2 National Electricity Market

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

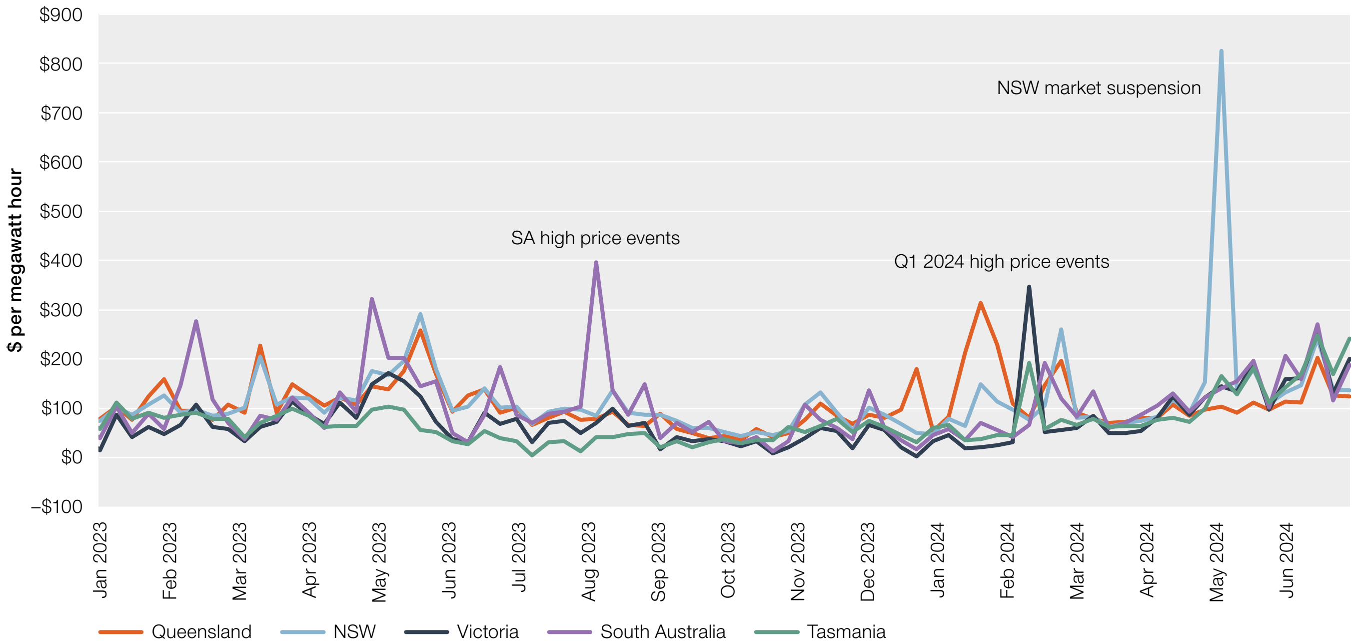
2.1 Snapshot

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

- Wholesale prices declined across all regions of the NEM for the 2023–24 financial year compared to the previous financial year, which was influenced by the record high prices during winter 2022. Prices were lowest in the second half of 2023, before increasing over 2024 when there was an increase in the number of high price events across the different regions. Contract market activity increased trade volumes and liquidity in all regions, although activity in the South Australian market remains low.
- The more extreme weather conditions in 2023–24 drove significant price variation. Queensland recorded record peak demand levels during the hot and humid summer and storm damage affected supply in southern states in February 2024. Increased demand for more expensive gas-powered generation in the April to June quarter was driven by unusually cold weather in May, unusually low wind output and drought conditions in Tasmania.

- Following the Liddell coal power stations retirement in 2023, network and generator outages in NSW drove high price events in Q2 and demonstrate the current tightness in the demand-supply balance as we transition to becoming more reliant on renewable energy. In May 2024 the cumulative price threshold was breached in NSW for the first time since 2022, triggering administered prices.[9]
- Entry of planned new capacity in 2023–24 slowed as projects have been delayed, with a substantial amount of capacity now forecast to enter over the next financial year. The next coal-fired generator to close has a planned closure date of 2027, with Eraring (2,880 MW capacity) to withdraw from the NEM in August 2027.
- Record lows in minimum demand were set across all regions except Queensland in 2023–24. This demonstrates the urgent need to increase storage and integrate consumer energy resources (CER) into the NEM so that consumers that are willing and able are better supported to shift some of their demand to times of excess supply.
- Major reforms to system security frameworks have supported forward-planning for the replacement of inertia and system strength services. RIT-T application processes for system security investments, new FCAS markets and greater transparency over AEMO's procurement system security services will support the market to respond with innovative solutions.

Figure 2.1 Weekly wholesale electricity prices



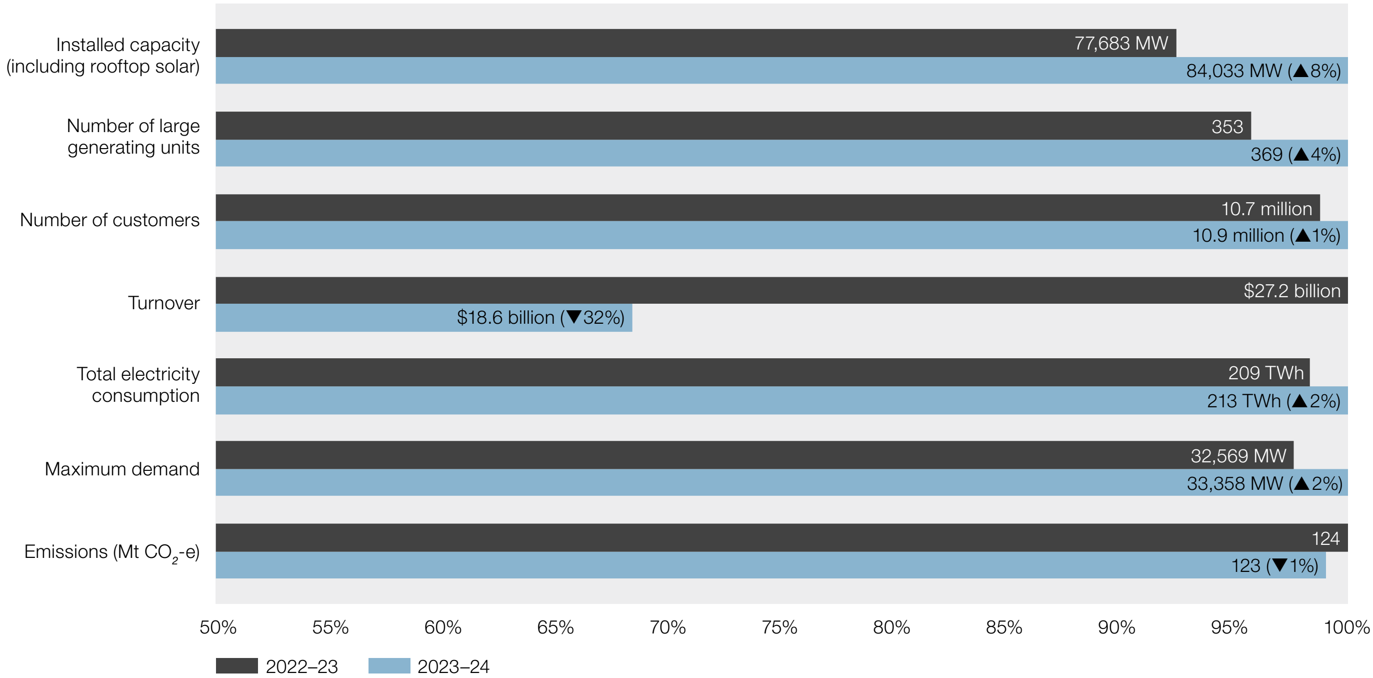
Note: Volume weighted weekly average prices.
Source: AER; AEMO (data).

9 The administered price is a component of the market safety net which operates to protect and sustain electricity trading in the National Electricity Market (NEM) during periods of sustained high prices. If market prices in a region rise to levels that are likely to cause substantial financial stress, then those prices are capped until they return to lower levels.

2.2 NEM overview

369 generating units produce electricity for sale into the NEM (Figure 2.2). A transmission grid carries this electricity along high voltage power lines to industrial energy users and local distribution networks (chapter 2). Energy retailers complete the supply chain by purchasing electricity from the NEM and packaging it with transmission and distribution network services for sale to residential, commercial and industrial energy users.

Figure 2.2 NEM key statistics



Note: MW: megawatts; TWh: terawatt hours. All data as at 1 July 2024, except customers, which are as at 30 June 2023. Includes energy met by the grid and rooftop solar generation.

Source: AER; AEMO (data); Clean Energy Regulator (data).

Box 2.1 How the NEM works

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

Power stations make offers to supply quantities of electricity in different price bands for each 5-minute dispatch interval. Scheduled loads, or consumers of electricity such as pumped hydro and batteries, also offer into the market. 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.[10] Electricity generated by rooftop solar systems and used by the consumer is not traded through the NEM, but it does lower the demand that market generators need to meet.

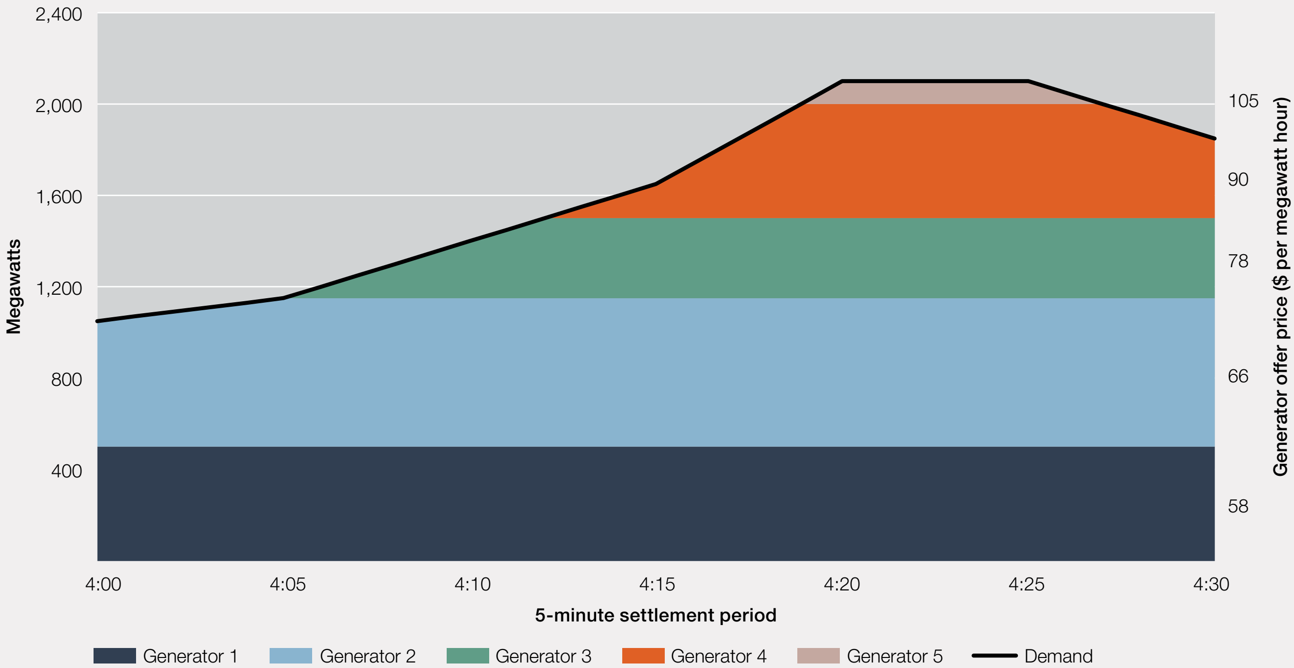
10 Large customers can participate through the wholesale demand response mechanism and small customers can participate through their retailers in virtual power plants (VPPs).

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 previously increased in line with the consumer price index (CPI) each year, but is due to increase to $18,600 on 1 July 2025, $20,700 on 1 July 2026, then $22,800 on 1 July 2027 in order to better support new entrant investment and reliability over the long term. The market floor price remains unchanged for now but will be considered as part of the next Reliability Standard and Settings Review.[11]

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 2.1 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 2.1 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.

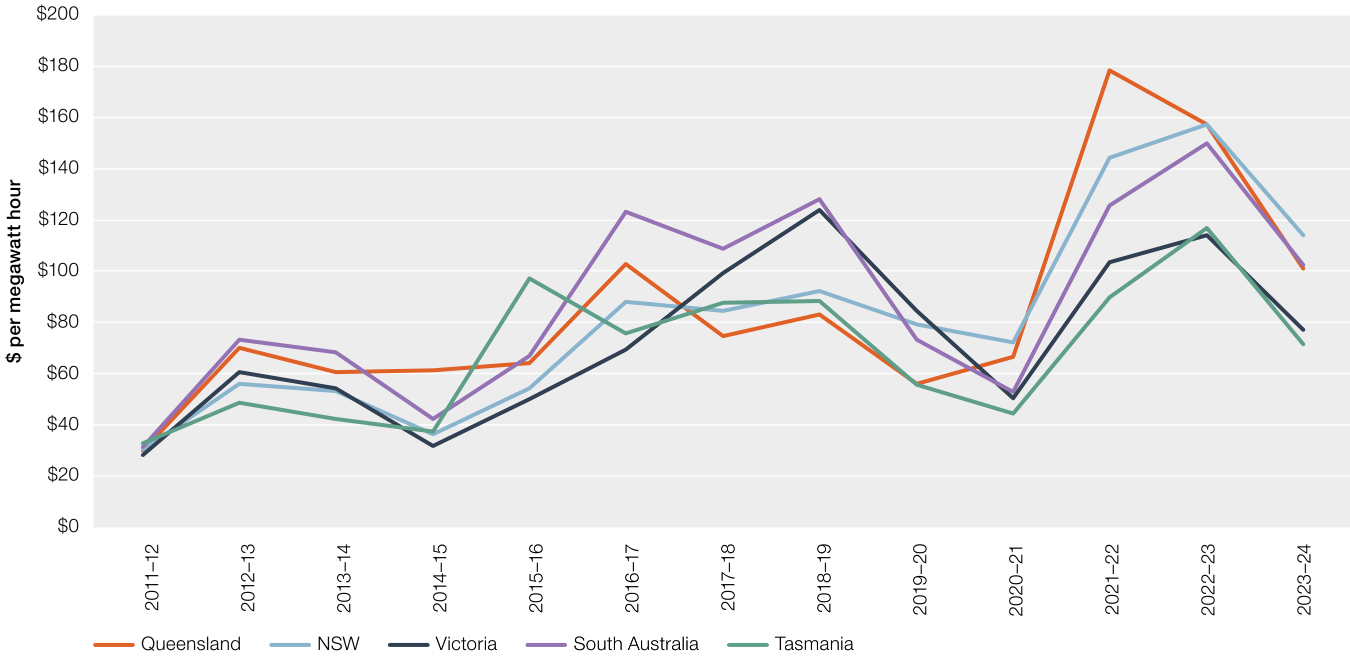
Retailers buy power from the wholesale market and package it with network services to sell as a retail product to their customers. They manage the risk of volatile prices in the wholesale market by taking out hedge contracts (derivatives) that lock in a firm price for electricity supplies in the future,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

11 AEMC, Amendment of the Market Price Cap, Cumulative Price Threshold and Administered Price Cap, Rule determination, Australian Energy Market Commission, 7 December 2023.

2.3 Wholesale prices and activity

Wholesale electricity prices have fallen significantly from the previous year, which can be attributed largely to the high prices in winter 2022 continuing to subside. Average prices remain high compared with historical levels in several regions (Figure 2.3).

Figure 2.3 Annual wholesale prices, financial year



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

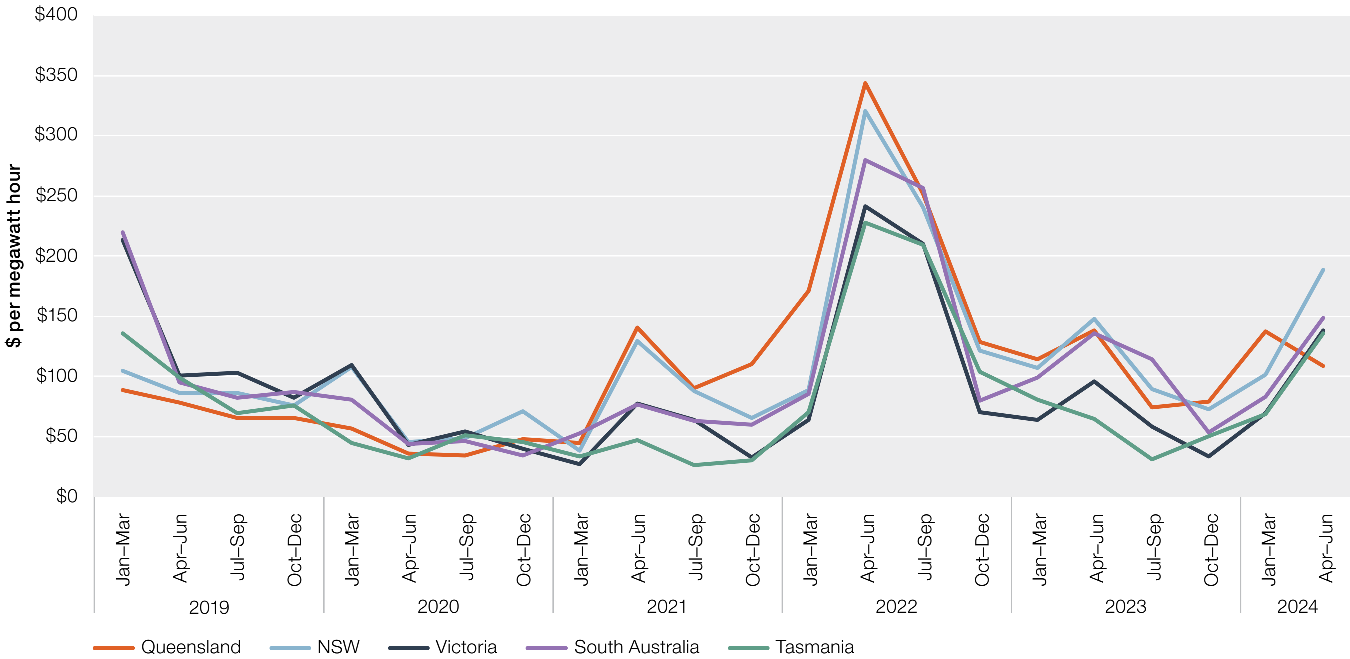
Average annual volume weighted prices fell across all regions in the 2023–24 financial year, following a decline from the high prices that occurred over the 2022–23 financial year (Figure 2.4). Comparing average quarterly prices across the NEM:

- Queensland ($101 per MWh) prices fell 36% in 2024 compared with 2023 and were higher than the other regions in the warmer months – October to December 2023 and January to March 2024 due to high demand days and warm and humid weather. However, low demand put downward pressure on average prices in other quarters, particularly April to June 2024, when Queensland was the only region to experience reduced demand.
- NSW ($114 per MWh) prices fell 27% compared with 2023 but replaced Queensland as the highest priced region over the year. NSW experienced the highest or second highest average prices across the NEM in all quarters. Prices were particularly impacted in the April to June 2024 quarter, when generator and network outages, combined with rebidding from some market participants, increased prices significantly. Higher prices caused the cumulative price to exceed the threshold for the first time since 2022, which triggered administered prices between 8 May and 15 May to stabilise wholesale spot prices and reduce financial stress for market participants. Administered prices cap wholesale prices at $600 per MWh.
- South Australia ($103 per MWh) prices fell 32% in 2024 and were marginally above Queensland prices. South Australia was the highest priced region in July to September 2023, experiencing several high price events in August due to low renewable output, interconnector network outages and generator rebidding.

