Image courtesy of Neoen

2

National Electricity Market

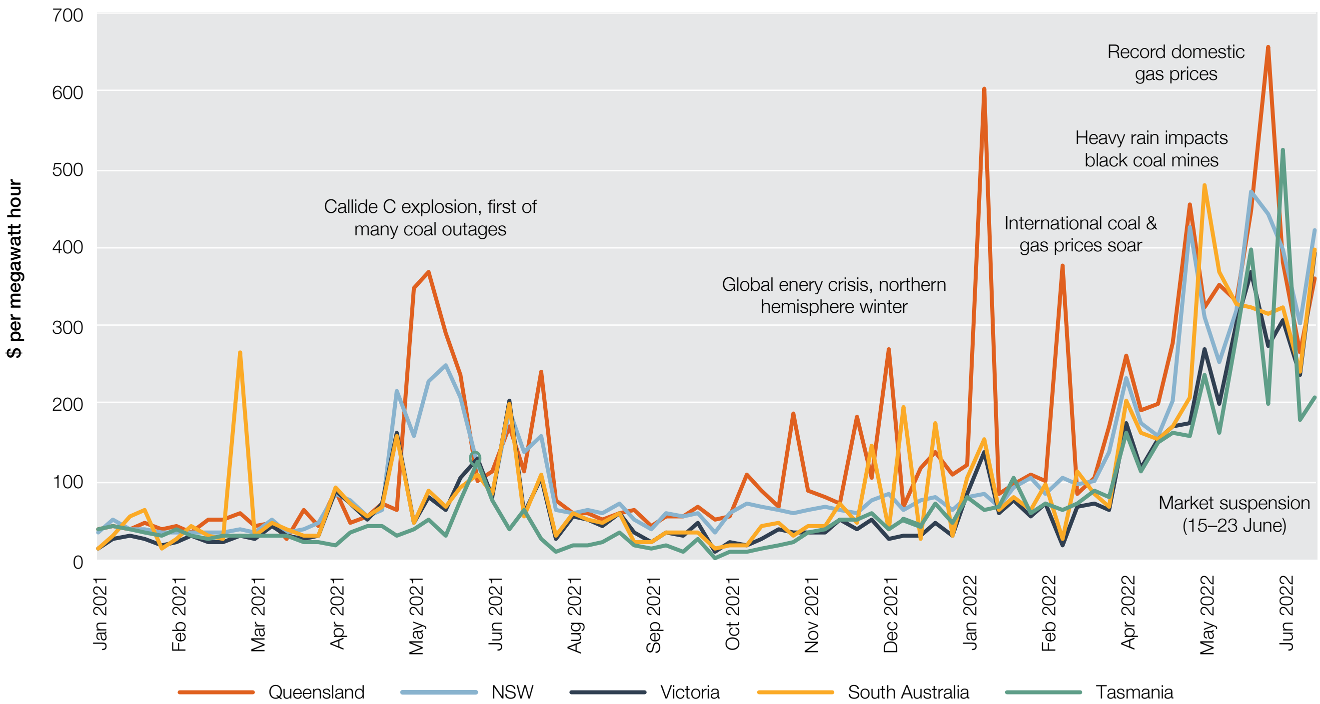
Electricity generated in eastern and southern Australia is traded through the National Electricity Market (NEM). Generators make offers to sell electricity into the market and the Australian Energy Market Operator (AEMO) schedules the lowest priced generation available to meet demand. The amount of electricity generated needs to match demand in real time. The market covers 5 regions – Queensland, New South Wales including the ACT (NSW), Victoria, South Australia and Tasmania. The NEM is one of the world's longest interconnected power systems, stretching from Port Douglas in Queensland to Port Lincoln in South Australia and across the Bass Strait to Tasmania.

2.1 NEM snapshot

Since the last *State of the energy market* report:

- Wholesale electricity prices across much of the NEM remained relatively low across 2021 but rose rapidly to record highs in all regions in May, June and July 2022 (Figure 2.1).
- These high and volatile prices were the consequence of a compounding set of drivers in domestic and international markets.
- Coal-fired generation fell due to a high level of outages and coal supply problems, and more expensive hydro and gas-powered generation was needed to fill the gap. At the same time, gas spot prices were at record high levels impacted by international prices and tight domestic supply conditions.
- The need to cover high fuel costs, or to ration fuel or water levels, caused market participants to offer their capacity at progressively higher prices.
- Sustained high prices triggered protective price caps, multiple market interventions, and unprecedented market suspension of the entire NEM.
- Futures markets suggest that NEM prices will remain high (relative to 2021) over the next 2 years.
- Unplanned aging coal plant outages accompanied by early closure announcements highlighted the pressing need for new investment.
- Major reforms are ongoing to transform the NEM's market design to ensure it is best equipped for the post-transition energy market. The Energy Security Board's *Health of the NEM 2022* addresses the greatest risks to the NEM and the actions required to address them.[8]

Figure 2.1 Weekly wholesale electricity prices



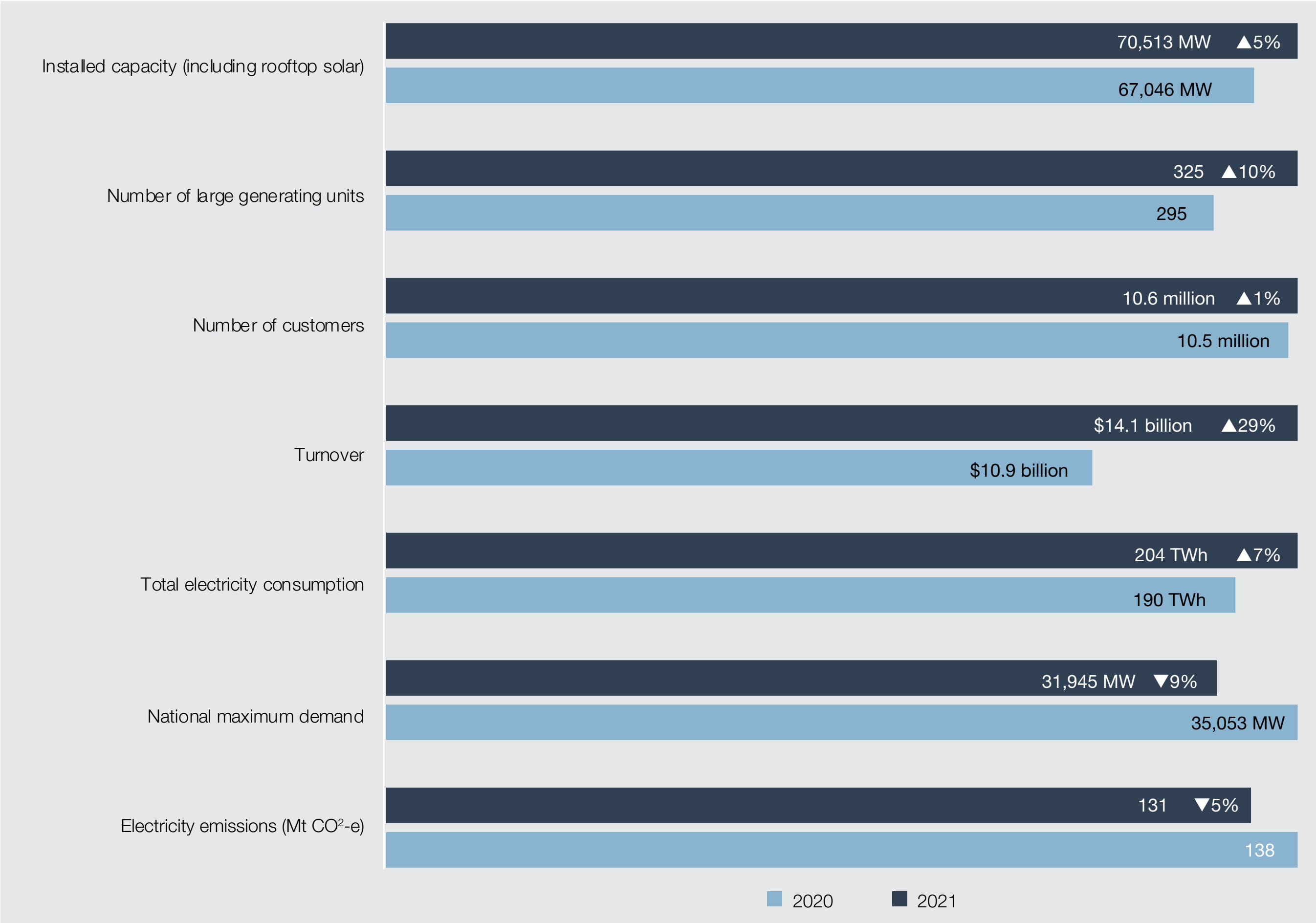
Note: Volume weighted weekly averages.
Source: AER; AEMO (data).

8 Energy Security Board, Health of the National Electricity Market 2022, September 2022.

2.2 The NEM at a glance

Around 325 generating units produce electricity for sale into the NEM (Figure 2.2). A transmission grid carries this electricity along high voltage power lines to industrial energy users and local distribution networks (chapter 3). Energy retailers complete the supply chain by purchasing electricity from the NEM and packaging it with transmission and distribution network services for sale to residential, commercial and industrial energy users.

Figure 2.2 NEM at a glance



Note: MW: megawatts; TWh: terawatt hours. All data as at January 2022, except customers, which are as at the second quarter of 2020–21, and Victoria customer numbers, which were reported in 2019–20.

Includes energy met by the grid and rooftop solar generation.

Source: AER; AEMO; Clean Energy Regulator; Energy Made Easy website (energymadeeasy.gov.au); Victorian Essential Services Commission, Department of Industry, Science, Energy and Resources, National greenhouse gas inventory.

Box 2.1 How the NEM works

The NEM consists of a wholesale spot market for selling electricity and a transmission grid for transporting it to energy customers.

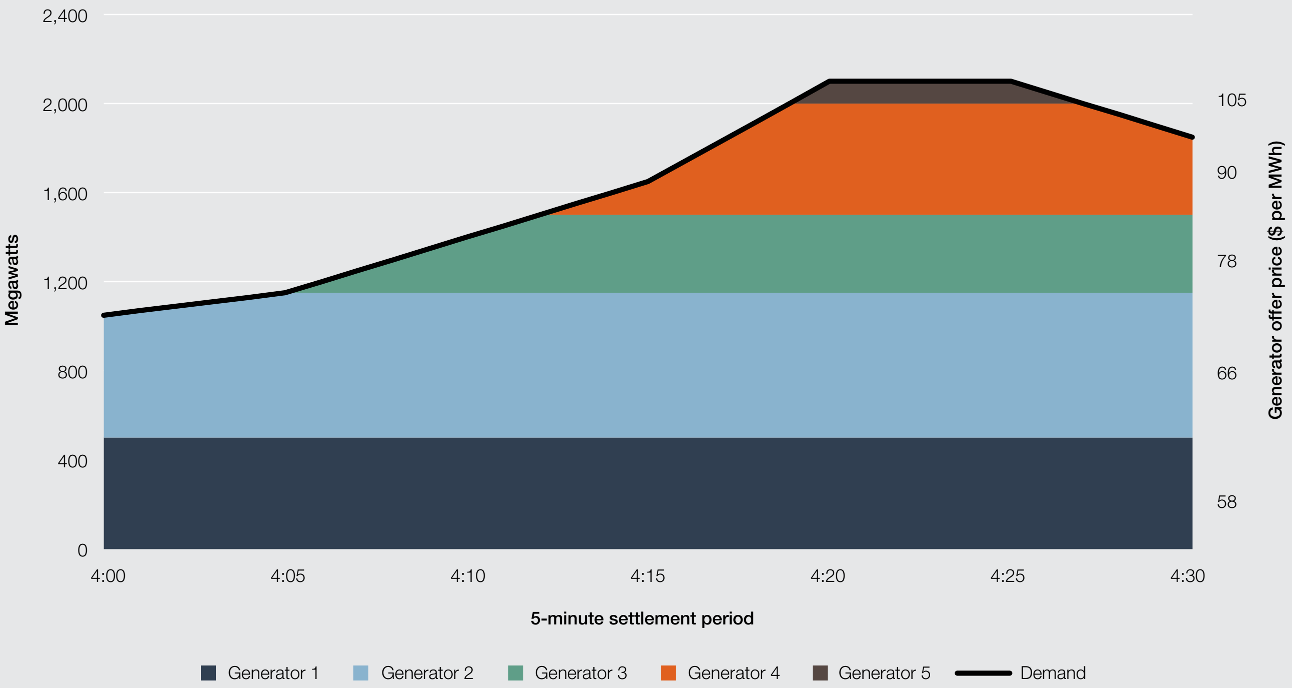
Power stations make offers to supply quantities of electricity in different price bands for each 5-minute dispatch interval. Scheduled loads, or consumers of electricity such as pumped hydro and batteries, also offer into the market. In 2021, for the first time, consumers (either directly or through aggregators) were able to bid demand response directly into the wholesale market as a substitute for generation (section 2.11.3). Electricity generated by rooftop solar systems is not traded through the NEM, but it does lower the demand that market generators need to meet.

A separate price is determined for each of the 5 NEM regions. Prices are capped at a maximum of $15,500 per megawatt hour (MWh) in 2022–23. A price floor of –$1,000 per MWh also applies. The market cap has increased in line with the consumer price index (CPI) each year, but the market floor price remains unchanged.

As the power system operator, AEMO uses forecasting and monitoring tools to track electricity demand, generator bidding and network capability to determine which generators should be dispatched to produce electricity. It repeats this exercise every 5 minutes for every region. It dispatches the cheapest generator bids first then progressively more expensive offers until enough electricity can be produced to meet demand. The highest priced offer needed to cover demand sets the 5-minute price in each region.

Figure 2.3 illustrates how prices are set. In this example, 5 generators offer capacity in different price bands between 4:00 pm and 4:30 pm. At 4:15 pm the demand for electricity is 1,650 MW. To meet this demand, generators 1, 2 and 3 must be fully dispatched and generator 4 is partly dispatched. The dispatch price is $90 per MWh. By 4:20 pm demand has risen to the point where a fifth generator is needed. This generator has a higher offer price of $105 per MWh, which becomes the dispatch price for that 5-minute interval. The price paid to all dispatched generators is the price in each 5-minute dispatch interval.

Figure 2.3 Setting the price



While the market is designed to meet electricity demand in a cost-efficient way, other factors can intervene. At times, dispatching the lowest cost generator may overload the network or risk system security, so AEMO dispatches more expensive (out of merit order) generators instead.

Retailers buy power from the wholesale market and package it with network services to sell as a retail product to their customers. They manage the risk of volatile prices in the wholesale market by taking out hedge contracts (derivatives) that lock in a firm price for electricity supplies in the future, by controlling generation plant or taking out demand response contracts with their retail customers.

2.3 Wholesale prices and activity

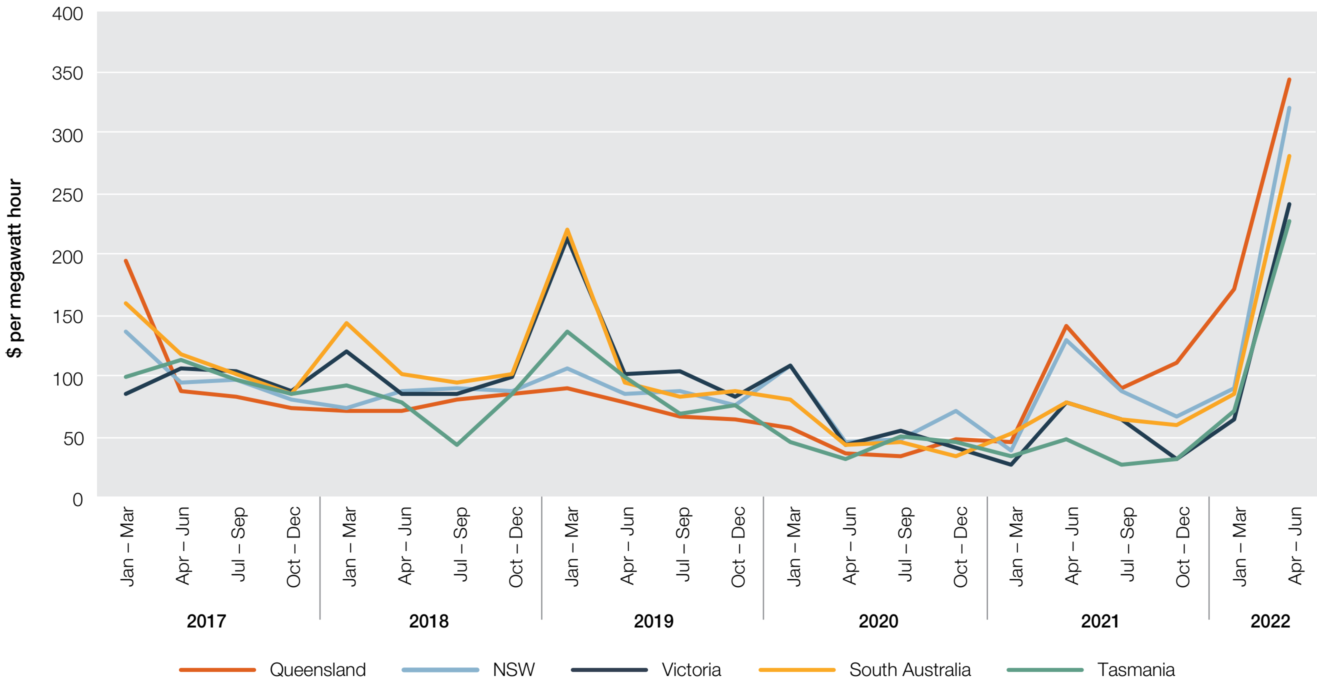
2.3.1 The market in 2022

Wholesale electricity prices rose dramatically in 2022 to reach record levels in all regions.

From January to March (Q1 2022) average prices increased across all regions compared to the same quarter in 2021, at least doubling in most regions and quadrupling in Queensland (Figure 2.4). Demand reached record highs in Queensland as plant outages in Queensland and NSW reduced supply. Network constraints meant that periodically, regions were limited in their ability to import electricity from neighbouring regions, and at the same time, international coal and gas prices started increasing as a result of the Ukraine war.

From April to June (Q2 2022) and continuing into July, supply-side pressures on wholesale prices intensified. Average quarterly 30-minute wholesale electricity prices increased significantly in all regions to reach their highest levels ever. These outcomes were largely the result of underlying high prices (particularly prices between $200 and $500 per MWh) over several months in all regions.

Figure 2.4 Quarterly wholesale electricity prices



Note: Prices are volume weighted quarterly averages.
Source: AER; AEMO (data).

Compounding factors drove these increases in spot market prices:

- very high international coal and gas prices
- ongoing coal plant outages, significant coal supply challenges and higher marginal coal prices
- reduced coal-fired generation causing the market to rely on more expensive sources of generation, such as gas and hydro to meet demand
- high demand for gas-powered generation coinciding with gas supply limits and soaring gas spot prices.
- increased demand due to an early and very cold winter.

A key driver of high prices in the NEM has been the dramatic increase in international prices for coal and gas, which are key fuels for electricity generation. The 2021–2022 global energy crisis led to energy shortages in the United Kingdom and China. European and Asian prices rose to record levels and Australian coal and gas was worth more in export than in domestic markets. In February 2022 Russia invaded Ukraine and global fuel prices rose even further (section 2.3.3). Coal and gas-powered generators needing to source additional fuel were exposed to these high prices.

Numerous coal plants experienced coal supply issues (section 2.6.1). Heavy rain in March impacted open cut mines and rail lines in NSW and Queensland, and geological issues reduced output from others. Prices for marginal coal bought on the spot market rose 4-fold compared to the same time the previous year.

Coal generator outages (planned and unplanned) reduced availability in May and June at the same time an early and very cold start to winter increased demand. At times of low renewable and reduced coal-fired generation, the NEM was reliant on expensive gas and hydroelectric generation to meet daily energy needs. Increased demand for gas to generate electricity and meet winter demand, combined with tight domestic supply conditions caused domestic gas prices to surge (section 4.3). High international gas prices strengthened the incentive for producers to export liquefied natural gas (LNG). By late May, domestic gas spot prices were 2 to 5 times higher than in March.

The soaring cost of fuel and the need for some generators to ration depleted fuel supplies led to a very large shift in bidding by coal and gas generators. Some generators buying coal on the spot market reported they needed a price of more than $300 per MWh to break even. Gas generators buying fuel on the spot market needed around $400 per MWh.

When the offers of coal or gas generators increase, hydro generators generally follow suit or risk overly depleting their water reserves. Thus, hydro offers increased in line with thermal offers. While hydro generation ran hard, Snowy Hydro's ability to further increase its output was limited by the amount of water it could release into the Tumut River, which risked downstream flooding.

The scale of these events and price increases triggered administered price caps and spot market suspensions.

High gas prices trigger price cap

From 24 May to 7 June, following the suspension of a gas market participant, AEMO imposed price caps in the Sydney and Brisbane short-term trading markets. A week later, the cumulative price threshold was reached in Victoria's wholesale gas market and it was placed under an administered price cap, lasting until 1 August when the cumulative price dropped below the threshold. The Sydney short-term market was also placed under an administered price cap from 8 to 14 June when the cumulative price exceeded the threshold.

High electricity prices trigger price cap and subsequent capacity withdrawals lead to market suspension

Between 12 and 14 June 2022, sustained high wholesale electricity prices triggered an administered price cap of $300 per MWh in Queensland, NSW, Victoria and South Australia. The price cap, combined with high fuel costs, contributed to several generators withdrawing capacity from the market. The resulting supply shortfalls prompted AEMO to use its powers to direct generators to provide electricity.

On 15 June, AEMO took the extraordinary step of suspending the wholesale electricity markets to ensure a reliable supply of electricity. NEM operations were not designed to cope with a withdrawal of such large volumes of capacity and AEMO was unable to sustain the level of manual resolution needed. During the market suspension, AEMO determined spot prices and participants were able to apply for compensation if those prices did not cover actual costs.[9]

Following negotiations with generators and the resolution of plant outages, almost 4,000 MW of coal capacity returned to the market. Nevertheless, there were occasions when the market came close to actual supply shortfalls and AEMO activated emergency reserves to reduce demand. On 22 June AEMO removed the price cap and on 23 June it lifted the market suspension.

