Wholesale electricity market performance report 2024

December 2024

AUSTRALIAN ENERGY REGULATOR

Australian Government

Important notice

The information in this publication is for general guidance only. It does not constitute legal or other professional advice. You should seek legal advice or other professional advice in relation to your particular circumstances.

The AER has made every reasonable effort to provide current and accurate information, but it does not warrant or make any guarantees about the accuracy, currency or completeness of information in this publication.

Parties who wish to re-publish or otherwise use the information in this publication should check the information for currency and accuracy prior to publication.

Inquiries about this publication should be addressed to:

Australian Energy Regulator
GPO Box 3131
Canberra ACT 2601
Email: aerinquiry@aer.gov.au
Tel: 1300 585 165

Contents

Executive summary

The Australian Energy Regulator (AER) has conducted this review on the performance of the wholesale electricity market under the National Electricity Law. In carrying out this role, we analyse and identify whether competition in the National Electricity Market (NEM) is effective and whether any market features may be detrimental to effective competition or the efficient functioning of the wholesale market. We are also empowered under the law to advise Energy Ministers on any legislative or regulatory reform to address key risks in the market.

This is our fourth biennial review of the wholesale electricity market. This report presents a comprehensive picture of the state of wholesale competition and analyses how the performance of the NEM has changed over the past 5 years, with a particular focus on outcomes since our last report in 2022. We also performed a deep dive into the South Australian electricity market to better understand the unique characteristics of the region.

Through our analysis of market performance, we have identified key considerations for policy makers to support a smooth transition to a low emissions electricity system and a future market that delivers efficient outcomes.

Key findings

Prices

Prices in the NEM have fallen since our last wholesale electricity market performance report (WEMPR) in 2022, due to lower fuel prices and increased renewable generation. The intervention by governments in late 2022 shielded the NEM from extremely high global fuel prices that arose in the post-COVID recovery and the Russian invasion of Ukraine. Now that the coal intervention has ended, more generators are again exposed to international coal prices. These prices have moderated from their peak but are still high.

The market has continued to experience significant volatility, revealing the extent to which prices can increase significantly due to network and generator outages or variability of wind and solar output. Higher priced trading intervals have reduced, but high price events remain prevalent, due to a combination of these factors and periods of high demand. These high price events are contributing to elevated forward contract prices. Contract markets respond to events like the one in NSW in May 2024, where a run of high prices led to the cumulative price threshold being breached and the market temporarily suspended.

Energy transition

The contribution of intermittent renewable generation continues to grow and was 32% of generation output in 2023–24[1]. Renewable generation is increasingly setting the price during the day. At these times negative prices have become increasingly common. While renewable generation has taken over the day, outside of solar hours dispatchable generation (primarily coal, gas, hydro and large-scale batteries) still sets the price over 90% of the time.

[1] This figure includes rooftop solar.

The NEM requires significant new investment over the next decade to enable a successful transition. As aging coal and gas plants retire, new wind, solar, batteries, pumped hydro, gas-fired generation and transmission will be needed to maintain reliability and to meet emissions targets. Over 2022–23 and 2023–24, 4.5 GW of new large-scale generation entered the market. Direct and indirect government support continues to be a key driver of new generation investment.

Our analysis indicates that new wind and solar generation could have earned revenue sufficient to cover its long-run marginal costs over the past 5 years, when factoring in revenue from the Renewable Energy Target. However, new renewable generation may face declining wholesale market revenue due to saturation. This dynamic is most notable with large-scale solar because it's competing against rooftop solar. In most regions there is a positive commercial case for investment in batteries, while investment in new commercial gas generation has been improving but remains challenging.

The exit of thermal generators and increased dispatch of inverter-based technologies, which don't have the grid-forming properties of synchronous generation, has required the electricity market rules to evolve to ensure system security. The pace of market change comes with the risks of creating inefficiencies. This is evident in the recent costs of directions to maintain system security, which have increased on a per megawatt hour (MWh) basis and added $79 million in total costs in 2023–24. It can also create new opportunities for the exercise of market power, particularly in the new market for system strength where the pool of currently available solutions is highly concentrated.

Market concentration

New entry since 2021–22 has led to lower market concentration in NSW, Victoria and South Australia. Market exit also contributed to declining concentration in NSW and South Australia, with AGL closing and mothballing coal and gas units. Diverse ownership of renewable generation means concentration is lowest when these assets are generating. As a result, concentration is now much lower during the middle of the day, particularly in Queensland and NSW.

Ownership of dispatchable generation remains concentrated and a few large participants are often needed to meet demand, outside of solar hours. This increases the scope of those participants to exercise market power. However, the reliance on the largest participants to meet demand has decreased across the NEM over the past 2 years, except in Victoria.

Volatility

In response to the events of 2022, there was a significant reduction in offers between $0 and $100 per MWh (low to mid-priced offers) in that year. All mainland regions, other than South Australia, have had an improvement in low to mid-priced offers since 2022. These offers are important because they reduce price volatility. If there is a low level of low to mid-priced capacity, prices will spike more often due to changing supply and demand. Greater spot price volatility can flow through to higher contract prices.

Expectations of system-wide reliability also affect contract prices. While the average level of coal plant reliability has improved, this obscures the impact of unplanned outages. Unplanned outages increase volatility, which puts upward pressure on contract prices. It is not just the number of megawatts (MW) lost in a given outage that cause volatility, but how frequently it happens. There was a significant increase in frequency of unplanned outages in Q3 2024. Reliability at a plant level also affects the level of contracting. As a plant ages and becomes more unreliable, the owner is likely to reduce their level of contracting to limit their risk of an unplanned outage when prices are high.

The events of 2022 also flowed through to the contract market. Swaptions are now the most widely traded contract, and they are being traded earlier, have higher premiums and are being exercised and converted into base futures at a higher volume. Swaptions are attractive to buyers because they can manage the risks accentuated in 2022. Swaptions allow buyers to hedge further into the future without the cash flow risks of margining, in exchange for a fixed up-front cost. Capping prices further in advance helps guard against unforeseen future shocks. If market conditions become more favourable, buyers can simply let the swaption expire. Sellers have been willing to take on more of the risk through these products, in exchange for higher premiums.

South Australian electricity market – deep dive analysis

We used our new contract market monitoring powers for the first time to conduct a deep dive into the South Australian market as part of this year’s report. The South Australian market is at the forefront of the renewables transition and studying this market can provide insight into the future performance of the entire NEM and the areas in which market design may need to change as the transition progresses.

In South Australia, increased renewable generation has led to lower prices at times. However despite this low cost supply, a multitude of factors including fuel costs, network congestion, participant bidding strategies and lower wind conditions have combined to maintain prices in recent years above their pre-2022 levels. Average prices are also increasingly influenced by extreme highs and lows.

Other regions demonstrate a similar average pricing trend. However, it is more pronounced in South Australia where low to mid-priced participant offers have now all but disappeared due to increased renewable generation and with thermal plants making high offers to avoid uneconomic dispatch. This is resulting in increased price volatility and creates greater incentives for participants to withhold capacity with the intent of benefiting from the higher prices this can create. A case study we examine in this report indicates that, at least in certain instances, participants can take advantage of market conditions to make significant financial returns from this strategy. While the case study analyses the behaviour of one participant in particular, we consider that market conditions in South Australia have created an opportunity for many participants to exercise this strategy and the incentive is particularly pronounced for marginal thermal generators who may struggle with returns on average.

We also studied the contract markets in South Australia and observed very limited trading. Low levels of contract trading, limited product options and an increasingly volatile spot market make risk management more difficult and expensive for smaller retailers.

Our analysis of the contract positions of selected large participants in the South Australian market indicates they are mostly internally hedged and have reduced their contracting levels over recent years. This could be due to aging assets with reduced reliability, the changing role of thermal plant and risk preferences, or the inability of the market to clear at the desired volumes or price.

Both wholesale market price volatility and the unsuitability of standard hedging products to manage this volatility may make the South Australian market risky for smaller retailers that do not own generation assets or other risk mitigation strategies such as the use of virtual power plants.

The changing incentives and drivers of generation, combined with changing market dynamics, have resulted in some emerging inefficiencies, challenges to competitive tension and costs that should be considered in the review of market design.

Recommendations

New market design needs a credible mechanism for new generation to recover its long-run marginal cost

The Australian Government has announced a review of the NEM wholesale market settings to promote investment in firmed, renewable generation and storage capacity following the conclusion of Capacity Investment Scheme tenders in 2027.[2]

There is no perfect market design, but trade-offs between different elements. Some of the questions this review may need to confront include should the market price cap be higher (or uncapped) to provide a stronger incentive to retailers to contract to underpin new investment? Should generators who will only be needed part of the time be able to access availability/capacity payments to lower the risk to invest? Should the latter have a much lower market price cap, reducing the impact of high price events but also reducing the incentive for retailers to rely so heavily on contracts to manage spot market risk? What is important is an internally coherent design that enables generators to recover their long-run marginal costs, while meeting emissions objectives, at the least cost to consumers.

Governments should also consider any options for market design reform based on their ability to:

- enable market entry of technologies and products that can help manage intermittency of supply and volatility of demand, both intra-day and seasonal shifting
- enable innovation in risk management products to reduce the costs of volatility and support competition
- deliver competitive tension in the provision of energy, firming and of essential system services.

Once the review is complete, governments must quickly decide the path forward and implement any changes. Confidence is essential to help support ongoing investment in the system and to reduce the cost of that investment.

Efficient operation of and investment in generation in part depends on transmission access. There remains a need for an enduring solution to transmission access. The status quo requires continued government direction and coordination of investments. This may address some issues of locational investment in generation but will have limited effectiveness in addressing operational inefficiencies arising from congestion. Reform is necessary to return

2 Minister Chris Bowen, Making the National Electricity Market fit for purpose, 26 November 2024.

to effective market-led investment and operation of generation beyond the horizon of government programs.

Governments need to ensure new generation enters the market in a timely fashion

In our 2022 report we recommended governments consider options to manage the exit of coal generators, including to ensure they withdrew from the market at a rate consistent with the entry of new generation and in light of the maintenance requirements and coal supply exposure they face.

The risk around the mismatch of entry and exit remains. Given the lumpy nature of thermal generation exits, there could be more market volatility as the supply-demand balance tightens at certain times. This is still principally an issue with coal generation exit, given the size of the units. But is also relevant for gas plants in South Australia. Governments have developed policy mechanisms such as the Orderly Exit Management Framework to help manage reliability and security risks as plants exit. However, we consider there is still a case for a policy response to manage price and competition impacts arising from risks of unplanned outages and fuel market prices and supply constraints.

Since our last report governments have committed to a range of new policies to deliver new generation, both renewable and dispatchable. The Australian Government alone is aiming to deliver 23 GW of new renewable generation and 9 GW of clean dispatchable capacity by 2030. State governments have also committed to supporting significant amounts of new investment. To put the scale of the commitment in perspective, there is currently 21.2 GW of large-scale intermittent renewable generation and 2.1 GW of batteries in the NEM.

Setting up the schemes and selecting the projects is only part of the task. It is critical that new generation is delivered in a timely manner. This is in part a function of selecting viable projects through well-executed programs. However, governments should also continue to pursue options to streamline project development and connection, building on work to date to improve planning processes and supply chains and gain and maintain social licence.

If the new generation does not enter in a timely fashion, it will provide opportunities for marginal and aging generators to exercise market power to push up prices. As part of thorough contingency planning, governments should develop options to manage exit in parallel to the roll-out of their entry schemes.

How existing thermal generation is replaced will affect the competitive landscape

A trade-off against the need for timely investment is the potential risk of worsening concentration of the future market. This is most acute for dispatchable generation. Governments should consider diversification of ownership when awarding contracts for capacity.

Diversification is important regardless of ownership structure. Snowy Hydro already controls a significant proportion of flexible dispatchable generation in NSW and Victoria. This may increase as coal generators are retired and Snowy 2.0 comes online. Very large storage projects are also planned in other regions.

Where governments support these projects, they should consider options for sharing trading rights among multiple participants to maintain competitive tension while allowing governments to pursue their policy objectives of investment in large-scale storage and public ownership.

Design of government schemes needs to ensure they incentivise contracting under current market design

Highly volatile prices create significant uncertainty for investors. Several of the government programs that are supporting investment in new capacity feature a degree of revenue risk underwriting. This can help overcome the revenue uncertainty created by market volatility and unlock or accelerate investment.

These schemes can de-risk a project by protecting generators from very low returns (and generally sharing higher returns). If the design of the scheme provides too great a level of de-risking, this may significantly reduce incentives for the generator to contract hedges or take part in other risk management transactions.

Removing risk for one participant is not the same as removing it for the market. Retailers still need to manage wholesale market price risk. Every generator that is insulated from risk is one less counterparty, making it more challenging for retailers to manage risk in the future.

Where risk sits must continue to be considered in the design and implementation of government schemes to help maintain competition in both the wholesale market and retail markets.

1 Monitoring the National Electricity Market

The AER monitors the performance of the National Electricity Market (NEM). The NEM is a wholesale spot market into which generators in eastern and southern Australia trade electricity (Box 2.1). This chapter outlines why and how we monitor this market.

1.1 Our reports provide information on the performance of the NEM to support efficient and competitive markets

Our reports provide an independent, expert and long-term perspective on the performance of wholesale electricity markets.

We monitor and report on the performance of the NEM under the National Electricity Law (NEL). The NEL requires us to review the performance of the wholesale electricity markets, including analysing and identifying whether there is effective competition and whether there are market features that may be detrimental to effective competition or the efficient functioning of the market.

We must report on the market at least every 2 years. From this, we may also advise the Australian and state governments on market performance and identify whether legislative or regulatory reform is required.

This 2024 report is our fourth report presenting a comprehensive picture of competition in the NEM. In addition, we also have other performance reporting obligations across our wholesale, retail and network areas.[3] For wholesale, many of our other functions focus on short-term market outcomes, compliance issues and individual price events.

Our monitoring roles support the National Electricity Objective in the NEL, which is to promote the efficient investment, operation and use of electricity services for the long-term interest of consumers. Through our monitoring and reporting, we assist consumers to understand the key drivers of outcomes in the wholesale electricity market and make more informed consumption decisions. Providing timely and relevant information to the market also supports efficient investment decisions and provides insights to policy makers to guide regulatory change.