- Victoria ($77 per MWh) remained one of the lower priced regions in the NEM and averaged only $6 per MWh more than Tasmania in 2024. Victoria experienced the lowest regional price between October and December 2023, averaging $34. Lower regional demand, driven by rooftop solar output alongside strong wind and solar generation, pushed down prices and contributed to negative daytime prices over the March to June quarter. Severe storms on 13 February led to the collapse of multiple transmission towers in Victoria, resulting in high priced events that increased prices over the January to March 2024 quarter.
- Prices in Tasmania ($72 per MWh) fell 39% in 2024. Tasmania was the lowest priced region in the NEM, a place it has held 4 out of the last 5 years. As with other regions, Tasmania's decrease was largely underpinned by the low prices experienced in the July to September 2023 quarter. Despite lower prices in 2024, Tasmania experienced high prices between April and June 2024, with average prices more than 100% higher than the same period in 2023, influenced by high hydro generation prices following significantly lower rainfall in the region.

As is typical, prices across the year varied from quarter to quarter with changing seasonal dynamics. Prices were lowest in the second half of 2023, increasing over 2024 due to strong seasonal impacts and the influence of high price events (Figure 2.4).

Figure 2.4 Quarterly wholesale electricity prices



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

July to September 2023

From July to September 2023, average prices fell across all regions. Prices were significantly below July to September 2022 prices, and closer to long-term averages. Mild weather and high rooftop solar generation contributed to record low demand for the July to September period. Although demand was low, several high price events (prices exceeding $5,000 per MWh) impacted average prices, particularly in South Australia. This illustrates that, even in favourable conditions, market outcomes are vulnerable to short-term changes in conditions.

October to December 2023

From October to December 2023, prices fell in NSW, Victoria and South Australia, but rose in Queensland and Tasmania. Prices were lower across all regions compared with the same period in 2022. Rooftop solar output increased due to longer days and strong growth in installations, and all regions set rooftop solar output records. Wind and large-scale solar also saw a record high share of generation output, accounting for 26% of output over the period.

There were large differences between daytime and evening prices – Victoria and South Australia averaged negative daytime prices, while evening peak prices in Queensland, NSW and South Australia exceeded $100 per MWh.

January to March 2024

From January to March 2024, prices increased across all regions. The 2023–24 summer was Australia's third warmest on record, which led to higher demand and prices.[12] Hot and humid weather in Queensland drove a material increase in demand from the last week of December 2023 to February 2024. This contributed to record maximum demand being recorded in Queensland as maximum demand exceeded the previous record 3 times over the period. Severe storms in Victoria led to the collapse of multiple transmission towers, which contributed to higher prices in Victoria, Tasmania and South Australia.

Summer periods can increase demand levels, but longer daylight hours can also lead to higher generation by rooftop solar, reducing demand from the grid. High rooftop solar output from January to March resulted in record minimum daily demand in Victoria and South Australia compared with equivalent quarters in previous years.

April to June 2024

From April to June 2024, prices increased in all regions except Queensland. With the exception of Queensland, prices were higher than the same period in 2023, but remained well below 2022 prices. Low wind and shorter days reduced wind and solar generation, resulting in increased generation from higher priced gas and hydro generators.

In NSW, generator and network outages, combined with rebidding from some market participants, increased prices significantly. This caused the cumulative price to exceed the cumulative price threshold, which triggered a period of administered prices and prices were capped from 8 May to 15 May to protect consumers.

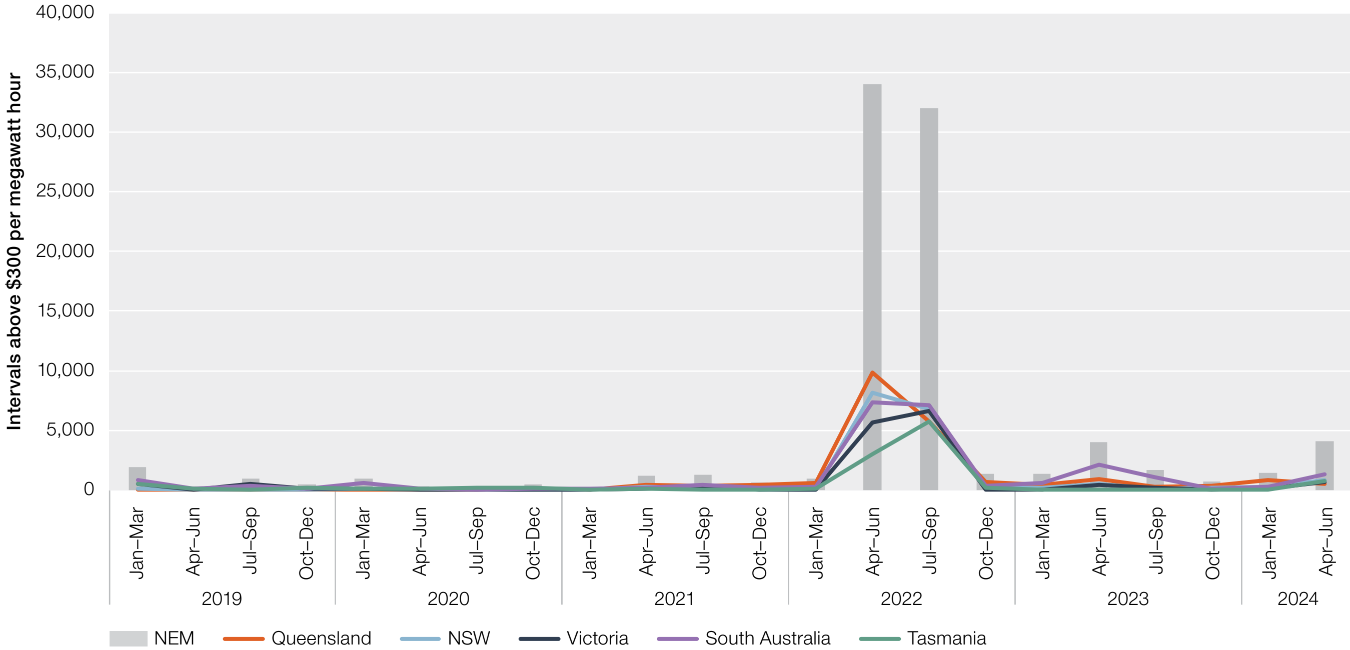
12 AER, Wholesale markets quarterly – Q1 2024, Australian Energy Regulator, 18 April 2024.

2.3.1 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 few years.

Once rare, spot prices above $300 per MWh have become more common. In the 2023–24 financial year, the frequency of 5-minute prices above $300 per MWh fell significantly compared with the previous 2 years. However, the rate of prices above $300 per MWh remains higher than any previous year before the winter 2022 market events (Figure 2.5).

Figure 2.5 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 a 5-minute basis using 5-minute prices.

Source: AER; AEMO (data).

Over the year, prices above $5,000 per MWh in a 30-minute period occurred 60 times, an increase on the previous year but not as often as in the 2021–22 financial year. Most significant price events occurred in NSW and were concentrated in May, when generator and network outages, combined with rebidding from some market participants, increased prices significantly.

2.3.2 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 output of wind and solar generators varies with prevailing weather conditions. These generators do not incur high startup or shutdown costs and have marginal costs close to zero. If wind and solar generating conditions are optimal, they may need to bid capacity at negative prices to guarantee dispatch. 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.

Some wind and solar generators also source revenue from power purchase agreements[13] (PPA) and the sale of renewable energy certificates.[14] As such, they may operate profitably even when wholesale prices are negative. Instances of negative spot prices are highest when these technologies, alongside rooftop solar, are generating.

If electricity demand is low, the market has surplus capacity and the chances of the market settling at a negative price are higher. With multiple low-cost generators all competing for dispatch, the likelihood of negative prices increases.

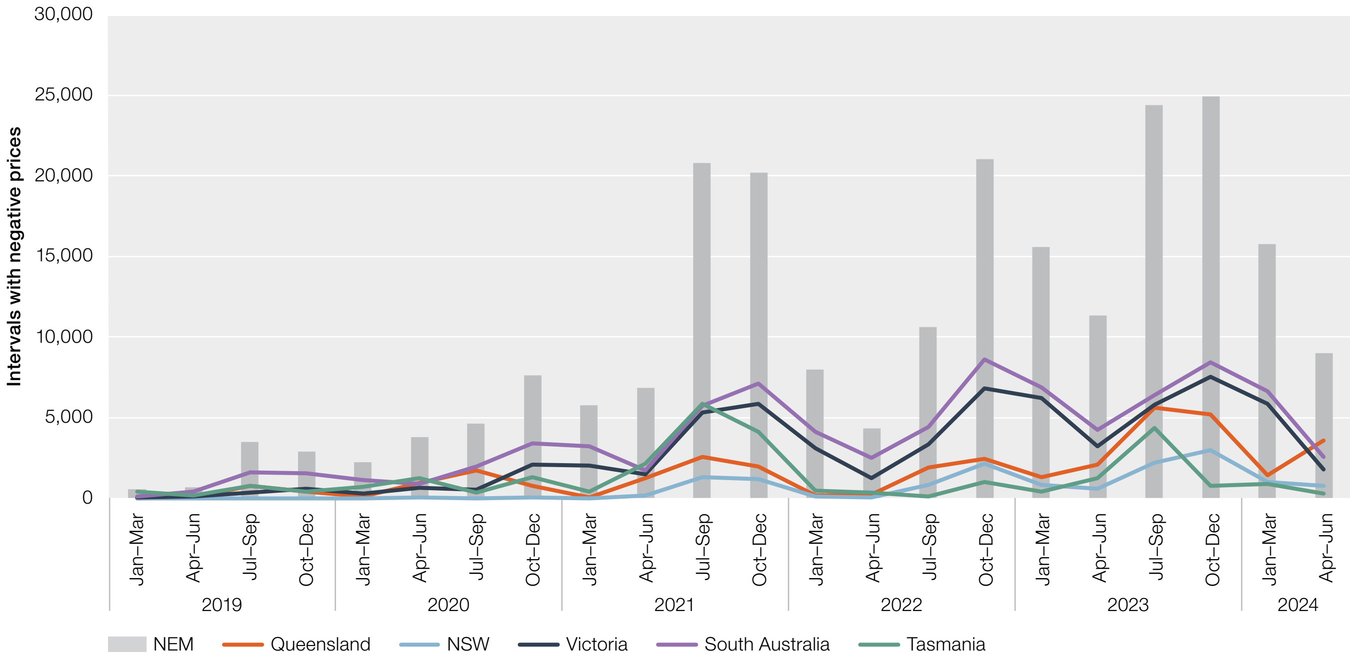
Negative prices usually occurred when electricity demand was low and weather conditions were optimal for renewable generation. While historically occurring overnight, they are now more common during the middle of the day when solar resources are producing maximum output and the generation of rooftop solar is being subtracted from demand.

In 2023–24 negative price events increased compared with the previous year and represented the fifth consecutive year in which a record number of negative prices were set (Figure 2.6). The number of negative price events in South Australia and Victoria remained relatively stable and continued to account for most negative price events, representing a combined 60% across the NEM. All other regions experienced a material increase in the number of negative price events. Queensland more than doubled and had the third highest number of negative price events, while events in Tasmania and NSW increased by 130% and 61%, respectively.

13 A power purchase agreement is a contract between an electricity generator and a purchaser (retailer or consumer) for the sale and supply of energy.

14 Clean Energy Regulator, Renewable Energy Target, July 2024.

Figure 2.6 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 a 5-minute basis using 5-minute prices.

Source: AER; AEMO (data).

Between July and September 2023, unseasonably mild weather and high rooftop solar output reduced demand to a record low for a July to September quarter. This, alongside record high Queensland solar output, contributed to a record number of negative price events. This record was subsequently broken in the following quarter as more renewables entered the NEM. Instances of negative price events are likely to continue to increase.

2.4 Generator fuel costs and market interventions

After reaching record highs in previous years, generator fuel costs had decreased by the start of 2023–24 and remained stable across the year. The international export price for coal averaged just over $200 per tonne, significantly lower than prices experienced in 2022–23, but still above historical averages. Domestic spot gas market prices fell to an average of $12 per GJ for 2023–24.

Coal generators offered more coal at lower prices into the NEM in 2023–24. This was the result of easing domestic and international prices for coal, improved domestic availability and fewer coal generation outages. Falling costs also appear to have been assisted by a temporary cap on the price of black coal supplied to domestic coal-fired power stations. However, the impact of the $12 per GJ gas price cap on NEM gas-powered generation is less clear. The gas price cap has since been replaced with a mandatory gas code of conduct (chapter 4, section 4.3.1).

2.4.1 Market interventions

Coal price cap

In the months preceding the NEM market suspension of June 2022, several coal-fired generators reported severe under-delivery of coal. This was attributed to unseasonable rains that caused flooding, resulting in the closure of some 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.

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

As a result of directions given, the price of black coal sold to black coal-fired generators was capped at $125 per tonne in NSW. Although the directions to Queensland coal-fired generators are not public, the AER understands Queensland has a mechanism in place to achieve a similar effect. Additionally, black coal-fired generators in NSW were required to plan to maintain a minimum coal stockpile sufficient to meet at least 30 days of projected demand. Certain coal mines in NSW were required to reserve a proportion of future coal production to supply NSW coal-fired generators, as well as prioritise delivery to generators with low stockpiles.

The NSW directions ended on 30 June 2024.

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-fired generation is typically the most frequent price setter in Queensland and NSW. Other regions that don't use black coal as a generation fuel can still benefit through cheaper imports of electricity available via interconnection.

Following the implementation of these interventions, the AER observed some material change to the offer structure of some NSW black coal-fired 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 largely continued throughout the period of the directions. In the 2023–24 financial year, coal-fired generation output was higher than in the previous year and was offered into the market at relatively lower prices.

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

Gas price cap and mandatory code of conduct

In winter 2022 the abnormally high number of unplanned coal generator outages, among other exacerbating factors, saw the NEM become significantly more reliant on gas-powered generators (GPGs) 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.

On 9 December 2022, the Australian Government announced an emergency, temporary cap on the price of gas at $12 per GJ, which came into effect on 23 December 2022, for a 12-month period. The cap applied to gas sold by gas producers under contracts negotiated directly between parties and trades scheduled more than 3 days ahead of delivery agreed through the Gas Supply Hub.

The Australian Government further introduced a mandatory Gas Market Code, which commenced on 11 July 2023, with a 2-month transition period before the obligations came into effect. The purpose of the code is to ensure the domestic wholesale gas market supplies adequate gas at reasonable prices and on reasonable terms for both suppliers and buyers. The code includes a reasonable price provision, currently set at $12 per GJ, and an exemptions framework to incentivise short-term supply commitments and investment to meet ongoing domestic medium-term demand.

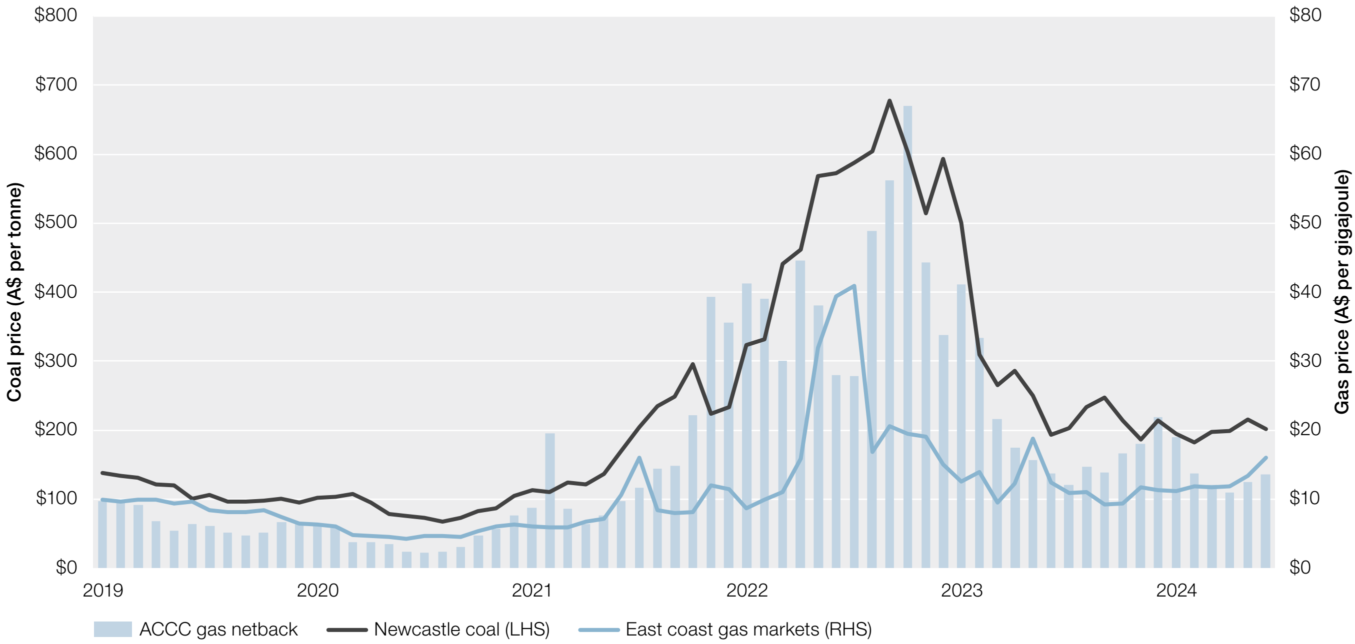
The effect of the gas price cap and mandatory code of conduct on wholesale electricity prices is less clear, with domestic trade through the spot markets exempt from the price cap. Chapter 3 includes more detailed analysis on wholesale gas prices, and the introduction of the gas price cap and Gas Market Code.

2.4.2 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 spot 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. In 2023–24 the international export price for coal averaged just over $200 per tonne, which equates to around $80 per MWh (Figure 2.7). These prices are significantly below the high prices that occurred in 2022, but higher than historical averages.

Over the same period, domestic spot gas market prices averaged around $12 while international LNG prices fell to the lowest level since early 2022. More detail on this is set out in chapter 3.

Figure 2.7 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 downstream spot markets. The ACCC gas netback is the Asian gas price benchmark plus additional costs associated with export.

Source: AER analysis using globalCOAL data; ACCC data.

2.5 Electricity derivative contract markets

Derivative 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.

Derivative (exchange-traded or over-the-counter) 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.

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, often referred to as swaptions.

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.

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.

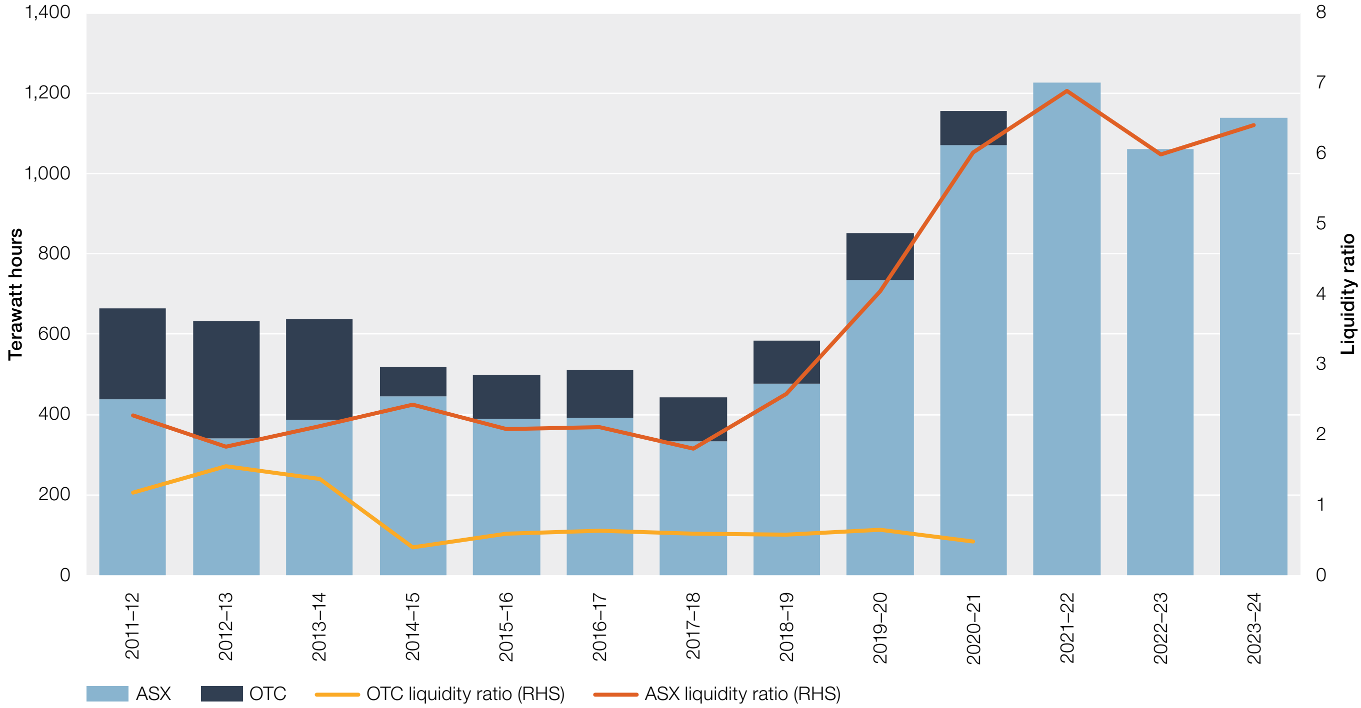
2.5.1 Contract market activity

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.

