Image source: iStock

3

National Electricity Market

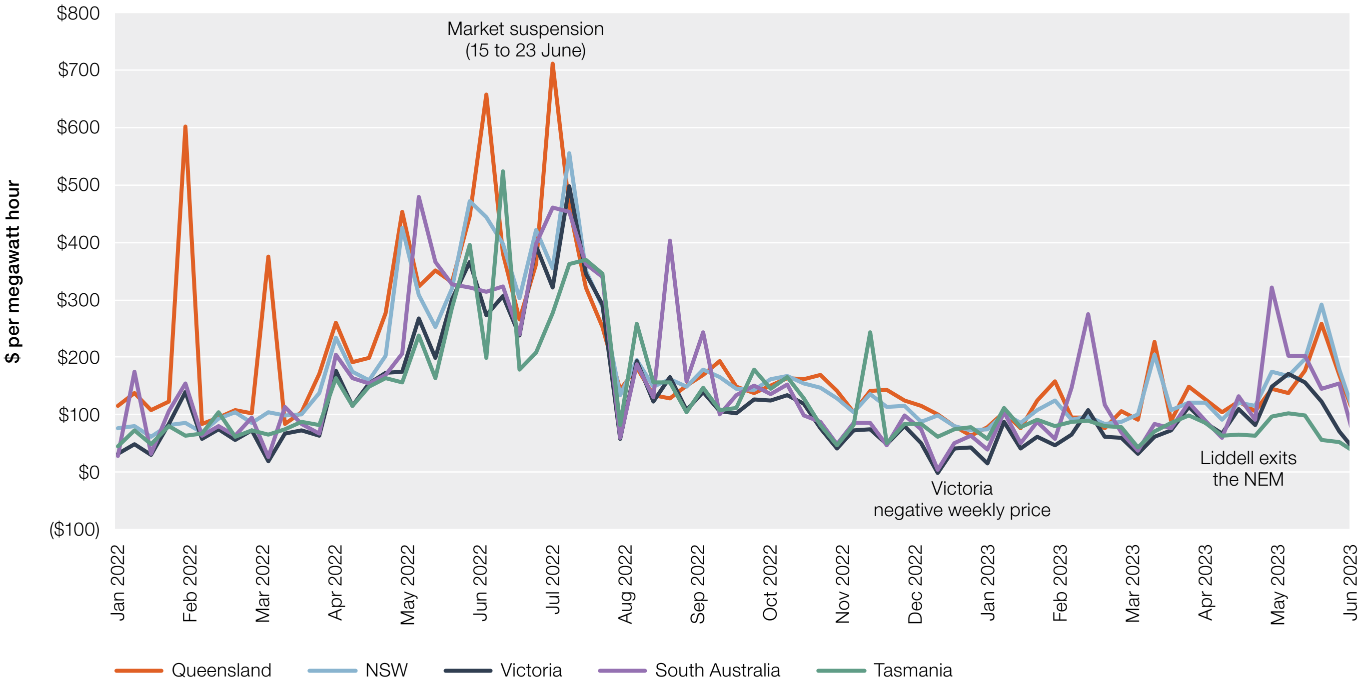
Electricity generated in eastern and southern Australia is traded through the National Electricity Market (NEM). Generators make offers to sell electricity into the market and the Australian Energy Market Operator (AEMO) schedules the lowest priced generation available to meet demand. The amount of electricity generated needs to match demand in real time. The market covers 5 regions – Queensland, New South Wales (NSW) including the ACT, 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.

3.1 Snapshot

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

- Wholesale electricity prices have fallen sharply from the record highs observed in mid-2022 but remain high compared with historical levels.
- Relatively mild weather conditions from the end of winter 2022 contributed to lower demand and prices. Factors such as coal generator outages, natural disaster, high international fuel prices and coal and gas supply issues also did not exert the same upward pressure on prices as in 2022. Nonetheless, the NEM remains vulnerable to these risks should they return.
- The AER has observed materially cheaper offers from some coal generators since the price of coal was capped by the NSW and Queensland governments (section 3.4.1)
- The price of futures contracts for electricity fell substantially in all regions after the Australian and state governments announced market interventions in December. Though they have since risen, they remain well below the levels observed before the intervention. Since the beginning of 2022–23 liquidity has declined slightly but volumes remain high, except in South Australia (section 3.5).
- Renewables output saw record highs in the October to December quarter 2022 and January to March quarter 2023. Ongoing investment in renewable generation has continued to improve supply, particularly during the daytime and in summer months (section 3.7).
- Liddell power station's remaining 3 black coal generation units retired in April 2023. While the loss of capacity following Liddell's exit from the NEM was partly mitigated by renewables entry, more investment in flexible generation will be needed in coming years to support the exit of other coal-fired generators (section 3.11).
- Major reforms have commenced or progressed to transform the NEM's market design to ensure it is best equipped for the post-transition energy market (section 3.14).

Figure 3.1 Weekly wholesale electricity prices

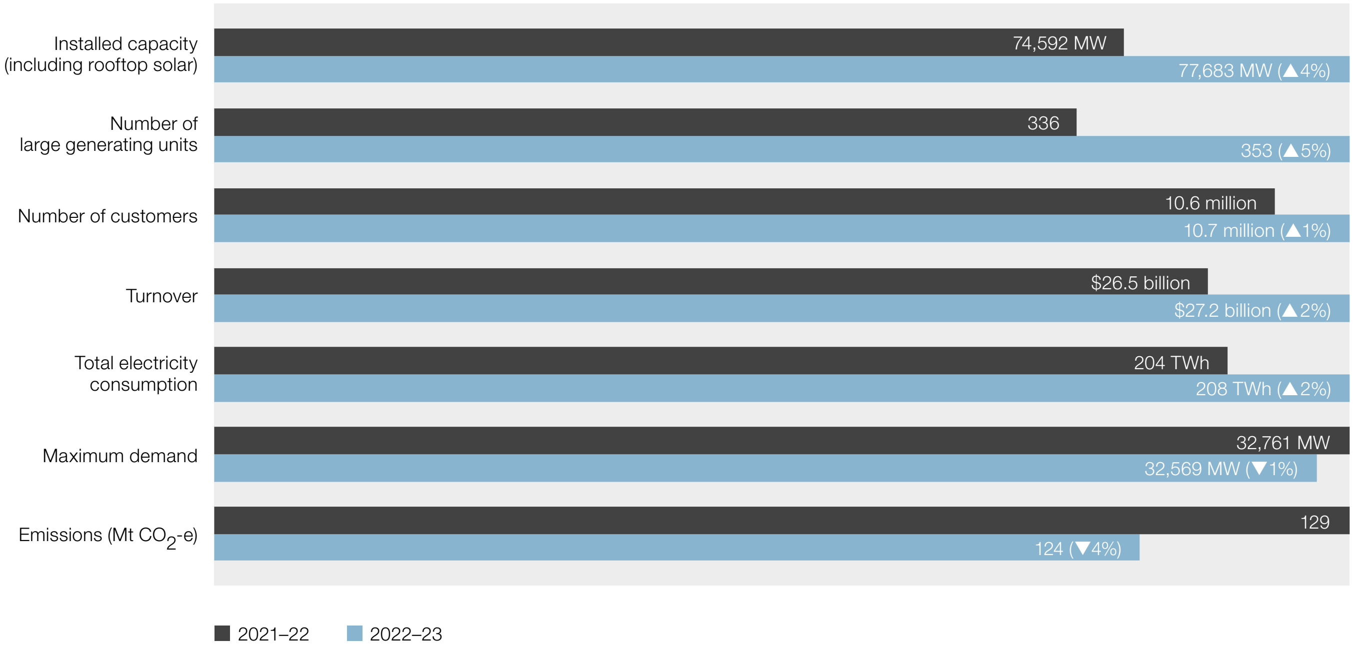


Note: Volume weighted weekly average prices.
Source: AER; AEMO (data).

3.2 NEM overview

353 generating units produce electricity for sale into the NEM (Figure 3.2). A transmission grid carries this electricity along high voltage power lines to industrial energy users and local distribution networks (chapter 4). 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 3.2 NEM key statistics



Note: MW: megawatts; TWh: terawatt hours.
All data as at 1 July 2023, except customers, which are as at 30 June 2022. Includes energy met by the grid and rooftop solar generation.
Source: AER; AEMO (data); Clean Energy Regulator (data).

Box 3.1 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.

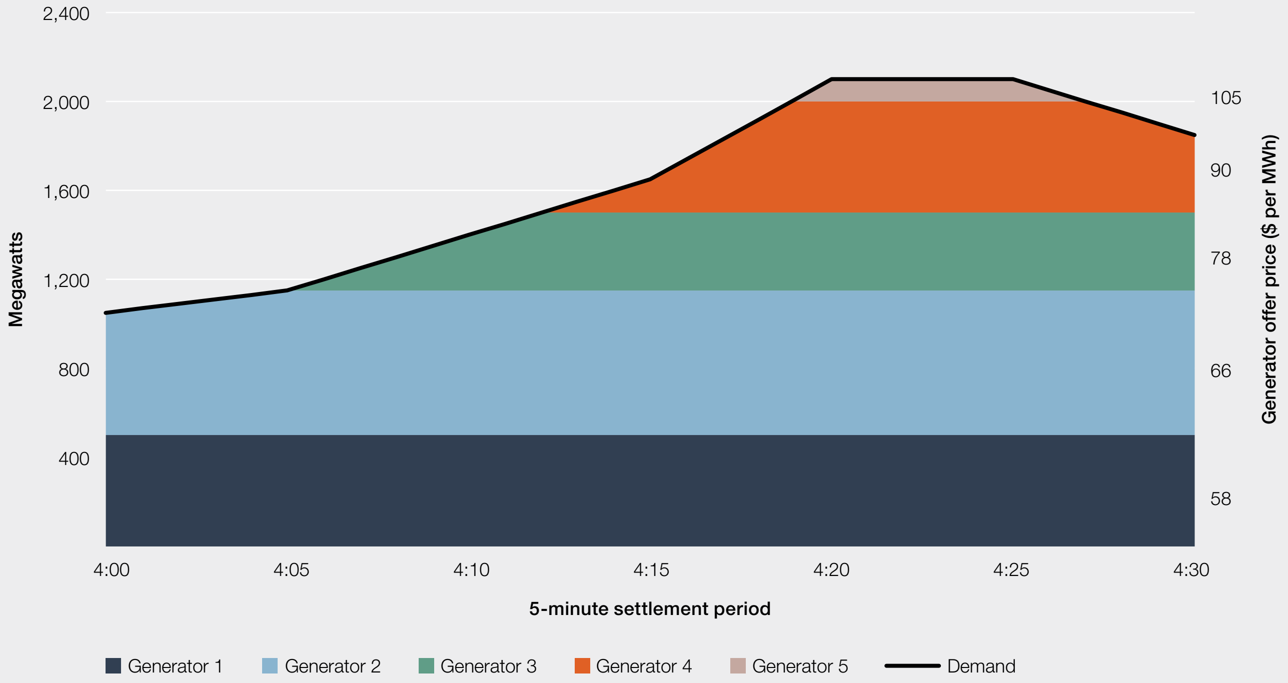
Power stations make offers to supply quantities of electricity in different price bands for each 5-minute dispatch interval. Scheduled loads, or consumers of electricity such as pumped hydro and batteries, also offer into the market. From 2021, consumers (either directly or through aggregators) are also able to bid demand response directly into the wholesale market as a substitute for generation (section 3.8). 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 $16,600 per megawatt hour (MWh) in 2023–24. 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.

The Box Figure 3.1 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. That price is paid to all dispatched generators, regardless of their offers. This process is repeated for all 5-minute intervals.

Box Figure 3.1 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.

3.3 Wholesale prices and activity

Wholesale electricity prices have fallen significantly from the record highs in winter 2022, which culminated in the suspension of the NEM's spot market. In most NEM regions, average prices remain high compared with historical levels (Figure 3.3).

Figure 3.3 Annual wholesale prices, financial year

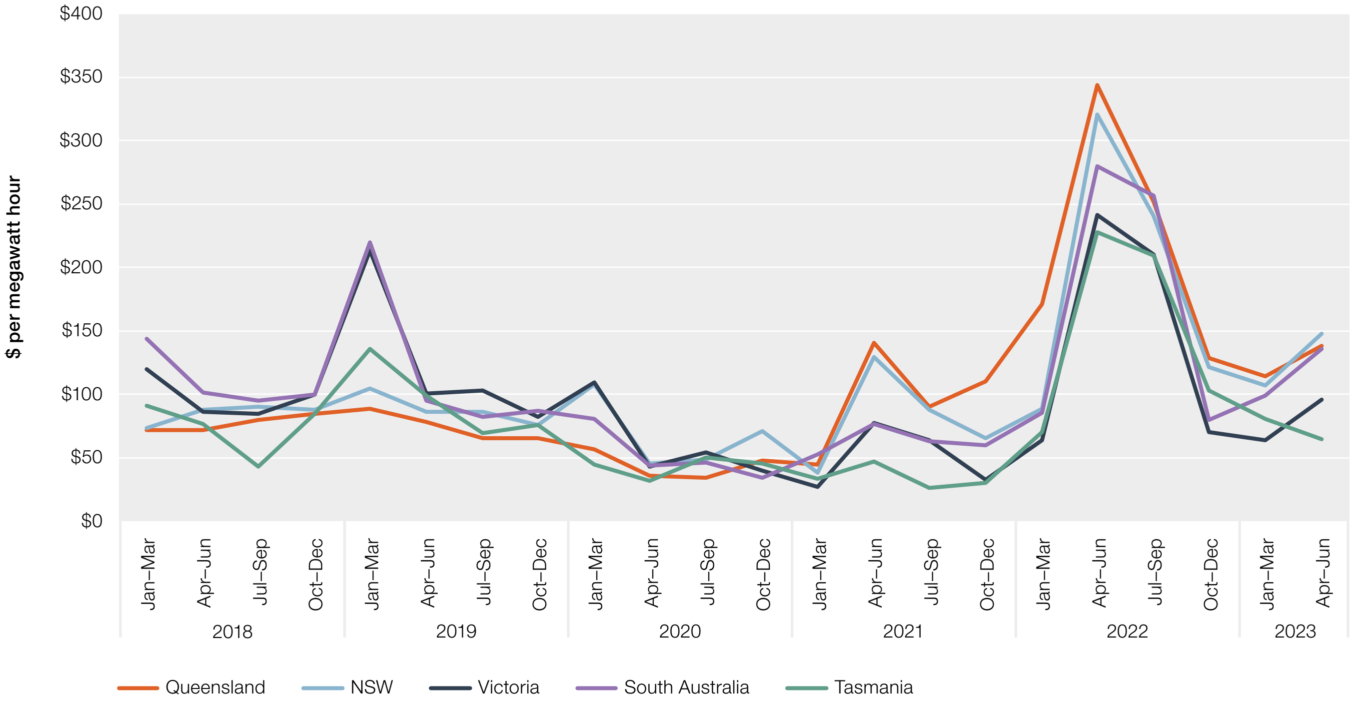
Note: Volume weighted average financial year prices.
Source: AER; AEMO (data).

Average prices rose across all regions other than Queensland in the 2022–23 financial year, due to high prices in the July to September quarter 2022 (Figure 3.4):

- Queensland ($157 per MWh) remained the NEM's highest priced region in 2022–23, although it was only 11 cents per MWh higher than NSW. Queensland was the only region to record a decrease in its average price from the 2021–22 financial year, falling 12%, having been elevated compared with the rest of the NEM prior to 2022–23. Like other regions, Queensland started the 2022–23 financial year with near-record prices in the July to September quarter. Prices in Queensland have decreased significantly since mid-2022; however, they remain elevated compared with historical levels.
- NSW ($157 per MWh) remained the NEM's second highest priced region. As with most other NEM regions, average prices in NSW increased on a financial year basis, up 9% on 2021–22. This was the result of significantly elevated prices in the July to September quarter 2022, occurring shortly after the unprecedented prices that resulted in the spot market suspension of June 2022. Prices fell sharply for the remainder of the financial year – all subsequent quarters were between 39% and 55% lower than the July to September quarter. Despite falling significantly since the unprecedented prices of mid-2022, average prices in NSW remain elevated compared with historical levels.
- South Australia ($150 per MWh) prices increased 20% in 2022–23. South Australian prices were highest in the July to September quarter, but have been significantly lower since. Even since falling from the unprecedented levels of mid-2022, South Australia has been more vulnerable than other regions to short lived, high magnitude price spikes. High prices often occurred at times of low wind output, when South Australia was also prevented from importing from Victoria. The region experienced more frequent and severe high price events than other regions, but also had the most instances of negative prices in the NEM.
- Tasmania ($117 per MWh) was not the NEM's lowest priced region in 2022–23, a position it had occupied since 2019–20. The July to September quarter 2022 was Tasmania's highest priced quarter of the financial year, and prices have fallen significantly since, although not as quickly as in other regions. With the lowest renewables penetration in the NEM, Tasmanian prices in summer months did not experience downward price pressure from low and negatively priced intervals to the same extent as other regions.
- Victoria ($114 per MWh) saw an increase of 10% from its average price in 2021–22 but replaced Tasmania to become the NEM's lowest priced region. As with other regions, Victoria's increase was the result of a high-priced July to September quarter 2022. Prices in subsequent quarters have been up to 60% lower than at the beginning of the financial year. Prices in Victoria were stable compared with the week-to-week volatility observed in NSW, Queensland and South Australia.

As is typical, prices across the year varied from quarter to quarter with changing seasonal dynamics. Prices were lowest in summer quarters, falling significantly from winter 2022, before increasing slightly again in winter 2023 (Figure 3.4).

Figure 3.4 Quarterly wholesale electricity prices



Note: Volume weighted average quarterly prices.

Source: AER; AEMO (data).

3.3.1 July to September 2022

From July to September 2022, average prices eased slightly across all regions (Figure 3.4). Throughout July, cold weather caused high demand to persist while supply continued to be hampered by outages of aging coal plants, coal supply issues and high international fuel prices. Prices began to decline entering spring, halving in August and remaining at that level in September. Demand fell as temperatures rose, offline coal generators returned to service and output of renewables improved as days got longer, sunnier and more windy.

3.3.2 October to December 2022

From October to December 2022, prices fell quickly, declining by 48% or more in all regions. Demand remained subdued as mild spring conditions continued into the summer, with record high output from rooftop solar further offsetting the energy that households required from the NEM. Favourable conditions and strong investment in renewables saw a quarterly record output of clean energy from wind and grid-scale solar farms. This resulted in a quarterly record number of negative prices and further reduced average prices. International fuel prices also began to ease but remained high by historical levels.

3.3.3 January to March 2023

From January to March prices remained subdued, rising slightly in South Australia while falling slightly in all other regions. Renewables output rose to set a second consecutive record quarterly output. Some NSW coal generators began to offer greater amounts of electricity into the NEM at lower prices than previous quarters, coinciding with the implementation of the coal price cap in NSW. Despite generally low prices, periodic high price events occurred as high temperatures coincided with peak evening demand and daily reduction of solar output as the sun set.

3.3.4 March to June 2023

Mainland prices increased from April through to June, but only by a fraction of the magnitude that they did in the April to June quarter 2022. This increase was driven by seasonal market dynamics, such as increased demand due to colder weather and falling solar output.

The increase was smaller than in the April to June quarter 2022 because the drivers of extreme prices were present to a much lesser extent in 2023. Coal generator outages were fewer and, despite Liddell's exit from the market in April, more coal capacity was offered into the market than in the April to June quarter 2022. International prices of coal and gas were also significantly lower and flooding did not impact the supply of fuel to various generators. Additionally, wind output saw a near-record quarterly high, while rooftop solar contributed to lower daytime demand, pulling down overall average demand.

3.4 Generator fuel costs, fuel availability and market interventions

Generator fuel costs reached an all-time high early in the 2022–23 financial year, but ultimately ended the financial year significantly lower than in 2021–22. This was the result of easing domestic and international prices for coal and gas and improved domestic availability. In the case of coal generation, falling costs also appear to have been assisted by the implementation of a temporary cap on the price of black coal. The impact of the $12 per GJ gas price cap on NEM gas generation is less clear. The gas price cap has since been replaced with a mandatory gas code of conduct (more detail in chapter 5).