1.2 We analyse competition and efficiency in the wholesale electricity market

Our assessment of market performance includes analysing whether there is effective competition and if the market is functioning efficiently.

---

3 AER, Performance reporting, Australian Energy Regulator.

1.2.1 Effective competition in the NEM

The level of competition in any market can be assessed against a range of competitive outcomes. At one end of the range is a monopoly, where one firm effectively controls all output in the market and there is no competition. At the other end is a perfectly competitive market, where no firm holds market power at any time. Perfect competition rarely occurs in practice.

The NEL requires us to assess whether there is 'effective' competition, rather than perfect competition, and provides a non-exhaustive list of factors to which we must have regard:[4]

- whether there are active competitors in the market and whether those competitors hold a reasonably sustainable position in the market (or whether there is merely the threat of competition in the market)
- whether prices are determined on a long-term basis by underlying costs rather than the existence of market power, even though a particular competitor may hold a substantial degree of market power from time to time
- whether barriers to entry into the market are sufficiently low so that a substantial degree of market power may only be held by a particular competitor on a temporary basis
- whether there is independent rivalry in all dimensions of the price, product or service offered in the market
- any other matters the AER considers relevant.

The NEL suggests the wholesale electricity market may still be considered 'effectively' competitive over the long term even if participants hold a substantial degree of market power at times. In particular, the NEL refers to prices over the long term and market power held by a participant on a temporary basis. These factors suggest we should have regard to whether market power is sustained.

An energy only market, such as the NEM, is characterised as being effectively competitive if it has many participants, with no one participant controlling a high proportion of capacity for a significant period. Participants should generally have an incentive to bid close to their fuel and operating costs; otherwise, they risk a cheaper competitor displacing their output.

Current market design is based on the assumption that periods of high spot and contract prices, driven by tightened supply and demand conditions, should provide a signal for new generators to enter the market. Conversely, if demand decreases relative to supply, there should be downward pressure on prices, which should prompt higher cost generators to exit the market.

Contract markets also act in conjunction with spot markets as a price risk management tool as well as a longer-term signal for investment. In an effectively competitive energy-only market, barriers to entry and exit are sufficiently low that investors can respond efficiently to price signals.

[4] National Electricity Law Section 18B.

1.2.2 Efficiency in the NEM

The NEL does not provide a definition of efficiency, but it is a well understood concept in economic literature. Economic efficiency is concerned with maximising overall welfare in a market given the available resources. We have had regard to 3 dimensions of efficiency:

- Allocative efficiency – resources are allocated to their highest value uses. In electricity markets this means the electricity that consumers demand is provided by the lowest cost supply and demand side options.
- Productive efficiency – the value of resources used are minimised for a given level of outputs. This includes removing any inefficient costs in supplying electricity to consumers.
- Dynamic efficiency – resources are allocated efficiently over time. In energy markets this means enabling innovation and having the right mix of demand and supply side options to provide maximum output at minimum cost over time.

1.3 We relied on a range of information and analysis, including contract market information collected from participants

We used a range of information for our 2024 analysis, including from:

- the Australian Energy Market Operator (AEMO)
- the Australian Energy Market Commission (AEMC)
- the Australian Securities Exchange (ASX)
- the Commonwealth Scientific and Industrial Research Organisation (CSIRO)
- market participants.

Previously, we relied primarily on public information to assess the performance of wholesale markets. However, public information provides very limited visibility of participants' contracting behaviour, which is a critical element to consider in a fulsome assessment of the market.

The *National Energy Laws Amendment (Wholesale Market Monitoring) Act 2023* provides additional means for the AER to request market monitoring related information from participants. We are no longer required to first identify an issue using public information before we can collect non-public information.

We used these powers for the first time in 2024 to collect and analyse contract information from selected participants who operate in the South Australian market.

1.3.1 Our approach included analysing the structure, conduct and performance of the markets

In 2024 we have applied the same approach as our 2022 report, using a structure–conduct–performance framework to analyse the market and focusing on effective competition and efficiency. In broad terms:

- structure refers to the market structure and includes the number and size of buyers and sellers, the nature of the products and the height of barriers to entry
- conduct refers to firms' behaviour in the market, including production, and buying and selling decisions
- performance refers to market outcomes, usually by reference to concepts of efficiency.

Our Enhanced wholesale market monitoring guideline (2024) provides more detail on this framework. We also published the *Wholesale electricity market performance report 2024 – Methods and assumptions* to explain the approach we have taken and allow stakeholders to replicate the analysis.

1.3.2 We expanded our analysis to conduct a deep-dive review of the South Australian wholesale electricity market

For each *Wholesale electricity market performance report*, we choose an area or areas to explore in more depth. In 2024 we extended our analysis to conduct a deep-dive review of the South Australian wholesale electricity market.

As part of this, we used contract information collected from participants using our new information-gathering powers. We also conducted new or deeper analysis using public information. Overall, our review of the South Australian market included new or extended analysis of:

- contract markets, using both public (ASX) and non-public information
- directions made to South Australian generators for system security
- vertical integration and the net contract position of participants
- economic and physical withholding.

1.3.3 How this document is structured

While we adopted the structure–conduct–performance framework to analyse the markets, this report is structured around our key findings and issues we identified.

This report covers:

- Chapter 2 – overview of market conditions and change drivers
- Chapter 3 – challenges facing contract markets
- Chapter 4 – whether the current market structure supports efficient and competitive markets
- Chapter 5 – whether participants are exercising market power
- Chapter 6 – entry and exit
- Chapter 7 – review of the South Australian energy market to assess whether it is functioning effectively.

2 Market conditions and change drivers

Key findings

- Prices in the National Electricity Market (NEM) have fallen since the last *Wholesale electricity market performance report* in 2022 due to lower fuel prices and increased renewable generation. However, prices are still at higher levels than pre-2022.
- Higher priced trading intervals have reduced, but high price events remain prevalent, due to a combination of high demand, network and generator outages, and variable wind output.
- The contribution of intermittent renewable sources continues to grow and was 32% of generation output in 2023–24.[5] Renewables have the greatest impact during the day. They are increasingly driving negative prices and increasing rooftop solar generation is decreasing average grid demand.
- The market transition is increasing the importance of flexible output that can address variations in demand throughout the day. Large-scale solar generation has displaced coal, gas and hydro generation in the middle of the day, while dispatchable generation still provides most generation at other times.
- In South Australia and Victoria, when renewables set the price during the day, most of the time it is wind, with solar at slightly lower levels. In Queensland and NSW, it is nearly all solar. Coal has been setting the price less often, particularly during the day and the evening peak.
- Frequency control ancillary service (FCAS) costs in 2023–24 were the lowest they have been since 2015–16, driven by falling prices due to increased competition.

Electricity generated in eastern and southern Australia is traded through the NEM. The NEM is a wholesale spot market, in which fluctuations in supply and demand determine the price of electricity.

To assess whether the NEM is effectively competitive or efficient over the long term, it is critical to understand the market conditions and the factors driving participant behaviour and price movements. Understanding these factors can also help determine whether current market conditions will persist.

Box 2.1 The NEM

The National Electricity Market (NEM) is a wholesale spot market for trading electricity. The market covers 5 regions – Queensland, NSW (including the ACT), Victoria, South Australia

[5] This figure includes rooftop solar.

and Tasmania. The regions are connected via high voltage transmission links called interconnectors.

Generators participate in the NEM by submitting offers to the Australian Energy Market Operator (AEMO) to supply quantities of electricity at different prices for periods of time. Around 284 power stations (comprising around 383 plant units in total) make offers to supply quantities of electricity in different price bands. The generators include coal-fired plant, gas-powered generators, wind turbines, hydro-electric plant and large-scale solar generators. There are also around 28 batteries and pumped hydro power stations that can store energy for later use. Electricity generated by rooftop solar systems is not traded through the NEM but does impact demand.

AEMO ensures electricity generation is matched with demand in real time by issuing instructions to generators every 5 minutes (known as a dispatch interval). AEMO selects the generators with the lowest offers first and then progressively more expensive offers until enough electricity can be dispatched to meet demand. The generator that provides the last megawatt needed to meet demand (or the marginal generator) sets the price for the 5-minute dispatch interval.

Spot prices can fluctuate in the NEM every 5 minutes. Participants can offer their capacity at any level between the price floor (−$1,000 per megawatt hour (MWh)) and the price cap ($17,500 per MWh). The highest priced offer needed to meet demand sets the spot price every 5 minutes. Generators that were dispatched are paid this price for the electricity they produce regardless of how they bid.

In practice, generators use a number of strategies to manage the risk of fluctuating wholesale spot prices in energy only markets. Generators and retailers will often enter into hedge contracts traded on the Australian Securities Exchange (ASX) or negotiated directly between the 2 parties (known as over-the-counter contracts), which lock in future electricity prices. Participants can also enter into long-term offtake agreements (that is, power purchase agreements) and often have both generation and energy retailing businesses to balance out the risks across each market (referred to as vertical integration).

While the market is designed to meet electricity demand in a cost-efficient way, other factors such as network limitations can intervene. For example, at times the network around the lowest cost generator may be congested, so to manage system security AEMO deploys more expensive (out of merit order) generators located in an uncongested area of the network instead. At other times, market conditions may allow a generator to bid in ways that cause prices to rise above competitive levels – for example, when a participant holds market power and rebids their capacity from low to high prices.

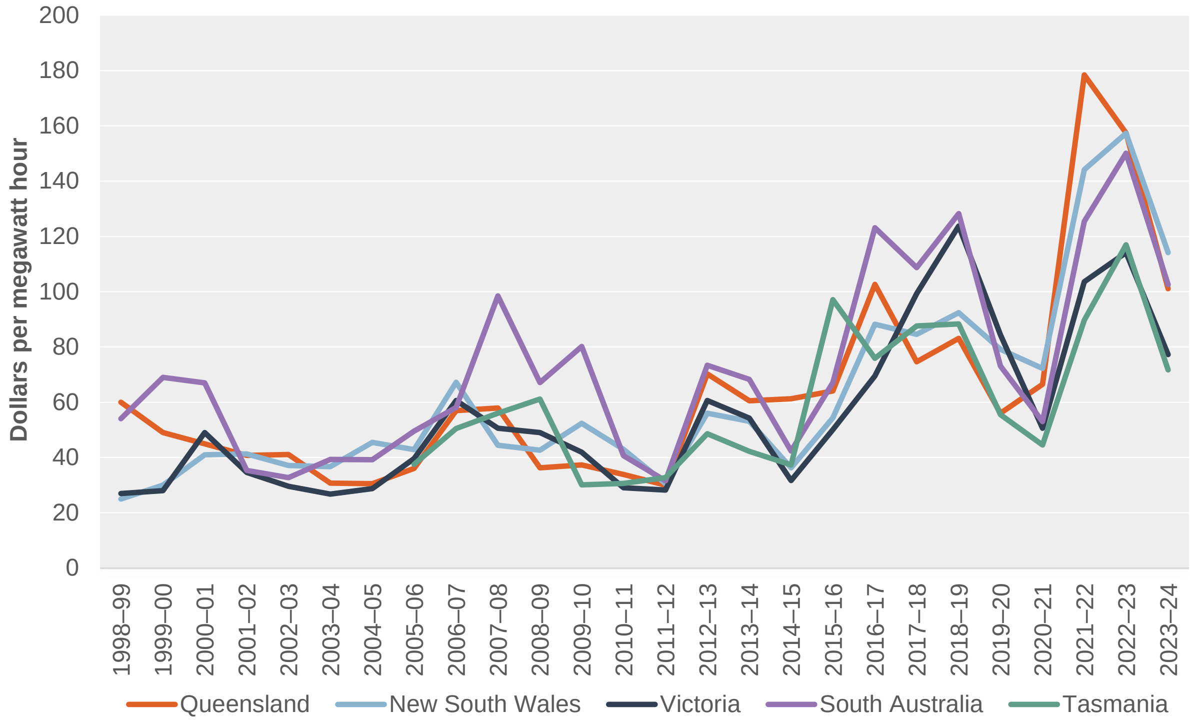
2.1 Average annual wholesale spot prices fell from unprecedented levels

The ‘energy squeeze’ in 2022, caused by significant outages of thermal generation, fuel supply problems in coal and gas markets, and an early winter increasing demand, has eased in the past 2 years. As a result, wholesale prices have decreased.

In 2022–23 average annual prices continued to rise in all regions except for Queensland. However, quarterly analysis shows that these annual outcomes were heavily influenced by price outcomes in July to September 2022, which were driven by high fuel prices and energy constraints. These effects started to unwind in the latter part of 2022, in part due to government intervention.

In 2023–24 average annual prices fell considerably in every region, mostly driven by low prices in the first 2 quarters, before prices started rising again in the last 2 quarters. Mild weather conditions and increased rooftop solar generation drove demand down to record low levels in the first 2 quarters, putting downward pressure on prices. Weather-related high price events, increased generator and network outages, and lower wind and solar output drove prices up in the last 2 quarters. While prices have dropped from the record highs in 2022, these outcomes show the market remains volatile.