ASX trade has increased materially since the 2017–18 financial year, more than tripling in volume by 2020–21 and trade peaking in the following year. In 2023–24, ASX-traded volumes increased 7% from the previous year but remain lower than peak volumes traded in 2021–22 (Figure 2.8).

Figure 2.8 Traded volumes in electricity futures contracts



Note: This liquidity ratio measures how liquid the contract market is by comparing its traded volumes to the total volume of electricity demand. 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 graph refers to financial years for both markets. OTC contracts data has not been available since 2020–21. The OTC liquidity ratio forecast is the liquidity ratio comparing the total traded volumes to demand across the 4 combined regions.

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

Increases in the volume of trade on the ASX from 2018 to 2022 was primarily driven by an increase in the volume of swaptions contracts being traded and, to a lesser extent, an increase in the volume of base futures contracts being traded. The increased level of trade on swaptions contracts has driven the increase in trade of base futures contacts. This is because if a swaption contract is exercised, it results in the trade of the underlying base futures contract.

Base futures contracts are typically traded seasonally, with large volumes traded between April and June, and September and December. This in part reflects market participants exercising their options contracts leading into the start of the calendar and financial years.

The trade of both swaptions and base futures contracts peaked in 2022 and represented 51% (624 TWh) and 39% (474 TWh) of trade, respectively. Since 2022, trade in base futures contracts have fallen year on year, by 1% in 2023 and 7% in 2024. The volume of options contracts similarly fell 19% in 2023 but rebounded in 2024, increasing by 12%.

2.5.2 Contract market liquidity

The liquidity ratio measures how liquid the contract market is by comparing its traded volumes to the total volume of electricity demand. Higher market liquidity allows market participants to trade contracts more readily and can provide greater price certainty.

Contract liquidity increased in 2023–24 after falling the previous year, driven by the increase in trade of swaptions. The liquidity ratio (contract trading relative to underlying demand) across the NEM increased from around 600% to 640% (Figure 2.8), with all regions except Queensland recording an increase.

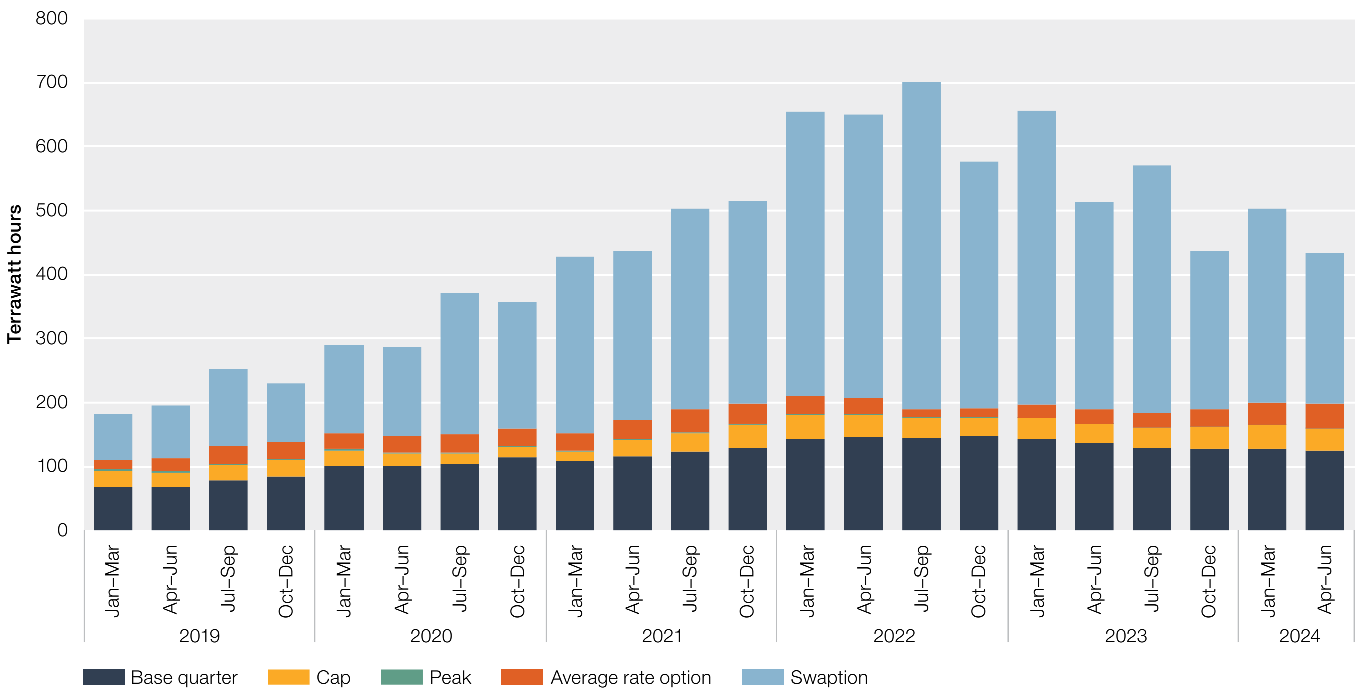
Total contract volumes across the ASX exceed the underlying demand for electricity by a significant margin in Queensland, Victoria and NSW. Given the extent of vertical integration in Victoria and NSW, this indicates that substantial trading (and re-trading) occurs in capacity made available for contracting.

Contract liquidity increased in South Australia but continues to remain poor, where traded volumes are less than underlying electricity demand. The volume of ASX contracts traded represented only 33% of underlying demand in 2023–24. The region's high proportion of renewable generation and relatively concentrated ownership of dispatchable generation has likely contributed to this weaker liquidity, with renewable energy less suited to underwriting the standard contracts listed on the ASX.

2.5.3 Open interest

Open interest reflects the total number of contracts that are not closed or delivered at the end of the day and is used as a measure of market activity. Open interest volumes continued to fall in the 2023–24 financial year, having peaked in the July to September quarter 2022 (Figure 2.9). Open interest volumes, primarily for swaptions, had more than tripled from 2019 to 2022, coinciding with increased volumes of trade in derivative contracts. Since mid-2022, open interest volumes in swaptions have been falling, but they remain above historical levels.

Figure 2.9 ASX open interest volumes



Source: AER; ASX Energy (data).

2.5.4 Composition of trade

Traded volumes increased in all regions except for Queensland in 2023–24 compared with the previous year. Traded volumes in Queensland, NSW and Victoria accounted for 36%, 33% and 31% of ASX volume, respectively. Trading in South Australia accounted for less than 0.3% of contract volumes despite the region accounting for around 7% of mainland NEM demand.

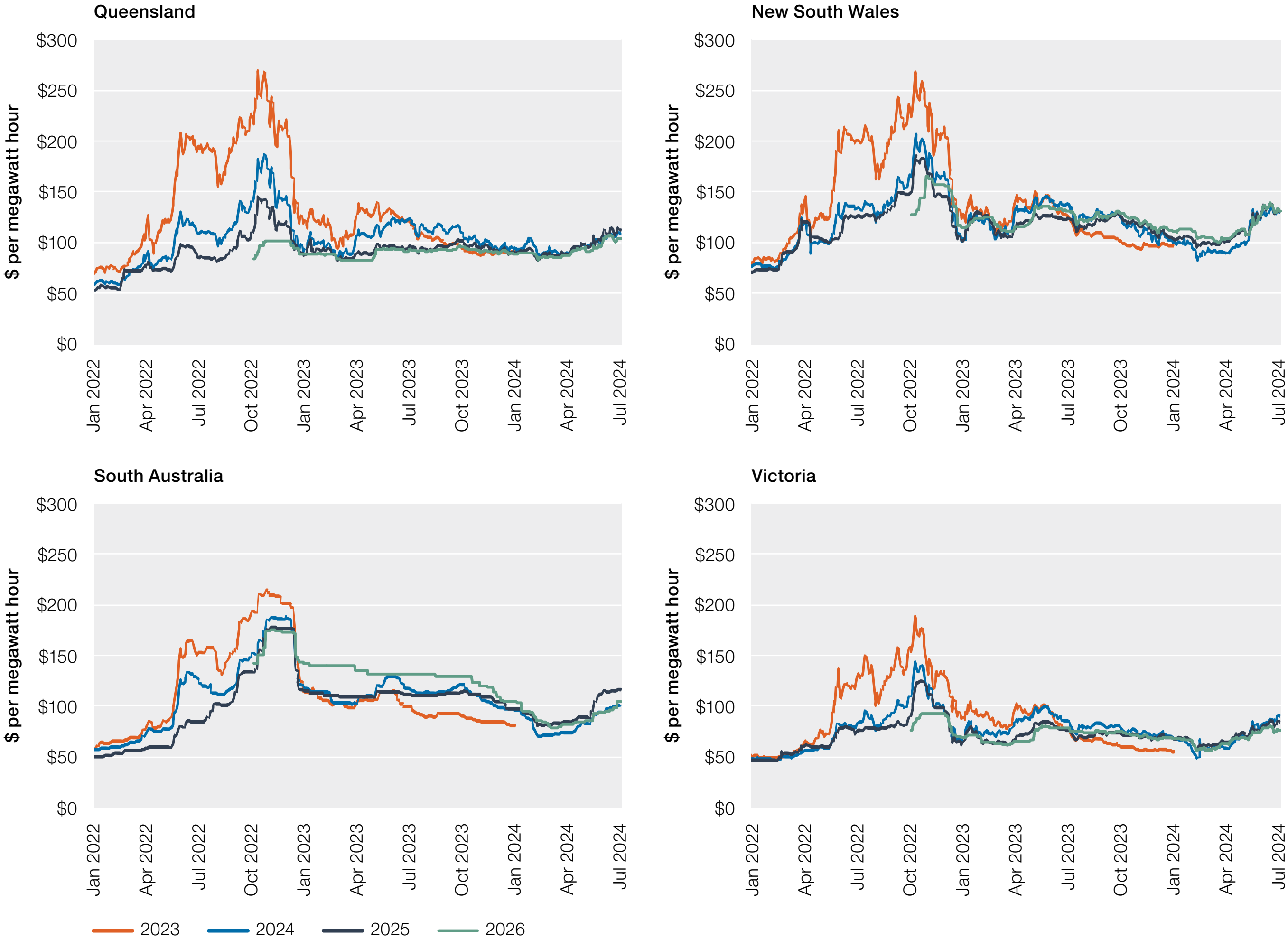
For 2023–24, swaptions (50%) were the most traded products on the ASX. The next most traded products were quarterly base futures, accounting for 39% of the traded volume. Average rate options (6%) and caps (6%) are traded at lower rates, with month base futures and peak contracts rarely traded (0.1%).

2.5.5 Contract prices

From mid-2023 to early 2024, calendar year base futures prices remained flat or fell in all mainland regions. Prices were lowest from February to March 2024 across all regions before increasing over the remainder of the financial year. Increases in base futures prices occurred in response to increased price volatility over April to June 2024, including several high price events, particularly in NSW.

At 30 June 2024, prices for 2024 contracts ranged between $91 per MWh in Victoria to $130 per MWh in NSW. Futures prices traded below the high prices that occurred in mid-2022 but remain higher than historical prices.

Figure 2.10 Prices for calendar year base futures

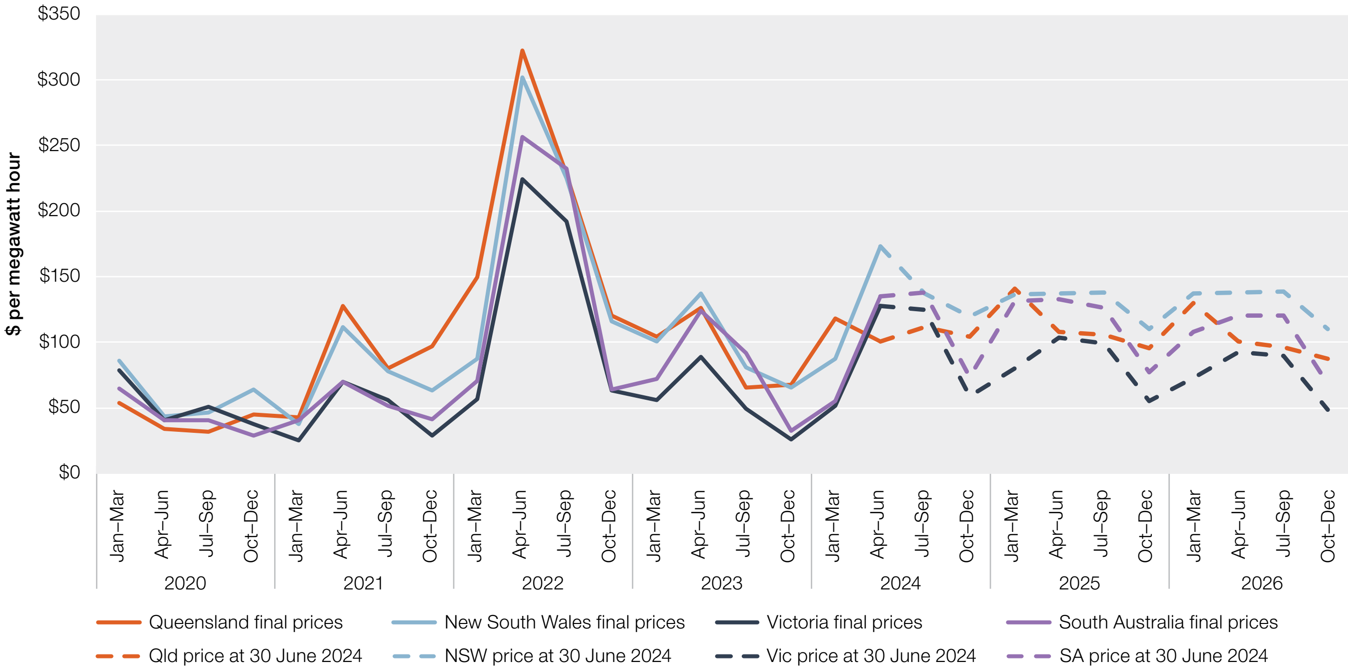


Source: AER; ASX Energy (data).

Prices for futures contracts in 2025 and 2026 mostly traded in line with prices for 2024 – prices as of 30 June 2024 ranged between $130 per MWh in NSW and $84 per MWh in Victoria for 2025 and $131 per MWh in NSW and $76 per MWh in Victoria for 2026. The outlook indicates that, while prices in future years are expected to be lower than in 2022, they are also expected to remain elevated compared with historical levels.

Quarterly base futures are stable for the remainder of 2024 but exhibit a seasonal profile, with prices lower in the October to December quarter when demand is usually at its lowest (Figure 2.11).

Figure 2.11 Prices for quarterly base futures



Note: Prices for quarterly base futures up to and including the April to June quarter are finalised (as they are no longer traded). Prices for quarterly base futures for the July to September quarter 2024 and beyond (which are still being traded) are as of 30 June 2024.

Source: AER; ASX Energy.

2.5.6 Access to contract markets

Access to contract markets, either via an exchange (ASX or FEX) 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 for 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.

Access to clearing services has been a key issue raised by participants in the past 2 years following the withdrawal of Bell Potter as an ASX clearing participant. To transact on either the ASX or FEX Global, a market participant requires a clearer to clear and settle the transaction. The Exchange Clearing House manages their risk by imposing margin requirements on their contracting counterparties, the clearing participants. The clearing participants then pass on these margin requirements to retailers and generators.

In 2023–24 the number of clearing service providers for electricity contracts on the ASX returned to 6, having fallen to 5 in the previous year. Marex has entered the market and onboarded new clients. The ASX has also confirmed that a new seventh clearing member will soon be ready to offer clearing services.

2.5.7 Developments in contract markets

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.[15] 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.

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

2.6 Electricity demand and consumption

Electricity 'grid demand' is demand for electricity produced by generators and sold through the NEM. Electricity consumption refers to the total amount of electricity consumed and includes electricity produced by consumer energy resources, such as rooftop solar and home storage batteries. Consumer energy resources reduce grid demand because they replace electricity that would otherwise be supplied by large generators.

Electricity grid demand is a key driver of wholesale electricity prices and varies by time of day and season. During a 24-hour period, grid demand typically peaks in the early evening when residential use increases and rooftop solar generation falls. Seasonal peaks occur in winter (driven by heating loads) and summer (for air conditioning), often reaching maximum levels on days of extreme heat.

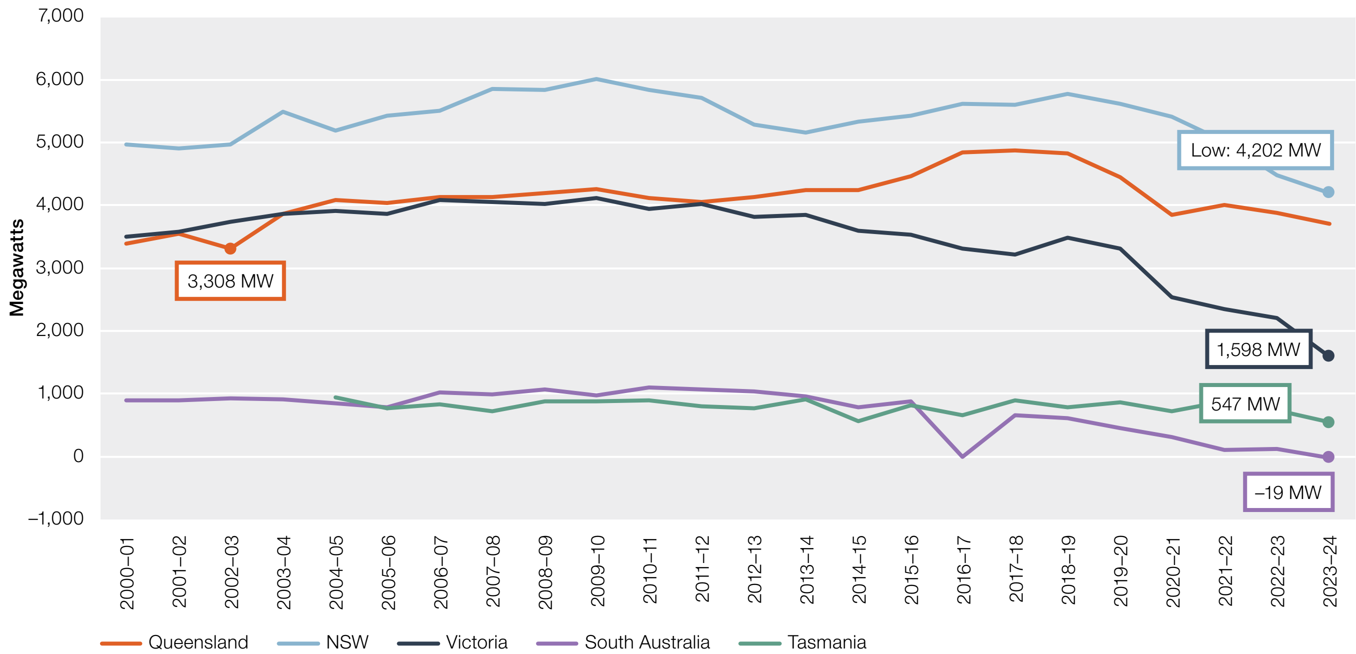
Electricity consumption has increased over the past decade. Increased consumption has been met by increasing rooftop solar generation, offsetting total grid demand. In 2023–24, 213 TWh of electricity was consumed by energy users in the NEM, a 2% increase from the previous year and the highest level recorded (Figure 2.15). Grid demand has remained relatively steady over the past few years but has fallen by nearly 15 TWh since 2011–12.