3.4.1 Market interventions

Coal price cap

On 22 December 2022, the NSW Premier declared a coal market price emergency. The NSW Minister for Energy was granted the power to give directions to respond to the emergency while the declaration is in place, with these issued the following day. The Queensland Government moved simultaneously to direct its coal generators.

As a result of directions given, the price of black coal sold to generators has been capped at $125 per tonne in NSW. Though the directions to Queensland coal generators are not public, the AER understands Queensland has a mechanism in place to achieve a similar effect. Additionally, coal generators in NSW are required to plan to maintain a stockpile that is sufficient to meet 30 days of projected demand. Coal mines in NSW are required to reserve a proportion of future coal production to supply NSW coal generators and are to prioritise delivery to generators with low stockpiles.

Fuel cost is an integral determinant of a generator's marginal cost of producing electricity. If a generator has a lower marginal cost, it may be more likely to offer electricity into the market at lower prices, depending on other market and generator-specific factors. With more supply available at lower offer prices, higher priced capacity is less likely to be required and this should put downward pressure on prices. The price cap is particularly impactful when attached to black coal because black coal generation is typically the most frequent price setter in Queensland and NSW. While other regions don't use black coal as a generation fuel, they can still benefit through cheaper imports available via interconnection.

Since the implementation of these interventions, the AER has observed material change to the offer structure of some NSW coal generators. In January 2023, the first month of the cap's implementation, several generators began to offer more capacity into the market, with most of the additional capacity offered in lower price bands. This trend has largely continued.

Other market dynamics such as international prices have also improved since the price cap was implemented. However, it appears likely that the coal price cap has played a role in lower wholesale prices.

Gas price cap

On 9 December 2022, the Australian Government announced an emergency, temporary cap on the price of gas at $12 per GJ. This cap was later extended until mid-2025. The cap applies to gas sold under contracts negotiated directly between parties and trades scheduled more than 3 days of ahead of delivery agreed through the Gas Supply Hub.

The effect of the gas price cap on wholesale electricity prices is less clear. Most domestic gas trade has been exempt from the price cap. However, due to improved coal generation availability, cheaper coal offers, higher renewable output and lower demand, gas generation has been a less impactful driver of NEM prices. Chapter 5 includes more detailed analysis on the gas price cap and its impacts.

3.4.2 Generator fuel availability

Coal

Coal generators in aggregate experienced fewer interruptions to their coal supply in the lead up to winter 2023 than was the case in 2022. In the months preceding the market suspension of June 2022, several coal generators reported severe underdelivery of coal. This was attributed to unseasonable rains that caused flooding, resulting in closure of mines and interruption of rail freight. Compounding these sourcing difficulties, above average volumes were diverted for export due to high international coal prices, with domestically available volumes falling as a result.

With neither of these difficulties repeating in 2023, significantly fewer coal generators reported problems with access to fuel.

Coal producers in NSW have also been required to set aside some production for coal generators and prioritise delivery to generators with low stockpiles. It is likely this has improved generator access to coal in the region.

Gas

Gas-powered generation output has been relatively lower and this is likely to have reduced demand pressures, in turn improving generator access to supply. However, access to longer-term gas contracts has declined over 2023 and the market remains vulnerable to both supply and demand shocks.

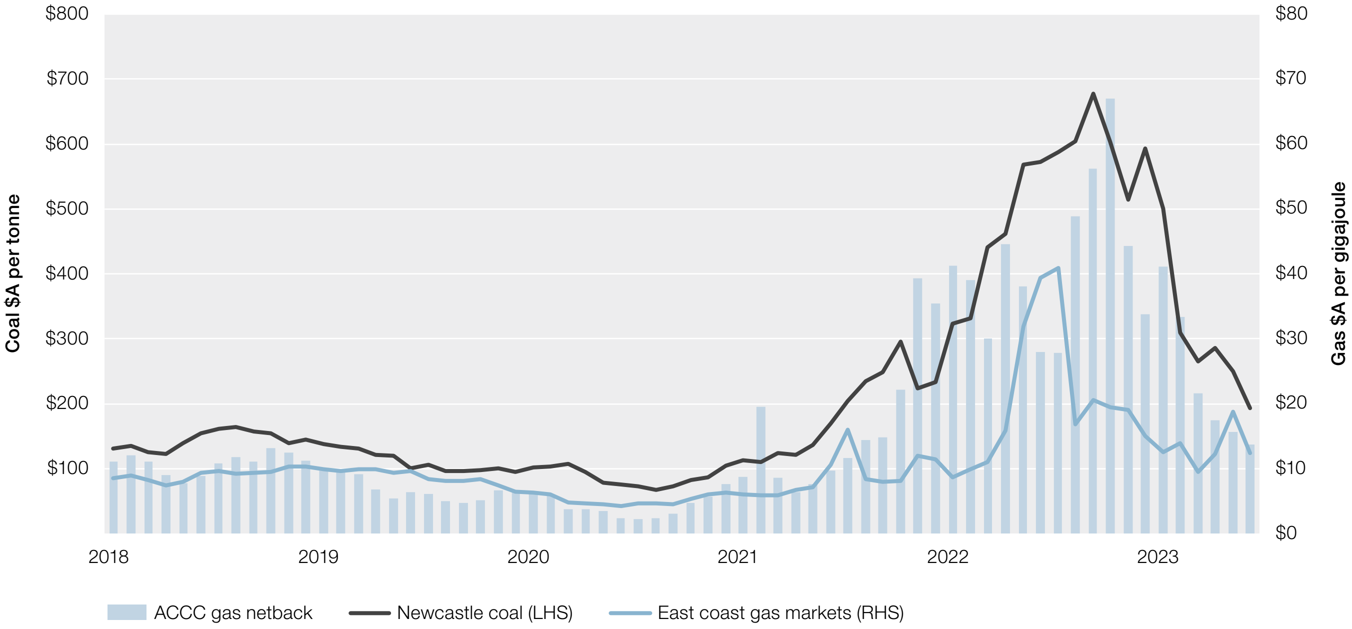
In winter 2022, an abnormally high number of unplanned coal generator outages, among other exacerbating factors, saw the NEM become significantly more reliant on GPGs (gas-powered generators) to meet demand. As a result, contracted deliveries of gas to GPGs were insufficient, resulting in an unprecedented volume of gas being purchased through spot markets. This in turn drove spot prices to record levels. Expensive gas purchased at short notice saw GPG marginal costs rise significantly, with severe effects on wholesale electricity prices. Similar trends have not been repeated so far in 2023. More detail on gas supply and demand is set out in chapter 5.

3.4.3 International fuel prices

Upstream black coal and gas market conditions can affect fuel costs for generators. Although black coal generators do not generally pay international prices for their coal supply, a high international price can put upward pressure on the domestic price. In NSW, it can shape prices for short-term supply contracts and determine when long-term contracts are renegotiated. The international export price for black coal has fallen by more than 70% since June 2022, falling from around $700 per tonne in mid-2022 to below $200 at the end of the 2022–23 financial year (Figure 3.5). While not all generators pay spot prices, these prices suggest that the short run marginal cost for coal plants needing to source coal from spot markets have fallen from above $200 per MWh to below $80 per MWh.

International gas prices also fell during the 2022–23 financial year. More detail on this is set out in chapter 5.

Figure 3.5 Coal and gas prices



Note: The black coal price is derived from the Newcastle coal index (US$ per tonne), converted to Australian dollars 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. The ACCC gas netback is the Asian gas price benchmark plus additional costs associated with export.

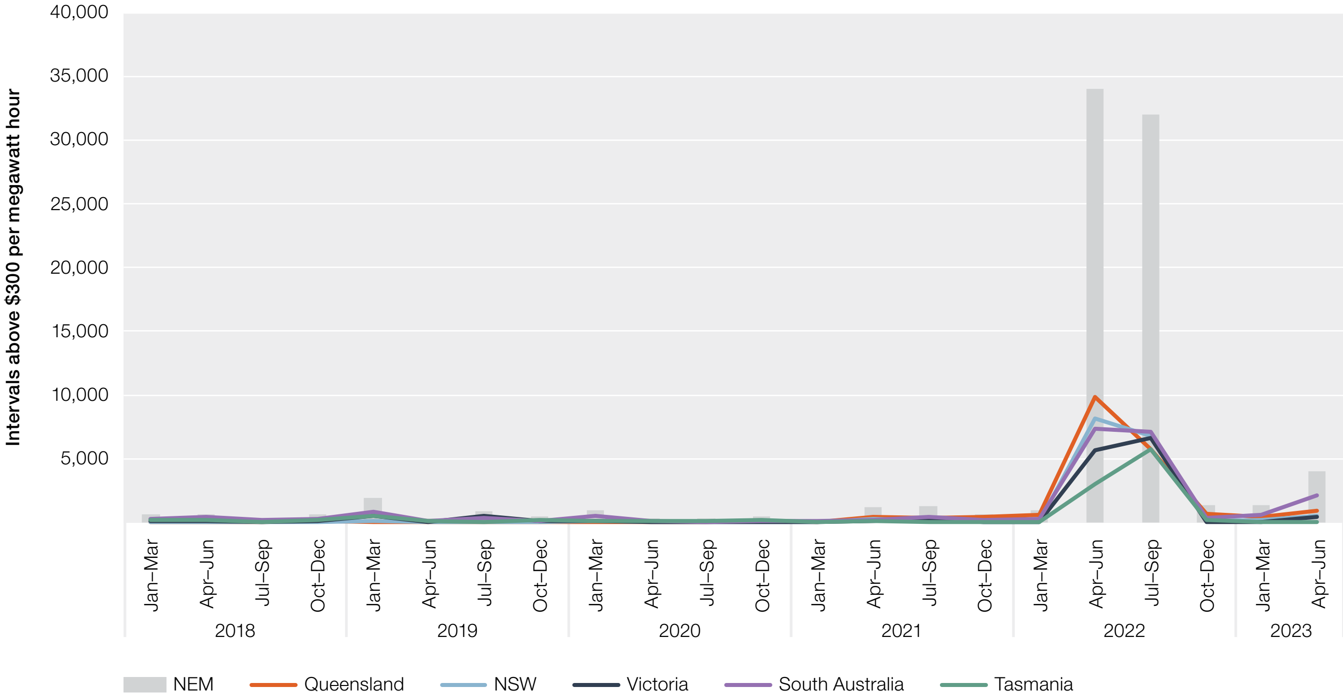
Source: AER analysis using globalCOAL data; ACCC data.

3.4.4 Price volatility

Price volatility is a natural feature of energy markets that can signal to the market that investment in new generation is needed. This signal is present in wholesale electricity markets today, with price volatility having increased dramatically in the last 2 years. In the 2021–22 financial year, the frequency of 30-minute prices above $5,000 per MWh more than doubled compared with 2020–21. The number of these high price events fell in 2022–23 but remained well above all financial years prior to 2021–22.

Once rare, spot prices above $300 per MWh are becoming more common. The events of mid-2022 saw the April to June quarter's count of prices above $300 per MWh increase more than tenfold on any previous record. Though the frequency of prices of $300 per MWh or above fell significantly as market issues resolved, the rate of their occurrence remains high by historical standards (Figure 3.6).

Figure 3.6 Count of prices above $300 per MWh



Note: Count of 5-minute prices above $300 per megawatt hour. Prices were not settled in 5-minute intervals until October 2021, although prior to this dispatch was determined on 5-minute basis using 5-minute prices.

Source: AER; AEMO (data).

3.4.5 Negative prices

In recent years the NEM has also seen more incidences of negative prices. Generators in the NEM may offer capacity as low as the market floor price of –$1,000 per MWh.

Historically, generators have offered negatively priced capacity into the market for a range of reasons. Generators whose capacity is dispatched by AEMO will receive the market price for that capacity, rather than the price for which they offered it. Because AEMO usually dispatches the lowest priced capacity first, a generator that bids negatively priced capacity is far less likely to have their bid rejected. Coal generators typically have high startup costs, so paying to generate for a period of time is usually more cost-effective than being switched off and incurring a startup cost. Additionally, 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 lower.

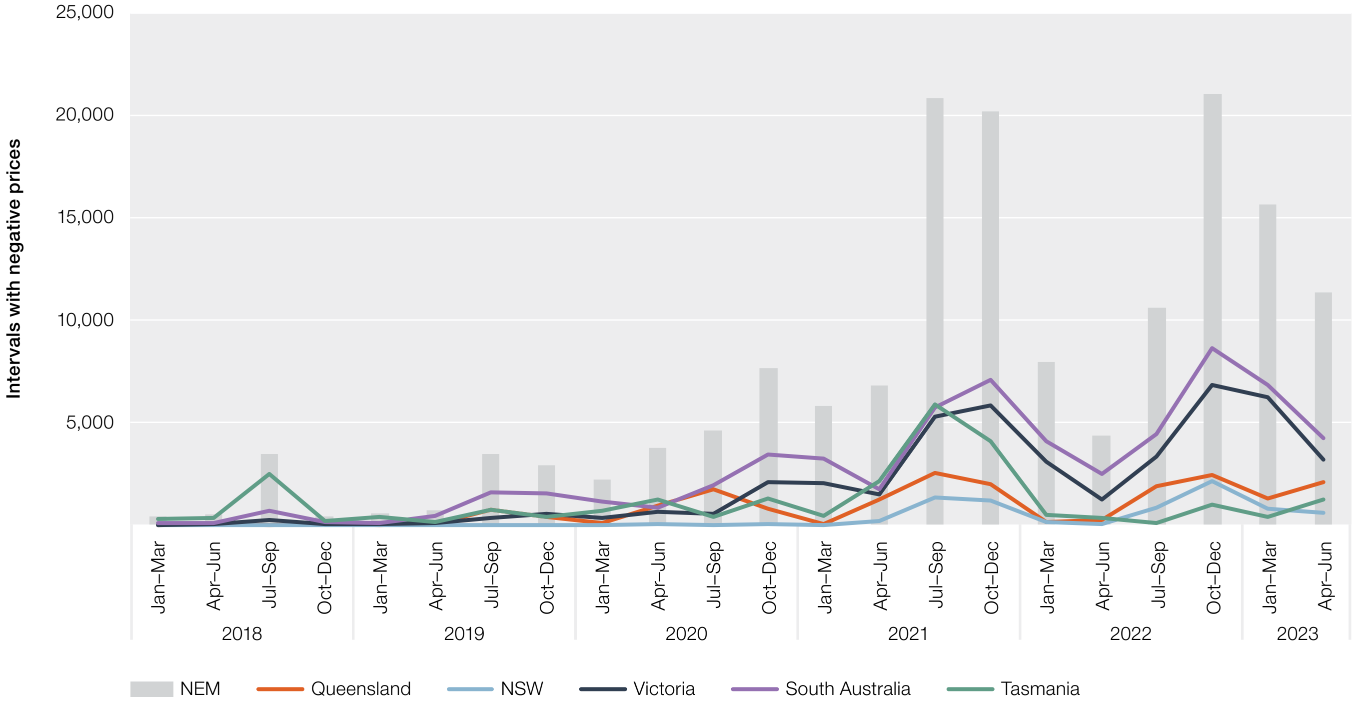
Negative prices have been more frequent since renewables entered the market

The ability of wind and solar generators to operate varies with prevailing weather conditions. These generators do not incur high startup or shutdown costs and have marginal 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[1] or power purchase agreements, so they may operate profitably even when wholesale prices are negative.

2022–23 was the fourth consecutive financial year in which a new record for number of negative prices was set, increasing in line with the amount of renewable capacity in the NEM (Figure 3.7). Almost three-quarters of negative prices occurred in South Australia and Victoria, where wind and solar (both grid-scale and rooftop solar) make up a greater portion of the overall generation mix. Instances of negative spot prices were highest when these technologies were generating.

1 Clean Energy Regulator, About the Renewable Energy Target, June 2022.

Figure 3.7 Count of negative prices



Note: Count of 5-minute prices below $0 per MWh. Prices were not settled in 5-minute intervals until October 2021, although prior to this dispatch was determined on 5-minute basis using 5-minute prices.

Source: AER; AEMO (data).

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 low-cost generators all competing for dispatch, the likelihood of negative prices increases.

Negative prices usually occurred 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 the generation of rooftop solar is being subtracted from demand.

More than 60% of negative prices in 2022–23 occurred in summer quarters (October 2022 to March 2023). In the October to December quarter 2022, Victoria recorded the first ever negative weekly average price in the NEM.

3.5 Electricity contract markets

Contract market prices have fallen significantly since the end of the 2021–22 financial year. Contract markets are critical for retailers to manage price risk on behalf of customers. They are also critical in driving generator behaviour. A liquid, accessible and adaptable contract market is integral to competitive and sustainable wholesale market outcomes.

Futures (contract or derivative) 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 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 (gentailer) to offset the risks in each market.

Typically, vertically integrated gentailers are imperfectly hedged – their position in generation may be 'short' (small relative to their retail load) or 'long' (large relative to their retail load). For this reason, gentailers 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 exchange traded markets, electricity futures products are traded on the Australian Securities Exchange (ASX) or through FEX Global (FEX). Electricity futures products are available for Queensland, NSW, Victoria and South Australia.
- 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.

Various products are traded in electricity contract markets. Exchange traded products are standardised to encourage liquidity. These products are also traded in the OTC market – the OTC offers additional products that can be tailored to suit the requirements of the counterparties. The standardised products available on exchanges and OTC include:

- 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. 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 spot market 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; 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. Cap contracts on the ASX have a strike price of $300 per MWh and the FEX caps have a strike price of $300 or $500 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 base load futures contracts.

Prices are publicly reported for exchange trades, but activity in OTC markets is confidential and not disclosed publicly. The Australian Financial Markets Association (AFMA) reported 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. This report was discontinued after 2020–21 – as such, no data on OTC trading activity is available since then. However, the AER is in the process of acquiring the legislative ability to gather such information.

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.

3.5.1 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, but the volume of trade on the exchange has been minimal.

Regular ASX trades occur for the Queensland, NSW and Victorian regions of the NEM, but liquidity has been poor in South Australia for several years and continues to worsen.

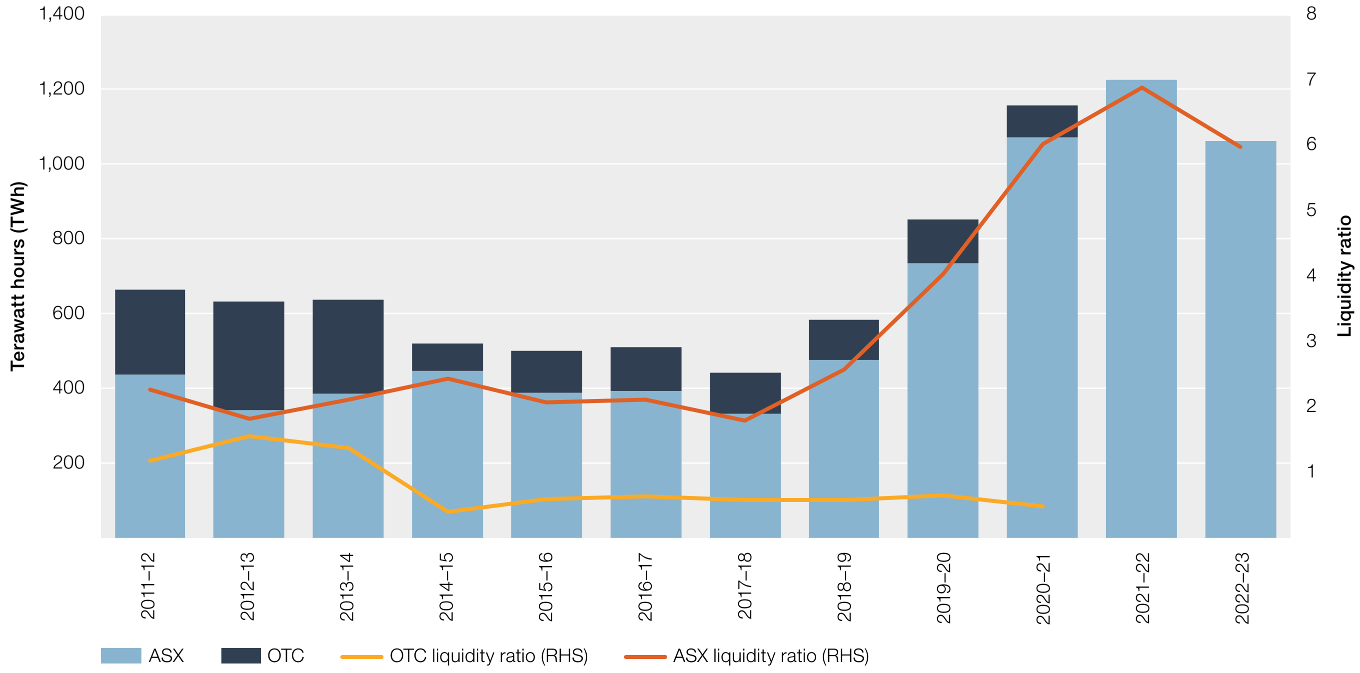
During 2022–23, ASX traded volumes fell after 4 consecutive years of growth, declining 13% from the record set in 2021–22 (Figure 3.8). During the July to September quarter 2022 there was a marked decline in ASX traded volumes, down 40% on the previous quarter. The fall in traded volumes was likely a reaction to the significant spot and contract market volatility seen in the April to June and July to September quarters and the resulting cashflow impacts on contract market participants. Several participants reported to the AER that, prompted by the increased volatility, they were reassessing their internal risk limits.