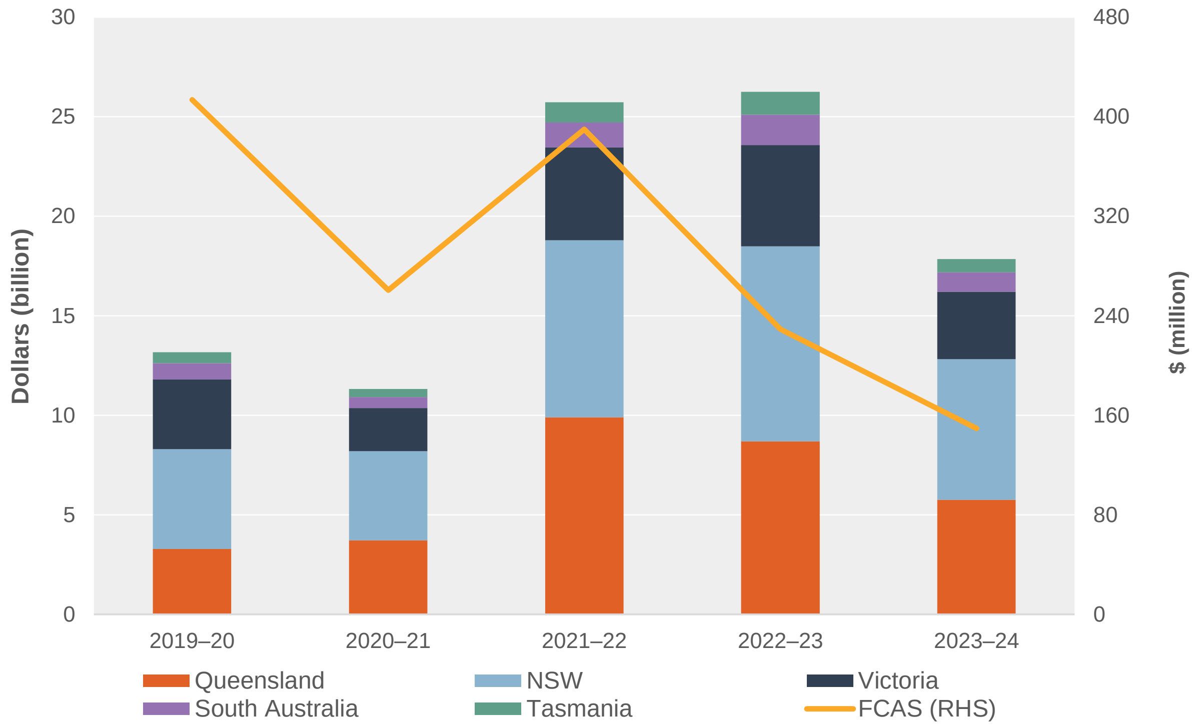
Figure 2.1 Annual volume weighted average prices in the NEM



Note: Volume weighted average price is weighted against native demand in each region. The AER defines native demand as the sum of initial supply and total intermittent generation in a region.
Source: AER analysis using NEM data.

Since our last report, the overall NEM turnover has decreased by around 30% from $26.5 billion in 2021–22 to $18.6 billion in 2023–24. This is mostly driven by falling prices in the last 2 financial years, while demand remained stable. FCAS revenue has decreased significantly to its lowest level since 2015–16, driven by falling prices due to increased competition with more service providers entering the market.

Figure 2.2 NEM turnover by region and FCAS revenue

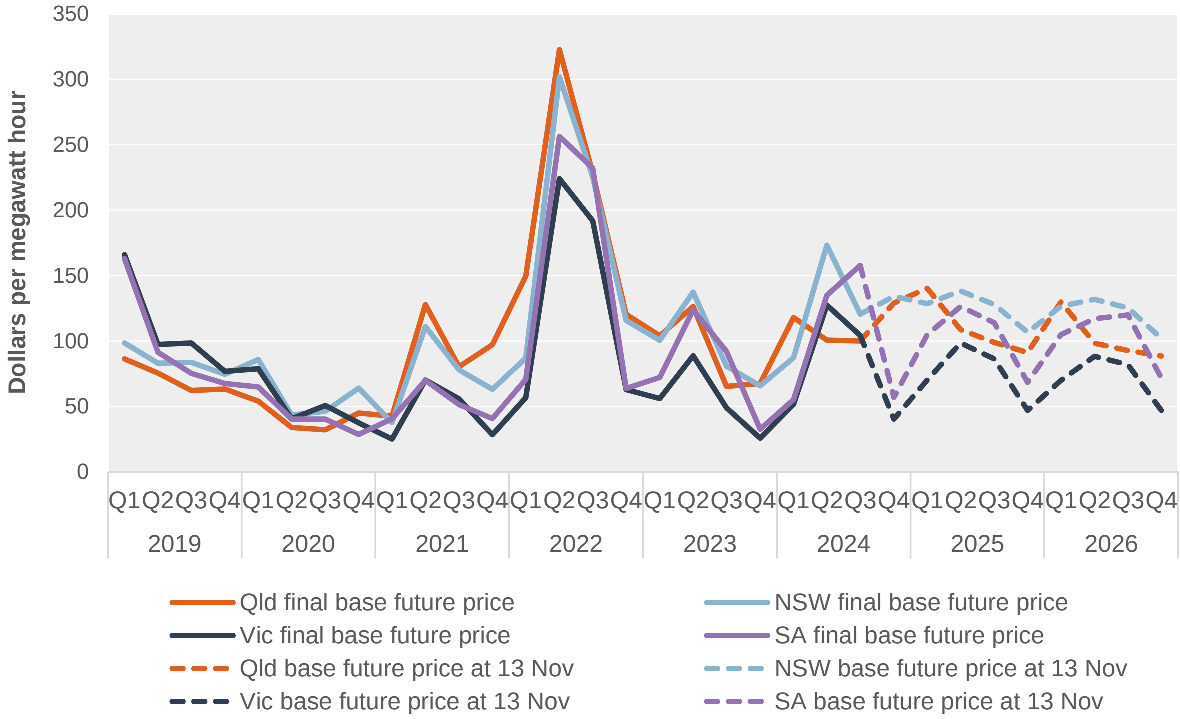


Source: AER analysis using NEM data.

2.1.1 Contract prices fell substantially, in line with spot prices

Contracts are used as a hedging tool by both generators and retailers to reduce their spot market risk. Base futures are one of the most traded contracts, allowing the buyer and seller to lock in a price for electricity in advance. The price of base futures gives us an indication of where market participants expect prices to be in the future. In line with spot price trends, final contract prices declined significantly from the peaks of 2022 to lows in Q4 2023 (Figure 2.3). However, futures prices increased again in Q2 2024, in part due to the high price events in May 2024.

Figure 2.3 Final and current quarterly base future contract prices



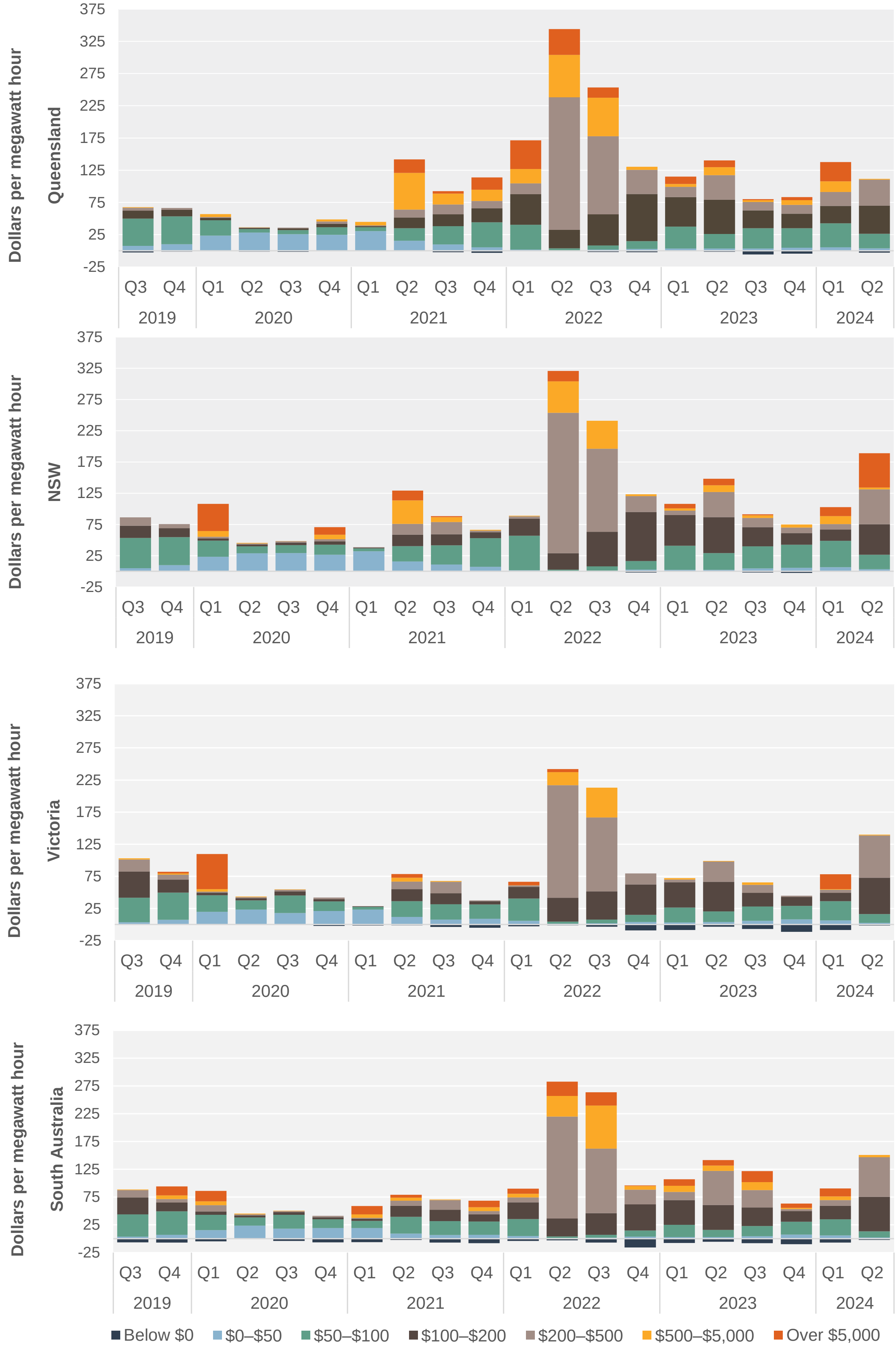
Note: Final contract prices are equal to the cash settlement price, calculated by taking the arithmetic average of the wholesale electricity spot prices over the contract term. Non-final prices are the daily settled price for the quarterly base future contract on 13 November 2024.

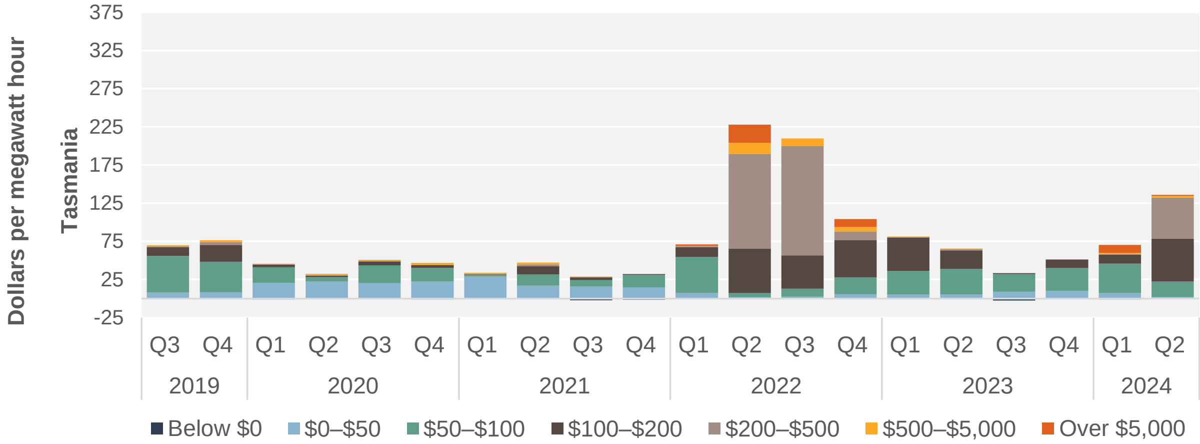
Source: AER analysis using ASX data.

2.1.2 Higher priced trading intervals have reduced, but high price events remain prevalent

Average prices can be driven by a general movement in prices or a more limited number of price events. In 2022 there was a significant increase in high-priced trading intervals, specifically between \$100 and \$500 per MWh and above \$5,000 per MWh. Since our last report, there has been a significant reduction in trading intervals priced between \$100 and \$500 per MWh and an increase in mid-priced intervals (between \$50 and \$100 per MWh). This is in line with improving supply conditions, which is in part due to government intervention (section 2.2.1). Prices above \$5,000 per MWh continued to have an impact on overall prices, particularly in Q1 and Q2 2024. The causes of the high prices varied between regions, but involved some combination of high demand, network and generator outages, and lower wind and solar output.

Figure 2.4 Contribution of different price bands to quarterly wholesale prices





Note: Shows the extent to which different spot prices within defined bands contributed to the volume weighted average wholesale prices in each region.

Source: AER analysis using NEM data.

The number of high-priced trading intervals from 2 May to 8 May 2024 led to the market exceeding the cumulative price threshold in energy for only the second time in the history of the NEM. This triggered a period of administered prices in NSW, where wholesale electricity prices and FCAS prices were capped at $600 per MWh until the cumulative price fell back below the threshold 7 days later. The common driver of almost all the high prices in this period was multiple scheduled network outages, which impacted NSW's ability to access low-priced generation from southern NSW and neighbouring regions. This was compounded by rebidding from some market participants, significant coal generation outages (mostly unplanned), in particular at Eraring and Vales Point power stations.

2.2 Supply conditions have improved, but input costs continue to exceed pre-2022 levels

Since the last report, gas and black coal fuel prices have decreased significantly and the reliability of thermal generation has increased. Government intervention in 2022 to 2024 helped thermal generators with access to and the cost of fuel. However, fuel prices are still elevated. Reliability has improved at the aggregate level. However, it is not just the number of megawatts lost in each outage but how frequently it happens that affects market outcomes.