While underlying conditions explain these market outcomes to a large degree, the AER is investigating whether bidding behaviour breached any rules and legislation. We will also examine broadly if generator conduct and market outcomes were consistent with an efficient and competitive market serving the long term interest of consumers. We will report our conclusions in the *Wholesale electricity markets performance report 2022*, to be released in December 2022.

Wholesale electricity prices eased in August 2022 but were more than double the prices in August 2021.

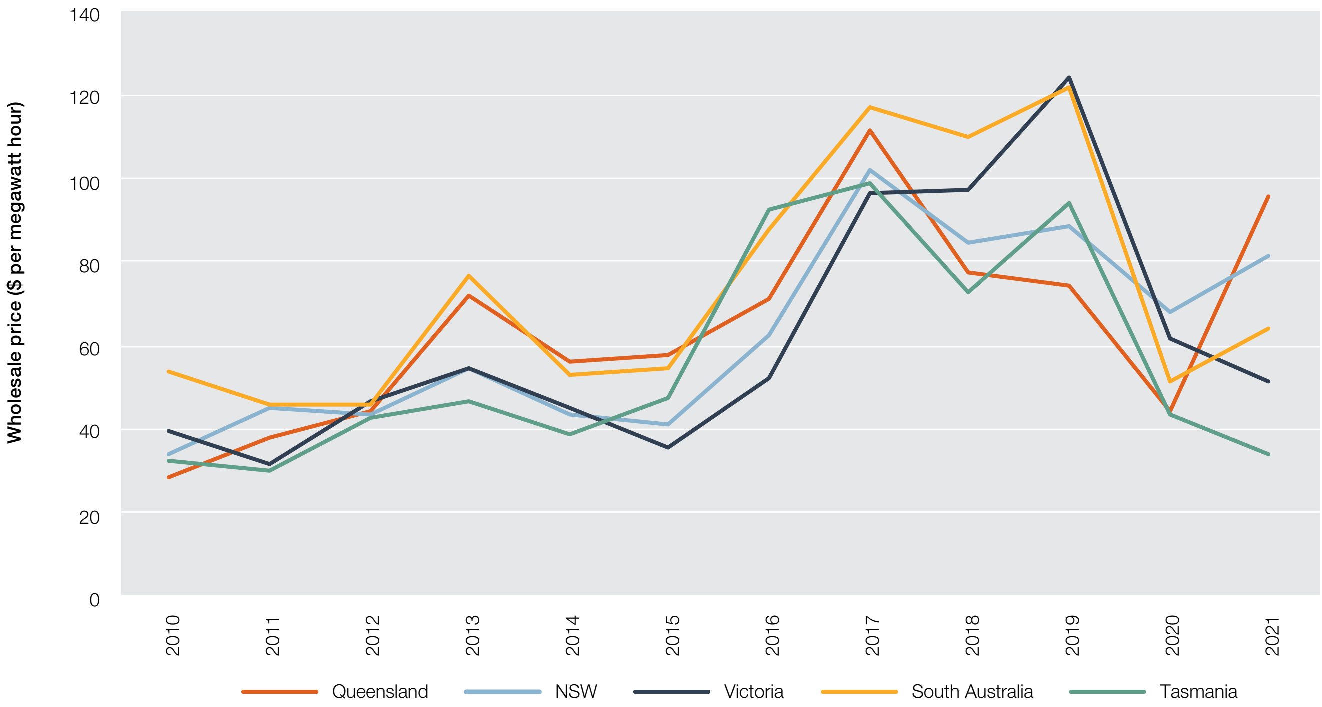
9 AEMO, Market suspension FAQs June 2022, June 2022.

2.3.2 The market in 2021

The outcomes in 2022 represent a dramatic reversal from those a little over a year earlier. Wholesale prices across the NEM were low at the start of 2021, driven largely by new investment in wind and solar and falling coal and gas fuel input costs through to late 2020. Demand was also lower due to increased rooftop solar output and mild summer conditions in 2020–21.

However, the supply-demand balance remained tighter than in the past and the outage at Callide C power station drove higher wholesale prices in Queensland and NSW, particularly in the evenings.

Figure 2.5 Annual wholesale electricity prices



Note: Prices are volume weighted calendar year averages.
Source: AER; AEMO (data).

Average annual prices in 2021 rose in Queensland, NSW and South Australia and fell in Victoria and Tasmania (Figure 2.5):

- Queensland ($96 per MWh) was the NEM's highest priced region. Average prices were affected by price spikes, starting with the long-running Callide outage, and network constraints, which limited the ability to import electricity from NSW.
- NSW ($81 per MWh) recorded the second highest prices in the NEM due to high prices in May and June. At times it was limited in its ability to import cheaper electricity from Victoria due to outages around the transmission lines connecting the 2 regions.
- South Australia ($64 per MWh) prices rose compared with 2020. High prices often occurred at times of low wind output when South Australia was also prevented from importing from Victoria.
- Victoria ($52 per MWh), on the other hand, recorded its second year of falling spot prices. These reflected an increase in low-cost renewable generation and low demand due to mild temperatures and output from rooftop solar.
- Tasmania ($34 per MWh) remained the NEM's lowest price region.

2.3.3 Generator fuel costs and fuel availability

In 2021 and 2022 generator fuel costs increased for many reasons. High prices for Australian coal and gas were fuelled by the global energy crisis, war in the Ukraine, sanctions against Russia, high Asian and European demand, as well as domestic coal supply problems.

Upstream black coal and gas market conditions can affect fuel costs for generators. Although black coal generators do not pay international prices for all their coal supply, the international price can be an important factor. In NSW in particular, it can shape prices for short-term supply contracts and determine when long-term contracts are renegotiated. The international export price for black coal quadrupled from the start of 2021, to over $500 per tonne in mid-2022 (Figure 2.6). These prices suggest that the short run marginal cost for coal plants needing to source coal from spot markets is well above $200 per MWh. With future coal prices expected to remain elevated into 2024, there will be a step increase in costs as coal supply contracts are renewed over the next 2 years.

Record La Niña-driven rains impacted open cut coal mines on Australia's east coast, particularly in the Hunter Valley.[10] Pits were flooded and rail lines disrupted. Some mines were unable to deliver forecast levels of coal to associated coal generators. Not all coal meets the correct specifications, and it takes time to purchase coal and create new logistic chains. Further, high export prices caused domestic coal sales in NSW to drop. These conditions resulted in a number of coal generators having low stockpiles going into winter.

The average price set by NSW black coal generators rose from $35 per MWh in Q1 2021 to over $400 per MWh in the week leading up to the administered price cap in June.

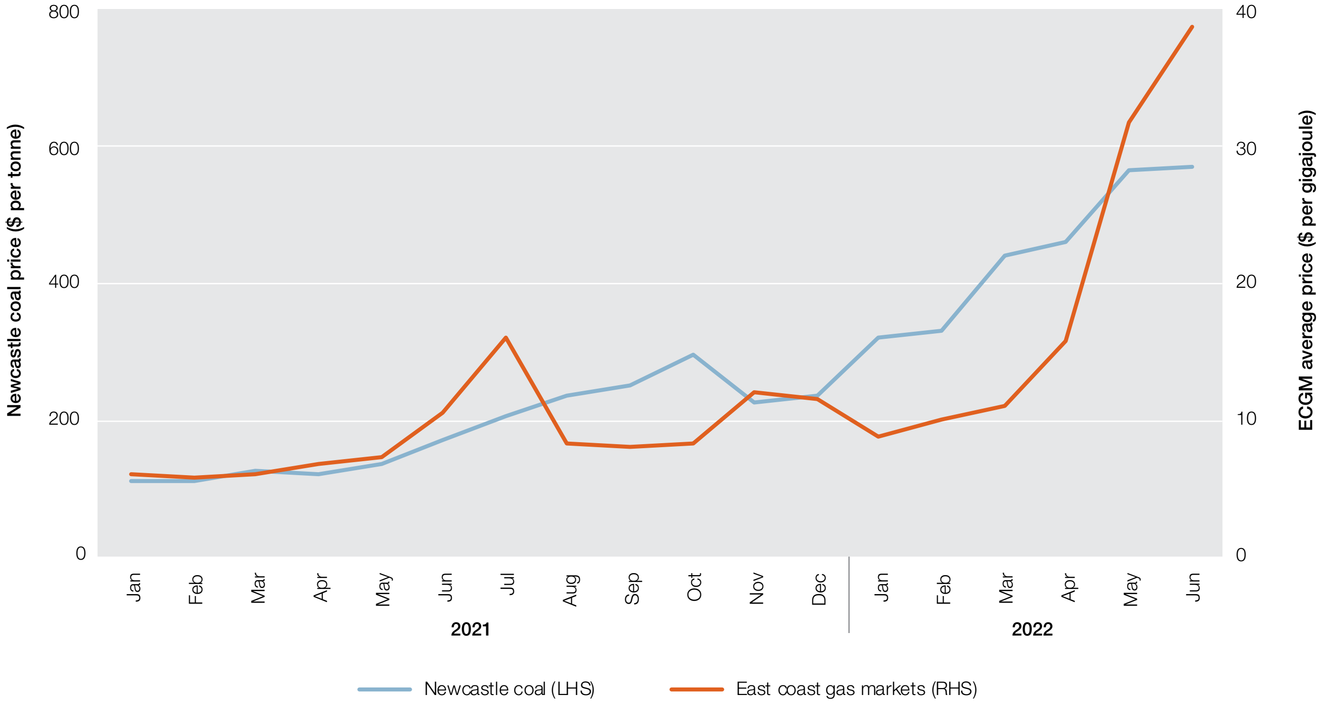
Fuel costs for gas plants also increased across 2021 and 2022. Gas generators are likely to value their fuel at the prevailing gas market price when deciding whether to generate. Record LNG demand driven by a dramatic spike in international LNG prices put upward pressure on domestic gas spot prices. The LNG netback price tripled from the start of 2021 to June 2022.

In May through to June 2022, gas market participants bought record levels of gas off the spot markets, either for gas generation or for other gas customers. These spot purchases were likely to be a relatively small percentage of these participants' total gas demand, most of which is sourced under long term contracts. Nevertheless, the increase in spot market purchases from generators had a significant impact on spot market demand and prices, and ultimately on NEM prices.

The average price set by NSW gas generators rose from around $50 per MWh in Q1 2021 to $325 per MWh in the week leading up to the administered price cap in June.

10 Yancoal, Quarterly Report for the quarter ending 31 March 2022, April 2022.

Figure 2.6 Black coal and gas fuel prices



Note: The black coal price is derived from the Newcastle coal index (US$ per tonne), converted to A$ with the Reserve Bank of Australia exchange rate. The east coast gas market (ECGM) average gas price is the average of gas prices in Queensland, NSW, Victoria and South Australia.

Source: AER analysis using globalCOAL data, and data from the short-term trading market and Victorian declared wholesale gas market.

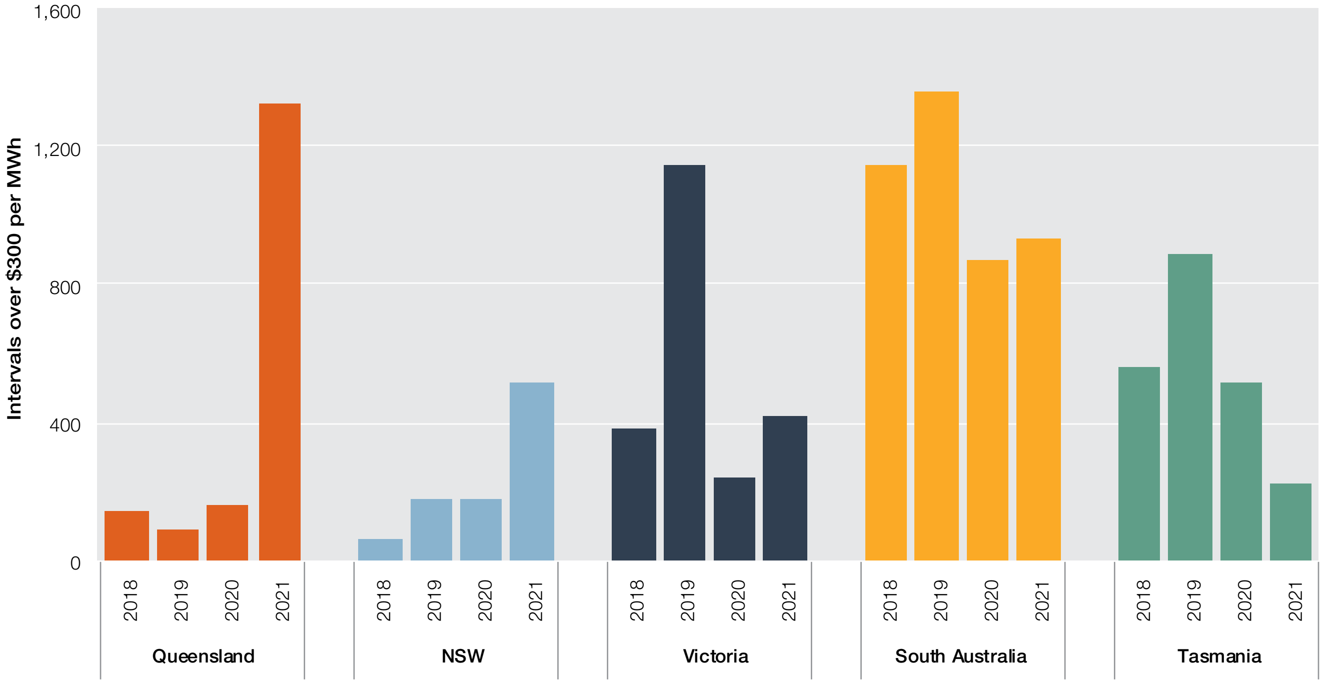
2.3.4 Price volatility

Price volatility is a natural feature of energy markets and can signal to the market that investment in new generation is needed. While price volatility was high in 2021, with more 30-minute prices over $5,000 per MWh in 2021 than in the last decade, price volatility was significantly higher again in 2022.

In 2022, high prices were the largely the result of underlying high prices over several months in all regions but were also increased by high price spikes in Queensland, NSW and South Australia. In the first 8 months of 2022 there were almost 11,000 instances of prices above $300 per MWh (compared to 632 in 2021) and 74 instances of prices above $5,000 per MWh (compared to 43 in 2021).[11]

11 The AER reports on all 30-minute prices above $5,000 per MWh through its Performance reporting.

Figure 2.7 Count of prices above $300 per MWh



Note: Count of 30-minute prices above $300 per MWh.
Source: AER; AEMO (data).

2.3.5 Negative prices

An aspect of market volatility that has emerged in recent years is a rising incidence of negative prices. Generators in the NEM can offer capacity as low as the market floor price of –$1,000 per MWh. Negative bids essentially signal a generator's willingness to pay to produce electricity rather than switch off. AEMO typically dispatches generators by using the lowest priced offers first, then working its way through the merit order until demand is met. Allowing generators to offer capacity at negative prices increases the chances of the generator being dispatched into the market.[12]

Generators may have various motivations to offer capacity at negative prices. As an example, it may be cost-effective for large baseload coal generators to offer large amounts of capacity at negative prices to ensure continuous operation and avoid the high costs of shutting down and then restarting a few hours later. Once generating, baseload plants generally have low operating costs.

A generator's hedge position in contract markets may also affect its bidding strategies. If a generator has a contract ahead of time that ensures a fixed price for electricity sold into the market, its exposure to negative prices may be minimal.

The ability of wind and solar generators to operate varies with prevailing weather conditions. These generators do not incur high start-up or shut down costs and have running costs close to zero. If generating conditions are optimal, they may bid capacity at negative prices to guarantee dispatch. Some wind and solar generators also source revenue from the sale of renewable energy certificates or power purchase agreements, so they may operate profitably even when wholesale prices are negative.

If electricity demand is low, the market has surplus capacity and the chances of the market settling at a negative price are higher. The geographic grouping of renewable generators can intensify the effect because, when conditions are favourable for one generator in the area, conditions tend to be favourable for others too. With multiple generators of similar technologies competing for dispatch, the likelihood of negative prices increases. Negative prices tended to occur when electricity demand was low and weather conditions were optimal for renewable generation. While historically occurring overnight, they are now more common during the middle of the day when solar resources are producing maximum output and demand is relatively low.[13]

12 While a generator may offer capacity at negative prices, it does not necessarily mean the spot price will settle at a negative price. The dispatch price is determined by the marginal generator required to meet demand every 5 minutes. The spot price is determined every 30 minutes as the average of the 6 dispatch prices within that half hour.

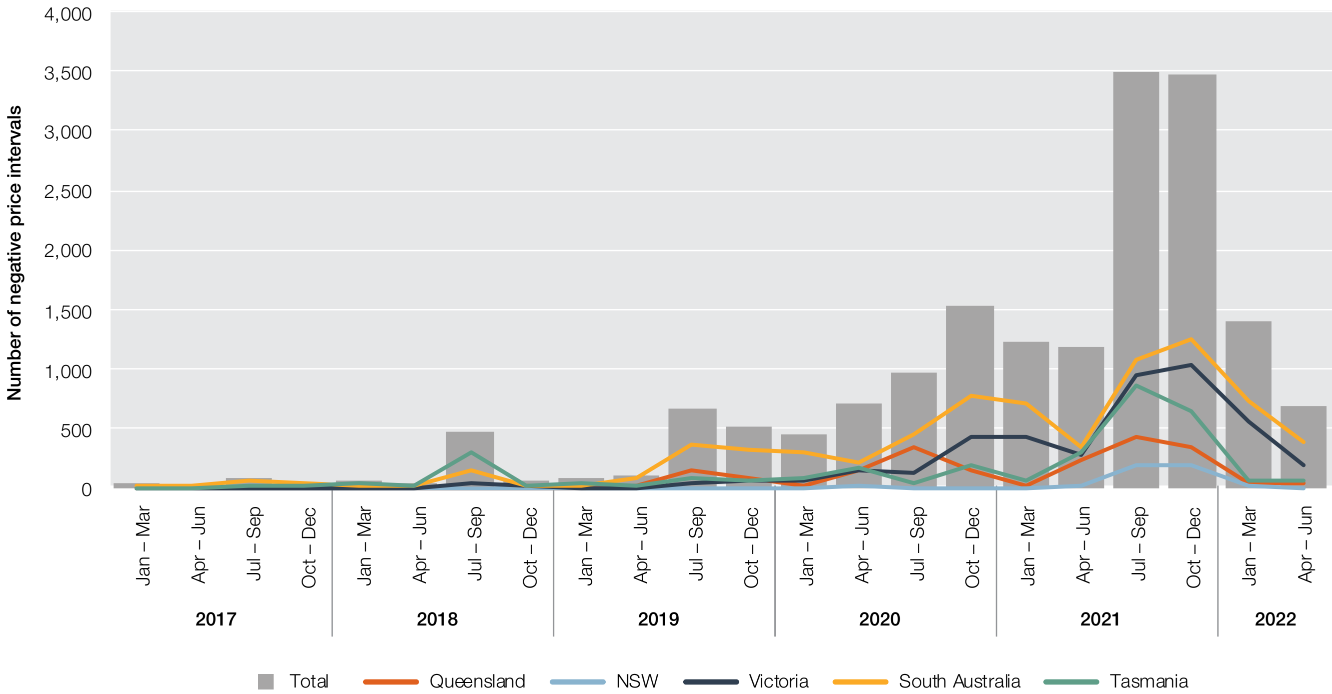
13 AER, Wholesale markets quarterly – Q3 2020, November 2020.

A record number of negative prices were seen NEM-wide in 2021, well over double the number in 2020. Nearly two-thirds occurred in South Australia and Victoria, which have the highest penetration of wind and solar (including grid-scale and rooftop) generation. Instances of negative spot prices were highest when these units were generating.

Over 65% of negative prices in 2021 occurred in the second half of the year, far exceeding the previous quarterly record set in October to December 2020. Between October to December in 2021, prices were negative in South Australia 27% of the time and in Victoria 22% of the time.[14]

In 2022, the instance of negative prices fell, particularly between April and June, reflecting fuel constraints and low renewable generating conditions. This may reverse in the Spring months with low demand and good wind and solar generating conditions.

Figure 2.8 Count of negative prices



Note: Count of 30-minute prices below $0 per MWh.
Source: AER; AEMO (data).

2.4 Electricity contract markets

Contract market prices increased by as much as 300% to 600% since the start of 2022. Market participants did not anticipate such a significant jump. These markets are critical to the ability of retailers to manage price risk on behalf of customers. They are also critical in driving generator behaviour. Contract prices, along with liquidity of contract markets, will drive wholesale outcomes for some time.

Futures (contract or derivatives) markets operate parallel to the wholesale electricity market. Prices in the wholesale market can be volatile, posing risks for market participants. Generators face the risk of low settlement prices reducing their earnings, while retailers risk paying high wholesale prices that they cannot pass on to their customers. A retailer may expand its operation and sign up a significant number of new customers at a particular price, only to then incur unexpectedly high prices in the wholesale market, ultimately leaving the retailer substantially out of pocket.

Generators and retailers can manage their market exposure by locking in prices for which they will trade electricity in the future. An alternative strategy adopted by some participants is to internally manage risk through vertical integration – that is, operating as both a generator and a retailer ('gentailers') to offset the risks in each market.

Typically, vertically integrated gentailers are imperfectly hedged – their position in generation may be 'short' (not enough generation) or 'long' (too much generation) relative to their retail position. For this reason, gentailers

14 AER, Wholesale markets quarterly – Q4 2021, February 2022, p 4.

participate in contract markets to manage outstanding exposures, although usually to a lesser extent than standalone generators and retailers do.

Alongside generators and retailers, participants in electricity contract markets include financial intermediaries and speculators, such as investment banks. Brokers often facilitate contracts between parties in these markets.

In Australia, 2 distinct financial markets support the wholesale electricity market:

- In over-the-counter (OTC) markets, 2 parties contract with each other directly (often assisted by a broker). The terms of OTC trades are usually set out in International Swaps and Derivatives Association (ISDA) agreements.
- In exchange traded markets, electricity futures products are traded on the Australian Securities Exchange (ASX) or through FEX Global (FEX).[15] Participants include generators, retailers, speculators, banks and other financial intermediaries. Electricity futures products are available for Queensland, NSW, Victoria and South Australia.

