day on record. A series of cold fronts in early June over eastern Australia and extended as far as north Queensland, driving up heating demand across the NEM coinciding with record maximum demand in Queensland and spot prices rising (Figure 1).

Figure 1 Cold start to winter across east coast
June 2022 mean temperature deciles for Australia

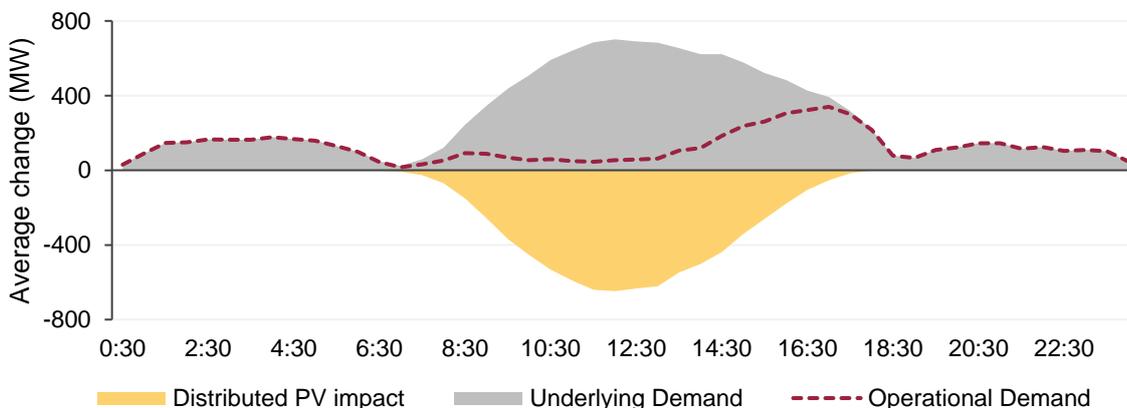


1.1.2 Demand outcomes

NEM quarterly average operational demand increased to 21,932 MW, 126 MW (+0.6%) higher than Q2 2021, driven by a 279 MW (+1.2%) increase in average underlying demand, offset by the lowest Q2 year-on-year (YoY) increase in average distributed PV output⁴ (+152 MW or +12%) in recent years (Figure 2).

Figure 2 Operational demand increase with lower PV growth and colder weather

Changes in average NEM demand components by time of day – Q2 2022 vs Q2 2021



³ Bureau of Meteorology (BoM) 2022, Queensland in May 2022, 5th wettest on record, warm nights: <http://www.bom.gov.au/climate/current/month/qld/archive/202205.summary.shtml>

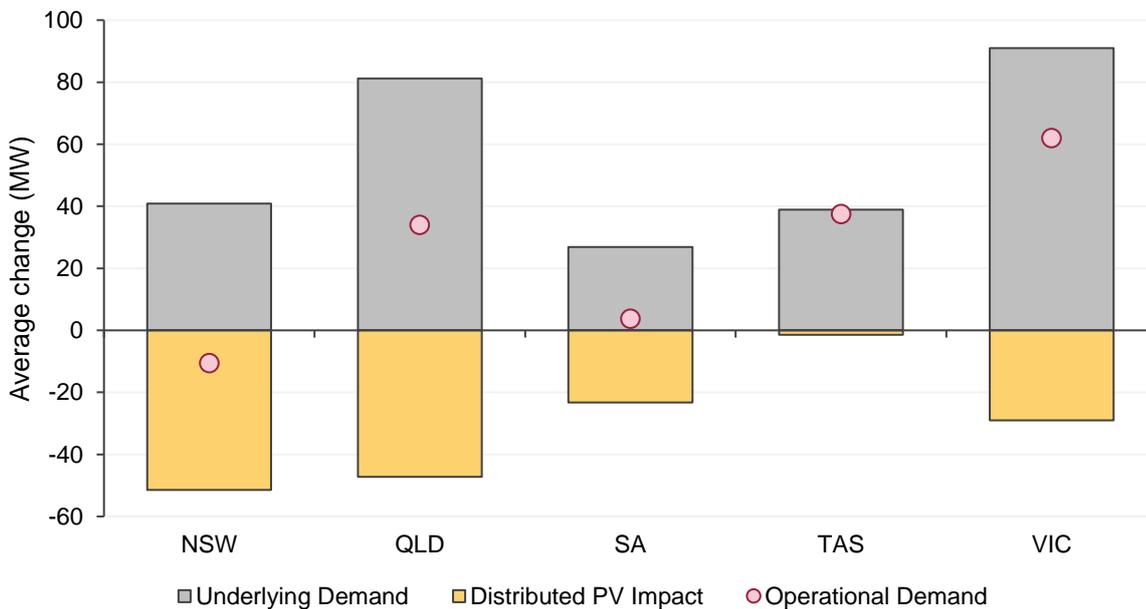
⁴ Increased distributed PV generation results in reduced operational demand because its production lowers supply required from the grid. Distributed PV production is based on AEMO estimates using Australian Solar Energy Forecasting System (ASEFS2).

While underlying demand⁵ increased across all states, changes by region varied within the quarter (Figure 3):

- Victoria recorded its highest Q2 average in recent years at 5,527 MW, a 91 MW increase (+1.7%) on Q2 2021, driven by colder weather from late May.
- In Queensland, despite large industrial demand falling by nearly 140 MW, underlying demand increased by 81 MW (+1.3%) to average 6,513 MW, its highest Q2 level in recent years, with warmer temperatures in May increasing cooling loads, followed by a cold start to June lifting heating requirements.
- Underlying demand increased in Tasmania by 39 MW or 3.1 % to 1,284 MW driven by increased industrial demand and heating load, and in South Australia by 1.7% to 1,586 MW. New South Wales at 8,478 MW saw minimal percentage growth.

Figure 3 Underlying demand increase across all regions due to cold start to winter

Change in demand components – Q2 2022 vs Q2 2021



Minimum and maximum demands

During Q2 2022, new Q2 operational demand minimums were set in both South Australia and Victoria:

- In South Australia, half-hourly operational demand fell to a new Q2 low of 346 MW on Sunday 3 April 2022 at 1300 hrs, 177 MW lower than the previous Q2 minimum set in 2021. A combination of sunny, mild conditions and low weekend underlying demand contributed to the record. During the interval, distributed PV provided 1,473 MW, meeting 77% of underlying demand.
- Victoria’s new Q2 minimum operational demand of 2,901 MW occurred at 1230 hrs on Easter Sunday 17 April 2022, and was 478 MW lower than the previous Q2 minimum set last year. Drivers were similar to those in South Australia, with low underlying demand on a public holiday contributing to the record. Distributed PV output during the interval supplied 38% of the region’s underlying demand.

⁵ Underlying demand is calculated by adding estimated production from distributed PV to operational demand, to yield an estimate of total electricity demand.

An extremely cold start to winter, with dry air from the south pushing into Queensland, resulted in elevated heating load during the first two weeks of June. On 9 June 2022, a new record Q2 maximum demand of 8,255 MW⁶ was set in Queensland at 1900 hrs, surpassing the previous high in 2018 by 83 MW (Figure 4). On the same day, Queensland also recorded its highest daytime intra-day demand swing for any quarter, with a difference of 3,741 MW⁷ between daytime minimum operational demand of 4,514 MW at 1300 hrs and maximum operational demand of 8,255 MW at 1900 hrs (Figure 5).

Figure 4 New high for Q2 maximum demand in Queensland

Q2 maximum operational demand - Queensland

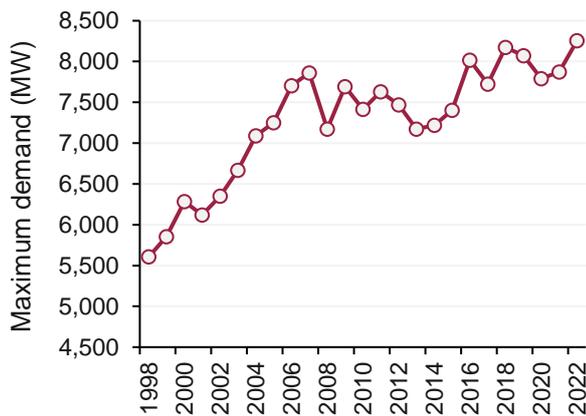
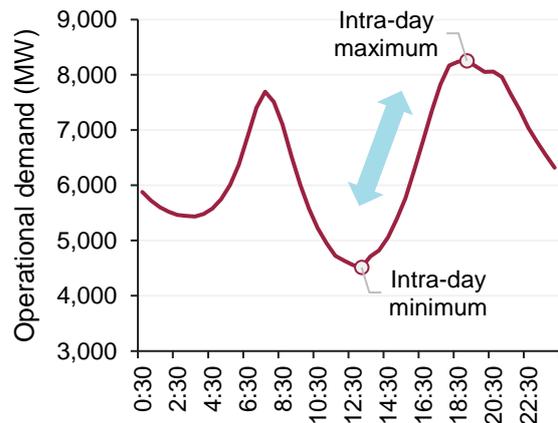


Figure 5 Record operational demand intra-day swing in Queensland

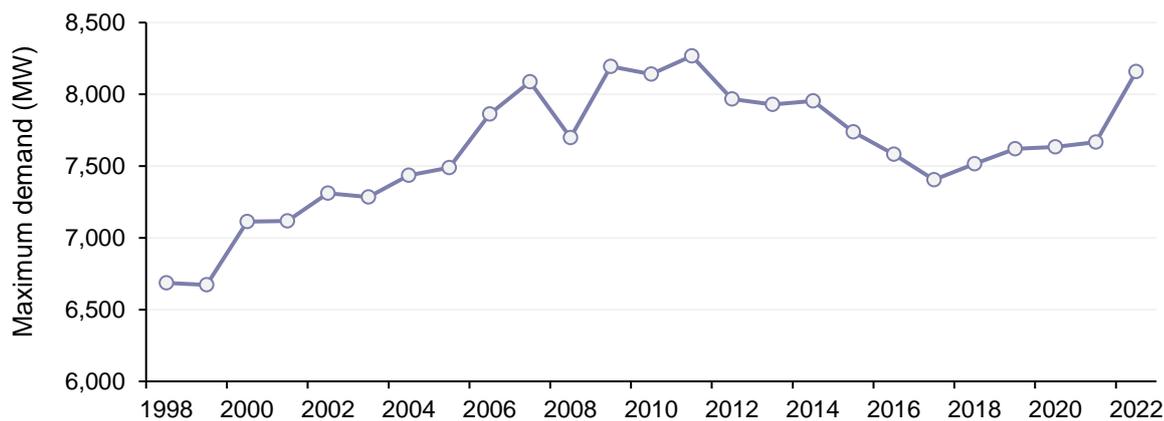
QLD operational demand by time of day – 9 June 2022



In Victoria, early winter conditions led to the state reaching its highest Q2 maximum operational demand since 2011 (Figure 6). On 31 May 2022, Victoria’s operational demand reached 8,158 MW at 1800 hrs, 492 MW higher than Q2 2021’s maximum, as several sites in the region recorded their coldest May day on record⁸.

Figure 6 Highest Q2 maximum demand in Victoria since 2011

Q2 maximum operational demand – Victoria



⁶ This was also a winter maximum operational demand record, which surpassed Queensland’s long-standing record of 8,212 MW set on 28 July 2008. This winter record was surpassed again on 4 July 2022 with Queensland operational demand reaching 8,716 MW at 1800 hrs.

⁷ Daytime intra-day operational demand swing is measured for each day as the difference between minimum and maximum operational demands recorded between 0600 hrs and 2000 hrs. Prior to high levels of distributed PV penetration, daily minimum demands typically fell outside this window, in the early overnight hours. The previous record of 3,605 MW was set in Q4 2021.

⁸ BoM 2022, Victoria in May 2022: <http://www.bom.gov.au/climate/current/month/vic/archive/202205.summary.shtml>

1.2 Wholesale electricity prices

Wholesale spot prices averaged \$264/MWh across the five NEM regions in Q2, up by \$177/MWh (+204%) from \$87/MWh in Q1, and by \$179/MWh (+211%) on Q2 2021's \$85/MWh average (Figure 7). This was the highest NEM average price recorded for any quarter since market commencement in 1998, being double the previous record of \$130/MWh set in Q1 2019 (Figure 8). Quarterly average price highs were also set for each NEM region, ranging from \$215/MWh in Tasmania to \$323/MWh in Queensland (Figure 9).

Spot prices jumped sharply from the commencement of the quarter, with April's NEM-wide average of \$168/MWh being nearly double the preceding quarter's average level. Prices continued to rise through Q2 leading up to triggering of administered price caps in the NEM mainland regions over 12-13 June, followed by suspension of the spot market in all regions between 15 and 24 June 2022. Section 1.2.1 below covers price outcomes during these price capping and market suspension events in more detail.

Figure 7 NEM average spot prices rising sharply through Q2

NEM average wholesale electricity spot price – quarterly, months of Q2 2022

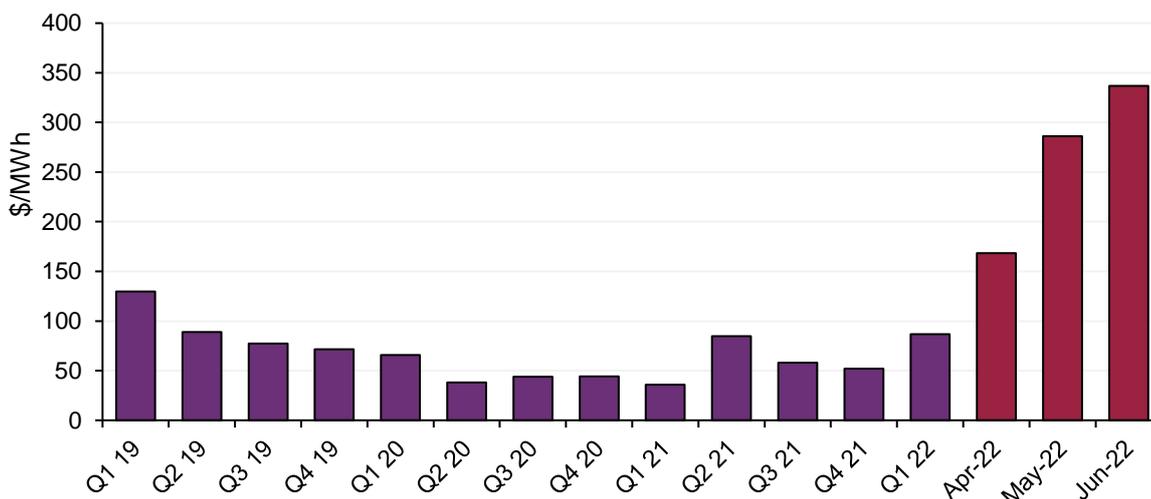


Figure 8 Highest quarterly average spot price since market commencement

NEM quarterly average wholesale electricity spot price

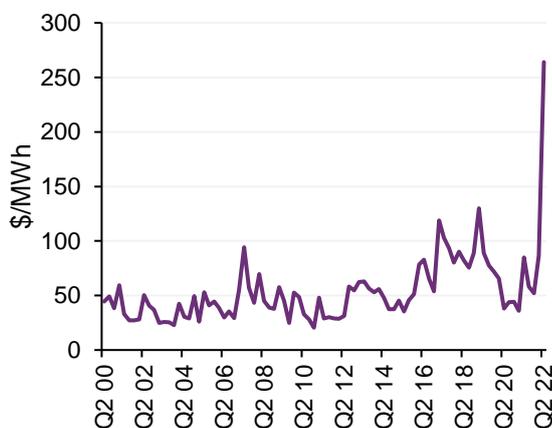
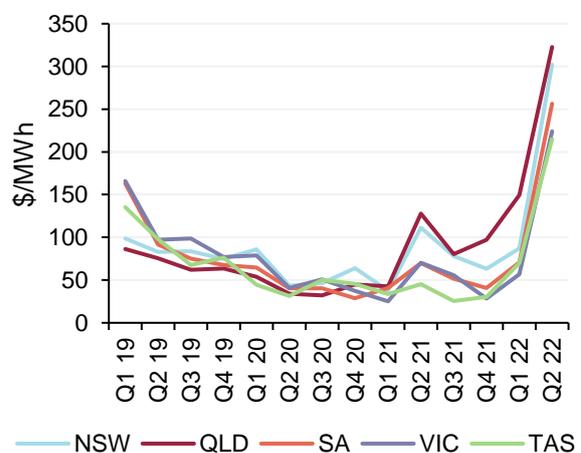


Figure 9 Prices elevated in all NEM regions

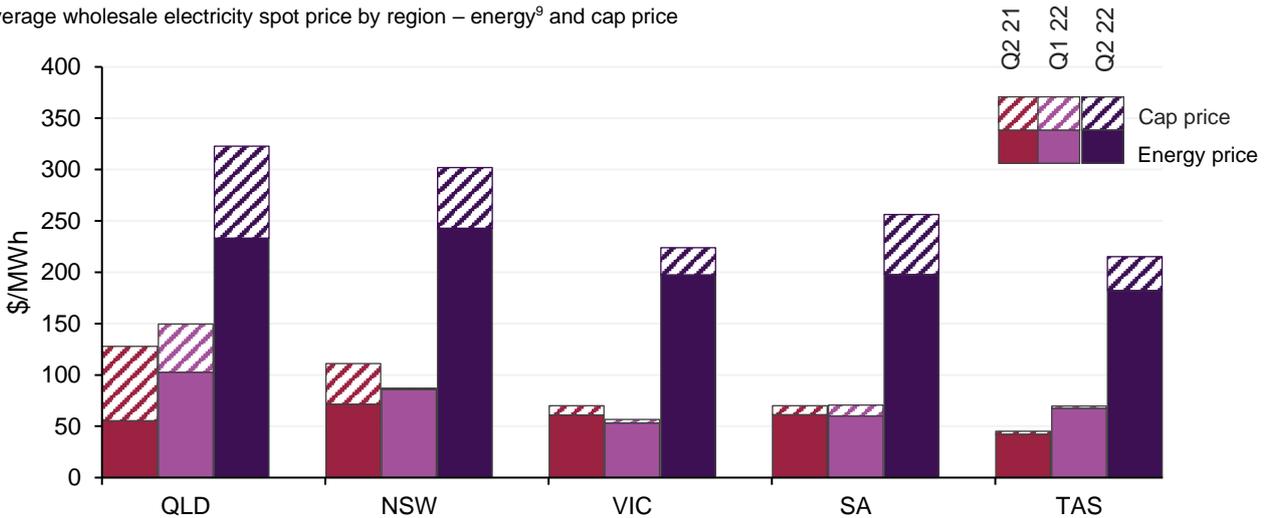
Average wholesale electricity spot price by NEM region



Price volatility, measured as the contribution of spot prices in excess of \$300/MWh to the quarterly average, was significant in all NEM regions, ranging from \$27/MWh in Victoria up to \$89/MWh in Queensland. The larger driver of elevated averages, however, was the consistently high energy or “underlying” price level in each region, which represents the contribution of the spot price component below \$300/MWh (Figure 10). Average regional energy prices in Q2 ranged from \$182/MWh to \$243/MWh, with regional increases of between 127% and 271% on energy prices in Q1 2022 and between 223% and 329% on Q2 2021 levels.

Figure 10 Large energy price increases drive overall spot averages, volatility also higher

Average wholesale electricity spot price by region – energy⁹ and cap price



The distribution of individual spot prices shifted dramatically in Q2, illustrated for Queensland in Figure 11. 91% of Q2 2022’s spot prices in the region exceeded \$100/MWh and 7% exceeded \$500/MWh; the corresponding figures for Q2 2021 were just 13% and 1%. Finally, the pattern of energy prices by time of day showed a relatively uniform shift across all hours, emphasising the consistently higher price levels during the quarter (Figure 12).

Figure 11 Incidence of high spot prices leaps

Queensland quarterly wholesale electricity spot price by price range

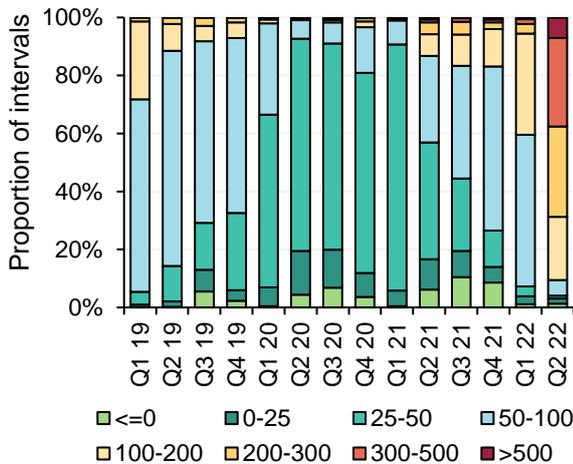
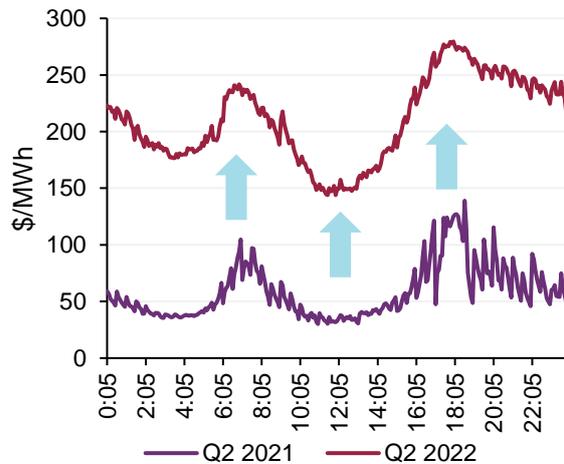


Figure 12 Energy prices up across all periods

Average NEM (energy¹⁰) price by time of day – Q222 vs Q221



⁹ ‘Energy price’ calculation in analysis of spot electricity price averages truncates the impact of price volatility (that is, price above \$300/MWh, also known as “cap return”). Since commencement of Five Minute Settlement (5MS) on 1 October 2021, energy and cap prices are calculated on a 5-minute basis.

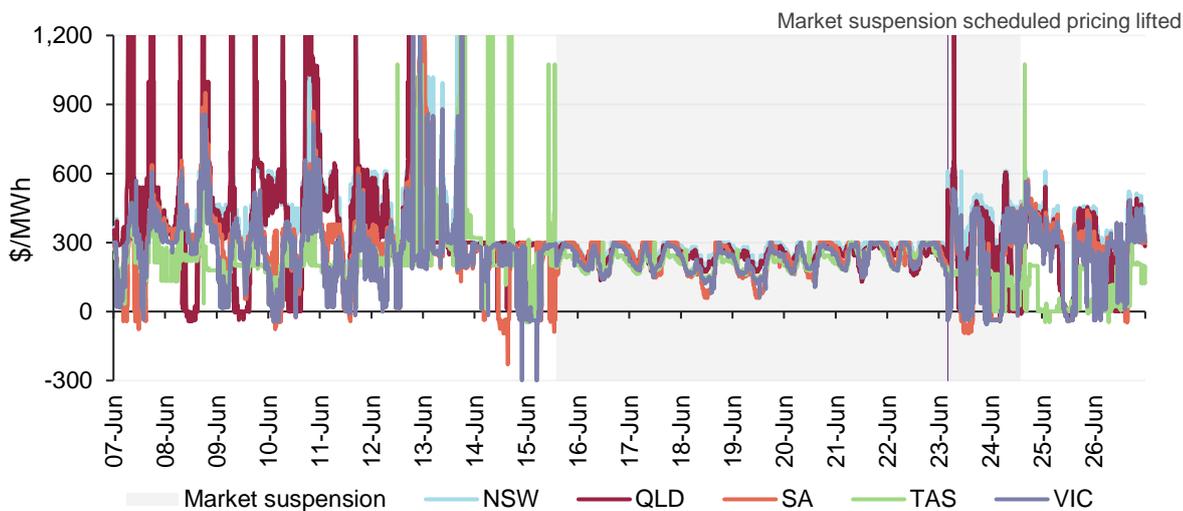
¹⁰ Spot price capped at \$300/MWh.

1.2.1 Administered price periods and market suspension

In the second week of June, price volatility surged in Queensland, progressing to other NEM regions (Figure 13). This triggered application of automatic market price caps in mainland regions over 12-13 June. The extent of the interventions needed to address subsequent lack of reserve conditions then led to AEMO's decision to suspend the spot electricity market in all regions on 15 June, with market-determined pricing being replaced with use of a pre-set pricing schedule. Market-based pricing recommenced on 23 June and the market suspension was formally lifted on 24 June.

Figure 13 Spot price capped under administered pricing and market suspension

5-minute regional reference price by region – 7 to 26 June 2022



Administered price periods (APPs) commenced in each mainland NEM region after cumulative spot prices exceeded the Cumulative Price Threshold (CPT) of \$1,359,100¹¹. This occurred in Queensland in the trading interval ending at 1850 hrs on 12 June, followed on 13 June by New South Wales, South Australia, and Victoria in trading intervals ending at 1830 hrs, 2155 hrs, and 2200 hrs respectively (Figure 14). During an APP, AEMO is required to cap the spot price at \$300/MWh in the affected region¹². The market dispatch process also continues to determine uncapped dispatch prices, used to track the underlying cumulative price for each region during an APP. Administered pricing ends in a region only at the end of the trading day in which this underlying cumulative price returns to a level below the CPT.

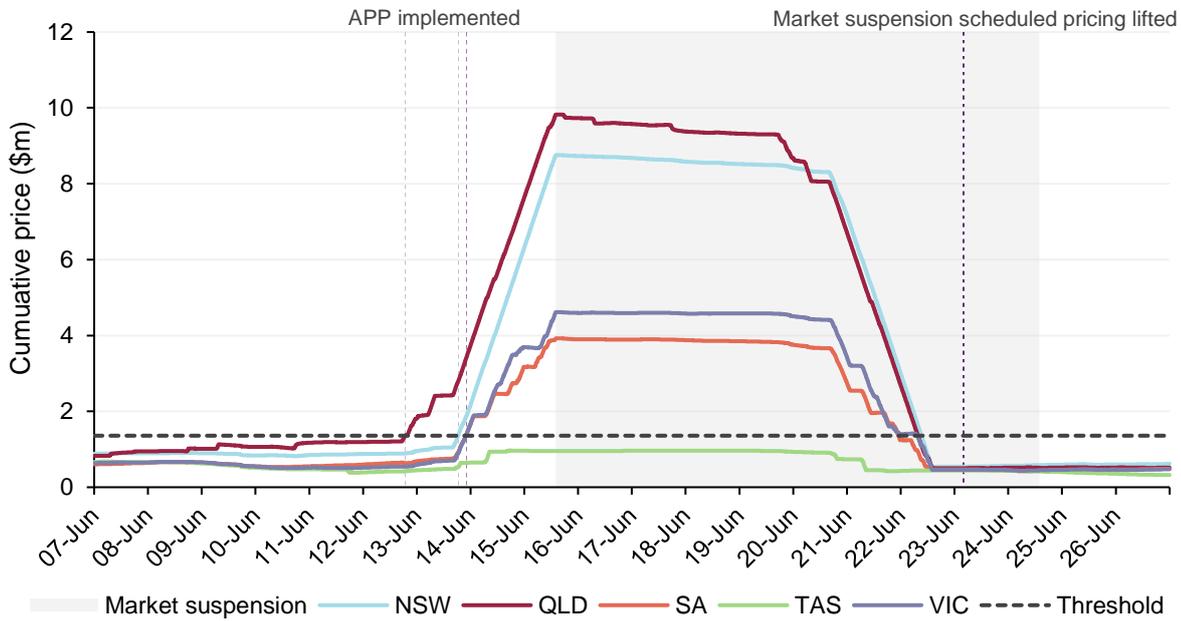
During June's APPs, uncapped dispatch prices rose to extremely high levels as generators reduced capacity offered to the market on top of already high levels of planned and unplanned plant outages. This is apparent in Figure 14 as the cumulative prices in mainland regions continued to rise well beyond the CPT. Cumulative prices only stabilised following suspension of the NEM spot market at the trading interval ending 1405 hrs on 15 June, when uncapped dispatch prices ceased being calculated and the scheduled market suspension prices entered the rolling calculation of cumulative prices. Cumulative prices in all mainland NEM regions had returned to levels below the CPT by the afternoon of 22 June.

¹¹ Under the NEM's administered price cap (APC) provisions (NER 3.14), spot prices for the 2,016 most recent 5-minute trading intervals (a rolling one-week window) are totalled into regional "cumulative prices" for each trading interval. If a region's cumulative price exceeds the Cumulative Price Threshold, set by the Australian Energy Market Commission at \$1,359,100 for 2021-22, then AEMO is required to begin capping subsequent regional spot prices at the administered price cap value of \$300/MWh.