2.6.1 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 in 2023–24. Record rooftop solar output for a 30-minute period occurred on 2 February 2024, totalling 13,311 MWh.

In 2023–24, minimum demand fell in all regions (Figure 2.12). Minimum demand set record lows in all regions except Queensland, which, while not a record, has fallen 24% from its peak in 2017–18. In South Australia, minimum grid demand was –19 MWh, the first time a region has experienced negative minimum demand. South Australia has the highest percentage of installed rooftop solar capacity, 40% of its total installed capacity, and the highest percentage of renewable capacity, 74% of its total installed capacity (Figure 2.14).

Figure 2.12 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 2016.

Source: AER; AEMO (data).

AEMO has noted that minimum grid demand is forecast to fall low enough to pose a risk to system security in coming years.[16] As rooftop solar output rises, demand at certain periods of the day is forecast to continue falling, with grid generators responding by withdrawing supply. Coal and gas-fired generators offer multiple essential system services alongside electricity supply, including voltage management, frequency control and inertia. Without these generators operating, the grid may be unable to operate safely unless essential system services come from elsewhere.

Several mechanisms have been developed to respond to grid demand low enough to threaten system security. Where gaps in system security occur, AEMO can intervene in the market to maintain system security.[17] 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. More information on system security is set out in section 2.13.

Consumer energy resources have the potential to offset some system security needs by shifting demand from peak periods into times of minimum demand or increasing demand during those times by charging batteries or EVs.

2.6.2 Maximum grid demand

In 2023–24, maximum grid demand rose compared with the previous year in Victoria, NSW and Queensland, with Queensland setting a record high. In most regions, high grid 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 grid demand for the financial year occurred during the January to March quarter, between 4:00 pm and 7:00 pm. For Tasmania, high demand typically occurs in winter when heating demand is at its greatest.

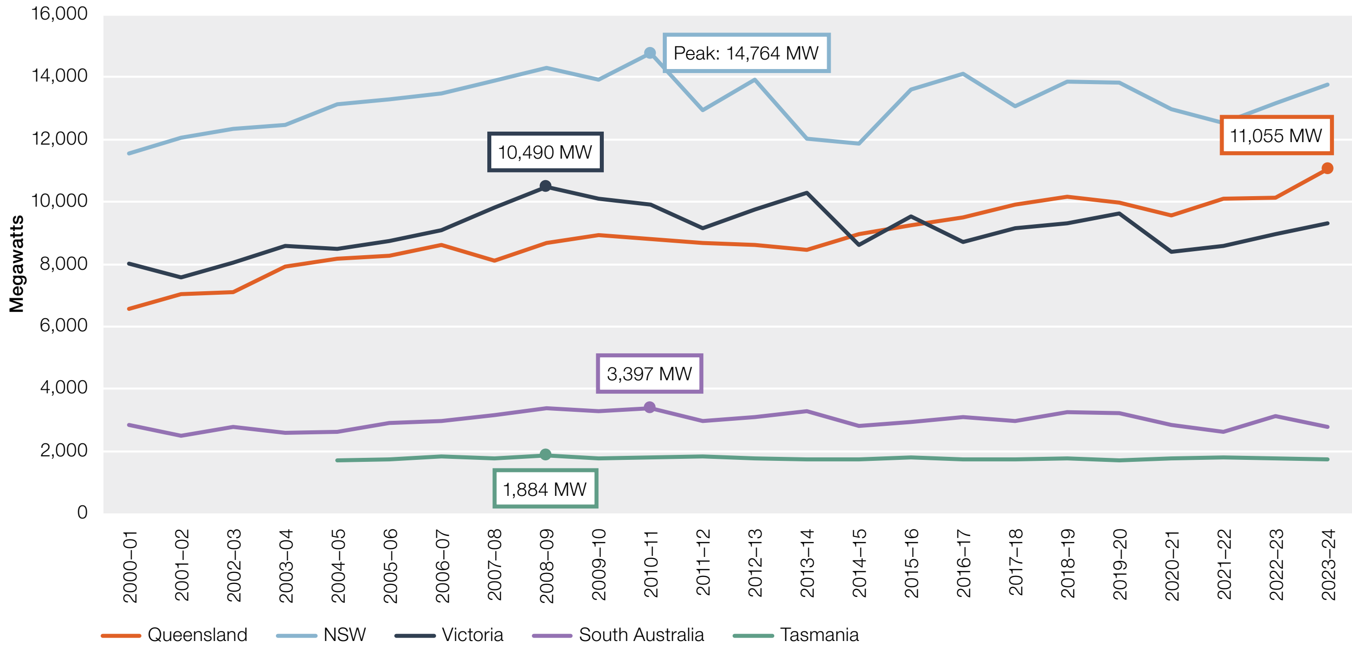
Looking forward, AEMO's 2023 Electricity Statement of Opportunities central planning scenario sees maximum grid demand increasing over the next 10 years.[18] High demand events pose significant likelihood of high wholesale prices should available generation be insufficient to respond. High maximum demand also increases the need to invest in increased network capacity to manage peak flows, unless demand can be shifted to times of surplus generation or energy efficiency can be improved to reduce demand overall.

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

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

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

Figure 2.13 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).

2.7 Sources of generation in the NEM

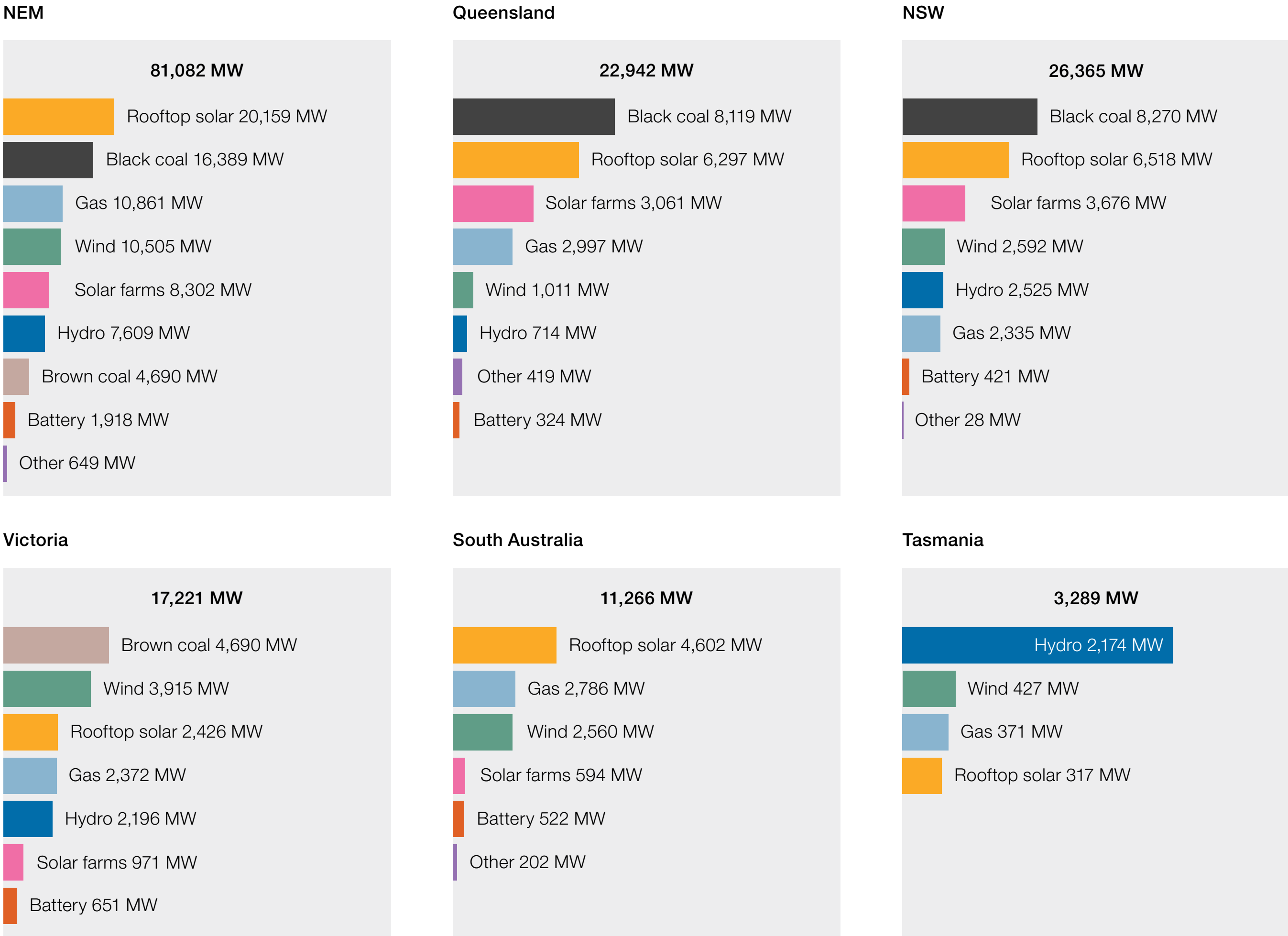
The NEM's generation fleet uses a mix of technologies to produce electricity (Figure 2.14). There are 2 ways to measure the NEM's generation mix – based on the registered capacity of each generating unit or based on their total output.

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, with different generation technologies able to produce electricity at different rates of their capacity. Thermal generators typically produce at a high rate relative to capacity because they can generate continuously throughout the day. Renewable generation is intermittent and produces electricity at a lower rate relative to capacity.

A fuel type's relative share of total generation capacity depends on whether rooftop solar is considered part of the generation mix. 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 2023–24, total generation capacity measured 81,082 MW. Rooftop solar was the highest capacity totalling 25% of registered capacity, followed by black coal at 20%. Renewable technologies (rooftop solar, solar farms, wind, hydro and battery) made up 60% of capacity. Capacity for renewable technologies increased from the previous year, while the capacity of fossil fuel generators (black and brown coal and gas) largely remained the same.

Figure 2.14 Generation capacity, by fuel source

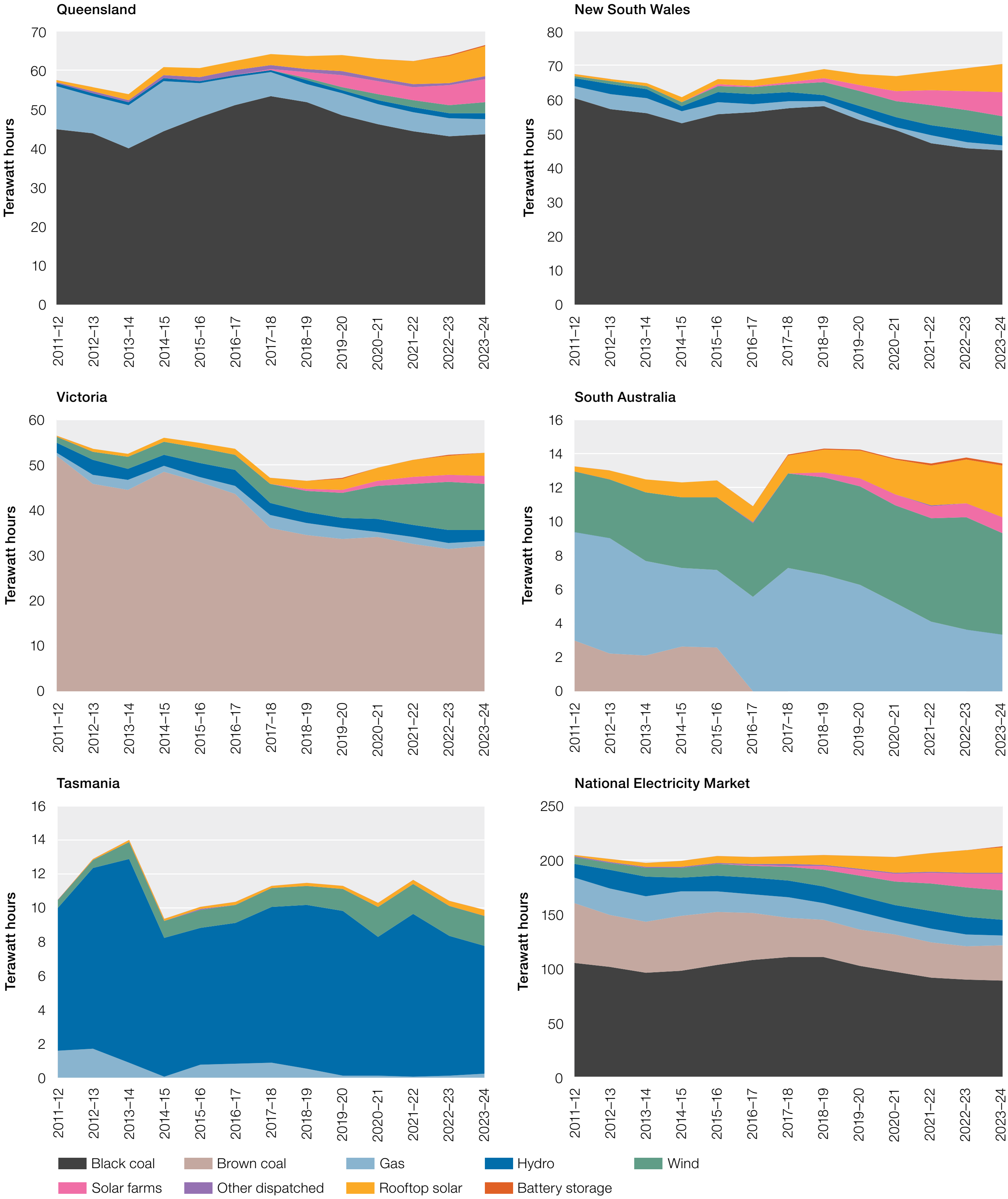


Note: Generation capacity at 30 June 2024. Other dispatch includes biomass, waste gas, diesel and liquid fuels. Loads and non-scheduled generation have been excluded. Solar capacity is maximum capacity, rather than registered capacity.

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

Generation output (Figure 2.15) refers to the total amount of electricity produced over a given period. In 2023–24, 213 TWh of electricity was generated. Fossil fuel generators produced 61% of electricity, a decrease of 1.5% from the previous year. Solar (solar farms and rooftop solar) and wind output increased to 31% of total generation.

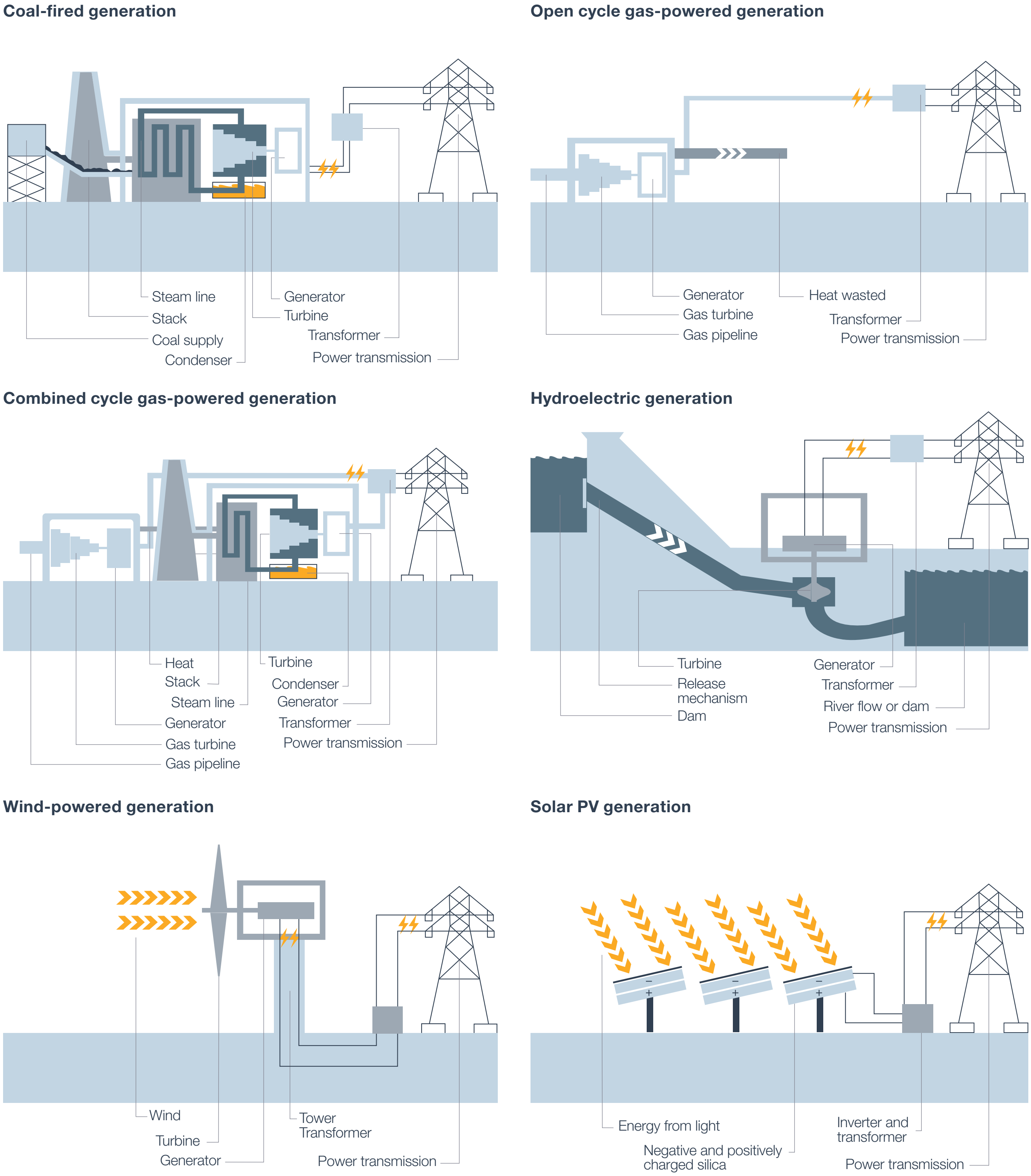
Figure 2.15 Generation output, by fuel source



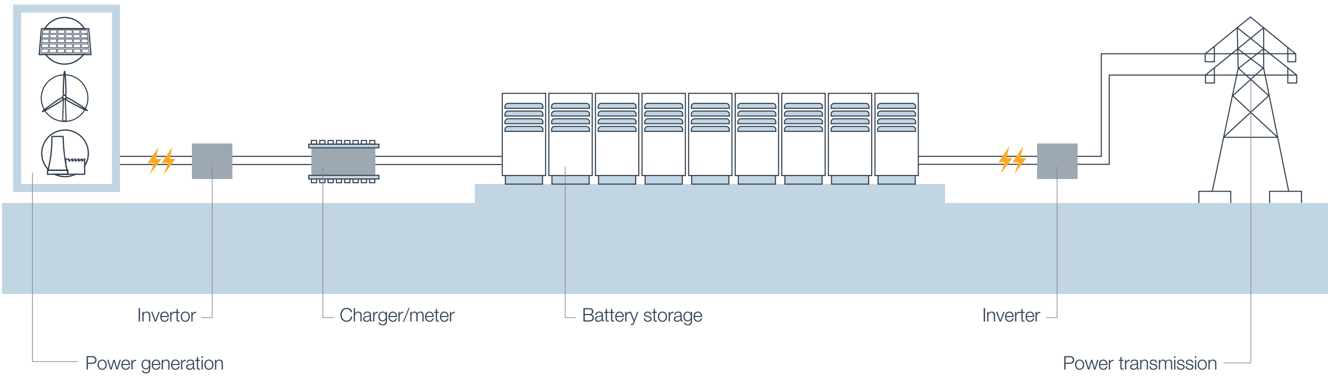
Note: Other dispatch includes biomass, waste gas, diesel and liquid fuels.
Source: AER; AEMO (data).