Various products are traded in electricity contract markets. Similar products are available in each market, but the names of the instruments differ. While exchange traded products are standardised to encourage liquidity, OTC products can be uniquely sculpted to suit the requirements of the counterparties:

- Futures contracts allow a party to lock in a fixed price (strike price) to buy or sell a given quantity of electricity at a specified time in the future. Each contract relates to a nominated time of day in a particular region. Available products include quarterly base contracts (covering all trading intervals) and peak contracts (covering specified times of generally high energy demand). Futures can also be traded as calendar or financial year strips covering all 4 quarters of a year. Futures contracts are settled against the average quarterly spot price in the relevant region – that is, when the spot price exceeds the strike price, the seller of the contract pays the purchaser the difference; and when the spot price is lower than the strike price, the purchaser pays the seller the difference. In OTC markets, futures are known as swaps or contracts for difference.
- Caps are contracts setting an upper limit on the price that a holder will pay for electricity in the future. Cap contracts on the ASX and FEX have a strike price of $300 per MWh. When the spot price exceeds the strike price, the seller of the cap (typically a generator) must pay the buyer (typically a retailer) the difference between the strike price and the spot price. Alternative (higher or lower) strike prices are available in the OTC market.
- Options are contracts that give the holder the right – without obligation – to enter a contract at an agreed price, volume and term in the future. The buyer pays a premium for this added flexibility. An option can be either a call option (giving the holder the right to buy the underlying financial product) or a put option (giving the holder the right to sell the underlying financial product). Options are available on futures and cap products.

Prices are publicly reported for exchange trades, but activity in OTC markets is confidential and not disclosed publicly. The Australian Financial Markets Association (AFMA) reports data on OTC markets through voluntary surveys of market participants, providing some information on the trade of standard OTC products such as swaps, caps and options.

Exchange traded contracts are settled through a centralised clearing house, which acts as a counterparty to all transactions and requires daily cash margining to manage credit default risk. In OTC trading, parties manage credit risk by determining the creditworthiness of their counterparties.[16]

2.4.1 Contract market activity

Until recently, the ASX was the sole futures exchange operating in the NEM. FEX Global launched a separate futures exchange in March 2021 offering a similar range of products. To 30 June 2022, only 3 trades have occurred.

Regular ASX trades occur for the Queensland, NSW and Victorian regions of the NEM, but liquidity is poor in South Australia.

Until June 2022, trading levels had increased over the previous 4 financial years due to a material growth in traded volumes on the ASX (Figure 2.9). The increased ASX volumes were driven by increases to options and quarterly base futures. Since 2017–18, the annual traded volume of options increased by more than 500% and quarterly base futures increased by over 150%.

In June and July 2022 there was a marked decline in ASX trade for some contract types, likely resulting from significant market volatility and the resulting cashflow impacts on generators. Retailers might have been hesitant to

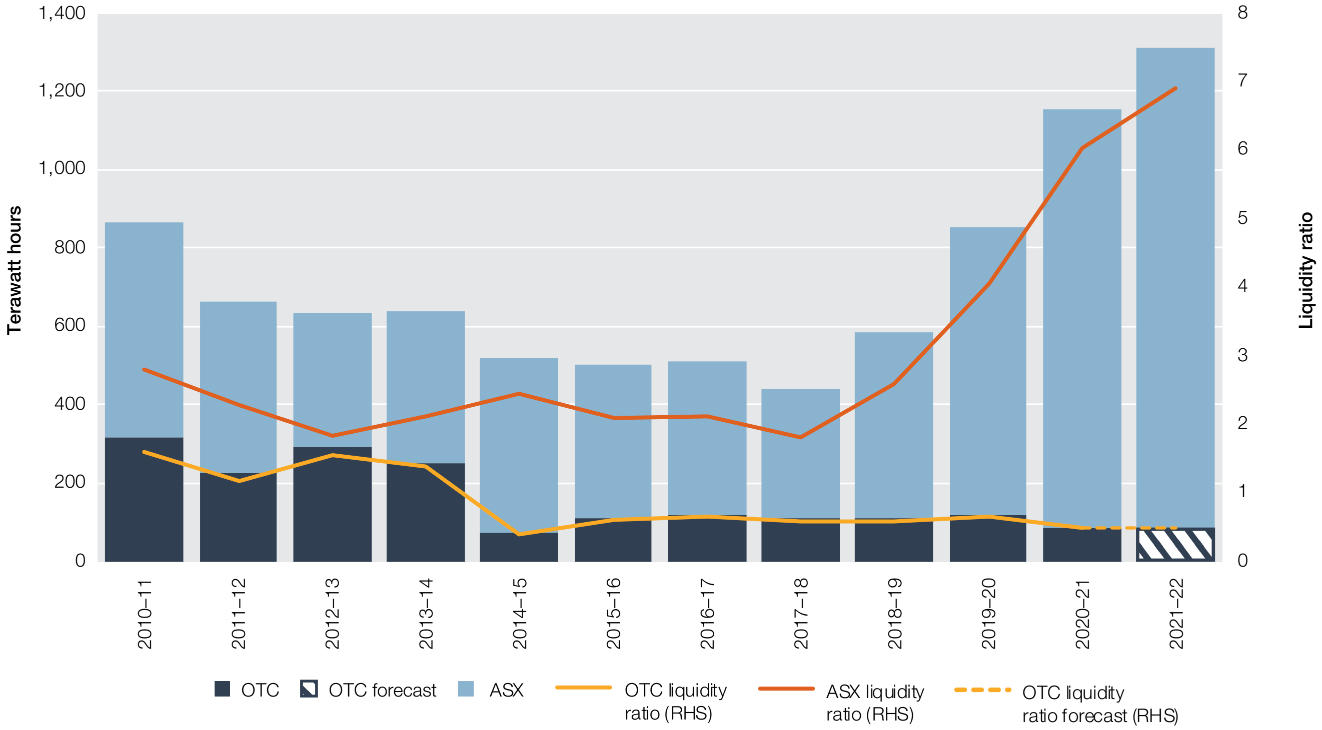
15 FEX launched its futures exchange on 26 March 2021.

16 Electricity derivatives markets are regulated under the *Corporations Act 2001* (Cth) and the *Financial Services Reform Act 2001* (Cth). The Australian Securities and Investments Commission is the principal regulatory agency.

contract being unwilling to lock in prices at such high levels and instead opted to wait and see if prices would fall in the future. Generators might have been hesitant to contract because additional contracting would expose themselves to potential margin calls.

In August 2022, however, trade volumes were higher than any volume previously traded in the month of August since records began in 2002. The increase in traded volumes after the low levels observed in June and July is a positive sign for liquidity increasing in the contract market.

Figure 2.9 Traded volumes in electricity futures contracts



Note: Exchange trades are publicly reported, while activity in over-the counter (OTC) markets is confidential and disclosed publicly only via voluntary participant surveys in aggregated form. The OTC data are published on a financial year basis. To allow some comparability across OTC and exchange traded data, this section refers to financial years for both markets. Data for 2021–22 trading of OTC contracts were not available at the time of publication. The OTC liquidity ratio forecast is the liquidity ratio compared the total traded volumes to the native demand across the 4 combined regions.

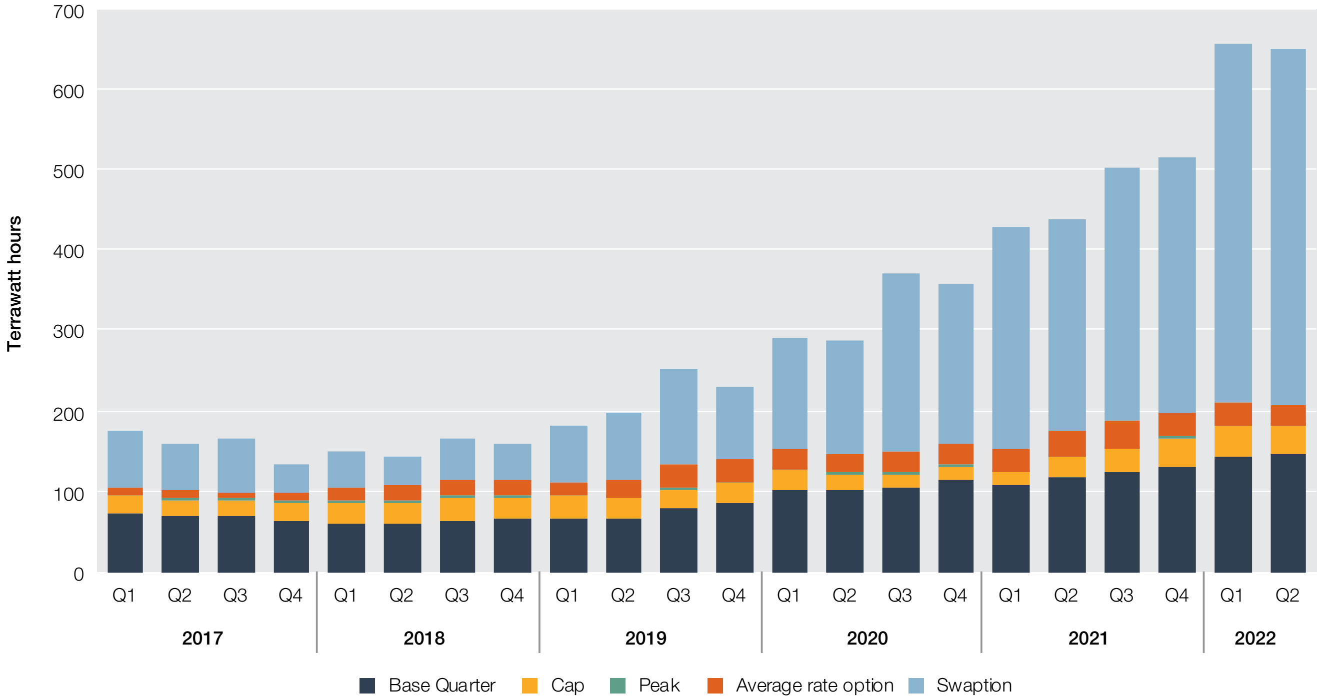
Source: AER; AFMA; ASX Energy.

Importantly, open interest volumes have been increasing (Figure 2.10). In the past 3 years, the total open interest volume for electricity futures and options has quadrupled despite the high contract prices. This indicates that the increase in traded volumes is not just due to higher turnover, but also because participants are holding larger open contract positions.

OTC trade volumes have remained steady or declined. In 2020–21 OTC trade was only 7% of total traded volume.

The growth in trading of ASX contracts until June 2022 continued despite the falling capacity of baseload coal generation and rising share of wind and solar generation in the market. Intermittent renewables generation is not as well suited to the sale of standard contracts as coal generation. This is because its output is uncertain and weather dependent. But ‘firming’ this generation with energy storage or gas-powered plant can help support contract market participation. Several market participants with flexible generation capacity offer firming products targeted at renewable generation.

Figure 2.10 ASX open interest volumes



Source: AER; ASX Energy.

ARENA provided funding support to Renewable Energy Hub, a specialist advisory and technology solutions provider, to establish a firming market platform that offers new hedge products designed for clean energy technologies. The platform aims to fill a gap in risk management products and overcome a market barrier for clean energy technologies.[17] New hedging products introduced by Renewable Energy Hub include:[18]

- 'Solar shape' and 'inverse solar shape' contracts to provide a level of flexibility to manage the intermittency of renewable generation. They are tailored to specific periods of the day and provide an alternative to flat contracts.
- A 'super peak' electricity contract for electricity supply during the high demand hours of the morning, afternoon and evening periods.
- A 'virtual storage' electricity swap for buying and selling stored energy. The price of the product is set at the spread of the agreed charge and discharge prices.

Products on the traditional exchanges are also adapting to market changes. In March 2021 the ASX began offering 5-minute settlement cap products. These replaced existing cap products in advance of changes to settle the market every 5 minutes.

Contract market liquidity

Overall, contract liquidity has improved across the NEM in recent years. The liquidity ratio (contract trading relative to underlying demand) across the NEM rose from around 240% in 2017–18 to over 650% in 2020–21 (Figure 2.9), with all regions improving. Trades through just the ASX in 2021–22 equated to 690% of underlying trade in the NEM.

The recent decline in liquidity in June and July 2022 was the result of market conditions including high contract prices, trading limits and margining requirement. Margining may have placed financial pressure on generators, reducing their ability to continue to offer contracts for sale.

Total contract volumes across ASX and OTC markets exceed the underlying demand for electricity by a significant margin in Queensland, Victoria and NSW. Given the extent of vertical integration in Victoria and NSW, this indicates that substantial trading (and re-trading) occurs in capacity made available for contracting.

Liquidity is poorer in South Australia, where trading volumes are less than underlying electricity demand. For just ASX trades, South Australia was the only region where the liquidity ratio dropped in 2020–21 and again in 2021–22. The region's high proportion of renewable generation and relatively concentrated ownership of dispatchable generation

17 ARENA, Renewable Energy Hub marketplace, ARENA website, May 2020.

18 Renewable Energy Hub, 'New energy contracts for a new energy future', May 2021.

likely contributed to this weaker liquidity. Given South Australia's liquidity issues, the Australian Competition and Consumer Commission (ACCC) recommended the imposition of a 'market maker' obligation, under which large vertically integrated retailers must make offers to buy and sell hedge products within a capped price spread. Similar reforms were introduced in 2019 under the Retailer Reliability Obligation (RRO) (section 2.4.3).

Composition of trade

Trade increased in Queensland and NSW and accounted for 48% and 30% respectively of ASX contracts traded in 2021–22. Traded volumes decreased in Victoria, accounting for 22% of trades. Trading in South Australia accounted for less than 1% of contract volumes. In the OTC market segment covered by the AFMA survey, Victoria had the highest traded volume, accounting for 40% of the total volume.

For 2021–22, swaptions (51%) were the most traded products on the ASX. The next most traded products were quarterly base futures, accounting for 39% of the traded volume. Average rate options (4%) and caps (6%) are traded at lower rates. Peak products continue to decline in popularity, accounting for only 0.04% of the volume. In the OTC market, swap products (78%) and caps (21%) accounted for most of the reported trading in 2020–21. Options are less popular in the OTC market, accounting for less than 1% of the OTC traded volume.

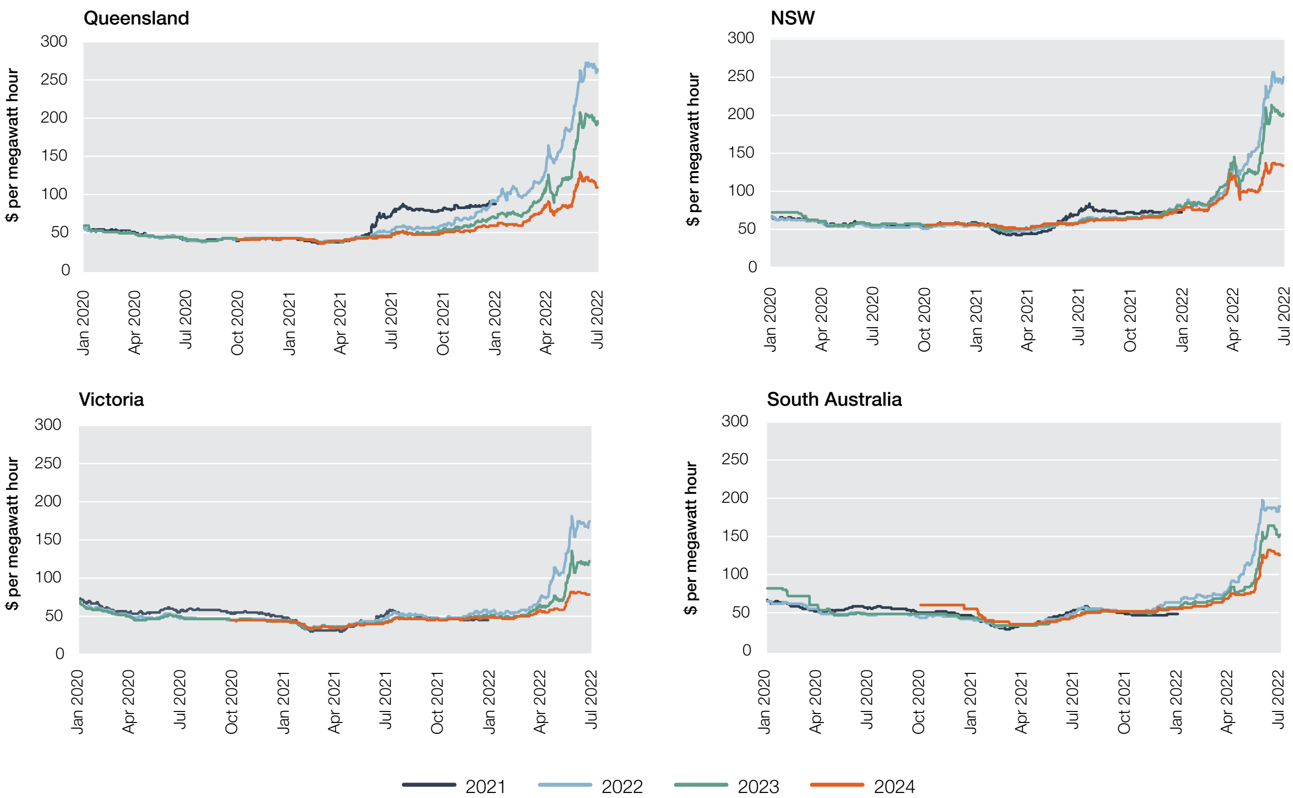
2.4.2 Contract prices

Base futures prices for calendar year 2022 ASX contracts were low at the start of 2021, before increasing in early 2022 and jumping considerably in April and May (Figure 2.11). At 30 June 2022, the calendar year prices for 2022 ranged from $177 per MWh in Victoria to $264 per MWh in Queensland. This is an increase of 360% to 540% since the start of 2021.

Final Q2 2022 contract prices set record highs in all regions. The final Q2 2022 base future prices were the highest ever recorded, not just in Q2 but in any quarter since the NEM commenced. The final Q2 2022 cap prices were the highest Q2 prices ever recorded in all regions. NSW and Queensland also recorded the highest ever final cap price regardless of the quarter.

These increases reflected higher than expected spot market prices due to the increased cost of generation with gas and coal fuel costs at record high prices, coal supply issues and increased opportunity costs with some generators rationing their fuel usage to save fuel for summer.

Figure 2.11 Prices for calendar year base futures

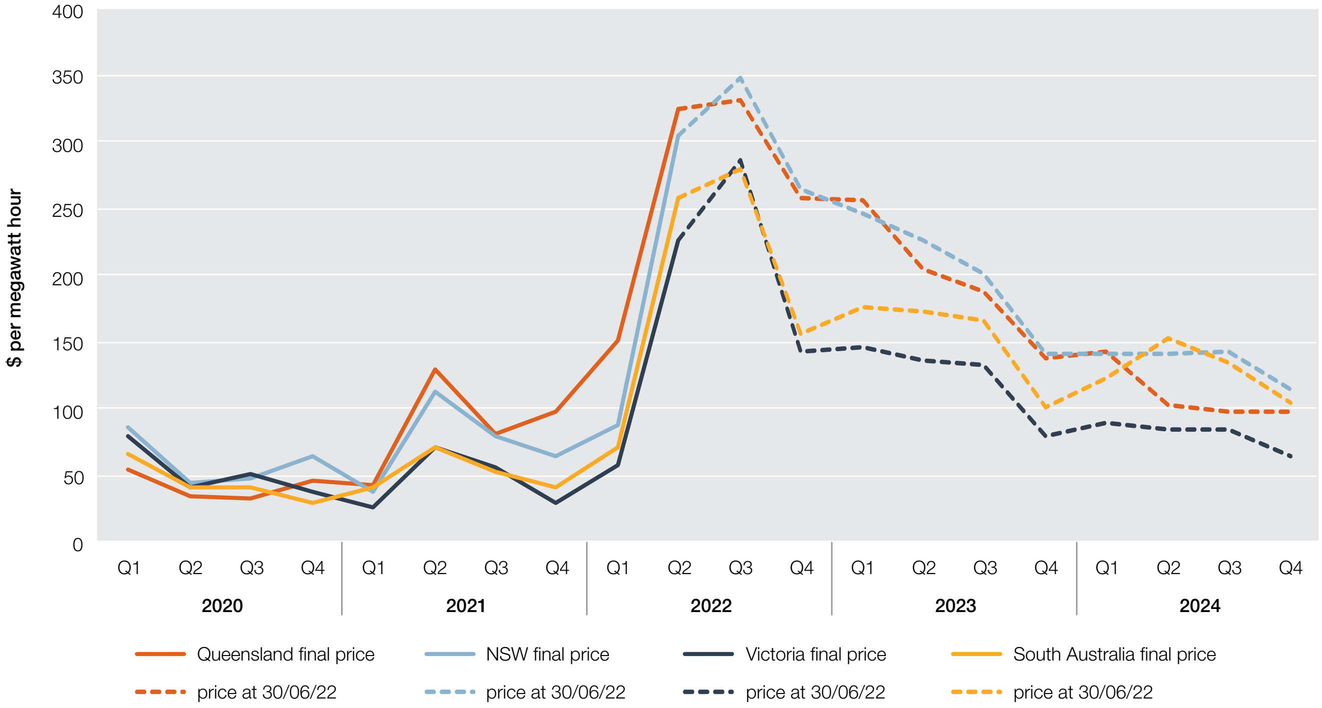


Source: AER; ASX Energy.

The outlook for 2023 and 2024 also increased, with high prices expected to continue into the coming years, but not as high as in 2022. On 30 June 2022, base future prices for 2023 and 2024 were highest in NSW and Queensland, rising to $202 per MWh in NSW and $195 per MWh in Queensland in 2023. NSW and Queensland prices for 2023 were $40–$80 per MWh higher than in South Australia and Victoria. These contract prices indicated that participants might have been anticipating a market impact from the closure of Liddell power station in NSW in 2023.

Quarterly base future prices start falling across 2023 and 2024, but they generally remain above $100 per MWh in every region except Victoria into 2024 (Figure 2.12).

Figure 2.12 Prices for quarterly base futures



Note: Prices for quarterly base future up to and including Q2 2022 are finalised (as they are no longer traded). Prices for quarterly base futures for Q3 2022 and beyond (which are still being traded) are as of 30 June 2022.