¹² If an adjoining region is exporting energy across a regulated interconnector to a region in an APP, "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.

Figure 14 Cumulative price threshold exceeded in all NEM regions apart from Tasmania

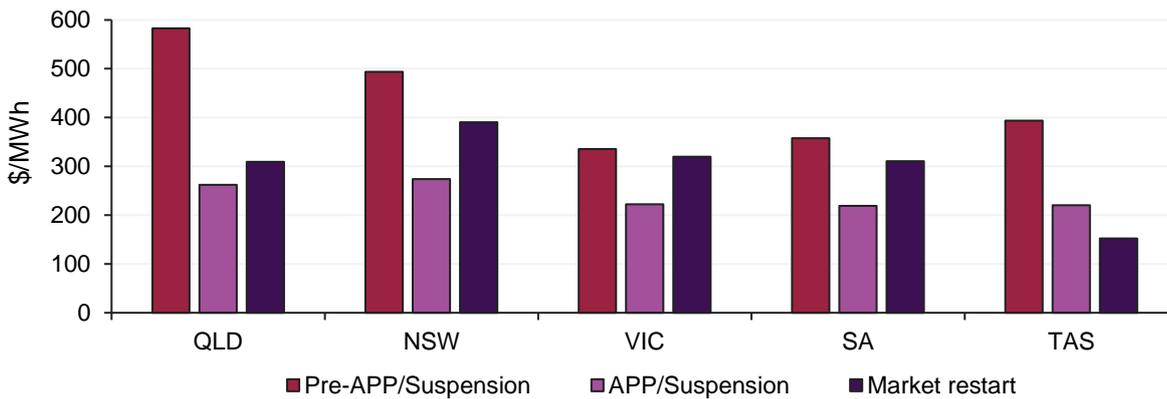
NEM cumulative price by region – 7 to 26 June 2022



Under market suspension, a fixed pricing schedule¹³ based on recent historic averages was used to determine spot prices until 0400 hrs on 23 June, when calculation of market dispatch prices resumed. Figure 15 shows average June spot prices for each region broken into periods prior to APP and market suspension, averages during that period, and averages over the balance of June after resumption of market dispatch pricing. Notably, averages once market dispatch pricing recommenced were lower in all regions than prior to APP and suspension.

Figure 15 June average prices reduced during and after APP and market suspension

June 2022 average wholesale spot price by period and region



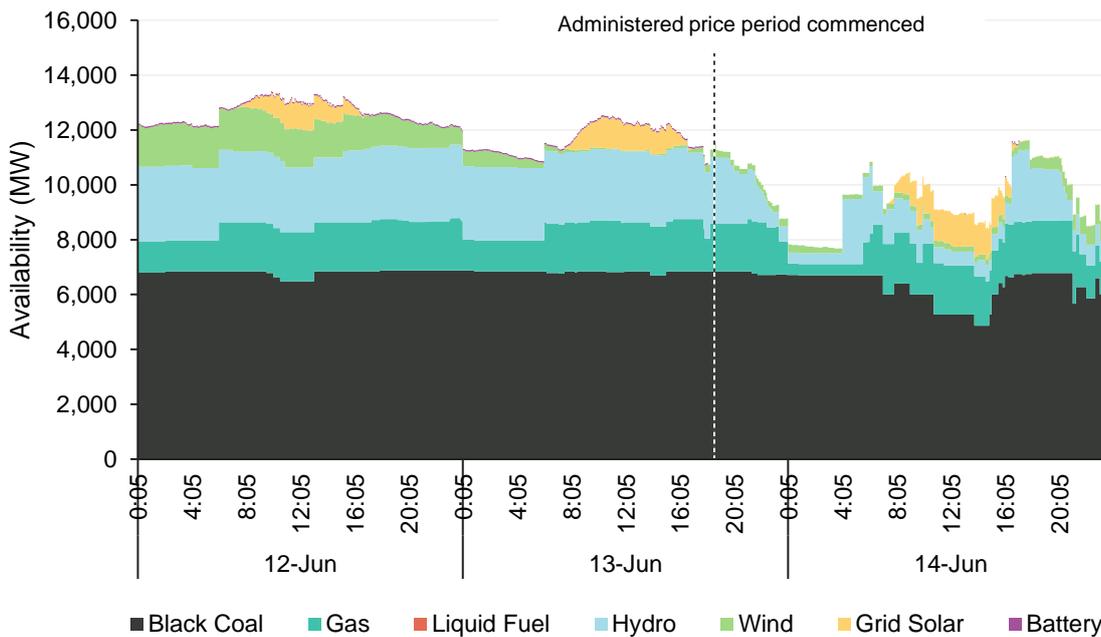
The final chart in this section shows one example of the overall reduction in generation supply offers following commencement of administered pricing. These reductions led to lack of reserve (LOR) conditions and forecasts which created the need for AEMO to direct participants to maintain system reliability, drove underlying dispatch

¹³ Prices during the initial period of market suspension were set according to AEMO’s published Market Suspension Pricing Schedule based on a four-week rolling average of historic regional prices, separated into business and non-business days, with half-hourly resolution. For the last 34 hours of market suspension, calculation of dispatch prices based on participant offers resumed and was used to set spot market prices.

prices to extreme levels and ultimately resulted in market suspension. Figure 16 shows offered availability from generators in New South Wales leading up to and after APP commencement in that region on 13 June. Compared to prior days there is an obvious reduction in offered availability from late on 13 June and continuing into 14 June; it is also important to note that offer availability shown for 14 June includes the effect of AEMO directions to some participants to make additional generation available for market dispatch.

Figure 16 Fall in offered generation availability after commencement of administered pricing

New South Wales availability by fuel type – 12 to 14 June 2022



1.2.2 Wholesale electricity price drivers

Multiple interacting factors combined to drive the unprecedented NEM wholesale price outcomes seen in Q2. These culminated in mid-June with the price-capping and market suspension events discussed above, but many of the underlying drivers outlined below were evident from much earlier in the quarter.

East coast gas market and thermal coal prices

Traded market prices for the NEM's major thermal generation fuels rose to new highs in Q2. East coast gas market prices averaged \$28.40/GJ, up from \$9.93/GJ in Q1 and \$8.20/GJ in Q2 2021 (Section 2.1). Export prices for Australian thermal coal averaged \$514 per tonne in Q2 2022, up from \$367/t in Q1 and \$139/t in Q2 2021 (Section 2.1.1).

While generators may 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 fuels¹⁴.

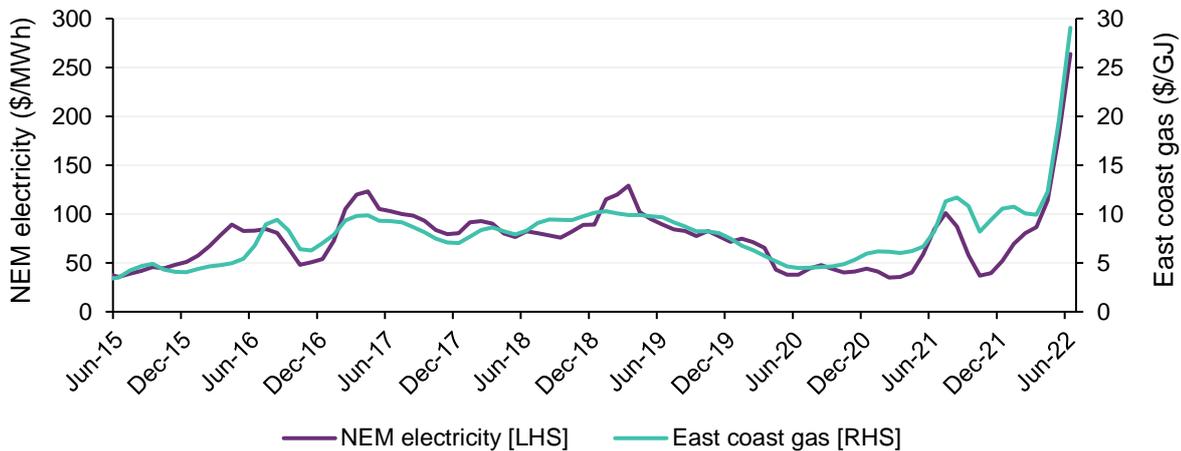
These changes in direct and opportunity costs of fuel are one principal driver of shifts observed in bidding behaviour from thermal generators, discussed later in this section and in Section 1.3, which then directly affect the

¹⁴ EnergyAustralia 2022, Media update: <https://www.energyaustralia.com.au/about-us/media/news/media-update-22-june-2022>

level of wholesale electricity prices. Figure 17 illustrates in particular the strong relationship across time between movements in east coast gas market prices and NEM wholesale spot prices, reflecting the role of gas-fired generation as a key marginal supply source in the NEM.

Figure 17 NEM electricity and east coast gas prices follow similar trajectories

NEM wholesale spot electricity prices and east coast wholesale gas prices – rolling three month averages



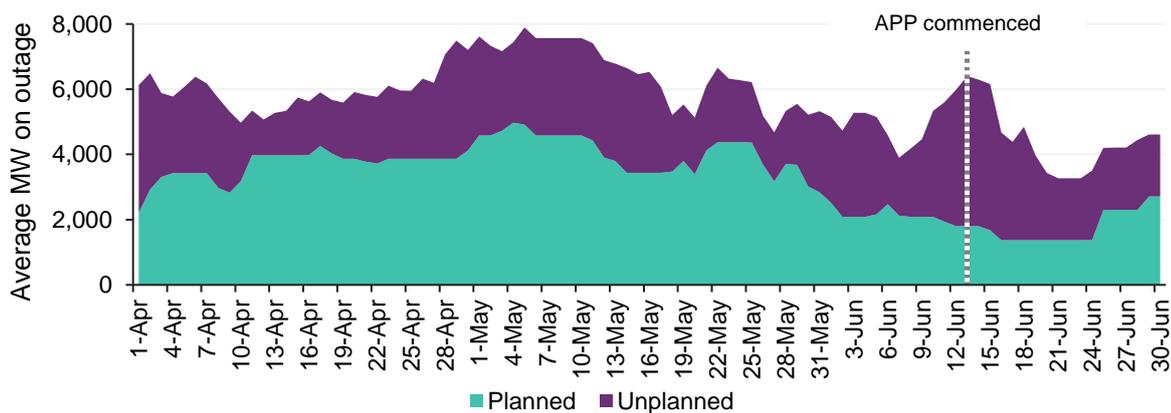
Note: NEM wholesale spot price, average all regions; Average of Victorian DWGM and STTM hub gas prices

Coal-fired generation outages

While Q2 typically sees higher levels of seasonal planned maintenance on thermal generation units in preparation for winter (Section 1.3.1), unplanned outages of coal-fired units clustered at different points in the quarter, reaching highs of around 3.6 gigawatts (GW) in late April and then in the second week of June peaking at 4.6 GW leading into the period of administered price capping and market suspension (Figure 18).

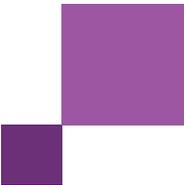
Figure 18 Coal-fired generation outage levels clustered during Q2

Average daily NEM black and brown coal capacity on outage by classification – Q2 2022



These planned and unplanned outages had multiple and compounding impacts on spot prices as they:

- removed lower cost supply from the market,
- increased the dispatch of higher-priced supply from other generators, and
- raised fuel or water usage rates at those other generators which increased price pressures in local fuel markets and impacted short-term hydro storage levels.



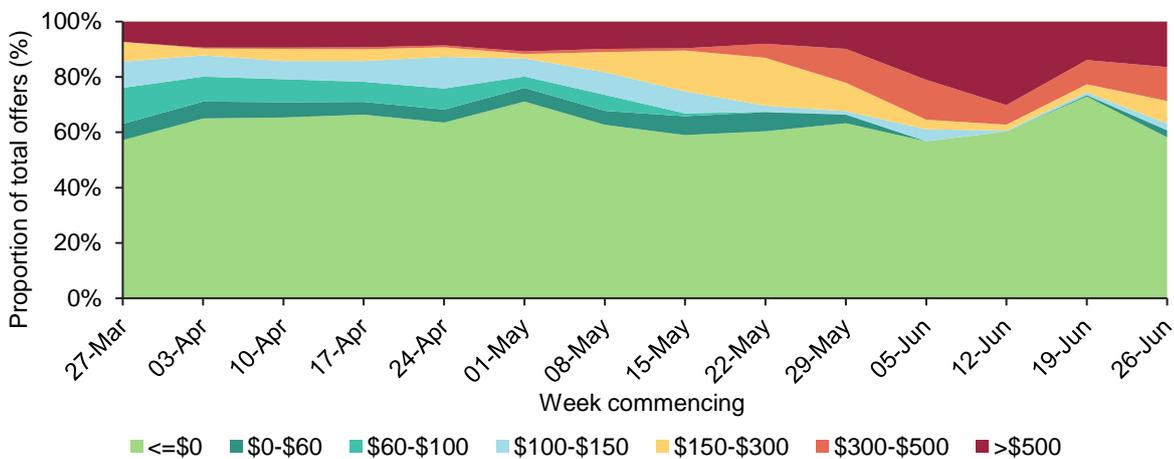
Increased marginal offer pricing from thermal and hydro generation

Relative to previous quarters, there were very large shifts in bidding by thermal and hydro generators across the NEM. Compared with Q2 2021 (in which low-price offers were already reduced by the 25 May 2021 incident at Callide C Power Station), volumes offered at prices below \$100/MWh by black coal-fired generation fell by over 2,700 MW. Corresponding reductions for gas-fired generation were around 300 MW and for hydro around 1,100 MW.

For coal-fired generators, these bidding shifts partly reflected higher outage levels removing lower cost supply, however for New South Wales black coal-fired generators in particular there was also a very clear trend in marginal offer volumes moving to progressively higher price bands through the quarter (Figure 19).

Figure 19 New South Wales black coal-fired generation offers moved to progressively higher prices

NSW black coal proportion of total offer volumes by price range – Q2 2022 weekly



Supply offers from gas-fired generators reflected high and rising prices in the east coast gas markets, discussed in Section 2, and the need to source additional gas in spot markets when dispatch levels increased to cover coal outages or periods of low wind and solar generation¹⁵. Shifts in hydro generation offers generally follow overall changes in thermal generation offer pricing in order to manage limited water supplies, reflect the changing opportunity cost of water in storage, and maintain dispatch volumes within upstream and downstream flow constraints (Section 1.3.3).

Physical fuel supply constraints

During the quarter some 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^{16,17}. 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 lack of reserve conditions in multiple NEM regions on 2 June

¹⁵ EnergyAustralia 2022, Media update: <https://www.energyaustralia.com.au/about-us/media/news/media-update-21-june-2022>

¹⁶ Origin 2022, Update on operating conditions and guidance: <https://www.originenergy.com.au/about/investors-media/update-on-operating-conditions-and-guidance/>

¹⁷ EnergyAustralia 2022, Media update: <https://www.energyaustralia.com.au/about-us/media/news/media-update-18-june-2022>

(Section 2.3.3). At other times gas supply limits caused dual-fuelled peaking generators to run on reserves of high-cost liquid fuel.

Spot price volatility

Volatility in Q2 associated with extremely high spot prices – typically \$5,000/MWh or greater – was at the upper end of previously observed quarterly values, while the standard “\$300/MWh cap return” measure of NEM volatility was further elevated by the unprecedented frequency of prices below extreme levels but higher than \$300/MWh. This is analysed further in Section 1.2.3.

Network outages

Network outages affecting inter-regional transfers contributed materially to a number of extreme spot price episodes, lifting spot price volatility and overall NEM average prices in Q2. Examples are covered in more detail in Section 1.2.3.

Maximum demands

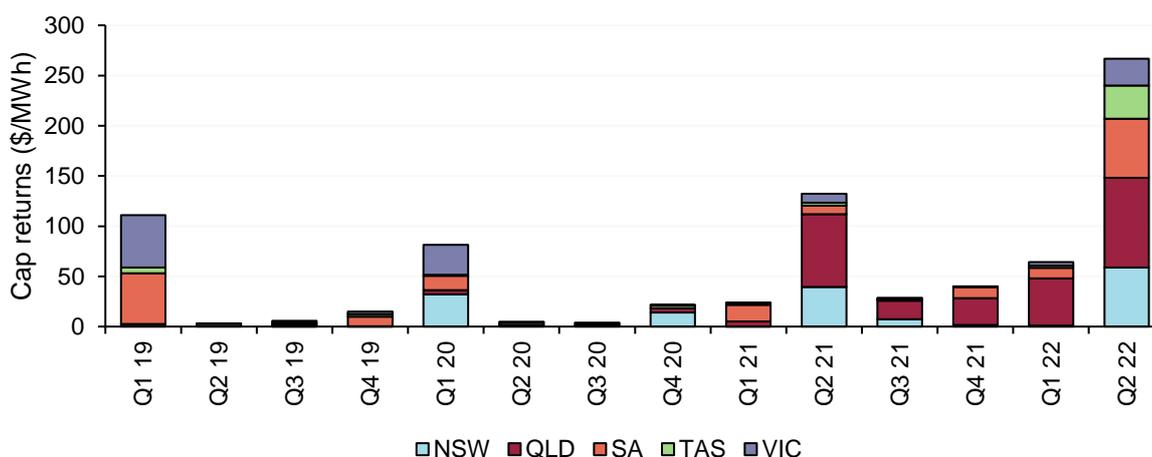
As outlined in Section 1.1, cold early winter conditions from late May into early June affected NEM east coast regions and led to high Q2 maximum demands in Queensland (9 June) and Victoria (31 May). This period coincided with a series of unplanned coal unit outages and increasing spot price volatility leading into the triggering of administered price capping.

1.2.3 Wholesale electricity price volatility

NEM spot price volatility as measured via cap returns (the excess component of spot prices above \$300/MWh) aggregated across the five NEM regions reached a record quarterly level of \$267/MWh in Q2 (Figure 20), 70% above the previous high of \$157/MWh in Q1 2008.

Figure 20 Aggregate NEM cap returns reach record levels

NEM average quarterly cap returns by region (stacked)



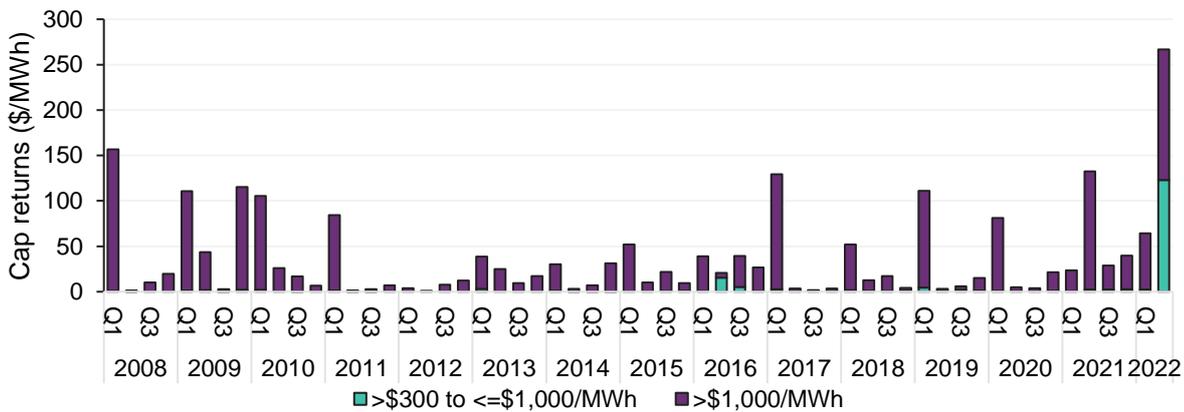
Historically, cap returns in the NEM have been driven principally by relatively infrequent occurrences of extremely high spot prices, often at or near the market price cap (MPC), and typically clustered into isolated “volatility events” associated with tight supply-demand balance or other constraints. However the unprecedented incidence

of spot prices above \$300/MWh in Q2 2022 (shown earlier in Figure 11) meant that a significant proportion of overall cap returns for the quarter arose from prices well below the MPC.

Figure 21 breaks aggregate NEM cap returns into contributions from spot prices higher than \$1,000/MWh and those between \$300/MWh and \$1,000/MWh. Prices in the lower range historically contribute only very small amounts to overall cap returns, but in Q2 accounted for 46% of the aggregate NEM return (and as much as 58% in New South Wales and 73% in Tasmania). This analysis also shows that while volatility arising from the more extreme spot prices that typically drive cap returns was still large in Q2, it remained within historic precedents.

Figure 21 Cap returns lifted by the high frequency of prices between \$300 and \$1,000/MWh

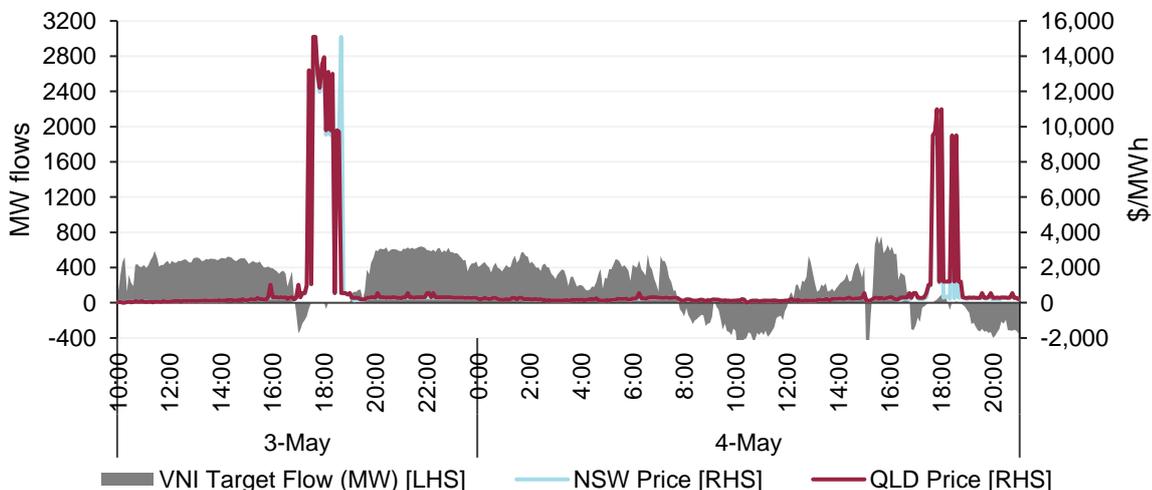
Contribution to total cap return by spot price range – Q1 2008 to Q2 2022



A significant proportion of historically typical volatility events in Q2, where spot prices rose towards the MPC, were associated with transmission constraints which limited transfers of power between NEM regions. Figure 22 illustrates an example from early May where a transmission outage in southern New South Wales prevented northward transfers on the Victoria to New South Wales interconnector (VNI) during periods of extreme prices in the northern NEM regions. Similarly, significant volatility events in Queensland over 7-9 June which pushed cumulative prices towards the CPT (Section 1.2.1) coincided with upgrade-related outage works on the Queensland – New South Wales Interconnector (QNI) effectively preventing power transfers into Queensland.

Figure 22 Spot price volatility associated with limitations on inter-regional transfers

VNI Target Flow, NSW and QLD price – 3 to 4 May 2022



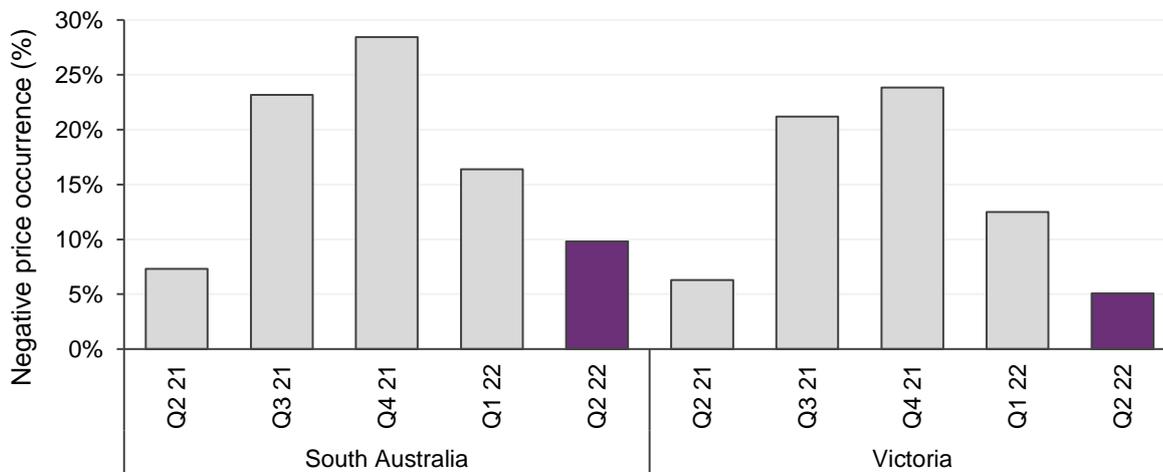
1.2.4 Negative wholesale electricity prices

The occurrence of negative and zero spot prices declined from 6% a year ago to 3.7% of dispatch intervals across the NEM regions in Q2 2022, as prices increased sharply. Southern states continued to see higher incidences, at 9.8% for South Australia and 5.1% in Victoria (Figure 23) compared to only around 1% across the northern states.

The impact of negative prices on quarterly spot price averages fell to just \$1.4/MWh across the NEM. South Australia saw the highest impact at \$4.7/MWh, while in Queensland impact declined from \$7.5/MWh in Q2 2021 to near zero, mainly due to much higher price levels and the near-completion of the QNI upgrade¹⁸.

Figure 23 Negative spot prices decline

Frequency of negative or zero spot prices



1.2.5 Price-setting dynamics

Q2 saw a marked shift in the proportions of spot prices set by different technologies in the NEM (Figure 24). The frequency with which black or brown coal-fired generators set prices in Q2 2022 fell to 27%, down from 48% in Q1 and 41% in Q2 2021. While price-setting frequency by gas-fired generation¹⁹ increased from 11% in Q1 to 14% in Q2 2022; this was down from 20% a year ago. Conversely, price-setting frequency for batteries increased from 1-2% to 5% in Q2, but the biggest increase came from hydro generation which set prices in 47% of intervals during Q2 2022, up from 31% in Q1 and 34% in Q2 2021. Almost all of this increase can be attributed to increased price setting frequency by Snowy Hydro’s Tumut and Murray generators which set prices in 17% and 15% of intervals respectively in Q2 2022.

The reduced price-setting role of coal-fired-generation can be explained by its lower availability, leading to increased marginal dispatch of gas-fired and hydro generation. While these two sources provided very similar shares of NEM supply in Q2 2022 at just over 9% each (Section 1.3), the much greater role in marginal price setting played by hydro may reflect more flexible “opportunity cost”-based pricing of underlying water reserves whereas gas-fired generation offer pricing is more constrained by actual fuel costs.

¹⁸ Transgrid 2022: <https://www.transgrid.com.au/projects-innovation/queensland-nsw-interconnector>

¹⁹ Price-setting data by generation technology is based on primary fuel source; there may be instances where gas-fired generation setting price was running on secondary liquid fuel. “Liquid-fuelled generation” price-setting data covers only generators whose primary fuel source is fuel oil, diesel or other liquids.