In the wake of the volatility, retailers might have been hesitant to contract, unwilling to lock in prices at high levels and generators might have been hesitant to contract because additional contracting could expose them to increased margin requirements. Margin payments serve as a security to cover any shortfall if the market participant is unable to pay at contract settlement. As contract prices rise and fall, contract holders must pay daily margin payments.

Traded volumes rebounded in the October to December quarter 2022, reaching the level seen in the same quarter the previous year. While cash flow and margining were likely still a concern, falling contract prices and less volatility in the spot market were reducing these risks. Contract prices fell coinciding with public speculation about possible government intervention following the Federal Budget in October and again following the coal and gas cap announcements in December.

The January to March and April to June quarter 2023 traded volumes remain below those seen in 2020–21 and 2021–22 (down 25% compared with last year). Both retailers and generators have reported trimming their acceptable risk limits since price records were set in June 2022, with the scale of those prices causing some to rethink their worst-case scenarios. Also, some volume has likely moved to OTC markets, which are not captured by any currently available datasets.

Figure 3.8 Traded volumes in electricity futures contracts

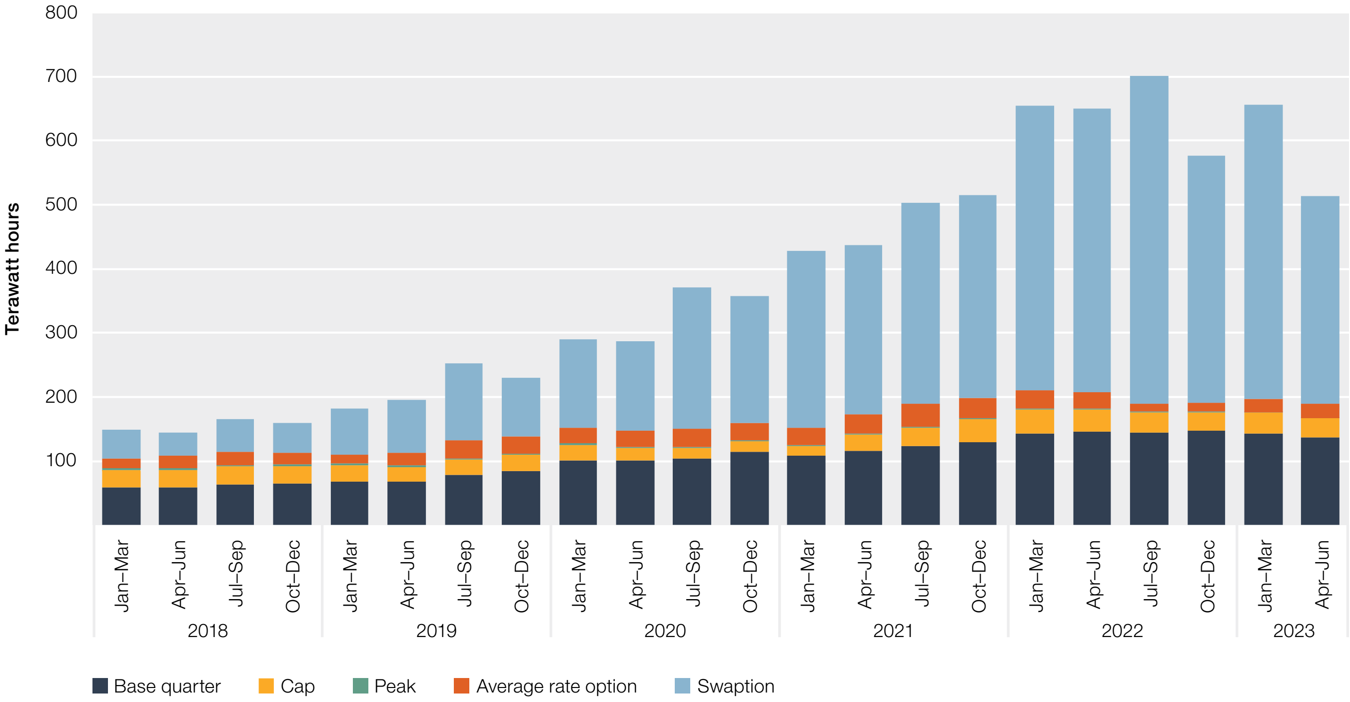


Note: Exchange trades are publicly reported, while activity in over-the-counter (OTC) markets is confidential and disclosed publicly only via voluntary participant surveys in aggregated form. The OTC data are published on a financial year basis. To allow some comparability across OTC and exchange traded data, this section refers to financial years for both markets. Data for 2021–22 and 2022–23 trading of OTC contracts were not available at the time of publication. The OTC liquidity ratio forecast is the liquidity ratio comparing the total traded volumes to the native demand across the 4 combined regions.

Source: AER; AFMA; ASX Energy (data).

Open interest volumes have fallen from the record high in the July to September quarter 2022 (Figure 3.9). In the previous 3 years, the total open interest volume for electricity futures and options had quadrupled. The majority of the growth has come from an increase in swaptions trading. Falling open interest indicates that, as contracts are closing, less new contracts are being opened in their place, perhaps as a reflection of less willingness to hold large open positions in the context of significant market volatility.

Figure 3.9 ASX open interest volumes



Source: AER; ASX Energy (data).

The decline in trading of ASX contracts in the 2022–23 financial year may also be due to 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. 'Firming' this generation with energy storage or gas-powered plant could help support contract market participation. Several market participants with flexible generation capacity offer firming products targeted at renewable generation.

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.[2] The platform aims to fill a gap in risk management products and overcome a market barrier for clean energy technologies. New hedging products introduced by Renewable Energy Hub include:

- '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 – trades in the contract have thus far been subdued
- 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. The first ever trade deal for stored energy was brokered for the 2021–22 financial year.

3.5.2 Contract market liquidity

Contract liquidity fell in 2022–23 after improving for several years. The liquidity ratio (contract trading relative to underlying demand) across the NEM fell from around 690% to 600% in 2022–23 (Figure 3.8), with all regions but Victoria recording a decrease. This figure is line with 2020–21 levels but does not capture energy traded through over-the-counter contracts (as AFMA has ceased publication of their OTC market survey).

The decline in liquidity in 2022–23 was the result of market conditions, including high contract prices, trading limits and margining requirements. Margining requirements are cash transfers required by participants to a hedging contract that cover against the risk of financial loss on a contract in response to adverse contract movements. Margining may have placed financial pressure on generators, reducing their ability to continue to offer contracts for sale. Retailers may also be cash constrained relative to their ongoing financial obligations.

2 ARENA, Renewable Energy Hub Contract Performance, Australian Renewable Energy Agency, accessed 15 August 2023.

Total contract volumes across the ASX 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's liquidity ratio has fallen in the past 5 financial years consecutively, reaching just 17% of underlying demand in 2022–23. The region's high proportion of renewable generation and relatively concentrated ownership of dispatchable generation has likely contributed to this weaker liquidity.

3.5.3 Composition of trade

Traded volumes fell in all regions except for Victoria in 2022–23 compared with the previous year. Traded volumes in Queensland, NSW and Victoria accounted for 40%, 33% and 26% of ASX volume, respectively. Trading in South Australia accounted for less than 0.2% of contract volumes despite the region accounting for around 7% of mainland NEM demand.

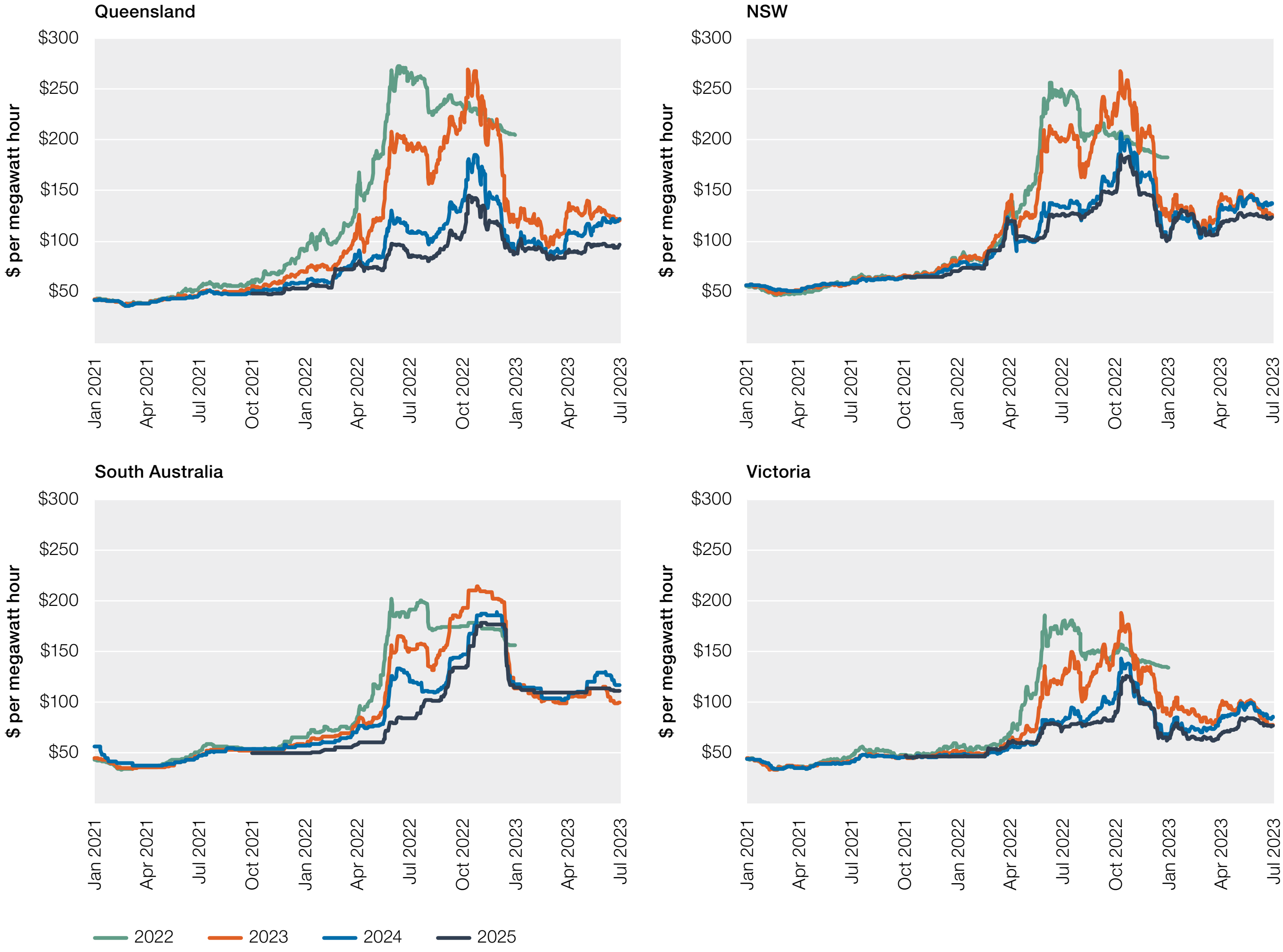
For 2022–23, swaptions (48%) were the most traded products on the ASX. The next most traded products were quarterly base futures, accounting for 39% of the traded volume. Average rate options (3%) and caps (4%) are traded at lower rates. Peak products continue to decline in popularity, accounting for only 0.01% of total volume.

3.5.4 Contract prices

Calendar year base futures prices on the ASX started the 2022–23 financial year at record highs, increasing steadily from July to October. Prices peaked in October, reaching as high as $269 per MWh in Queensland. Prices fell considerably in December 2022 and have remained stable since then. The December decrease coincided with the announcement of interventions in coal and gas markets. At 30 June 2023, calendar year prices for 2023 ranged from $77 per MWh in Victoria to $126 per MWh in NSW. This represents a decrease of more than 40% in all regions since the same time last year, though prices remain elevated compared with historical levels.

These decreases reflected stabilisation of wholesale electricity spot prices. Given most of the value shed by contract prices occurred as interventions into coal and gas markets were announced, the AER considers their announcement likely to have reduced future price expectations.

Figure 3.10 Prices for calendar year base futures

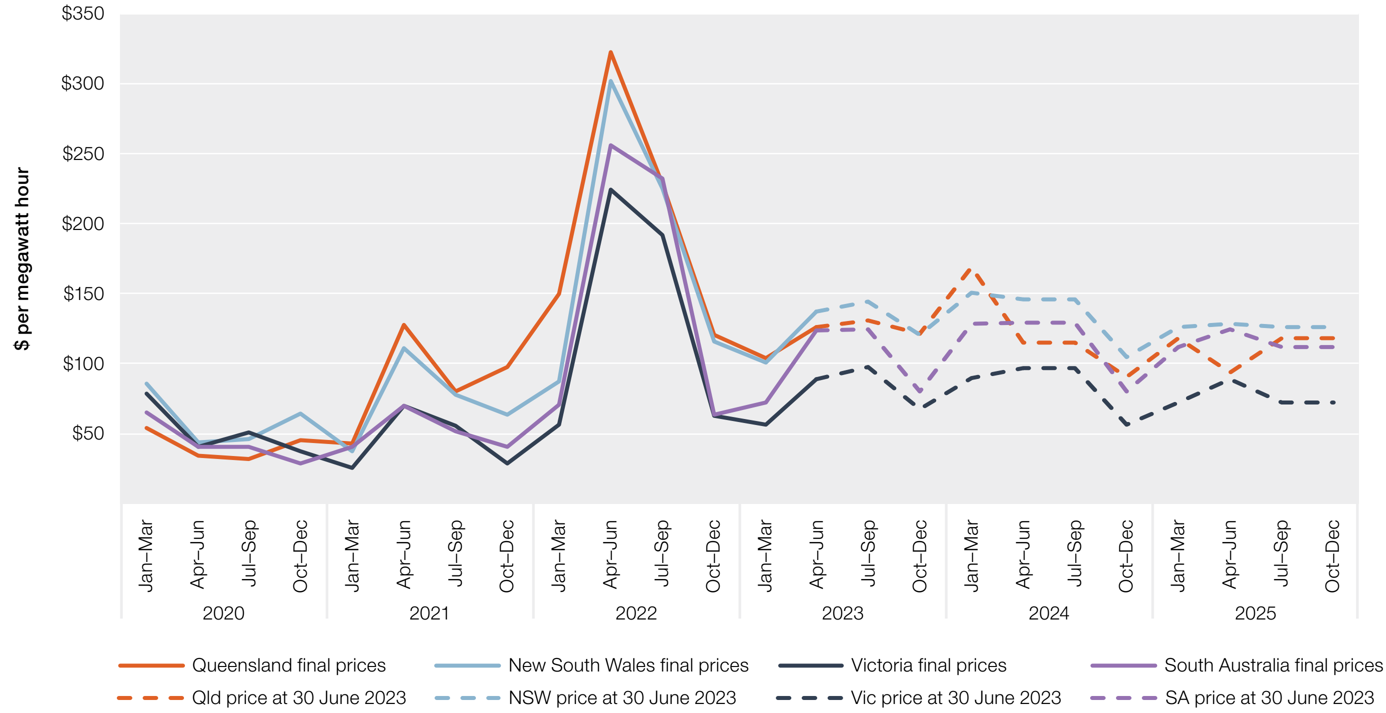


Source: AER; ASX Energy (data).

The outlook for prices in 2024 and 2025 also decreased, falling with the announcement of market interventions and stabilising through to the end of the 2022–23 financial year. Despite the fall, base futures prices for 2024 ended 2022–23 above $100 per MWh in all regions except for Victoria. Prices are seen falling further in 2025, though on 30 June 2023 were still above $100 per MWh in all regions except Victoria. The outlook indicates that, while future years are expected to be lower priced than 2022, they are also expected to remain elevated compared with historical levels.

Quarterly base futures are stable through the remainder of 2023, peaking in the January to March quarter 2024 for most regions, before falling into 2025 (Figure 3.11).

Figure 3.11 Prices for quarterly base futures



Note: Prices for quarterly base future up to and including the April to June quarter 2023 are finalised (as they are no longer traded). Prices for quarterly base futures for the July to September quarter 2023 and beyond (which are still being traded) are as of 30 June 2023.

Source: AER; ASX Energy.

3.5.5 Access to contract markets

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

In the ASX market, the cash requirements of clearers through initial and daily margining of contract positions imposes 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 costly to set up. Further, the retailer must establish a separate agreement with each party with whom it contracts, resulting in further costs.

Additionally, lack of access to clearing services is preventing some participants from engaging in contracting. The role of a clearing house is to impose margin requirements on relevant counterparties within a contract arrangement. In late 2022 the number of clearing service providers for electricity contracts on the ASX fell from 6 to 5, with Bell Potter having withdrawn its services. Some affected participants have reported to the AER that they have not been able to secure a new clearer despite contacting all listed service providers. Macquarie also restricted access to its clearing services to existing clients only. A small pool of clearing service providers is proving a significant barrier to entering the contract market for some participants.

The Retailer Reliability Obligation (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. The AEMC will publish a review of operational aspects of the RRO in early 2024.[3]

3 AEMC, Review of the Retailer Reliability Obligation, Australian Energy Market Commission, March 2023.

3.6 Electricity demand and consumption

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.

'Grid demand' is demand for electricity produced by generators, sold through the wholesale market. 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.