2.2.1 Fuel costs have decreased significantly but are still elevated

Fuel costs are a key determinant of a generator's cost of producing electricity. Black coal generators can source their fuel from a range of sources, including directly from an attached mine or through short-term or long-term contracts. NSW black coal generators typically acquire their fuel through contracts. Short-term supply contracts for coal are likely to align more closely with the prevailing international coal price, but it is common for long-term domestic supply contracts to also set prices by reference to international coal price benchmark indexes. Generators may also be exposed to changes in the international coal price if:

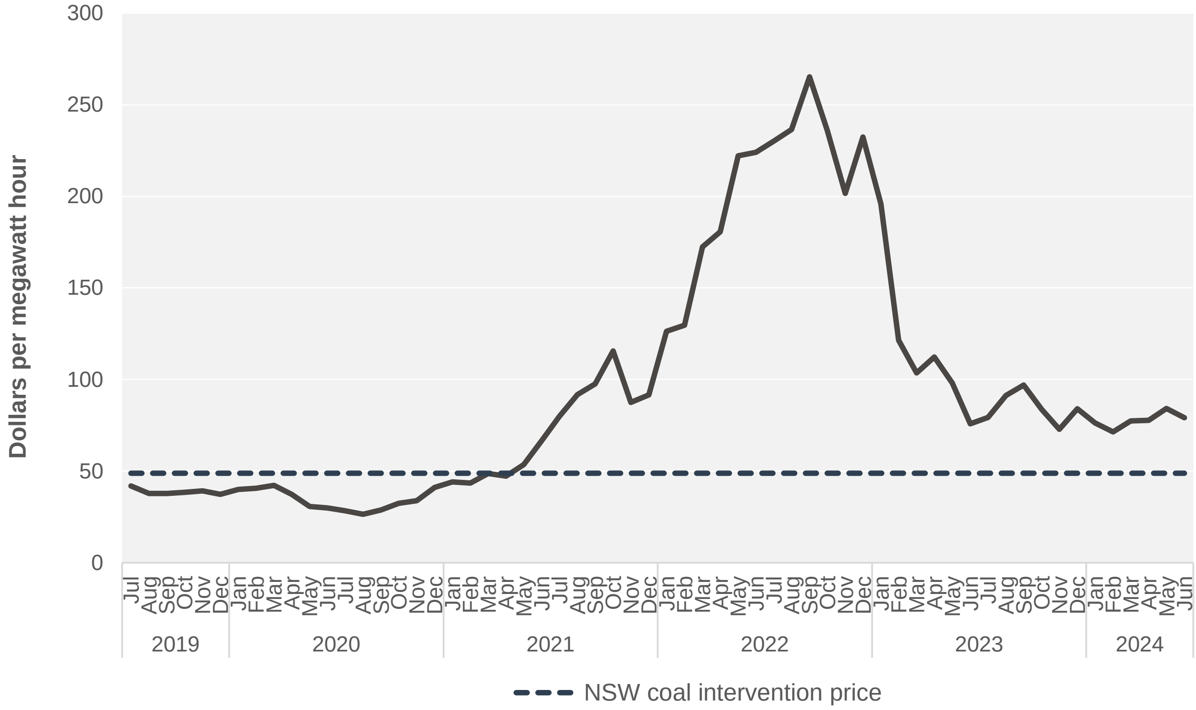
- they require additional coal that their contracts or mines cannot supply (due to supply disruptions from weather or transport congestion or other delays in delivery)

- they use spot markets to supply coal for flexible levels of generation
- long-term contract negotiations coincide with fluctuating prices.

Similarly, gas-fired generators source their fuel from a variety of sources. The opportunity cost of using gas for electricity generation is, among other things, selling it on the Short Term Trading Markets in Adelaide, Brisbane and Sydney, the Declared Wholesale Gas Market in Victoria, or the Gas Supply Hubs at Wallumbilla and Moomba.

The international reference price for thermal coal has decreased significantly since hitting a record high of an equivalent of $265 per MWh in September 2022 (Figure 2.5). Prices are still elevated ($84 per MWh in November 2024) compared with January 2021 ($44 per MWh).

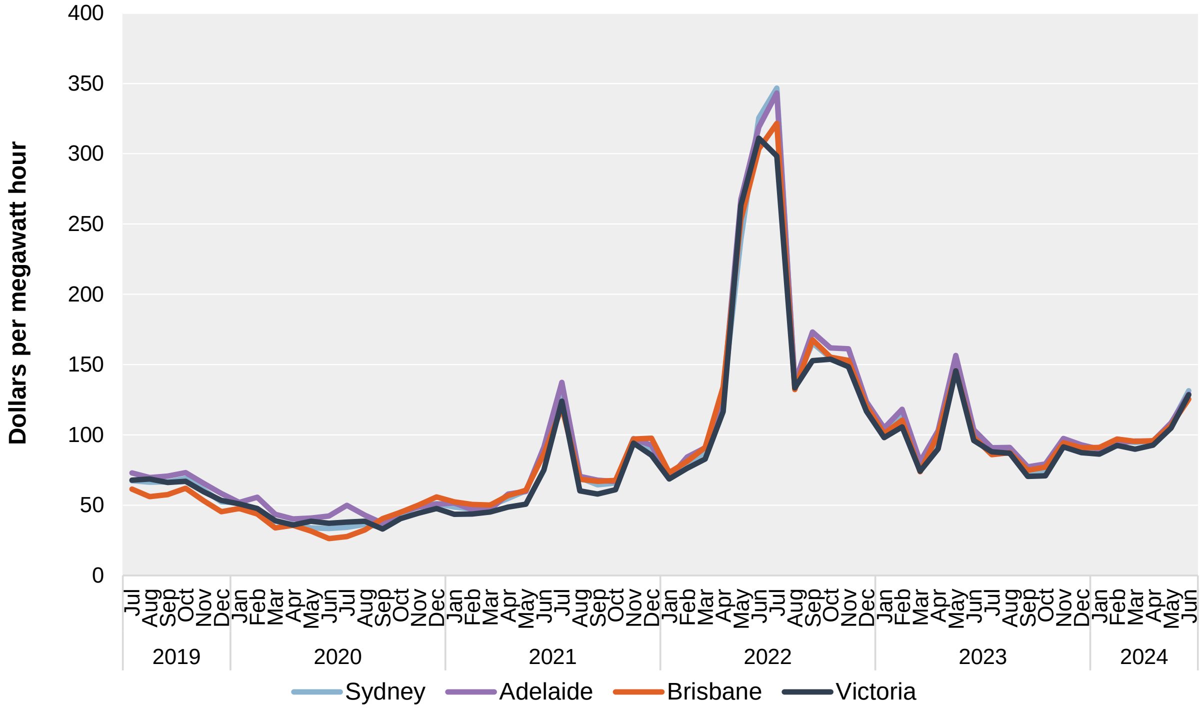
Figure 2.5 Proxy input cost for coal, based off international reference price for spot thermal coal



Note: To convert coal prices from US$ per tonne to A$ per MWh, we use the formula: $ per MWh = coal cost (US$ per tonne) divided by the exchange rate (monthly average) x heat rate (GJ per MWh)/low heating value (GJ per tonne). For coal, we use a constant heat rate of 9 GJ per MWh and a low heating value of 23 GJ per tonne.

Source: AER analysis of the Newcastle thermal coal index using data from GlobalCOAL.

Figure 2.6 Proxy input costs for gas in all regions, based off domestic spot gas prices



Note: Adelaide, Brisbane and Sydney Short Term Trading Market hub prices are average daily ex ante gas prices by month; Victorian Declared Wholesale Gas Market prices are average daily weighted prices by month. To convert the gas prices from per GJ to per MWh, we use the formula: $ per MWh = gas cost x heat rate (GJ per MWh). For gas, we use an average constant heat rate for combined cycle gas turbine (CCGT) units of 8 GJ per MWh. However, open cycle gas turbine (OCGT) units are more likely to set the price in periods of peak demand; as they operate less efficiently than CCGT, they have higher heat rates. As a result, the cost of gas in $ per MWh is higher.

Source: AER analysis using gas market data.

On 22 December 2022, the NSW Premier declared a coal market price emergency. The NSW Minister for Energy was granted the power to give directions to respond to the emergency. The NSW Government capped the price of black coal sold to generators at $125 per tonne. This is the equivalent of $49 per MWh. The Queensland Government moved simultaneously to direct its coal generators. The directions to the Queensland coal generators are not public, but the AER understands Queensland has a mechanism in place to achieve a similar effect to NSW. The NSW intervention ended on 30 June 2024.

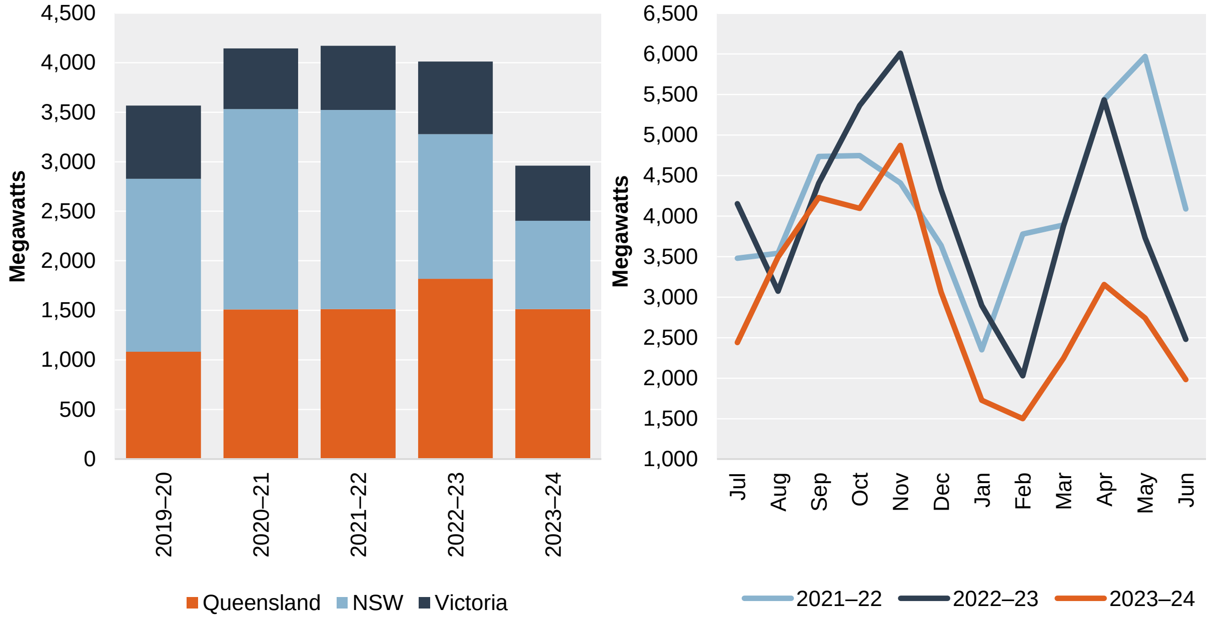
Following the market interventions, we observed an increase in low and mid-price offers from NSW and Queensland coal generators (see section 5.3.1 for more detail). The increase of cheaper coal offers helped bring down wholesale electricity prices because black coal set the price nearly half the time in NSW and Queensland (and nearly one-quarter of the time in Victoria and South Australia) in 2023–24. Wholesale prices will remain vulnerable to coal prices during the transition, as coal will continue to set the wholesale price, albeit less frequently.

Gas prices also decreased from a historical record of around $347 per MWh in July 2022. However, prices are still at higher levels (around $107 per MWh in November 2024) compared with prices in early 2021 (around $43 to $53 per MWh).

2.2.2 Baseload generator reliability has improved on average

The level of baseload generation outages[6] has improved in the past 2 financial years but is still worse than in 2017–18. Outages peaked in 2021–22 with an average of 4,171 MW of baseload capacity not available to the market. This improved slightly in 2022–23 before the average outage level declined by 26% to 2,962 MW in 2023–24. Baseload generator outages in NSW have reduced significantly, partially driven by the closure of Liddell units in NSW in April 2023, which had cumulatively 819 days of outages in 2020–21 and 2021–22.

Figure 2.7 Baseload outages, by region and by month



Note: Average coal generator outages are calculated based off registered capacity when dispatch for the day is zero. Includes planned and unplanned outages. Actual maximum capacity can differ from registered capacity due to changing performance of units through time and seasonal factors.

Source: AER analysis using NEM data.

Expectations of system-wide reliability affects future contract prices. While there has been an improvement at the average level, this obscures the impact of unplanned outages. Despite a significant overall improvement in NSW and Queensland generator outages in the last financial year, there was only a modest decrease in unplanned outages. It is not just the number of megawatts lost in each outage, but how frequently it happens which matters. In the first 3 months of the 2024–25 financial year there was a significant increase in frequency of unplanned outages – this quarter had more unplanned coal outages than any other quarter since 5-minute settlement began in October 2021. Unplanned outages increase volatility, which puts upward pressure on future contract prices. Reliability at a plant level also affects the level of that plant's contracting. As a plant ages and becomes more unreliable, the owner is likely to reduce their level of contracting to limit the risk of an unplanned outage when prices are high. However, the fact that prices may rise as a result of

---

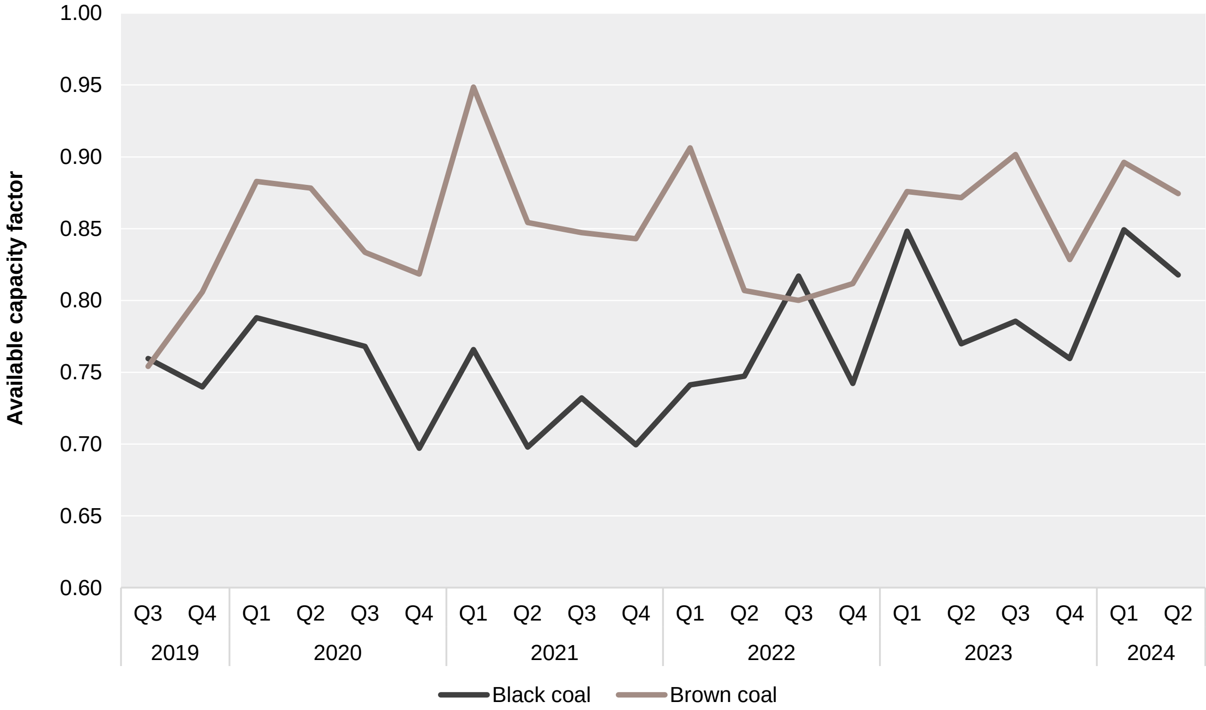
Baseload generators includes black coal stations in NSW and Queensland and brown coal stations in Victoria, which supply the 'base' capacity to the NEM. Outages refers to instances when a baseload generator is completely offline either due to planned or unplanned circumstances.

this reduced reliability may also increase the demand from retailers for contracts to hedge against these prices.