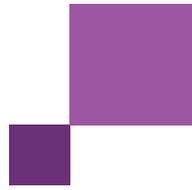
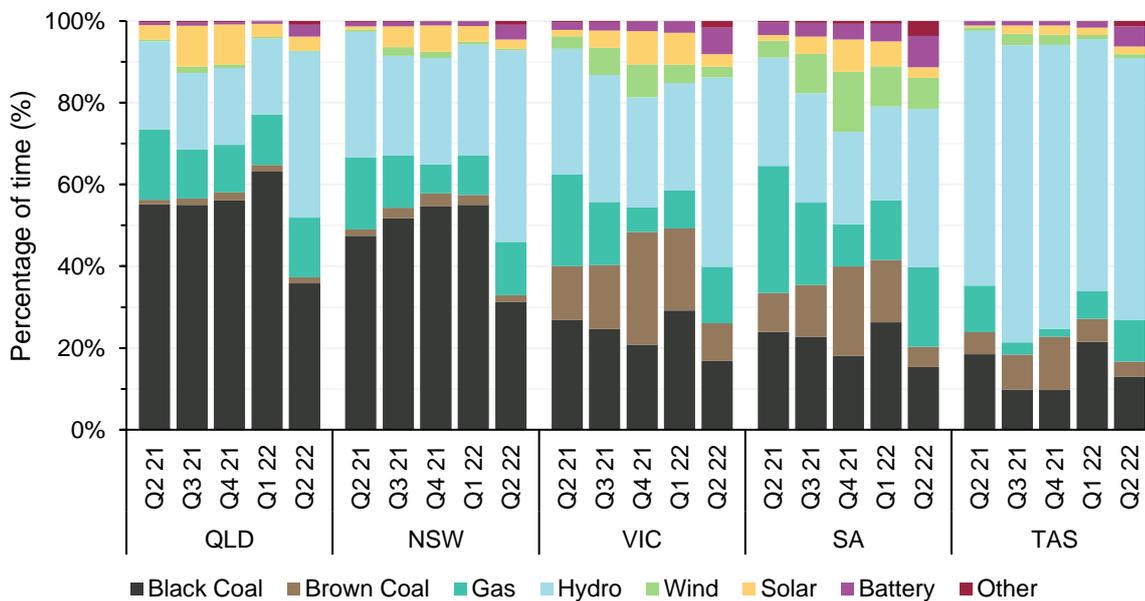


Figure 24 Hydro generation sets price more frequently in Q2 while price-setting role of coal diminishes

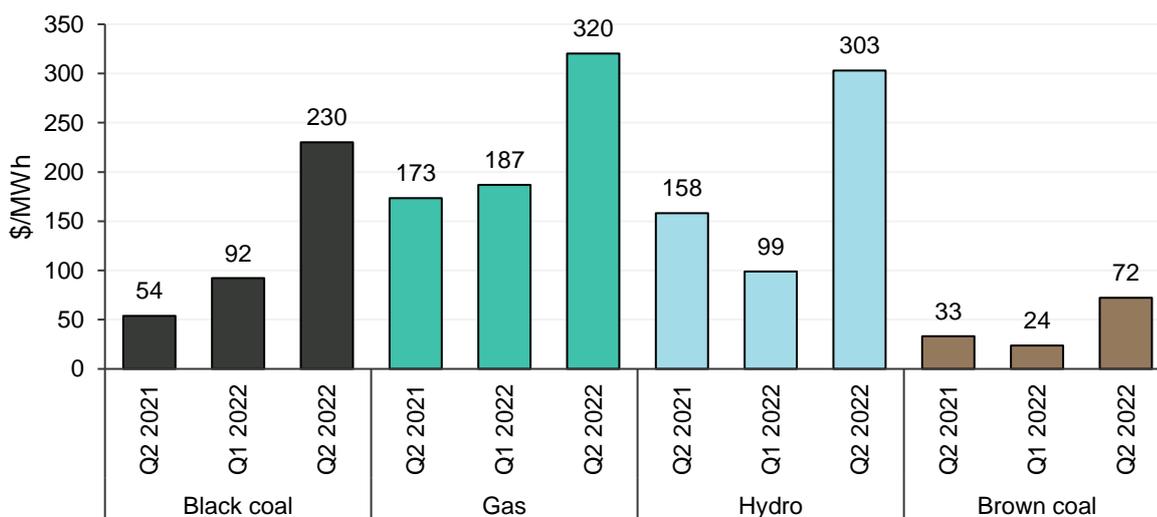
Price-setting frequency by fuel type²⁰



The average spot prices set by key fuel types when operating as marginal price-setters provide further insight into these dynamics as well as the overall upward shift in NEM spot prices (Figure 25). Prices set by all these sources increased markedly, with hydro and gas-fired generators setting price at over \$300/MWh on average, while liquid-fuelled generation set prices at an average of \$446/MWh when dispatched as marginal supply. As outlined in Section 1.2.2, thermal generation offer pricing reflected conditions in local fuel markets, influenced by international factors and supply constraints, while hydro generation offer pricing generally reflects the opportunity value of limited water in storage, which in turn is driven by market prices and competing fuel sources' offer pricing.

Figure 25 Average marginal prices set by thermal and hydro generators increase steeply

Average NEM spot prices set by fuel type – selected quarters²¹



²⁰ Q2 2022 data only includes periods up to commencement of APP in Queensland.

²¹ See footnote 20.

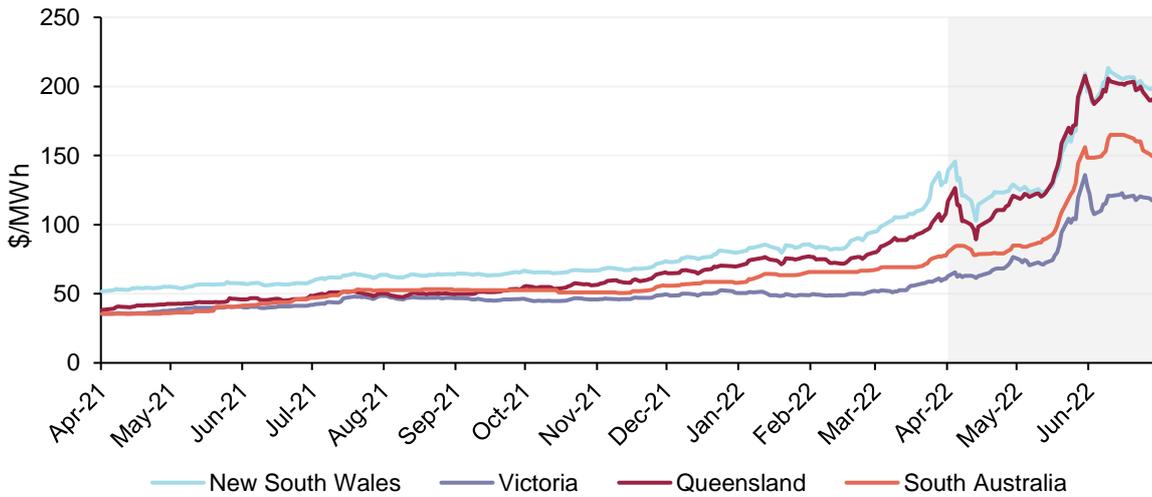
1.2.6 Electricity futures markets

ASX Calendar 2023 (Cal23) base futures prices increased sharply, from an average of \$94/MWh for the four mainland NEM regions at the end of the previous quarter to finish Q2 2022 at \$168/MWh (Figure 26).

Queensland's Cal23 base futures rose by \$87/MWh to reach \$195/MWh, closing the gap to the highest priced region New South Wales at \$202/MWh. Victoria (\$123/MWh) continued as the lowest priced region followed by South Australia (\$153/MWh), with the average spread to the northern states increasing by \$11/MWh to \$61/MWh.

Figure 26 Cal23 futures rally to record levels

ASX Energy – daily Cal 2023 base futures price by region



Extremely high spot prices and volatility coupled with generator reliability concerns, in addition to higher future fuel cost expectations, drove up short- and long-term futures prices²². New South Wales led the increase (Figure 27), and the mainland regions saw Q3 2022 jump from an average of \$110/MWh at the end of last quarter to finish Q2 2022 at \$309/MWh with Cal25 contracts averaging \$92/MWh across the regions (Figure 28).

Figure 27 NSW forward curve shifts up

ASX Energy – NSW closing prices end Q2 vs end Q1 2022

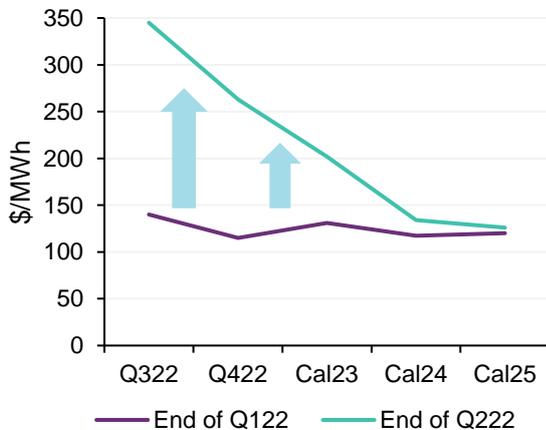
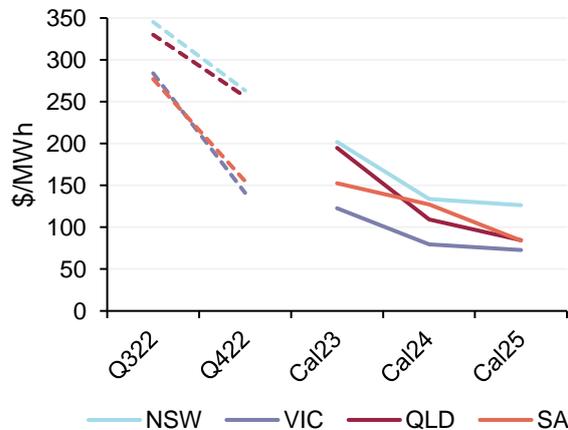


Figure 28 Forward prices higher for longer

ASX Energy – End Q2 2022 closing prices by region



²² ASX 2022, Response to AEMO suspension: https://www.asxenergy.com.au/newsroom/industry_news/update-to-asx-australian-elec-2

1.3 Electricity generation

Figure 29 and Table 1 show the change in NEM generation mix in Q2 2022 compared to Q2 2021, while Figure 30 shows the change by time of day. Compared to Q2 2021:

- Black coal-fired generation output fell by 947 MW to its lowest Q2 level since NEM start, driven by a combination of units repricing marginal offers upwards, fuel supply constraints and increased outages. High levels of unplanned outages, particularly at Loy Yang A reduced brown coal quarterly output by 142 MW.
- A confluence of low coal availability, sustained high spot prices and participant portfolio dynamics resulted in higher gas-fired generation this quarter (+472 MW). Despite very high rainfall, hydro output was only up by 171 MW on average, as some generators in New South Wales were constrained by water release restrictions.
- Wind and grid-solar output grew by 664 MW on average. Overall renewable supply share for the quarter was 31.8% while maximum instantaneous renewable penetration peaked at 58.7%²³.

Figure 29 Large decline in coal generation

Change in supply – Q2 2022 versus Q2 2021

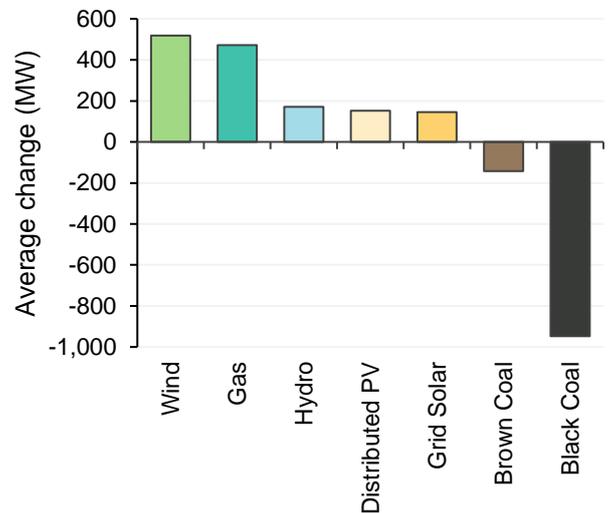
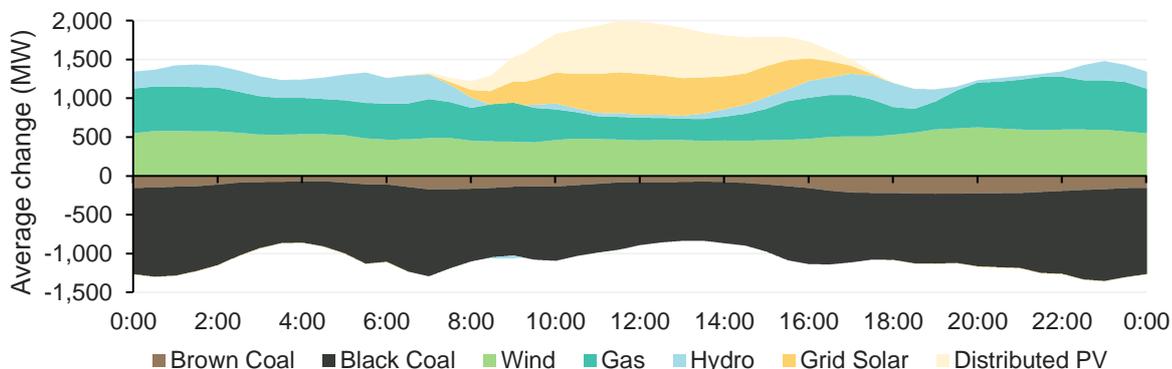


Table 1 NEM supply mix by fuel type²⁴

Quarter	Black coal	Brown coal	Gas	Hydro	Wind	Grid solar	Distributed PV	Other
Q2 2021	47.8%	16.5%	7.4%	8.9%	10.3%	3.4%	5.6%	0.2%
Q2 2022	43.0%	15.6%	9.3%	9.4%	12.3%	3.9%	6.1%	0.3%
Change	-4.8%	-0.9%	1.9%	0.6%	2.0%	0.6%	0.5%	0.1%

Figure 30 Coal output declined across the day while all other generation sources increased

Change in supply – Q2 2022 versus Q2 2021 by time of day



²³ Instantaneous renewable penetration is calculated as the NEM renewable generation share of total large-and small-scale generation. The measure is calculated on a half-hourly basis, because this is the granularity of estimated output data for distributed PV. Renewable generation includes grid-scale wind and solar, hydro generation, biomass, battery generation and distributed PV, and excludes battery load and hydro pumping. Total generation = NEM generation + distributed PV generation. Last record was set on 15 November 2021 at 61.8%.

²⁴ Distributed PV has been included in the total supply mix (total generation = NEM generation + distributed PV generation).

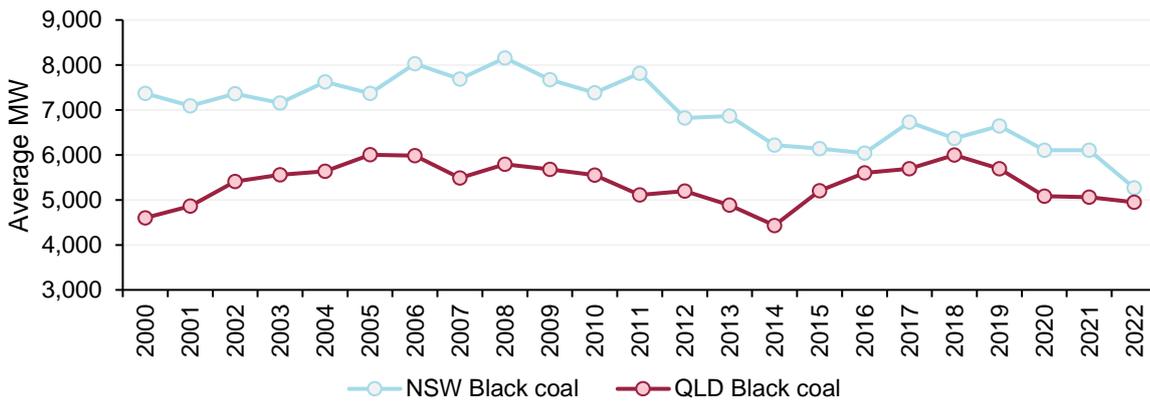
1.3.1 Coal-fired generation

Black coal-fired fleet

During Q2 2022, average black coal-fired generation declined to 10,217 MW, its lowest Q2 output since NEM start and 947 MW lower than Q2 2021. Record low Q2 output was predominantly driven by the New South Wales fleet (-836 MW), followed by Queensland (-111 MW, Figure 31).

Figure 31 Lowest Q2 black coal generation on record

Average NEM black coal-fired generation by region – Q2s



A key driver for the reduction in black coal output this quarter was a shift in supply offers to much higher price bands, particularly in New South Wales (Section 1.2.2). As noted in AEMO's Q1 2022 QED report, black coal marginal offers have been trending upwards since mid-2021, however record high international coal prices this quarter (Section 2.1.1) coupled with several key generators experiencing coal supply issues further exacerbated this trend. Compounded with lower Q2 availability (-586 MW), driven by high levels of outages in April and May (largely planned, Figure 32) and closure of Liddell Unit 3 at the start of the quarter²⁵, these factors resulted in the volume of black coal offers priced under \$100/MWh reducing by 2,700 MW compared to Q2 2021 (Figure 33).

Figure 32 High levels of coal outages across the NEM

Coal outage classification – Q2s

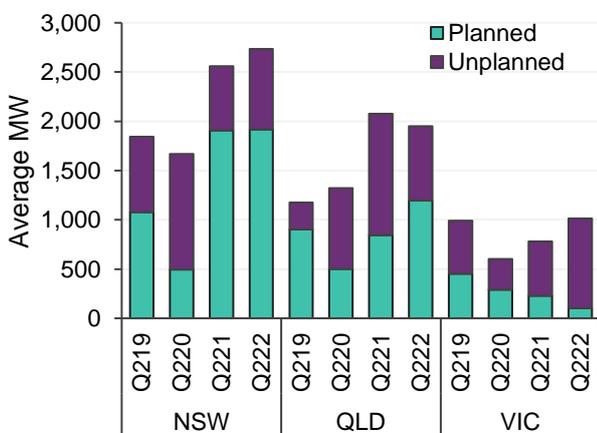
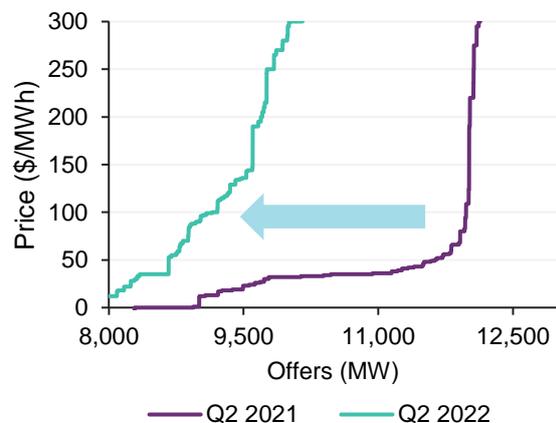


Figure 33 Large shift in bids out of lower price bands

NEM Black coal bid supply curve – Q2 2022 vs Q2 2021



²⁵ AGL 2022, Liddell's first unit closure marks another major step in AGL's energy transition: <https://www.agl.com.au/about-agl/media-centre/asx-and-media-releases/2022/april/liddell-s-first-unit-closure-marks-another-major-step-in-agl-s-e?qiha9n=hrd26h>

In New South Wales, key changes by power station compared to Q2 2021 included:

- Lower availability due to outages (mainly planned) at Mt Piper Power Station, coupled with ongoing challenges with lower than expected production and delivery of coal from the Springvale mine²⁶, reduced average output by 427 MW to 768 MW this quarter. Unit 2 which had been out for major planned maintenance since Q1 2022 returned to service in May, but experienced several unplanned outages after its return.
- Average output at Eraring Power Station declined by 404 MW to 1,491 MW this quarter, driven by a combination of repricing of offers and increased outages. Despite substantially higher spot prices this quarter, utilisation rate²⁷ at Eraring fell to only 68% from 82% in Q2 2021 (Figure 34), with offered capacity under \$100/MWh declining by 960 MW as the power station was impacted by coal supply issues that are expected to continue into the first half of FY 2023²⁸.
- At Liddell and Bayswater Power Stations, combined average quarterly output declined by 216 MW. In June, combined Bayswater and Liddell output was at a record low for any June, impacted by both planned and unplanned outages and the retirement of Liddell Unit 3.

In Queensland, lower output (-111 MW on average) was mainly driven by outages at Callide C (the ongoing unplanned outage of Unit 4 following its major incident in May 2021, and a planned outage at Unit 3) and Gladstone. Lower output was however partially offset by increased output from Kogan Creek and Callide B.

Brown coal-fired fleet

Compared to Q2 2021, average brown-coal fired generation decreased by 142 MW this quarter, driven by reductions from Loy Yang A (-254 MW), which more than offset increased output from Yallourn (+75 MW) and Loy Yang B (+37 MW). High unplanned outage levels during the quarter impacted operations at Loy Yang A, with output declining to its lowest Q2 level since NEM start (Figure 35). Most notably, Unit 2 was taken out of service on 15 April due to a generator electrical failure and is expected to remain out of service until the second half of September 2022 due to global supply chain issues and availability of specialised materials²⁹.

Figure 34 Low utilisation rates at Eraring

NSW black coal utilisation rates – Q2s

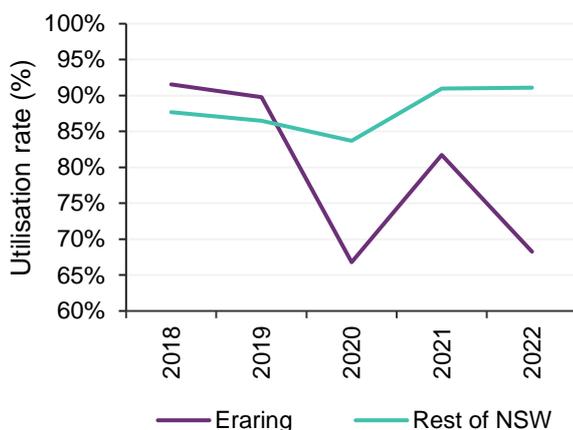
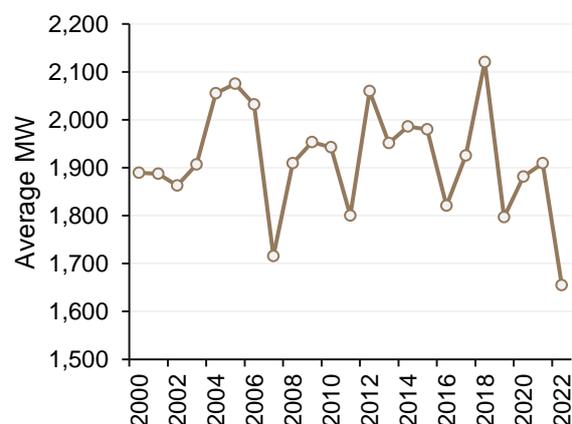


Figure 35 Lowest LYA Q2 output since NEM start

Loy Yang A average quarterly output – Q2s



²⁶ EA 2022, Media Update – 18 June 2022: <https://www.energyaustralia.com.au/about-us/media/news/media-update-18-june-2022>

²⁷ Ratio of generator's average generation divided by average availability.

²⁸ Origin 2022, Operating conditions: <https://www.originenergy.com.au/about/investors-media/update-on-operating-conditions-and-guidance/>

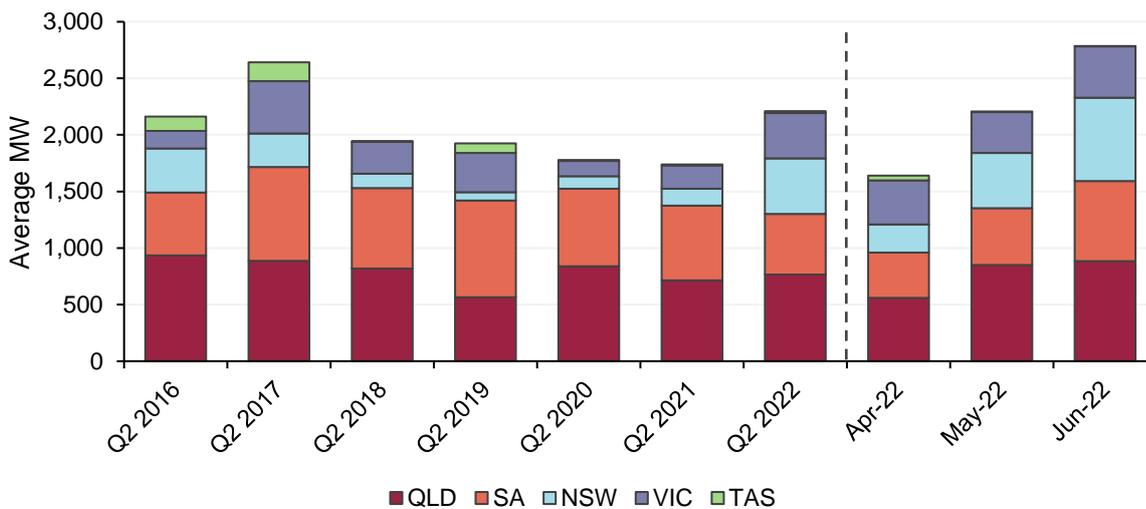
²⁹ AGL 2022, LYA2 Generator Fault – Update on expected return to service: <https://www.agl.com.au/about-agl/media-centre/asx-and-media-releases/2022/june/loy-yang-a-unit-2-generator-fault---update-on-expected-return-to>

1.3.2 Gas-fired generation

During the quarter, NEM gas-fired generation output³⁰ increased to 2,211 MW on average, 818 MW higher than the previous quarter and 472 MW higher than in Q2 2021 (Figure 36). This represented the highest Q2 level for gas-fired generation since 2017. Output grew strongly during the quarter reaching its highest June monthly average since 2014 despite record gas prices (Section 2.1), as operational demand and spot electricity prices increased.

Figure 36 Gas-fired generation ramps up during Q2

Average gas-fired generation by state – Q2s and monthly for Q2 2022



- Gas-fired generation in New South Wales (+340 MW) increased to its highest Q2 average since 2014, driven by lower black coal-fired generation and sustained higher spot prices.
 - EnergyAustralia’s Tallawarra (+197 MW) reached its highest Q2 average since 2014, covering for reduced Mt Piper output. In particular, Tallawarra was running at very high levels in May and June averaging 78% of capacity.
 - Snowy’s Colongra (+94 MW) generated at record quarterly levels, influenced by portfolio dynamics related to hydro generation constraints.
- Generation in Victoria (+195 MW) reached its highest Q2 average since 2017, affected by lower brown coal generation and spot price volatility.
 - EnergyAustralia’s Newport (+92 MW) averaged its highest Q2 since 2008, covering for outages at Yallourn (Section 1.3.1).
 - Snowy’s Laverton (+52 MW) and Valley Power (+33 MW) both increased to their highest Q2 average since 2007, again driven by portfolio dynamics related to hydro generation.
- Reduced South Australian generation (-122 MW) was led by Pelican Point’s decline (-132 MW), mainly due to a planned outage in April, followed by AGL’s Torrens Island’s decrease (-74 MW) mainly due to the ongoing closure of older units. Partially offsetting these was an increase at Origin’s Osborne’s plant (+81 MW).

³⁰ This includes any generation from liquid fuels where generators whose primary fuel source is gas were running on secondary liquid fuel sources such as diesel or fuel oil, due to limited availability or high prices of gas.

1.3.3 Hydro

Hydro generation (2,239 MW on average) increased by 171 MW (8%) on Q2 2021 to levels comparable with Q2 2018 (Figure 37). Despite low coal-fired output, very high spot prices, and La Niña-driven rainfall raising upstream storage levels³¹, further output increases at some key generators were limited by downstream hydrological constraints also linked to wet conditions.

Figure 37 La Niña impacts limited NSW hydro output growth in Q2 2022

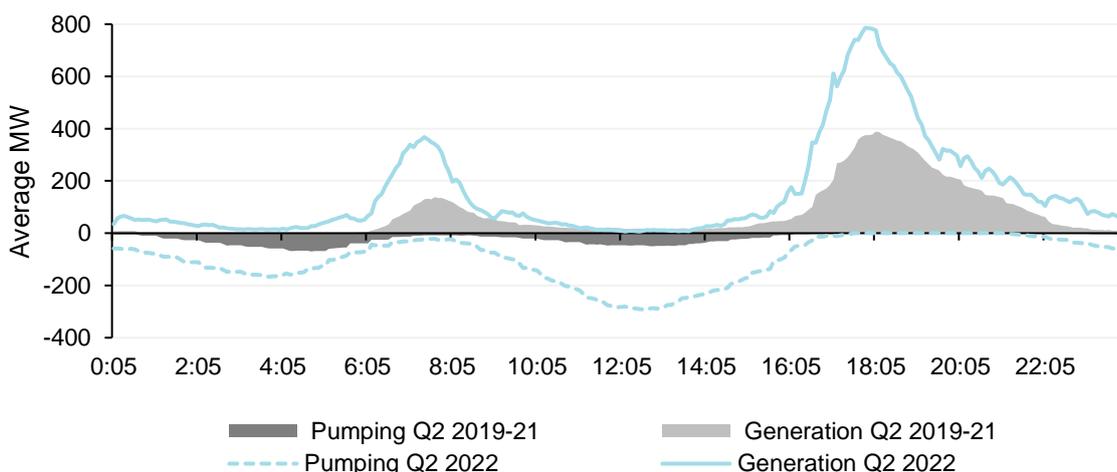
Average hydro generation by state – Q2s and monthly for Q2 2022



New South Wales average hydro generation output increased (+113 MW) to its highest Q2 average since NEM start. At Snowy Hydro’s largest power station, Tumut 3 (1,800 MW capacity), high water levels in the downstream Blowering Reservoir and restricted release capacity into the Tumut River^{32,33} capped generation output despite record levels of pumping water back to its upstream storage (Figure 38).