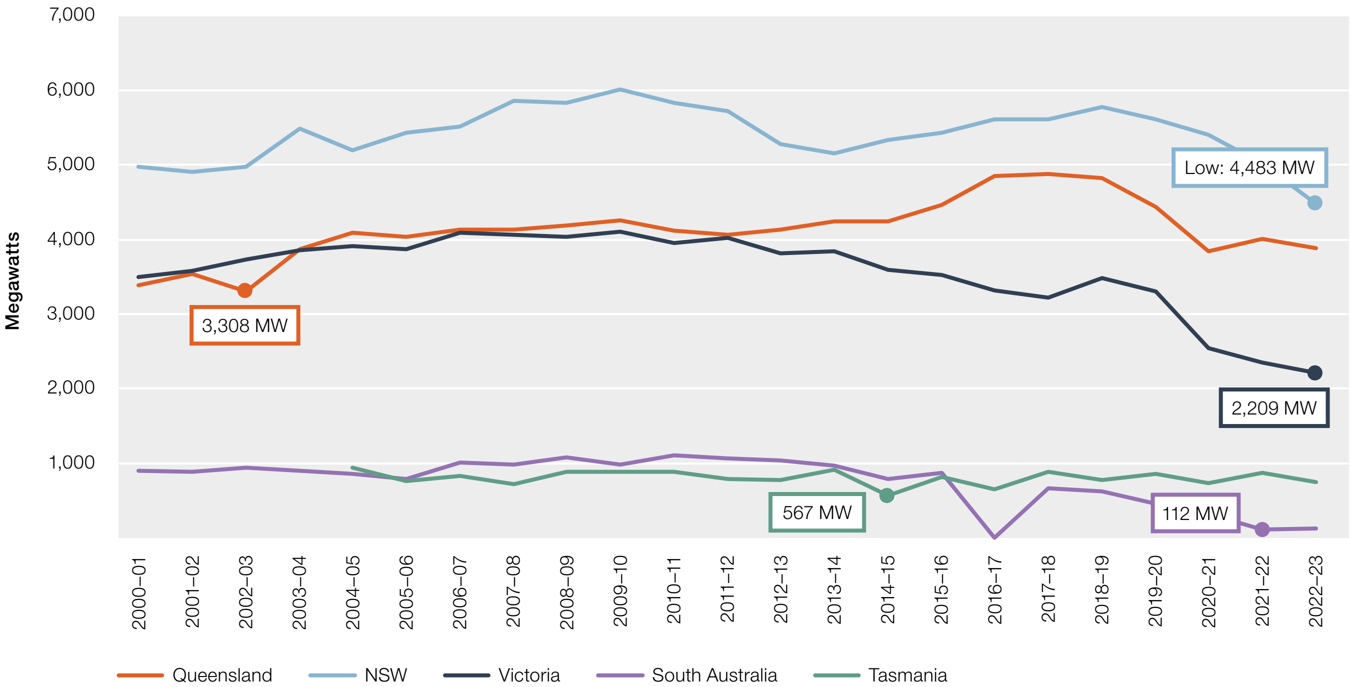
Grid demand has been falling for the past 6 years due to the increasing number of electricity customers generating their own electricity using rooftop solar (section 3.8.1). However, consumption has fallen only slightly in the past 3 years, after rising steadily for 5 years. The increase in consumption was largely driven by the expansion of Queensland's coal seam gas (CSG) and LNG industries and air conditioning, while the fall over the past 3 years was mostly due to milder weather reducing the need for air conditioning.

3.6.1 Minimum grid demand

Output from rooftop solar continued to increase in line with ongoing installations by households, further reducing grid demand during the middle of the day across the NEM. Consecutive rooftop solar output records were set over summer 2022–23, the first in the October to December quarter 2022 and the most recent on 11 February 2023, when rooftop solar reached a record 11,504 MWh. This trend continues to substantially offset daytime demand.

In 2022–23, minimum demand fell in all regions except South Australia (Figure 3.12). Minimum demand in NSW and Victoria set new record lows, while all regions recorded minimum demand below their 5-year average.

Figure 3.12 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. The low value for South Australia in 2016–17 is due to the Black System Event in October of that year.

Source: AER; AEMO (data).

AEMO has noted that minimum demand is forecast to fall low enough to pose a risk to system security in coming years.[4] As rooftop solar output rises demand is forecast to fall, with grid generators responding by withdrawing supply. The challenge is that these generators offer multiple essential system services, including voltage management, frequency control and inertia. Without these, the grid may be unable to operate safely.

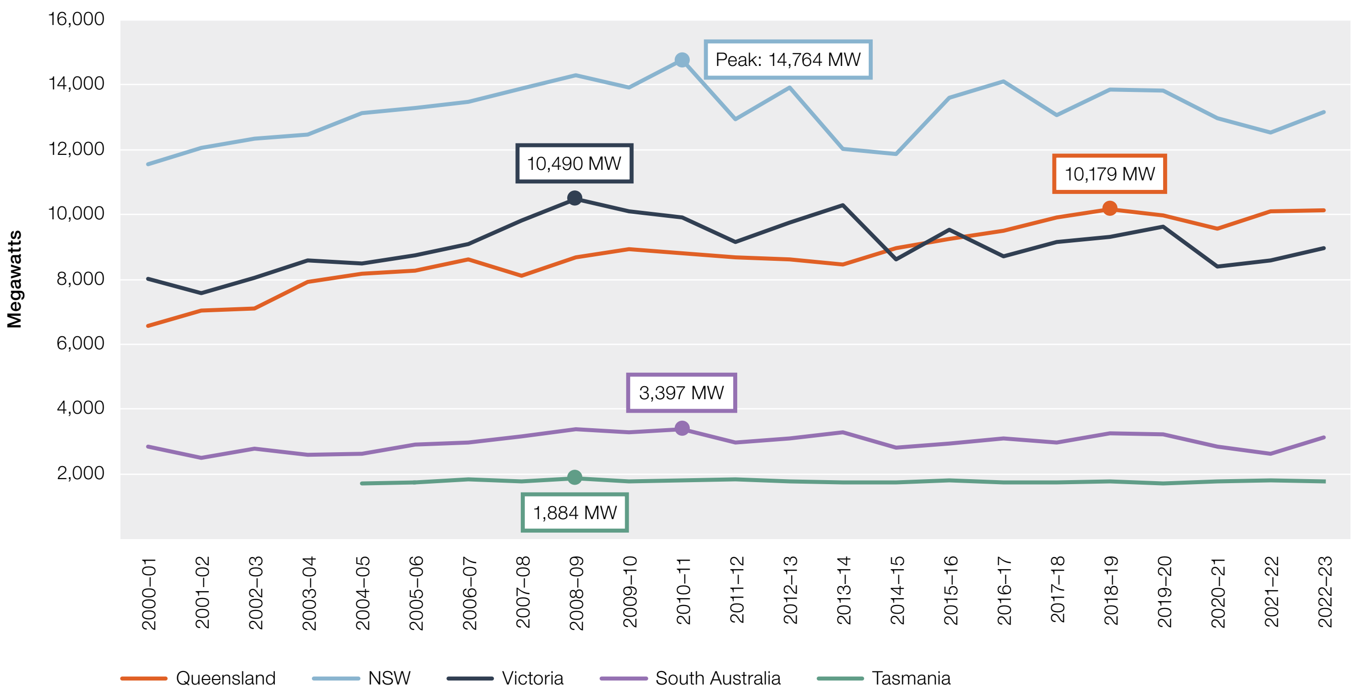
Several mechanisms have been developed to respond to demand low enough to threaten system security. AEMO has announced that, in such events, it will intervene to maintain system security through directing generators and loads, and directing network service providers to return lines to service.[5] The South Australian and Queensland governments have also implemented rooftop solar management programs, whereby AEMO may prevent some rooftop systems from generating during a 'minimum system load event' to minimise risk of blackouts.

3.6.2 Maximum grid demand

Maximum grid demand rose in all mainland regions except for Tasmania in 2022–23 (Figure 3.13). High demand usually occurs when temperatures are hot enough to prompt widespread use of air conditioning, particularly after the sun has set and rooftop solar no longer offsets demand. For all mainland regions the interval with the highest demand for the financial year occurred during the January to March quarter, between 5:30 pm and 7:00 pm. In all cases, the daily maximum temperature was above 35 degrees Celsius in the respective region's capital city.

Looking forward, AEMO's ESOO 2023 central planning scenario sees maximum demand increasing over the next 10 years.[6] High demand events pose significant risk of high wholesale prices should available generation be insufficient to respond.

Figure 3.13 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).

4 AEMO, Factsheet: Minimum operational demand, Australian Energy Market Operator, November 2022.

5 AEMO, Factsheet: Minimum operational demand, Australian Energy Market Operator, November 2022.

6 AEMO, National Electricity and Gas Forecasting, Australian Energy Market Operator, accessed 27 July 2023.

3.7 Generation in the NEM

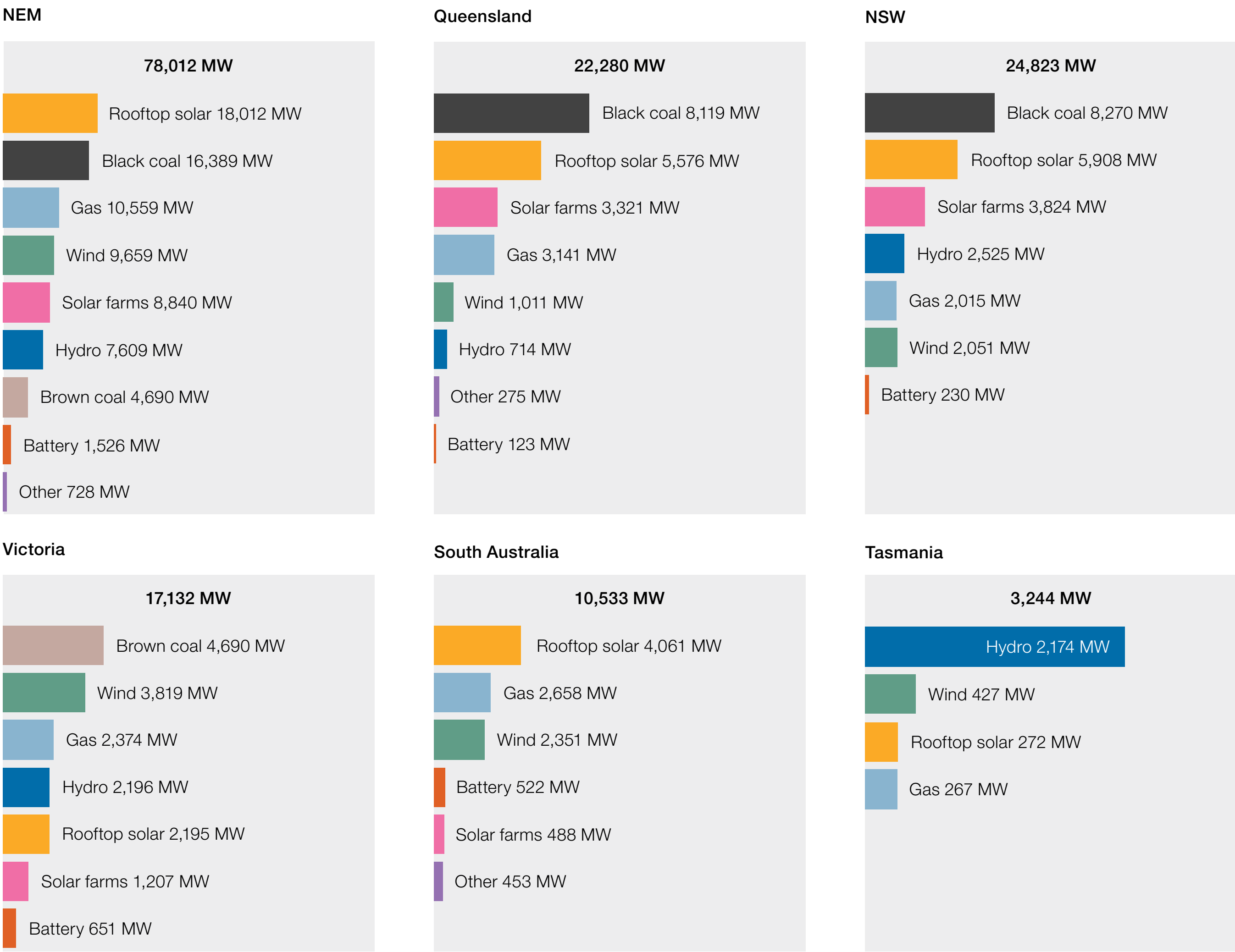
The NEM's generation fleet uses a mix of technologies to produce electricity (Figure 3.14). There are 2 ways to measure the NEM's generation mix – based on the registered capacity of each generating unit or based on their total output.

Registered capacity refers to the highest amount of electricity a generator has been registered to produce per hour. A typical generator will produce electricity at a rate lower than its registered capacity most of the time.

A fuel type's relative share of total generation capacity depends on whether rooftop solar is considered part of the generation mix. Since the last report, rooftop solar has replaced black coal as having the most installed capacity in the NEM.

While the energy produced by household rooftop solar systems reduces grid demand, this reduction is the result of localised electricity generation. To reflect this, the analysis below includes rooftop solar as generation. By the end of the 2022–23 financial year, rooftop solar was responsible for 23% of generation capacity compared with black coal's 21%. This change has been driven by the continual uptake of rooftop solar and the exit of the Liddell power station's remaining 3 black coal units. On a registered basis, fossil fuels (black and brown coal and gas) make up just over 40% of the generation mix.

Figure 3.14 Generation capacity, by fuel source



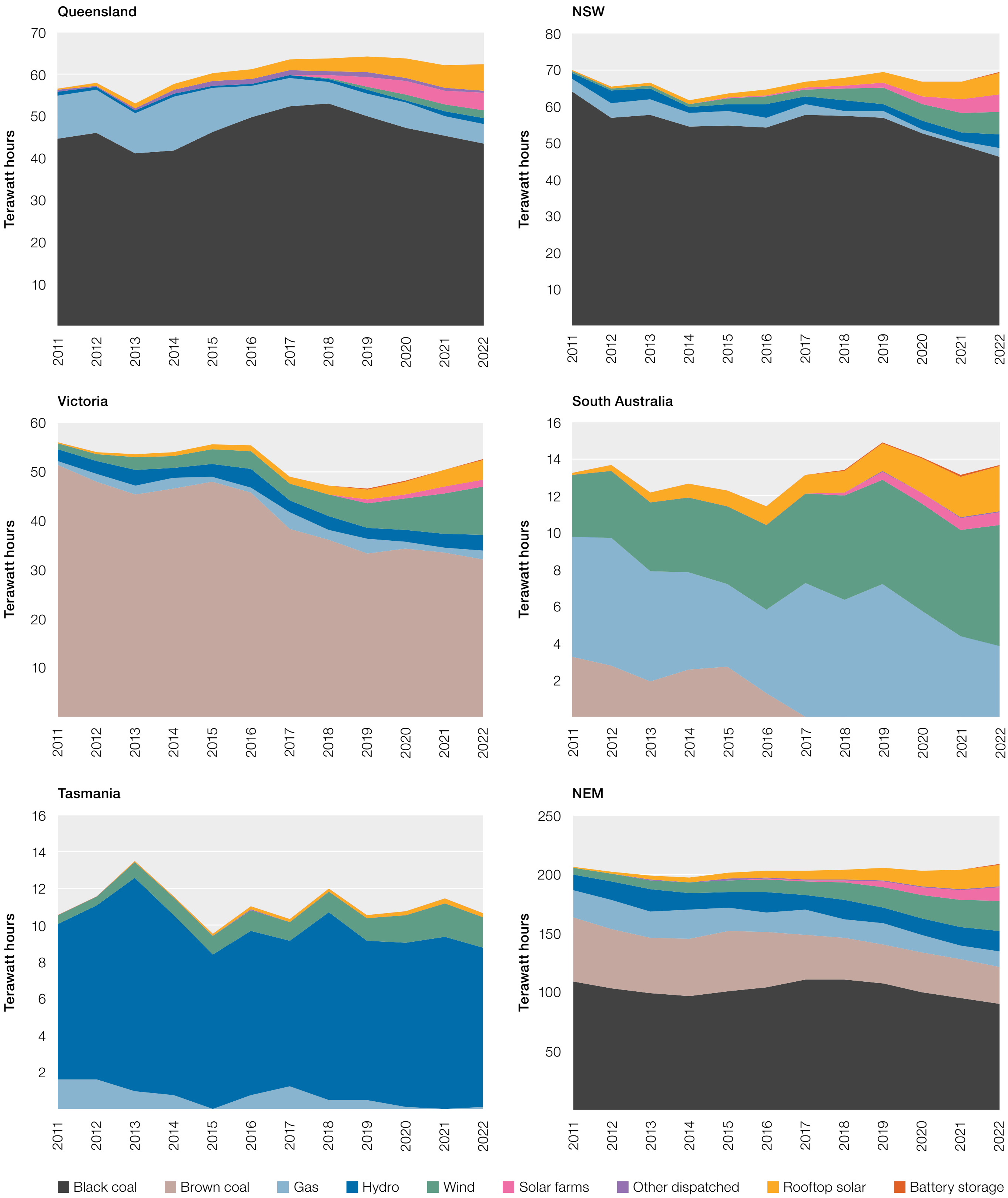
Note: Generation capacity at 30 June 2023. Other dispatch includes biomass, waste gas, diesel and liquid fuels. Loads and non-scheduled generation have been excluded. Solar capacity is maximum capacity, rather than registered capacity.

Source: Grid demand: AER; AEMO (data). Rooftop solar: AER; Clean Energy Regulator (data).

Generation output (Figure 3.15) refers to the total amount of electricity produced over a given period.

The proportion of thermal generation is higher measured by output, mostly because renewable generation output is intermittent, while coal tends to generate continuously throughout the day. Fossil fuel generators produced 64% of electricity in the NEM in 2022, 4% less than in 2021. The fall corresponded with an increase in wind and solar output, which accounted for a combined 27% of total generation, having more than doubled since 2018.

Figure 3.15 Generation output, by fuel source

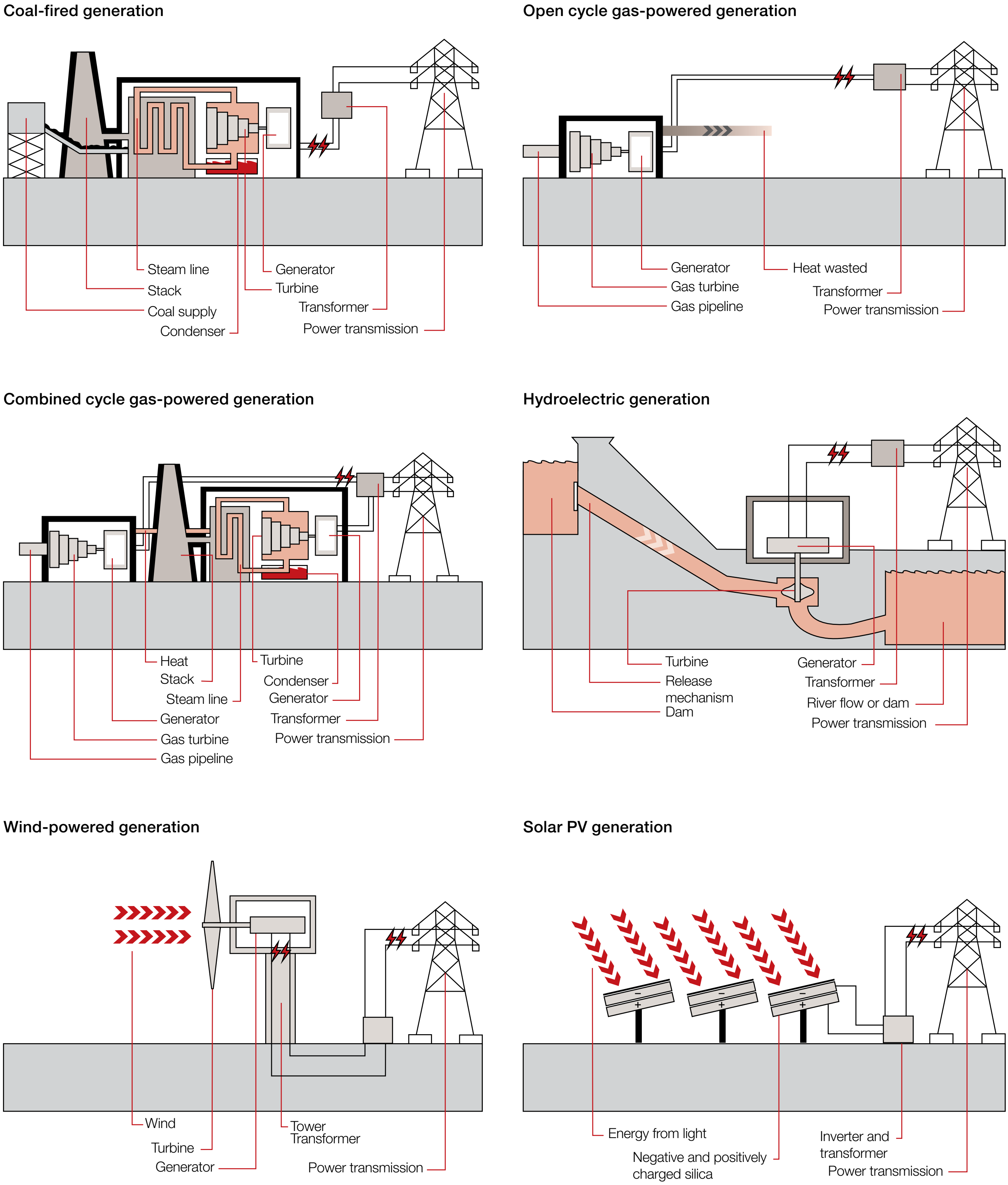


Note: Other dispatch includes biomass, waste gas, diesel and liquid fuels.