Outages usually peak in spring and autumn seasons when generators shut off some units for maintenance. This trend continued, with outages peaking in November 2023 and April 2024 in 2023–24, although at lower levels than in the previous 2 years.

The average availability capacity factor, which measures the maximum availability of different types of units over their registered capacity, has increased since Q3 2023 for both brown and black coal generators (Figure 2.8). The increase in the availability capacity factor indicates that units are offering a larger proportion of their registered capacity to the market and that, at an average level, coal reliability has improved since our last report.

Figure 2.8 Average available capacity factor of coal generators



Note: The average available capacity factor is calculated by comparing generator availability to registered capacity.
Source: AER analysis using NEM data.

2.3 Renewables continue to drive segmentation of the wholesale market

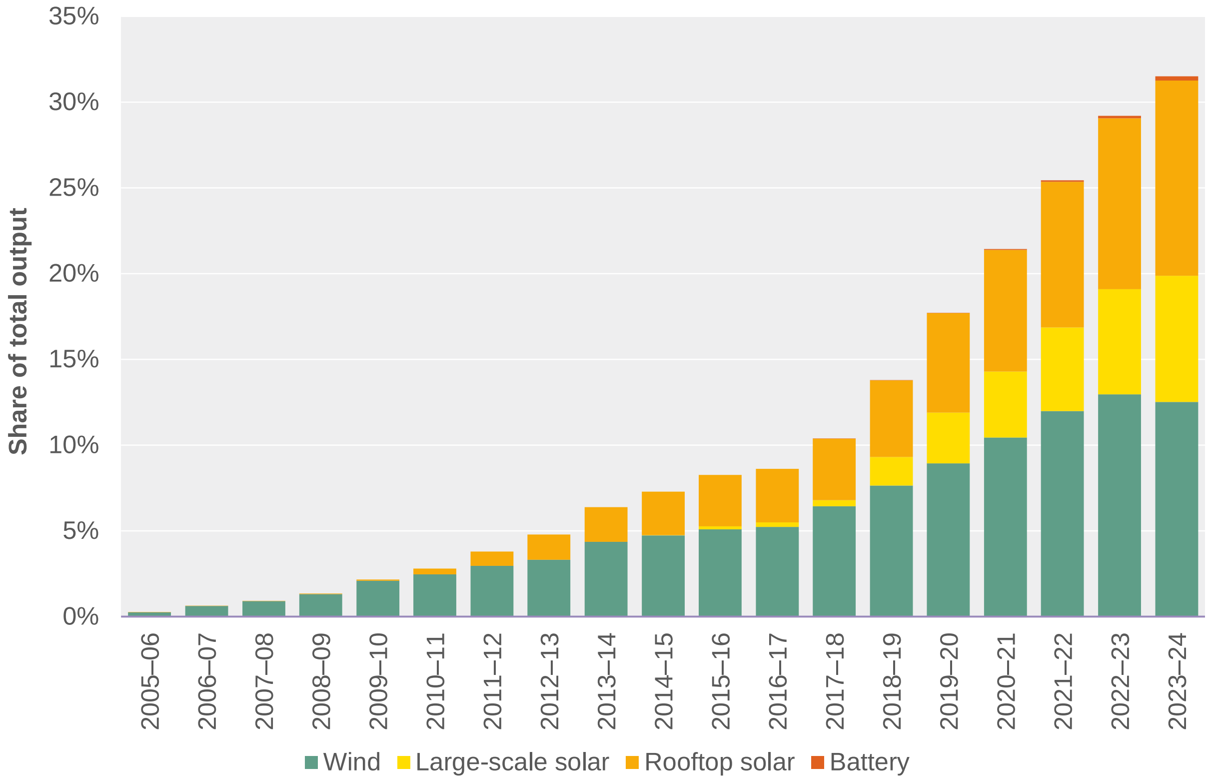
The NEM has continued to transition away from coal, towards intermittent renewable generation and storage technologies. Market outcomes vary considerably between when renewables are operating and when they are not. The increased investment in renewable generation is increasing the number of low and negative price intervals during the day, while rooftop solar continues to reduce demand. Dispatchable generation is required to ramp up from low levels during the day to meet evening peak demand.

2.3.1 Renewables share of generation output is growing, as rooftop solar also continues to reduce demand

Generation from intermittent renewable sources, including rooftop solar, has continued to increase, reaching 32% of total NEM generation in 2023–24 (Figure 2.9). In 2023–24 intermittent renewable output increased by its lowest amount since 2017–18, in part due to poor wind conditions. It increased by 5.7 GWh, compared with the average increase over the previous 5 years of 7.9 GWh.

Wind generation continues to have the highest output in the NEM after black and brown coal. Wind penetration continues to be strongest in South Australia, meeting around 45% of the state's electricity requirements in 2023–24. In the past 2 financial years 1,424 MW of wind capacity entered the market (section 6.1.1).

Figure 2.9 Wind, solar and battery generation share of total output

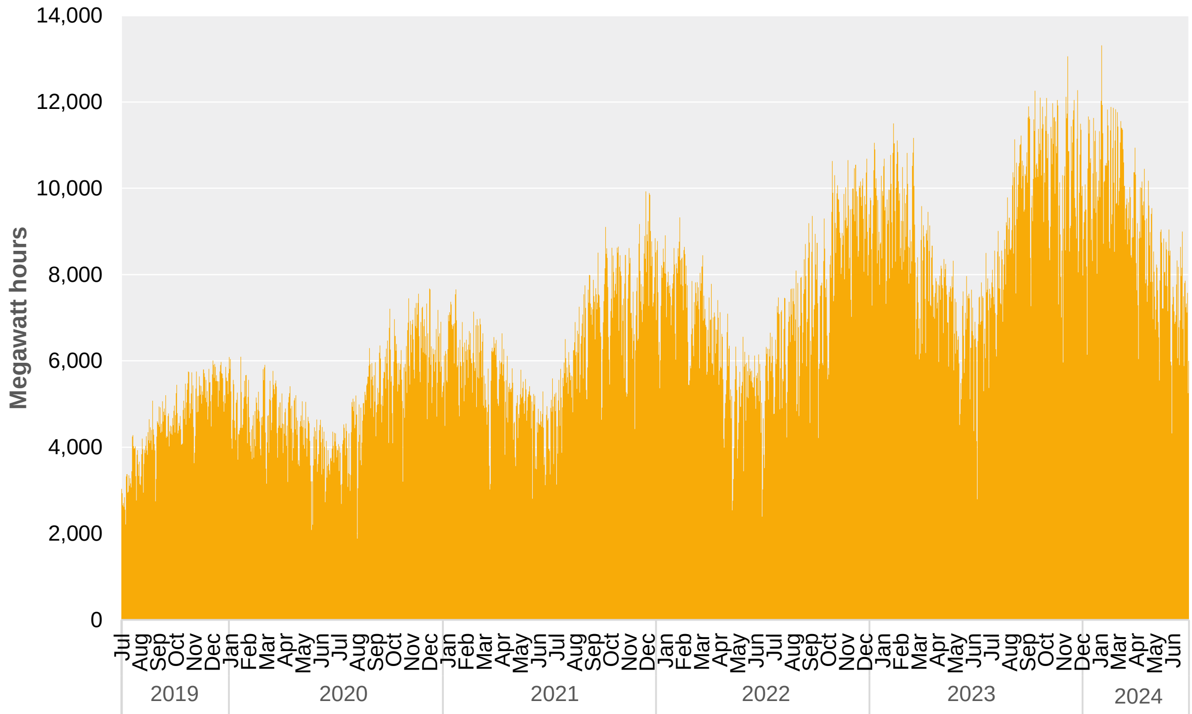


Note: Sum of generation as share of total output by financial year.
Source: AER analysis using NEM data.

Large-scale solar generation has continued to grow, and in 2023–24 it exceeded hydro generation for the first time. In the past 2 financial years 1,871 MW of solar capacity entered the market (section 6.1.1).

Rooftop solar is not dispatched in the wholesale market but reduces demand that must be met by grid generation. Rooftop solar generation has been increasing steadily since our last report and reached 11.4% of total electricity produced (up from 8.5% in 2021–22). This represents a reduction of over 24 GWh of demand that would otherwise need to be met by grid generation in 2023–24. Solar generation is at its lowest during the winter months. In recent years, the amount of rooftop solar added has been so great that output for winter 2024 exceeded the output of summer 2020 (Figure 2.10).

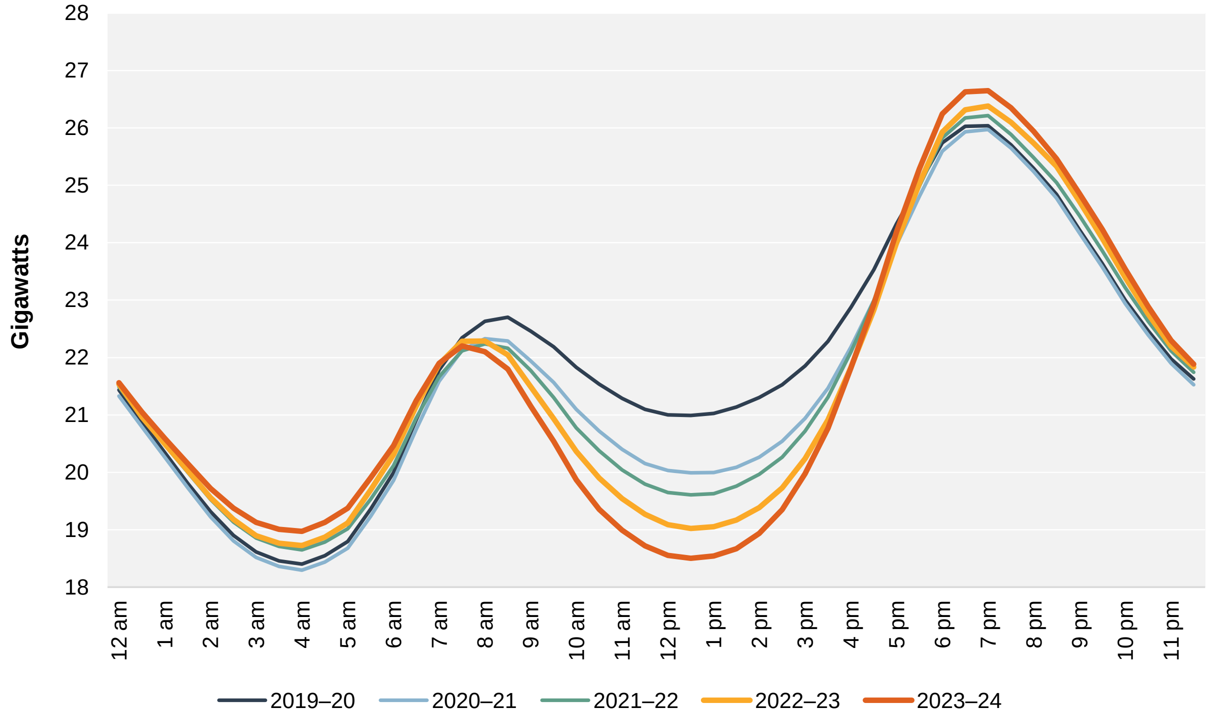
Figure 2.10 Daily rooftop solar generation in the NEM



Source: AER analysis using NEM data.

Solar only reduces demand during the day. Outside of solar hours, average demand has been increasing, in part due to population growth. This dynamic has increased the need for dispatchable generation to ramp up from low levels during the day to meet the evening peak. This is contributing to the segmentation of the market described above but presents growing opportunities for flexible technologies that can respond to rapid changes and shift energy between these times of day.

Figure 2.11 Average NEM native demand, by time of day



Note: The AER defines native demand as the sum of initial supply and total intermittent generation in a region. This figure presents outcomes in NEM time (Australian Eastern Standard Time). Values of y-axis do not start at zero to highlight the changes in demand.

Source: AER analysis using NEM data.