Figure 38 Snowy’s 1,800 MW Tumut 3 power station constrained by downstream flow limits

Tumut 3 average hydro generation and pumping by time of day – Q2 2022 vs Q2 2019-21



³¹ Snowy Hydro 2022, Dam Levels: <https://www.snowyhydro.com.au/generation/live-data/lake-levels/>

³² Snowy Hydro 2022, Snowy Hydro release from Tumut 3 power station: <https://www.snowyhydro.com.au/news/snowy-hydro-water-releases-from-tumut-3-power-station/>

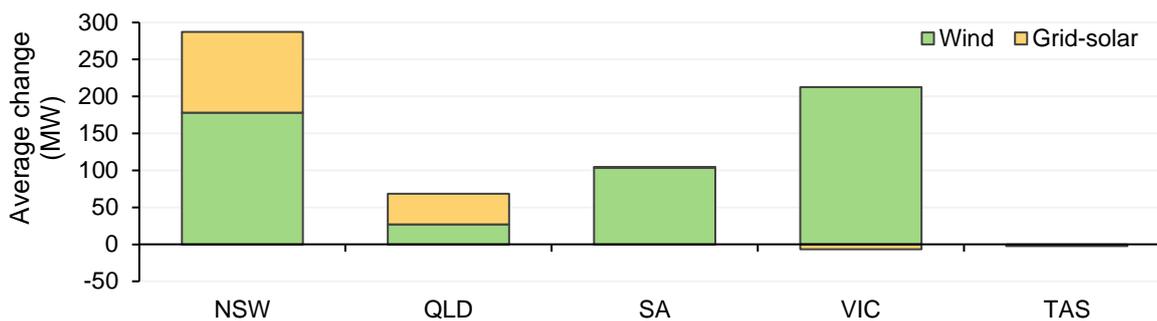
³³ ABC News 2022, Snowy Hydro’s water problem shows how weather is a driver of the energy crisis: <https://www.abc.net.au/news/2022-06-20/snowy-hydro-water-problem-weather-driver-energy-crisis/101158300>

1.3.4 Wind and grid-scale solar

Compared to Q2 2021, average variable renewable energy (VRE) generation increased by 664 MW, with wind and grid-scale solar contributing increases of 518 MW and 145 MW respectively (Figure 39). Higher output was a product of new capacity additions that have entered the NEM over the past year, including capacity continuing its ramp up while commissioning, and in the case of wind generation higher June wind speed.

Figure 39 Increased VRE output across mainland NEM

Average change in VRE generation – Q2 2022 versus Q2 2021



With continued increases in VRE output, several renewable generation records were set during the quarter:

- Highest VRE output – NEM VRE output (wind and grid-scale solar) reached 9,012 MW at 1300 hrs on 6 June 2022, 636 MW higher than the previous record set in Q1 2022.
- Highest wind output – NEM wind output reached 6,743 MW at 1700 hrs on 31 May 2022, surpassing the previous record set in Q3 2021 by 341 MW.

Average wind generation was 2,916 MW this quarter, with increases across the mainland NEM particularly in Victoria (+212 MW) and New South Wales (+178 MW). Quarterly output grew predominantly because of substantially higher generation during June (Figure 40), driven by ramping up of key wind farms and much higher wind speeds. NEM-wide available capacity factor for wind generation in June 2022 averaged 40%, well above the 3-year June average of 33% (Figure 41).

Figure 40 Wind output up substantially in June

Average monthly wind output by region – April-21 to June-22

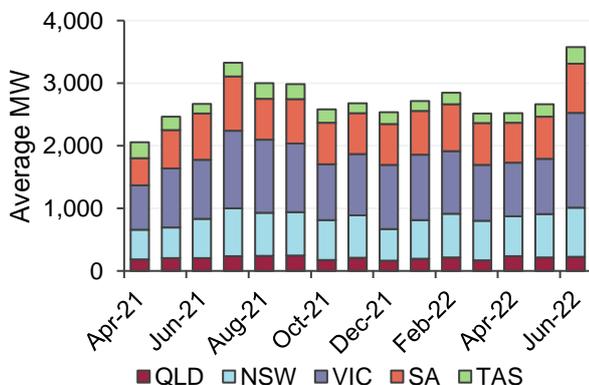
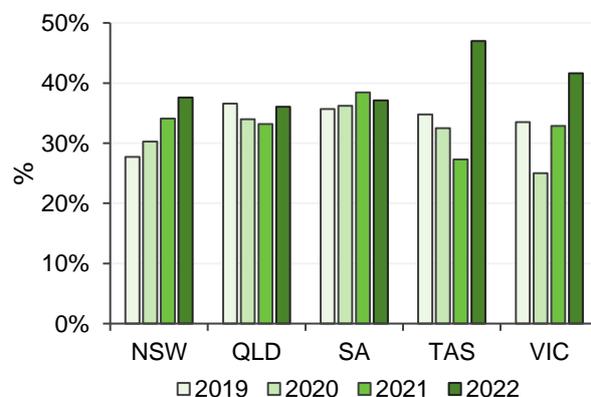


Figure 41 Significant increase in June wind speeds

Volume weighted wind capacity factors by region – June³⁴



³⁴ Capacity factors of each project are weighted by maximum capacity to derive the weighted average by state. Project capacity factors are calculated using average availability divided by maximum installed capacity. The use of availability instead of generation removes the impact of any economic offloading or curtailment and better captures plant available capacity and underlying wind or solar resource levels.

- In Victoria, increased output from Stockyard Hill Wind Farm (+168 MW) – Australia’s largest operating wind farm – accounted for the majority of output increase in the state this quarter. During June, output from Stockyard Hill progressively increased close to full capacity³⁵ as it moved to its next stages of commissioning.
- Higher wind output in New South Wales this quarter was due to a combination of continued ramp up of recently installed capacity (Bango, Gullen Range 2 and Crudine Ridge wind farms) and increased wind speed, with available capacity factors increasing from 29% in Q2 2021 to 34% this quarter.
- Similarly, increased output from South Australian wind farms this quarter (+103 MW) was mainly due to higher wind speeds, with new capacity entering the market over the past year also contributing. One new wind farm commenced generation in the state this quarter – Port Augusta Renewable Energy Hub (201 MW).

While average grid-scale solar output increased by 145 MW relative to Q2 2021, growth was impacted by the ongoing La Niña weather pattern, with solar irradiation levels well down across all regions this quarter.

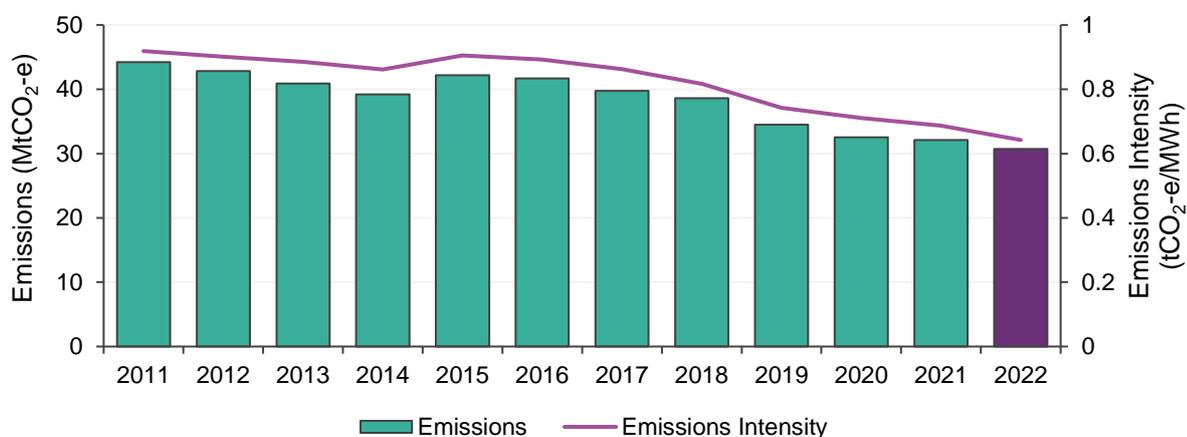
- Despite lower solar irradiation in New South Wales, continued ramp up of newly installed capacity coupled with output from new capacity additions over the past year were key drivers of increased output.
- In Queensland, cloudy wet conditions also impacted grid-scale solar output, with May being most affected. However lower output due to lower solar irradiation was largely offset by ramping up of recently installed capacity as well as higher output from Sun Metals Solar Farm which was out of service in Q2 last year. During the quarter, two new solar farms commenced generation in the state – Woolooga Solar Farm (176 MW) and Columboola Solar Farm (162 MW).
- Conversely, in Victoria, despite contributions from ramping up of recently installed capacity such as Winton Solar Farm, average grid-scale solar output declined slightly by 7 MW, again driven by lower solar irradiation.

1.3.5 NEM emissions

During the quarter, NEM emissions declined to their lowest Q2 on record at 30.7 million tonnes carbon dioxide equivalent (MtCO₂-e), 4% lower than a year ago (Figure 42), despite increased operational demand. The reduction was driven by lower coal generation combined with continuing growth in VRE output.

Figure 42 Record low Q2 quarterly emissions

Quarterly NEM emissions and emissions intensity (Q2s)



³⁵ Registered at 511 MW maximum capacity.

1.3.6 Storage

Batteries

Total estimated net battery market revenue reached \$41 million in Q2 2022, representing the second-highest quarter on record (Figure 43). Net revenue increased compared to Q2 2021 (+\$23 million), with contributions from both energy arbitrage (+\$17.9 million) and frequency control ancillary services (FCAS) markets (+\$5.5 million). Continuing on the trend noted in the Q1 2022 QED report, the proportion of total gross revenue from the energy markets trended upwards this quarter, from 49% in Q1 2022 to 64%, supplanting FCAS markets as the primary source of battery revenue (Figure 44). Higher energy market revenue reflected increased battery dispatch volume, particularly in Victoria, as well as a significant increase in energy arbitrage value from higher spot prices during the quarter.

Figure 43 Second highest net revenue on record

Estimated battery revenue sources – quarterly

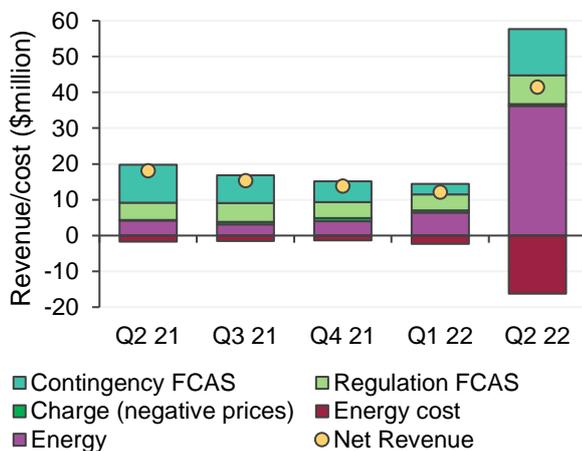
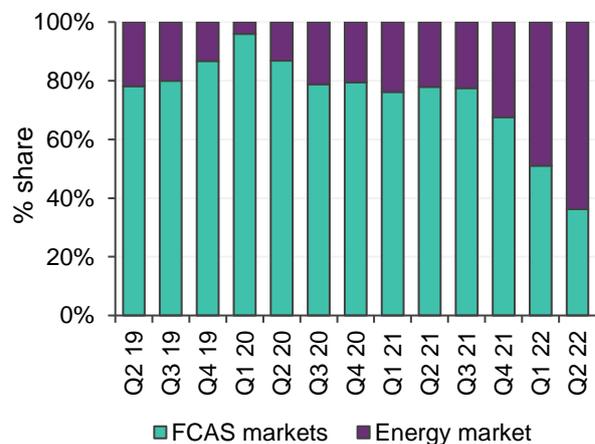


Figure 44 Energy markets' share continuing to rise

FCAS and energy market share of total gross revenue – quarterly



By region, compared to Q2 2021:

- The marked increase in net revenue in Victoria this quarter (+\$13.8 million) from both energy arbitrage (+\$7.2 million) and FCAS markets (+\$6.6 million) was driven by increased activity from the Victorian Big Battery (VBB). A key driver for increased participation from VBB this quarter was the battery's ability to participate in energy and FCAS markets at its full capacity outside of the System Integrity Protection Scheme (SIPS) contract period from 1 November to 31 March³⁶.
- In Queensland, higher net revenue (+\$4.5 million) predominantly from the energy markets was due to increased dispatch at Wandoan battery energy storage system (BESS) as it fully commissioned from early May. However, Wandoan was also enabled for FCAS towards the end of Q2 following its registration in all eight markets on 21 June.
- Battery net revenue in New South Wales increased by \$4.2 million this quarter, with almost equal contribution from energy and FCAS markets.
- Net revenue from South Australian batteries only increased slightly this quarter (+\$0.9 million) as increased revenue from energy markets (+\$4.2 million) was largely offset by a decline in FCAS revenue (-\$3.3 million).

³⁶ Under the SIPS contract, AEMO reserves up to 250 MW of VBB's 300 MW capacity to support a control scheme to increase capability of the Victoria – New South Wales Interconnector (VNI) and respond to unexpected network outages in Victoria between 1 November and 31 March of each year until 2032.

- Higher net revenue from energy markets arose from increase in volume-weighted average energy arbitrage value (from \$88/MWh to \$306/MWh) offsetting lower energy dispatch (-16%). Lower FCAS revenue, particularly from the contingency FCAS markets, was largely due to a decline in volumes enabled in those markets as recently commissioned batteries in other regions competed for FCAS market share.

Battery operation during administered pricing and market suspension

An observable impact on battery operation from the application of administered price caps followed by market suspension in the NEM is illustrated in Figure 45 and Figure 46. As shown in Figure 45, there was a notable decline in battery discharge after the APP commenced in Queensland on 12 June, a reflection of reduced availability. A further decline in availability and therefore battery discharge occurred on 15 June following spot market suspension in all regions. Possible factors that drove these reductions in activity in the energy markets during APP and market suspension were the decrease in energy price arbitrage spread and limited storage capability resulting in a lower incentive for batteries to participate. Conversely, battery FCAS enablement increased substantially over this period, as shown in Figure 46.

Figure 45 Reduction in battery discharge during APP and market suspension

Average daily battery discharge by region – June 2022

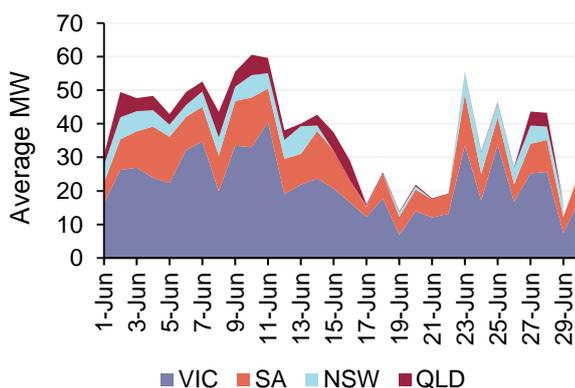
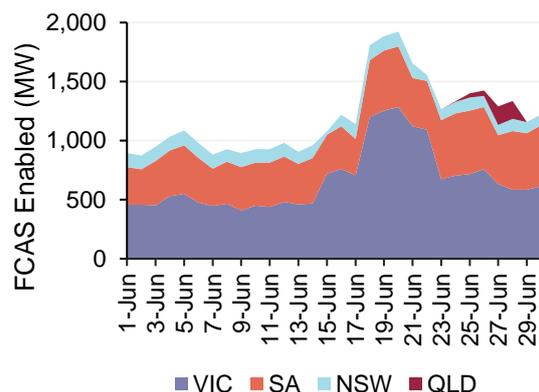


Figure 46 FCAS enablement increased substantially during APP and market suspension

Average daily FCAS enablement by region (stacked) – June 2022



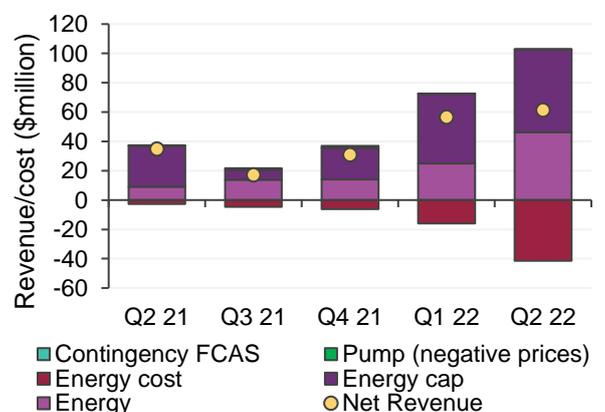
Pumped hydro

Pumped hydro spot market revenue in Q2 2022 continued to trend upwards, reaching a quarterly record of \$61 million, surpassing the previous high of Q1 2022 and \$27 million higher than Q2 2021 (Figure 47). This was driven by revenue increases at both Wivenhoe and Shoalhaven Pumped Hydro which contributed \$15 million and \$12 million, respectively.

Increased utilisation at both pumped hydro stations this quarter, coupled with sustained high spot prices across the NEM, were key drivers of this record. In particular, Shoalhaven’s utilisation was up substantially this quarter (+648%) compared to Q2 2021 when the generator was on an extended outage for most of the quarter.

Figure 47 Record high pumped hydro revenue

Estimated pumped hydro revenue sources – quarterly



1.3.7 Wholesale demand response

Following the NEM’s first dispatch of Wholesale Demand Response (WDR) during Q1 2022, the mechanism³⁷ continued to gain momentum with active participation from the New South Wales and Victorian units during Q2 2022, especially in May and June at times of high electricity price and supply scarcity (Figure 48).

WDR units in New South Wales, accounting for more than half of total capacity (Figure 49), were particularly responsive in the market during the quarter, dispatching close to their full capacity in early May when the region experienced extreme spot price volatility. On 3 May, transmission line outage in the state compounded with constraints on the Victoria – New South Wales Interconnector (VNI) limiting imports and a particularly steep bidding curve led to spot prices spiking above \$10,000/MWh during the evening peak. Over this period, up to 30 MW³⁸ of WDR from five New South Wales units was dispatched between 1730 hrs and 2115 hrs.

In Victoria, WDR units also participated throughout the quarter, with up to 14 MW dispatched during a period of price volatility on 13 June. As WDR typically dispatches at times of very high spot prices when supply-demand conditions are tight, the average prices received³⁹ for the New South Wales and Victorian units during Q2 were high at \$1,852/MWh and \$759/MWh, respectively.

Figure 48 Active participation from WDR units

NSW and VIC WDR daily maximum dispatch – May and June-22

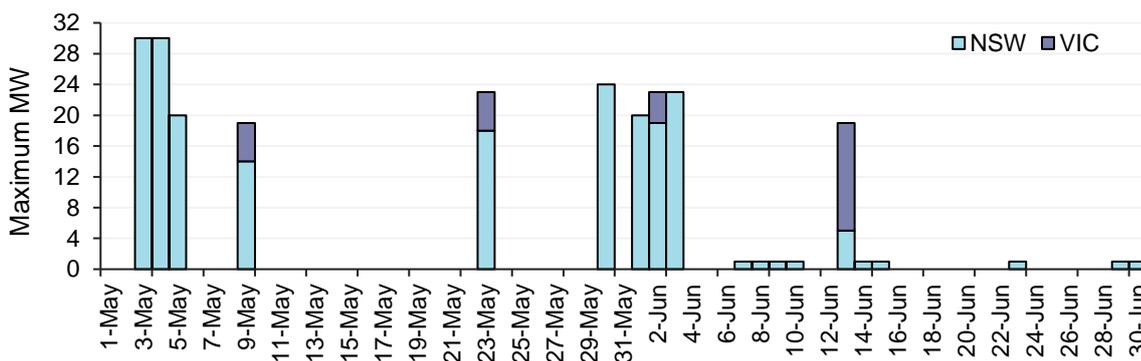
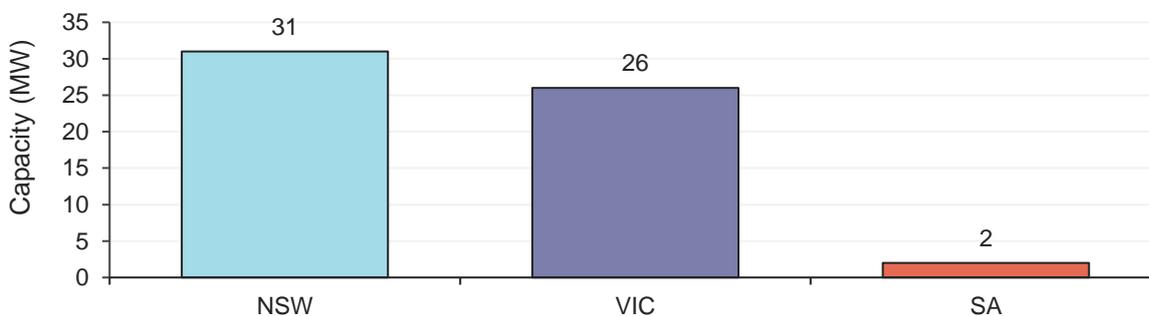


Figure 49 Majority WDR registration in NSW and VIC

Total WDR capacity registered by region as at 30 June 2022



³⁷ The WDR mechanism commenced operation on 24 October 2021. WDR enables demand-side (consumer) participation in the NEM spot market separately from retail energy procurement.

³⁸ Dispatch target a WDR unit receives from AEMO. Under the rules governing WDR, the quantity of response provided will be assessed by comparing metered consumption (or export) against a baseline, which reflects a counter-factual level of demand of the WDR unit. The actual quantity of demand response assessed as being provided by WDR units is confidential.

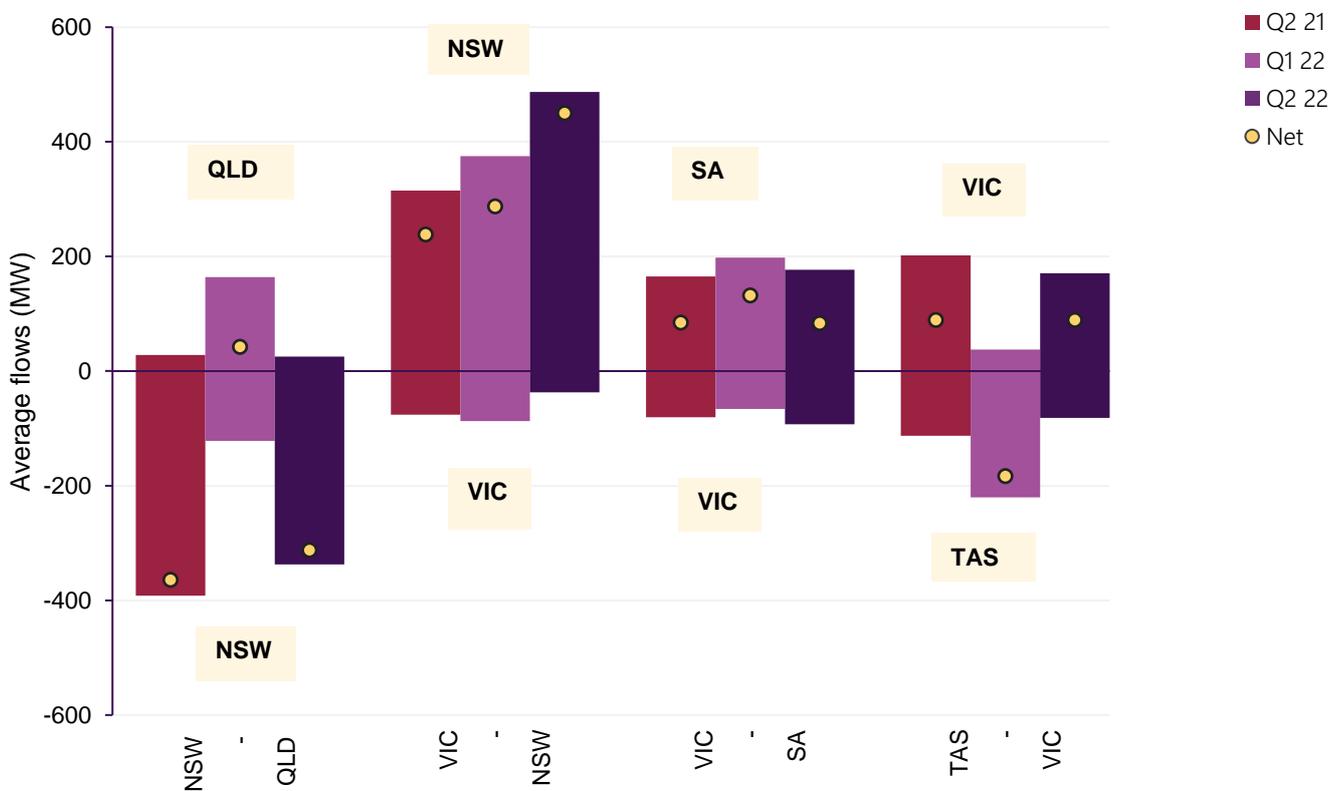
³⁹ Calculated based on dispatch target a WDR unit receives from AEMO.

1.4 Inter-regional transfers

Inter-regional energy transfers in Q2 were similar to levels in Q2 2021, with the exception of net flows from Victoria into New South Wales over VNI, which increased by 89% from a Q2 2021 average of 239 MW to 450 MW (Figure 50). This increase reflected a much larger average energy price difference between the two regions in Q2 2022 at \$46/MWh compared with \$11/MWh in Q2 2021. Relative to recent quarters, flows were also less affected by the daytime constraints on VNI discussed in recent QEDs, due to seasonally lower solar generation levels in south western New South Wales and north western Victoria.

Figure 50 Transfers from Victoria to New South Wales rise with price differential and fewer constraints

Quarterly inter-regional transfers



1.4.1 Inter-regional settlement residue

Higher spot prices, large absolute price differences between regions, and episodes of regional price volatility combined to yield the highest quarterly aggregate level of positive inter-regional settlement residues (IRSR) since the current regional structure of the NEM was established in July 2008. Positive IRSR totalled \$156 million, \$41 million higher than in Q2 2021, and \$10 million above the previous high recorded in Q4 2009 (Figure 51). Higher flows on VNI and the large price difference between these regions noted in the previous section also resulted in a quarterly record positive IRSR of \$91 million on Victoria to New South Wales transfers, \$22 million above Q2 2021.

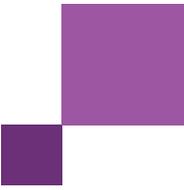
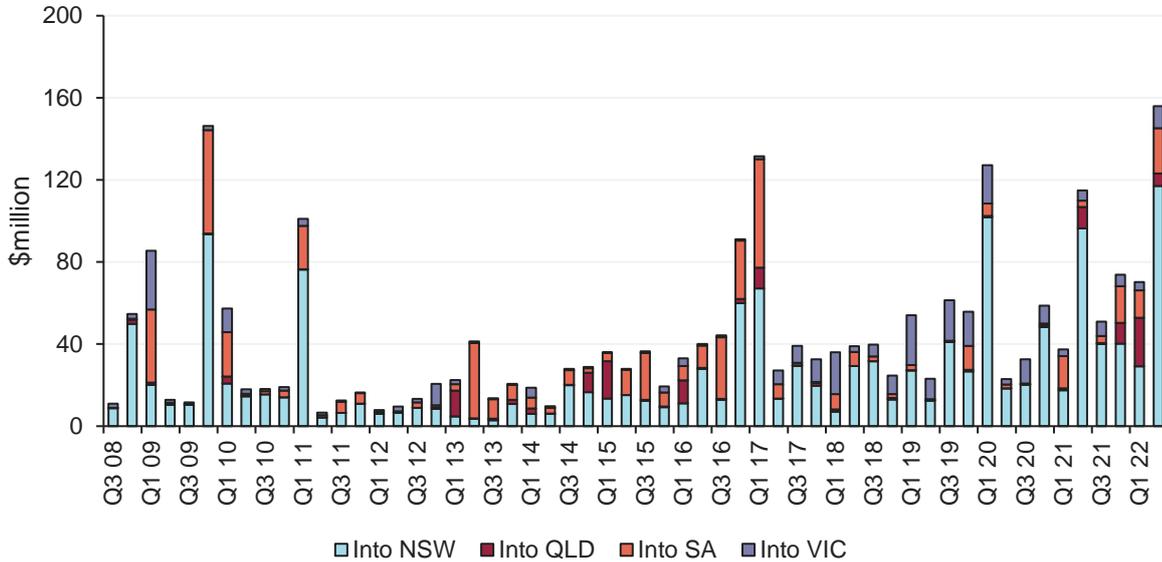


Figure 51 Regional price differences and volatility drive record quarterly positive IRSR

Quarterly positive Inter-regional settlement residue by region



Negative residue management

Negative IRSR totalled \$11 million in Q2 2022, comparable to recent quarters but still the third highest Q2 level since 2009 (Figure 52). Accumulation of negative residues was generally concentrated on days when price volatility in a region coincided with transmission constraints which forced flows into an adjoining region against a large spot price difference. Examples included constraints on QNI creating negative IRSR on flows into New South Wales over 7-9 June, and intra-regional constraints in New South Wales in early May driving counter-price flows into Victoria during a period of price volatility in New South Wales (Section 1.2.3, Figure 22).