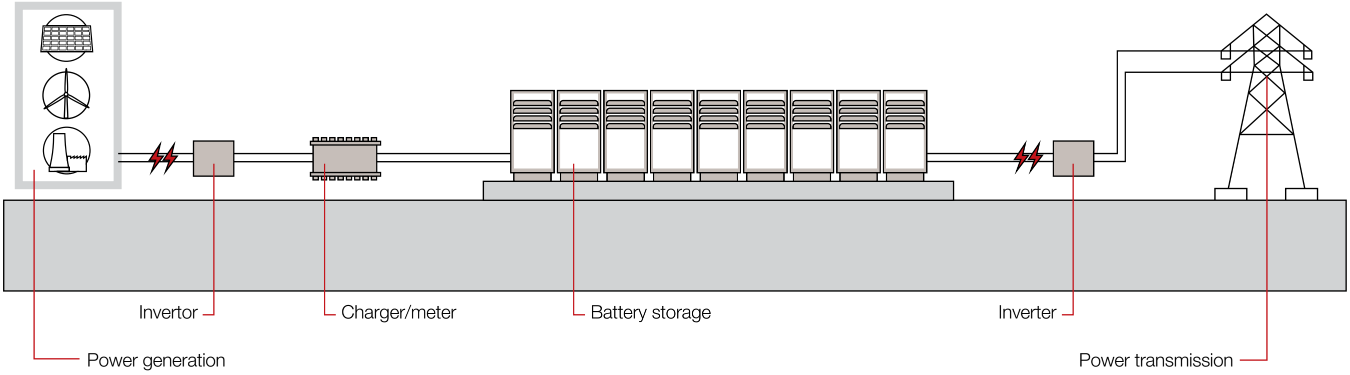
Source: AER; AEMO (data).

The various generation technologies have differing characteristics (Figure 3.16). 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 3.16 NEM generation technologies



Battery energy storage system



3.7.1 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 3.16). Coal is the only fuel type in the NEM that tends to generate at all hours of the day. Coal-fired generation remains the dominant supply technology in the NEM, producing just under 60% of all electricity traded through the market in 2022.

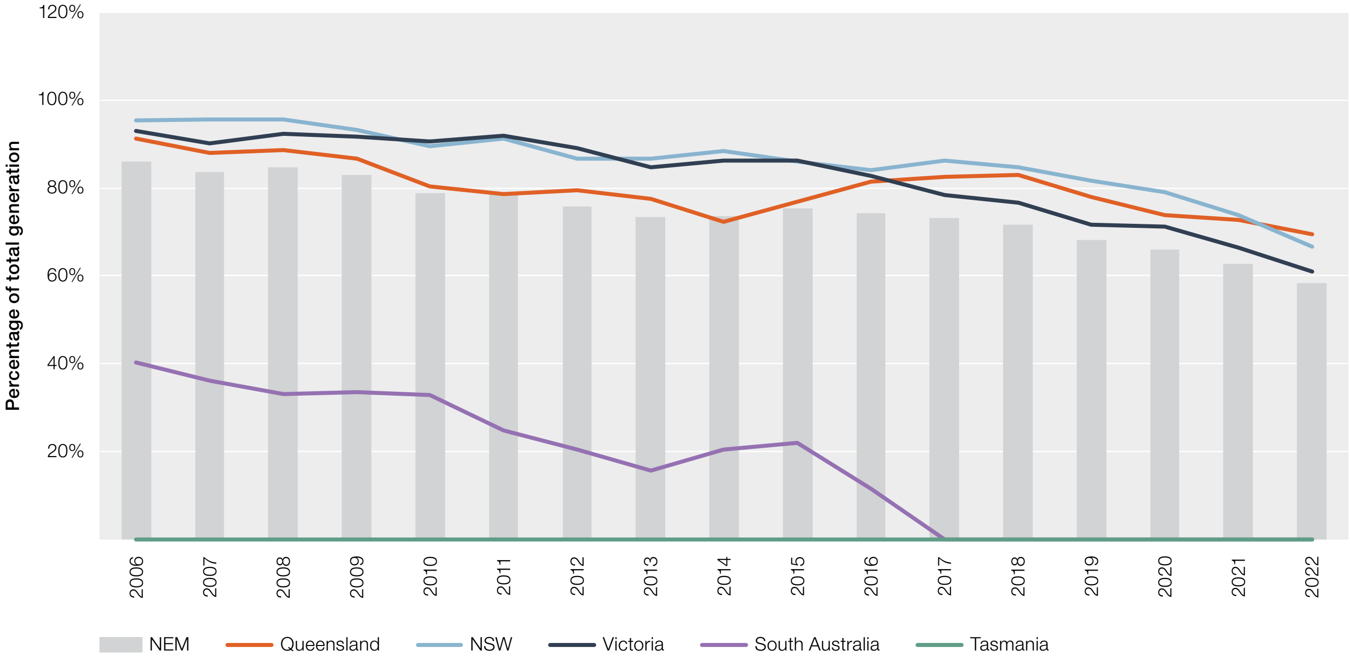
Coal plants operate in Queensland, NSW and Victoria. Generators in Queensland and NSW burn black coal and generators in Victoria depend on brown coal. Black coal produces more energy than brown coal because it has lower water content and produces 30–40% lower greenhouse gas emissions when used to generate electricity. 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.

Impact of solar on coal-fired generation

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. As a result, coal-fired generation makes up a declining but still large proportion of total NEM generation (Figure 3.17).

Figure 3.17 Proportion of total generation by region, coal



Note: The share of regional output produced by coal generators. South Australia and Victoria output is from brown coal generators while all other regions are from black coal generators.

Source: AER; AEMO (data).

These changing conditions, backed by global investors and a local push to decarbonise, are compromising the economic viability of the NEM's 16 remaining coal-fired power stations. As energy companies that depended on fossil fuel pivot toward renewable energy, many of these coal-fired power stations are expected to close earlier than previously announced.

NSW's Liddell power station closed in April of this year and 3 more coal-fired power stations are currently due to close by 2030.

The next coal station scheduled to close is Eraring – Australia's largest power station. It was initially due to close in 2032 but its owner, Origin Energy, has brought the closure date forward to 2025. A NSW government review has recommended Eraring's closure be delayed beyond 2025, with the government committing to 'engage with Origin Energy' on a later closure date.[7] In 2021 EnergyAustralia announced that it will retire Victoria's Yallourn power station in 2028, 4 years earlier than planned. CS energy's Callide B power station is also expected to close that year. Delta Energy's Vales Point B power station was expected to close the following year in 2029 but has been pushed back to 2033. Early in 2022, AGL announced the accelerated closure of its remaining coal-fired power stations of Bayswater (2030–2033) and Loy Yang A (2035).

While around 5 GW of the current 21 GW of coal-fired capacity has already been announced to withdraw by 2030, AEMO's most recent integrated system plan[8] suggests this number will be closer to 13 GW. That is, it estimates about 58% of current coal-fired capacity will withdraw by 2030.

While the exit of coal generation is necessary to meet emissions reduction targets and inevitable due to its declining financial viability, disorderly exit poses risks to both reliability and wholesale prices. AEMO has forecast reliability gaps in periods of low renewables output should the rate of investment in firm capacity (that which is dispatchable on command) fail to increase significantly.[9] The first of these reliability gaps is forecast in summer 2023–24 and will increase in frequency thereafter.

7 Marsden Jacob Associates, NSW Electricity Supply and Reliability Check Up, August 2023.

8 AEMO, Integrated System Plan, Australian Energy Market Operator, June 2022.

9 AEMO, Update to 2022 Electricity Statement of Opportunities, Australian Energy Market Operator, February 2023.

Coal outages fell in 2022–23 but remain a risk

Coal generators break down more frequently as they age – the NEM's aging fleet of coal generators is particularly prone to outage as stations near the end of their lives. Winter quarters are emerging as the periods during which coal outages pose the greatest risk to wholesale prices and reliability, due to seasonally lower renewables output.
The April to June quarter usually sees planned maintenance of coal plant as operators prepare stations for peaking winter demand.

Outages of coal plant, particularly unplanned outages, were a significant contributing factor to the record high prices of the April to June quarter 2022, which saw the spot market suspended for the first time in the NEM's history. In the April to June quarter 2022, coal outages in the NEM reached nearly 8 GW compared with historical averages of 3 to 4 GW. This saw a large portion of electricity demand shifted to more expensive gas generators, which were not prepared or appropriately contracted for the additional workload. Outages were again higher than the historical average in the April to June quarter 2023 but remained lower than during the same time the previous year.

With the NEM's coal fleet growing increasingly prone to outage as it ages, the seasonal trough in renewables output in the middle of the year will continue to be a period of high risk for electricity markets in coming years.

3.7.2 Gas-powered generation

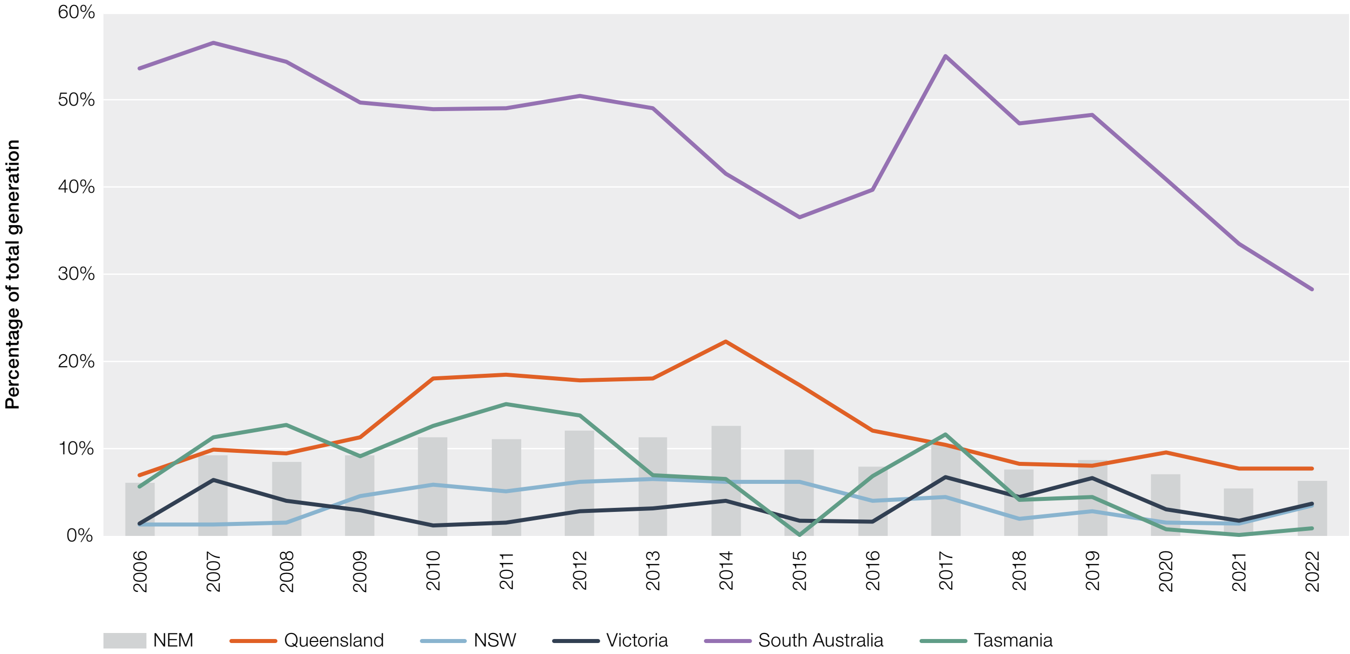
Two dominant types of gas generation technologies operate in the NEM (Figure 3.16). Open cycle gas turbine (OCGT) plants burn gas to heat compressed air that is then released into a turbine to drive a generator. In combined cycle gas turbine (CCGT) plants, waste heat from the exhaust of the first turbine is used to boil water and create steam to drive a second turbine. 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 responsive than coal to prices since the start of 5 minute settlement in October 2021.

The ability of gas plants to respond quickly to sudden changes in the market makes them 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.

Despite these benefits, gas is generally the most expensive fuel for electricity generation, so gas generators more typically operate as 'flexible' or 'peaking' plant, preferring to be dispatched only when wholesale prices are high. Across the NEM, gas-powered plants supplied only 6% of electricity generated in 2022. South Australia relies more on gas-powered generation than other regions. In 2022, the state produced 28% of its local generation from gas plants (Figure 3.18).

Figure 3.18 Proportion of total generation by region, 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.

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 integrated system plan[10] calls for 10 GW of gas-powered generation, or a doubling of current capacity, by 2050 to help firm renewable energy.

There are currently 2 significant proposals for new gas plant in NSW, totalling almost 1,000 MW. The construction of EnergyAustralia's Tallawarra B gas power station (320 MW) is due for completion in the summer of 2023–24. It will be based in the Illawarra, capable of using a blend of hydrogen and natural gas. Snowy Hydro plans to construct a 660 MW open-cycle gas-powered power station at Kurri Kurri in the Hunter Valley. Kurri Kurri is expected to be completed in December 2024 and, as a gas peaking plant, is only expected to operate around 2% of the time.

3.7.3 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 3.16). Like 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.

10 AEMO, 2022 Integrated System Plan, Australian Energy Market Operator, June 2022.

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. When it was announced in 2017, Snowy 2.0's estimated completion date was 2021. Since the last report, Snowy Hydro has pushed back the completion date from 2026 to 2029.[11]

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)[12] scheme also affect incentives to produce.

Hydroelectric generation can also be constrained by environmental factors. In NSW in 2022, 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 due to concerns resulting from heavy rains. These included high water levels in the release reservoir, Blowering Dam, and the limited release capacity of the Tumut River.[13]

Hydroelectric generators account for 10% of capacity in the NEM in 2022 and supplied 8% of electricity generated. Tasmania is the region most reliant on hydroelectric generation, with 81% of its 2022 generation coming from that source. NSW and Victoria also have significant hydroelectric generation plants located in the Snowy Mountains region.

3.7.4 Wind generation

Wind turbines convert the kinetic energy of wind into electricity. Wind turns blades that spin a shaft connected (directly or indirectly via a gearbox) to a generator that creates electricity (Figure 3.16).

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.

As is typical of renewables in a time of rapidly increasing investment, wind has broken several of its own output records since the last *State of the energy market* report. On 17 September 2022 wind set a new daily output record of 149.1 GWh. On the same day it achieved its largest ever share of daily generation, accounting for just over 30% of the electricity produced in the NEM that day. On 25 June 2023, wind generation set another record, reaching 158.7 GWh of total daily output. In 2022, wind accounted for 12% of all electricity produced in the NEM, almost double that of gas generation.

600 MW of wind generation was added to the NEM in 2022–23. Since June 2019, almost 5 GW has been added. Wind penetration is especially strong in South Australia, where it provided 48% of the state's electricity output in 2022.

3.7.5 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. All solar investment to date has been in photovoltaic systems, which use layers of semi-conducting material to convert sunlight into electricity (Figure 3.16).

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. By 2022, solar farms made up 11% of capacity and 5% of output. In 2022–23, 9 solar farms, over 1 GW, entered the market. All but one of these new entrants are located in Queensland or NSW.

Like wind, solar constantly breaks previous output records as new capacity enters the market. It set consecutive records for total quarterly output in the October to December quarter 2022 and January to March quarter 2023. Relatedly, the January to March quarter 2023 set a seasonal record for number of negatively prices intervals while the October to December quarter 2022 set the all-time record.

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11 Snowy Hydro, Snowy 2.0 – Project Update, May 2023.

12 Clean Energy Regulator, About the Renewable Energy Target, June 2022.

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

High solar output is strongly correlated with negative prices for 2 reasons:

- it floods the NEM with cheap electricity – sunshine is free and often widespread
- if grid-scale solar is producing strong output, rooftop solar is usually doing the same, reducing demand in the process.

To fully optimise the low-priced capacity solar brings to the NEM, the market needs the infrastructure to store it so it can be dispatched during evening demand peaks when it is needed most.

3.7.6 Grid-scale storage

Stored energy can be used to support system reliability by being injected into the grid at times of high demand and can provide stability services to the grid by balancing variability in renewable generation. Storage technologies in the NEM include batteries and pumped hydroelectricity. As the firm capacity of coal generators exits the market and is replaced by intermittent 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. They typically charge when prices are low, which is often in the middle of the day, and discharge when prices are high during morning and evening demand peaks. The difference between the charge price and the dispatch price determines the battery's profit ratio per megawatt. With increasing instances of negative spot prices during the day being followed by high evening prices, batteries can often profit from both charging and dispatching.

Batteries in the NEM can also earn significant revenue from operating in frequency control markets, although this comes at the expense of their availability in the energy-only market. Analysis from 2022's *Wholesale electricity market performance report* indicated that batteries prefer to operate in electricity spot markets when prices are high, but favour frequency control markets at other times.

In 2022–23, 7 batteries (totalling about 600 MW) entered the NEM, the highest rate of entry for a single financial year so far. This brought the total number of batteries in the NEM to 16 (totalling just less than 1.5 GW). The Waratah Super Battery is due to be completed in 2025 – at 700 MW it will be the largest battery in the NEM. Increased presence of batteries saw their total output in the NEM more than double from 2021 to 2022; however, they still account for less than 0.5% of total output.