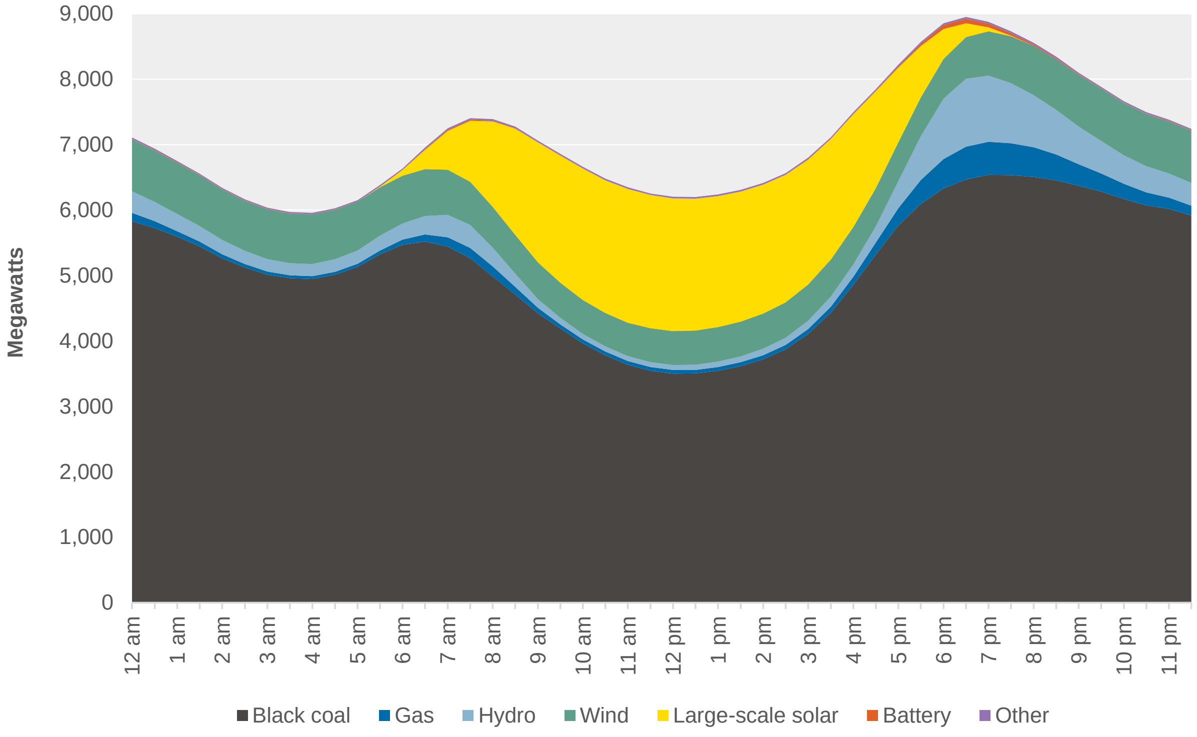
2.3.2 Renewables are taking over the day, but dispatchable generation is still key at other times

While rooftop solar is reducing demand, large-scale solar is increasing its share of grid generation during the day. All mainland regions had increased large-scale solar generation, providing 10% to 33% of output on average in the middle of the day.[7] This has displaced coal, gas and hydro. Outside of solar hours this dispatchable generation still provides most of the generation.

For example, NSW had the highest large-scale solar penetration among all regions in 2023–24. On average solar accounted for up to 26% of generation between 7 am and 5 pm, up from 15% in 2021–22 (Figure 2.12). At the same time, there has been up to a 3% reduction in total generation in the middle of the day since 2021–22, due to rooftop solar replacing generation required from the grid. At other times of the day, dispatchable generation provided on average over 85% of the generation.

7 In 2023–24 Victoria had the lowest large-scale solar penetration, reaching 10% of output at 12 pm, while NSW had the greatest at 33%.

Figure 2.12 NSW average generation by time of day, by fuel type, 2023–24



Note: Figure presents outcomes in NEM time (Australian Eastern Standard Time).
Source: AER analysis using NEM data.

2.3.3 Renewable generation has set price more often

Compared with 3 years ago, wind and solar generation are setting the price more often across all regions (Figure 2.13). Overall intermittent renewables set the price more often than last year, but there were small reductions in some regions, particularly for wind generation. As renewables generally set the price at negative levels, this has contributed to the overall price falls. Since our last report, batteries have started to play a more significant role in setting prices.[8]

[8] Batteries can set price as a generator or a load. This does not include times when battery is setting prices as a load.

Figure 2.13 Price setter, by fuel type and region

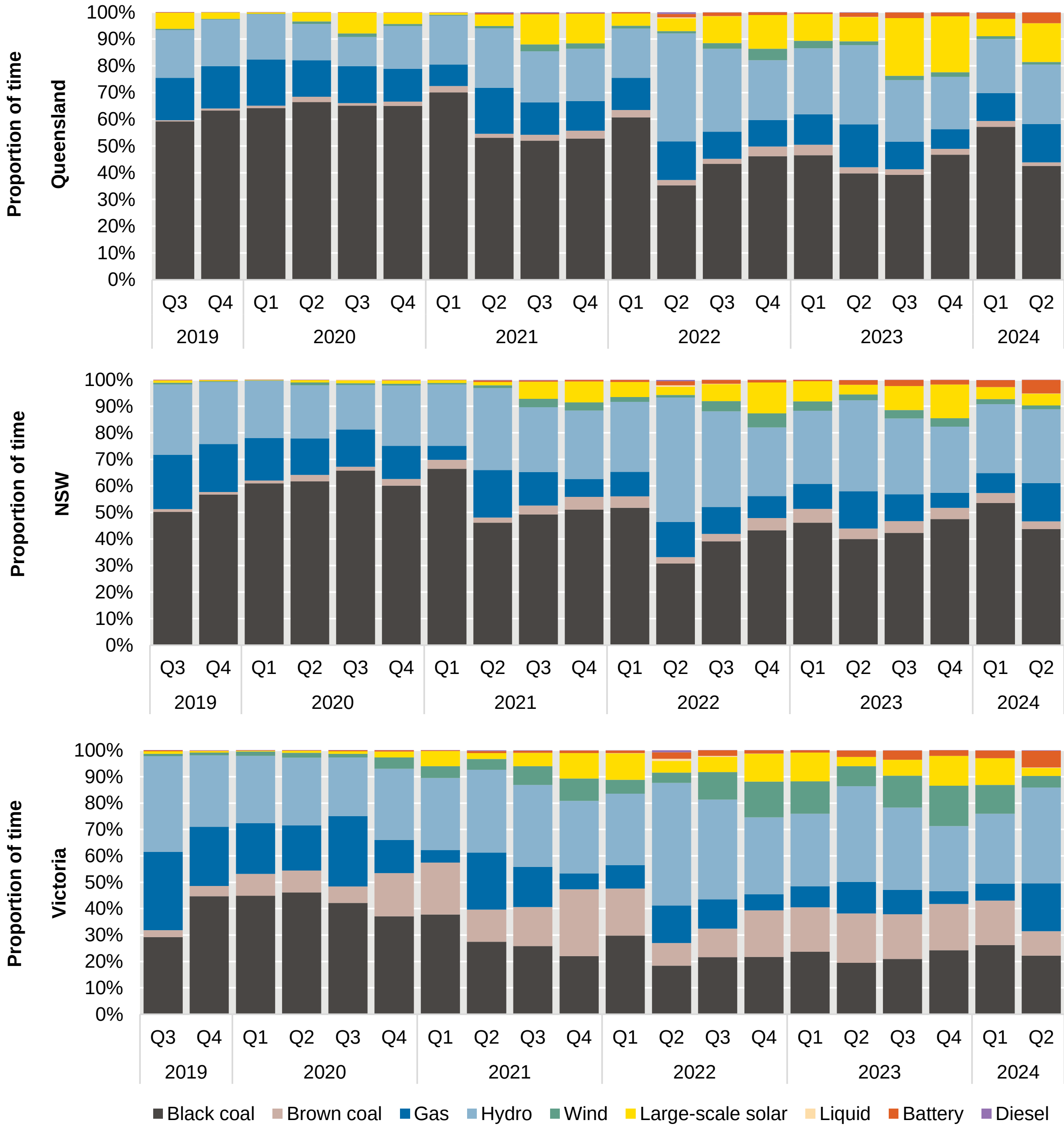
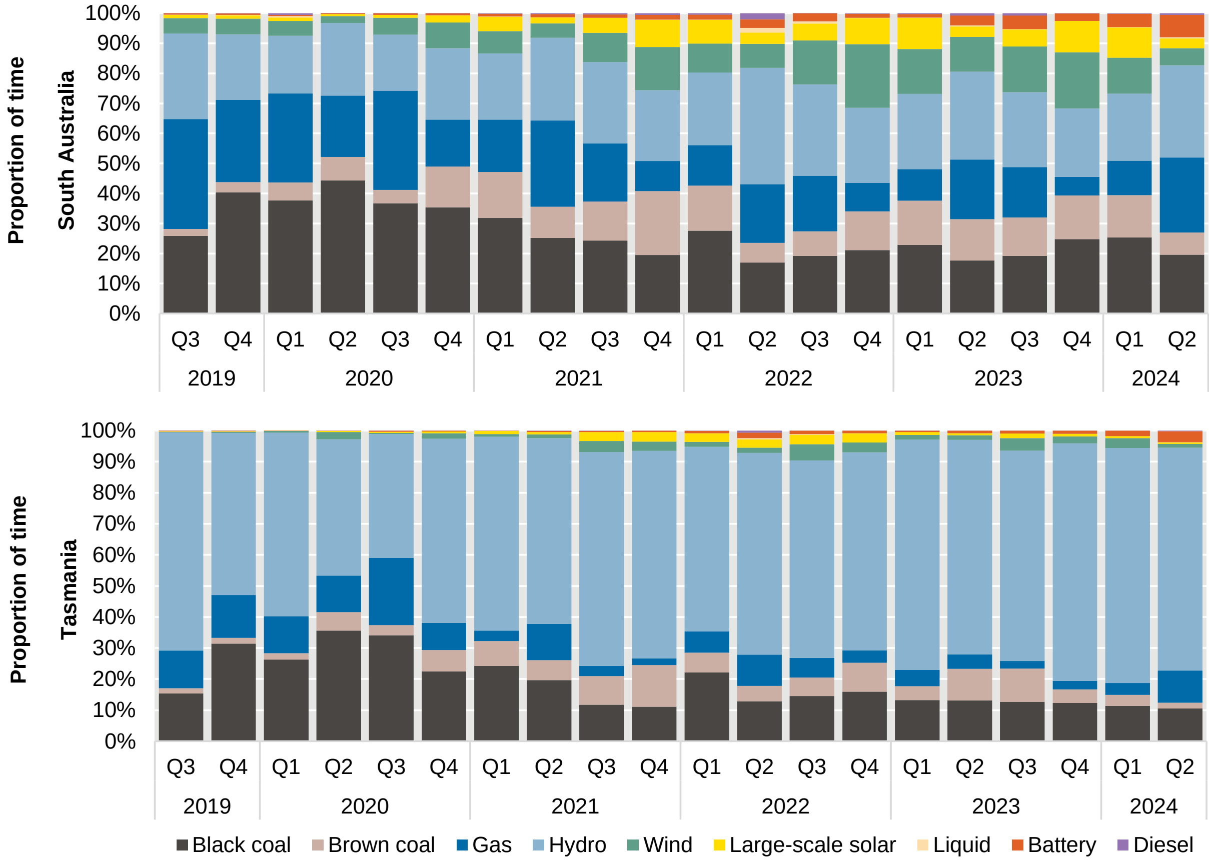


Figure 2.13 Price setter, by fuel type and region (continued)



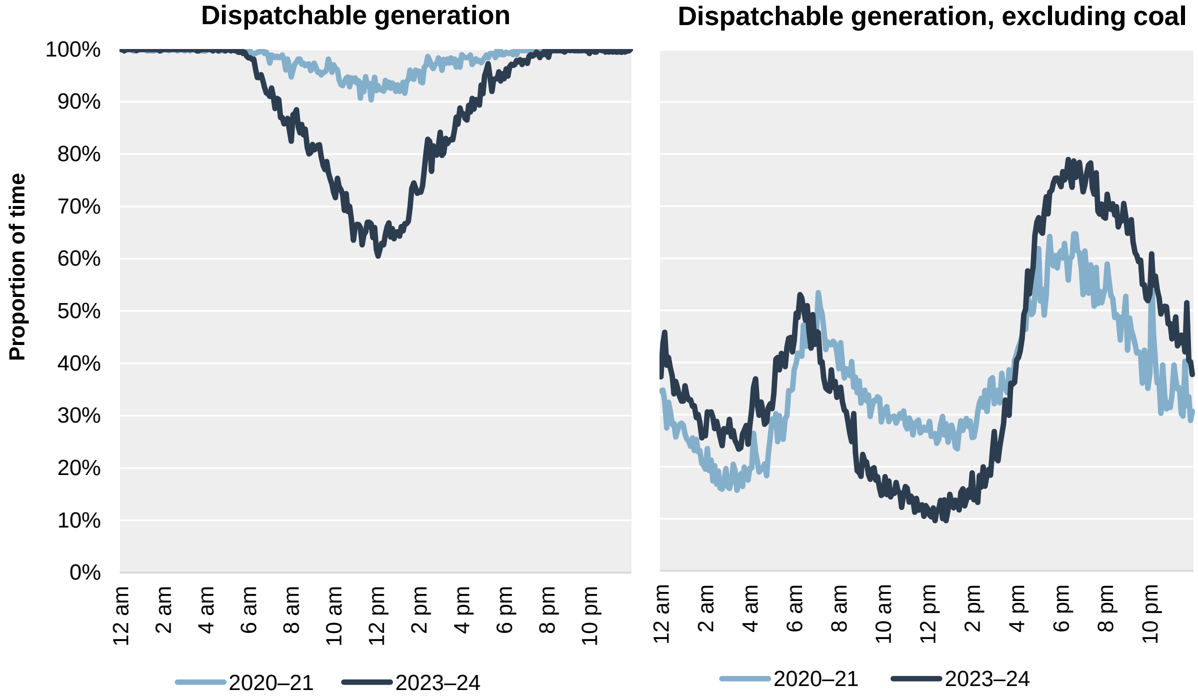
Source: AER analysis using NEM data.

2.3.4 Solar generation has set the price more often during the day; coal is setting the price less during the evening peak

Renewables are increasingly setting the price during the day. At these times negative prices have become increasingly common. While renewables have taken over the day, outside of solar hours dispatchable generation (primarily coal, gas, hydro and batteries) still sets the price over 90% of time.

There is some variation between the regions that have significant wind penetration (South Australia and Victoria) and the others (Queensland and NSW). In South Australia and Victoria, when renewables set the price during the day, most of the time it is wind, with solar at slightly lower levels. However, in Queensland and NSW it is nearly all solar. The higher amounts of wind in South Australia and Victoria also reduce the number of times dispatchable generators set the price outside of solar hours.