Figure 52 Negative inter-regional settlement residues remain elevated

Quarterly negative inter-regional settlement residue

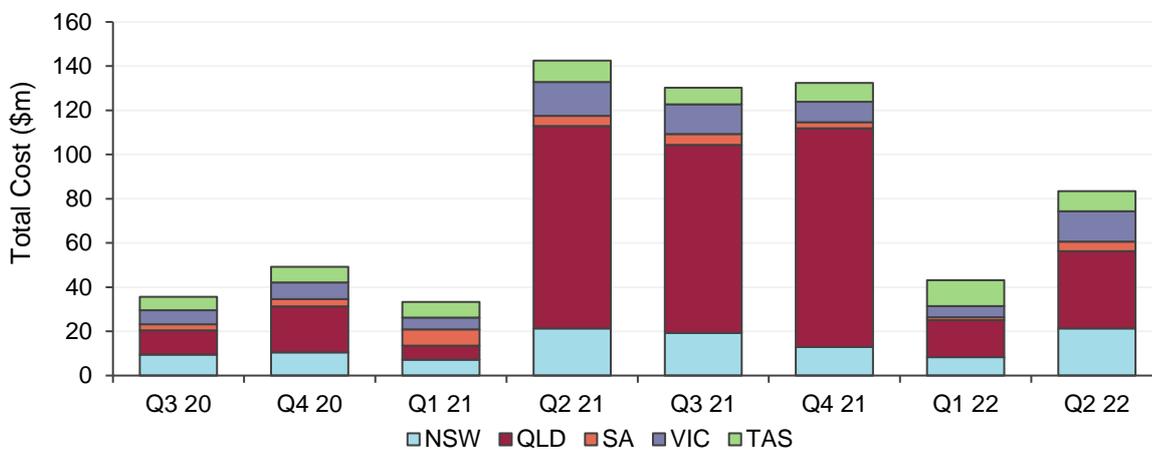


1.5 Frequency control ancillary services (FCAS)

Total FCAS costs for Q2 2022 were \$84 million, down \$59 million on the very high level of Q2 2021, with all but \$2 million of this reduction attributable to Queensland, where costs between Q2 and Q4 2021 were extremely elevated by FCAS price volatility attributable to upgrade-related outage constraints on QNI (Figure 53). Relative to Q1 2022, total FCAS costs increased by \$40 million (93%), with all states except Tasmania experiencing increases. These increases were attributable to higher costs for contingency raise services (+\$39 million) and regulation raise (+\$9 million), with FCAS prices for these services being most directly affected by spot energy prices⁴⁰.

Figure 53 Total FCAS costs down from Q2 2021 but well above Q1 2022 levels

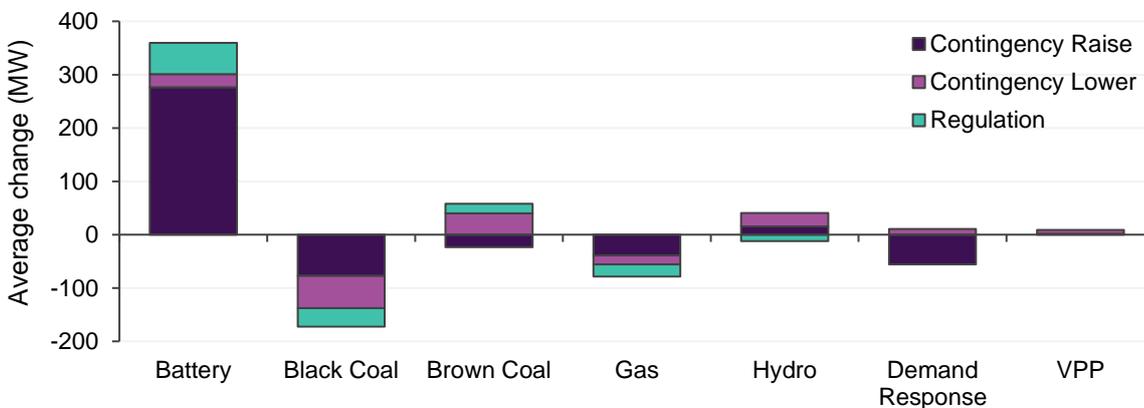
Quarterly FCAS cost by region⁴¹



Relative to Q2 2021, utility-scale battery provision of all FCAS products increased very strongly, taking market volume away from almost all other sources (Figure 54). This has been driven by the installation of an additional 476 MW of NEM utility-scale battery capacity by the end of Q2 2022, primarily at the Victorian Big Battery (300 MW), Wallgrove BESS (50 MW) in New South Wales, and Wandoan BESS (100 MW) in Queensland.

Figure 54 Batteries dominate FCAS market volume growth

Changes in FCAS enablement by technology – Q2 2022 vs Q2 2021



⁴⁰Provision of FCAS raise services by generators and batteries typically involves a trade-off against energy output in order to preserve capacity “headroom” for FCAS response. The opportunity cost of this headroom increases with high energy prices, impacting FCAS raise prices.

⁴¹Based on AEMO Settlement data and represents preliminary data that will be subject to minor revisions.

1.6 Power system management

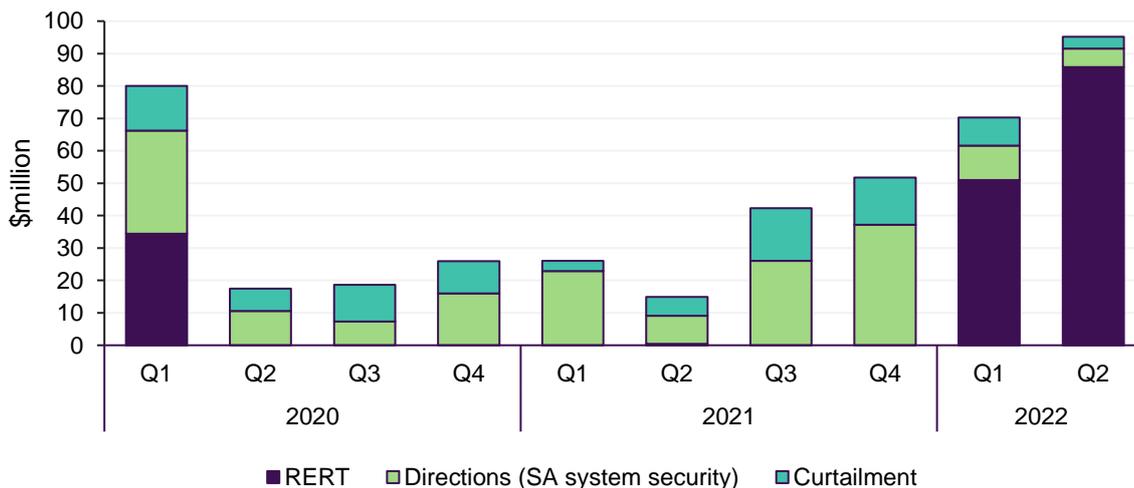
As outlined in the preface to this report and in Section 1.2.1, the level of intervention by AEMO required to maintain system reliability during June was unprecedented, and will result in contract and compensation costs under the NER. The magnitude of a large proportion of these costs, comprising compensation claims for operation under administered and market suspension pricing and directions cannot currently be estimated as claims are still being received and assessed⁴².

In this report, costs associated with power system management are only quantified for South Australian system security directions (Section 1.6.2) and RERT reserve contracts which were dispatched to maintain system reliability during administered pricing and market suspension (Section 1.6.1). An overview of direction activities undertaken to maintain system reliability is provided in Section 1.6.1.

As shown in Figure 55, even without inclusion of reliability direction and compensation costs, currently quantified power system management costs for Q2 2022 reached record levels, driven by RERT expenses.

Figure 55 Increase in NEM system costs driven by RERT activations to maintain reliability

Quarterly system costs by category⁴³ – excludes Q2 2022 reliability direction and compensation costs



1.6.1 Reliability and Emergency Reserve Trader and directions for reliability and security

During the quarter, both directions and RERT activation as discussed below were in response to specific lack of reserve (LOR) conditions requiring AEMO intervention. 406 actual and forecast LOR conditions were declared by AEMO during Q2, around 11 times higher than the levels in Q1 2022 and six times higher than Q2 last year (Table 2)⁴⁴.

⁴² Lists of the administered price cap compensation claims received by the AEMC have been published at <https://www.aemc.gov.au/our-work/apc-claims/current-and-historic>. Under the NER, claims for directions and suspension pricing compensation are to be submitted to AEMO in August, in accordance with the 2022 intervention settlement timetable published at <https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/market-operations/settlements-and-payments/prudentials-and-payments/settlement-calendars/intervention-settlement-timetables>.

⁴³ 'Power system management costs' are those associated with RERT, directions compensation and VRE curtailment. Market FCAS costs previously included in this section are now reported separately in Section 1.5. The notional cost of curtailed VRE is calculated using a generic value of \$40/MWh for output curtailed.

⁴⁴ AEMO's NEM Lack of Reserve Framework quarterly reports provide details of the methodology used for counting distinct Lack of Reserve declarations: <https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/power-system-operation/nem-lack-of-reserve-framework-quarterly-reports>

Table 2 Number of LOR declarations – Q2 2022 vs Q2 2021 and Q1 2022

LOR declaration	Q2 2021	Q1 2022	Q2 2022
Actual	30	11	55
Forecast	43	25	351
Total	73	36	406

Directions for reliability and security

During June, AEMO issued numerous directions to market participants across the NEM to maintain system reliability and security. Table 3 summarises daily direction activities that occurred between 10 June and 23 June and illustrates the magnitude of directions that were issued during this time, with directions on some days covering close to 5 GW of capacity. AEMO's forthcoming reviewable operating incident report will discuss these market intervention events in more detail, however the following provides a high level overview of this series of events:

- On 10 June 2022, there were noticeable changes in generator bidding including the reduction of capacity in market supply offers, as the cumulative price in several NEM regions approached the CPT which would trigger the administered price cap (Section 1.2.1). The reduction of available capacity led to actual LOR2 conditions in Queensland which necessitated the first reliability direction associated with this series of events.
- On 12 June, CPT was reached in Queensland at 1850 hrs. This was followed by New South Wales, South Australia and Victoria on 13 June (Section 1.2.1). Commencement of the APP coincided with reductions in the amount of generation offered into the market, resulting in forecast and actual LOR conditions requiring AEMO to intervene by directing generators to make capacity available for system reliability.
- Over the following days, AEMO continued to intervene and direct market participants, with directed capacity reaching close to 5 GW on 14 and 15 June. The large number of constraints necessary to manage directions and supply limitations created issues for AEMO's automated systems and processes that become impossible to manage, ultimately resulting in AEMO suspending the market on 15 June at 1400 hrs.
- AEMO continued to issue directions under market suspension, however the volumes and number of directions required progressively declined after 18 June, with all directions cancelled by 23 June.

Table 3 Summary of NEM daily direction activities – 10 June to 23 June

Date	MW of NEM directed capacity per day ⁴⁵	NEM number of direction related participant notices per day
10/06/2022	260	2
11/06/2022	0	0
12/06/2022	260	4
13/06/2022	3544	37
14/06/2022	4668	30
15/06/2022	4945	48
16/06/2022	3849	46
17/06/2022	2728	110
18/06/2022	4565	71

⁴⁵ 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.

Date	MW of NEM directed capacity per day ⁴⁵	NEM number of direction related participant notices per day
19/06/2022	2680	16
20/06/2022	1426	25
21/06/2022	1085	30
22/06/2022	899	26
23/06/2022	0	38 (all notices were cancellations of directions)

Reliability and Emergency Reserve Trader (RERT)

AEMO activated RERT reserves⁴⁶ on three occasions during the June APPs and market suspension when available wholesale market reserves were insufficient to maintain system reliability. Table 4 summarises these interventions, which had a total estimated cost of \$86 million. AEMO will shortly be publishing a Quarterly RERT report providing full details of RERT activation and dispatch.

Table 4 Estimated payments and volumes for RERT activation – Q2 2022⁴⁷

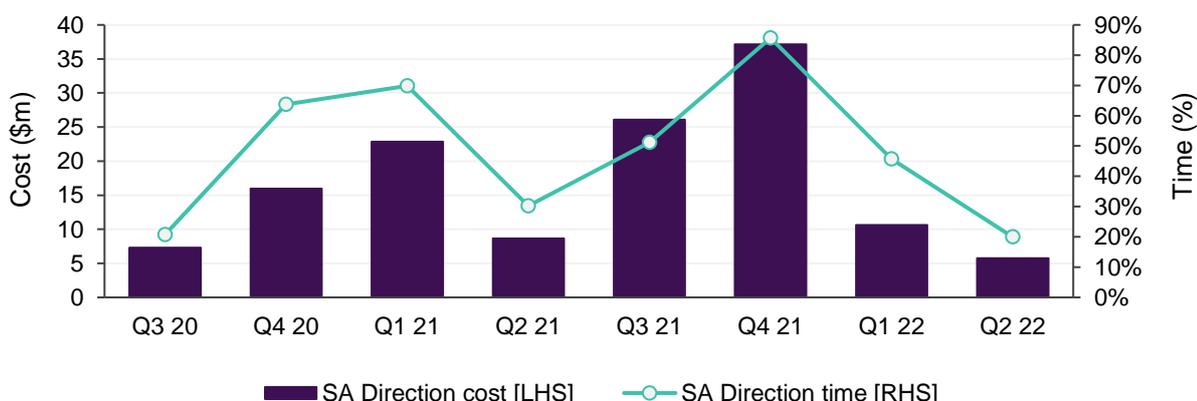
Date	Region	Activation reason	Estimated volume (MWh)	Estimated cost (\$ million)
14 June 2022	NSW	Forecast LOR 3	900	\$21.6
15 June 2022	NSW	Forecast LOR 2 and 3	1,484	\$30.1
	QLD	Forecast LOR 2 and 3	241	\$4.2
17-18 June 2022	NSW	Forecast LOR 2	1,417	\$29.9

1.6.2 South Australia system security directions

During Q2 2022, AEMO continued to issue directions to generators in South Australia to maintain system security. South Australian system security directions costs declined to \$5.8 million this quarter, \$2.9 million and \$4.9 million lower than Q2 2021 and Q1 2022, respectively (Figure 56).

Figure 56 South Australian direction costs continue to decline

Time and cost of system security directions (energy only) in South Australia



Note: direction costs are preliminary costs which are subject to revision

⁴⁶ 'RERT reserves' are non-market generation or demand-side resources procured by AEMO under provisions of the NER (Rule 3.20) specifically to manage conditions where levels of reserve in the wholesale spot market are insufficient to maintain adequate reliability.

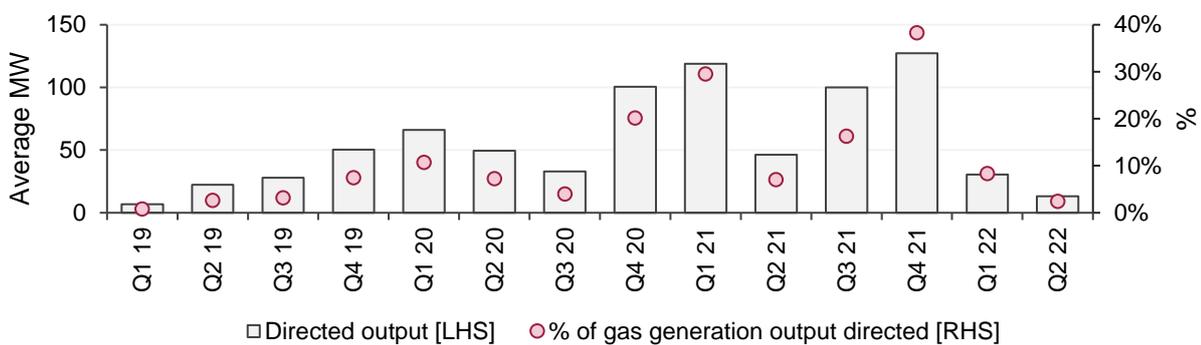
⁴⁷ AEMO 2022, RERT Reporting: <https://aemo.com.au/en/energy-systems/electricity/emergency-management/reliability-and-emergency-reserve-trader-rert/rert-reporting>

Lower directions costs – despite an increase in the average 12-month 90th percentile spot price⁴⁸ – was a reflection of much lower volumes directed, decreasing from an average of 31 MW in Q1 2022 to just 13 MW this quarter, the lowest quarterly levels since Q1 2019 (Figure 57). With reduced volumes directed, the proportion of South Australian gas generation output being attributable to directions also fell to just 2% from 8% in Q1 2022.

The key driver of reduced volumes directed this quarter was the sustained high spot prices across the NEM as discussed in Section 1.2. With South Australian spot prices exceeding \$100/MWh 81% of the time this quarter compared to 22% in Q1 2022, it was more economic for gas generators to remain online, reducing requirements for AEMO to direct them for system security.

Figure 57 Lowest volume directed since Q1 2019

South Australian gas-fired generation directed

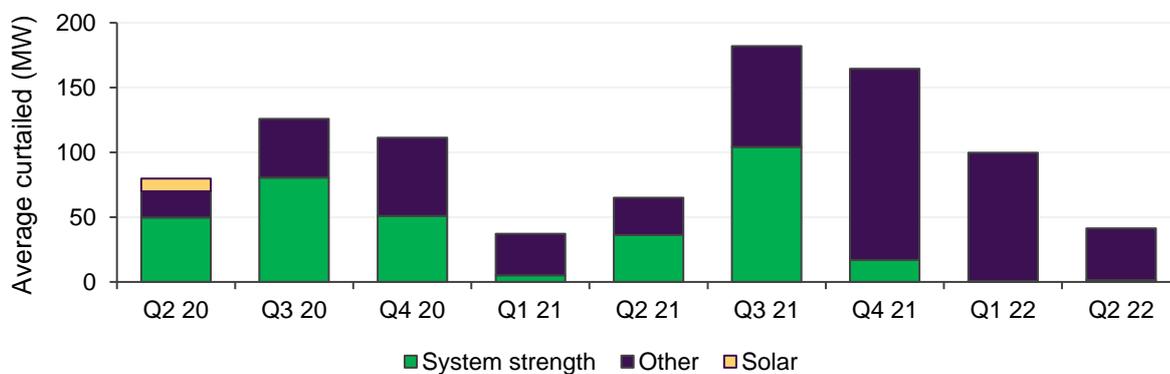


1.6.3 VRE curtailment

Continuing recent quarterly trends, curtailment of grid-scale wind and solar generation due to transmission congestion, security, or system strength constraints reduced to an average of 41 MW in Q2, down by 59 MW from Q1 and by 24 MW from Q2 2021 (Figure 58). Reduced curtailment relative to Q2 2021 reflected the near-disappearance of curtailment for system strength reasons (-35 MW), principally in South Australia due to commissioning of the region’s synchronous condensers. Curtailment for transmission congestion and other reasons increased (+11 MW) on a year ago primarily due to year-on-year growth in VRE output. As a proportion of available VRE generation, curtailment represented a NEM-wide average of 1.1% of potential output, its lowest level since Q1 2019, with the level in each region well below 2%.

Figure 58 VRE curtailment continuing to reduce

Average NEM VRE curtailed by curtailment type



⁴⁸ Used as a benchmark for compensating participants.

2 Gas market dynamics

2.1 Wholesale gas prices

Quarterly average prices were at record levels across all AEMO markets, averaging \$28.40/GJ compared to \$8.20/GJ in Q2 2021 (Table 5). Sydney and Brisbane markets were placed under an administered price cap from 24 May to 7 June due to a retailer of last resort (RoLR) event. Brisbane's price was capped at \$40/GJ, while Sydney's price began at \$28/GJ then increased to \$40/GJ from 1 June. Victoria's Declared Wholesale Gas Market (DWGM) was capped at \$40/GJ from 10am on 30 May due to Cumulative Price Threshold (CPT) exceedance. This price cap remained in effect for all of June. Sydney's price was also capped at \$40/GJ from 8-14 June due to CPT exceedance after the RoLR event ended. The RoLR events and their effect on the gas markets are discussed in Section 2.1.2. The CPT events are discussed in Section 2.1.3.

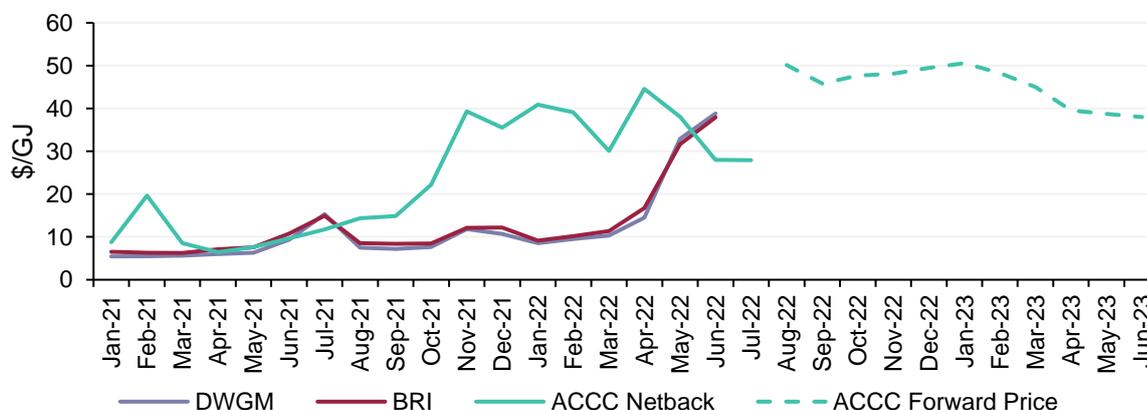
Table 5 Average gas prices – quarterly comparison

Price (\$/GJ)	Q2 2022	Q1 2022	Q2 2021	Change from Q2 2021
DWGM	28.81	9.47	7.22	299%
Adelaide	29.88	10.18	8.69	244%
Brisbane	28.81	10.22	8.48	240%
Sydney	28.87	9.81	8.46	241%
GSH	25.62	9.97	8.14	215%

Domestic market prices had remained significantly lower than international prices since August 2021, as represented by the Australian Competition and Consumer Commission (ACCC) netback price (Figure 59). Prices rose sharply across all markets in May narrowing the gap between domestic and international prices. By June domestic prices exceeded the netback price for the first time since July 2021, by almost \$10/GJ. The ACCC forward curve indicates the effect on this netback price of high international gas price expectations extending well into 2023. Drivers for higher international prices are discussed in Section 2.1.1.

Figure 59 Domestic prices reach record levels surpassing international netback in June

ACCC netback and forward prices⁴⁹; DWGM and STTM Brisbane average gas prices by month

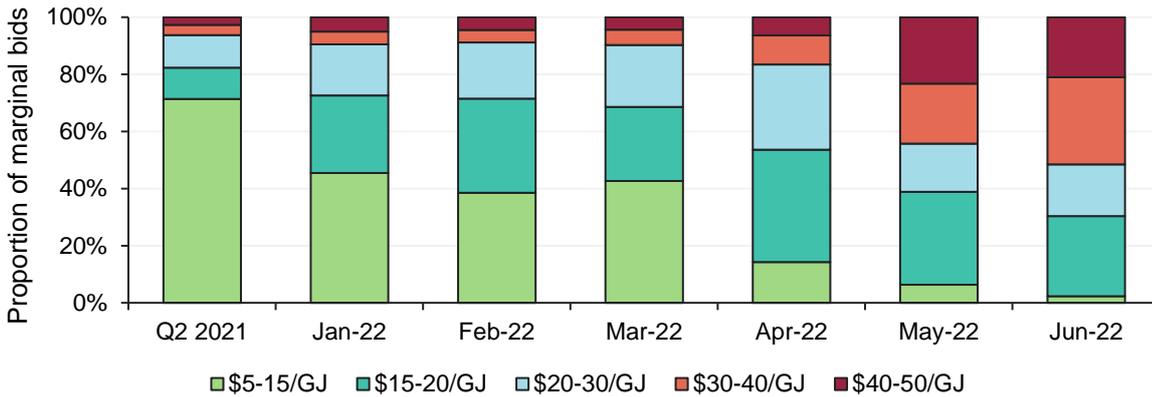


⁴⁹ ACCC 2022, LNG netback price series: <https://www.accc.gov.au/regulated-infrastructure/energy/gas-inquiry-2017-2025/lng-netback-price-series>

The record market prices coincided with an increase in demand during May as a result of increased heating demand, higher gas-fired generation (Section 2.2.1) and gas supply limits, with participants carefully managing their Iona storage inventory levels which were trailing behind 2021 levels (Section 2.3.2). Consequently, prices in all markets reached international levels, and surpassed them into June. The tighter supply and demand situation prompted market participants to move bid volumes into higher price bands (Figure 60).

Figure 60 DWGM bids driving record prices in Q2 2022

DWGM – proportion of marginal bids by price band



2.1.1 International energy prices

International energy commodity price volatility continued into Q2 2022, influenced by the war in Ukraine and sanctions against Russia. Thermal export coal prices averaged A\$514/tonne, A\$147/tonne higher than the previous quarter⁵⁰, after briefly reaching a high of A\$595/tonne on 20 May, close to the previous record (A\$604/tonne) set on 2 March 2022 (Figure 61).

Figure 61 Thermal coal rally towards previous record high

Newcastle export thermal coal A\$/Tonne daily



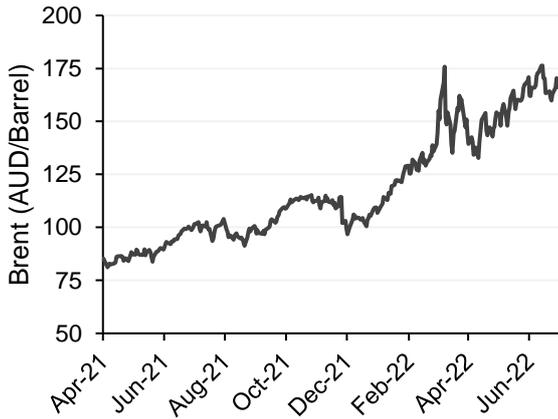
Source: Bloomberg ICE data

⁵⁰ Bloomberg 2022, Russia's war is turbocharging the world's addiction to coal: <https://www.bloomberg.com/news/articles/2022-04-25/coal-prices-soar-as-russia-war-energy-crisis-risk-global-climate-goals?sref=kkhkDP70>

Influenced by sanctions on Russian oil exports⁵¹, Brent Crude oil averaged A\$157/barrel during the quarter, A\$22/barrel higher than in Q1 2022 and reached the same intra-quarter high of A\$176/barrel seen in Q1 (Figure 62). Asian LNG prices were comparable to the previous volatile quarter, averaging A\$36/GJ or A\$3.5/GJ lower, while ending the quarter near Q1 2022 highs at A\$51/GJ as uncertainty and volatility continued (Figure 63).

Figure 62 Brent Crude oil rally on sanctions

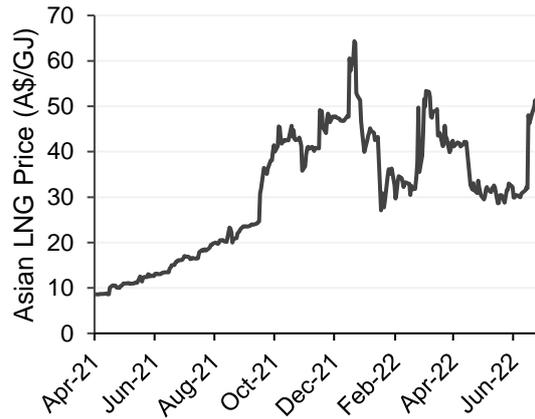
Brent Crude oil in A\$/Barrel daily



Source: Bloomberg ICE data

Figure 63 Asian LNG prices stabilise at high levels

Asian LNG price in A\$/GJ daily



Source: Bloomberg ICE data

2.1.2 Retailer of Last Resort impact on gas markets

On 23 May 2022, AEMO issued a suspension notice to Weston Energy due to a failure to meet financial obligations under the National Gas Rules (NGR), effective from 24 May 2022. This suspension applied to the Adelaide, Brisbane and Sydney STTM hubs⁵², as well as the DWGM in Victoria⁵³. Consequently under the NGR AEMO declared a minor RoLR event for Brisbane, and due to Weston’s greater share of the Sydney market, a major RoLR event for Sydney. This was the first time in STTM history that either of these RoLR thresholds in the NGR had been met.