Pumped hydroelectricity

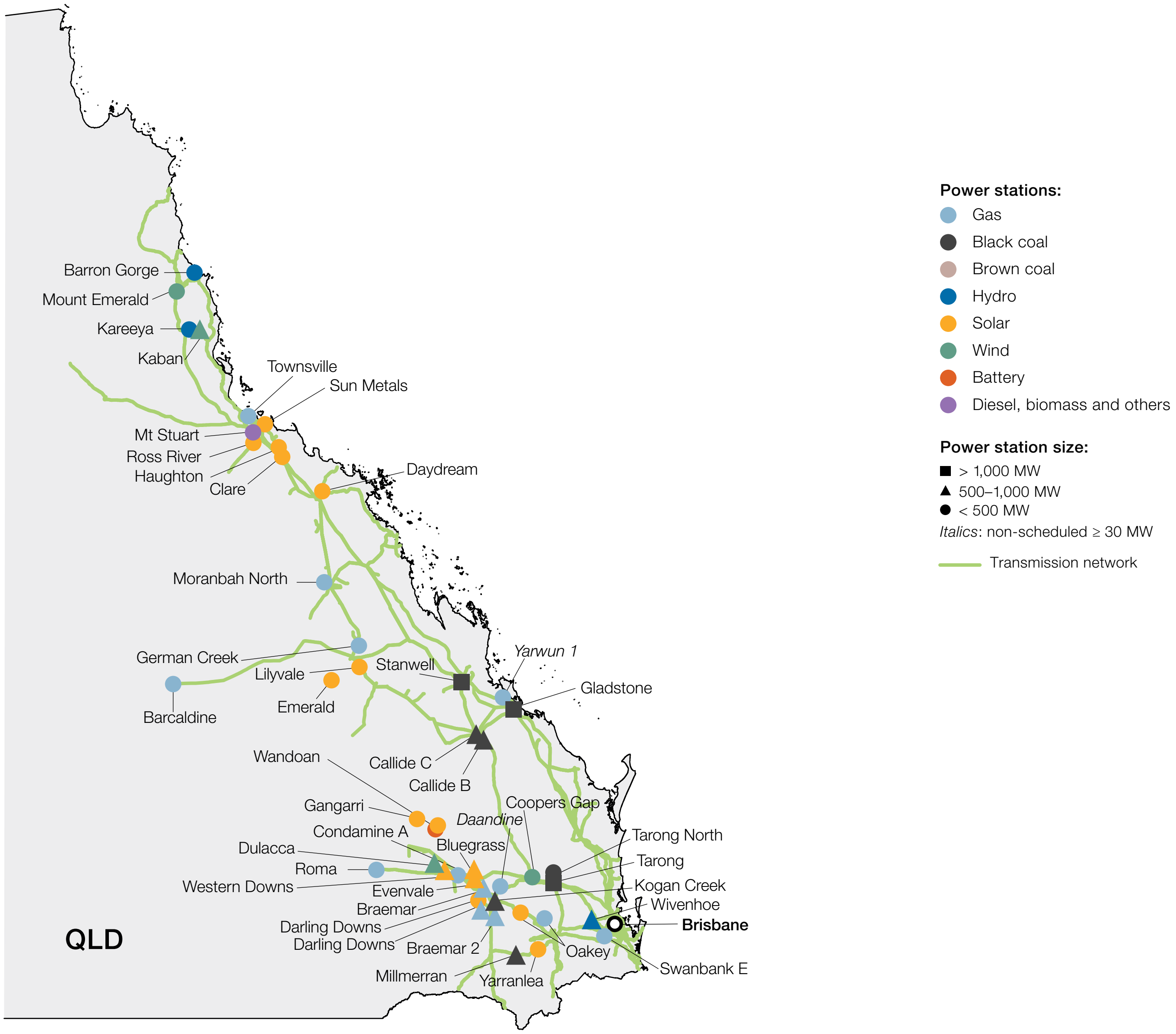
Large-scale storage can be provided through pumped hydroelectric projects, which allow hydroelectric plants to reuse their limited water reserves. The technology involves pumping water into a raised reservoir while electricity is cheap and releasing it to generate electricity when prices are high. Like batteries, a greater difference in the pump price against the dispatch price results in a higher profit margin per megawatt.

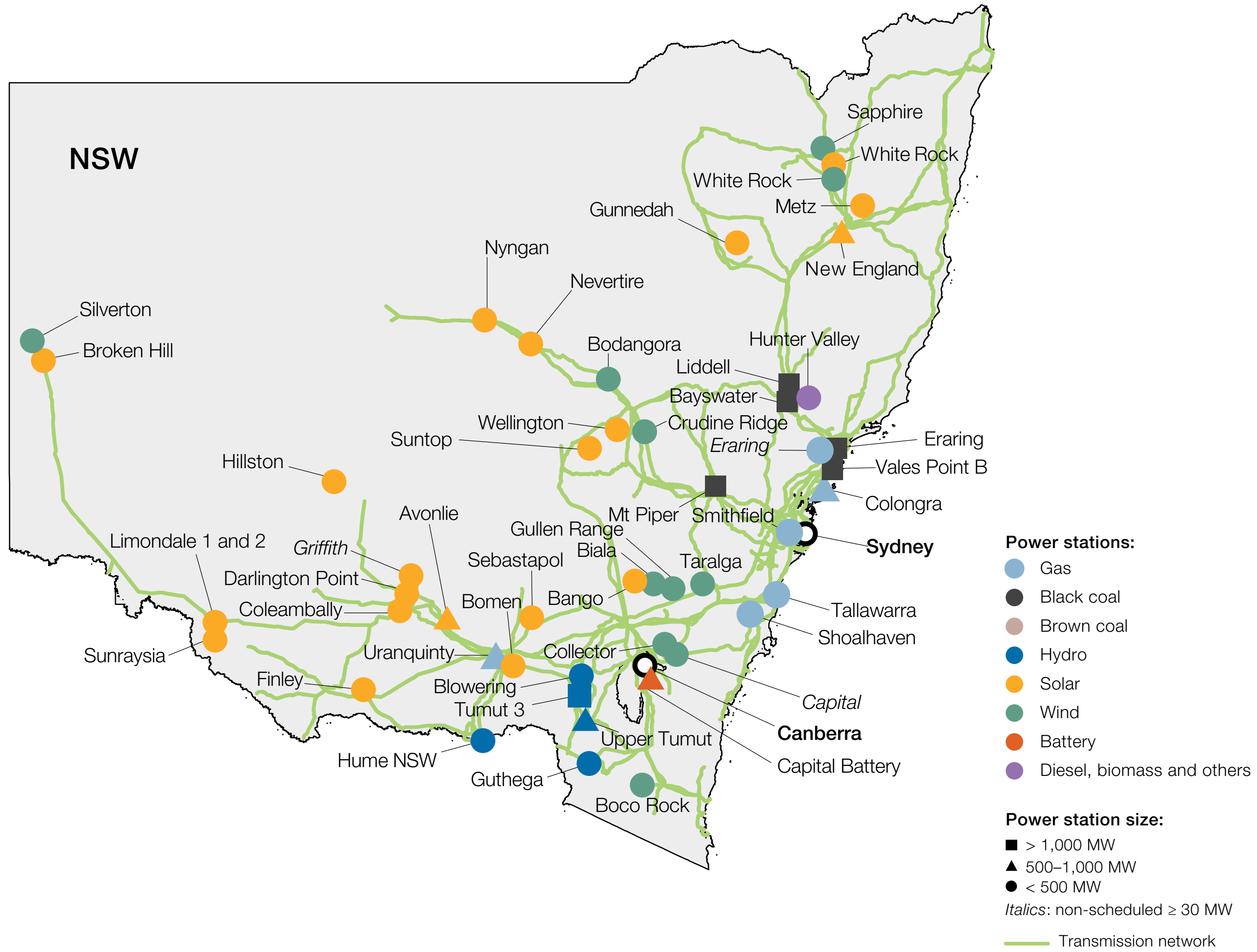
Pumped hydroelectric technology has been available in the NEM for some time, with generation in Queensland (570 MW at Wivenhoe) and NSW (240 MW at Shoalhaven and 1,500 MW at Tumut 3). Use of this technology is limited by the availability of appropriate geography. However, advances in technology and the 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 Snowy 2.0 (2,000 MW) and Battery of the Nation (2,500 MW) projects in NSW and Tasmania.

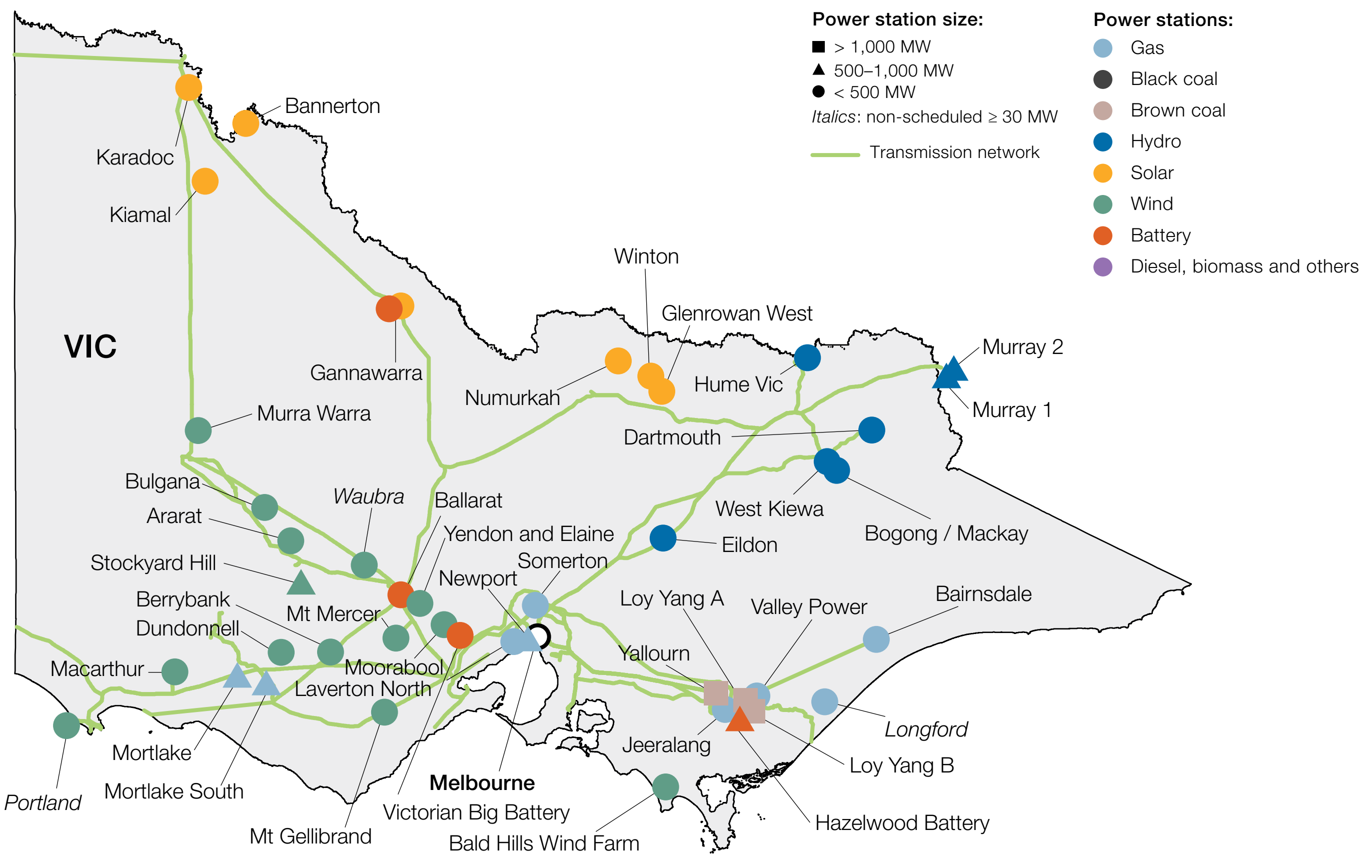
3.7.7 Generator information

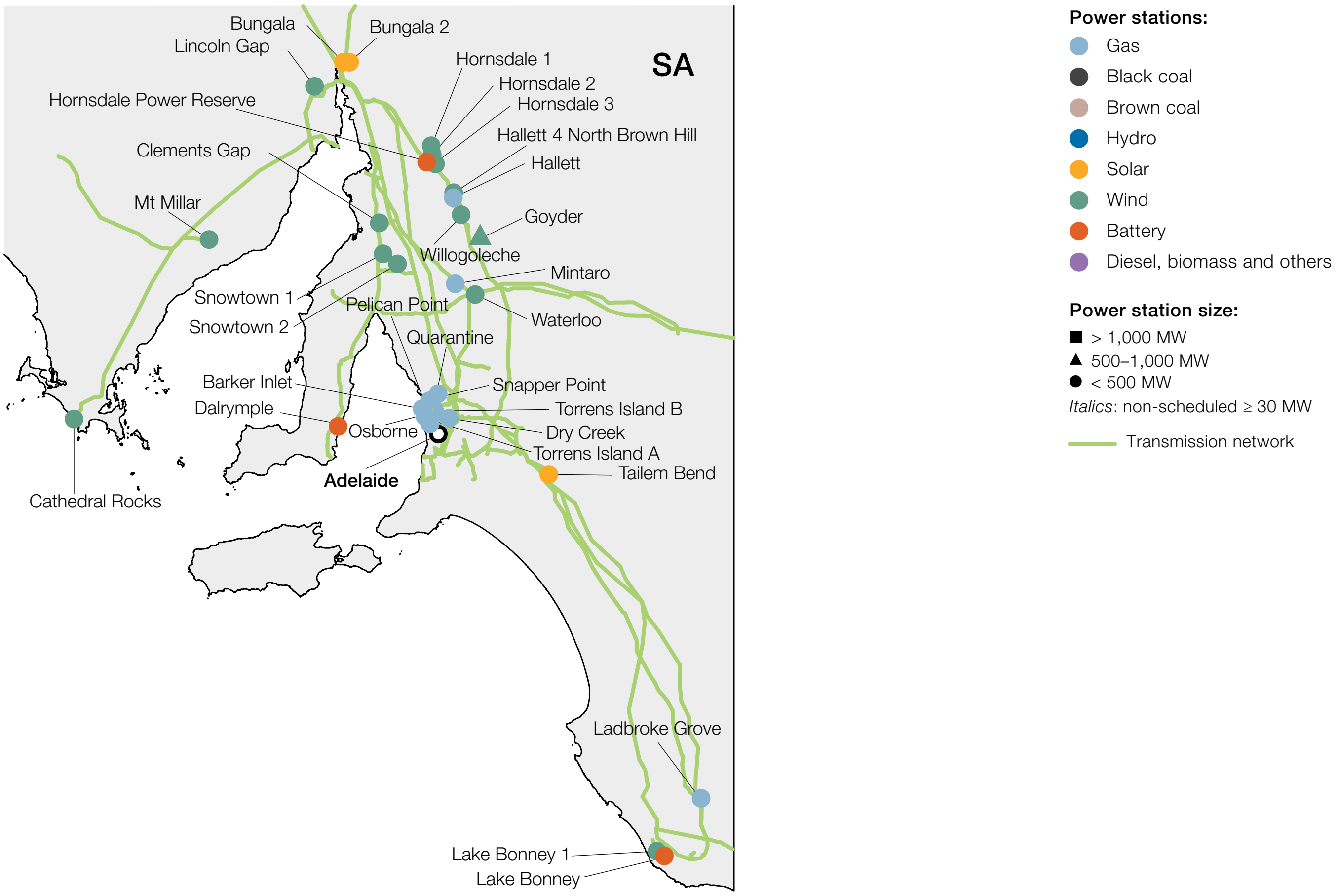
Figure 3.19 maps the locations of generation plants and the types of technology in use.

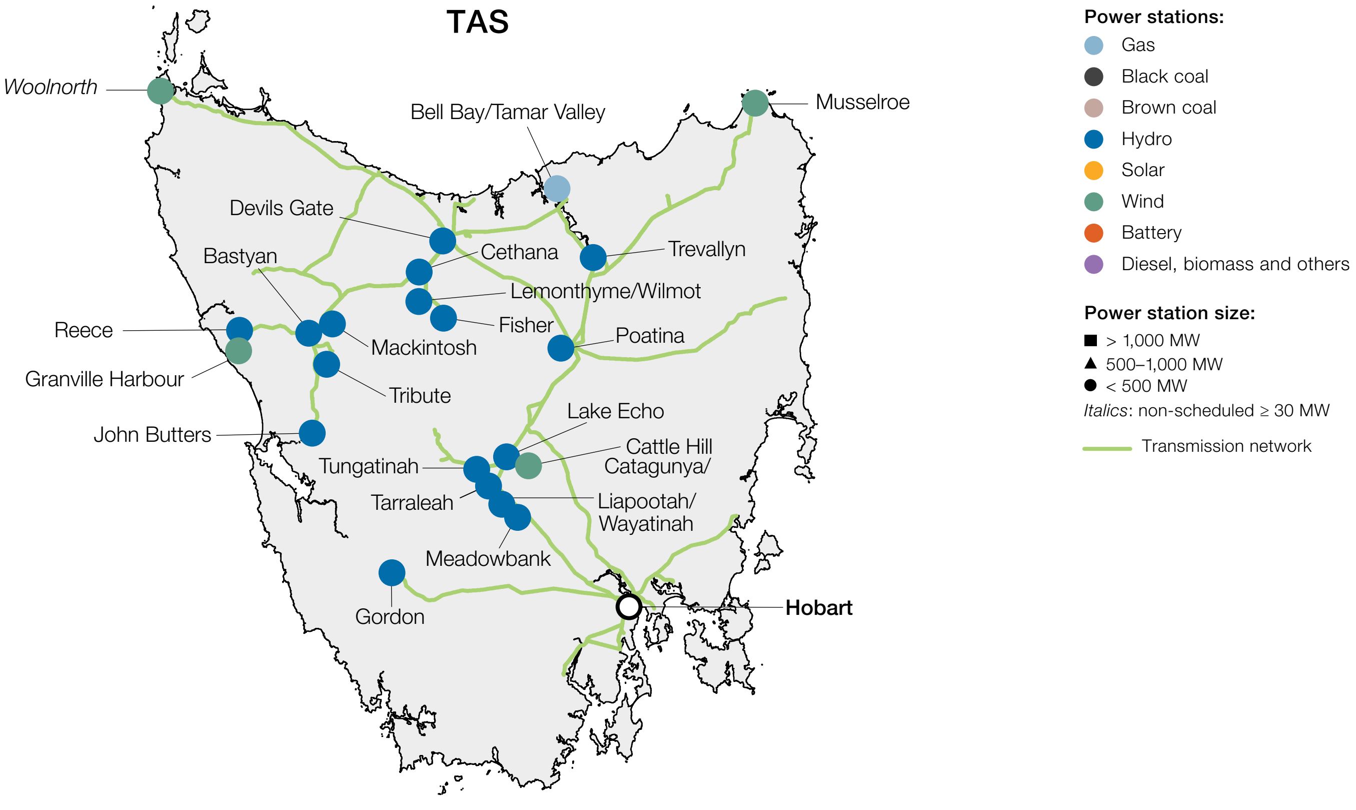
Figure 3.19 Generators in the NEM




NSW
Sapphire
White Rock
White Rock
Metz
Gunnedah
New England
Nyngan
Nevertire
Silverton
Broken Hill
Bodangora
Hunter Valley
Liddell
Bayswater
Wellington
Crudine Ridge
Suntop
Eraring
Eraring
Vales Point B
Hillston
Colongra
Mt Piper
Smithfield
Avonlie
Gullen Range
Sydney
Limondale 1 and 2
Griffith
Biala
Sebastapol
Taralga
Darlington Point
Bango
Bomen
Coleambally
Tallawarra
Shoalhaven
Sunraysia
Uranquinty
Collector
Finley
Blowering
Capital
Tumut 3
Canberra
Upper Tumut
Hume NSW
Capital Battery
Guthega
Boco Rock
Power stations:
Gas
Black coal
Brown coal
Hydro
Solar
Wind
Battery
Diesel, biomass and others
Power station size:
> 1,000 MW
500–1,000 MW
< 500 MW
Italics: non-scheduled ≥ 30 MW
Transmission network


VIC
Power station size:
> 1,000 MW
500–1,000 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
Bannerton
Karadoc
Kiamal
Winton
Glenrowan West
Gannawarra
Murray 2
Numurkah
Hume Vic
Murray 1
Murra Warra
Dartmouth
Bulgana
Waubra
Ballarat
West Kiewa
Ararat
Yendon and Elaine
Bogong / Mackay
Eildon
Stockyard Hill
Somerton
Newport
Berrybank
Mt Mercer
Loy Yang A
Valley Power
Bairnsdale
Dundonnell
Macarthur
Moorabool
Yallourn
Laverton North
Longford
Jeeralang
Mortlake
Loy Yang B
Portland
Mortlake South
Melbourne
Victorian Big Battery
Hazelwood Battery
Mt Gellibrand
Bald Hills Wind Farm





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

3.8 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 resources allow individual consumers and groups to generate or store their own electricity, as well as enabling them to actively manage their consumption. They 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.

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

3.8.1 Rooftop solar generation

Capacity generated by rooftop solar is not traded in the NEM but is instead subtracted from demand. By installing solar panels consumers may save on their electricity bills in 2 ways. The most efficient is to consume the electricity generated directly, rather than paying for supply from the grid. The second is to export the electricity back into the grid for other households to consume; however, this is subject to a feed-in tariff, which partially offsets savings for exporting consumers. Importantly, the electricity generated by solar panels is unable to be stored for later consumption, unless connected to a battery.

Australia is the largest per capita user of rooftop solar in the world. Backed by state government incentives, households and businesses have continued to install large volumes of rooftop solar capacity every year since 2015. From the beginning of 2022 to 30 June 2023, NEM households added 3.7 GW of rooftop solar capacity. As at 30 June 2023, rooftop systems in the NEM totalled over 17 GW of capacity, surpassing black coal as the largest fuel type by generation capacity (Figure 3.14). Queensland and NSW have the most installed capacity, but South Australia has the highest capacity per capita.