The various generation technologies have differing characteristics (Figure 2.16). 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 2.16 NEM generation technologies



Battery energy storage system



2.7.1 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. 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 57% of all electricity traded through the market in the 2023–24 financial year (Figure 2.17). In absolute terms, coal-fired generation increased marginally compared with 2022–23.

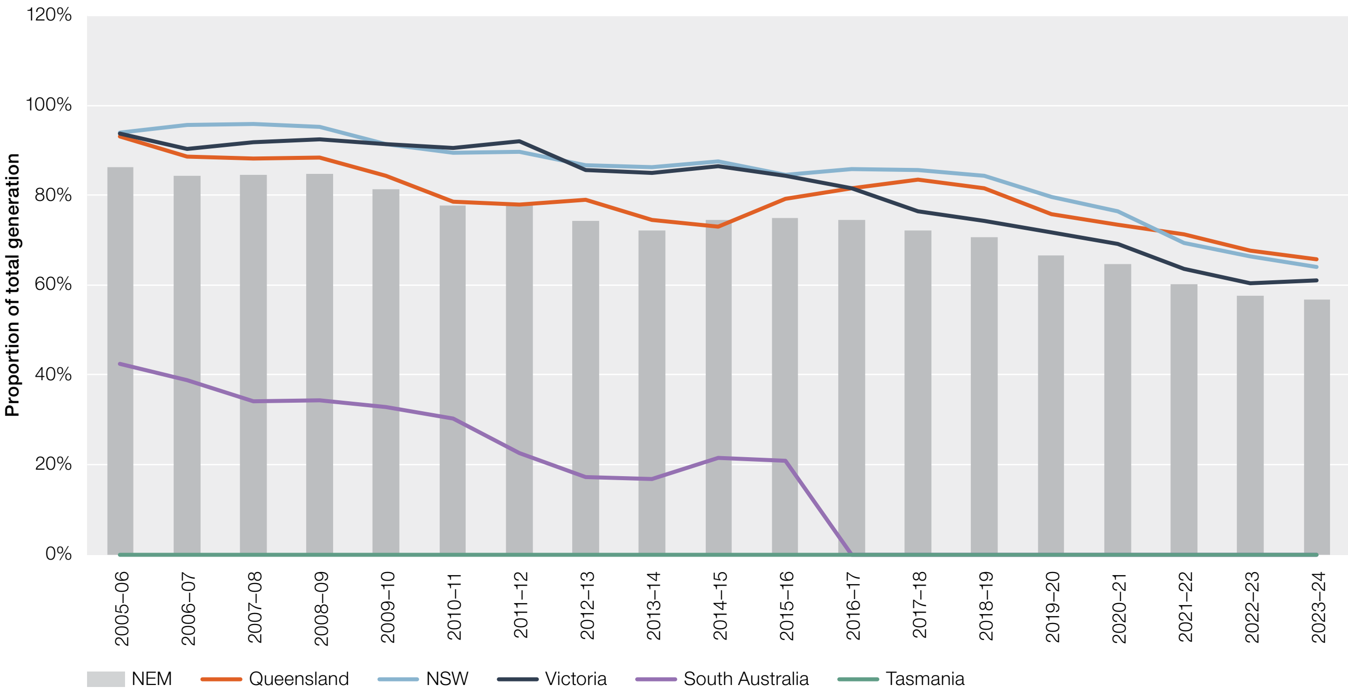
Coal plants operate in Queensland, NSW and Victoria. Generators in Queensland and NSW burn black coal and generators in Victoria depend on brown coal. Black coal produces more energy than brown coal because it has lower water content and 30–40% lower greenhouse gas emissions when used to generate electricity. 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 5 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 2.17).

Figure 2.17 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 remaining coal-fired power stations. NSW's Liddell power station closed in April 2023, and retirements have been announced for all but one of the remaining coal-fired power stations, with half announcing they will close by 2035. AEMO's most recent Integrated System Plan[19] suggests that, to meet government policy objectives, the remaining coal fleet will close 2 to 3 times faster than that, with all coal generators retired by 2037–38.

Current announcements for upcoming coal closures include:

- Eraring (2,880 MW) – Australia's largest power station. It was initially due to close in 2032 but its owner, Origin Energy, brought the closure date forward to 2024. In 2024 the NSW Government came to an agreement with Origin to delay closure until August 2027.[20]
- Yallourn (1,480 MW) – In 2021 EnergyAustralia announced that it would retire Victoria's Yallourn power station in 2028, 4 years earlier than planned.
- Callide B (840 MW) – CS Energy's Callide B power station is also expected to close in 2028.
- Vales Point B (1,320 MW) – Delta Energy's Vales Point B power station was expected to close in 2029 but has been pushed back to 2033.
- Bayswater and Loy Yang A (4,850 MW) – In early 2022, AGL announced the accelerated closure of its remaining coal-fired power stations of Bayswater (2030–2033) and Loy Yang A (2035).

While the exit of coal-fired 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 over the next 10 years should the rate of investment in firm capacity (that which is dispatchable on command) fail to increase significantly[21] Further information on system reliability is set out in section 2.12.

19 AEMO, Integrated System Plan, Australian Energy Market Operator, June 2024.

20 NSW Government, NSW Government secures 2-year extension to Eraring Power Station, NSW Government, 23 May 2024.

21 AEMO, Update to the 2023 Electricity Statement of Opportunities, Australian Energy Market Operator, May 2024.

Coal outages fell in 2023–24 but remain a risk

Coal-fired 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 peak winter demand.

While coal-fired generator outages have been increasing over time, outages in the 2023–24 financial year decreased compared with the previous year, averaging 2.7 GW per quarter.

2.7.2 Gas-powered generation

Two dominant types of gas-powered generation technologies operate in the NEM (Figure 2.16). 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-powered generation more responsive than coal to prices since the start of 5minute settlement in October 2021.

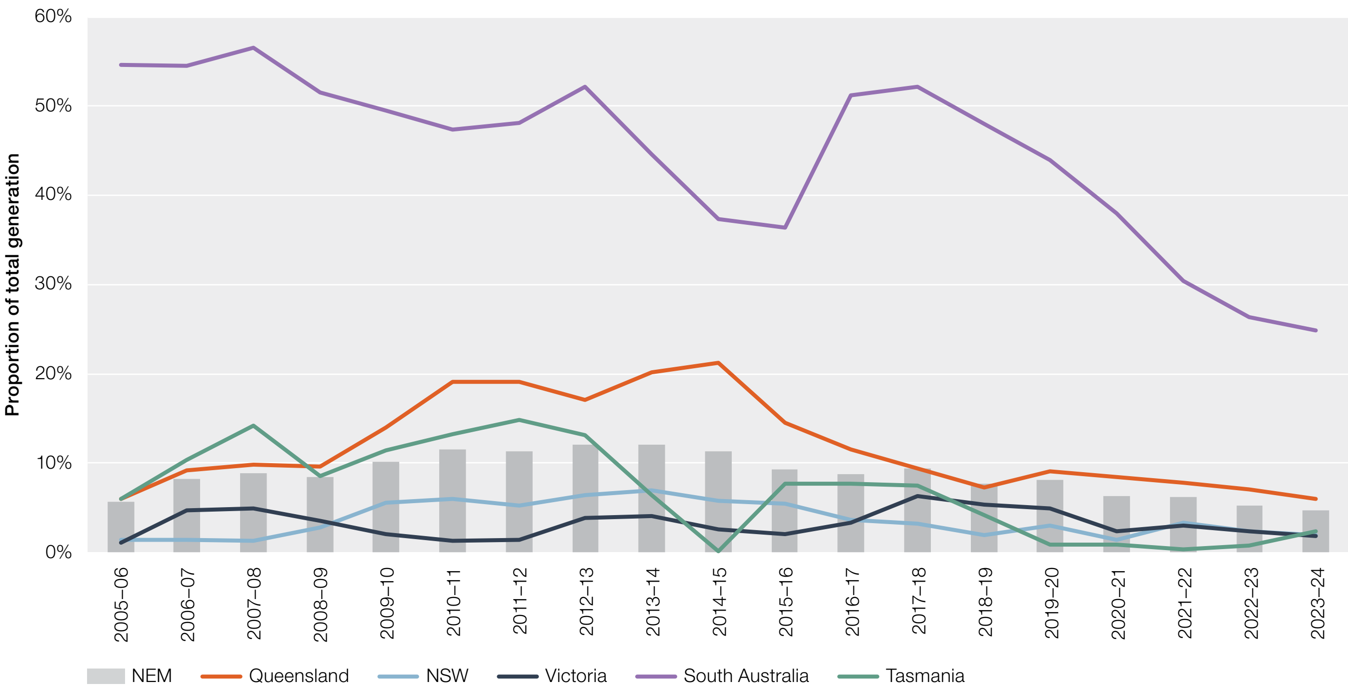
The ability of gas plants to respond quickly to sudden changes in the market makes them a useful complement to wind and solar generation, which can be affected by sudden changes in weather conditions. The most efficient gas-powered generation is less than half as emissions intensive as the most efficient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

Gas is generally the most expensive fuel for electricity generation, so gas generators typically operate as 'flexible' or 'peaking' plants, preferring to be dispatched only when wholesale prices are high. Gas will increasingly be used as a flexible generation technology. It will be used to support renewables by supplying energy during periods of renewable drought and extreme peak demand periods. Gas generation also provides system security services to maintain grid stability, as is the case currently in South Australia, until cheaper solutions are implemented. AEMO's latest Integrated System Plan[22] calls for 15 GW of gas-powered generation by 2050 to help firm renewable energy in the absence of suitable renewable options.

Across the NEM, gas-powered plants supplied only 5% of electricity generated in 2023–24. South Australia relies more heavily on gas-powered generation than other regions, primarily because it has no coal-fired generation. In 2023–24, the state produced 25% of its local generation from gas-powered generation. Gas usage in South Australia has decreased over recent years as renewable generation increased and gas-powered generation moved to a firming role (Figure 2.18).

22 AEMO, 2024 Integrated System Plan, Australian Energy Market Operator, June 2024.

Figure 2.18 Proportion of total generation by region, gas



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

In response to the closure of the Liddell power station, the previous Australian Government supported the entry of 2 new gas generators. In early 2024, the construction of EnergyAustralia's Tallawarra B gas power station (320 MW) was completed, and it is now generating electricity in the NEM. It is based in NSW's Illawarra region and can use a blend of hydrogen and natural gas.

Additionally, Snowy Hydro plans to construct a 660 MW open-cycle gas-powered power station at Kurri Kurri in NSW's 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.

2.7.3 Hydro-electric generation

Hydropower uses the force of moving water to generate power. The technology involves channelling falling water through turbines. The pressure of flowing water on the blades rotates a shaft and drives an electrical generator, converting the motion into electrical energy (Figure 2.16). Like coal and gas plants, hydro-electric 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 hydro-electric 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.

Hydro-electric 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, hydro-electric generators typically operate as 'flexible' or 'peaking' plant, similar to gas-powered generation. As the NEM transitions to increased renewable generation, hydro-electric generation will play an important role firming renewables, uniquely placed to provide longer-term storage and balance energy availability across seasons.

Conditions in the electricity market affect incentives for hydro-electric generation. Subject to environmental water release obligations, hydro-electric 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)[23] scheme also affect incentives to produce.

Hydro-electric 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.[24] In 2024, hydro-electric generation has been constrained in Tasmania due to low storage levels following below average rainfall in the region.

In the 2023–24 financial year, hydro-electric generators accounted for 9% of capacity in the NEM and supplied 7% of electricity generated. Tasmania is the region most reliant on hydro-electric generation, with 76% of its 2023–24 generation from this source. NSW and Victoria also have significant hydro-electric generation plants located in the Snowy Mountains region.

2.7.4 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 2.16).

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.

Wind-powered generation continues to grow in the NEM, with 822 MW of capacity added in the 2023–24 financial year. In 2023–24 wind-powered generation accounted for 13% of total generation in the NEM. While capacity was added, total output was slightly lower than the previous year due to differences in wind conditions. Generation was down across the year, and particularly low in the April to June quarter 2024, which had the lowest amount of quarterly wind-powered generation since the same period in 2021.

Wind-powered generation penetration is especially strong in South Australia, where it provided 45% of the state's electricity output in 2023–24.

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

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

2.7.5 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 2.16).

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. In 2023–24, solar farms made up 10% of registered capacity and 7% of generation output.

Generation from solar farms continued to break output records in 2023–24 as new capacity entered the market. Solar generation was higher in all quarters relative to comparative quarters in the previous year, and the absolute quarterly output record was broken in the October to December quarter 2023 and then again in the January to March quarter 2024.

Relatedly, 2023–24 saw record quarterly negative price intervals in the July to September 2023 quarter and subsequently in the October to December 2023 quarter. 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 sufficient infrastructure to store it so it can be dispatched during evening demand peaks when and where it is needed. As consumer energy resources grow, the role of storage in avoiding curtailment of rooftop solar and the resulting loss of income for consumers becomes even more significant.

2.7.6 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 hydro-electricity. As the 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 plants 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.

Batteries made up just under 2 GW of capacity in the NEM in 2023–24. Total output from batteries increased compared with the previous year but accounted for less than 0.5% of total generation output.

AEMO's latest ISP[25] forecasts grid-scale battery storage to grow rapidly, peaking at 21,912 MW in 2037–38 before stabilising and eventually falling to 12,007 MW in 2050. Over the next year, around 2 GW of battery capacity is expected to enter the NEM, nearly doubling existing capacity. This includes the Waratah Super Battery, which at 700 MW will be the largest battery in the NEM.

Pumped hydro-electricity

Large-scale storage can be provided through pumped hydro-electric projects, which allow hydro-electric 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 hydro-electric 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 hydro-electricity is the basis of the Snowy 2.0 (2,000 MW) and Battery of the Nation (2,500 MW) projects in NSW and Tasmania. In its April 2024 project update, Snowy Hydro's target date for commercial operation of all units is December 2028, a year earlier than reported in our last report.[26]

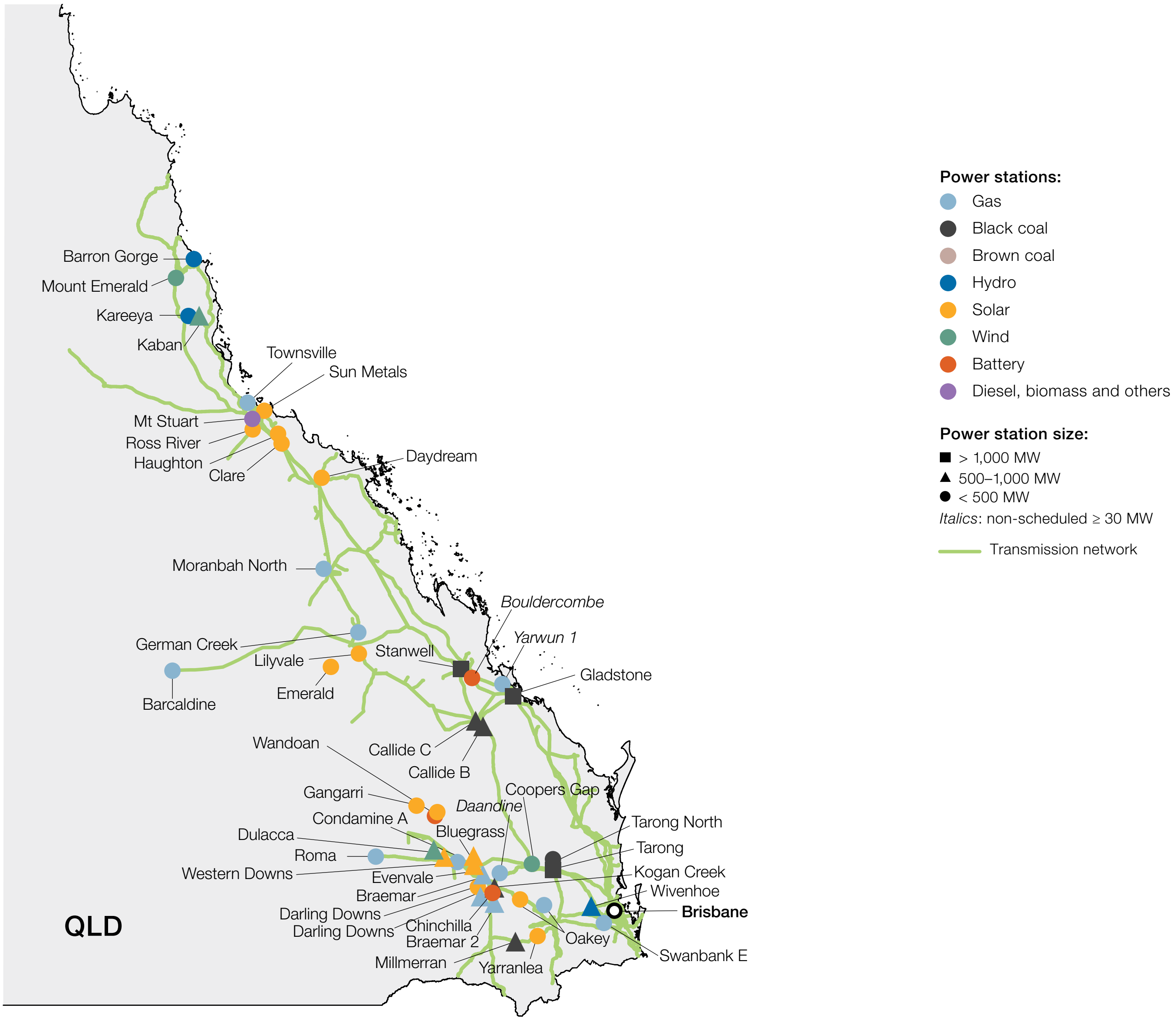
25 AEMO, 2024 Integrated System Plan, Australian Energy Market Operator, June 2024.

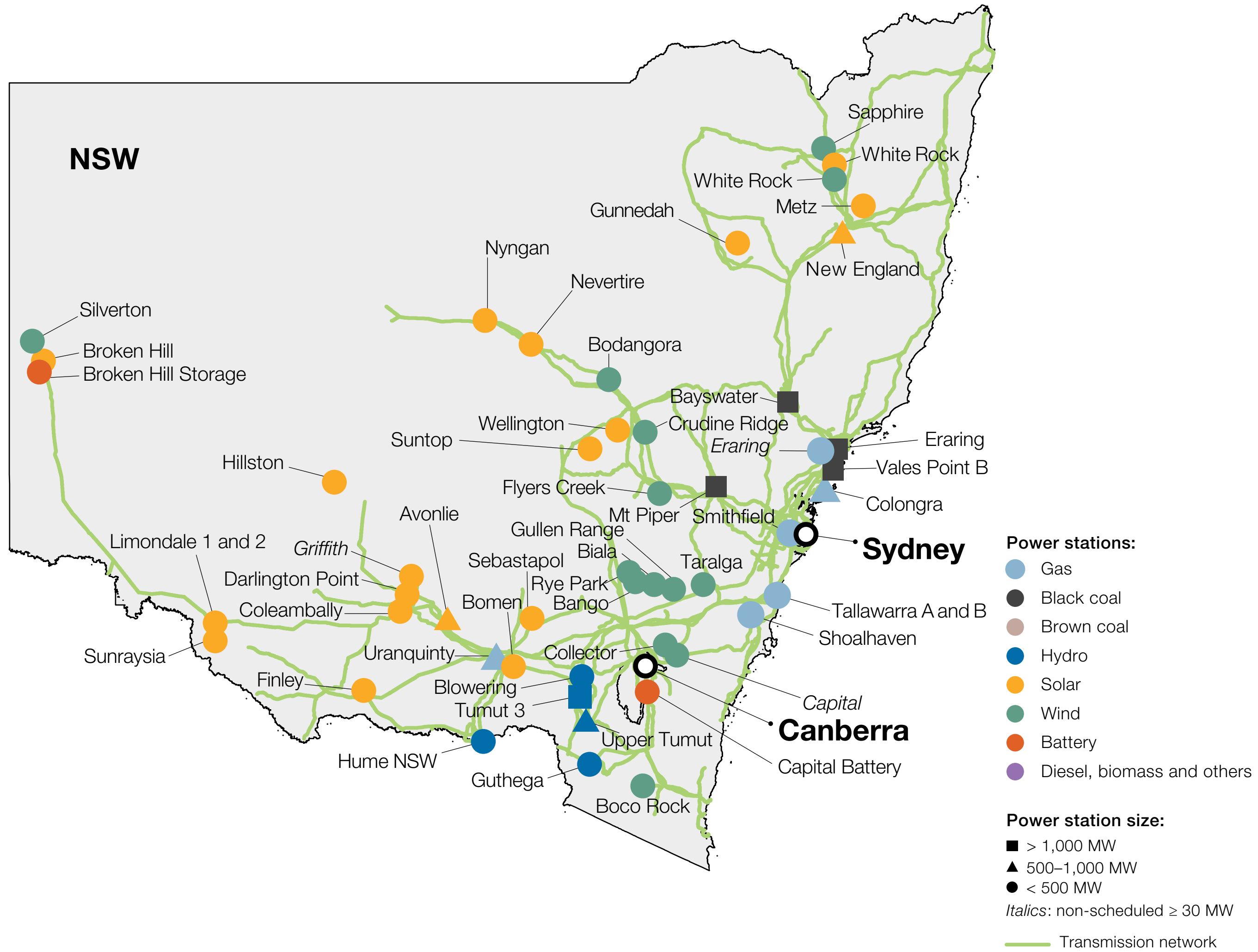
26 Snowy Hydro, Snowy 2.0 Project Update – April 2024, April 2024.