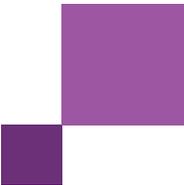
A minor RoLR event meant prices in Brisbane would be capped at \$40/GJ until 7 June, while for a major RoLR event the NGR prescribe a different calculation using the average Sydney price over the previous 30 days. As prices had been increasing from lower levels over May, using a 30 day average led to an outcome where the Sydney price was initially set at approximately \$28/GJ, significantly lower than other markets. This form of pricing was required to continue under the NGR until 21 June.

The lower Sydney market cap meant that many market participants were sourcing gas at a cost up to \$10-12/GJ higher than the Sydney price. Consequently, for 25 May a shortfall between forecast Sydney demand and supply occurred, triggering a Contingency Gas event. This led to AEMO instigating an industry teleconference, which eventually led to additional gas being supplied to Sydney to avoid a supply shortfall.

⁵¹ Bloomberg 2022, EU approves partial Russian oil ban: <https://www.bloomberg.com/news/articles/2022-06-02/eu-approves-partial-russian-oil-ban-sanctions-on-sberbank?sref=kxhkDP70>

⁵² See AEMO’s STTM reports for further information: <https://aemo.com.au/energy-systems/gas/short-term-trading-market-sttm/sttm-events-and-reports>

⁵³ See AEMO’s DWGM reports for further information: <https://aemo.com.au/en/energy-systems/gas/declared-wholesale-gas-market-dwgm/dwgm-events-and-reports>



On 30 May a New South Wales Ministerial Direction was made to AEMO to effectively apply the minor RoLR event price capping to the Sydney hub. This brought forward the end of the administered price period from 21 June to 7 June in line with Brisbane, and removed the 30-day average price calculation, bringing the Sydney hub price in line with other markets, although the price remained capped due to CPT exceedance until 14 June.

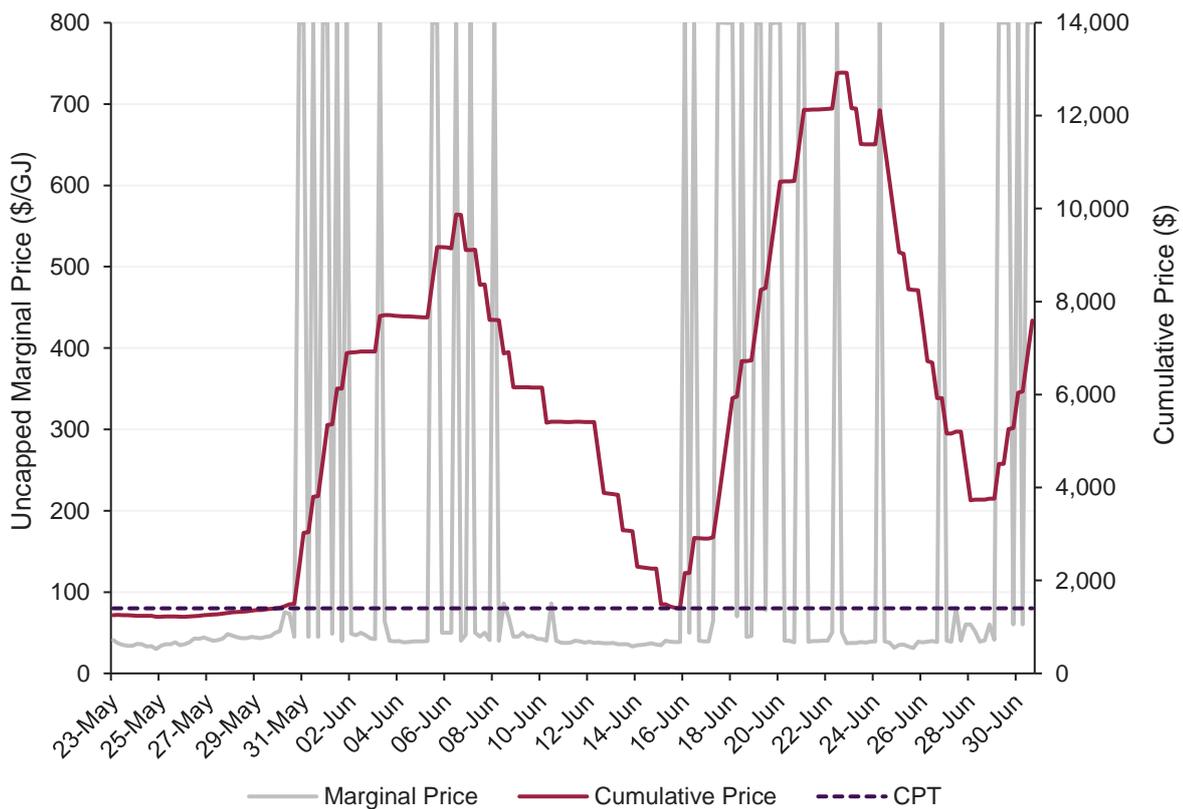
2.1.3 Cumulative Price Threshold exceedance

In the Victorian DWGM the CPT is set at \$1,400/GJ. The market rules require that if the cumulative price is greater than or equal to CPT then an administered price period is triggered, which caps the price at \$40/GJ. The cumulative price calculation encompasses the previous 35 consecutive trading schedules, which for the DWGM is equal to one week.

On 30 May at the 1000 hrs schedule the cumulative price exceeded \$1,400, triggering an administered pricing period. This is the first time in DWGM history the market price cap has been applied. Many schedule (marginal) prices subsequently exceeded \$40/GJ after the cap was put in place, meaning the price cap remained in place for the rest of the quarter (Figure 64).

Figure 64 DWGM uncapped schedule and cumulative prices

Uncapped DWGM marginal price and cumulative price



In Sydney a CPT event also occurred immediately at the end of the minor RoLR event. The STTM CPT is \$440 with the cumulative price calculation considering uncapped prices over the previous seven days. As the uncapped price calculation under the RoLR event had exceeded the threshold, this triggered the price cap of \$40/GJ. The price cap ended in Sydney after gas day 14 June when the cumulative price dropped below the threshold.

2.2 Gas demand

Total east coast gas demand slightly increased compared to Q2 2021 (+0.5%, Figure 65, Table 6). A significant increase in gas-fired generation demand (+9.7 PJ) was largely offset by demand reductions for Queensland liquefied natural gas (LNG) production (-1.8 PJ) and in AEMO markets (-5.7 PJ) where decreases were due to a combination of milder weather across all regions leading to reduced heating demand in April and May, as well as lower Commercial and Industrial (C&I) demand in all regions except Sydney.

Figure 65 Higher gas-fired generation demand largely offset by other reductions

Change in east coast gas demand – Q2 2022 vs Q2 2021

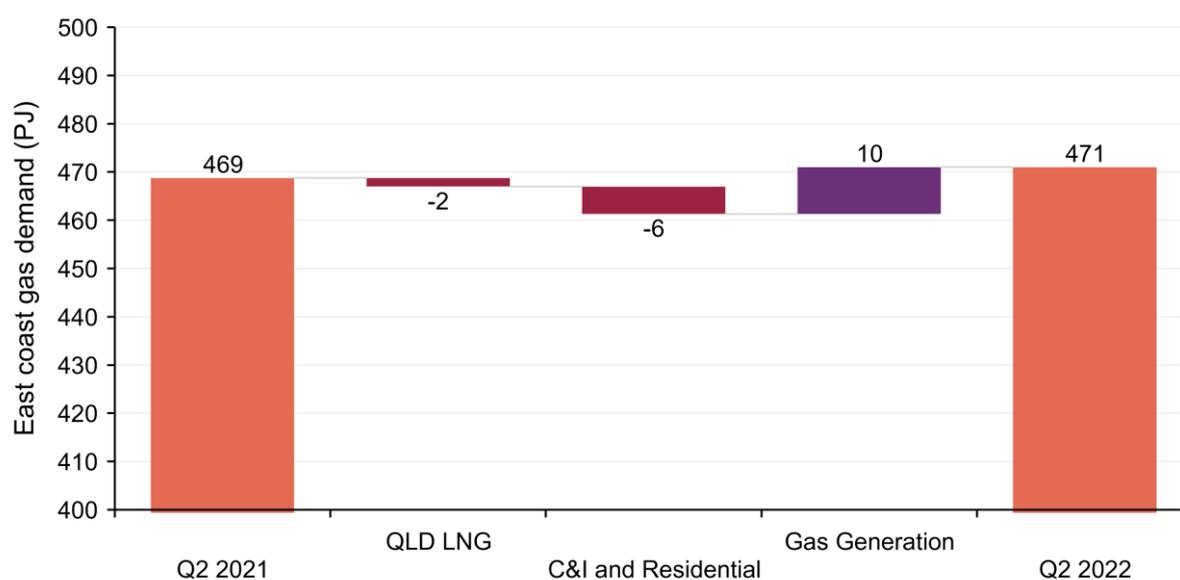


Table 6 Gas demand – quarterly comparison

Demand (PJ)	Q2 2022	Q1 2022	Q2 2021	Change from Q2 2021
AEMO Markets *	91.8	52.5	97.5	-6 (-6%)
Gas-fired generation **	45.1	26.8	35.4	10 (+28%)
QLD LNG	334.0	358.3	335.8	-2 (-1%)
TOTAL	471.0	437.7	468.8	2 (+0.5%)

* AEMO Markets demand is the sum of customer demand across STTM hubs and the DWGM and excludes gas-fired generation in these markets.

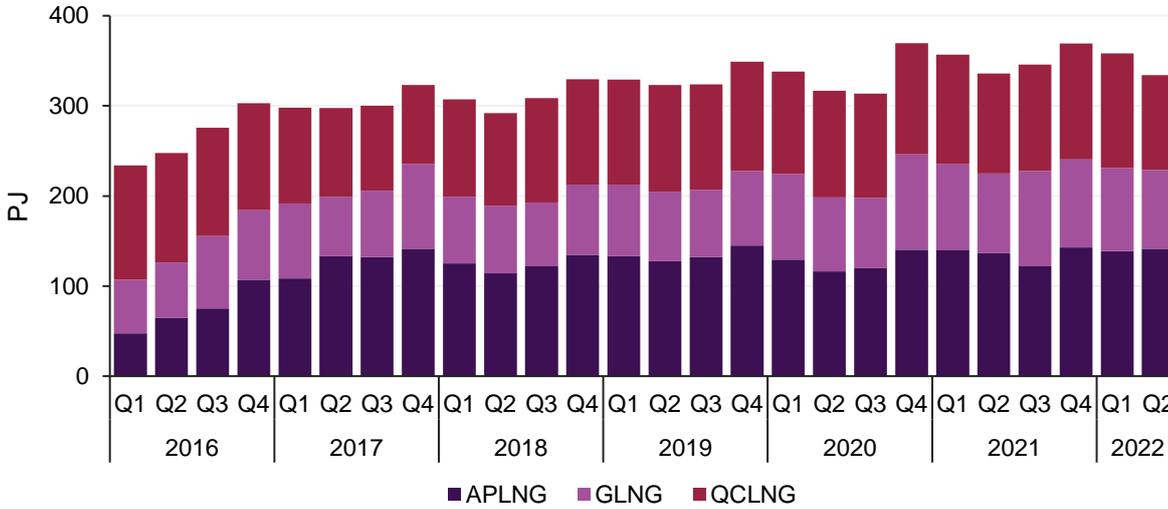
** Includes demand for gas-fired generation usually captured as part of total DWGM and STTM demand. Excludes Yabulu Power Station.

Queensland LNG exports continue to be influenced by strong Asian LNG demand and high prices (Section 2.2.1). Volumes were slightly down compared to Q2 2021 mostly due to planned maintenance by Queensland Curtis LNG (QCLNG) in June, but were still the second highest Q2 flows on record.

By participant, Australia Pacific LNG (APLNG) recorded an increase of 4.8 PJ while QCLNG and Gladstone Liquefied Natural Gas (GLNG) decreased by 5.6 and 1.0 PJ respectively (Figure 66). During the quarter, 87 LNG cargoes were exported, an increase from 86 in Q2 2021.

Figure 66 Flows to Curtis Island for LNG export slightly down but still second highest Q2 on record

Total quarterly pipeline flows to Curtis Island



2.2.1 Gas-fired generation

Demand from gas-fired generators increased significantly during the quarter (Figure 67). Demand was particularly strong in Victoria and New South Wales, with New South Wales demand increasing by 210% in Q2 2022 compared to Q2 2021 and Victorian demand increasing by 76%. Queensland demand increased by 13%, while South Australian demand decreased by 21%. These increases in 2022 occurred despite already significant increases in demand in May and June 2021 as a result of Callide and Yallourn outages.

Cumulative gas-fired generation demand has significantly increased in New South Wales and Victoria compared to 2021. NSW gas-fired generation year to date 2022 demand is 14.7 PJ compared to 4 PJ in 2021 (Figure 68), while Victorian gas-fired generation year to date 2022 demand is 12.3 PJ compared to 6.0 PJ in 2021. Drivers for higher demand are discussed in Section 1.3.2.

Figure 67 Significant gas-fired generation demand increase in NSW and VIC

Average daily demand for gas-fired generation by month

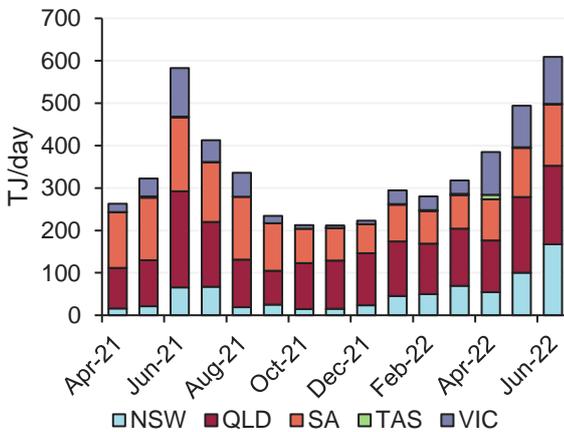
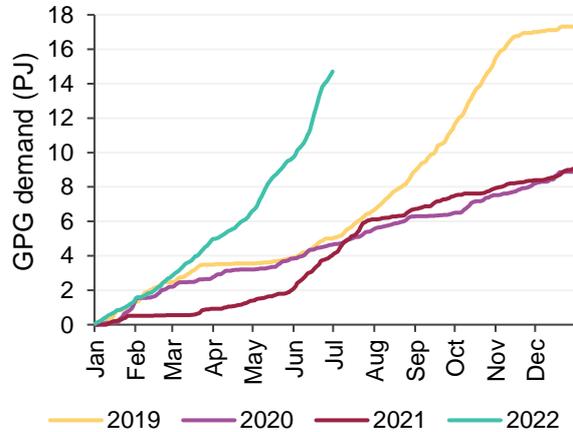


Figure 68 NSW gas-fired generation demand to end of Q2 more than treble recent year levels

Cumulative annual demand for gas-fired generation in NSW



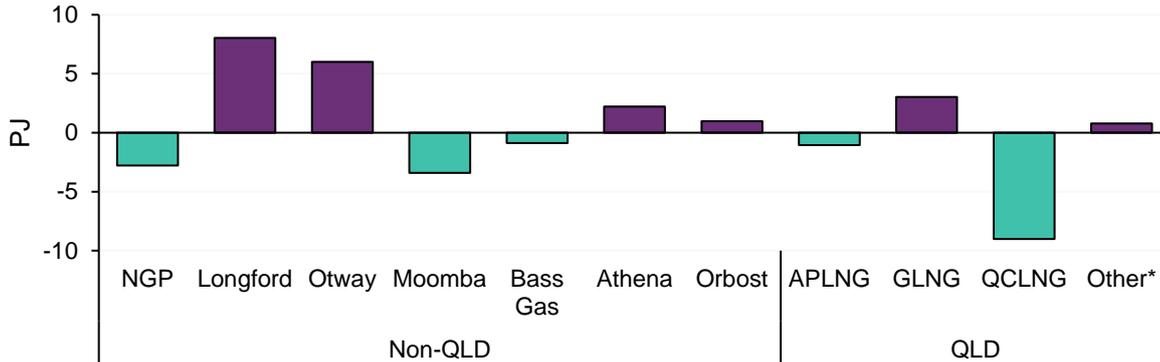
2.3 Gas supply

2.3.1 Gas production

East coast gas production increased by 5.5 PJ compared to Q2 2021 (+1.3%, Figure 69).

Figure 69 Victorian production up 17 PJ replacing Queensland and Moomba production

Change in east coast gas supply – Q2 2022 versus Q2 2021

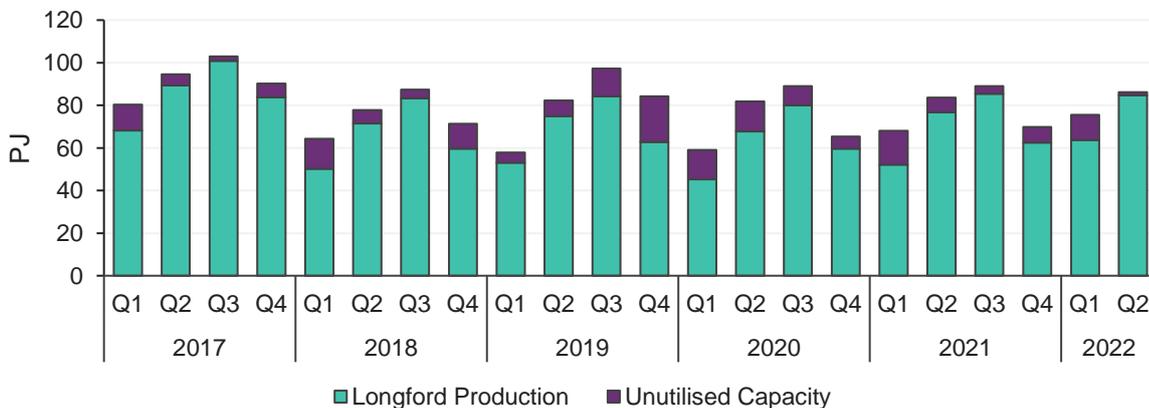


Key changes included:

- Higher Victorian production (+17.2 PJ), mainly driven by higher production at Longford (+8.0 PJ) and Otway (+6.0 PJ). Longford’s production was its highest Q2 since 2017 (Figure 70).
- Decreased Moomba production (-3.4 PJ), continuing the trend of lower Moomba production year on year. The last quarter Moomba saw an increase in production compared to the same quarter 12 months prior was Q4 2020, when there was a 0.6 PJ increase.
- Decreased Queensland production, particularly QCLNG (-9.0 PJ) and APLNG (-1.1 PJ) despite continued high Curtis Island flows. GLNG however increased production (+3.0 PJ), due to an increase in utilisation of its Roma Underground Storage (RUGS) facility, and an increase in its Arcadia production facility. QCLNG’s production decrease was mainly caused by a planned shutdown of its Woleebee Creek production facility, which began ramping down to zero production from 17 June and remained offline for the rest of the quarter. This coincided with QCLNG’s partial LNG processing train shutdown for planned maintenance.

Figure 70 Highest Q2 Longford production since 2017

Longford production and unutilised capacity by quarter

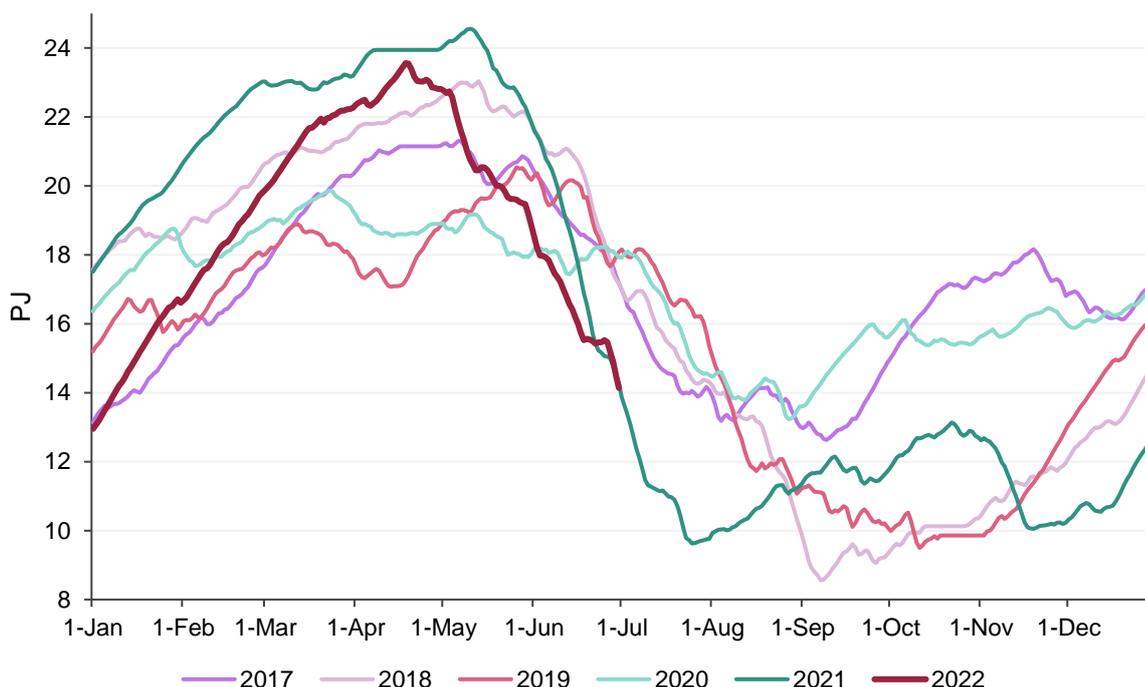


2.3.2 Gas storage

Iona Underground Gas Storage (UGS) facility finished the quarter with a gas balance of 14.1 PJ, only 0.1 PJ lower than at the end of Q2 2021 (Figure 71). The gap between Q2 2022 and 2021 became as wide as 4 PJ on 12 May, and gradually narrowed throughout June, particularly towards the end of the month, assisted by milder temperatures, and lower demand compared to June 2021. Increases in supply from Longford and Otway gas plants were also contributing factors.

Figure 71 Iona storage levels begin winter below 2021 but end the quarter at a similar level

Iona storage levels



2.3.3 Gas Supply Guarantee

In March 2017, production facility operators and pipeline operators made commitments to the Commonwealth Government to make gas available for gas-fired generation to meet peak demand periods in the NEM. The Gas Supply Guarantee is a mechanism developed by the gas industry to facilitate the delivery of these commitments.

The Gas Supply Guarantee mechanism comprises processes to identify, assess and confirm a potential gas supply shortfall, and then to communicate with industry and to call for a response to a shortfall.

On 1 June AEMO identified a potential gas supply shortfall across Victoria, South Australia and Tasmania for 2 June, due to high gas-fired generation demand and lack of reserve forecasts for multiple NEM regions. As a result, for the first time AEMO triggered the Gas Supply Guarantee and called an assessment conference with the Queensland LNG producers.

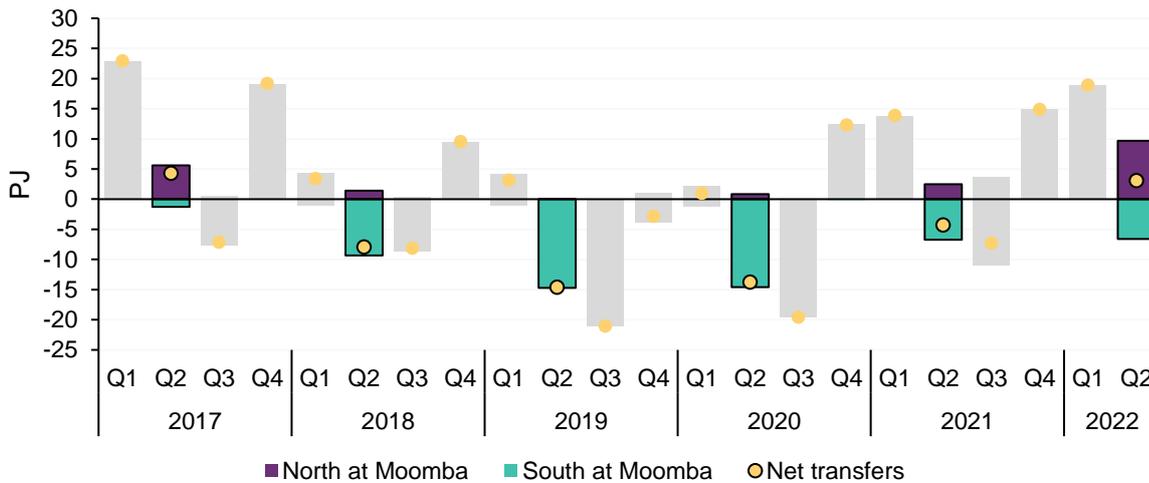
Based on increased southward gas flows from Queensland the following day, as well as improved NEM conditions, the trigger event was deemed to be resolved.

2.4 Pipeline flows

Compared to Q2 2021, there was a 7.3 PJ increase in net transfers into Queensland on the South West Queensland Pipeline (SWQP, Figure 72). This represents the highest flow north from Moomba for any Q2 since Q2 2017, driven by a decrease in Queensland production greater than the reduction in QLD LNG exports, coupled with lower supply from the Northern Territory.

Figure 72 Net Q2 flows into Queensland on SWQP for the first time since Q2 2017

Flows on the South West Queensland Pipeline at Moomba

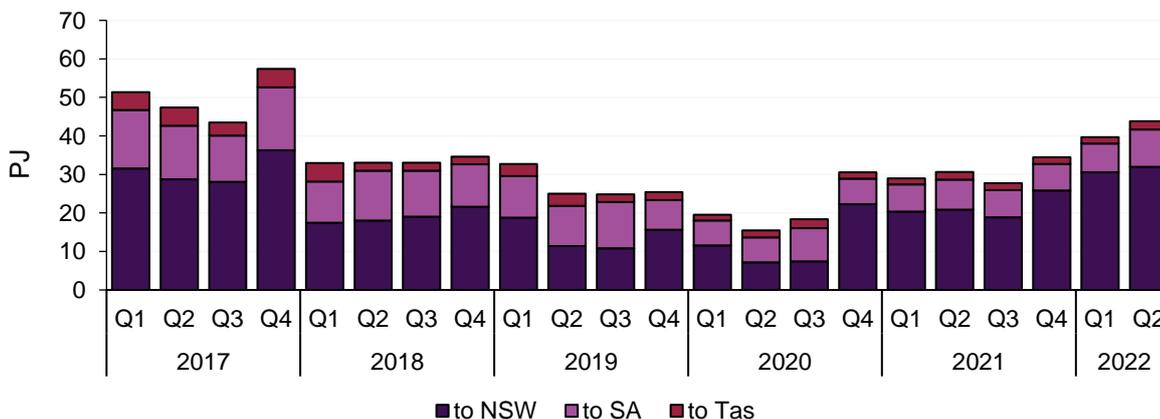


Victorian net gas transfers to other states increased by 13.1 PJ from Q2 2021 levels, due to increased Victorian supply, lower Moomba production (Section 2.3.1) and reduced net domestic production in Queensland. This surpasses Q1 2022 as the highest net transfer out of Victoria for any quarter since Q4 2017.

This represented the highest net transfer out of Victoria for any quarter since Q4 2017 (Figure 73). There were increased flows from Victoria to New South Wales comprising 9.8 PJ via Culcairn, compared to 1.9 PJ in Q2 2021, and 22.1 PJ via the Eastern Gas Pipeline (EGP), up from 19 PJ in Q2 2021. Flows from Victoria to South Australia also increased by 1.9 PJ while there was a 0.1 PJ increase in the flow to Tasmania.