In 2022, output from rooftop solar across the NEM increased by 15% compared with 2021; its output has more than doubled since 2018. It accounted for 9% of total generation in 2022. At 1 pm on 11 February 2023, rooftop solar set a new record output of 11.5 GW in a half hour, fulfilling 38% of total NEM demand at the time.

Rooftop solar's rapid uptake has dramatically changed the shape of daily spot price and demand curves in the NEM. Prior to mass adoption of the technology, the middle of the day typically saw the peak of both prices and demand in summer months; the opposite is now true.

3.8.2 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 during peak times. 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 supply electricity back to the grid at times of high demand.

Small-scale battery installations in the NEM saw a rated capacity increase of 14% from 2022 to 2023, though the pace of installation has fallen for the first time since 2021.[14]

3.8.3 Controlled load

Controlled load involves the installation of a separate meter for consumption-heavy appliances, and typically incurs a lower usage tariff. Electricity distribution network service providers are happy to charge a lower usage tariff for appliances included in a controlled load package in exchange for a guarantee that those appliances will only be

14 AEMO, DER Data Dashboard, Australian Energy Market Operator, accessed 15 August 2023.

switched on at certain times of day. Controlled load tariff times vary by distribution network. Controlled load allows electricity retailers and distribution networks to predict demand more accurately and can grant savings to consumers with predictable usage patterns.

3.8.4 Virtual power plants (VPPs)

A rooftop solar system coupled with a small-scale battery installation can make a meaningful difference to a single household's energy bill, but aggregated across thousands of households these technologies can enhance system reliability and security. By connecting home batteries and those in electric vehicles to an energy sharing network, the electricity stored within them can be used to supplement supply during shortfalls. During a demand peak, when grid supply is strained, the electricity stored in consumer-owned batteries can dispatch in a coordinated response, servicing excess demand and taking pressure off grid supply. By picking up the slack during a supply shortfall, homes that participate in a VPP initiative help to mitigate high spot prices and prevent potential blackouts, and receive credits on their electricity bills for what they contribute.

3.9 Trade across regions

Transmission interconnectors (mapped and listed in chapter 4) 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 the generation plant of their neighbours. This allows for more efficient use of the generation fleet.

Typically, Queensland has surplus generation capacity, making it a net electricity exporter (Figure 3.20). Export levels fell significantly in the 2021–22 financial year due to network outages associated with the upgrade of the QNI interconnector. Exports from Queensland to NSW rebounded in 2022–23 after the upgrade was completed but remain slightly below historical levels.

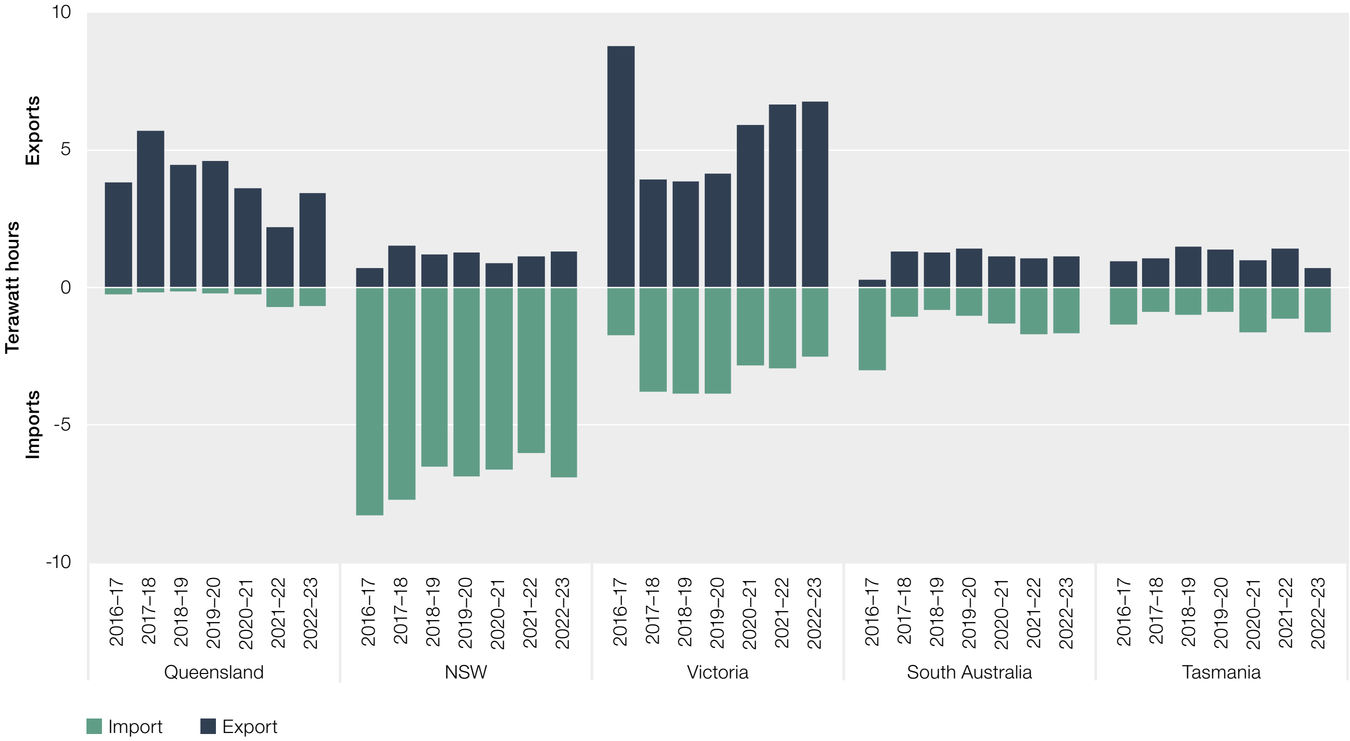
NSW has relatively high generation fuel costs, typically making it a net importer of electricity. NSW is able to import electricity from both Queensland and Victoria, so the outages during the QNI upgrade impacted NSW imports less than it did Queensland's exports. With the completion of the upgrade, NSW imports increased slightly in 2022–23.

Victoria's abundant supply of low-priced brown coal generation traditionally makes it a net exporter of electricity. Its exports increased slightly in 2022–23.

South Australia has been a net importer in some years and a net exporter in others. Its ability to import or export has been restricted by ongoing outages on the Heywood interconnector. In 2022–23, exports from South Australia fell while imports rose; as such, the region remained a net importer.

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). Tasmania has historically switched between net importer and exporter. In 2021–22 it switched from net import to exporter but this trend was reversed in 2022–23 as exports fell and imports rose, causing the region to revert to a net importer.

Figure 3.20 Inter-regional trade

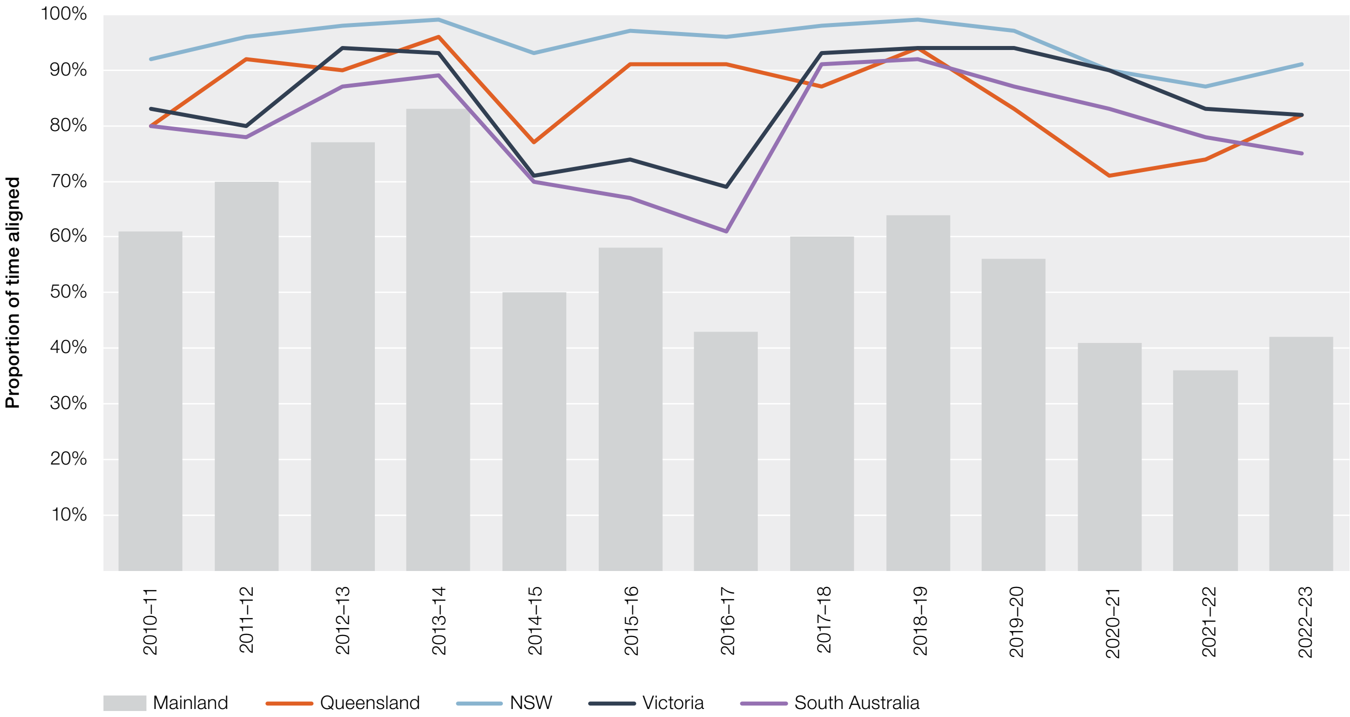


Source: AER; AEMO (data).

3.9.1 Market alignment and network constraints

Price alignment in the NEM rose in the 2022–23 financial year, having fallen over the 3 years prior (Figure 3.21). The market sets a separate spot price for each NEM region. When interconnectors are unconstrained, competitive pricing pressure from neighbouring regions brings prices into alignment across the NEM (with slight variations caused by physical losses that occur when transporting electricity). At these times, the NEM functions more like a single market than a collection of regional markets, as generators are exposed to competition from generators in other regions.

Figure 3.21 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).

Being the geographical middle of the NEM, NSW prices were the most aligned, at over 90% of the time. In 2022–23, the alignment of both NSW and Queensland increased with the completion of the QNI interconnector as related outages ceased. Queensland's alignment increased 8% to 82% of the time. Victoria's price alignment fell slightly as the VNI interconnector experienced frequent constraints, isolating the region from NSW. South Australia's price alignment also fell due to outages and constraints on the Heywood interconnector. In 2021–22 electricity flowed more freely between NSW and Queensland, and less so between NSW, Victoria and South Australia, resulting in price separation between the northern and southern regions of the NEM.

3.10 Market structure

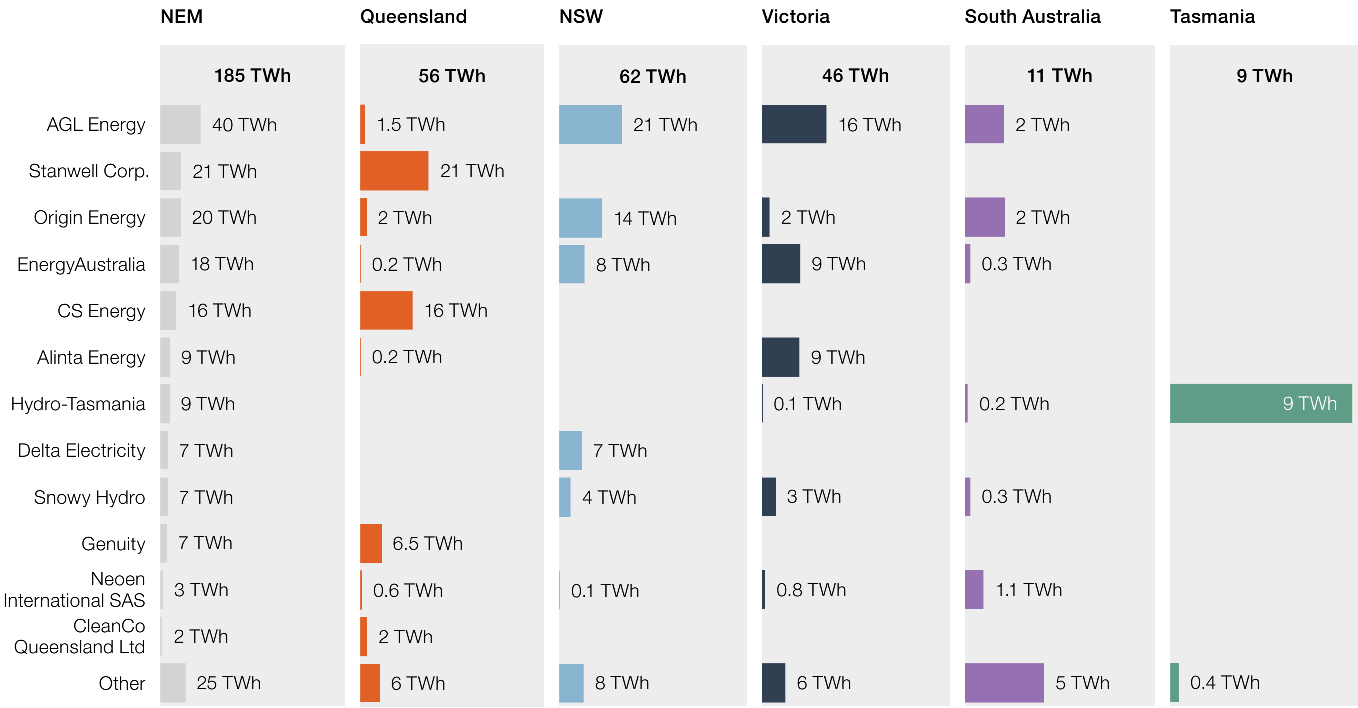
Over 200 power stations sell electricity into the NEM spot market. Despite significant new entry over recent years, a few large participants control a significant proportion of generation in each NEM region. Ownership of flexible generation is particularly concentrated. The AER released its *Wholesale electricity market performance report* in December 2022, setting out detailed analysis of market structure and competition.[15]

3.10.1 Market concentration

Generation in the NEM is concentrated among a relatively small number of owners. In each NEM region except for South Australia, the largest 2 owners account for over half of the region's output capacity (Figure 3.22).

15 AER, Wholesale electricity market performance report 2022, Australian Energy Regulator, December 2022.

Figure 3.22 Market shares in generation output



Note: Output in 2022–23. 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 2022–23. Data exclude output from rooftop solar systems and interconnectors. Loads and non-scheduled generation are excluded. Where multiple owners are invested in a generating unit, the output of that unit has been split proportionally between owners according to their percentage of total ownership.

Source: AER; AEMO; company announcements.

Private entities control most generation output in NSW, Victoria and South Australia, whereas government-owned entities control most generation output in Queensland and Tasmania.

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 registered flexible generation capacity. Most of these assets are located in NSW and Victoria and, as a result, Snowy Hydro controls more than 60% of flexible generation in NSW and almost 50% in Victoria. 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 half in Victoria. Ownership of flexible capacity is less concentrated in the other regions.

As intermittent renewables (wind and solar) continue to increase their share of total capacity, flexible generation will play an increasingly important role in the market. Concentration and competition in the supply of flexible capacity, in addition to broader market outcomes, are addressed in the AER's *Wholesale electricity market performance report* released in December 2022.[16]

3.10.2 Vertical integration

Most large generators in the NEM are vertically integrated, with portfolios in both generation and retail. Because generators sell into the spot market while retailers buy from it, vertical integration allows 'gentailers' to hedge against price risk in the wholesale market without entering into external contract agreements. Reduced participation in contract markets has reduced their liquidity, posing a potential barrier to entry and expansion for generators and retailers that are not vertically integrated.

16 AER, Wholesale electricity market performance report 2022, Australian Energy Regulator, December 2022.

Vertical integration has become the primary business structure for large electricity companies 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 43% of electricity generation in 2021–22 and supplied 64% of residential energy customers in the January to March quarter 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 19% of electricity generation in 2021–22 and 13% of residential energy customers in the January to March quarter 2022.

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.

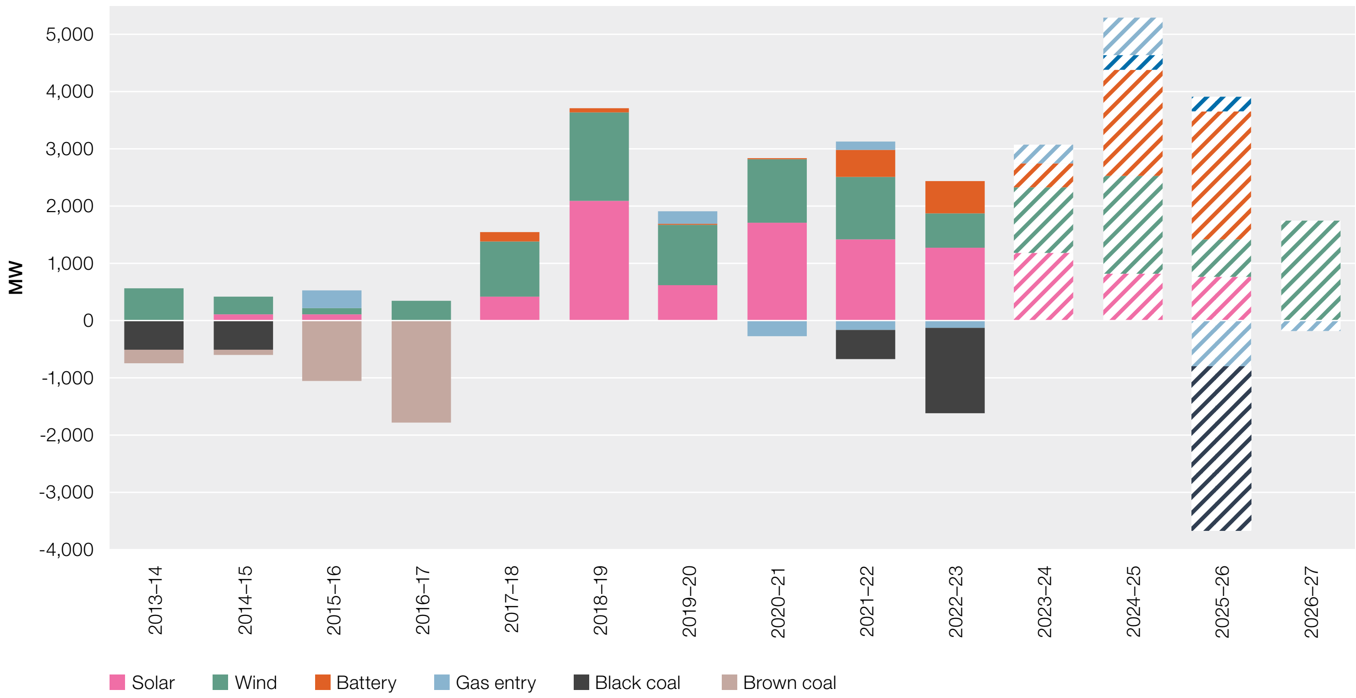
Several smaller retailers are also vertically integrated:

- 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.

3.11 Generation investment and plant closures

Around 14 GW of new grid-scale solar, wind and battery investment was added to the NEM in the 5 years to the end of the 2022–23 financial year. Over the same period, just over 2.5 GW of coal and gas capacity was withdrawn (Figure 3.23).

Figure 3.23 New generation investment and plant withdrawal



Note: Capacity includes scheduled and semi-scheduled generation, but not rooftop solar capacity. New entry and exit are by registered capacity, except for solar which uses maximum capacity. Committed investment and closures from 30 June 2023 are shown as shaded components. These include Eraring power station in 2025.

Source: AER; AEMO (data).