Source: AER; ASX Energy.

2.4.3 Access to contract markets

Access to contract markets, either on the ASX or in OTC electricity markets, can pose a significant barrier to retailers and generators looking to enter or expand their presence in the market. This poses a significant risk as contracts offer a degree of control over costs (for retailers) and revenue (for generators).

In the ASX market, the credit requirements of clearing houses and daily margining of contract positions also impose significant costs on retailers. The use of standardised products with a minimum trade size of 1 MW is too high for smaller retailers, which may be better served with the kind of 'load following' hedges accessible through the OTC market. These OTC hedge contracts remove volume risk and are particularly sought by smaller or new retailers without extensive wholesale market capacity. However, credit risk can act as a barrier to smaller retailers in the OTC market, with counterparties likely to impose stringent credit support requirements on them. Before entering an OTC contract, the parties must generally establish an ISDA agreement, which is a costly process to set up. Further, the retailer must establish a separate agreement with each party with whom it contracts, resulting in further costs.

The RRO scheme introduced in July 2019 includes features aimed at improving access to contracts through an exchange. It includes a market liquidity obligation (MLO) on specified generators to post bids and offers in contract markets in the period leading up to a forecast reliability gap, to help smaller retailers meet their requirements.

Box 2.2 The AER's role in the National Electricity Market

The AER has regulatory responsibilities in the NEM across the entire supply chain. We regulate competitive markets primarily through monitoring and reporting. At the wholesale level, we oversee and report on spot and contract market activity.

We monitor the markets to ensure participants comply with the National Electricity Law and National Electricity Rules and take enforcement action if necessary. A recent focus is on the provision of accurate and timely information to the Australian Energy Market Operator to help maintain power system security and efficient market outcomes.

We draw on our monitoring work to advise policy bodies and other stakeholders on market trends, policy issues and irregularities. When appropriate, we also propose or participate in reforms to improve the market's operation.

2.5 Electricity demand and consumption

'Grid demand' is demand for electricity produced by generators, sold through the wholesale market.[19] Rooftop solar output is treated as an offset against grid demand because it replaces electricity that would otherwise be supplied by large generators. Consumption is a wider concept covering the total amount of electricity used, including rooftop solar generation.

Grid demand has been falling significantly for 5 years, due to the increasing number of electricity customers generating their own electricity using rooftop solar (section 2.6.7). However, consumption fell only slightly in 2020 and 2021, after rising steadily for 5 years. The increase in consumption was largely driven by the expansion of Queensland's coal seam gas (CSG) and LNG industries and air conditioning, while the fall in 2020 and 2021 was mostly due to milder weather reducing the need for air conditioning.

Electricity demand varies by time of day, season and temperature. It typically peaks in early evening, when rooftop solar generation falls and business and residential use overlap. Seasonal peaks occur in winter (driven by heating loads) and summer (for air conditioning), often reaching maximum levels on days of extreme heat. Demand is a key driver of wholesale electricity prices.

2.5.1 Minimum grid demand

Investment in rooftop solar was high in 2021, further reducing grid demand during the middle of the day across the NEM.

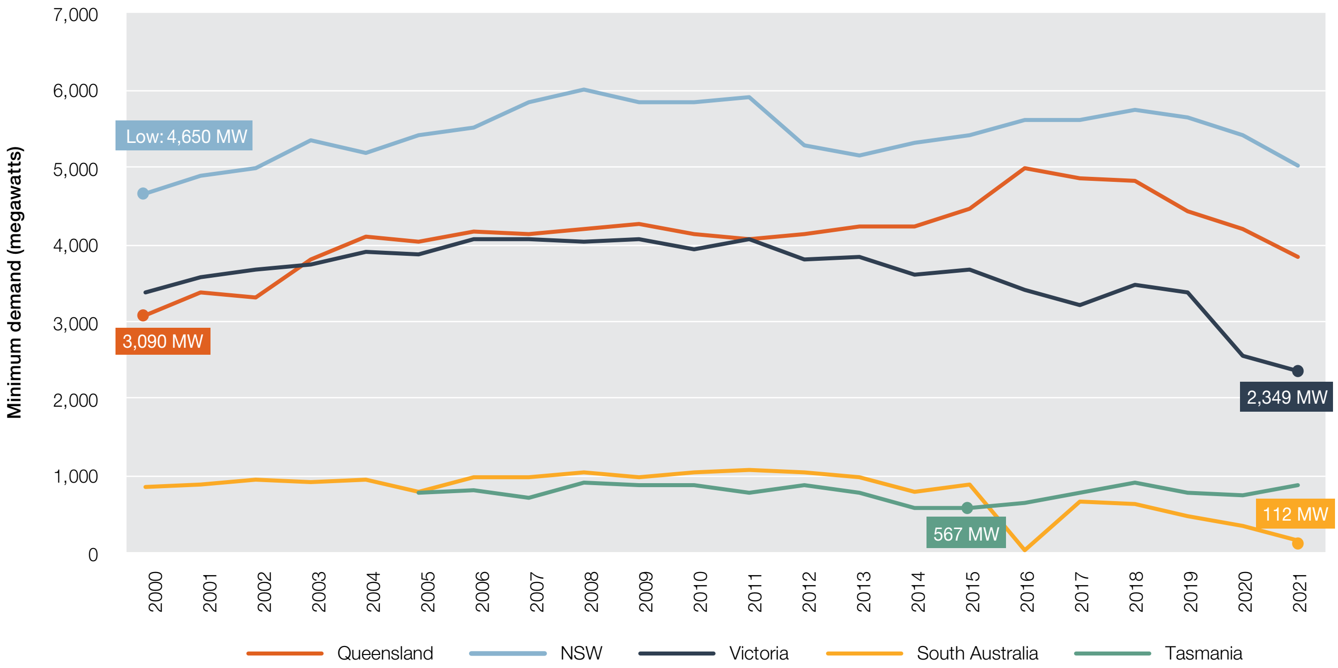
In 2021 demand across the NEM fell to its lowest level since 2005, when Tasmania joined the market.[20] The fall in minimum demand was most pronounced in Victoria and South Australia, where it has been trending down for the past decade. Both regions set new minimum demand records on sunny spring weekend days (Figure 2.13).[21] AEMO reported that for 30 minutes rooftop solar provided 92% of underlying demand in South Australia. It is likely that minimum demand records will be broken again in Spring 2022.

19 More specifically grid demand is demand for electricity produced by scheduled and semi-scheduled generators.

20 Record minimum NEM-wide demand occurred on Sunday 17 October 2021 (13,924 MW, 9% lower than in 2020).

21 South Australia set a new minimum demand record (excluding the System Black event in October 2016) on Sunday 21 November 2021 and Victoria on Sunday 28 November 2021.

Figure 2.13 Minimum grid demand



Note: Minimum 30-minute grid demand (including scheduled and semi-scheduled generation, and intermittent wind and large-scale solar generation) is for any time during the year. Data excludes consumption from rooftop solar systems. Drop in 2016 in South Australia is due to the System Black event in October.

Source: AER, AEMO (data).

As a result of low demand in the middle of the day and high renewable output, prices were negative 27% of the time in South Australia and 22% of the time in Victoria during Q4 2021.

Demand needs to be above certain thresholds for the power system to operate securely. AEMO considers that very low levels of forecast demand in the next 5 years will make it increasingly challenging for it to operate the market with all the required security services.

As the penetration of rooftop solar continues to accelerate, AEMO forecasts a rapid decline in minimum demand, and that:

› minimum operational demand – the lowest level of demand from the grid – will shift from the middle of the night to the middle of the day in all NEM mainland regions in the next 5 years
› the challenges created by falling minimum demand will be experienced earlier than has been expected.[22]

2.5.2 Maximum grid demand

Maximum grid demand fell in all mainland regions in 2021, particularly in Victoria (Figure 2.14). Maximum grid demand has been steady or declining in most regions since 2011, except in Queensland. In Queensland, maximum demand steadily increased due to mining and LNG demand until 2019, before falling in 2020 and 2021. However, in March 2022, with the hot weather and high humidity in Queensland, demand reached over 10 GW, close to the record set in February 2019.

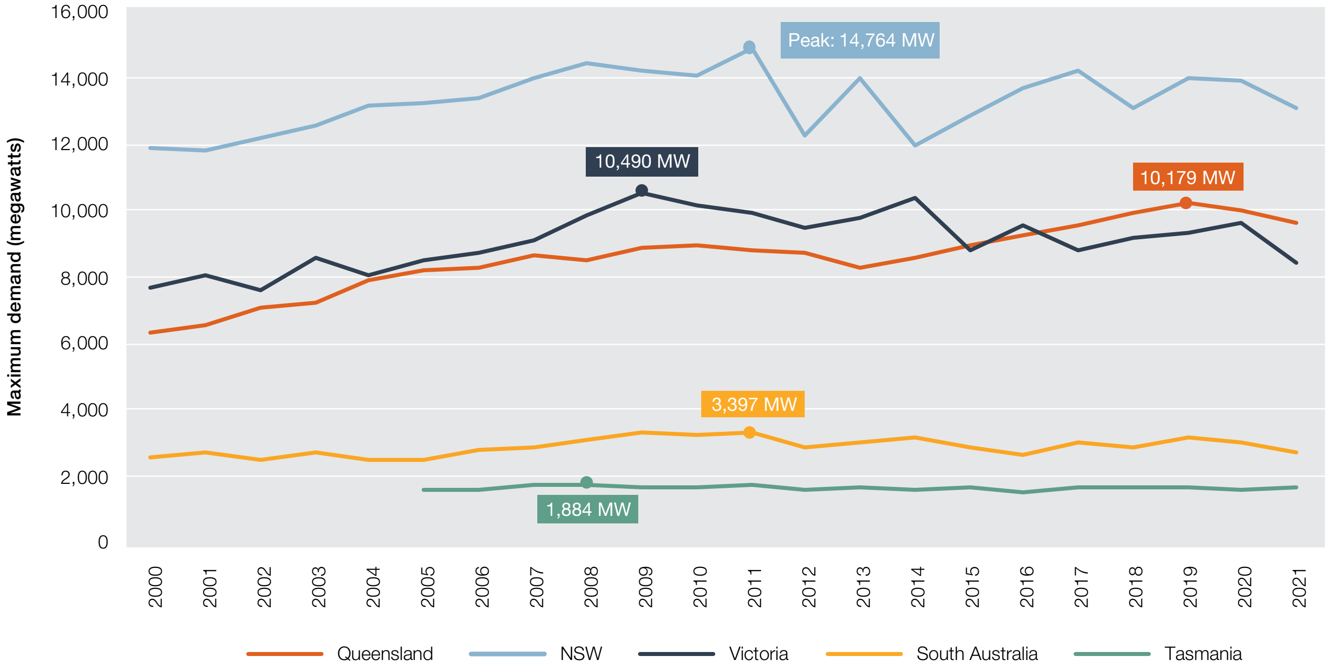
Looking forward, AEMO forecasts maximum demand in every mainland NEM region to be lower in the next 5 years because it expects the business sector's consumption to reduce.[23]

Rooftop solar has a limited impact on maximum demand, which typically occurs in the early evening when solar output ramps down and residential demand increases.

22 AEMO, 2021 Electricity statement of opportunities, August 2021, p 9.

23 AEMO, 2021 Electricity statement of opportunities, August 2021, p 7.

Figure 2.14 Maximum grid demand



Note: Maximum 30-minute grid demand (including scheduled and semi-scheduled generation, and intermittent wind and large-scale solar generation) is for any time during the year. Data excludes consumption from rooftop solar systems.

Source: AER, AEMO (data).

2.6 Generation in the NEM

The NEM's generation fleet uses a mix of technologies to produce electricity. Figure 2.15 and Figure 2.16 compare generation capacity and output across regions.

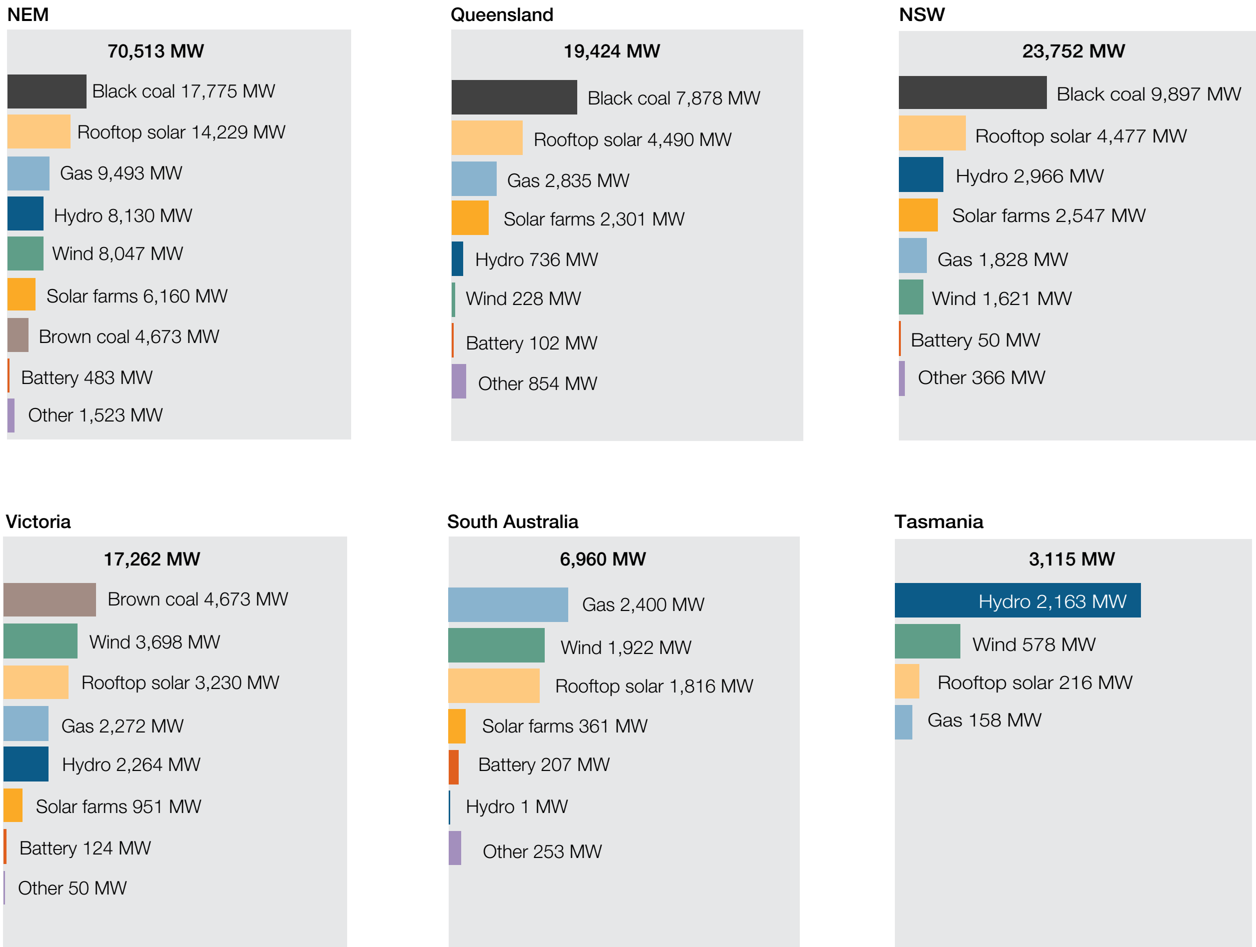
At the end of 2021, black coal provided the most generating capacity in the NEM at over 17 GW, closely followed by rooftop solar with 14 GW of generating capacity. While rooftop solar capacity is not considered as generation in the NEM, its output reduces demand from the grid. Wind and solar farms provided an additional 14 GW.

Looking at output, fossil fuel generators produced 74% of electricity in the NEM in 2021, 6% less compared with 2020.[24] The fall corresponded with an increase in renewable output, which accounted for more than 25% of total grid generation, double that just 4 years earlier.[25]

24 Includes black and brown coal, and gas-powered generation. The total does not include rooftop solar.

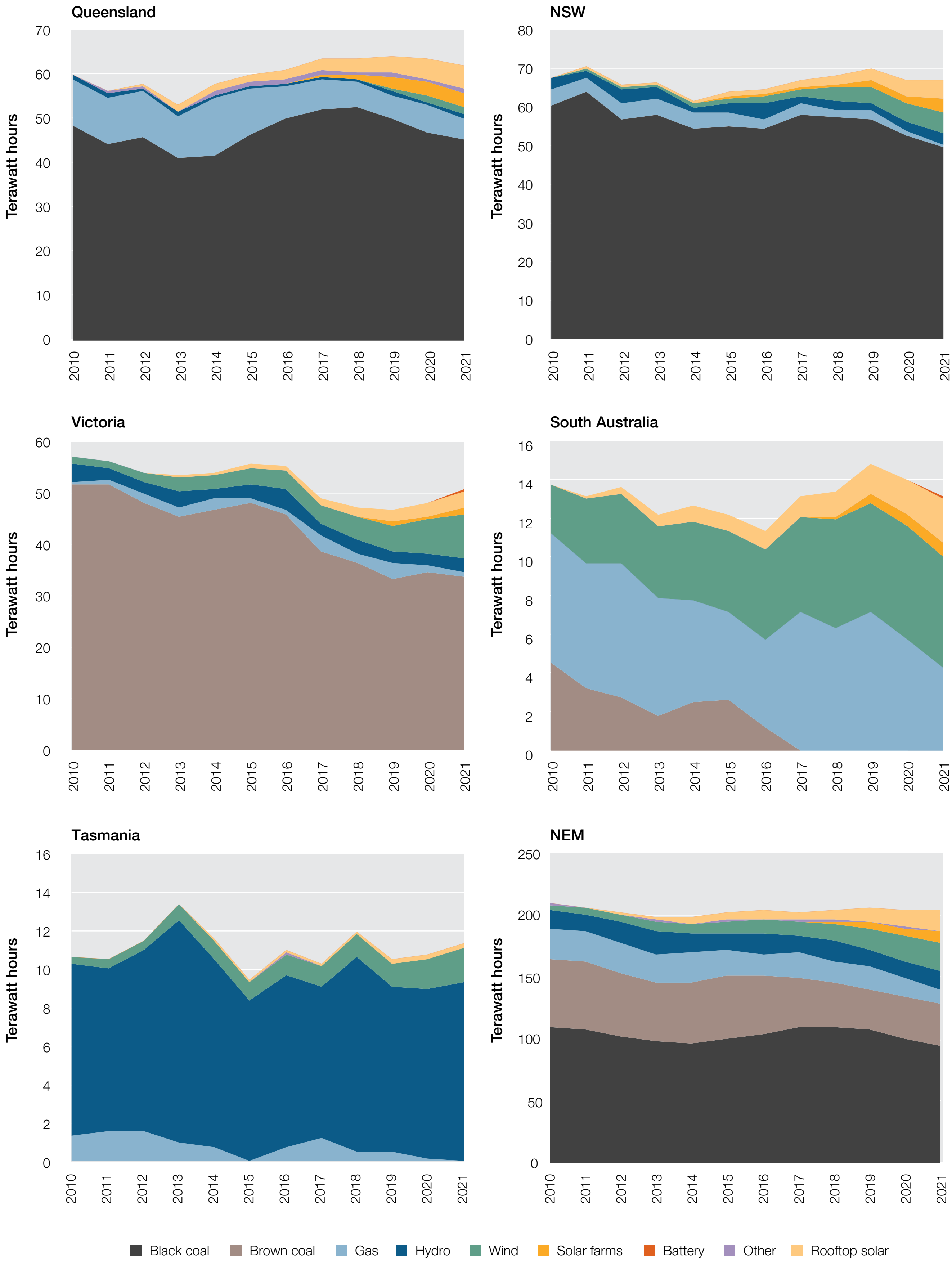
25 AER, Wholesale markets quarterly – Q4 2021, Wholesale electricity markets data, February 2022. Renewable grid generation includes hydro and does not include rooftop solar.

Figure 2.15 Generation capacity, by fuel source



Note: Generation capacity at 1 January 2022. Other dispatch includes biomass, waste gas and liquid fuels.
Source: Grid demand: AER, AEMO; rooftop solar: AER, Clean Energy Regulator, AEMO.

Figure 2.16 Generation output, by fuel source

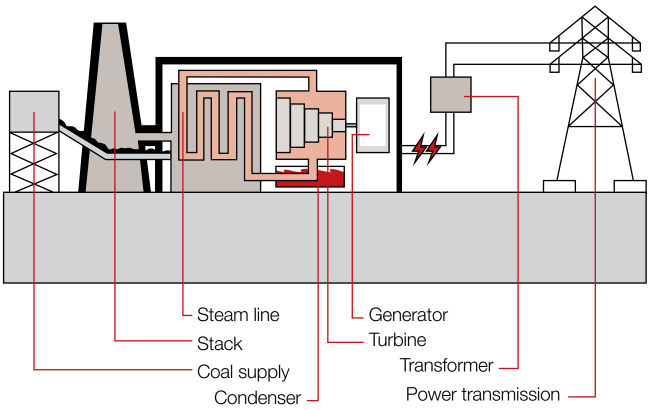


Note: Other dispatch includes biomass, waste gas and liquid fuels.
Source: AER; AEMO (data).

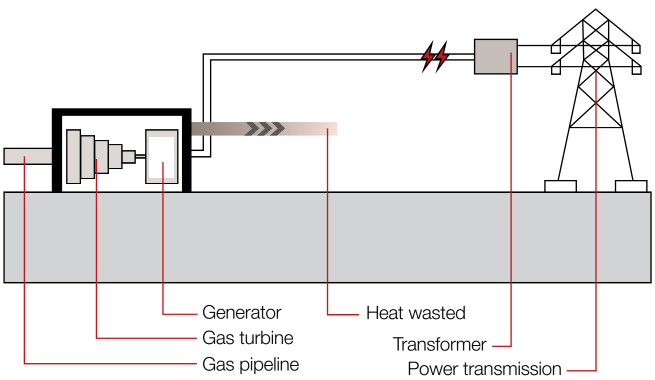
The various generation technologies have differing characteristics. Differences in startup, shutdown and operating costs influence each fuel type's bidding and generation strategies. Technology types also have different implications for power system security, including system strength and frequency.