Figure 73 Highest Victorian gas exports for any quarter since 2017

Victorian net gas transfers to other regions

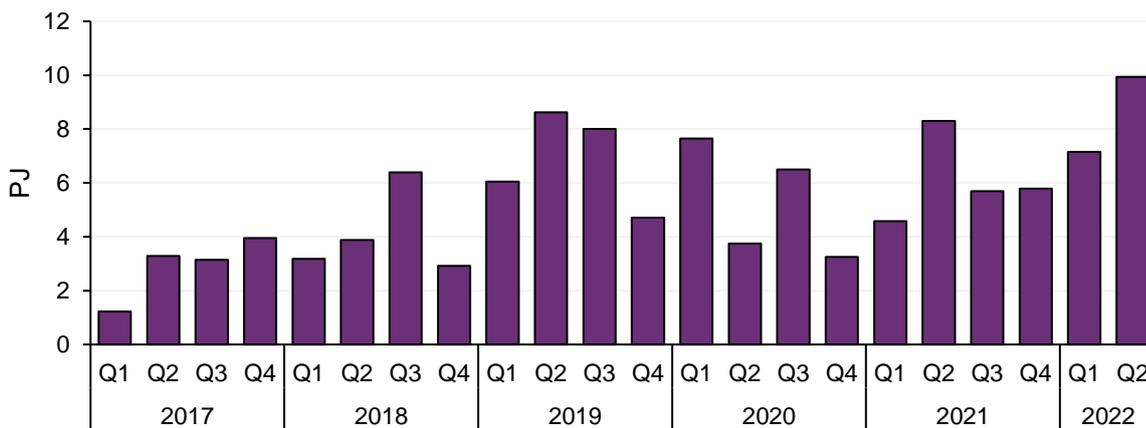


2.5 Gas Supply Hub (GSH)

In Q2 2022 there were increased trading volumes on the GSH compared to Q2 2021 (Figure 74), with traded volume up by 1.6 PJ. This represents a record for any quarter. Drivers for the trading increase include a significant increase in volume for future periods beyond Q2 2022, including volume traded for Q3, Q4 2022 and Q1 2023.

Figure 74 Highest Gas Supply Hub trading volumes on record

Gas Supply Hub – quarterly traded volume

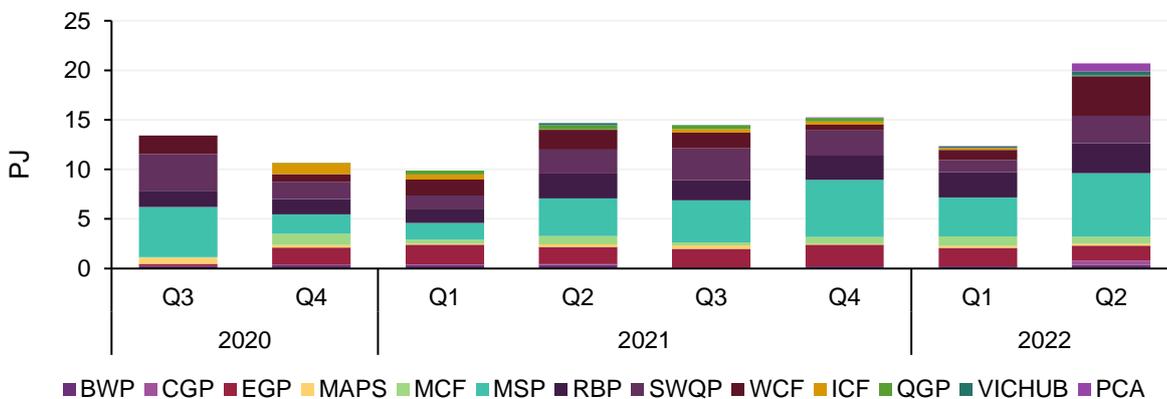


2.6 Pipeline capacity trading and day ahead auction

Day Ahead Auction (DAA) volumes set a record for any quarter, 5.5 PJ higher than the previous record set in Q4 2021, and 6 PJ higher than Q2 2021 (Figure 75). Compared to Q2 2021, the largest increases occurred on the Moomba Sydney Pipeline (MSP, +2.6 PJ) and the Wallumbilla Compressor (WCF, +2.0 PJ).

Figure 75 Highest quarterly Day Ahead Auction utilisation since market start

Day Ahead Auction results by quarter



The increase in MSP volume was due to an uptake of shippers using the auction to transport gas south from Moomba despite the physical pipeline flow being north to Moomba for much of the quarter. This is known as a

notional gas flow. These notional flows allow auction participants to utilise unused pipeline capacity in the opposite direction to the physical flow.

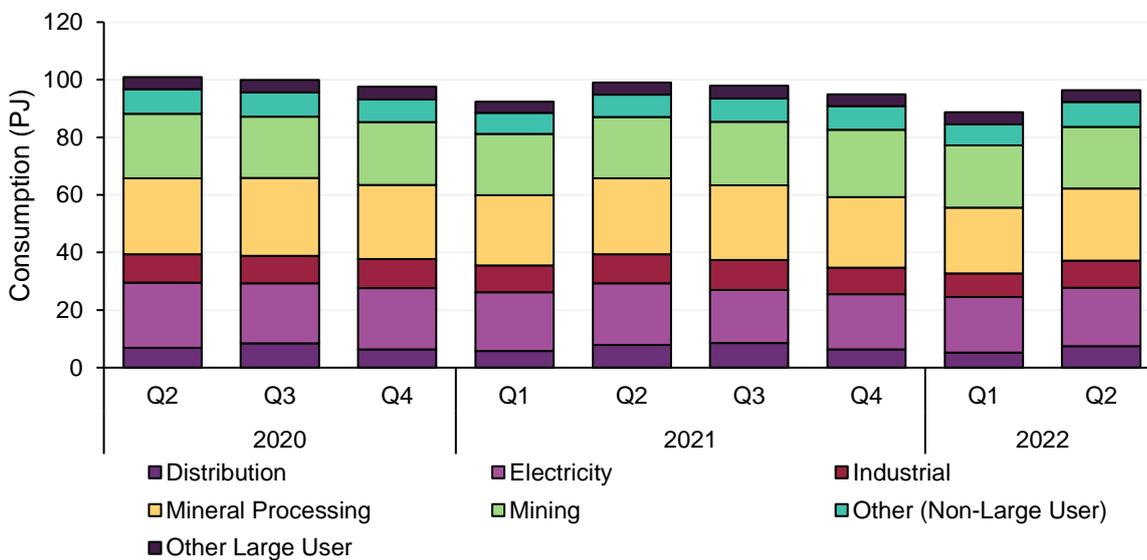
Average auction clearing prices remained at or close to \$0/GJ on most pipelines. The exceptions to this were the EGP which averaged \$0.44/GJ, MSP which averaged \$0.14/GJ, RBP which averaged \$0.07/GJ and SWQP which averaged \$0.04/GJ.

2.7 Gas – Western Australia

A total of 96 PJ was consumed in the Western Australian domestic gas market in Q2 2022, which was an increase of 8 PJ (+8%) from Q1 2022 and a 2 PJ (-3%) decrease from the same quarter last year (Figure 76).

Figure 76 Western Australia domestic gas consumption drops 3% from Q2 2021

WA quarterly gas consumption by facility – Q2 2020 to Q2 2022

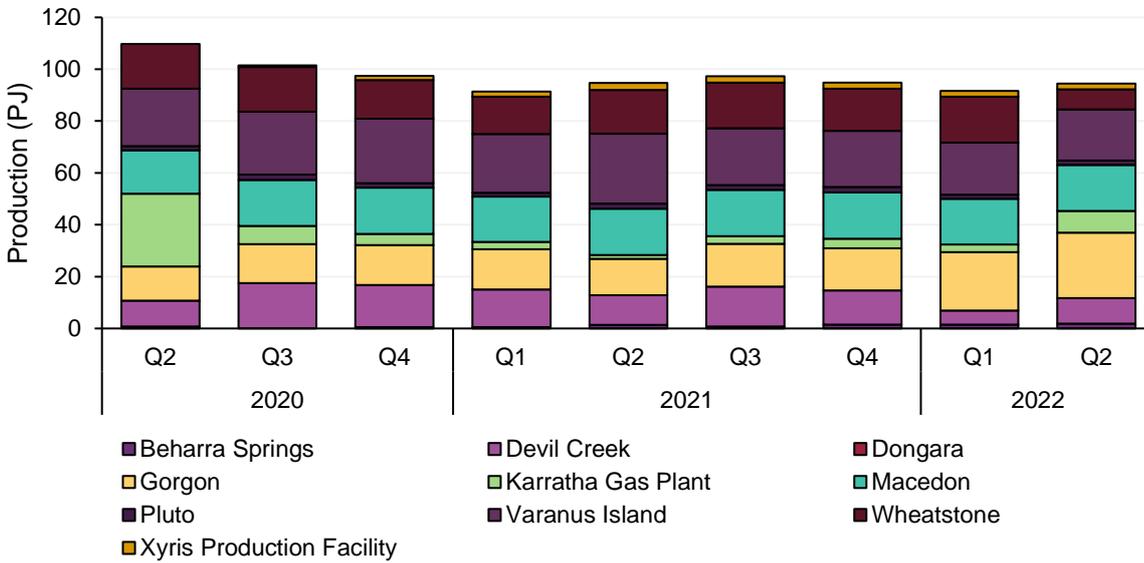


Domestic gas consumption in Western Australia decreased in most user categories compared to the same quarter last year, primarily driven by reduced consumption for electricity generation and mineral processing:

- Gas consumed for electricity generation reduced by 1 PJ (-5%), primarily due to a reduction in consumption from Pinjarra Cogeneration of 1 PJ (-15%) and the Kwinana Cogeneration Plant, which deregistered as a large user effective 4 March 2022, consuming no gas in Q2 2022 compared to consuming 2 PJ in Q2 2021.
- Mineral processing consumption was 1 PJ (-5%) lower than Q2 2021, with nearly all large users consuming less this quarter. The largest decrease was Alcoa Wagerup which reduced consumption by 1 PJ (-12%).
- Total Western Australian gas supply this quarter was 94 PJ, an increase of 3 PJ (+3%) from Q1 2022 but relatively stable compared to the same time last year (-0.3 PJ, -0.3%, Figure 77). The increase from last quarter was primarily driven by increased production from Karratha Gas Plant by 5 PJ (+178%) and Devil Creek by 5 PJ (+87%). The largest decrease in production since last quarter was Wheatstone by 10 PJ (-56%) due to plant maintenance for most of April 2022.

Figure 77 Western Australia domestic gas production remains stable from Q2 2021

WA quarterly gas production by facility – Q2 2020 to Q2 2022

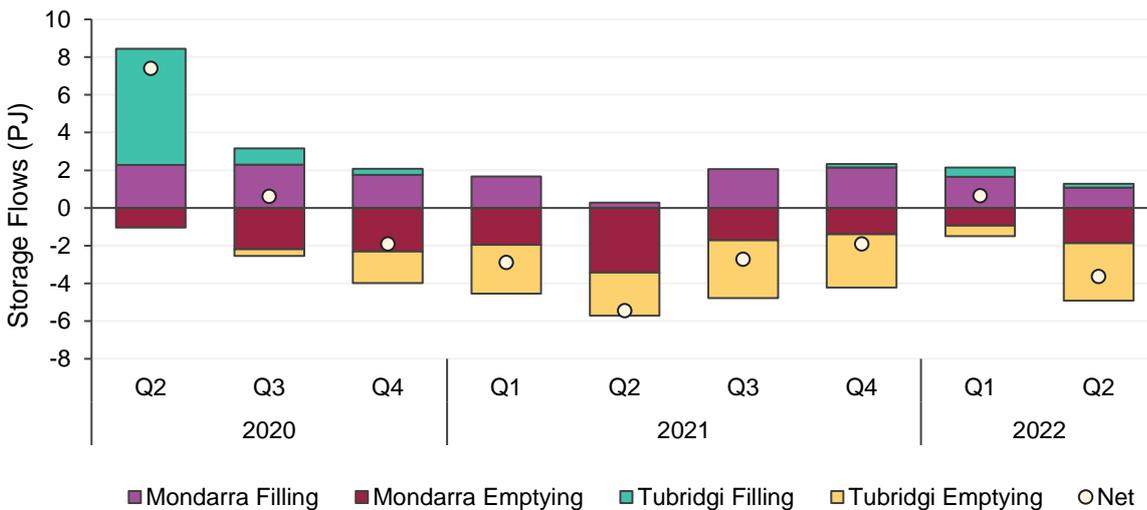


2.7.1 Storage facility behaviour

There was a net injection⁵⁴ of gas from storage facilities into pipelines in Q2 2022. Storage flows reduced 4 PJ compared to Q1 2022, where it reached a net withdrawal⁵⁵ for the first time since Q3 2020 (Figure 78). This change in storage flows is largely driven by Tubridgi injecting 2 PJ more than in Q1 2022. There was a net change of 2 PJ (+33%) from Q2 2021, with this change also driven by Mondarra injecting an additional 2 PJ (+45%).

Figure 78 Net flows from gas storage facilities shifts to net injection

WA gas storage facility injections and withdrawals – Q2 2020 to Q2 2022



⁵⁴ A net injection occurs when gas flows from storage facilities into pipelines, resulting from emptying a gas storage facility.

⁵⁵ A net withdrawal occurs when gas flows from pipelines into storage facilities, resulting from filling a gas storage facility.

3 WEM market dynamics

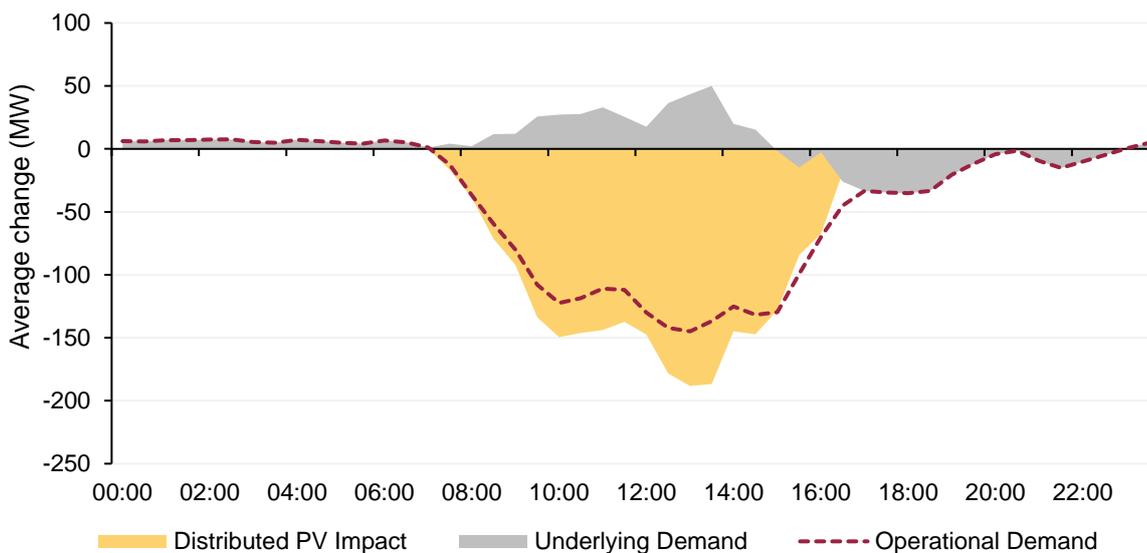
3.1 Electricity demand

Average underlying demand⁵⁶ in Q2 2022 was relatively similar compared to the previous year, being 3.8 MW (0.2%) higher than Q2 2021. The small change in underlying demand is consistent with relatively similar temperatures to last year throughout the quarter, with the average temperature increasing by only 0.1°C from Q2 2021. The average maximum temperature this quarter remained similar to last Q2, at 22.6°C.

Average operational demand⁵⁷ was also relatively similar to Q2 2021, decreasing by 42 MW (2%, Figure 79). Last year Perth experienced the coldest June in 31 years, along with Perth's lowest minimum temperature since 2015, resulting in higher peak demand in Q2 2021 compared with this quarter.

Figure 79 Underlying demand increases, while higher distributed PV reduces midday operational demand

Change in average WEM demand components by time of day – Q2 2022 vs Q2 2021



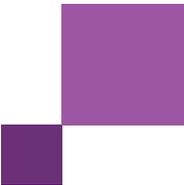
3.1.1 Lowest Q2 minimum operational demand record

Minimum operational demand is decreasing over time, with Q2 2022 recording the lowest Q2 minimum operational demand of 978 MW on 24 April 2022 at 1200 hrs (Figure 80). This was 12% lower than the previous Q2 minimum in 2021 of 1,105 MW on 18 April 2022. This decrease in operational demand can be attributed to continued growth in distributed PV capacity. Total installed PV capacity in Q2 2022 reached 2,174 MW⁵⁸, 22% higher than in Q2 2021.

⁵⁶ Underlying demand is an estimated measurement of the total load on the SWIS, including behind-the-meter demand. Underlying demand is measured as Operational demand adjusted to remove the impact of distributed PV output.

⁵⁷ Operational demand is the average measured total of all wholesale generation from registered facilities in the SWIS and is based on non-loss adjusted sent out SCADA data: <http://data.wa.aemo.com.au/#operational-demand>.

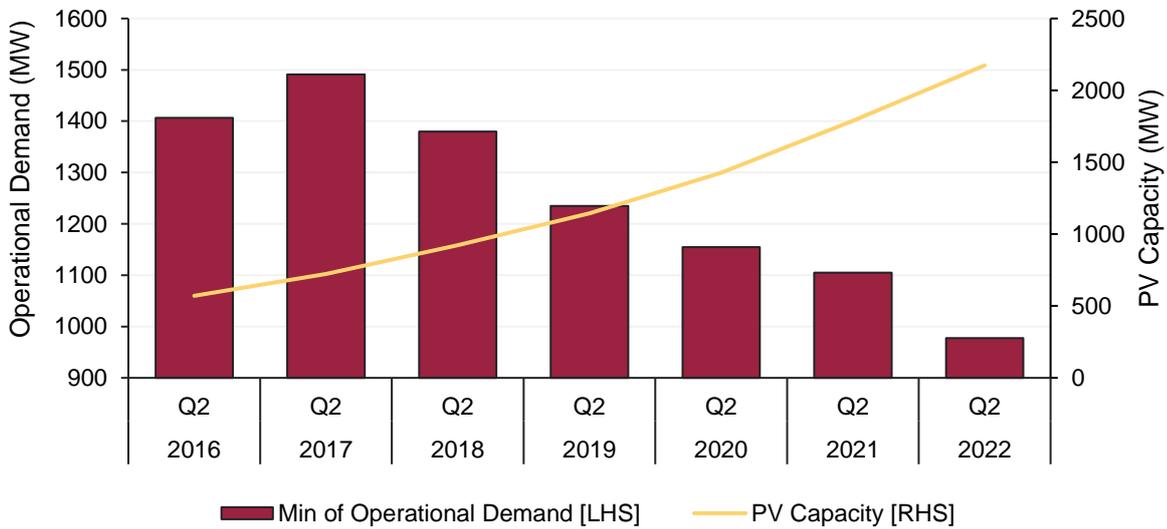
⁵⁸ Estimates are based on Clean Energy Regulator small-scale solar data installations and solar-irradiance sensors in the SWIS: <https://www.cleanenergyregulator.gov.au/RET/Forms-and-resources/Postcode-data-for-small-scale-installations>.



Q2 2022 also recorded the highest Q2 maximum distributed PV output at 1130 hrs on 5 April 2022, with estimated PV output reaching 1,328 MW, 186 MW higher than the previous Q2 record of 1,142 MW set on 6 April 2021.

Figure 80 Q2 minimum operational demand continues to decline

Q2 minimum operational demand and distributed PV capacity

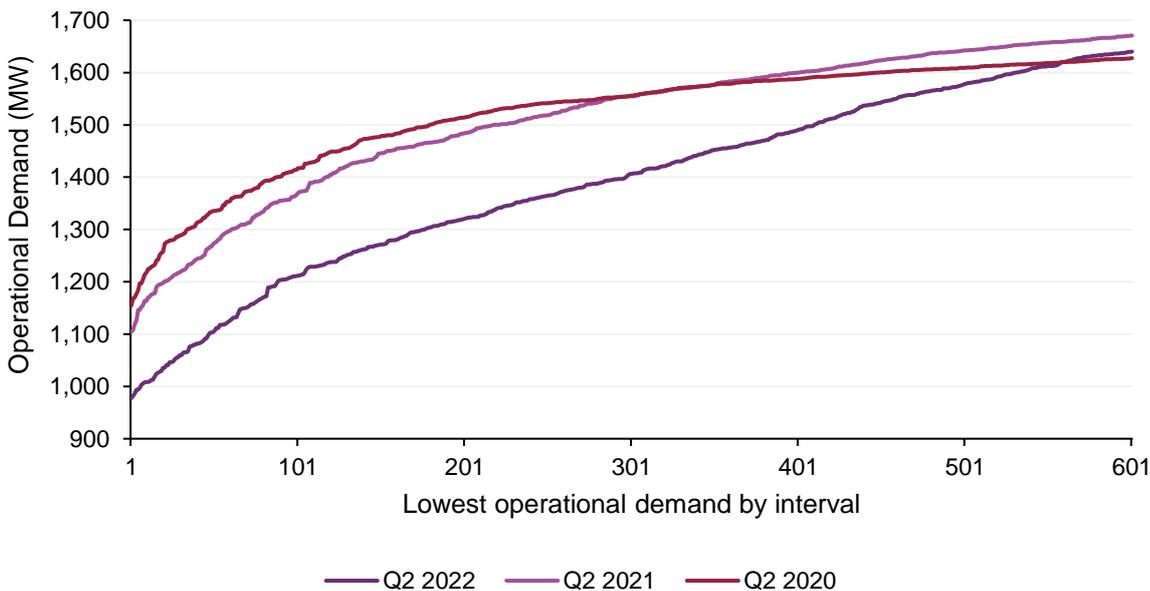


3.1.2 Increased frequency of low demand events this quarter

Growth in distributed PV capacity has also resulted in an increase in the number of intervals in which operational demand fell below 1,500 MW compared to both Q2 2021 and Q2 2020. In Q2 2022, there were 50 intervals where operational demand fell below the previous Q2 minimum demand record of 1,142 MW set on 6 April 2021, and 71 intervals where it fell below the Q2 2020 minimum demand interval of 1,155 MW (Figure 81).

Figure 81 Frequency of low load events increased this quarter

Lowest operational demand intervals – Q2 2020 to Q2 2022



3.2 WEM prices

The weighted average Balancing Price⁵⁹ in the WEM for Q2 2022 was \$68/MWh, a four-year high and \$6/MWh (11%) increase from Q1 2022 (Figure 82). This was also a \$6/MWh increase from Q2 last year and was due to a reduction in quantities offered by market generators into the Balancing Market in the \$0 to \$50/MWh price band, along with an increase in gas-fired generation, offsetting the impact of increased low-cost generation output, such as wind (Section 3.3.1).

The weighted average Short-Term Electricity Market (STEM) Price⁶⁰ for Q2 2022 also increased this quarter to \$57/MWh, a \$11/MWh (23%) increase compared to Q2 2021. The quantity of energy cleared in STEM increased compared to both the same quarter last year (12%) and last quarter (9%).

Figure 82 Weighted average Balancing Price increases to four-year high

WEM weighted average Balancing Prices, STEM Prices and quantity cleared in STEM – Q2 2018 to Q2 2022



3.2.1 Balancing merit order dynamics

Participant behaviour in the Balancing Market shows a decrease in the average quantities offered in the \$0 to \$50/MWh price band, and an increase in average quantities offered at the ceiling price band (>\$200/MWh) across every interval compared to Q2 2021 (Figure 83). The key changes in Balancing Market participation were:

- Participant offers in the \$0 to \$50/MWh price band decreased by an average 184 MW (33%) between Q2 2021 and Q2 2022. This led to a decrease in the percentage of time this price band set the Balancing Price down from 50% of the time in Q2 2021, to 29% of the time this quarter (Figure 84).
- A decrease in average volumes offered in all negative price bands in Q2 2022 compared to Q2 2021. In particular, there was an average 28 MW (6%) less offered in the -\$100 to \$0/MWh, and 39 MW (4%) less

⁵⁹ The weighted average Balancing Price is a measure of the average Balancing Price that puts greater weighting on intervals where greater quantity is generated. This is to reflect the average Balancing Price more accurately against quantity of electricity generated, rather than against intervals. Weighted average Balancing Price is $\text{sum}(\text{Balancing Price} * \text{EOI Demand}) / \text{sum}(\text{EOI Demand})$ across the quarter.

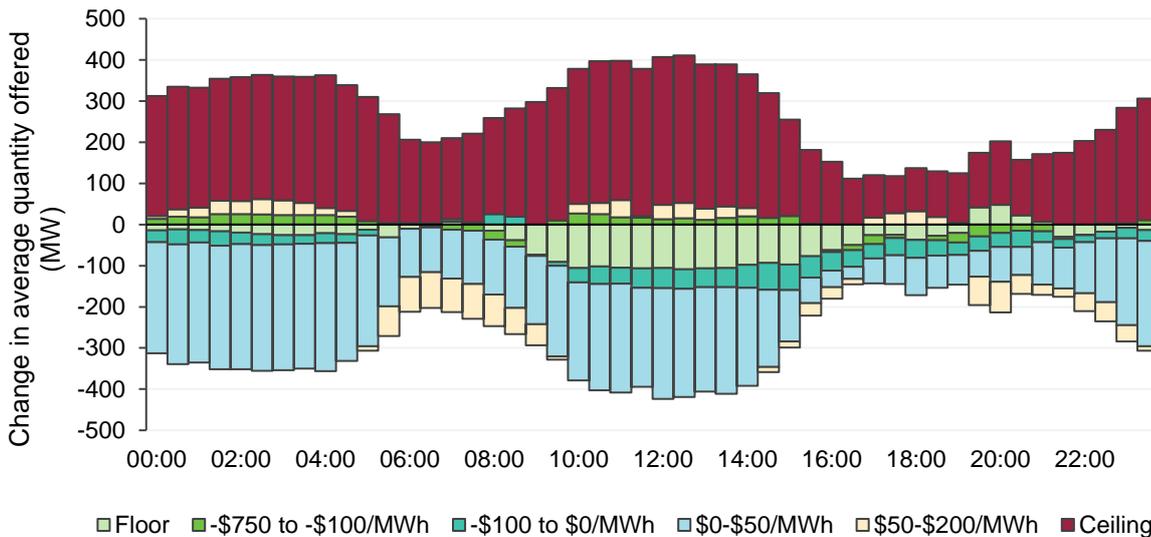
⁶⁰ The weighted average STEM Price is a measure of the average STEM Price that puts greater weighting on intervals where greater quantity is cleared. This is to reflect the average STEM Price more accurately against quantity of electricity cleared, rather than against intervals. Weighted average STEM Price is $\text{sum}(\text{STEM Price} * \text{Qty Cleared}) / \text{sum}(\text{Qty Cleared})$ across the quarter.

offered at the price floor (-\$1,000/MWh to -\$750/MWh). Volumes offered at negative prices decreased the most during the middle of the day and contributed to an overall decrease in the number of negatively priced intervals this quarter compared to last year (Section 3.2.2).

- Offer volumes instead shifted into the price ceiling band (>\$200/MWh) this quarter in every interval. Compared to Q2 2021, an average 248 MW (17%) more was offered into the price ceiling compared to Q2 2021. Despite this, only two price ceiling events occurred this quarter, down from four in Q2 2021.

Figure 83 Balancing Market offer volumes shift from lower price bands to the ceiling

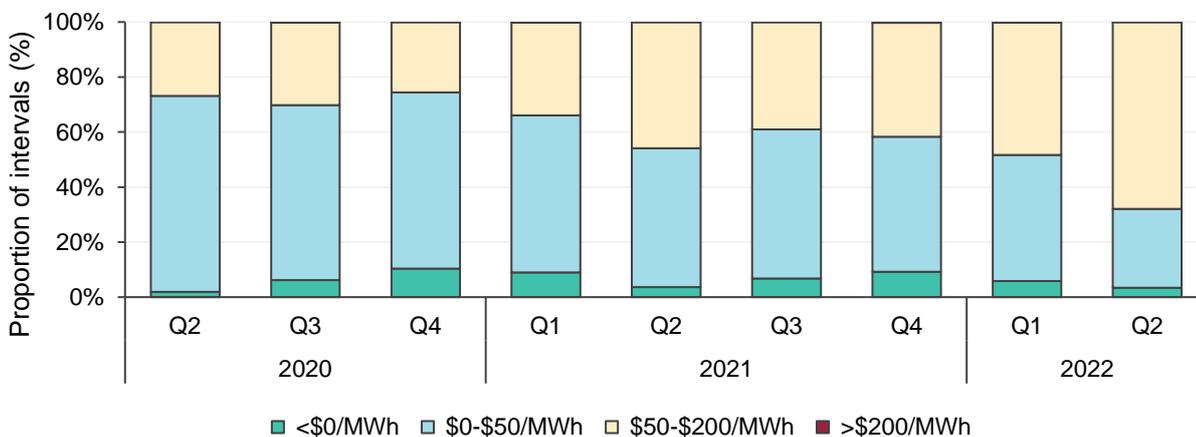
Change in average forecast Balancing merit order structure by time of day – Q2 2022 vs Q2 2021



Decreases in quantities offered into the Balancing Market in sub-\$50/MWh price bands resulted in the Balancing Price clearing more frequently between \$50 to \$200/MWh; this contributed to the 9% increase in prices this quarter compared to Q2 2021 (Section 3.2). The Balancing Price cleared in the \$50 to \$200/MWh price band 68% of the time this quarter (Figure 84), an increase from 46% of the time in Q2 2021, and from 48% last quarter. Conversely, the balancing price cleared in the \$0 to \$50/MWh price band 29% of the time this quarter compared to 50% in Q2 2021.