Figure 2.14 Price setter by time of day, NSW[9]

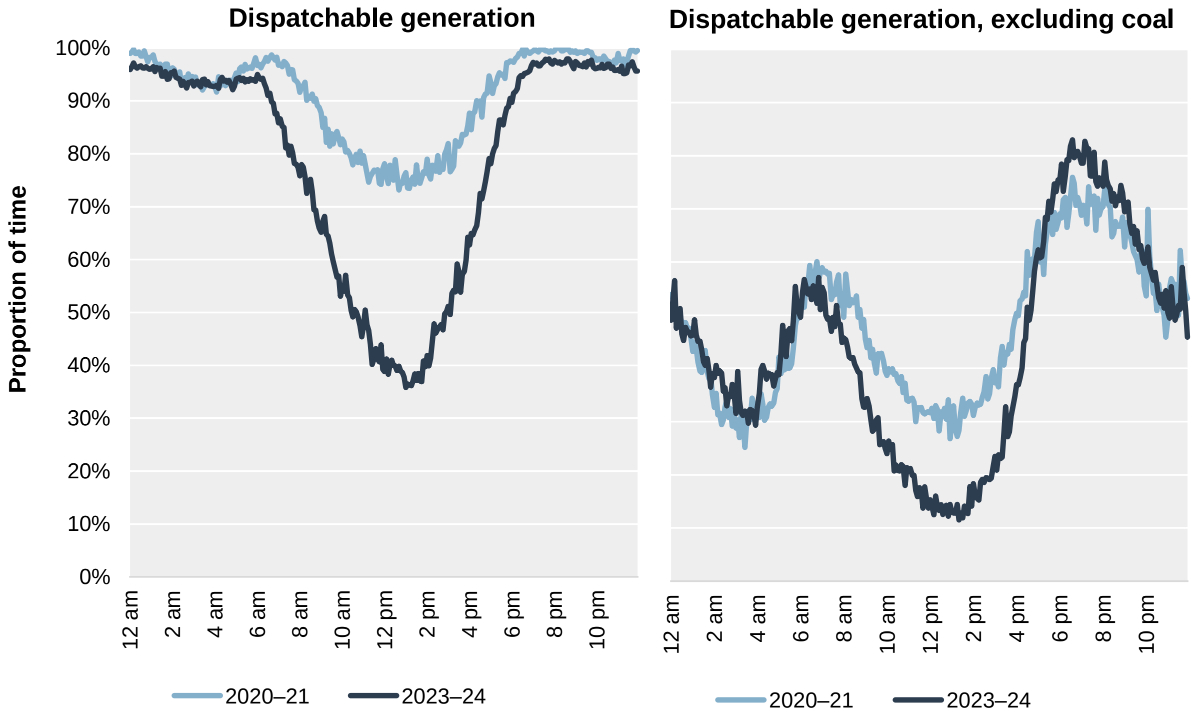


Note: Figure presents outcomes in NEM time (Australian Eastern Standard Time).
Source: AER analysis using NEM data.

Since 2020–21 black coal has been setting the price less often during the evening peak (5 pm to 9 pm). This decrease is in part due to a reduction in low to mid-price coal offers. Black coal offers priced below $90 per MWh are, on average, between 625 MW and 853 MW lower than in 2020–21. Coal has primarily been replaced by other forms of dispatchable generation, mainly gas and hydro with batteries playing an increasing role. In 2023–24 other forms of dispatch generation combined set the price around 70% to 80% of the time in the evening peak in all mainland regions. Queensland and NSW have seen the largest change with around a 20 percentage point increase, while in South Australia and Victoria the increase is around 10 percentage points. This compositional change is likely to have contributed to higher prices during the evening peak, as existing coal generation is often the lowest cost form of dispatchable generation at that time.

9 Dispatchable generation is all types of generation, excluding solar and wind.

Figure 2.15 Price setter by time of day, South Australia

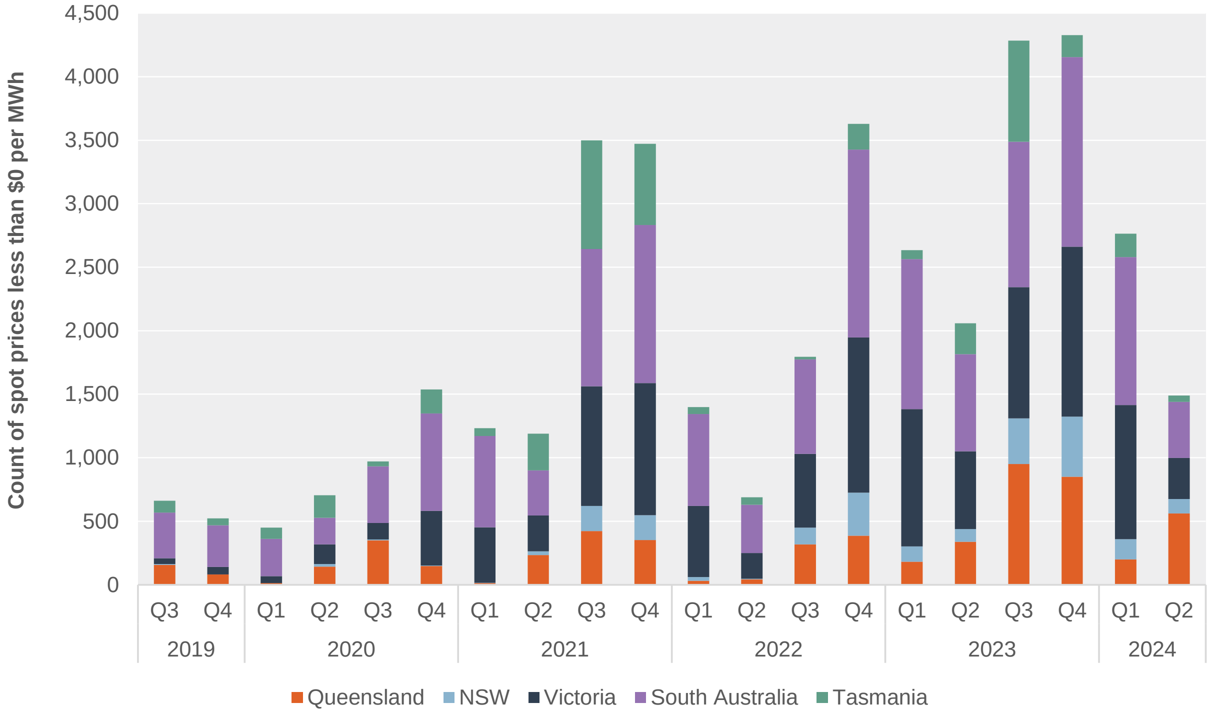


Note: Figure presents outcomes in NEM time (Australian Eastern Standard Time).
Source: AER analysis using NEM data.

2.3.5 Renewables are driving increased negative prices, particularly during the day

Instances of negative prices increased significantly since our last report (Figure 2.16), rising from 9,057 instances (10% of annual intervals) to 12,865 (15% of annual intervals) in 2023–24. South Australia (24.2%) and Victoria (21.4%) have the highest proportion of annual negative intervals, due to higher renewable penetration. Q3 and Q4 in each year have the most instances of negative prices, due to lower demand and higher solar output.

Figure 2.16 30-minute prices below $0 per MWh

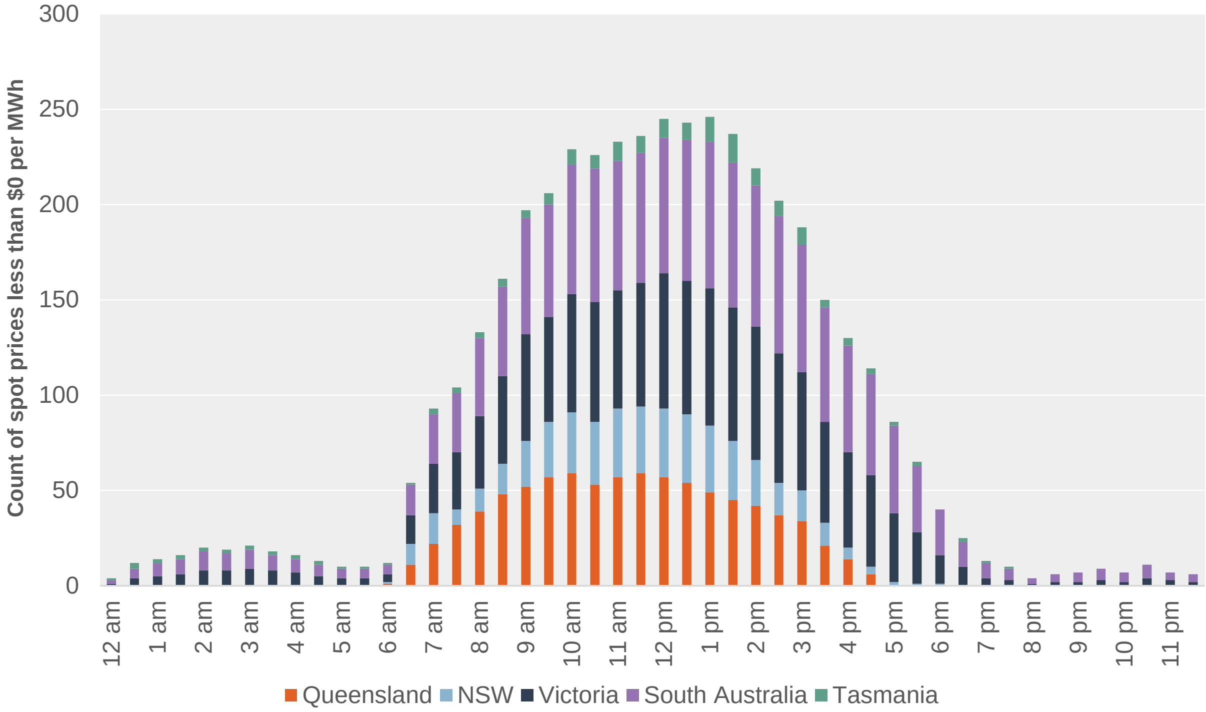


Source: AER analysis using NEM data.

Instances of negative prices mostly occurred between 8 am and 5 pm, when solar generation is high (presents opportunities for batteries, as they have an opportunity to arbitrage. The wider spread between the price they pay to charge and what they receive to dispatch generation, the more revenue they earn (section 5.4.1).

Figure 2.17). Queensland and Victoria had the largest increase in instances of negative prices since 2021–22. Increases in negative prices have resulted in solar generators effectively bidding themselves unavailable during daytime to avoid negative prices (section 5.5.1). This presents opportunities for batteries, as they have an opportunity to arbitrage. The wider spread between the price they pay to charge and what they receive to dispatch generation, the more revenue they earn (section 5.4.1).

Figure 2.17 30-minute prices below $0 per MWh by time of day, Q4 2023



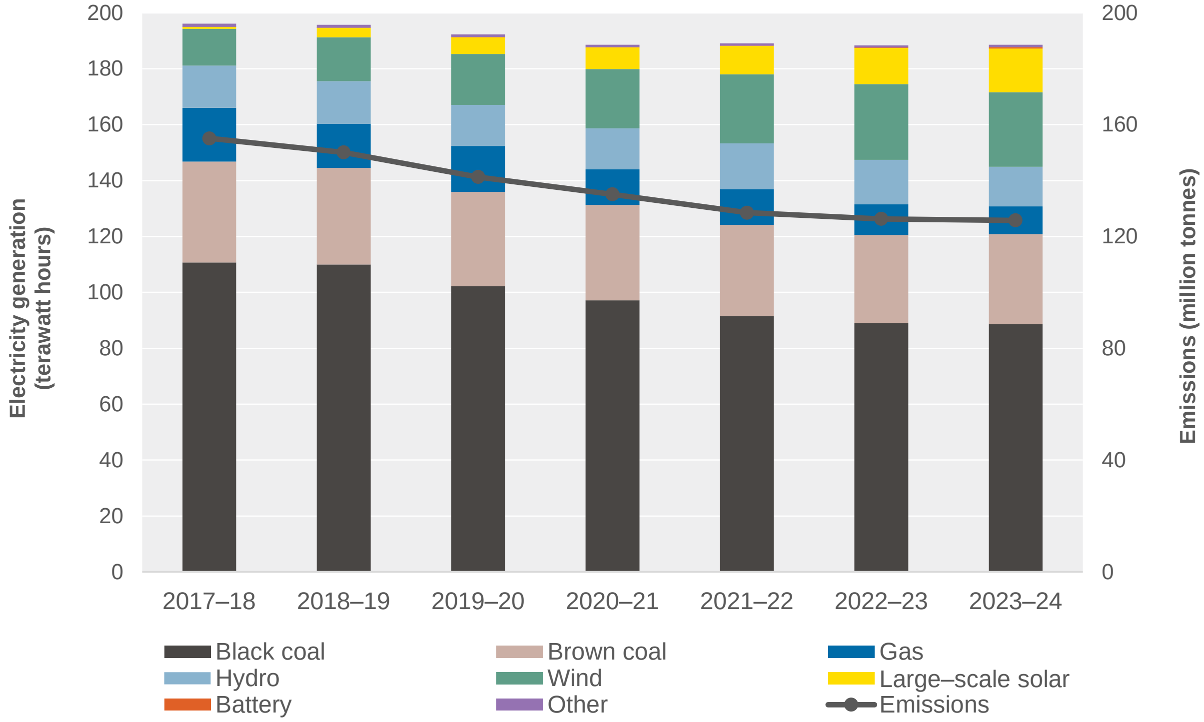
Source: AER analysis using NEM data.

2.3.6 Carbon emissions have reduced steadily due to less coal and gas generation in the NEM

On 12 August 2022, Energy Ministers agreed to fast track the introduction of an emissions reduction objective into the national energy objectives, consisting of the National Electricity Objective, National Gas Objective and National Energy Retail Objective. On 21 September 2023, the *Statutes Amendment (National Energy Laws) (Emissions Reduction Objectives) Act 2023* received Royal Assent.