2.7.7 Generator information

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

Figure 2.19 Generators in the NEM




NSW
Sapphire
White Rock
White Rock
Metz
Gunnedah
New England
Nyngan
Nevertire
Silverton
Broken Hill
Broken Hill Storage
Bodangora
Bayswater
Wellington
Crudine Ridge
Suntop
Eraring
Eraring
Vales Point B
Hillston
Flyers Creek
Colongra
Avonlie
Mt Piper
Smithfield
Gullen Range
Limondale 1 and 2
Griffith
Sydney
Biala
Sebastapol
Taralga
Darlington Point
Rye Park
Bomen
Bango
Coleambally
Tallawarra A and B
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:
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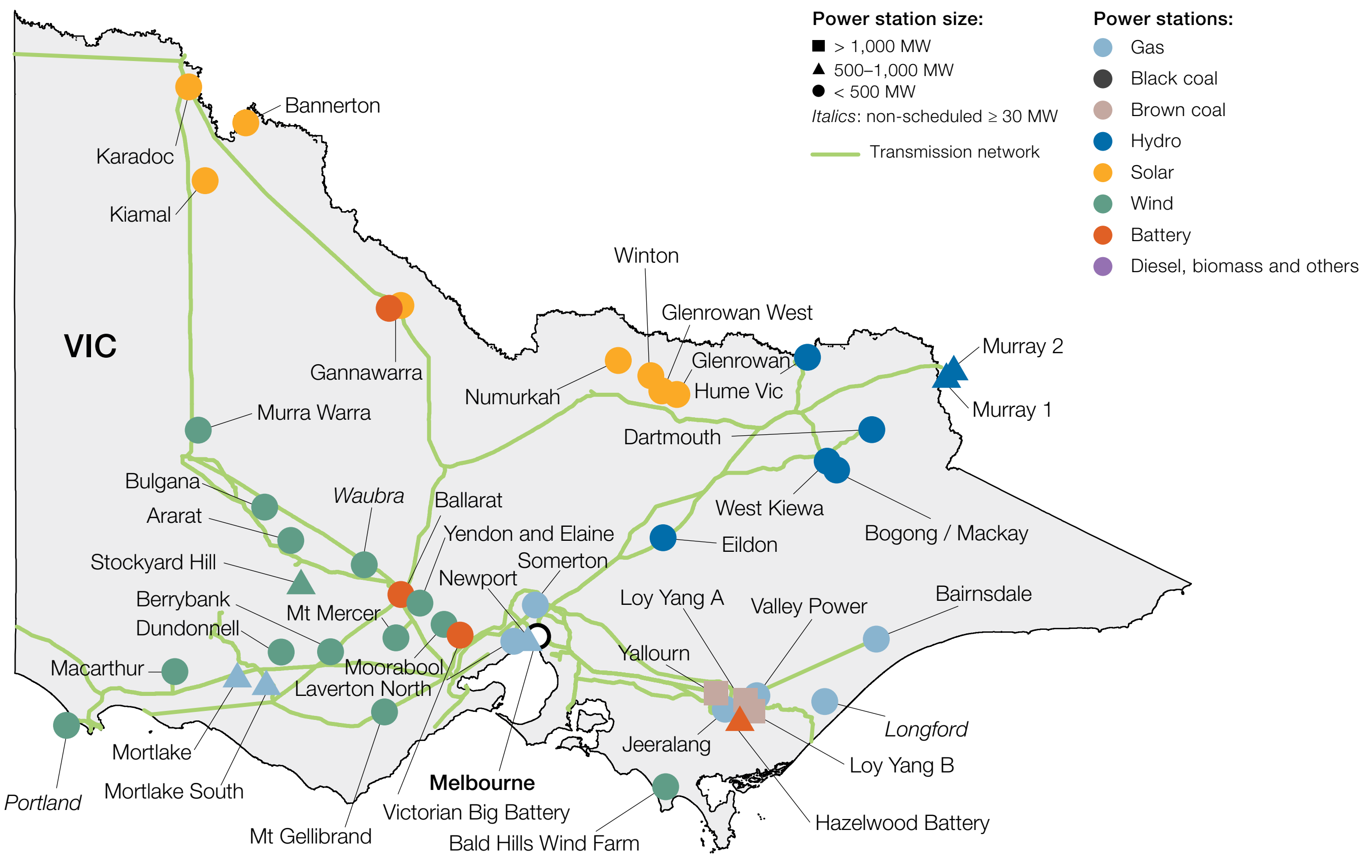
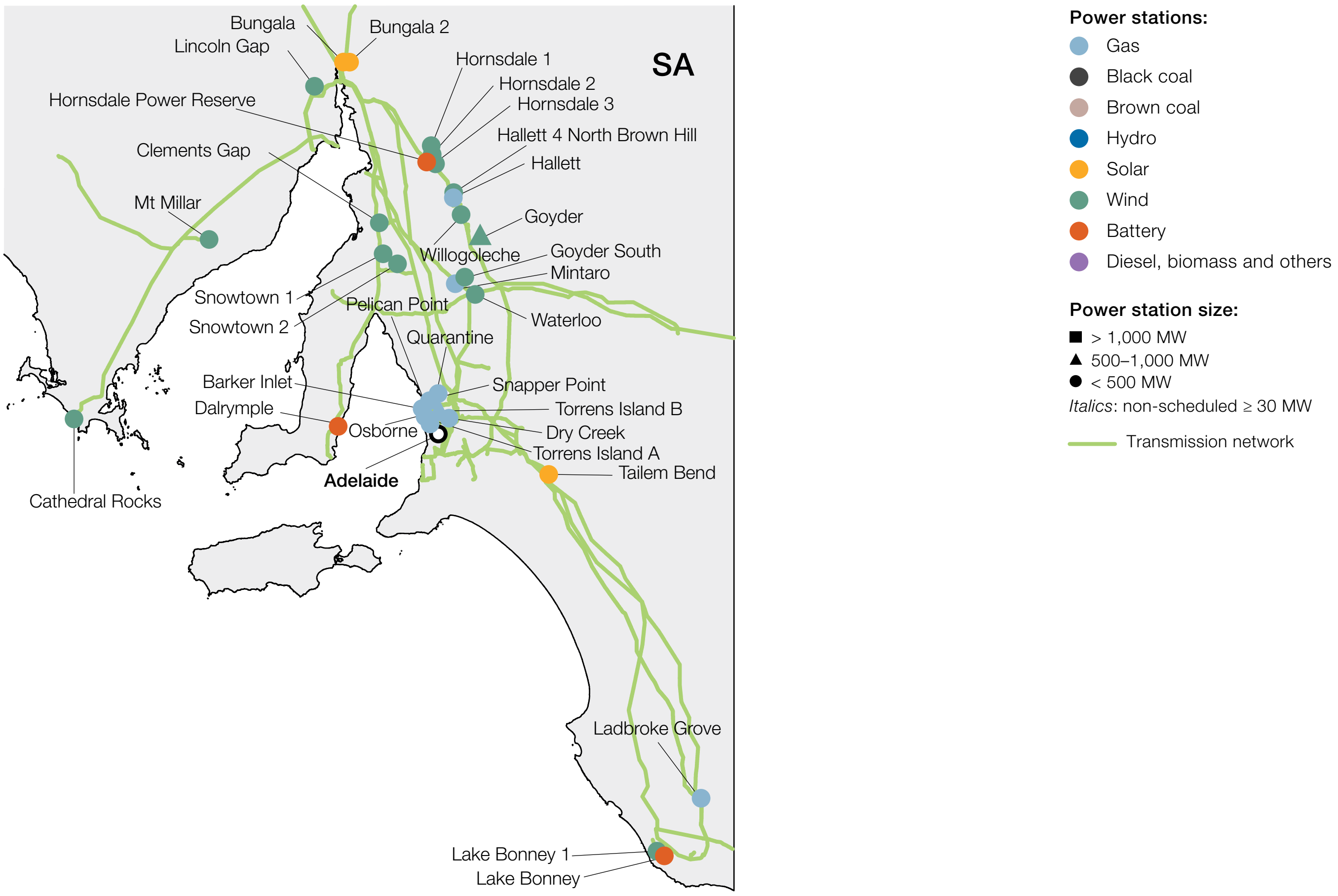
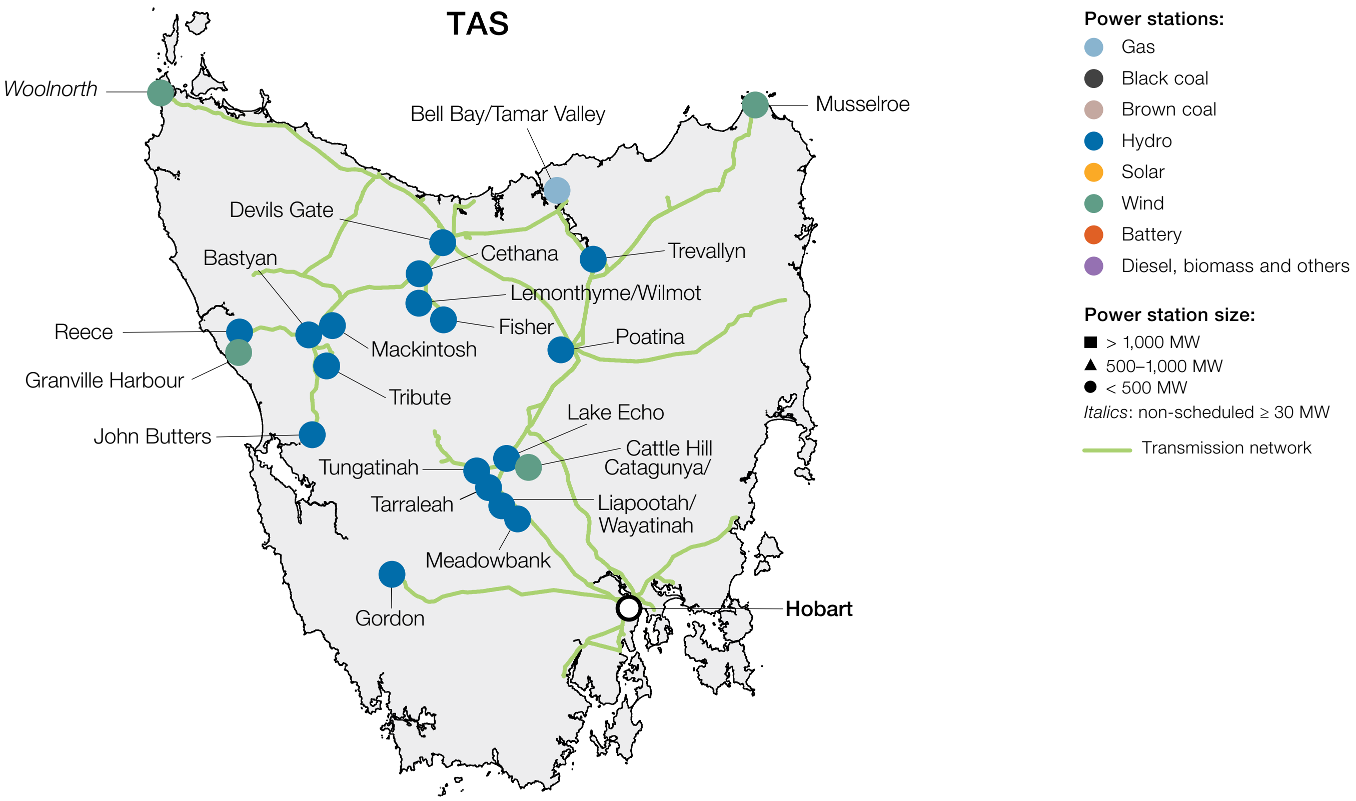
500–1,000 MW
< 500 MW
Italics: non-scheduled ≥ 30 MW
Transmission network


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





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

2.8 Consumer energy resources

Alongside major shifts occurring in the technology mix at the grid level, significant changes are occurring in small-scale electricity supply with the uptake of consumer energy resources (CER). 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.

2.8.1 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 Australian and state government incentives, households and businesses have continued to install large volumes of rooftop solar capacity every year since 2015. In the 2023–24 financial year, rooftop solar capacity totalled over 20 GW (Figure 2.14). Queensland and NSW have the most installed capacity, but South Australia has the highest relative rooftop solar capacity, making up 40% of its total capacity.

In 2023–24, output from rooftop solar increased by 16% compared with the previous year, and total output has more than tripled since 2017–18. In 2023–24 it accounted for over 11% of total generation, up from 10% the previous year.

The rapid uptake of rooftop solar has dramatically changed the shape of daily spot price and grid demand 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.

2.8.2 CER 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. Community batteries or other distribution-connected batteries can also provide storage close to sources of rooftop solar generation, lowering transport costs and curtailment due to congestion.

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. Coordinated CER storage is projected to exceed the growth in large-scale utility storage in the NEM in the coming years.[27]

Small-scale battery installations in the NEM saw storage capacity increase by 64% from 2022 to 2023, with 2023 having the largest volume of storage capacity additions in the NEM to date. In the first half of 2024, a further 12% of storage capacity has been added compared with 2023, with total installed storage capacity totalling 1,755 MVAh.[28]

27 CER storage means consumer energy resources such as batteries and electric vehicles. AEMO, 2024 Integrated System Plan, Australian Energy Market Operator, June 2024.

28 AEMO, DER Data Dashboard, Australian Energy Market Operator, accessed 26 August 2024.

2.8.3 Bespoke tariffs

The use of bespoke tariffs for commercial and industrial consumers is a longstanding method of incentivising customers to shape their energy demand around the available capacity on the network by offering them cheaper prices at times of abundant electricity supply.

For small customers, this has historically been known as controlled load. It has previously involved the installation of a separate meter for consumption-heavy appliances such as hot water heaters, 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 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.

As technology advances, including home energy systems, and smart meters are rolled out, the potential for new, innovative controlled load products has increased beyond the traditional application to hot water heaters and pool pumps to include a wider range of loads including EV charging.[29] There are trials of two-way charging taking place, where an EV can either discharge electricity to power a home or export energy to the grid when it is needed.[30]

2.8.4 Orchestrated CER

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, orchestrated CER can mitigate high spot prices and prevent potential blackouts and receive credits on their electricity bills for what they contribute.

AEMO forecasts within its optimal development path that coordinated consumer energy resources, including virtual power plants (VPPs), vehicle to grid and other coordinated CER storage, will need to provide 31 GW of dispatchable storage capacity by 2050. Orchestration is also important for system security. As the volume of unscheduled price-responsive resources such as VPPs grows, this could create problems for the grid through deviations from forecast demand. AEMC released a draft determination in July 2024 setting out the potential issues and options for better integrating CER into AEMO's scheduling and dispatch functions, with a final determination due by the end of 2024.[31]

29 ARENA, Flexible Demand, accessed 6 September 2024.

30 Endeavour Energy, EV charging trial, accessed 24 September 2024.

31 AEMC, Integrating price-responsiveness resources into the NEM, 25 July 2024, Australian Energy Market Commission, accessed 16 September 2024.

2.9 Trade across regions

Transmission interconnectors enable energy transfers between the NEM's 5 regions (mapped and listed in chapter 3). Interconnectors generally deliver energy from lower priced regions to higher priced regions. They also increase the reliability and security of the power system by enabling demand in one region to be met by generation from an adjacent region.

The ability of generators to supply energy to other regions is limited by the capacity of the transmission network. This capacity can change depending on the direction of flow, outages on the network or other physical constraints and limits AEMO imposes to manage system security.

An interconnector is constrained when the flow across it reaches its technical limit. When an interconnector is constrained, cheaper sources of generation in one region cannot replace more expensive generation in another, effectively separating those regions into separate markets (price separation). Interconnector constraints are often a factor in high price events.

To support the transition to renewable generation, new transmission infrastructure will be needed. AEMO's 2024 Integrated System Plan provides a coordinated whole-of-system plan for efficient development of the power system in the NEM to ensure needs are met in the long-term interests of consumers. As part of this transition, several major interconnector transmission projects are planned or underway. More information on transmission projects is set out in chapter 3.

Queensland and Victoria tend to be net exporters of energy, providing surplus baseload energy to NSW and South Australia. This was the case in the 2023–24 financial year, with Queensland and Victoria net exporters of energy and NSW and South Australia net importers. Tasmania's trade position varies with environmental and market conditions; in 2023–24 it was a net importer of electricity.

Figure 2.20 Inter-regional trade

Source: AER; AEMO (data).

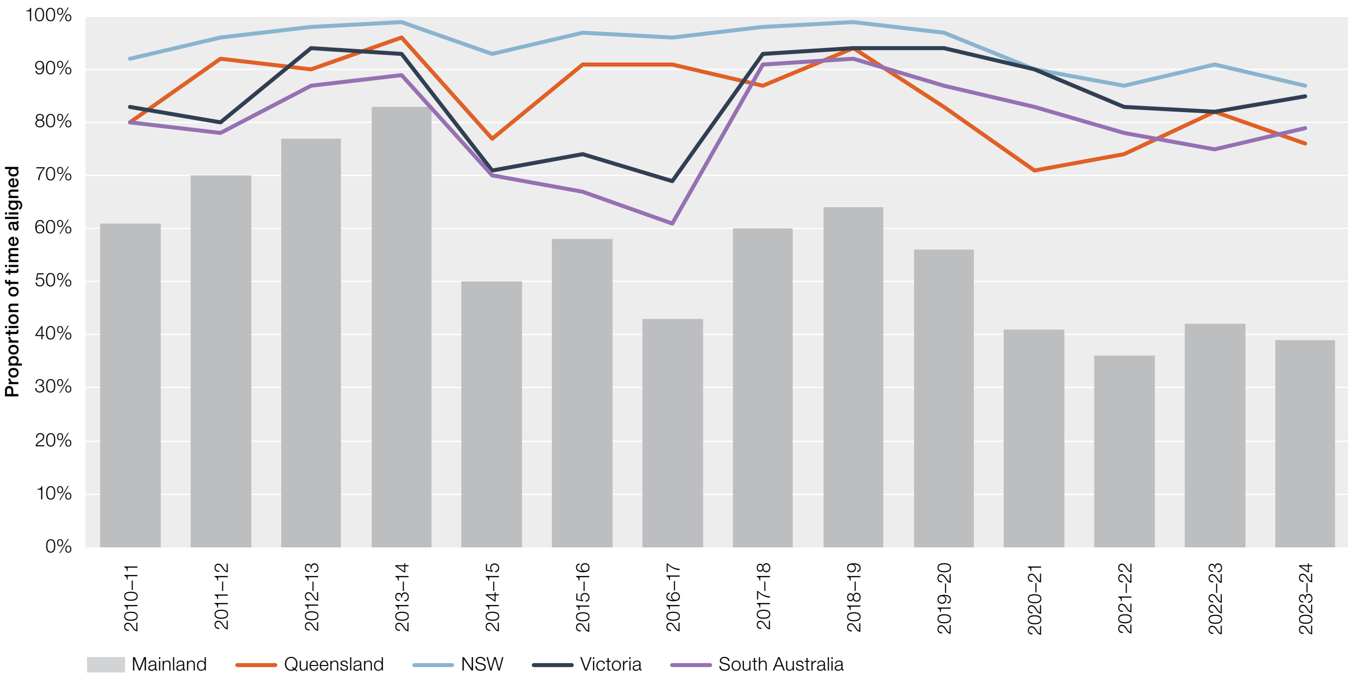
2.9.1 Market alignment and network constraints

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, because generators are exposed to competition from generators in other regions.