Figure 2.17 NEM generation technologies

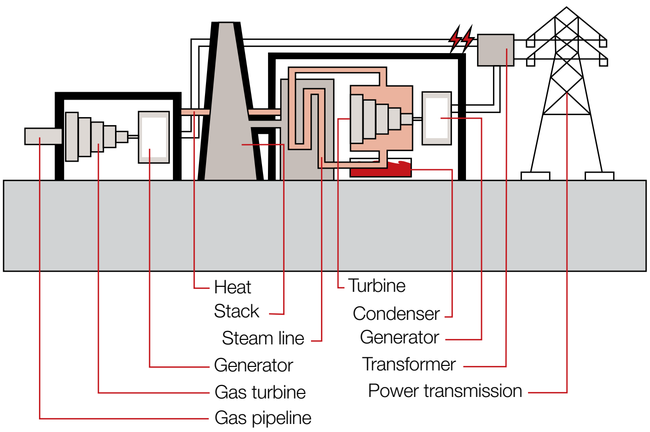
Coal fired generation



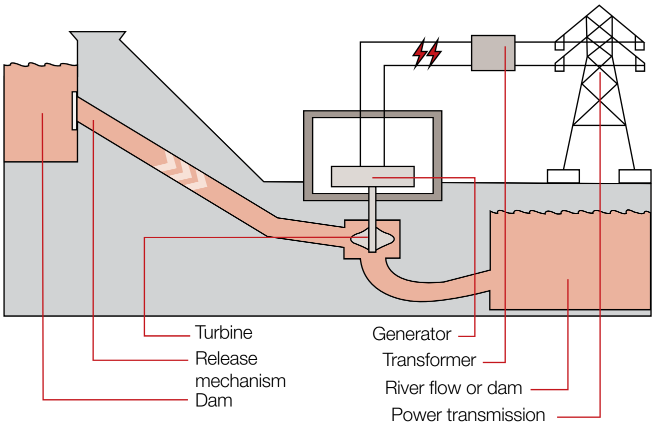
Open cycle gas powered generation



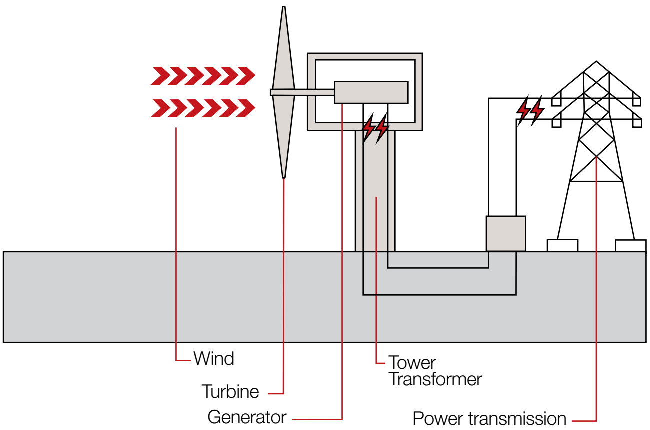
Combined cycle gas powered generation



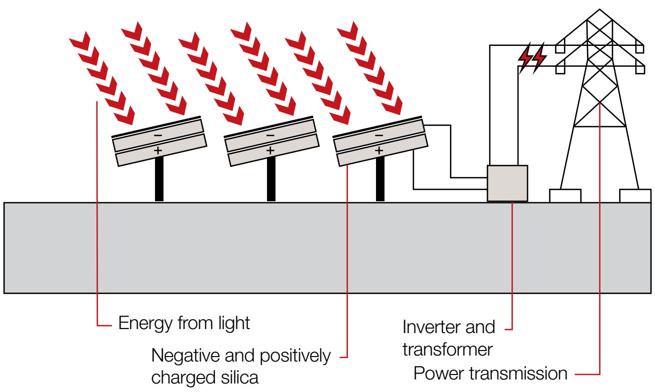
Hydroelectric generation



Wind powered generation



Solar PV generation



2.6.1 Coal-fired generation

Coal-fired generators burn coal to create pressurised steam, which is then forced through a turbine at high pressure to drive a generator (Figure 2.17). Coal-fired generation remains the dominant supply technology in the NEM, producing over two-thirds of all electricity traded through the market in 2021.

Coal plants operate in Queensland, NSW and Victoria. Generators in Queensland and NSW burn black coal, and generators in Victoria depend on brown coal. Black coal produces more energy than brown coal because it has lower water content and produces 30–40% fewer greenhouse gas emissions when used to generate electricity. However, Victorian brown coal is among the lowest cost coal in the world, because the Gippsland region has abundant reserves in thick seams close to the earth's surface.

Coal-fired generators can require a day or more to activate, but their operating costs are low. Once switched on, coal plants tend to operate continuously. For this reason, coal-fired generators usually bid a portion of their capacity into the NEM at low prices to guarantee dispatch and keep their plant running. Aside from providing relatively low-cost electricity to the market, coal-fired generators also help maintain power system stability.[26]

Impacts of solar generation on coal-fired plant

The rapid influx of grid and rooftop solar over the past 3 years has changed the shape of wholesale electricity prices and demand for baseload (coal) generation during the day. These changing conditions, backed by the global investor and local push to decarbonise, are compromising the economic viability of the NEM's 16 remaining coal-fired power stations. As fossil fuel dependent energy companies pivot toward renewable energy, many of these coal-fired power stations are slated to close earlier than previously announced. Five coal-fired power plants are currently due to close by 2030.

While around 8 GW of the current 23 GW of coal-fired capacity has already been announced to withdraw by 2030, AEMO's most recent integrated system plan (ISP) suggests this number will be closer to 14 GW. That is, it expects 60% of current coal-fired capacity will withdraw by 2030.[27]

The next to exit is Liddell power station in NSW. In April 2022, AGL Energy retired the first Liddell unit, removing 500 MW of black coal generation. The remaining units will be retired in 2023, removing a further 1,500 MW of black coal capacity from the NEM.

This will be followed by the closure of Eraring – Australia's largest power station. In February 2022, Origin Energy announced it would potentially bring forward the retirement of the Eraring black coal power station in NSW by 7 years, from 2032 to 2025.[28]

EnergyAustralia also announced in 2021 that it will retire its Yallourn power station in Victoria in 2028, 4 years earlier than planned. Callide B power station is also expected to close that year and Vales Point B power station is expected to close the following year in 2029. Early in 2022, AGL announced the accelerated closure of its remaining coal-fired power stations of Bayswater (2030–2033) and Loy Yang A (2040–2045).[29]

The economics and operating capability of coal-fired generators have been challenged by the impact of rooftop solar in particular. When rooftop solar generation is high in the middle of the day, the demand for electricity from the grid falls significantly. If demand drops below the minimum technical operating levels of coal plants, which are not engineered to run at low levels of output, plant operations may be significantly disrupted. Options include shutting some generating units from mid-morning before firing them back up in the evening. The ability of generators to operate more flexibly depends on plant age and condition. The increased cycling of output compounds stress on equipment, potentially requiring more frequent maintenance (planned outages) or, as we are seeing more frequently, earlier retirement.

No further investment in new coal plant is proposed for the NEM.

26 Synchronous generators – including hydroelectric and thermal plant such as coal, gas and solar thermal generators – contain heavy spinning rotors that provide synchronous inertia, slowing down the rate of change of frequency. They also help with voltage control by producing and absorbing reactive power, and they provide high fault current that improves system strength.

27 AEMO, 2022 Integrated system plan, June 2022.

28 Origin Energy, Origin proposes to accelerate exit from coal-fired generation, February 2022.

29 Department of Industry, Statement on early closure of Loy Yang A and Bayswater power stations, February 2022.

Coal outages were high in 2021 and 2022

A high level of coal generation outages contributed to the tight supply conditions across several regions in 2021, starting with the outage at Callide C power station and continuing into 2022. The level of outages was particularly high in April and May 2022, when at times almost 8 GW of capacity was on outage, compared to a normal level of 3 to 4 GW. Black coal outages occurred at Liddell, Eraring, Bayswater and Mount Piper power stations. Brown coal outages occurred at Loy Yang A and B and Yallourn power stations.

The level of planned outages is typically high in these months which are considered a shoulder season and an appropriate time to undertake maintenance. The impact of Covid also changed some of the maintenance schedules, pushing more maintenance into 2022. The level of unplanned outages was also high. Aging coal plants are moving closer to their exit dates. This is impacting long term maintenance decisions and reducing the incentive to undertake expensive overhauls.

The high level of unexpected outages can transfer generation requirements on to other generators (that may not have planned and contracted for this additional workload).

2.6.2 Gas-powered generation

A number of gas generation technologies operate in the NEM. Open cycle gas turbine (OCGT) plants burn gas to heat compressed air that is then released into a turbine to drive a generator (Figure 2.17). In combined cycle gas turbine (CCGT) plants, waste heat from the exhaust of the first turbine is used to boil water and create steam to drive a second turbine (Figure 2.17). The capture of waste heat improves the plant's thermal efficiency, making it more suitable for longer operation than an open cycle plant. Reciprocating engine gas plants use gas to drive a piston that spins a turbine. These plants operate similarly to OCGTs but are more flexible. Some legacy 'steam turbines' – which operate similarly to coal plants – also remain in the market.

Gas plants can operate more flexibly than coal – open cycle plants (and newer CCGT plants and reciprocating engines) need as little as 5 minutes to ramp up to full operating capacity. This has made gas generation more competitive than coal since the start of 5-minute settlement in October 2021.[30]

The ability of gas plants to respond quickly to sudden changes in the market makes it a useful complement to wind and solar generation, which can be affected by sudden changes in weather conditions. The most efficient gas-powered generation is less than half as emissions intensive as the most efficient coal-fired plant.[31]

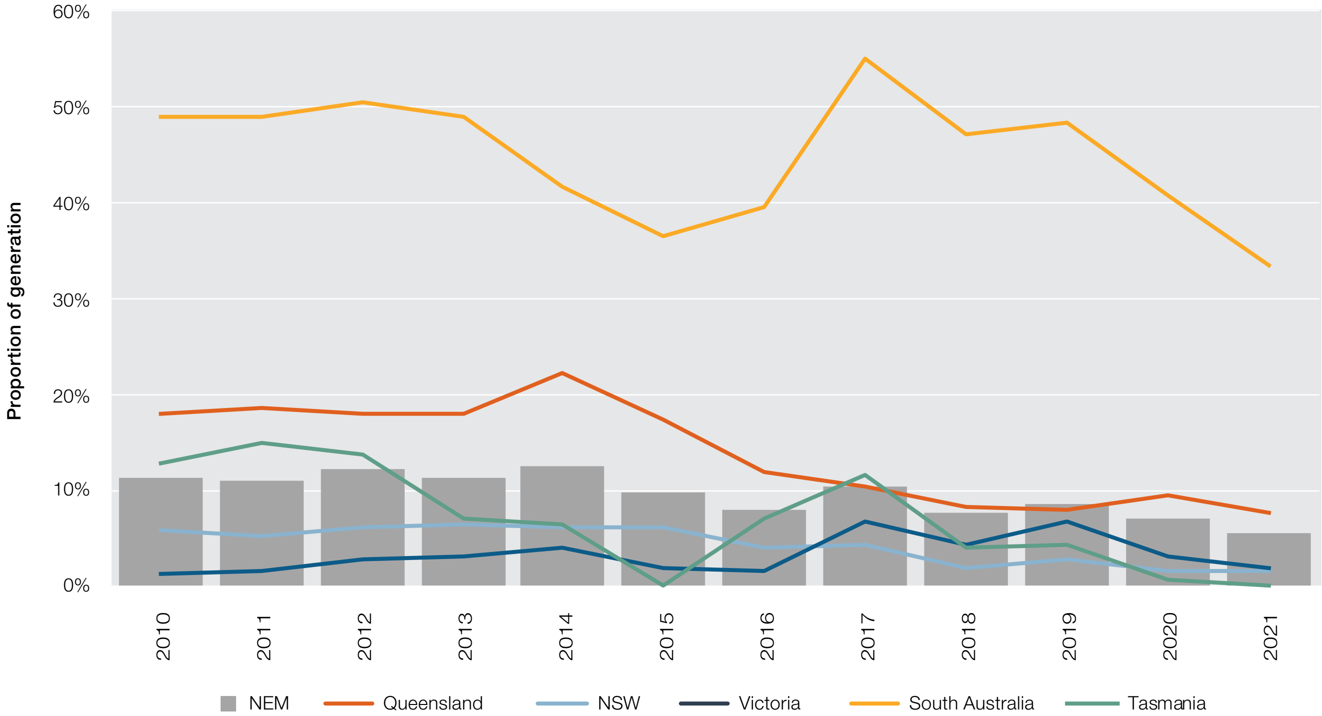
Despite these benefits, gas is a relatively expensive fuel for electricity generation, so gas generators more typically operate as 'flexible' or 'peaking' plant.32 Across the NEM, gas-powered plants supplied only 5% of electricity generated. South Australia relies more on gas-powered generation than other regions. In 2021, the state produced 33% of its local generation from gas plants – the lowest level since 2015 (Figure 2.18).

30 AER, Wholesale markets quarterly – Q3 2021, p 25, November 2021.

31 Dr Alan Finkel AO, Chief Scientist, Chair of the Expert Panel, Independent review into the future security of the national electricity market: blueprint for the future, June 2017, p 109.

32 Flexible or peaking plant can be turned on at short notice and is often turned on during high price periods.

Figure 2.18 Dependence on gas



Note: The share of total regional output produced by gas-powered generators.
Source: AER; AEMO (data).

Gas generation in the NEM tends to be seasonal, peaking in summer (and sometimes winter) when electricity demand and prices are highest. It also varies with the amount of intermittent generation and outages affecting coal-fired generators.

The interaction between the wholesale electricity and gas markets was particularly prominent in May to July in 2022. A reduction in the availability of coal-fired electricity generation due to outages, lower than expected renewable generation and early winter demand led to an increase reliance on gas-powered generation, despite gas price increases. Spot market prices for gas reached record highs in May as high international gas prices strengthened the incentive for producers to export LNG rather than supply into the domestic market (section 4.3). At the same time, local gas markets were being used to cover short-term spot exposure over the higher demand winter period. Average gas spot prices rose in April to June 2022 to roughly 3 times higher than in the same period in 2021.

As coal-fired generation retires, gas-powered generation is expected to help meet peak demand, particularly during times of low renewable output. It will also provide system services to maintain grid security and stability. AEMO's latest ISP calls for 10 GW of gas-powered generation, or a doubling of current capacity, by 2050 to help firm renewable energy.[33]

There are currently 2 significant proposals for new gas plant in NSW, totalling almost 1,000 MW. Both projects are expected to be operational by the summer of 2023–24.

Snowy Hydro plans to construct a 660 MW open-cycle gas-powered power station at Kurri Kurri in the Hunter Valley. Construction is expected to begin in 2022 and, as a gas peaking plant, it is only expected to operate around 2% of the time.[34] In May 2021, EnergyAustralia committed to developing its Tallawarra B power station (316 MW) in the Illawarra, capable of using a blend of hydrogen and natural gas.[35]

33 AEMO, Integrated system plan 2022, June 2022.

34 Snowy Hydro, Hunter Power Project Overview, September 2020.

35 EnergyAustralia, EnergyAustralia gives green light to Australia's first net zero emissions, hydrogen/gas power plant, May 2021.

2.6.3 Hydroelectric generation

Hydropower uses the force of moving water to generate power. The technology involves channelling falling water through turbines. The pressure of flowing water on the blades rotates a shaft and drives an electrical generator, converting the motion into electrical energy (Figure 2.17). Similar to coal and gas plants, hydroelectric generators are synchronous, meaning they provide inertia and other services that support power system security. Because their fuel source is usually available (except in drought conditions), they are 'dispatchable' plants that can switch on as required.

Most of Australia's hydroelectric plants are large-scale projects that are over 40 years old. A number of 'mini-hydro' schemes also operate. These schemes can be 'run of river' (with no dam or water storage) or use dams that are also used for local water supply, river and lake water level control, or irrigation.

Hydroelectric plants have low fuel costs (that is, they do not explicitly pay for the water they use), but they are constrained by storage capacity and rainfall levels to replenish storage, unless pumping is used to recycle the water. For this reason, the opportunity cost of fuel is comparatively high. Therefore, hydroelectric generators typically operate as 'flexible' or 'peaking' plant, similar to gas-powered generation. While some pumped hydroelectric generation already operates in NSW and Queensland, the construction of Snowy 2.0 will add a further 2,000 MW of pumped hydroelectric capacity in the Snowy Mountains. Snowy Hydro currently expects the pumped hydroelectric storage project will be completed by 2026.[36]

Conditions in the electricity market affect incentives for hydroelectric generation. Subject to environmental water release obligations, hydroelectric generators tend to reduce their output when electricity prices are low and run more heavily when prices are high. Incentives under the Renewable Energy Target (RET) scheme also affect incentives to produce.

Hydroelectric generators accounted for 14% of capacity in the NEM in 2021 and supplied 8% of electricity generated. Tasmania is the region most reliant on hydroelectric generation, with 83% of its 2021 generation coming from that source. NSW and Victoria also have significant hydroelectric generation plants located in the Snowy Mountains region.

In 2021, hydroelectric generation in Queensland increased by 65% compared with the previous year as outages and higher fuel costs impacted black coal and gas generators. This is the highest level of hydroelectric generation in Queensland since at least 2006.

In Q2 2022, hydroelectric generation across the NEM was at the highest level since Q3 2018, and the second highest level since Q1 2015. In NSW, despite pressure to run harder to compensate for the high level of coal outages, generation at Snowy Hydro's biggest power station, Tumut 3, was constrained by environmental concerns. These included high water levels in the release reservoir, Blowering Dam, and the limited release capacity of the Tumut River.[37]

2.6.4 Wind generation

Wind turbines directly convert the kinetic energy of wind into electricity. The wind turns blades that spin a shaft connected (directly or indirectly via a gearbox) to a generator that creates electricity (Figure 2.17).

Renewable generation, including wind, has filled much of the supply gap left by thermal plant closures. Government incentives, including the RET scheme, provided impetus for the growth of wind generation in the NEM. While providing low-cost energy, the weather-dependent nature of wind generators makes their output variable and sometimes unpredictable.

On 4 August 2022, a new record high was set for wind generation in the NEM reaching over 7,300 MW. A new record high was also set for the highest proportion of demand in the NEM met by wind generation. At 1:30am on Friday 5 August one third of all native demand was met by wind generation.

Wind output increased more in 2021 than in any previous year, increasing by 17% from the previous year. Wind farms generated almost 12% of all electricity produced in the NEM and produced twice as much energy as gas-powered generators. With over 1 GW of new wind farms connected in 2021 (accounting for almost a third of all new investment), wind accounted for 14% of the NEM's total capacity.

36 Australian National Audit Office, Snowy 2.0 Governance of Early Implementation, June 2022.

37 Snowy Hydro, Snowy Hydro water releases from Tumut 3 Power Station, June 2022.

Wind penetration is especially strong in South Australia, where it provided 53% of the state's electricity output in 2021. More recently, the focus of wind investment has shifted to NSW and Victoria, where over 40% of capacity installed or committed since July 2017 has occurred. In 2021, after lengthy delays, the NEM's largest wind farm, Stockyard Hill (530 MW) in Victoria, entered the market.

2.6.5 Grid-scale solar farms

Australia has the highest solar radiation per square metre of any continent, receiving an average 58 million petajoules of solar radiation per year.[38] All solar investment to date has been in photovoltaic systems that use layers of semi-conducting material to convert sunlight into electricity (Figure 2.17).

Investment in large-scale solar farms in Australia did not occur at a significant scale until 2018, supported by government incentives under the RET scheme and funding support from the Australian Renewable Energy Agency (ARENA) and Clean Energy Finance Corporation (CEFC). In 2017, commercial solar farms accounted for only 0.5% of total NEM generation capacity and met only 0.3% of the NEM's electricity requirements. But just 4 years later, in 2021, solar farms made up 11% of capacity and 5% of output. In 2021, 18 solar farms, or almost 1.6 GW, entered the market. Most of these were located in Queensland and NSW, including the NEM's largest solar farm, the Western Downs Green Power Hub (500 MW).

Solar output reached record levels in 2021 and continues to grow. In the last quarter of 2021, large-scale solar generation had the highest quarterly output on record – up a massive 41% from a year previous.

2.6.6 Grid-scale storage

Stored energy can be used to support system reliability by being injected into the grid at times of high demand and providing stability services to the grid by balancing variability in renewable generation. Storage technologies in the NEM include batteries and pumped hydroelectricity. With less coal-fired generation and more wind and solar generation, increased storage will be essential to manage daily and seasonal variations in output.

Battery storage

Lower costs and expanding opportunities for battery technology has seen a significant increase in battery investment.

Batteries provide multiple benefits to the market. They have fast response times which enable them to help maintain the power system in a secure state faster than other technologies (although they cannot provide sustained generation). They can be co-located with renewable resources to firm output or with gas plant to provide instant energy while the gas plant starts up.

Batteries take advantage of variations in the spot price, typically charging when prices are low, which is often in the middle of the day, and discharging when prices are high. This is often in the morning and evening when demand is high. The greater the difference between these two prices determines how much revenue the battery will make in the spot market. With the increase in negative spot prices this makes storage loads an attractive option.

Batteries in the NEM can also earn significant revenue from operating in frequency control markets.[39]

In 2021, 4 batteries (totalling over 500 MW) entered the NEM. This brought the total number of batteries in the NEM to 9 (totalling over 800 MW). This included the Victorian Big Battery (360 MW), which is now the largest battery in the NEM. The Victorian Big Battery provides support to Victoria's transmission network – allowing for increased wind and solar generation in the region and increased flows over interconnectors with adjacent regions.[40]

An additional 1,700 MW of battery capacity is committed to enter the NEM by 2025. AGL Energy and Origin Energy have announced new batteries to replace capacity lost by the closures of Liddell and Eraring power stations in NSW.[41] [42] These are in addition to the 700 MW Waratah Super Battery the NSW Government has announced.[43]

38 Geoscience Australia, Solar energy, Geoscience Australia website, May 2020.

39 For example, the AER estimated that South Australia's Hornsdale battery earned around $58 million for frequency services across 2019–20 – more than 15 times the battery's spot earnings from wholesale energy sales. AER, Wholesale electricity market performance report 2020, December 2020.