Figure 84 Price bands shifting away from \$0-\$50/MWh price band to higher price bands

Quarterly balancing prices by price range – Q2 2020 to Q2 2022

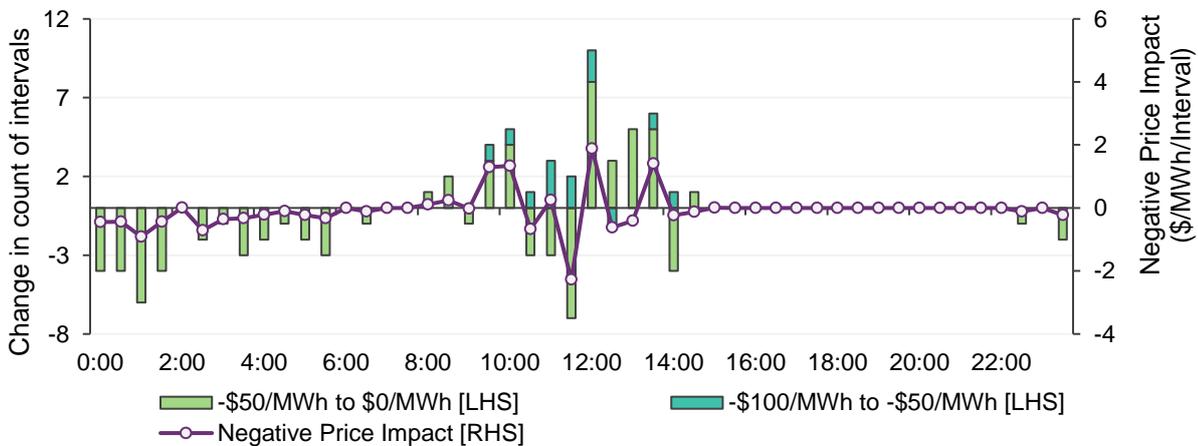


3.2.2 Negative prices

The total number of negatively priced and \$0/MWh intervals in Q2 2022 (3% of all intervals) reduced from Q2 2021 (4% of all intervals). The reduced frequency of negatively priced and \$0/MWh intervals was predominantly observed overnight⁶¹ and can be attributed to increased operational demand. This was partially offset by an increased frequency of negatively priced intervals during the middle of the day due to decreased operational demand driven by distributed PV. This resulted in an overall reduction in the negative price impact⁶² to \$0.8/MWh (-\$0.1/MWh, -7%) compared to last year (Figure 85).

Figure 85 Reduced impact of negative prices on average despite more intervals below -\$50/MWh

Change in count of intervals with zero or negative Balancing Price – Q2 2022 vs Q2 2021

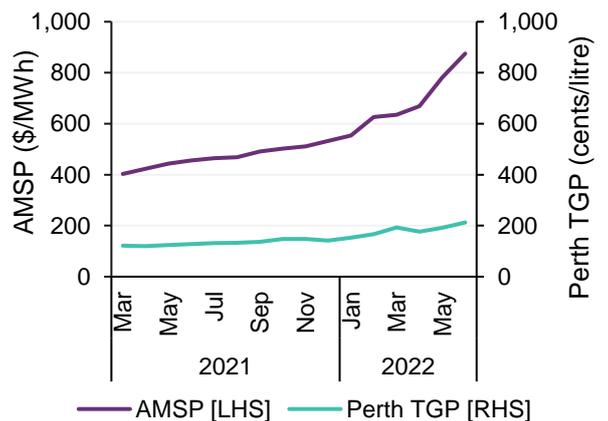


3.2.3 New Alternative Maximum STEM Price

The Alternative Maximum STEM Price (AMSP)⁶³ continued to trend upwards, reaching a record high of \$875/MWh⁶⁴ this quarter. This result is driven by the continuing rise in fuel prices (Figure 86). The AMSP has increased by 88% in the 12 months since Q2 2021 (+\$456/MWh).

The driver of the increasing AMSP is the Perth diesel terminal gate price (TGP) which has grown an average 6.6% per month in the past 12 months, from an average price of \$1.3 in June 2021 to \$2 per litre in June 2022.

Figure 86 AMSP price hit record high
AMSP and Perth Diesel TGP by month

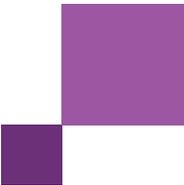


⁶¹ Between 2330 hrs and 0600 hrs.

⁶² Impact of negative prices is a measure of both frequency and magnitude of negative prices. It is defined as the change from the average Balancing Price including negative intervals to the average that would result if the floor price was \$0/MWh. It is calculated as the absolute sum of the Balancing Price in all negatively priced intervals, divided by the total number of intervals.

⁶³ The Alternative Maximum STEM Price applies to generators that use distillate as a fuel source.

⁶⁴ June 2022 Alternative Maximum STEM Price: <https://aemo.com.au/en/energy-systems/electricity/wholesale-electricity-market-wem/data-wem/price-limits>



3.3 Electricity generation

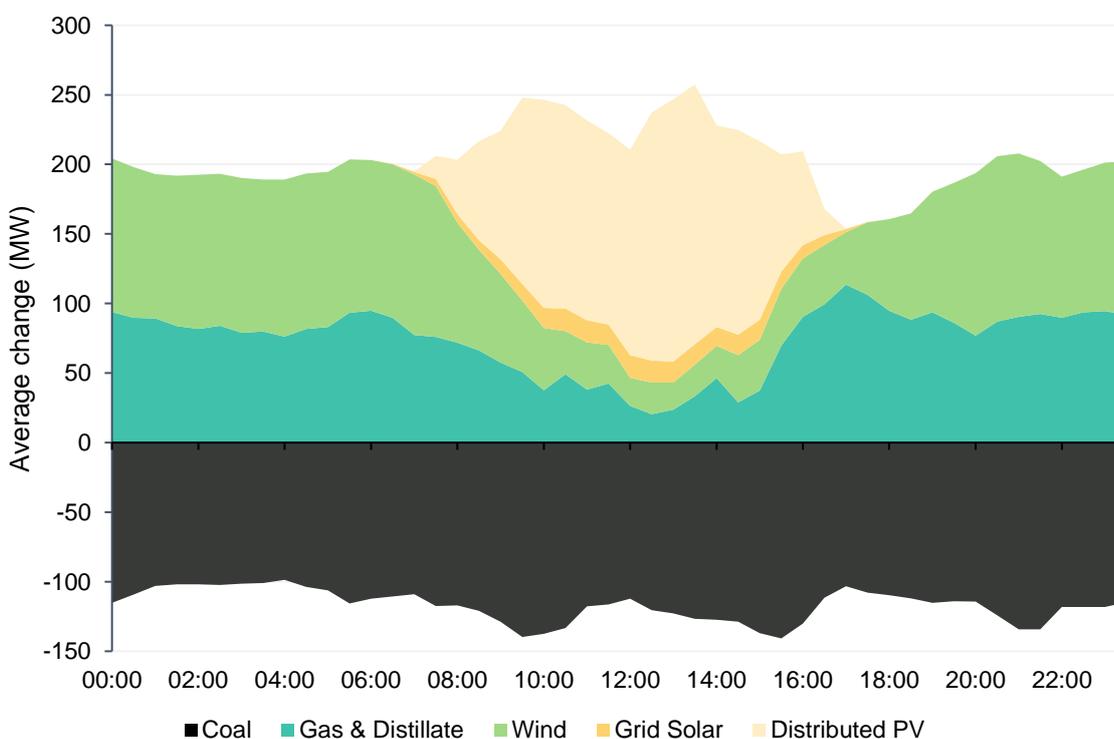
3.3.1 Change in fuel mix

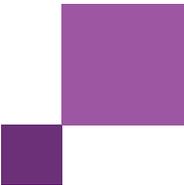
Q2 2022 saw an increase in wind, grid-scale solar and gas-fired generation at all times of the day, with a decrease in coal-fired generation when compared to Q2 2021 (Figure 87):

- Coal-fired generation decreased by an average 117 MW (12%), with coal-fired generation partially displaced by lower cost generation sources, such as wind. A change in Market Participant bidding behaviour reduced the quantity of coal in-merit from mid-June 2022 onwards, decreasing the output of coal generation at all times of the day towards the end of the quarter (Section 3.3.3).
- Wind generation increased by an average of 79 MW (27%) in Q2 2022. This increase was mostly attributed to Cyclone Seroja in Q2 2021 which caused a significant increase in GIA constraints for that quarter, predominantly impacting wind generation (Section 3.3.2).
- Grid-scale solar increased by an average of 5 MW (20%), which was predominantly due to an increase in output from Greenough River Solar Farm, which generated an additional average 5 MW (122%).
- Distributed PV continued to grow, increasing by 46 MW (28%) on average compared to Q2 2021. This increase was due to an estimated 386 MW (22%) of additional PV capacity installed in the SWIS compared to Q2 2021.
- Gas and distillate generation increased by an average of 25 MW (11%), predominantly during the evening peak and overnight periods.

Figure 87 Solar, wind and gas increases, coal generation decreases

Average change in WEM generation – Q2 2022 vs Q2 2021





3.3.2 Increase in wind generation compared to Q2 2021

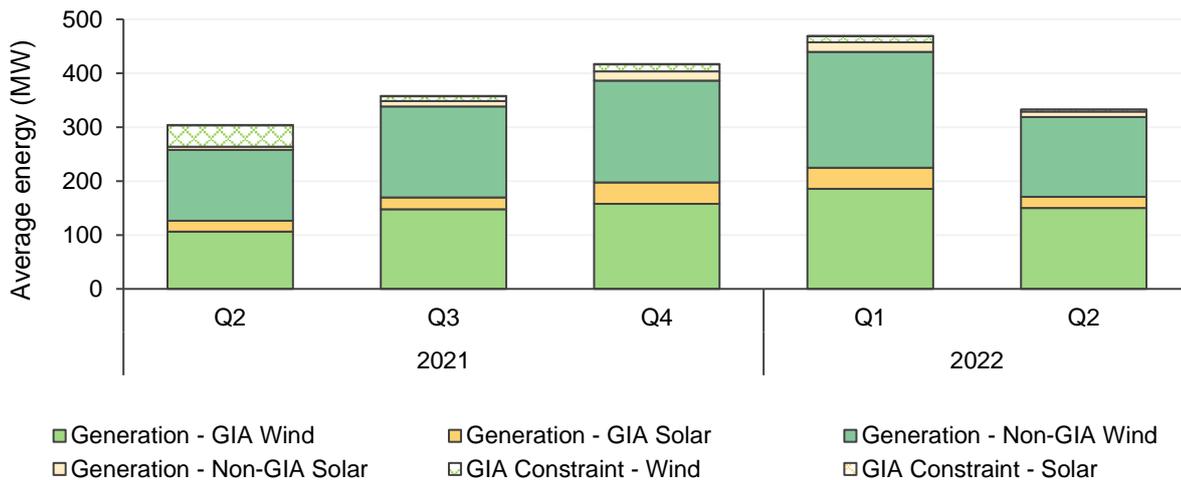
There was a 35% increase in generation from wind and solar GIA⁶⁵ facilities this quarter compared to Q2 2021. This increase can be mostly attributed to the 90% decrease in average GIA constraints compared to Q2 2021, from 40 MW to 4 MW (Figure 88)⁶⁶.

Last year, on 11 April 2021, Cyclone Seroja⁶⁷ made landfall on the Western Australian coast near Kalbarri, resulting in the outage of several transmission lines connecting the North Country⁶⁸ region to the rest of the SWIS. The region was islanded until 21 April and a number of transmission lines were impacted until 25 May. A total of 767 MW of installed wind capacity was affected by the network outages.

Given the large impact of Cyclone Seroja, and the high level of GIA constraints in Q2 2021, wind output increased by an average of 79 MW (27%) in Q2 2022. The largest contributions to this change were from Yandin Wind Farm, Badgingarra Wind Farm and Warradarge Wind Farm, which respectively generated an additional average 25 MW, 20 MW and 19 MW compared to Q2 2021. These three wind farm facilities are connected under the GIA arrangement and were impacted by network constraints as a result of Cyclone Seroja.

Figure 88 Wind GIA constraints significantly decrease in Q2 2022 compared to Q2 2021

GIA constraints – Q2 2021 to Q2 2022



3.3.3 Decrease in coal generation

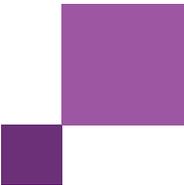
The decrease in coal-fired generation at all times of the day this quarter compared to Q2 2021 was largely due to a decrease in coal generation at the end of Q2 2022. From April to May 2022, coal generation on average met 41% of underlying demand, in line with the longer-term fuel mix average. However, this share of underlying demand dropped to only 30% during June 2022. The main driver for this was a change in Market Participant bidding behaviour which reduced the quantity of coal generation in-merit.

⁶⁵ Refer to section 3.4.4 of the Q3 2021 Quarterly Energy Dynamics Report for further details: <https://aemo.com.au/-/media/files/major-publications/qed/2021/q3-report.pdf?la=en>

⁶⁶ GIA constraints are estimated based on a theoretical calculation of a generators output using wind or solar forecasts.

⁶⁷ Analysis of this event was published in the Q2 2021 QED: <https://www.aemo.com.au/-/media/files/majorpublications/qed/2021/q2-report.pdf?la=en>

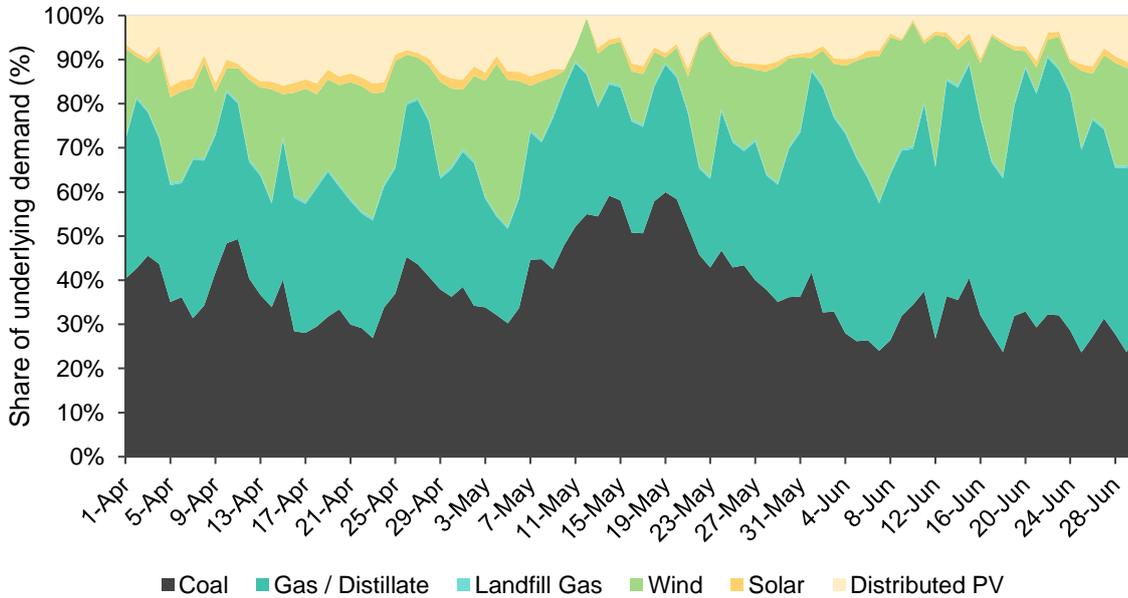
⁶⁸ The North Country region include parts of the SWIS north of Pinjar.



This resulted in an increase in the share of gas-fired generation from 29% of operational demand in April and May, to 45% in June and made gas the primary fuel for the remainder of the quarter.

Figure 89 Gas overtook coal as the primary fuel at the end of the quarter

Daily fuel mix as a share of underlying demand – Q2 2022

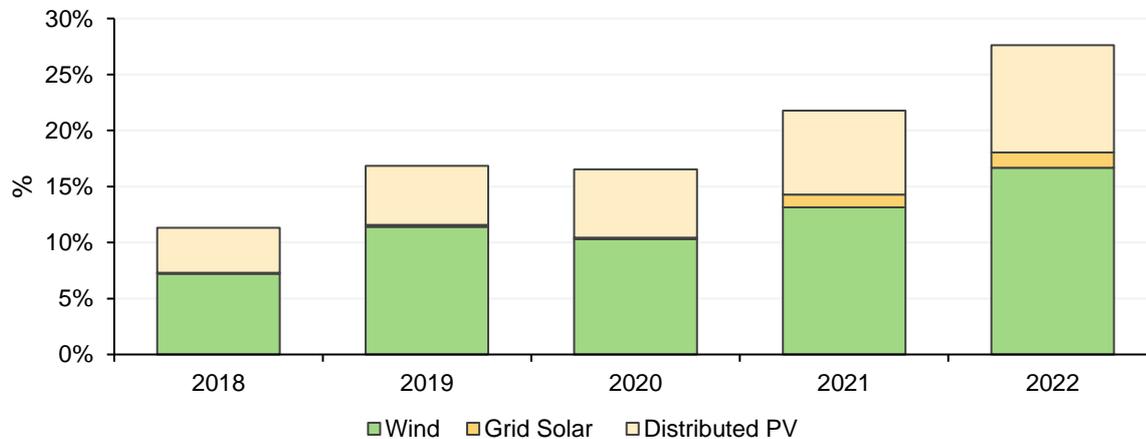


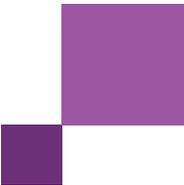
3.3.4 New Q2 renewable generation record

On 23 April 2022 during the 1200 hrs interval renewable generation (including distributed PV) supplied 73% of underlying demand, only 6% below the all-time record of 79% set on 7 September 2021. This was also 6 percentage points higher than the previous Q2 record of 67%, set during the 1230 hrs interval on 10 April 2021. In Q2 2022 renewable generation (including distributed PV) supplied an average of 28% of underlying demand, an increase of 6 percentage points from Q2 last year (Figure 90).

Figure 90 Renewable energy meets a Q2 record share of underlying demand

Average Q2 renewable generation and maximum renewable generation trend





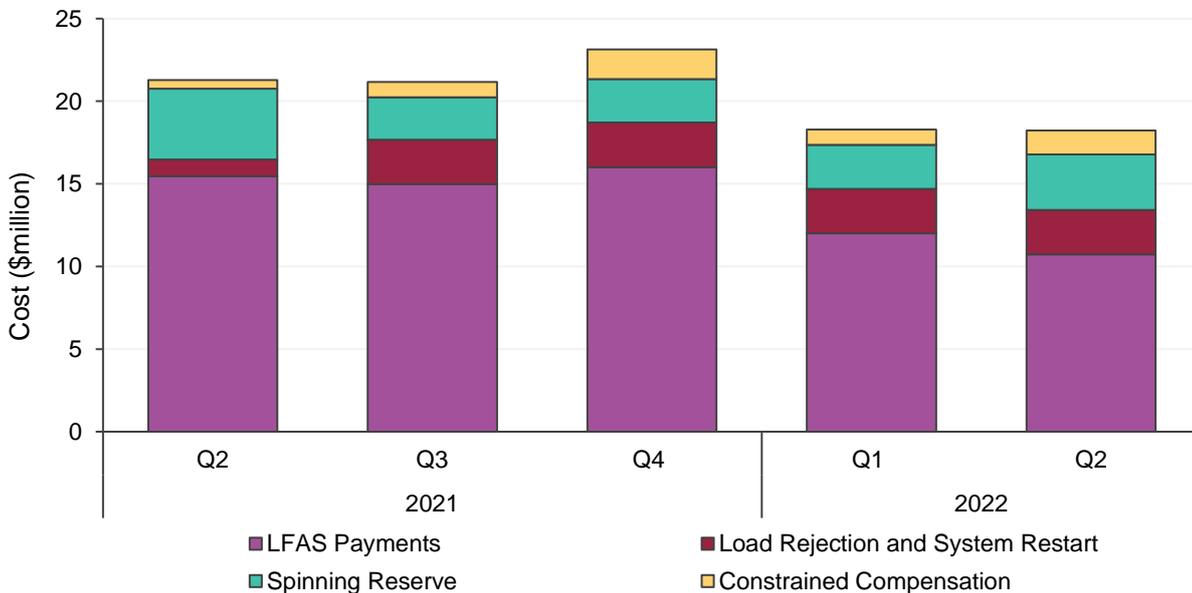
3.4 Power system management

The total cost of essential system services in Q2 2022 was \$18 million, a marginal decrease compared to Q1 2021 (-\$60k, -0.3%). The small decrease in costs was largely attributed to a reduction in Load Following Ancillary Service (LFAS) costs, which were partially offset by increases in Spinning Reserve and Constrained Compensation costs (Figure 91).

- Estimated LFAS costs for Q2 2022 were \$11 million and accounted for 59% of all essential system services costs for the quarter. LFAS costs decreased by \$1 million (-11%) from Q1 2022 due to the lower average prices in both LFAS Upwards and LFAS Downwards markets. LFAS costs also decreased by \$5 million (-31%) compared to Q2 2021.
- Estimated spinning reserve costs increased by \$0.7 million (+26%) compared to last quarter, driven by higher average Balancing Prices during all periods (+\$7/MWh).
- Estimated load rejection and system restart costs remained the same in Q2 2022 as for Q1 2022, as the COST_LR⁶⁹ parameter is set annually in line with financial years⁷⁰. The higher COST_LR value for 2021-22 is the driver of increased load rejection and system restart costs compared to Q2 2021 (+167%).
- Estimated constrained compensation increased by \$0.6 million (+69%) compared to Q1 2022. The increase in constrained compensation compared to Q1 2022 partially offset the decrease in LFAS costs on the total cost of ancillary services.

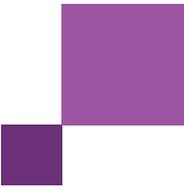
Figure 91 Total estimated cost of operating power system remain consistent with Q1 2022

Ancillary service costs and constrained compensation by quarter – Q2 2021 to Q2 2022



⁶⁹ COST_LR refers to the total cost of Load Rejection Reserve and System Restart, as determined by the Economic Regulation Authority (ERA).

⁷⁰ Load Rejection and System Restart costs determined by the ERA are at: https://www.erawa.com.au/electricity/wholesale-electricitymarket/ancillary-services-parameters/load-rejection-cost_lr/load-rejection-cost_lr-1-july-2019-to-30-june-2022.



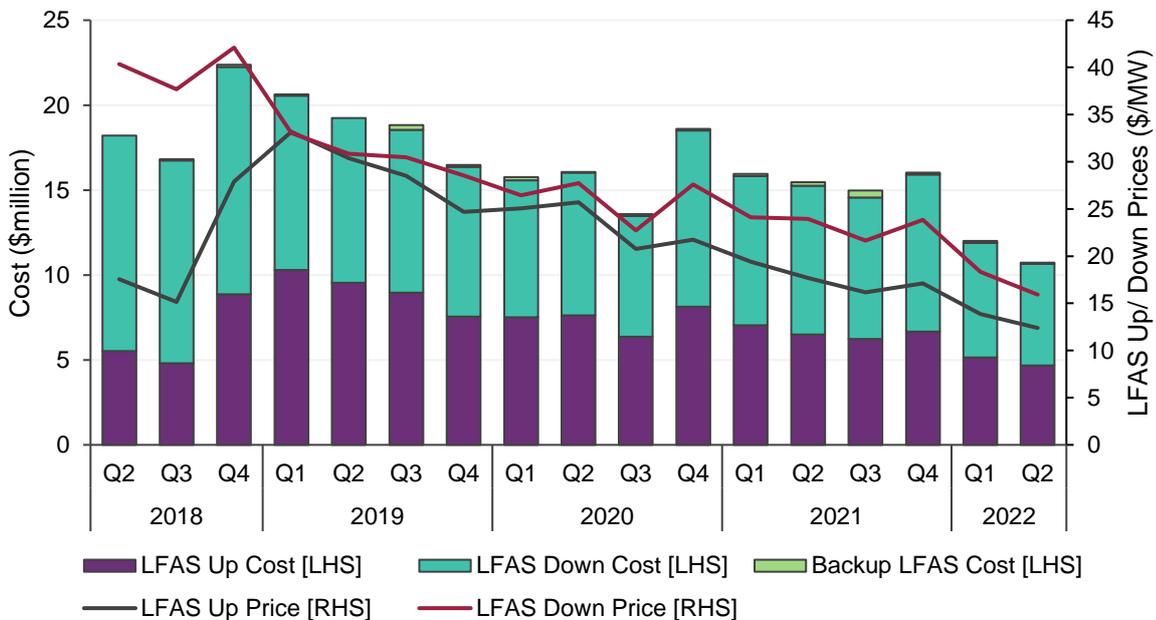
3.4.1 LFAS market

The cost of LFAS decreased again in Q2 2022 (-11%) compared to the previous quarter, following a 25% decrease in Q1 2021 (Figure 92). This was primarily driven by further decreases in both LFAS Up Prices (-\$1/MW) and LFAS Down Prices (-\$2/MW).

The decrease in average prices can be attributed to an increase in the average volume offered below \$20/MW in both LFAS markets. The LFAS Down market saw an 11 MW (+11%) increase offered below \$20/MW, while an additional 3 MW (+2%) was offered in this price range in the LFAS Up market. This change in bidding behaviour was primarily from Synergy who offered on average an additional 13 MW below \$20/MW in LFAS down, and on average an additional 19 MW in LFAS up. The change in bidding behaviour was partially offset by decreases in quantities offered by Alinta in both LFAS markets (-11 MW in down, -10 MW in up) due to the decreased availability of one of the Alinta LFAS facilities to 4% over May.

Figure 92 Continued downwards trend in average LFAS prices reduces total LFAS costs

LFAS costs and prices – Q2 2018 to Q2 2022



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Abbreviations

Abbreviation	Expanded term
ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMSP	Alternative Maximum STEM Price
APLNG	Australia Pacific LNG
APC	Administered price cap
ASEFS2	Australian Solar Energy Forecasting System
ASX	Australian Securities Exchange
BESS	Battery energy storage system
BoM	Bureau of Meteorology
C&I	Commercial and Industrial
CPT	Cumulative price threshold
CY	Calendar Year
DAA	Day Ahead Auction
DWGM	Declared Wholesale Gas Market
EOI	End of interval
EGP	Eastern Gas Pipeline
ERA	Economic Regulation Authority
FCAS	Frequency control ancillary services
GIA	Generator Interim Access
GJ	Gigajoule
GW	Gigawatts
GLNG	Gladstone LNG
GSH	Gas Supply Hub
ICE	Intercontinental Exchange
IRSR	Inter-regional settlement residue
LFAS	Load Following Ancillary Services
LNG	Liquefied natural gas
MPC	Market price cap
MSP	Moomba to Sydney Pipeline
MtCO ₂ -e	Million tonnes of carbon dioxide equivalents
MW	Megawatts
MWh	Megawatt hours
NEM	National Electricity Market
NER	National Electricity Rules
NGP	Northern Gas Pipeline
NGR	National Gas Rules

Abbreviation	Expanded term
NRM	Negative residue management
NSG	Non-scheduled generation
OPEC	Organisation of Petroleum Exporting Countries
PJ	Petajoule
PV	Photovoltaic
QED	Quarterly Energy Dynamics
QCLNG	Queensland Curtis LNG
QNI	Queensland – New South Wales Interconnector
RBP	Roma Brisbane Pipeline
RERT	Reliability and Emergency Reserve Trader
RoLR	Retailer of Last Resort
SCADA	Supervisory Control and Data Acquisition
SIPS	System Integrity Protection Scheme
STEM	Short-Term Energy Market
STTM	Short Term Trading Market
SWIS	South West Interconnected System
SWQP	South West Queensland Pipeline
TGP	Terminal Gate Price
TJ	Terajoule
TWh	Terawatt hours
UGS	Underground Storage Facility
VBB	Victoria Big Battery
VRE	Variable renewable energy
VNI	Victoria to New South Wales Interconnector
YoY	Year on year
WEM	Wholesale Electricity Market
WDR	Wholesale demand response