As coal-fired generators retire and new generation sources appear in new locations, new constrained locations are appearing, potentially due to line capacity or system security reasons. This can have price impacts if they prevent cheaper electricity making it to market and could influence inter-regional trade outcomes in the future.

Over recent years price alignment across regions has been falling. Price alignment in the NEM fell in 2023–24 but remains higher than the low set in 2021–22 (Figure 2.21).

Figure 2.21 Price alignment in mainland NEM regions



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

Source: AER; AEMO (data).

Being the geographical middle of the NEM, NSW prices are typically the most aligned, this remained consistent in 2023–24. However, in 2023–24 NSW alignment decreased compared with the previous year, as did alignment in Queensland, which is only connected to NSW. Victoria and South Australia recorded increases in price alignment compared with the previous year.

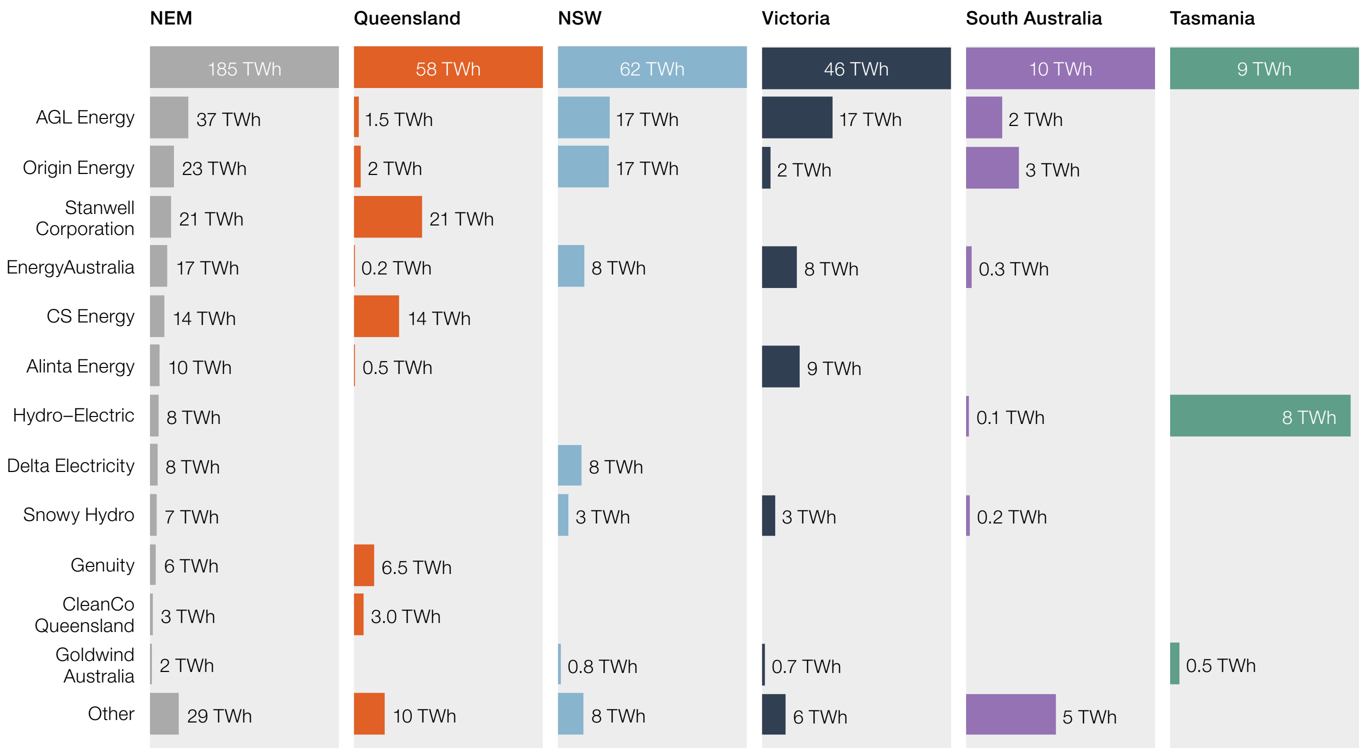
2.10 Market structure

Over 350 electricity generators sell electricity into the NEM. Despite significant new entry in recent years, a few large participants control a significant proportion of generation in each NEM region. 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. Detailed analysis of market structure and competition, including 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 every two years, most recently in December 2022.[32] The AER will publish the next edition of the report in December 2024.

2.10.1 Market concentration

Generation in the NEM is concentrated among a relatively small number of owners. In each NEM region except South Australia, the largest 2 owners account for over half of the region's output capacity. In South Australia, the largest 2 owners account for 47% of capacity (Figure 2.22).

Figure 2.22 Market shares in generation output



Note: Output in 2023–24. Market shares are determined based on ownership of each unit's output. Where we have been unable to determine ownership of output, we have allocated market shares according to ownership of the asset. Output is split on a pro rata basis if ownership changed in 2023–24. 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. Output from rooftop solar systems, interconnectors, loads and non-scheduled generation are excluded from the data.

Source: AER; AEMO; company announcements.

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

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 over 80% of all flexible capacity in NSW and nearly 60% in Victoria. Ownership of flexible capacity is less concentrated in the other regions.

2.10.2 Vertical integration

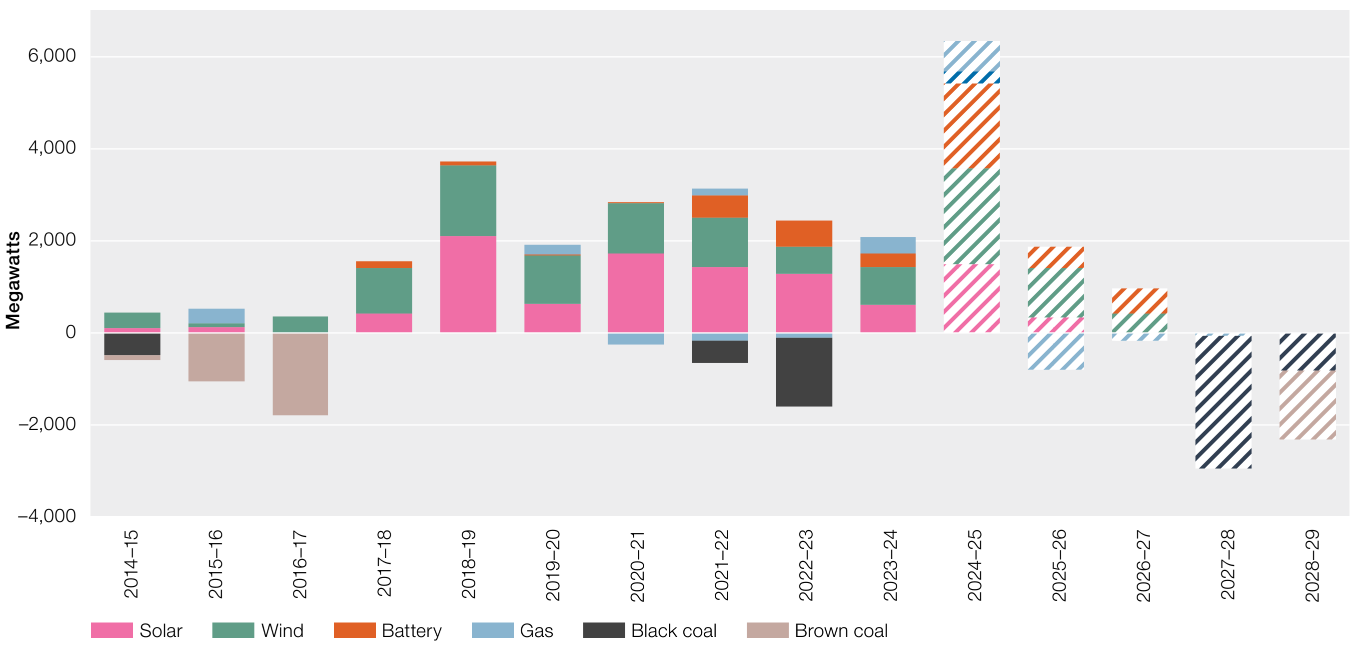
Most large generators in the NEM are vertically integrated, with portfolios in both generation and retail. Because generators sell into the spot market while retailers buy from it, vertical integration allows 'gentailers' to hedge against price risk in the wholesale market without entering into external contract agreements.

The 4 largest vertically integrated participants in each region account for most of the generation output and supply more than half of retail load. Second tier retailers also own major generation assets. More information on retailers in the NEM is set out in section 6.7.4 in chapter 6.

2.11 Generation investment and plant closures

Over 15 GW of new grid-scale solar, wind and battery investment has been added to the NEM since the beginning of the 2017–18 financial year. Over the same period, just over 2.5 GW of coal and gas capacity was withdrawn (Figure 2.23).

Figure 2.23 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 2024 are shown as shaded components.

Source: AER; AEMO (data).

In 2023–24, nearly 2.1 GW of capacity entered the market, including:

- 600 MW of solar capacity, located in NSW, Victoria and South Australia
- 820 MW of wind capacity, located mostly in NSW and South Australia
- 300 MW of battery capacity (2 batteries in NSW, 2 in Queensland and 1 in South Australia)
- 350 MW of gas capacity, including 320 MW at Tallawarra B, a gas peaking plant in NSW.

While no generator exits are expected in the next financial year, large volumes of historical fossil fuel generators are scheduled to close in the next 5 years. This includes 1,050 MW of gas, 3,720 MW of black coal and 1,480 MW of brown coal. Large volumes of renewable and dispatchable generation will be required to meet the supply gap.

AEMO's most recent Integrated System Plan noted that, in 2023–24 alone, 13.5 GW of generation and storage connection applications were approved. However, it also noted that in recent years, projects have been taking longer to reach commissioning stage. This is due to a range of factors, including changes in financial markets, supply chain constraints, construction contracting challenges, and environmental and planning approvals.[33] Imminent investment is required to ensure the ongoing reliability of the NEM.

2.12 Power system reliability

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

The transition in the energy market has increased the risk of reliability gaps. Coal plant closures remove a source of firm capacity that could historically be relied on to operate when needed. As contribution from 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 are typically highest over summer, particularly at times of peak demand. But they may also emerge at other times in the year, when solar or wind output is low, or there are transmission or plant outages.

33 AEMO, Integrated System Plan, Australian Energy Market Operator, June 2024.

Box 2.2 How reliability is measured

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

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 measure of 0.0006% was introduced in 2020 and recently extended to run until 30 June 2028.[34] The interim reliability measure is used as a trigger for 2 mechanisms to prevent forecast supply shortages from occurring. If it forecasts unserved energy will exceed the 0.0006% threshold, AEMO can:

- request the AER to trigger the Retailer Reliability Obligation and organise for liable entities to enter sufficient qualifying contracts to cover their share of a 1-in-2-year demand event; this can occur up to 3 years before a forecast reliability gap
- if a forecast reliability gap persists, contract out of market capacity under the reliability and reserve trader mechanism to reduce the risk of a supply gap.

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

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

2.12.1 Reliability outlook

In its May 2024 update to the 2023 Electricity Statement of Opportunities, AEMO forecast reliability gaps in all mainland regions across varying time periods over the next 10 years.

Against the interim reliability measure, AEMO has forecast that NSW and Victoria will face reliability gaps from 2024–25 until 2027–28, while South Australia will face a reliability gap in 2026–27. AEMO has indicated it will tender for interim reliability reserves to cover the reliability gaps in 2024–25. Against the normal reliability standard, NSW and Victoria will continue to face reliability gaps from 2028–29 onwards, while South Australia and Queensland are forecast to experience reliability gaps in 2031–32.

The main reason for forecast reliability gaps is the exit of over 8 GW of firm capacity in the next decade, as coal-fired and other thermal generators retire. Liddell's (NSW) closure in April 2023 marked the first of 4 coal station exits for the decade, with Eraring (NSW, 2027), Yallourn (Victoria, 2028) and Callide B (Queensland, 2028) all set to retire before 2030. Vales Point (NSW) is expected to retire in 2033. There are increased risks of reliability gaps if there are delays in planned transmission network infrastructure or delays in dispatchable generation such as batteries.

In releasing its updated 2023 Electricity Statement of Opportunities, AEMO noted that urgent investments in capacity in the NEM were needed to manage reliability risks and that 'once federal and state government programs, actionable transmission developments, and orchestration of forecast consumer energy resources (CER) are also considered, beyond the short term, reliability risks have the potential to be managed within relevant standards over most of the next 10-year horizon'.[35]

34 AEMC, Final rule to extend Interim Reliability Measure, Australian Energy Market Commission, September 2023.
35 AEMO, Update to the 2023 Electricity Statement of Opportunities, Australian Energy Market Operator, May 2024.

2.12.2 Managing reliability

The wholesale market is the primary mechanism for delivering reliability. Price signals in electricity spot and contract markets provide incentives for market participants to supply generation and, over a longer time horizon, investment in additional generation where required. Forward planning documents such as AEMO's Electricity Statement of Opportunities provide important transparency to the market, as well as mechanisms such as the Capacity Investment Scheme (section 2.14), should also support longterm investment. Where supply shortfalls are forecast and market options have been exhausted, the Retailer Reliability Obligation and the Reliability and Emergency Reserve Trader mechanisms can be used to mitigate the shortfall risk. AEMO also has the ability to issue directions to individual participants to manage reliability.[36]

AEMO's 2023 Electricity Statement of Opportunities forecast that reliability gaps are likely to be more common, and increased volumes of interim reliability reserves or long notice reserves may be required to meet reliability shortfalls. This cost will ultimately be borne by customers.

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, as well as interim reliability reserves if the stricter reliability target is forecast to be exceeded.

Market participants that provide short notice reserves are compensated if the reserves are activated, or preactivated, but are not compensated based on availability. In contrast, participants that provide long-run or interim reliability reserves are compensated for making generation available. 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 customers.

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.[37] 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.[38]

36 AEMO, Procedures for issue of directions and clause 4.8.9 instructions, Australian Energy Market Operator, effective 4 July 2024, accessed 16 September 2024.

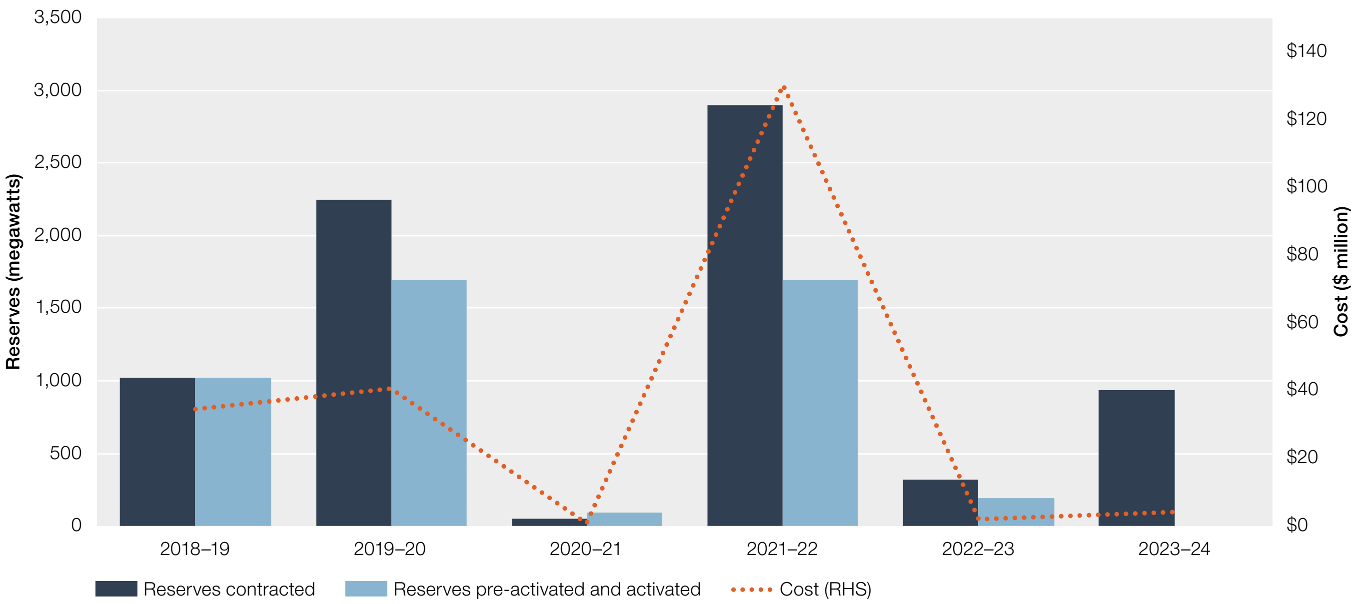
37 AER, Values of customer reliability, Australian Energy Regulator, accessed 20 August 2024.

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

In 2023–24 AEMO entered into interim reliability reserve (IRR) contracts for the first time, in response to reliability shortfalls identified in its 2023 Electrical Statement of Opportunities. AEMO contracted a total of 100 MW of IRR in Victoria and 10 MW in South Australia for the period between 1 December 2023 and 31 March 2024. It subsequently contracted an additional 19 MW in Victoria for the period between 1 January 2024 and 31 March 2024.[39] The contracted interim reliability reserves were not activated or preactivated but incurred an availability cost of $98 per day per MW in South Australia and $645 per day per MW in Victoria on average, totalling $4,252,685.

AEMO entered into several short notice contracts in response to forecast lack of reserve 2 conditions on 14 December 2023, 27 January 2024 and 13 February 2024, totalling 807 MW. AEMO did not preactivate or activate any of the contract capacity, so no costs were incurred.

Figure 2.24 RERT reserves and costs



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

Source: AER analysis of AEMO's RERT reporting.

The RERT has averted multiple instances of load shedding since the initiative began, but doing so comes at significant cost to the consumer. Typically, RERT costs have been calculated in reference to the MWh usage of activated contracted capacity. The average cost of the RERT in the previous 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 average cost of RERT in 2022–23 was more than $50,000 per MWh and more than the VCR.

In the 2023–24 financial year no RERT contracted volumes were activated. However, because interim reliability reserves were contracted, the total cost was higher than the previous year. AEMO's 2023 Electricity Statement of Opportunities forecast that reliability gaps are likely to be more common, and increased volumes of interim reliability reserves or long notice reserves may be required to meet reliability shortfalls. This cost will ultimately be borne by customers.

39 AEMO, Reliability and Emergency Reserve Trader (RERT) Quarterly Report Q4 2023, Australian Energy Market Operator, February 2023.

Retailer Reliability Obligation

The Retailer Reliability Obligation (RRO) is designed to be a long-term solution to ensure reliability at the lowest cost by preparing for and eliminating forecast reliability gaps before they occur.