40 Victorian Big Battery, Neoen starts operating 300 MW Victorian Big Battery in Australia, December 2021.

41 Origin Energy, Origin proposes to accelerate exit from coal-fired generation, February 2022.

42 AGL, AGL's Hunter Energy Hub takes shape with Liddell grid-scale battery, March 2022.

43 Energy NSW, Waratah Super Battery, May 2022.

Pumped hydroelectricity

Large-scale storage can be provided through pumped hydroelectric projects, which allow hydroelectric plants to reuse their limited water reserves. The technology involves pumping water into a raised reservoir when energy is cheap and releasing it to generate electricity when prices are high. As with batteries, price arbitrage and the increase in negative prices when demand is low in the middle of the day, may help make pumped hydroelectric more profitable.

Pumped hydroelectric technology has been available in the NEM for some time, with generation in Queensland (570 MW at Wivenhoe) and NSW (240 MW at Shoalhaven and 1,500 MW at Tumut 3). Use of this technology is limited by the availability of appropriate physical sites, but advances in technology and the rise of intermittent generation are providing new opportunities for deploying this form of storage at a larger scale. In particular, pumped hydroelectricity is the basis of the proposed Snowy 2.0 (2,000 MW) and Battery of the Nation (2,500 MW) projects in NSW and Tasmania.

2.6.7 Consumer energy resources

Alongside major shifts occurring in the technology mix at grid level, significant changes are occurring in small-scale electricity supply with the uptake of consumer energy resources. These consumer-owned devices can generate or store electricity or actively manage energy demand. Consumer energy resources include:

- rooftop solar
- storage, including batteries and electric vehicles
- demand response, which uses load control technologies to regulate the use of household appliances such as hot water systems, pool pumps and air conditioners (section 2.11.3).

By far the fastest development has been in rooftop solar installations, but interest is also growing in battery systems, electric vehicles and demand response.

Rooftop solar generation

Backed by state government incentives, households and businesses have continued to install record volumes of rooftop solar capacity every year since 2015. In 2021, households across Australia installed more than 3 GW of small-scale solar capacity, of which more than 2.7 GW was connected to the NEM.[44]

As of 1 January 2022, rooftop systems in the NEM totalled over 14 GW of capacity, making it second largest fuel type by capacity after black coal (Figure 2.15). By mid–2022 this total had increased to over 15 GW. Around 30% of Australian houses have rooftop solar, a larger share than in any other country. Queensland and NSW have the most installed capacity, but South Australia has the highest capacity per capita.

Output from rooftop solar across the NEM in the first 6 months of 2022 was 19% higher than over the same months in 2021. Output in 2021 had already increased by 24% compared with the year prior, breaking records in every region and meeting 8% of total consumption. A milestone was reached on 14 December 2021 when generation from rooftop solar in the NEM reached 10 GW.

Rooftop solar generation is not traded through the NEM. Instead, installation owners receive reductions in their energy bills for feeding electricity into the grid.

Small-scale storage

Customers are increasingly storing surplus energy from rooftop solar systems in batteries to draw from when needed, thus reducing their demand for electricity from the grid. Home battery systems may play an important role in meeting demand peaks in the grid, depending on the extent to which technology improvements can reduce installation costs.

The pace of uptake of electric vehicles will potentially have a significant impact on electricity demand and supply. Charging the batteries of electric vehicles will likely generate significant demand for electricity from the grid. As charging technologies mature, electric vehicle batteries may also provide electricity back to the grid at times of high demand.

44 Clean Energy Regulator, Quarterly Carbon Market Report – September Quarter 2021, December 2021. Note there is a reporting time lag with rooftop solar installations, so 2021 data is incomplete.

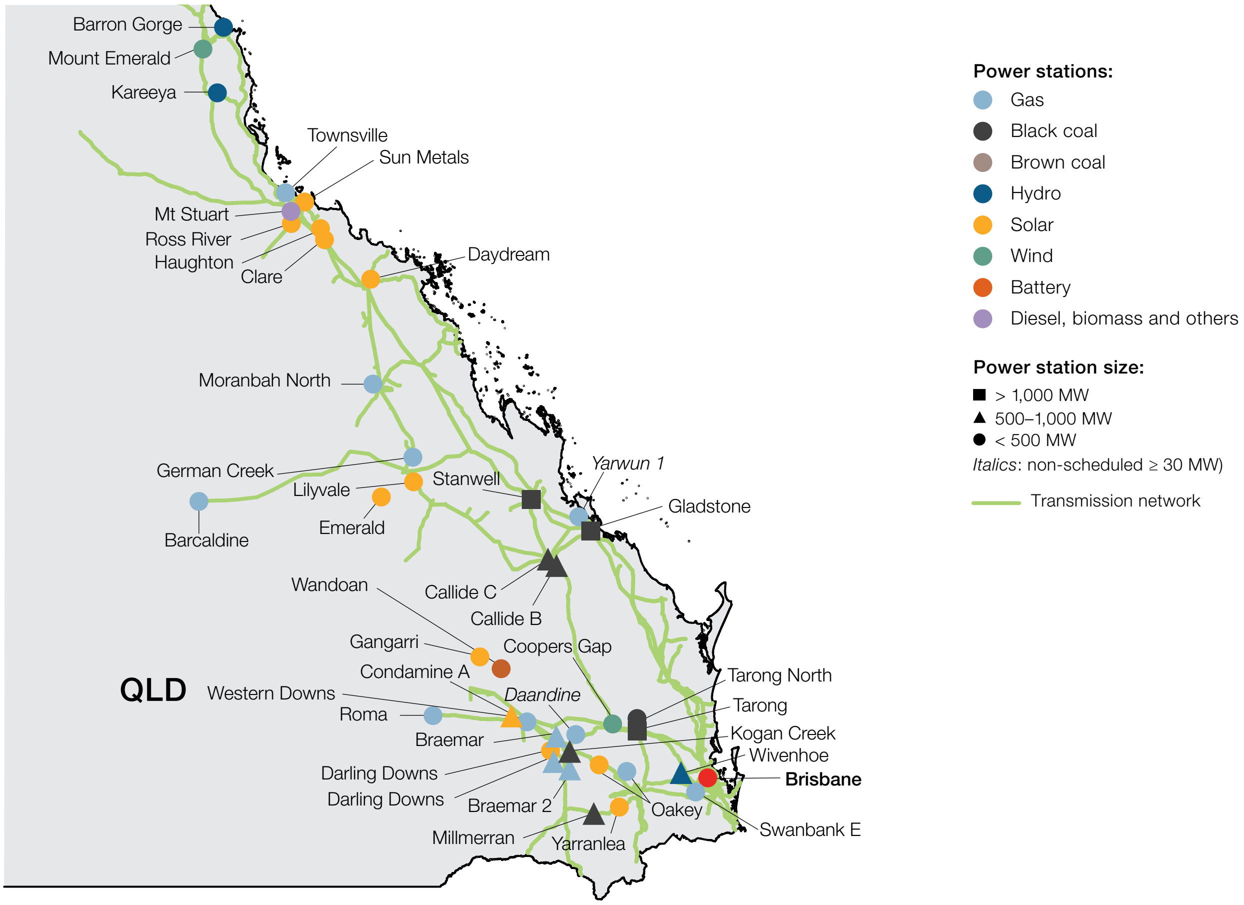
In 2021 small-scale battery installations increased by 33% compared with 2020, continuing the upward trend since 2016.[45]

Individually, distributed storage is largely invisible to the market. But, if aggregated and operated together as a microgrid or virtual power plant, these devices can enhance reliability and power system security.

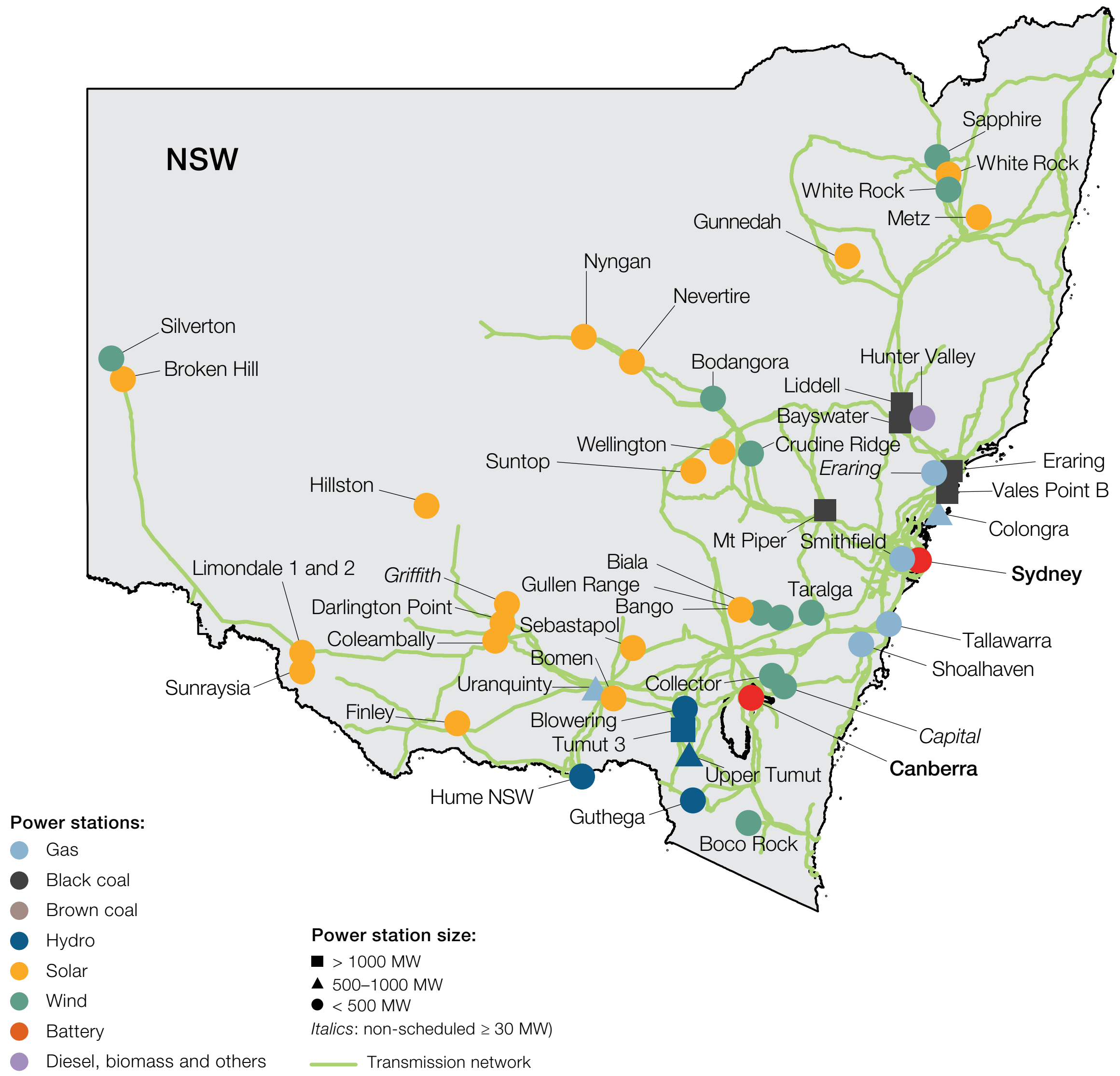
2.6.8 Generator information

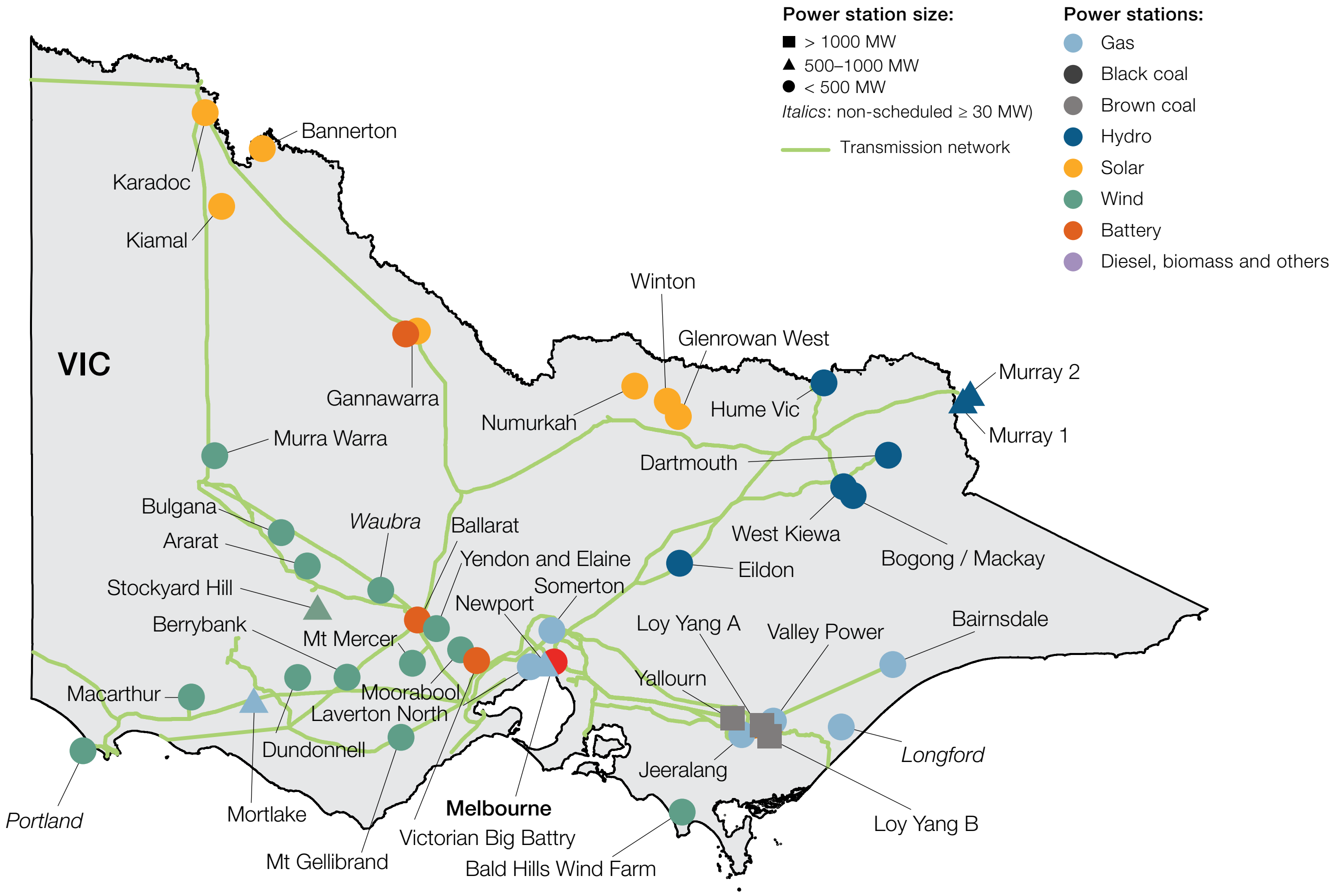
Figure 2.19 maps the locations of generation plants and the types of technology in use.

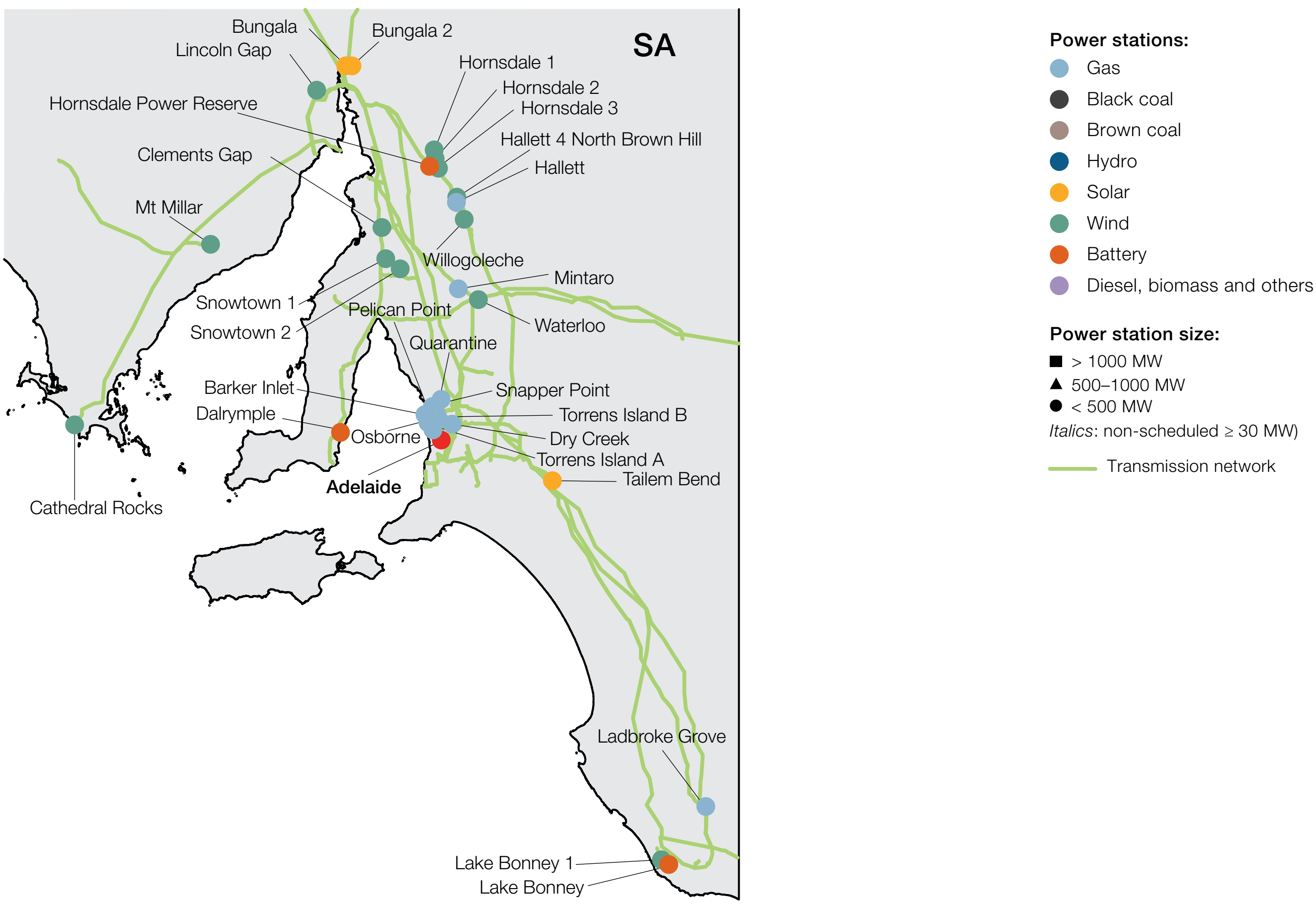
Figure 2.19 Generators in the NEM

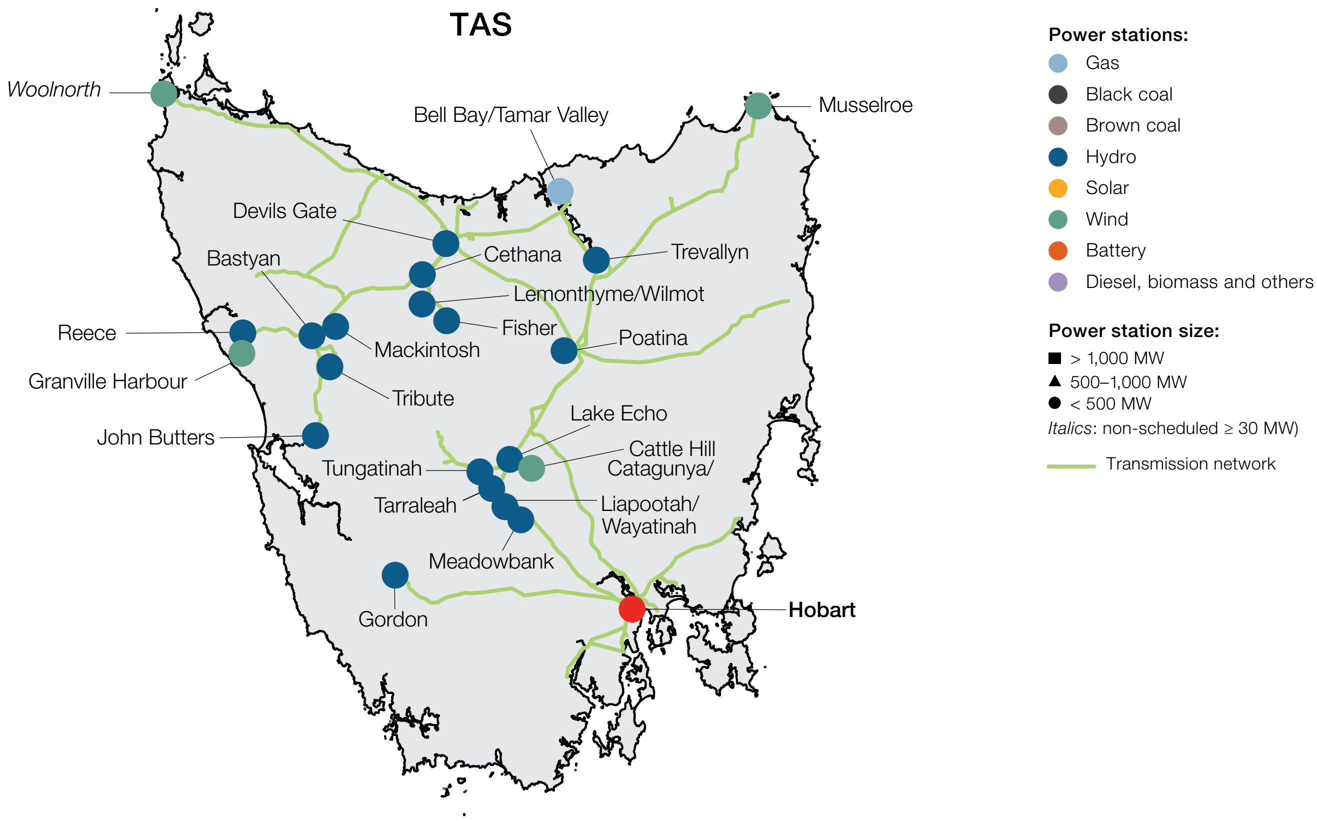


45 Data on small-scale battery installations from Clean Energy Regulator, State data for battery installations with small scale systems, Clean Energy Regulator website, March 2022.