In 2022–23, just over 2.4 GW of renewable capacity entered the market, comprising:

- 1.3 GW of solar capacity, which was located mostly in NSW and Queensland
- 0.6 GW of wind capacity, which was located mostly in Victoria and Queensland
- 0.5 GW of battery capacity (4 batteries in NSW, 2 in Victoria and 1 in South Australia).

1,500 MW of coal and 120 MW of gas capacity exited the NEM in 2022–23 – namely, Liddell, a black coal-fired power station in NSW, and Torrens Island A, a gas generator in South Australia.

More than 8 GW of additional capacity is committed to come online in 2023–24 and 2024–25. As well as solar and wind, committed new entry includes the 660 MW Kurri Kurri and 320 MW Tallawarra B gas-powered power stations, along with over 2 GW of new batteries.

While no exits are expected in the next 2 financial years, Australia's largest power station, Eraring (2,880 MW), is currently scheduled to close in the second half of 2025, pending engagement with the NSW Government on a later closure date. 800 MW of gas capacity is scheduled to exit soon after.

3.12 Power system reliability

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

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 over winter 2022 due to coal plant outages, fuel constraints and high demand. While fewer outages of coal plant occurred in 2023, they are increasingly likely to break down as they age, and outages will represent a greater portion of supply as more exit.

Box 3.2 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 applied to trigger the Retailer Reliability Obligation (RRO)[17]. If unserved energy is forecast to exceed the 0.0006% threshold, the AER can trigger the RRO and organise for liable entities to enter into sufficient qualifying contracts to cover their share of a once-in-two-year demand event.

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.

17 AER, Retailer reliability obligation, Australian Energy Regulator, accessed 18 August 2023.

3.12.1 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 for activation.

Reliability and Emergency Reserve Trader

The Reliability and Emergency Reserve Trader (RERT) is a mechanism through which AEMO may use reserve contracts to prevent load shedding (deliberate disconnection of customers to prevent potentially significant damage to the power system) or other threats to reliability. When forecast reliability is outside the relevant standard, AEMO can pay large industrial customers to standby to reduce their consumption should this be required to prevent load shedding. AEMO may also pay generators from outside the market to standby in case additional supply is required.

Reserves procured under the RERT must be ‘out of market’. Any generator or load that participated in the wholesale market in the previous 12 months may not provide emergency reserves through the RERT. 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.

The RERT should only be activated if necessary to avert load shedding or other risks to reliability and system security. The capacity activated under the RERT scheme is typically more expensive than that acquired through the market; this is a cost that is ultimately borne by consumers. The average cost of the RERT over the past 5 financial years has been just over $36,000 per MWh, more than double the current market price cap of $16,600 per MWh. The RERT has averted multiple instances of load shedding since the initiative began, but doing so comes at significant cost to the consumer.

The cost incurred by AEMO for these standby services should be less expensive than the projected cost of load shedding for customers. The value of customer reliability (VCR) is a threshold set by the AER.[18] The VCR represents the per kilowatt cost to the economy of a load shedding event. A guiding principle of RERT payments is that they should not exceed the VCR, but doing so is not prohibited.[19]

AEMO has activated the RERT in each summer since its inception in 2018. The RERT costs in 2021–22 totalled just over $130 million, more than 2 and half times higher than in any year prior. The majority of these costs were incurred in the context of record prices in May and June.

Total RERT costs in 2022–23 were significantly lower than the previous financial year, but have been more expensive per MWh activated (Figure 3.24). For example, AEMO reported that RERT costs exceeded the average VCR on 3 February 2023.[20] In response to a forecast Lack of Reserve 2 (LOR2) notice, AEMO contracted 115 MW of short notice reserve capacity – it pre-activated 95 MW of this, but ultimately only activated 21 MW. As a result, the total cost paid relative to capacity actually activated was higher than expected and exceeded the VCR. A similar event occurred on 5 July 2022, with RERT payments also exceeding the average VCR in Queensland on this occasion.[21] While the RERT was exercised significantly less than in previous years, the average cost of the RERT in 2022–23 was more than $50,000 per MWh.

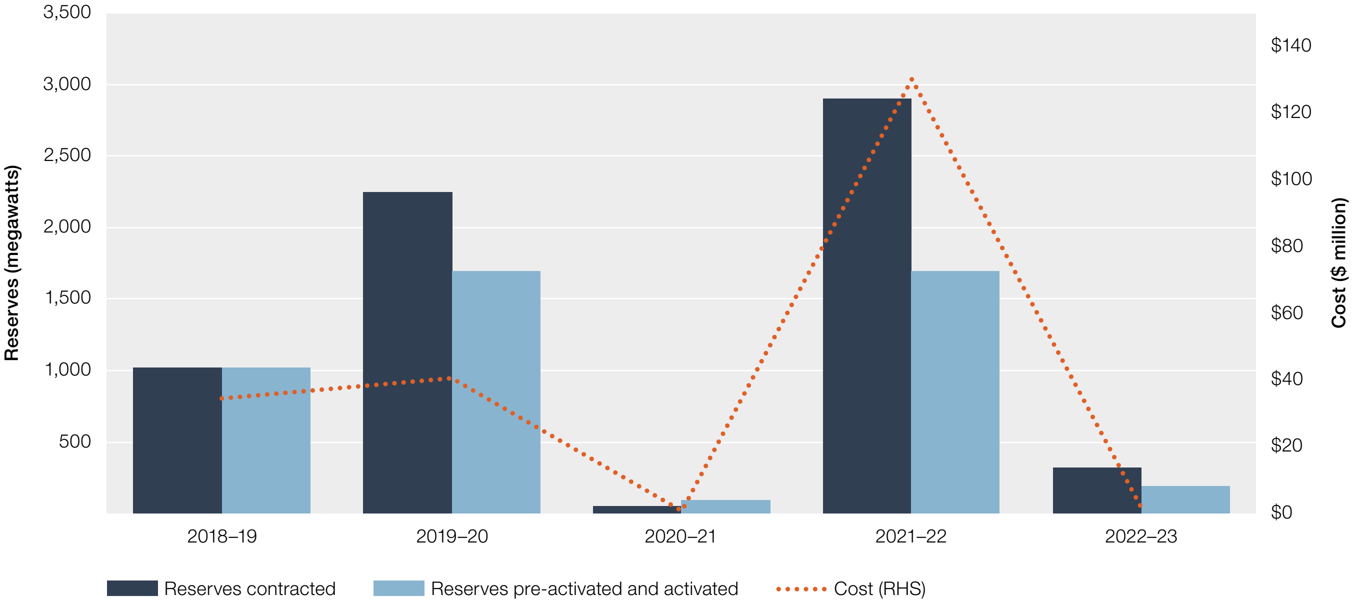
18 AER, Values of customer reliability, Australian Energy Regulator, accessed 18 August 2023.

19 AEMC, National Electricity Amendment (Enhancement to the Reliability Emergency Reserve Trader) rule 2019, Australian Energy Market Commission, May 2019.

20 AEMO, Reliability and Emergency Reserve Trader (RERT) Quarterly Report Q1 2023, Australian Energy Market Operator, May 2023.

21 AEMO, Reliability and Emergency Reserve Trader (RERT) Quarterly Report Q3 2022, Australian Energy Market Operator, November 2022.

Figure 3.24 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.

3.12.2 Reliability outlook

AEMO's 2023 Electricity Statement of Opportunities (ESOO) identified forecast reliability gaps for all mainland regions over the next 10 years.[22]

Against the stricter Interim Reliability Measure, South Australia and Victoria are forecast to experience reliability gaps as early as summer 2023–24. Against the normal reliability standard, gaps are forecast for NSW from 2025–26, Victoria from 2026–27, South Australia from 2028–29, and Queensland from 2029–30.

The major reason for forecast reliability gaps is the exit of 8.3 GW of firm capacity in the next decade, as coal plants retire. Liddell's (NSW) closure in April 2023 marked the first of 4 coal station exits for the decade, with Eraring (NSW, 2025), Yallourn (Victoria, 2028) and Callide B (Queensland, 2028) all set to retire before 2030. Vales Point (NSW) is expected to retire in 2033.

In releasing the 2023 ESOO, AEMO stated that 'To ensure Australian customers continue to have access to reliable electricity, it's critical that planned investments in transmission, generation and storage projects are urgently delivered'.[23] AEMO's modelling indicates that, should the 3.4 GW of currently anticipated storage projects (additional to more than 8 GW of already committed generation) enter the market according to their current schedules, reliability gaps will be delayed until later in the decade. This additional capacity will need to be developed alongside actionable transmission projects from AEMO's Integrated Systems Plan. Delays to completion of generation or transmission projects have been common; further delays will increase the risk of reliability gaps.

22 AEMO, 2023 Electricity Statement of Opportunities, Australian Energy Market Operator, August 2023.

23 AEMO, 2023 Electricity Statement of Opportunities, Australian Energy Market Operator, August 2023.

3.13 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. Inertia is provided by the energy generated through continual rotation of turbines after a generator stops running, due to stored momentum. This can help smooth changes to frequency after a large generator exits suddenly. System strength refers to the power system's ability to maintain correct voltage waveforms. It is supported by synchronous generators, which are typically electromagnetically connected to the voltage waveform of the grid.[24] As older synchronous plants retire, or reduce operations in response to falling demand, these sources of inertia and system strength are reduced with them. 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 or provide inertia. 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. This can damage both the power system and the quality of power supplied. It also raises challenges to the generation fleet's ability to ramp (adjust) quickly to sudden changes in renewable output.

The energy transition is necessitating frequent directions from AEMO to maintain power system security. Directions for system security are intended as 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 for the past 3 years.[25]

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 of market interventions and relaxed constraints on wind and solar output. Directions in South Australia fell from being in place over 50% of the time in the 2021–22 financial year to 43% in 2022–23.

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 have either been implemented or are in development to improve system security:

- AEMO is now required to report annually on the adequacy of system strength requirements for the next decade, including minimum fault level requirements at each system strength node of the NEM and requirements for stable voltage waveforms at connection points.
- AEMO will implement a very fast ancillary service market in October 2023. The new markets, 1 second raise and 1 second lower, will allow for more rapid response than the current fastest 6 second services.
- The AEMC continues to consult on market reforms for valuing, procuring and scheduling essential system security services.

3.13.1 Security performance in the NEM

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 2022 report identified voltage shortfalls in NSW, Queensland and Tasmania. 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.

24 AEMO, System Strength Explained, Australian Energy Market Operator, March 2020.

25 AEMO, Quarterly Energy Dynamics Q2 2023, Australian Energy Market Operator, July 2023.

3.13.2 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.

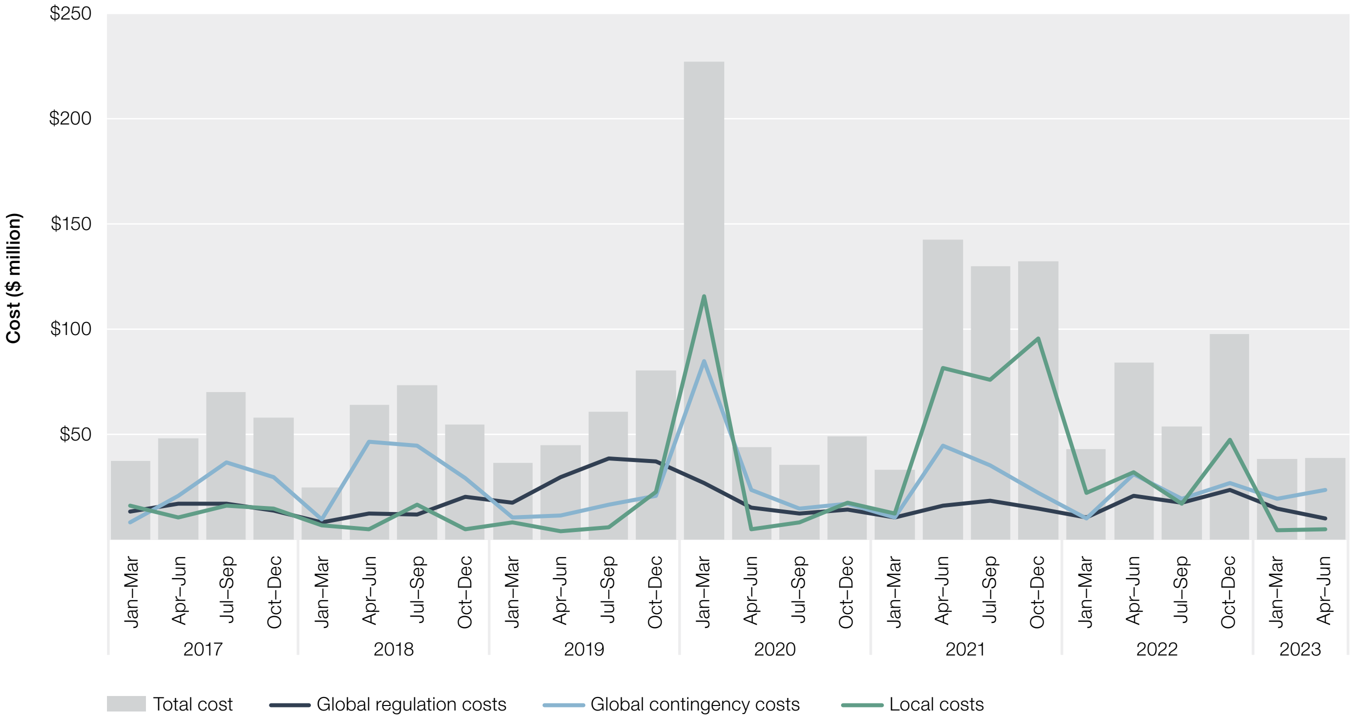
Frequency control ancillary services (FCAS) are used to maintain the frequency of the power system close to 50 hertz. With the introduction of 1 second raise and lower services in October 2023, the NEM will have 10 FCAS markets, which fall into 2 categories – regulation services and contingency services. 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 have emerged in recent years. In mid-2023, 13 participants were providing FCAS in Queensland, 16 in NSW, 16 in Victoria, 21 in South Australia and 3 in Tasmania. Batteries, demand response and virtual power plants offer FCAS services. Some of these new entrants account for only a small proportion of FCAS trades and others such as batteries have displaced incumbent providers. Batteries are the largest provider of FCAS in the NEM – in the April to June quarter 2023 they provided a record 40% of all FCAS (by volume). Demand response provided 13% of FCAS volumes.

FCAS costs fell in 2022–23 (Figure 3.25). The fall was observed in both local and global costs. The fall in local costs was driven by improved interconnection between regions, while global costs also fell. South Australia was the only region to see an increase in local costs, in part because it was required to provide its own FCAS during the Tailem Bend outage of November 2022.

Figure 3.25 Frequency control ancillary service costs



Note: Record FCAS costs in the January to March quarter 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).

3.14 Market reforms and policy developments

In addition to significant market reforms implemented in 2021, further reforms progressed in 2022 and 2023. In addition to 5-minute settlement and the wholesale demand response mechanism implemented in 2021, several other reforms have developed.

Energy ministers have agreed to include an emissions reduction objective in the National Electricity Objective. The amendment aims to empower AEMO, the AER and the AEMC to consider emissions reduction in how they undertake their respective powers and functions.[26]

The Australian Government has also received endorsement to develop a Capacity Investment Scheme (CIS).[27] This revenue underwriting mechanism will unlock $10 billion of investment in clean power, which is also dispatchable regardless of renewable generation conditions. The CIS will be designed to complement rather than overlap with existing state and territory schemes. Open tenders will determine the projects that will gain CIS support. An agreed revenue floor will be established to assist in covering costs and debt repayments. The government will pay the difference where revenue falls short, while a share of profits will be returned where revenues exceed an agreed ceiling.

Other initiatives to support investment in generation and transmission received funding in the 2022–23 budget. The Australian Government's $20 billion Rewiring the Nation initiative aims to provide low-cost financing for connection of new renewable generation to the grid.[28] The $224 million Community Batteries initiative will support deployment of 400 community batteries across Australia and aims to facilitate storage and sharing of electricity generated by rooftop solar systems.[29] $84 million will be invested in First Nations Community Microgrid projects to improve reliability and reduce costs in Aboriginal and Torres Strait Islander communities.[30] Several other state-level policies exist, including the NSW Transmission Acceleration Facility[31] and the Victorian Renewable Energy Zones Development Plan.[32]

Amendments to the National Electricity Law to improve the AER's visibility of the electricity contract market and its ability to monitor effective competition in this market are also progressing.[33] Constraints requiring the AER to use only public information in its monitoring function will be removed, allowing the AER to respond to market issues before (rather than after) they arise. These reforms come with information protection mechanisms, including requiring the AER to consider redaction requests and set out guidelines as to how it will protect information acquired through its enhanced functions.

3.14.1 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. This ensures consumers 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 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. In addition to these priorities, the AER was appointed as regulator for directions pertaining to the NSW coal market intervention.

Over 2022–23 the AER has undertaken several compliance and enforcement actions pertaining to the NEM.

26 AEMC, Consultation on Reliability Panel guide to applying the emissions component of the NEO, Australian Energy Market Commission, July 2023.

27 DCCEEW, Capacity Investment Scheme to power Australian energy market transformation, Department of Climate Change, Energy, the Environment and Water, December 2022.

28 DCCEEW, Budget October 2022–23, Department of Climate Change, Energy, the Environment and Water, October 2022.

29 DCCEEW, Budget October 2022–23, Department of Climate Change, Energy, the Environment and Water, October 2022.

30 DCCEEW, Budget October 2022–23, Department of Climate Change, Energy, the Environment and Water, October 2022.

31 NSW Government, $1.2 billion to fast track Renewable Energy Zones, June 2022.

32 Victorian Government, Victorian Renewable Energy Zones development Plan, February 2021.

33 DCCEEW, Amending the Australian Energy Regulator Wholesale Market Monitoring and Reporting Framework – draft legislation and consultation paper, Department of Climate Change, Energy, the Environment and Water, June 2023.

In 2022–23 the AER undertook an investigation into the conduct of generators prior to and during the suspension of the spot market in June 2022. The investigation considered whether generators had intentionally or recklessly caused or contributed to circumstances leading AEMO to issue a direction. A number of stakeholders had alleged that generators were withdrawing capacity in order to be directed by AEMO and receive resulting compensation payments. The investigation also considered other potential breaches of the National Electricity Rules (NER)[34], including false or misleading offers, bids or rebids, and conduct related to projected assessment of system adequacy (PASA) submissions.

The resulting report was released in December 2022.[35] It found that the evidence gathered demonstrated that generator behaviour resulted in poor market outcomes and, in some cases, significantly contributed to circumstances that caused AEMO to issue a direction. However, the report noted that generators may have had reasonable cause to withdraw capacity given limited fuel availability. Currently, the Rules do not compel generators to dispatch available capacity and they may decide not to do so for commercial reasons. The report noted that, although not against the Rules, prioritisation of commercial freedom can be detrimental to power system security, particularly during times of system stress. The report raised a number of options for consideration that could tighten the Rules to ensure generators continue to offer capacity during time of system stress. The investigation also revealed poor compliance from some generators regarding PASA submissions; one generator remains under investigation.

The AER has also initiated proceedings against AGL Loy Yang Marketing Pty Ltd for alleged breaches of the NER. The aforementioned party made offers to AEMO and were paid to standby to provide market ancillary services to stabilise network frequency in the event of a disturbance during various periods between September 2018 and August 2020. The AER alleges that the respondents' failures to ensure their units were capable of providing FCAS in accordance with their offers and AEMO's dispatch instructions created a risk to power system security by undermining AEMO's ability to prepare for and respond to frequency disturbances. The respondents have cooperated with the AER in these proceedings and have admitted to the contraventions. The parties intend to make joint submissions to the Court about the appropriate relief.

More detail on the AER's compliance and enforcement work is outlined in the *Annual compliance and enforcement report 2022–23.*[36]

34 AEMC, National Electricity Rules, Australian Energy Market Commission, accessed 18 August 2023.

35 AER, June 2022 market events report, Australian Energy Regulator, December 2022.

36 AER, Annual compliance and enforcement report 2022–23, Australian Energy Regulator, July 2023.