If AEMO identifies a material reliability gap 3 years and 3 months out, it will apply to the AER to trigger the RRO by making a T-3 reliability instrument. Each Minister for Energy in a NEM region can also trigger the RRO by making an instrument directly. Where a reliability instrument is made, liable entities (retailers and other parties that purchase electricity directly from the wholesale energy market) are on notice to enter into sufficient qualifying contracts with generators to cover their share of a 1-in-2-year peak demand. If AEMO continues to identify a reliability gap 1 year and 3 months out, it will apply to the AER to make a T-1 reliability instrument, which requires liable entities to report their net contract position (NCP) to the AER. Liable entities can face civil penalties if they do not submit an NCP report and if a reliability gap eventuates and their NCP is insufficient. Liable entities with insufficient contracts may be liable to pay Procurer of Last Resort costs of up to $100 million each under the RERT scheme.

The RRO also includes a market liquidity obligation 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 AER has made several reliability instruments in response to forecast reliability gaps between 2024 and 2027. The first T-1 reliability instrument was made for South Australia between 8 January 2024 and 29 February 2024.[40] On 12 March 2024, AEMO reported that actual demand did not exceed the 1-in-2-year peak demand forecast and the reliability instrument was closed.

In February 2024 the AEMC published a final report on recommendations to improve the operation of the RRO.[41]

2.13 Power system security

Power system security refers to the power system's technical stability in terms of frequency, voltage, inertia and similar characteristics. System strength refers to the power system's ability to ensure correct operation of network protection equipment and maintain stable voltage waveforms. To ensure a secure power system, system security and system strength must be maintained within defined limits.

The NEM's coal, gas and hydro-electric generators help maintain a stable and secure system as a by-product of producing energy. Generally, these services are provided from the heavy spinning turbines used to generate electricity, which are physically coupled (synchronised) to the grid. This means that these turbines spin at a rate that lines up with the electrical frequency of the power grid and their physical momentum provide inertia to help resist unwanted changes to system frequency. As coal and gas generators retire, or reduce operations in response to falling demand, the supply of system security and strength are reduced with them.

Generation technologies replacing retiring coal and gas generators, such as wind and solar, are less able to provide system security and system strength services. Energy rule reforms have widened the pool of providers (such as batteries and demand response) of certain security services and made changes to how it is procured to support more efficient planning by network service providers. More recent reforms have put responsibilities on network service providers to maintain minimum security standards set by AEMO, for example, through their inertia and system strength reports as well as those encoded in the National Electricity Rules. In terms of managing system strength, nominated network service providers are required to meet a new system strength standard by 2 December 2025. Market policy and regulatory bodies are developing further reforms of the energy market's architecture to manage security risks in the context of an evolving energy market.

Where gaps in security or strength emerge, AEMO has powers to intervene in the market to protect system security and strength.

40 AER, T-1 and T-3 reliability instruments decision - FINAL, Australian Energy Regulator, October 2022.
41 AEMC, Review of the Retailer Reliability Obligation, Australian Energy Market Commission, February 2024.

2.13.1 Security performance in the NEM

As part of AEMO's market operations, it is required 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) and uncertain supply demand balance. AEMO reports annually on system security needs across the NEM for the coming 5-year period. Its December 2023 report confirmed previously identified voltage shortfalls in NSW, Queensland and Tasmania and noted that remediation for the shortfalls is currently in place or being progressed by the relevant network businesses.[42]

AEMO expects the need for additional system security services will only increase over the coming yearsas power stations that previously supplied these services withdraw from the system. AEMO needs to consider what technologies will be incentivised to provide these services in future and whether the new market arrangements currently being developed will provide sufficient incentives to do so.

2.13.2 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. Following the introduction of very fast raise and lower FCAS markets in October 2023, the NEM has 10 FCAS markets, which are either regulation services or 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.

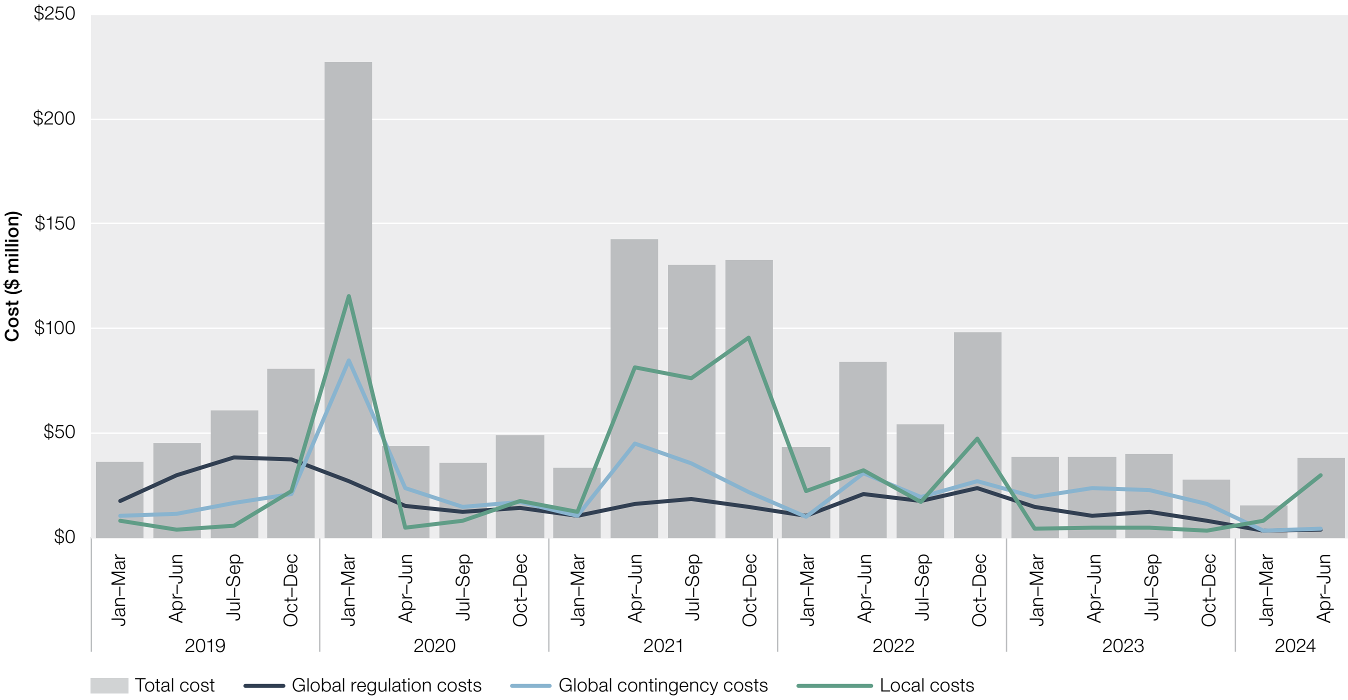
Local FCAS services are provided from market participants in a region when that region is electrically islanded from the NEM. Global FCAS services occur when services are provided in a region that is connected to other regions, through available interconnectors.

Fewer participants operate in FCAS markets than in the wholesale electricity market, but participation is growing – just over 60 participants are currently registered to provide services.[43] On 30 June 2024, 15 participants were providing FCAS in Queensland, 18 in NSW, 17 in Victoria, 16 in South Australia and 3 in Tasmania. New generation technologies, such as 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.

FCAS costs fell by 47% in 2023–24 compared with 2022–23 (Figure 2.25). The fall in costs was observed in both global and local costs. Global costs in 2024 for both regulation and contingency were materially lower than in previous years. Local costs were also lower compared with previous years, except in the April to June 2024 quarter. This was driven by local costs in Queensland – FCAS prices increased in May to support Queensland generation flowing into NSW following extreme high price events.

42 AEMO, 2023 System Strength Report, Australian Energy Market Operator, December 2023.
43 AEMO, Registered Participants, Australian Energy Market Operator, accessed 22 August 2024.

Figure 2.25 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).

Very fast raise and lower FCAS markets were introduced on 9 October 2023. Since then, 1-second FCAS costs have made up a large portion of contingency raise costs; 6-second and 60-second costs have declined materially. One-second contingency raise costs accounted for $13.5 million (84%) of raise costs between January and March 2024 and $6.7 million (60%) between April and June 2024. One-second FCAS costs in contingency lower markets have not seen similar growth, accounting for less than 1% of contingency lower costs.

2.13.3 Other system security market features

System security services previously provided by synchronous generators can be replicated by other technologies and the design of the NEM.

For example, synchronous condensers are machines specially built to supply only reactive power and can replicate system security services. They can also include a flywheel with a large amount of stored momentum to provide inertia. In South Australia, 4 synchronous condensers, installed by ElectraNet, started operating in October 2021 to provide system strength and inertia. In the event of a disturbance on the network, the synchronous condensers provide some electrical inertia to ride through the fault. Under the new system strength framework, network service providers are required to identify most efficient solution for meeting minimum system strength requirements in a proactive manner by addressing the need before a shortfall arises.[44]

Large-scale grid batteries with advanced inverter technology are also a potential source of system security.[45] Batteries can also improve the utilisation of new and existing transmission lines. AEMO has directly contracted several large-scale grid batteries to provide system strength services.[46]

Strategic construction of transmission interconnectors will also support system security in the NEM, reducing the risk of a region being islanded and increasing inter-regional transfer capabilities.

44 AEMC, Efficient management of system strength on the power system, Australian Energy Market Commission, 21 October 2021, accessed 16 September 2024.

45 AEMO, Voluntary Specification for Grid-forming Inverters, Australian Energy Market Operator, May 2023.

46 AEMO, Integrated System Plan, Australian Energy Market Operator, June 2024.

2.13.4 AEMO use of directions

AEMO has powers to direct market participants to take relevant actions to maintain or restore power system security or system strength. Directions are intended as a last resort intervention when the market has not delivered the necessary requirements.

The energy transition is necessitating more frequent directions from AEMO to maintain power system security. 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 several years.[47] In March 2024, new rules improving the transparency of AEMO's power to issue directions were published, alongside a new requirement for AEMO to report annually on the steps it will take to manage security through the transition.

2.14 Market reforms and policy developments

In 2021, significant market reforms were introduced to support the NEM's transition to a low carbon future. In the past year, market reform and policy development has continued to support the transition, following the inclusion of a new emissions reduction objective in the National energy objectives in June 2023.

Following consultation throughout 2023, the Australian Government began launching its Net Zero Plan in 2024. This is now a legislated, economy-wide plan to achieve net zero emissions in Australia by 2050.[48] The Net Zero Plan builds on the Australian Government's Capacity Investment Scheme, a revenue-underwriting mechanism to unlock investment in clean, dispatchable power.[49] In November 2023, the Australian Government announced expansion of the scheme to deliver 9 GW of dispatchable capacity and 23 GW of variable capacity nationally, representing a total $67 billion in investment.[50]

Throughout 2023 and 2024, the Australian Government consulted with industry and state and territory jurisdictions to design the Capacity Investment Scheme. The first competitive tender was launched in May 2024. Since then, 1.1 GW of dispatchable capacity has been made available.[51] The remaining 30.9 GW of total capacity will be rolled out in stages via competitive tenders approximately every 6 months, to 2027. The additional capacity is anticipated to help fill reliability gaps as aging coal-fired generation exits the market and aims to deliver the Australian Government's target of 82% renewable electricity by 2030.

Unlocking investment in clean, dispatchable energy will support Australia's greenhouse gas emissions reductions target to achieve net zero (or lower) by 2050.[52] In June 2024, the AEMC released indicative targets to reduce greenhouse gas emissions at Australian, state and territory levels across electricity and gas sectors.[53] These include interim targets for Australian jurisdictions to reach by 2030 and 2035 to 2045, with net zero (or lower) to be achieved by 2050.

The AEMC guide includes, by jurisdiction, several supply-side and demand-side strategies and targets likely to contribute to reducing emissions. Key target areas include renewable energy uptake, energy storage or firming of renewables, electrification of transport and of domestic and industrial gas consumption and demand response.[54] The greenhouse gas emission reduction targets have been officially incorporated into the National Electricity Rules and national energy objectives; this is a significant development enabling formal consideration of emissions reduction within the energy sector.[55]

47 AEMO, Quarterly Energy Dynamics Q2 2024, Australian Energy Market Operator, July 2024.

48 Australian Government, Net Zero, accessed 22 August 2024.

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

50 Australian Government, Energy and Climate Change Ministerial Council Meeting Communique – 24 November 2023.

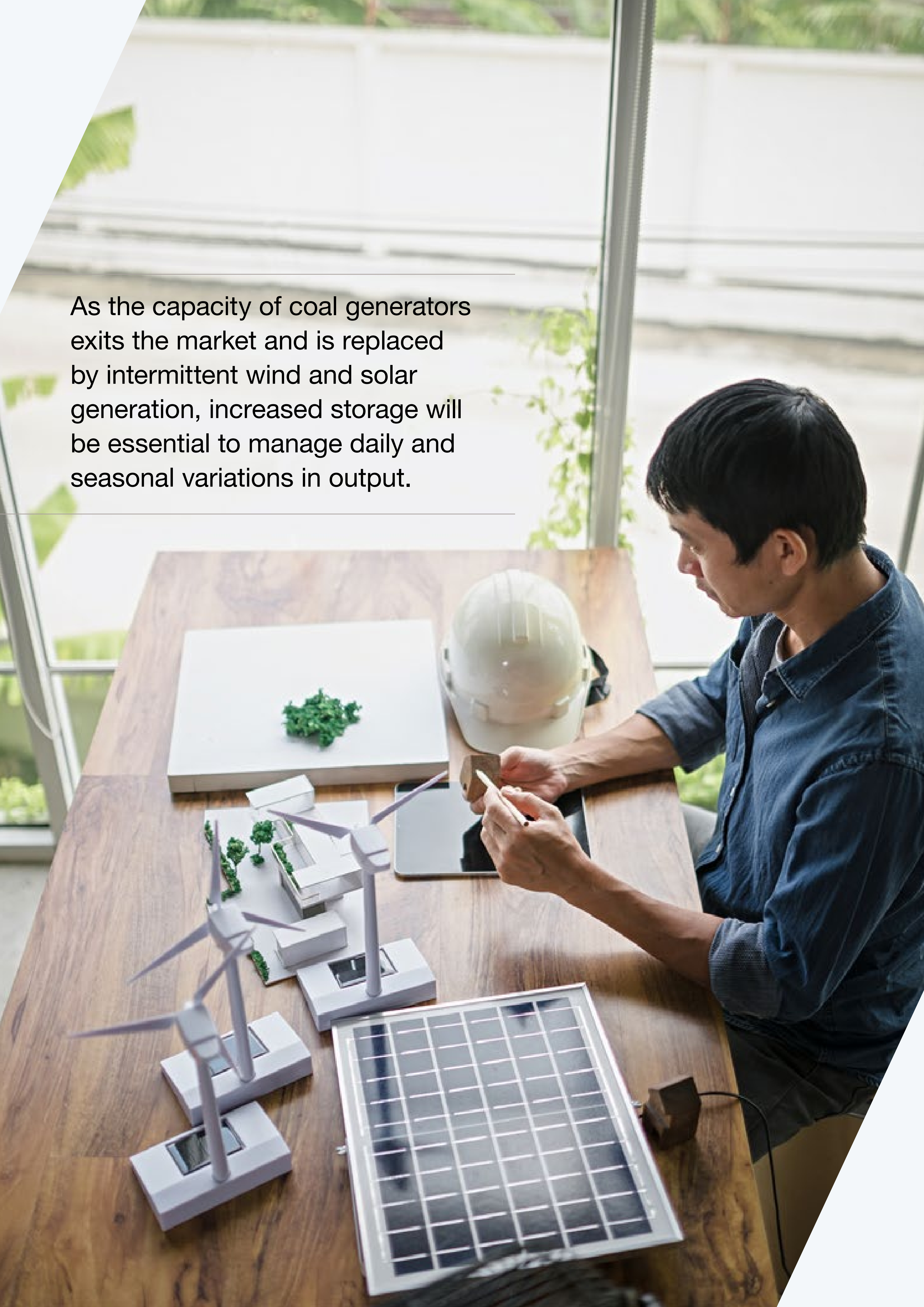
51 Australian Government, Capacity Investment Scheme, accessed 22 August 2024.

52 Australian Government, Net Zero, accessed 22 August 2024.

53 AEMC, Targets statement for greenhouse gas emissions, Australian Energy Market Commission, accessed 25 September 2024.

54 AEMC, Emissions targets statement under the national energy laws, June 2024, Australian Energy Market Commission, accessed 25 September 2024.

55 AEMC, Transformative changes as emissions reduction included in national energy rules, Australian Energy Market Commission, 1 February 2024.



As the 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.

2.15 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 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 when 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 AER's key 2022–23 priority for wholesale electricity markets was to support power system security and an efficient wholesale electricity market by focusing on generators' compliance with offers, dispatch instructions, bidding behaviour obligation and providing accurate and timely capability information to AEMO.

It is critical that generators provide accurate and timely information about capacity and availability to AEMO, including for system services such as frequency control ancillary services (FCAS) and for AEMO's project assessments of system adequacy (PASA), which assesses the adequacy of electricity supply to meet demand.

Since July 2023 the AER has undertaken a range of actions to support system operation. These include:

- reviewing self-forecasting data and its potential impact on wholesale market bidding behaviour
- commencing a review of various compliance guidance to identify updates required due to recent market reforms
- issuing compliance messaging to industry to support AEMO's management of risks identified in its *Summer operations 2023–24 work program*
- obtaining 2 important court judgements – the Pelican Point judgement and AGL FCAS judgement.

Pelican Point judgment

On 20 September 2023, the Federal Court found that Pelican Point Power Limited (Pelican Point) breached the Electricity Rules by failing to disclose to AEMO the full capacity of its Pelican Point Power Station that was available during heatwave conditions in South Australia on 8 February 2017. Specifically, it found that Pelican Point failed to comply with its legal obligation to disclose short-term availability information to AEMO.

Pelican Point was ordered to pay a pecuniary penalty of $900,000 for not disclosing its short-term availability and not updating AEMO of changes to its medium-term availability. The AER and Pelican Point agreed that Pelican Point pay $950,000 in costs. The AER sent a letter to industry reiterating the importance of complying with PASA obligations and calling on relevant scheduled generators and market participants to assess and plan for the medium-term and short-term operation of the energy system and submit details of physical plant capability available.

AGL FCAS judgment

On 30 October 2023, the Federal Court ordered that operators of AGL's Bayswater and Loy Yang power stations pay penalties totalling $6 million for failing to comply with dispatch instructions given to them by AEMO in relation to FCAS they had offered, and were paid to provide, in periods between September 2018 and August 2020. The finding reinforced the importance of market participants ensuring effective internal lines of communication about the status of any plant settings affecting plant ability to deliver FCAS, proactively monitoring plant performance in response to frequency deviations and having comprehensive processes and procedures in place to support compliance.

The AER has also supported AEMO's work in improving overall compliance with supervisory control and data acquisition (SCADA) infrastructure. In March 2024, AEMO published a detailed incident report covering 18 incidents that occurred throughout the NEM between January 2021 and November 2023. SCADA infrastructure is a system of software and hardware elements that enables plant operators, owners and other stakeholders an inside, real-time look at what's happening in a plant, facility or process. It provides AEMO and transmission network service providers with data on the status of transmission, load and generator equipment and facilitates delivery of dispatch instructions. The AER has written to the Energy Networks Association to encourage ongoing commitment from network service providers to work with AEMO to enhance overall SCADA system resilience and reliability and will continue to assess potential individual breaches with a focus on identifying systemic issues.

Other wholesale electricity compliance and enforcement activities

During 2023–24 the AER also:

- reviewed generator compliance programs, engaging certain stakeholders to review their compliance frameworks and make any necessary improvements
- initiated proceedings in the Federal Court against Callide Power Trading Pty Ltd for failing to comply with its performance standards for the Callide C power station
- issued letters to system strength service providers setting out compliance approaches for maintaining a stable power system
- received payment from CS Energy totalling $67,800 for an infringement notice issued for an alleged breach of the National Electricity Law for operating a generating system without the required regulatory approval.

More detail on the AER's compliance and enforcement work is outlined in the *Annual compliance and enforcement report 2023–24.*[56]

56 AER, AER Annual compliance and enforcement report 2023–24, Australian Energy Regulator, July 2024.