NSW
Sapphire
White Rock
White Rock
Metz
Gunnedah
Nyngan
Nevertire
Silverton
Broken Hill
Bodangora
Hunter Valley
Liddell
Bayswater
Wellington
Crudine Ridge
Suntop
Eraring
Eraring
Vales Point B
Hillston
Colongra
Mt Piper
Smithfield
Biala
Sydney
Limondale 1 and 2
Griffith
Gullen Range
Taralga
Darlington Point
Bango
Sebastapol
Coleambally
Tallawarra
Bomen
Shoalhaven
Uranquinty
Collector
Sunraysia
Finley
Capital
Blowering
Tumut 3
Canberra
Upper Tumut
Hume NSW
Guthega
Boco Rock
Power stations:
Gas
Black coal
Brown coal
Hydro
Solar
Wind
Battery
Diesel, biomass and others
Power station size:
> 1000 MW
500–1000 MW
< 500 MW
Italics: non-scheduled ≥ 30 MW)
Transmission network


Power station size:
> 1000 MW
500–1000 MW
< 500 MW
Italics: non-scheduled ≥ 30 MW)
Transmission network
Power stations:
Gas
Black coal
Brown coal
Hydro
Solar
Wind
Battery
Diesel, biomass and others
VIC
Bannerton
Karadoc
Kiamal
Winton
Glenrowan West
Murray 2
Murray 1
Gannawarra
Numurkah
Hume Vic
Murra Warra
Dartmouth
Bulgana
Waubra
Ballarat
West Kiewa
Bogong / Mackay
Ararat
Yendon and Elaine
Eildon
Stockyard Hill
Somerton
Newport
Berrybank
Mt Mercer
Loy Yang A
Valley Power
Bairnsdale
Yallourn
Macarthur
Moorabool
Laverton North
Longford
Dundonnell
Jeeralang
Portland
Mortlake
Melbourne
Loy Yang B
Victorian Big Battry
Mt Gellibrand
Bald Hills Wind Farm


SA
Bungala
Lincoln Gap
Bungala 2
Hornsdale 1
Hornsdale 2
Hornsdale 3
Hornsdale Power Reserve
Hallett 4 North Brown Hill
Clements Gap
Hallett
Mt Millar
Willogoleche
Mintaro
Snowtown 1
Pelican Point
Snowtown 2
Waterloo
Quarantine
Barker Inlet
Snapper Point
Dalrymple
Torrens Island B
Osborne
Dry Creek
Torrens Island A
Adelaide
Tailem Bend
Cathedral Rocks
Ladbroke Grove
Lake Bonney 1
Lake Bonney
Power stations:
Gas
Black coal
Brown coal
Hydro
Solar
Wind
Battery
Diesel, biomass and others
Power station size:
> 1000 MW
500–1000 MW
< 500 MW
Italics: non-scheduled ≥ 30 MW)
Transmission network



Note: Excludes solar, wind and diesel/biomass smaller than 100MW registered capacity.
Source: AER.

2.7 Trade across regions

Transmission interconnectors (mapped and listed in chapter 3) link the NEM's 5 regions, allowing trade to take place. Trade enhances the reliability and security of the power system by allowing each region to draw on generation plant from across the market. This allows for more efficient use of the generation fleet.

Typically, Queensland has surplus generation capacity, making it a net electricity exporter (Figure 2.20). However, export levels significantly dropped in 2021 compared with previous years because of network outages that were part of the QNI upgrade. In the first 3 months of 2022, for the first time, Queensland imported more than it exported.

NSW has relatively high fuel costs, typically making it a net importer of electricity. Constrained imports from both Queensland and Victoria meant NSW had to source more of its own generation throughout 2021.

Victoria's abundant supplies of low-priced brown coal generation traditionally make it a net exporter of electricity. In 2021, lower prices in Victoria led to more than a doubling in net exports.

Though South Australia had switched from net importer to net exporter from 2019 following increased wind generation, ongoing network outages in South Australia limited its ability to export cheaper generation to Victoria in 2021.

Tasmania's trade position varies with environmental and market conditions. Key drivers include local rainfall (which affects dam levels for hydroelectric generation), Victorian spot prices, and the availability of the Basslink interconnector (which has suffered multiple extended outages in recent years). In 2021 Tasmania was a net exporter, reflecting that it had the lowest volume weighted average (VWA) prices in the NEM.

Figure 2.20 Inter-regional trade

Source: AER; AEMO.

2.7.1 Market alignment and network constraints

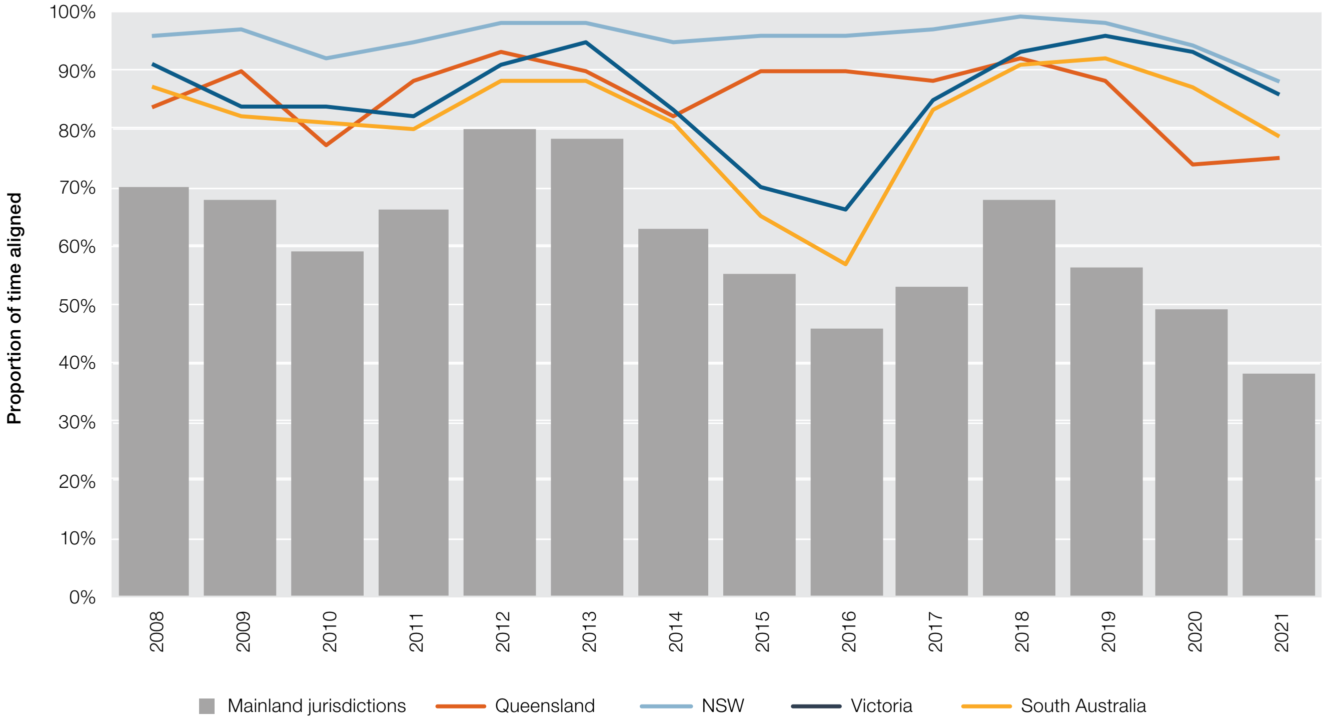
Price alignment in the NEM has fallen over the past 3 years. The market sets a separate spot price for each NEM region. When the interconnectors linking NEM regions are unconstrained, trade brings prices into alignment across all regions (apart from variations caused by physical losses that occur when transporting electricity). At these times, the NEM acts as a single market rather than as a collection of regional markets, and generators within a region are exposed to competition from generators in other regions.

NSW and Victoria were the most aligned regions, with prices aligned almost 90% of the time in 2021. Prices in Queensland and South Australia, at either end of the grid, were less aligned, with prices aligned 75% of the time in Queensland and 80% of the time in South Australia.

Queensland's alignment rates declined in 2020 and 2021, driven by work to upgrade NSW interconnector that limited flows between the regions (Figure 2.21). NSW's alignment rates also fell, driven by transmission outages that restricted flows across the Victoria–NSW interconnector.

Price alignment in Victoria and South Australia had been less regular, with congestion on the Victoria – South Australia interconnectors. But the completion of the Heywood upgrade and the closure of Victoria's Hazelwood power station in 2017 (which reduced Victorian exports of electricity to South Australia and NSW) reduced congestion between the regions (Figure 2.21). However, price alignment in Victoria and South Australia also fell in 2021.

Figure 2.21 Price alignment in mainland NEM regions



Note: Inter-regional price alignment shows the proportion of the time that prices in one NEM region are the same as those in at least one neighbouring region, accounting for transmission losses.

Source: AER; AEMO (data).

2.8 Market structure

Around 200 power stations sell electricity into the NEM spot market. Despite significant new entry over recent years, a few large participants control a significant proportion of generation in each NEM region. Ownership of flexible generation is particularly concentrated.

2.8.1 Market concentration

The 2 largest participants account for around 60% of output (Figure 2.22) in all regions except South Australia.

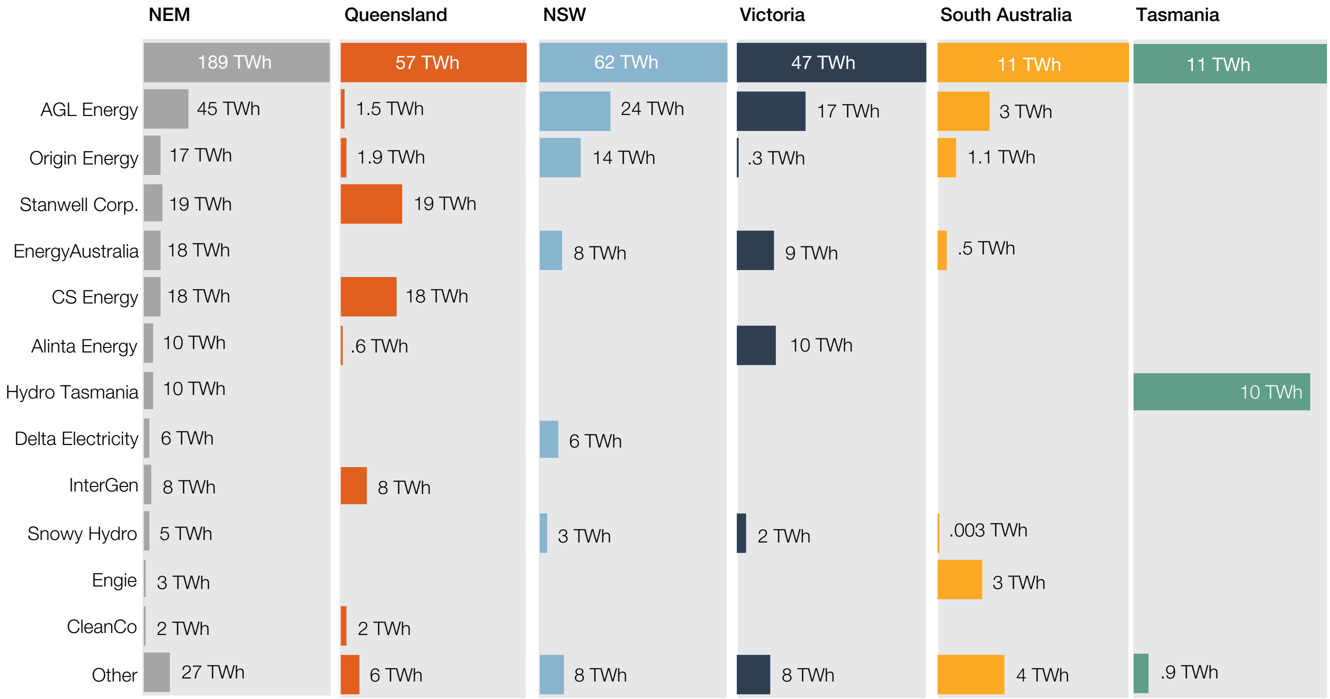
Private entities control most generation output in NSW, Victoria and South Australia:

- In NSW, AGL Energy and Origin Energy produced around 60% of output in 2021 and own over 40% of the region's capacity. EnergyAustralia and Delta are other major players. Snowy Hydro, owned by the Australian government produced 4% of output in the region but owns 19% of its capacity.
- In Victoria, AGL Energy and Alinta produced around 57% of output in 2021 and own over 30% of the region's capacity. EnergyAustralia produced a slightly smaller share of output than Alinta. Snowy Hydro produced 5% of output in the region but owns 16% of its capacity.
- In South Australia, AGL Energy and Engie produced 50% of output in 2021and own 45% of the region's capacity. The other significant entity is Origin Energy.

Government-owned entities control most generation output in Queensland and Tasmania:

- In Queensland, state-owned corporations Stanwell and CS Energy controlled 65% of generation output in 2021 and own 42% of its capacity. A third state-government owned entity, CleanCo, produced 4% of the state's output. It was created in 2019 to increase competition and support growth in renewables. The largest private operator by output is InterGen.
- In Tasmania, the state-owned Hydro Tasmania owns most of the generation capacity. To encourage competition in the retail market, the Office of the Tasmanian Economic Regulator regulates the prices of 4 safety net contract products offered by Hydro Tasmania and ensures adequate volumes of these products are available.

Figure 2.22 Market shares in generation output



Note: Output in 2021. Market shares are attributed to the owner of the plant or the intermediary (should one be declared to AEMO). Output is split on a pro rata basis if the owner or intermediary changed in 2021. Data exclude output from rooftop solar systems and interconnectors.

Source: AER; AEMO; company announcements.

Ownership of flexible generation, or generation that can respond quickly to changing market conditions, is particularly concentrated. A few participants control significant flexible generation capacity in NSW, Victoria and Tasmania. Snowy Hydro controls more than 5,000 MW of flexible generation capacity. Most of these assets are located in NSW and Victoria and, as a result, Snowy Hydro controls around 60% of flexible generation in NSW and 50% in Victoria.[46] In addition, Snowy Hydro is developing Snowy 2.0, which would add a further 2,000 MW of flexible capacity to its portfolio. It also plans to construct a 660 MW gas-fired power station near Kurri Kurri. Origin Energy is the second largest provider of flexible generation, with significant capacity across the mainland. Collectively, Snowy Hydro and Origin Energy control almost all flexible capacity in NSW and more than three-quarters in Victoria. Ownership of flexible capacity is less concentrated in the other regions.

Flexible generation is playing an increasingly important role in the market. In the recent high priced market events, this plant played a particularly critical role in meeting demand. We monitor concentration and competition in the supply of flexible capacity, in addition to broader market outcomes, in our *Wholesale electricity market performance report* due to be released in December 2022.

2.8.2 Vertical integration

Most large generators in the NEM are vertically integrated, with portfolios in both generation and retail. Vertical integration allows generators and retailers to insure internally against price risk in the wholesale market, reducing their need to participate in hedge (contract) markets. But the reduced participation in contract markets reduces liquidity in those markets, posing a potential barrier to entry and expansion for generators and retailers that are not vertically integrated.

Vertical integration has become the primary business structure for large electricity retailers in the NEM. The 4 largest vertically integrated participants in each region account for the majority of generation output and supply more than half of retail load. Across the NEM, 3 retailers – AGL Energy, Origin Energy and EnergyAustralia – supplied 44% of electricity generation in 2021–22 and supplied 64% of residential energy customers in Q1 2022.

Second tier retailers – Red Energy and Lumo Energy (Snowy Hydro), Simply Energy (Engie) and Alinta – also own major generation assets. These vertically integrated businesses supplied 9% of electricity generation in 2021–22 and 13% of residential energy customers in Q1 2022.

46 AER, Wholesale electricity market performance report, December 2020.

The retail and generation profiles of these vertically integrated businesses across the NEM vary significantly. AGL Energy and Alinta have larger generation portfolios, while EnergyAustralia and Engie have more balanced portfolios. Origin Energy and Snowy Hydro's share of the retail load is greater than its share of generation output, but they also have a greater share of peaking generation. This allows them to manage the risk of high prices. These differences drive different contracting strategies across the businesses.

Several smaller retailers are also vertically integrated:

- Sunset Power and Shell Energy (formerly ERM Power) provide retail services to large customers across the NEM. Sunset Power owns the black coal Vales Point Power Station in NSW and Shell Energy owns the gas-powered Oakey Power Station in Queensland.
- Powershop and Tango Energy each have a portfolio of wind and hydroelectric generation operated by their respective parent companies, Meridian Energy and Pacific Hydro.
- Momentum Energy is backed by Hydro Tasmania, which owns most of the generation capacity in Tasmania.

2.9 Generation investment and plant closures

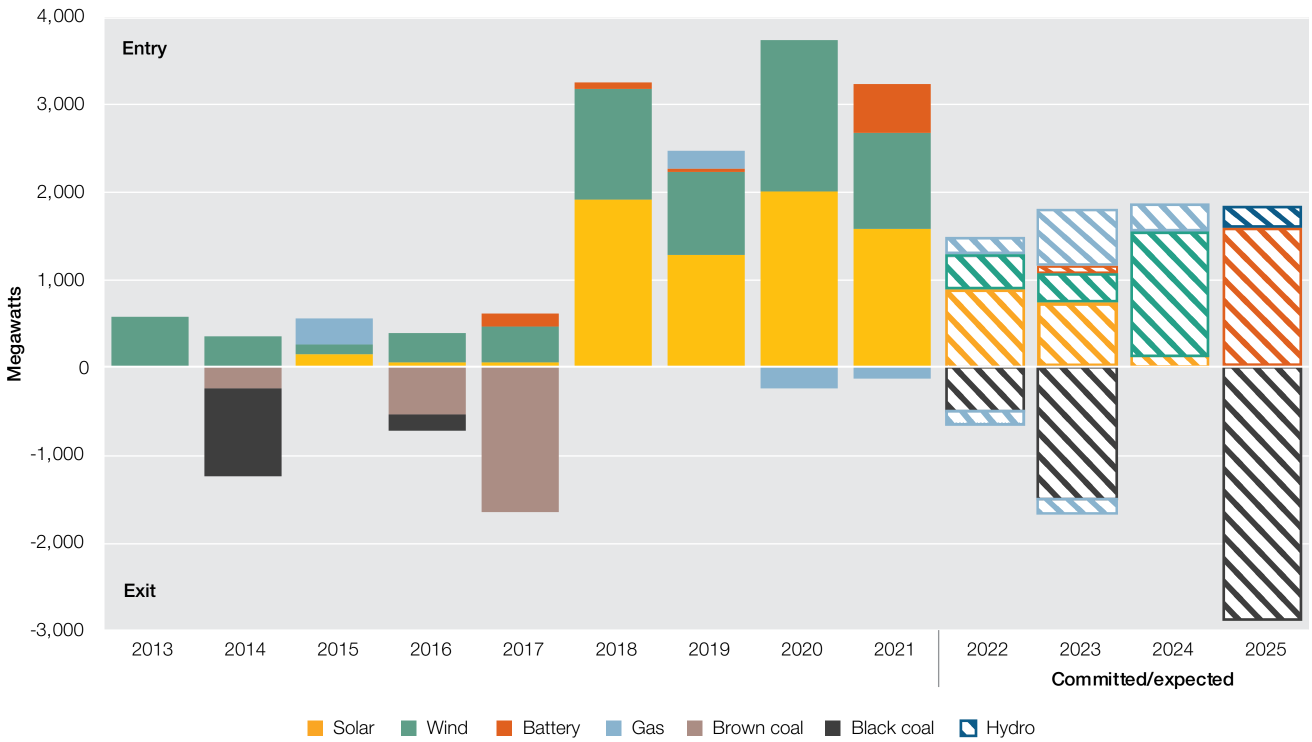
Around 12,500 MW of new utility-scale solar, wind and battery investment was added to the NEM in the 4 years to 2022. Over the same period, a net 150 MW of gas capacity was withdrawn (Figure 2.23).

In 2021, over 3 GW of renewable capacity entered the market, comprising:

- 1.5 GW of solar capacity, which was located mostly in NSW and Queensland
- 1 GW of wind capacity, which was located mostly in Victoria
- 0.5 GW of battery capacity (2 batteries in Victoria, 1 in Queensland and 1 in NSW).

This new entry included the NEM's largest wind farm (Stockyard Hill), largest solar farm (Western Downs Green Power Hub) and largest battery (the Victorian Big Battery). 150 MW of gas capacity exited the NEM in 2021 – namely, the Mackay Gas Turbine (30 MW) in Queensland and the third unit (120 MW) at Torrens Island A Power Station in South Australia.

Figure 2.23 New generation investment and plant withdrawal



Note: Capacity includes scheduled and semi-scheduled generation, but not rooftop solar capacity. Actual and expected investment and closures from 1 January 2022 are shown as shaded components. These include Liddell and Osborne power stations in 2023 and Eraring power station in 2025.

Source: AER; AEMO (data).

More than 5,000 MW of additional capacity is committed to come online in 2022 and 2023. As well as solar and wind, committed new entry includes the 660 MW Kurri Kurri gas-powered power station and over 500 MW of new batteries.

2,300 MW of base load capacity is expected to retire in 2022 and 2023. Exits in 2022 include AGL's Hunter Valley Gas Turbines (50 MW) in January, the first black coal unit (500 MW) at AGL's Liddell Power Station in April (with full closure taking place in April 2023) and AGL's final Torrens Island gas-powered unit (120 MW) in September.

Further fossil fuel plant withdrawals are expected, including 8,200 MW of coal-fired generation expected to retire between 2023 and 2029.

2.10 Power system reliability

Reliability is about the power system being able to consistently supply enough electricity to meet customers' requirements.[47]

The transition in the energy market has increased concerns about reliability. Coal plant closures remove a source of 'dispatchable' capacity that could historically be relied on to operate when needed. As the contribution of weather-dependent generation increases, the power system must respond to increasingly large and sudden changes in output caused by changes in weather conditions and dispatch decisions by plant operators.

Reliability risks remain highest over summer, particularly at times when peak demand coincides with low renewable generation, or transmission or plant outages. But they may also emerge over winter when solar output is low. Reliability concerns were elevated this winter 2022 due to coal plant outages, fuel constraints and high demand.

Box 2.2 How reliability is measured

Reliability outcomes are measured in terms of unserved energy – that is, the amount of energy required by consumers that cannot be supplied due to a shortage of capacity. The reliability standard requires any shortfall in power supply to not exceed 0.002% of total electricity requirements. It has rarely been breached, but AEMO increasingly intervenes in the market to manage forecast supply shortfalls.

While the 0.002% target is used to assess market performance and the appropriateness of reliability settings such as the market price cap, a stricter interim reliability standard is used as a trigger for market mechanisms to prevent forecast supply shortages. From 2020 to 2025 a tighter standard of 0.0006% is used to trigger the RRO and set the threshold where AEMO can procure interim reliability reserves.

The reliability standard excludes outages caused by 'non-credible' threats, such as bushfires and cyclones, because the power system is not engineered to cope with these issues and the cost of doing so would be prohibitive. It also excludes supply interruptions originating in local distribution networks. Around 95% of a typical customer's power outages originate in distribution networks and are caused by local power line and substation issues.

In effect, the standard sets a level of unserved energy that balances the cost of providing reliability against the value that customers place on avoiding an unexpected outage.

2.10.1 Managing reliability

The wholesale market remains the primary mechanism for delivering reliability. However, AEMO has powers to mitigate reserve shortfalls, including having emergency reserves on standby.

Reliability and Emergency Reserve Trader

Over the 5 summers up to and including 2021–22, AEMO used the Reliability and Emergency Reserve Trader (RERT) mechanism to maintain reliability. The mechanism allows AEMO to procure additional supply from generators and/or demand management from customers (to reduce their consumption) at times of limited reserves to reduce the risk of load shedding.

47 Reliability should be distinguished from security, which refers to the power system's technical stability in terms of frequency, voltage, inertia and other characteristics (section 2.11).

Reserves procured under the RERT must be 'out of market'. Specifically, any generator or load that participated in the wholesale market in the previous 12 months may not provide emergency reserves through the RERT.[48]

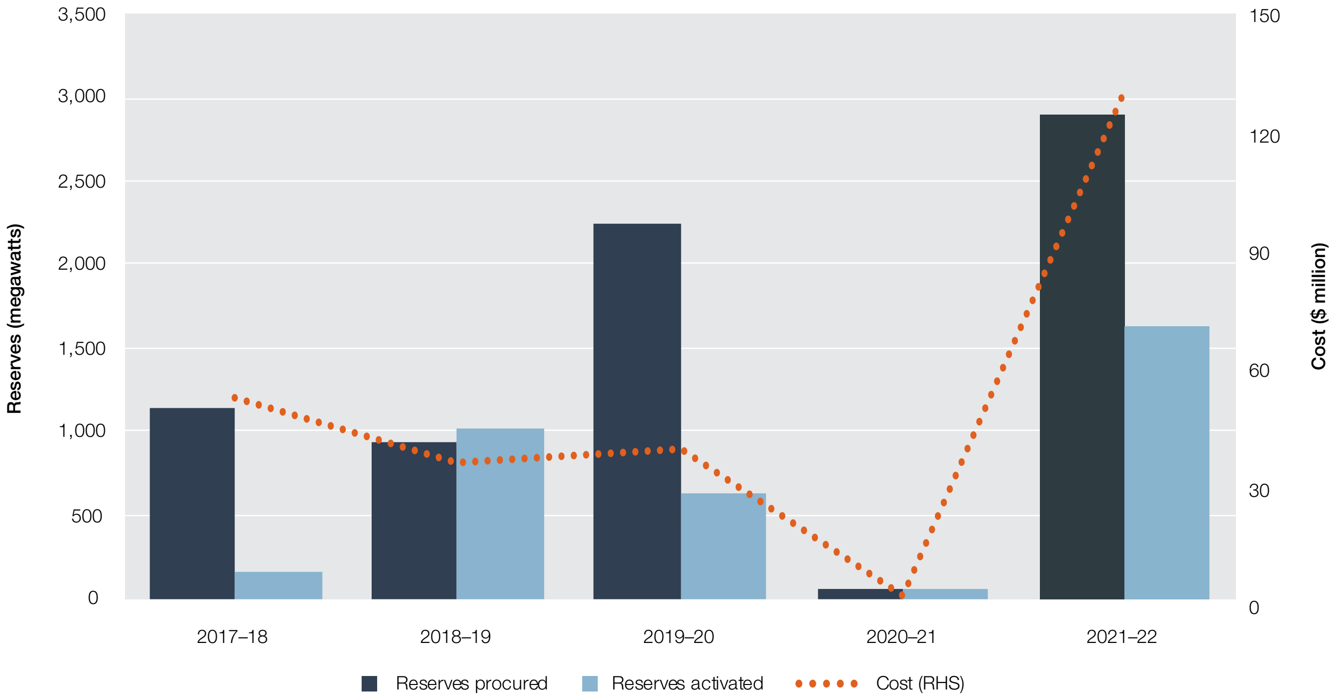
RERT is activated only if required. The RERT scheme is expensive to operate and consumers ultimately bear these costs. AEMO maintains a panel of RERT providers that can provide short notice and medium notice reserve if required. Panel members for short notice RERT agree on prices when appointed to the panel, whereas panel members for medium notice RERT negotiate the price when reserves are required. AEMO may procure long notice reserve through invitations to tender where it has 10 weeks or more notice of a projected shortfall.

Before 2017–18, the RERT mechanism had been used to procure backup capacity only 3 times and was never activated. AEMO activated the RERT for the first time in November 2017 to manage a forecast lack of reserves in Victoria and a further 6 times in Victoria and South Australia over the 2017–18, 2018–19 and 2019–20 summer periods. The RERT was activated in NSW for the first time in January 2020 and again in December 2020. The cumulative cost of the RERT between 2017 and 2020 was around $126 million (Figure 2.24).

In 2021 AEMO activated RERT in Queensland for the first time, following a serious fire at the Callide C power station in May 2021, at a cost of $460,000.[49]

In the first half of 2022, AEMO has relied on RERT to manage reliability more than at any other time at a record cost of over $130 million. In February it activated RERT in Queensland on a hot, humid day with plant outages and low wind generation, at a cost of $50.1 million. In June, it activated RERT following the administrated price cap and subsequent withdrawal of generation capacity. During this period, it activated RERT 3 times in NSW (14, 15 and 16 June) at a cost of $76.2 million and once in Queensland (15 June) at a cost of $3.7 million.[50]

Figure 2.24 RERT reserves and costs



Note: Reliability and Emergency Reserve Trader (RERT) costs include costs for availability, pre-activation, activation and other costs (including compensation costs).

Source: AER analysis of AEMO's RERT reporting.

48 AEMC, National Electricity Amendment (Enhancement to the Reliability and Emergency Reserve Trader) Rule 2019, rule determination, May 2019.

49 AEMO, Reliability and Emergency Reserve Trader End of Financial Year 2020–21 Report, August 2021.

50 AEMO, Reliability and Emergency Reserve Trader End of Financial Year 2021–22 Report, August 2022.

2.10.2 Reliability outlook

In August 2022, AEMO forecast relatively low reliability risks for the coming summer, although risks remain under extreme conditions.[51] These include weather uncertainty or simultaneous generator and/or transmission outages that may reduce available supply when it is required.

A change since last year's forecast and now, is that both South Australia and Victoria could breach the Interim Reliability Standard in 2023–24. AEMO also brought forward the timing for potential gaps in reliable power supply by up to 7 years due to accelerating coal power station closures, delays in transmission projects and expectations of rising demand.

The NEM faces 5 announced coal-fired generator retirements in the next decade. Liddell (NSW) in 2023, Eraring (NSW) as soon as August 2025, Yallourn (Victoria) and Callide B (Queensland) in 2028 and Vales Point B (NSW) in 2029.

As a result, AEMO forecast there will be periods when electricity supply may not meet demand in NSW from as early as 2025–26. The 2022 ISP sets out the scale and urgency of the transmission projects needed to support new generation.[52]

The Health of the NEM 2022 found the best strategy to manage the risk of the transition is to build replacement assets quicky and cost-effectively, in advance of generation retirements.[53] This will reduce our exposure to the shocks of international gas and coal price movements, reduce our reliance on ageing assets, and allow consumers to benefit from renewable energy resources. However, if there are delays in proposed generation, storage or transmission projects, or enabling reform, there is a growing risk of reliability gaps.

2.11 Power system security

Power system security refers to the power system's technical stability in terms of frequency, voltage, inertia and similar characteristics. Historically, the NEM's coal, gas and hydroelectric generators helped maintain a stable and secure system through inertia and system strength services provided as a by-product of producing energy. However, as older synchronous plants retire, or reduce operations in response to falling demand, these sources of inertia and system strength are being removed from the system. Falling inertia makes it harder to keep frequency within an acceptable band and falling system strength makes it harder to keep voltages stable.

The wind and solar generators entering the market are less able to support system security. For this reason, the rising proportion of renewable plant in the NEM's generation portfolio will mean more periods of low inertia, weak system strength, more volatile frequency and voltage instability. It also raises challenges to the generation fleet's ability to ramp (adjust) quickly to sudden changes in renewable output.

AEMO is more frequently relying on directions to keep the system secure. Directions for system security are intended a last resort intervention, when the market has not delivered the necessary requirements. In South Australia, directions to market participants to take action to maintain or restore power system security have been in place for a substantial amount of time in the past 2 years at a substantial cost. In 2021 total costs for directing South Australian generators for system strength reached $94 million – almost double those costs in 2020.

In South Australia, 4 synchronous condensers, installed by ElectraNet, started operating in October 2021 to provide system strength and inertia. Each has a flywheel with a large amount of momentum. In the event of a disturbance on the network, these provide the electrical inertia to power through the fault. They have reduced the number and cost of market interventions, relaxed constraints on wind and solar output and reduced the amount of gas generation required down to 2 units. Directions in South Australia fell from being in place over 80% of the time in the last quarter of 2021 to below 20% of the time in the first quarter of 2022.[54]

51 AEMO, 2022 electricity statement of opportunities, August 2022.

52 AEMO, Integrated system plan (ISP) 2022, 30 June.

53 ESB, Health of the National Electricity Market 2022, September 2022.

54 AEMO, Quarterly energy dynamics, Q1 2022, April 2022.

Energy rule reforms have widened the pool of providers (such as batteries and demand response) of security services. An initial reform to support more flexible generation saw the settlement period for the electricity spot price change from 30 minutes to 5 minutes from 1 October 2021. Market policy and regulatory bodies are developing broader reforms of the energy market's architecture to manage security risks in the context of an evolving energy market. Three key regulatory changes are expected to improve system security:

- A new system strength framework will apply from December 2022.
- AEMO will implement a very fast ancillary service market in 2023. In July 2021 the AEMC published a rule requiring that AEMO introduce 2 new market ancillary services to help control system frequency and keep the future electricity system secure – namely, very fast raise services and very fast lower services markets, which will facilitate the delivery of fast frequency response services.
- Market reforms for valuing, procuring and scheduling essential system security services are under consultation. Consistent with the broader ESB post-2025 reform program, the AEMC is consulting on rule change requests concerning valuing, procuring and scheduling essential system services to ensure the power system remains secure.[55]

2.11.1 Security performance in the National Electricity Market

As part of AEMO's market operations, it seeks to maintain system frequency within a secure range (between 49.85 and 50.15 hertz). Any deviations from this range should not exceed more than 1% of the time over any 30-day period. Maintaining system security during the energy transition has been a key focus of the NEM market bodies.

Security performance can be impacted by changing system conditions (including extreme weather), generation volatility and an increase in load. AEMO reports annually on system security needs across the NEM for the coming 5-year period. Its December 2021 report identified system strength shortfalls in NSW and Queensland, and inertia and voltage shortfalls in Queensland and South Australia.[56] AEMO expects the need for additional system security services will only increase over the coming years as power stations that previously supplied these services withdraw from the system. AEMO needs to consider what technologies will be incentivised to provide these services in future, and whether the new market arrangements currently being developed will provide sufficient incentives to do so.

2.11.2 Frequency control markets

AEMO procures some of the services needed to maintain power system stability through markets. In particular, it operates markets to procure various types of frequency control services.

Frequency control ancillary services (FCAS) are used to maintain the frequency of the power system close to 50 hertz. The NEM has 8 FCAS markets, which fall into 2 categories: regulation services and contingency services. Regulation services operate continuously to balance minor variations in frequency caused by small changes in demand or supply during normal operation of the power system. Contingency services manage large frequency changes from sudden and unexpected shifts in supply or demand, and they are used less often.

Costs for regulation services are recovered from participants that contribute to frequency deviations (causer pays), costs for raise contingency services are recovered from generators, and costs for lower services are recovered from market customers (usually retailers). AEMO acquires FCAS through a co-optimised market that coordinates offers from generators and other participants in both energy and FCAS markets to minimise overall costs.

Fewer participants operate in FCAS markets than in the wholesale electricity market, but several new participants emerged in recent years. In mid-2022, 10 participants were providing FCAS in Queensland, 12 in NSW, 10 in Victoria, 16 in South Australia and 2 in Tasmania. Demand response aggregators now offer FCAS across all NEM regions, and virtual power plants and battery storage offer services in all mainland regions.[57] Some of these new entrants account for only a small proportion of FCAS trades and others such as batteries have displaced incumbent providers.

In the first quarter of 2022, helped by the Victorian Big Battery which started providing FCAS in November 2021, batteries became the largest provider of FCAS in the NEM, providing almost a third of all FCAS (by volume). This was more than either black coal or hydroelectric. Demand response also provided more FCAS, growing to 14% of FCAS volumes.[58]

55 A more detailed discussion of these essential system services can be found in AEMO and AEMC's Joint Paper on Essential System Services and inertia in the NEM (June 2022) and AEMO's Engineering Framework.

56 AEMO, 2021 System Security Reports, December 2021.

57 AEMO, NEM registration and exemption list, June 2022.

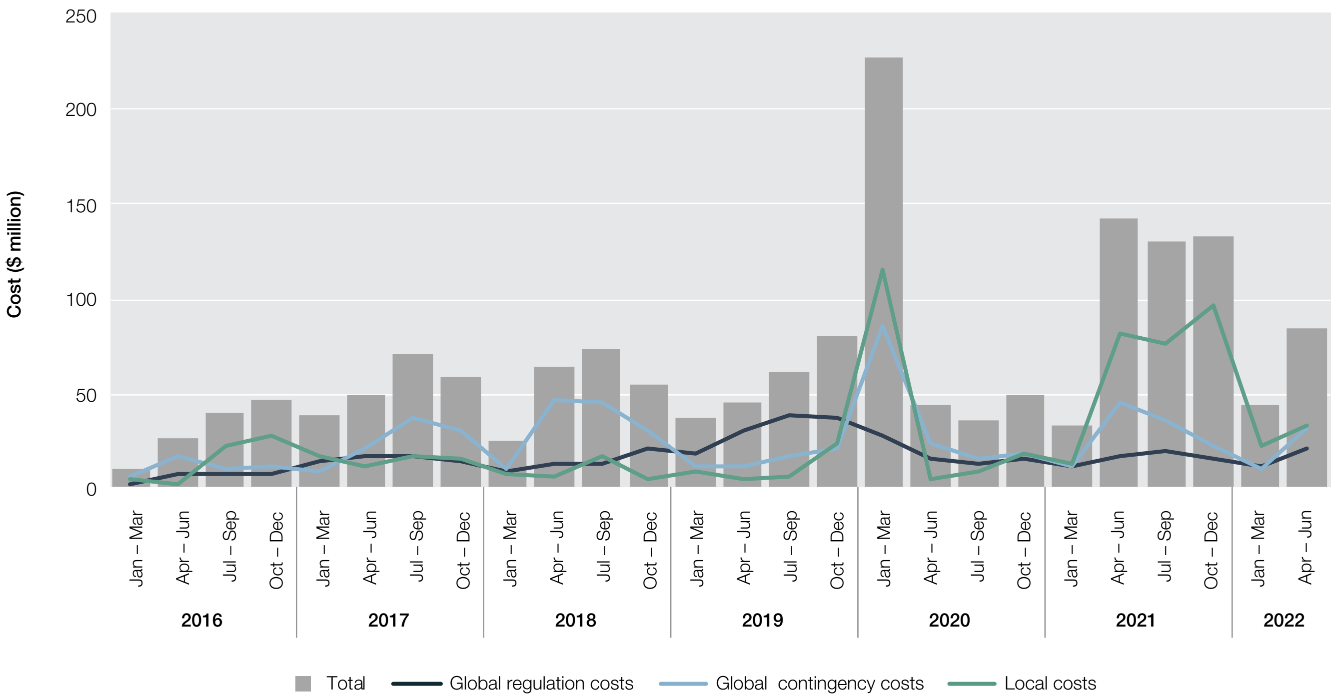
58 AEMO, Quarterly energy dynamics Q1 2022, April 2022.

Historically, FCAS costs were comparatively low in relation to energy costs. However, these costs have risen steadily over the past few years.

Despite low FCAS costs in the first quarter of 2021, FCAS costs rebounded sharply in the second quarter of 2021 and remained high for the remainder of the year. This drove record FCAS costs of $438 million over the year. Most of the cost increase reflected very high local FCAS costs in Queensland, driven by individual days of extreme FCAS price volatility (Figure 2.25). High FCAS prices were caused by a combination of factors. The ongoing upgrade to the Queensland–NSW interconnector meant that at times FCAS requirements in Queensland had to be met exclusively by local supply. Some Queensland FCAS providers had units on outage, which reduced available supply. Further, FCAS prices were also strongly impacted by high energy prices in the region, which reflected the opportunity cost of providing some services. The combination of these factors meant at times it was necessary to dispatch very expensive local capacity.[59]

In 2022 FCAS costs fell from the very high levels of 2021. FCAS prices in Queensland dropped because the region didn't need to provide its own FCAS as often, with fewer outages on the Queensland–NSW interconnector related to the transmission upgrade works. The fall in local FCAS costs was slightly offset by an increase in local Tasmanian FCAS costs at the start of 2022.

Figure 2.25 Frequency control ancillary service costs



Note: Record FCAS costs in the first quarter of 2020 were due to high local costs in South Australia when it was islanded for several weeks following the loss of the Heywood interconnector. In January 2020 bushfires also drove high prices across the NEM.

Source: AER; AEMO (data).

2.11.3 Market reforms

Significant market reforms were implemented in 2021.[60] In October 2021, 5-minute settlement was applied in the NEM to provide better price signals for fast response technologies such as batteries, new gas-peaking plants and demand response. Previously, participants were paid an average 30-minute price.

The wholesale demand response mechanism was also introduced in October 2021.[61] Demand response involves paying energy consumers to cut their use of power. Consumers (either directly or through aggregators) are able to bid demand response directly into the wholesale market at any time, but most likely at times of high electricity prices. It is also used to help keep the power system stable. New Zealand began using demand response in 2007 and now meets over 16% of peak demand through demand response programs.[62] Adoption of demand response in Australia is

59 AER, Wholesale markets quarterly – Q4 2021, February 2022.

60 Energy Security Board, *Health of the NEM 2022*, September 2022.

61 AEMO, Wholesale demand response mechanism, August 2022.

62 ARENA, What is Demand Response?, April 2022.

still limited, but by June 2022 Enel X had registered 60 MW of demand response facilities in NSW, Victoria and South Australia. These units participated in the market in May and June at times of high prices.

2.11.4 Future market reforms

Governments, the ESB and market bodies are progressing future reform workstreams, which include:

- a capacity mechanism to create a signal for investment in dispatchable capacity
- initiatives to maintain the system's secure operation, including system strength, frequency, operating reserve and inertia
- improved integration of consumer energy resources to ensure these resources are coordinated and aligned with system and market signals
- supporting the timely and efficient delivery of major transmission projects, as well as consideration of a congestion management mechanism to improve market signals for generator connections.[63]

2.11.5 Compliance and enforcement activities

The AER's compliance and enforcement work ensures that important protections are delivered, and rights are respected. It gives consumers and energy market participants confidence that the energy markets are working effectively and in their long term interests, so that they can participate in market opportunities as fully as possible and are protected when they cannot do so.

Compliance work helps to proactively encourage market participants to meet their responsibilities, and enforcement action is an important tool where breaches occur.

Each year, the AER identifies and publishes a set of compliance and enforcement priorities, some of which relate to participants in the NEM. The challenge to maintain system security has increased our focus on generators' meeting technical standards and providing accurate information to AEMO. Providing inaccurate information undermines AEMO's ability to manage frequency deviations, creating a risk to system security and stability.

Over 2021–22, one priority was to focus on generators' compliance with AEMO dispatch instructions and their ability to comply with their latest offers at all times. The AER released two compliance bulletins providing key guidance to participants and encouraged them to review and update their practices as appropriate.

In September 2021 the AER instituted proceedings against Hornsdale Power Reserve Pty Ltd (HPR) for alleged breaches of the National Electricity Rules. Between July and November 2019 HPR made offers to AEMO and was paid to provide market ancillary services, which allegedly it could not provide including when it was called on to provide those services after a frequency disturbance. On 28 June 2022 HPR was ordered by the Federal Court to pay $900,000 in penalties.[64]

During the recent suspension of the NEM, the AER wrote to market participants reminding them of their obligations around bidding and providing accurate and timely capability information to AEMO. The AER also provided detailed guidance to generators as the market suspension lifted to encourage orderly market conduct. This priority will be expanded in 2022–23 to include a focus on obligations relating to bidding behaviour and providing accurate and timely capability information to AEMO as the east coast energy market continues to face challenges.

More detail on the AER's compliance and enforcement work is outlined in the Annual compliance and enforcement report 2021–22.

63 The AEMC published a draft report as part of the Transmission planning and investment review on 2 June 2022.

64 AER, 'Hornsdale Power Reserve penalised $900,000 for inability to provide contingency services as offered' [media release], June 2022.