Coal and gas account for almost 99% of total emissions in electricity generation. Brown coal generators produce around 1.2 tonnes of carbon dioxide to generate 1 MWh electricity, black coal generators produce 0.9 tonnes and gas generators produce around 0.7 tonnes. With the exit of coal power stations and greater investment in renewable energy, total emissions in the NEM have continued to decline over the past few years, reducing by 16% compared with 5 years ago (Figure 2.18). Reducing emissions from the energy sector is also expected to support the decarbonisation of other high-emitting sectors, including transportation and industrial processes.

Figure 2.18 Electricity generation by fuel type and carbon emissions in the NEM



Source: AER analysis using NEM and National Greenhouse Gas Inventory data.

2.4 FCAS costs have declined significantly

FCAS are used to maintain the frequency of the power system. There are markets for both energy and FCAS, which AEMO manages through a process called co-optimisation. To minimise overall costs, AEMO co-optimises offers and requirements between energy and FCAS markets simultaneously (Box 2.2). Most of the time, FCAS markets operate as a global market and participants providing FCAS compete across all regions of the NEM. However, if a region is separated or at risk of separation, the ability to transfer FCAS between regions is limited and local markets emerge.

Box 2.2 Frequency control ancillary services

There are 2 general categories of FCAS – regulation and contingency. Regulation services continuously adjust to small changes in demand or supply that cause the frequency to move by only a small amount. Contingency services manage large changes in demand or supply that occur relatively rarely and move the frequency by a large amount.

From October 2023, FCAS markets have expanded to include 2 new ‘very fast’ services to help control power frequency following system events and to foster innovation in faster responding technologies. These new markets are intended to support the transition away from relying on FCAS provided by thermal generators as part of their participation in the NEM.

After the introduction of the 2 new ‘very fast’ services, AEMO now dispatches services in 10 FCAS markets to maintain system frequency at close to 50 Hz. These services are:

- raise and lower regulation services
- raise and lower 1-second contingency

- raise and lower 6-second contingency
- raise and lower 60-second contingency
- raise and lower 5-minute contingency.

If there is a credible risk of at least one region separating from the rest of the NEM, regulation costs are recovered from participants that contribute to any deviations in frequency away from a secure operating state, known as causer pays.[10] Participants that operate in a manner that assists in correcting frequency deviations are assigned a low causer pays factor, while those that operate in a manner that causes the frequency to deviate are assigned a high factor.[11] The frequency deviation factors are used to determine the payment each participant must make.

Contingency services, like insurance, manage the risk of a large generator or load tripping. Raise contingency costs are recovered from generators and lower contingency costs are recovered from market customers. Each are apportioned a share of local contingency costs based on their share of total generation or load.

FCAS can refer to global or local requirements:

- Most of the time, FCAS can be shared over interconnectors between all regions. In these times we consider the markets for FCAS to be global. When we refer to global offers, we are describing offers from participants in all regions that can be used to meet global requirements.
- If there is a credible risk of at least one region separating from the rest of the NEM, such as from the potential loss of an interconnector, local FCAS requirements can be established. Local requirements ensure that, should separation occur, each region remains stable. At these times FCAS requirements can only be met by participants in the local region. This is typically an issue for regions at the extremities of the grid (Queensland, South Australia and Tasmania), where there are less connections to other regions.

AEMO's procurement of each FCAS service (in megawatts) depends on several constantly varying factors. For contingency services, AEMO procures an amount equal to the size of the largest credible contingency event minus assumed load relief. For regulation services, AEMO sets a minimum procurement, which it continually adjusts depending on other system requirements.

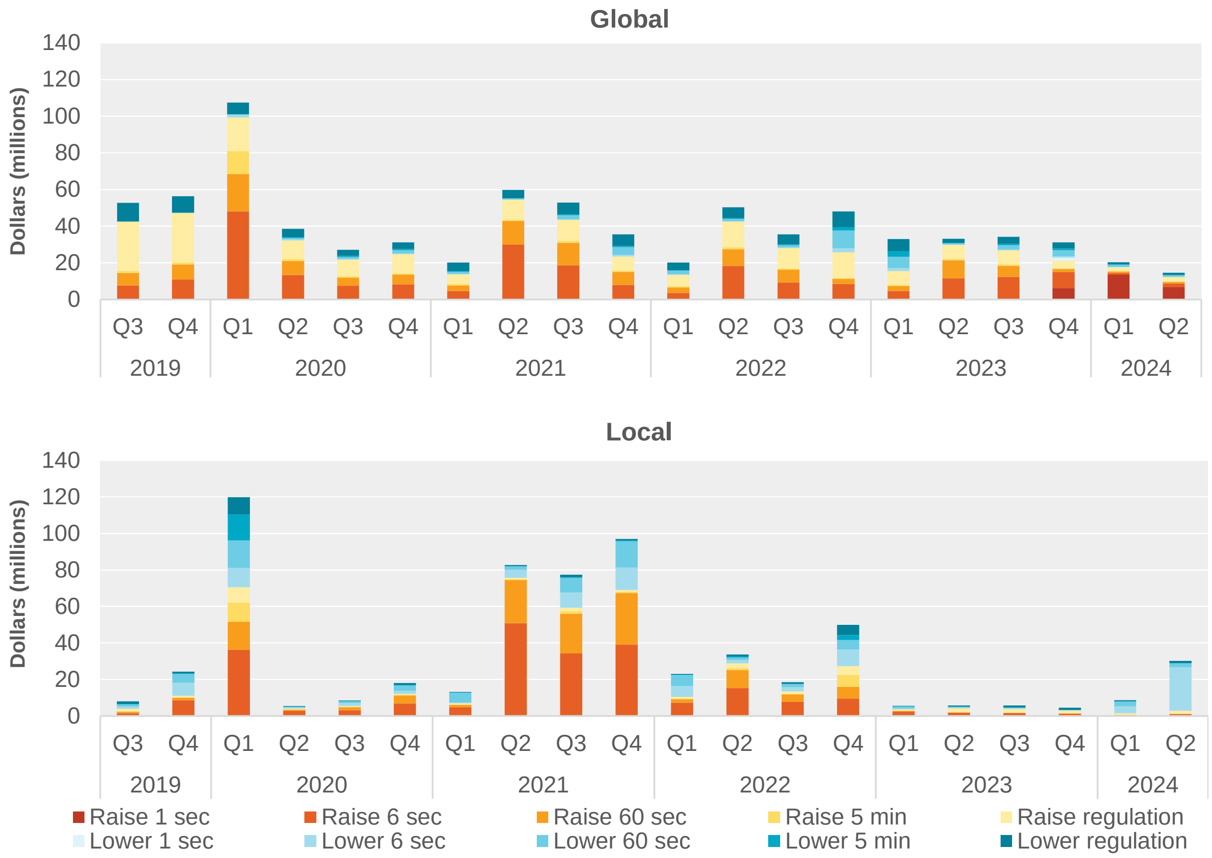
As in energy, participants offer into FCAS markets across 10 price bands. For most participants, a generator must be actively providing energy in order to provide FCAS, by raising or lowering generation output. But the degree to which a participant is dispatched in the energy market impacts the amount of FCAS it can provide. If a participant is already generating energy at its maximum capacity, it could not further increase generation to provide raise FCAS so, despite its offers, its 'effective' availability for raise services would be

10 AEMC. Security of the Power system, Australian Energy Market Commission, accessed 31 October 2024.

11 AEMO, Guide to Ancillary Services in the National Electricity Market, Australian Energy Market Operator, October 2023.

0 MW. If a participant is generating at its minimum, it could not decrease its generation to provide lower FCAS, so its effective availability for lower services would be 0 MW.

Figure 2.19 Global and local FCAS costs

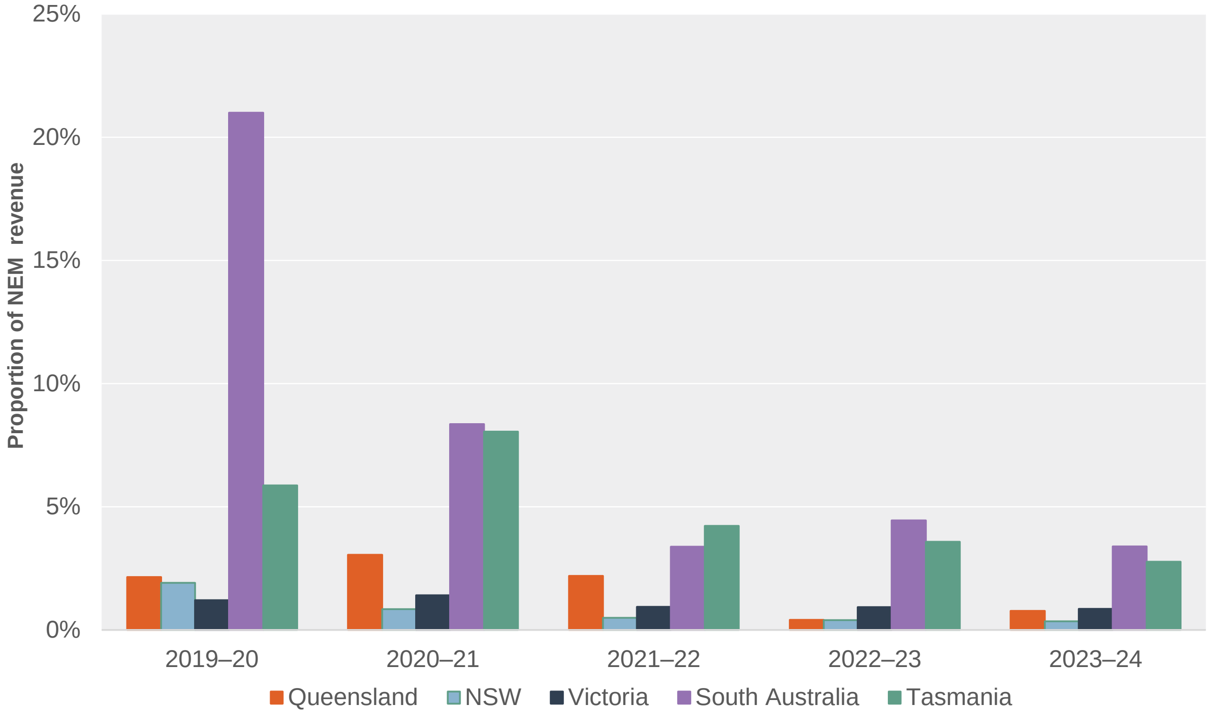


Note: Global FCAS costs are the sum of total costs for each ancillary service for the NEM, calculated by multiplying the price with the enablement of each service for all regions. Local FCAS costs are the sum of total costs for each service in each region.

Source: AER analysis of NEM data.

Since our last report FCAS costs have declined significantly, particularly in local costs (Figure 2.19). The costs for local services were lower than global costs for all quarters except for Q2 2024, suggesting fewer credible risks and improved generator and interconnector reliability compared with 2022. Overall, FCAS costs are at their lowest since 2015–16, driven by increased competition following more battery service providers entering the market, putting downward pressure on prices. In 2023–24 FCAS revenue only accounted for 0.3% of total energy market revenue in NSW and 3.4% in South Australia (Figure 2.20).

Figure 2.20 FCAS revenue as a percentage of wholesale market revenue, by region

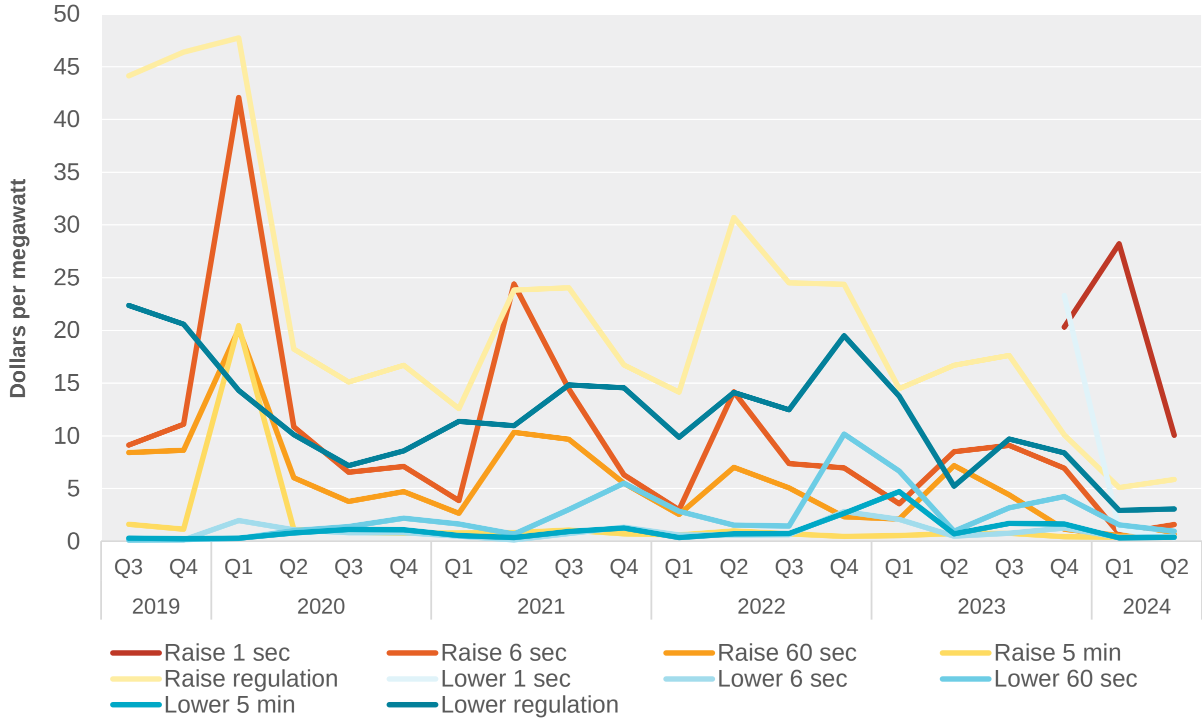


Source: AER analysis of NEM data.

2.4.1 New FCAS services were introduced with higher costs but decreased in following quarters

Two new FCAS services were introduced into the market in October 2023: raise 1-second and lower 1-second contingency services ('very fast' FCAS services). When the new markets started, 16 participants were registered to provide the service. There were participants in all NEM regions, and most were batteries or demand response aggregators.

Figure 2.21 Global FCAS prices



Source: AER analysis of NEM data.

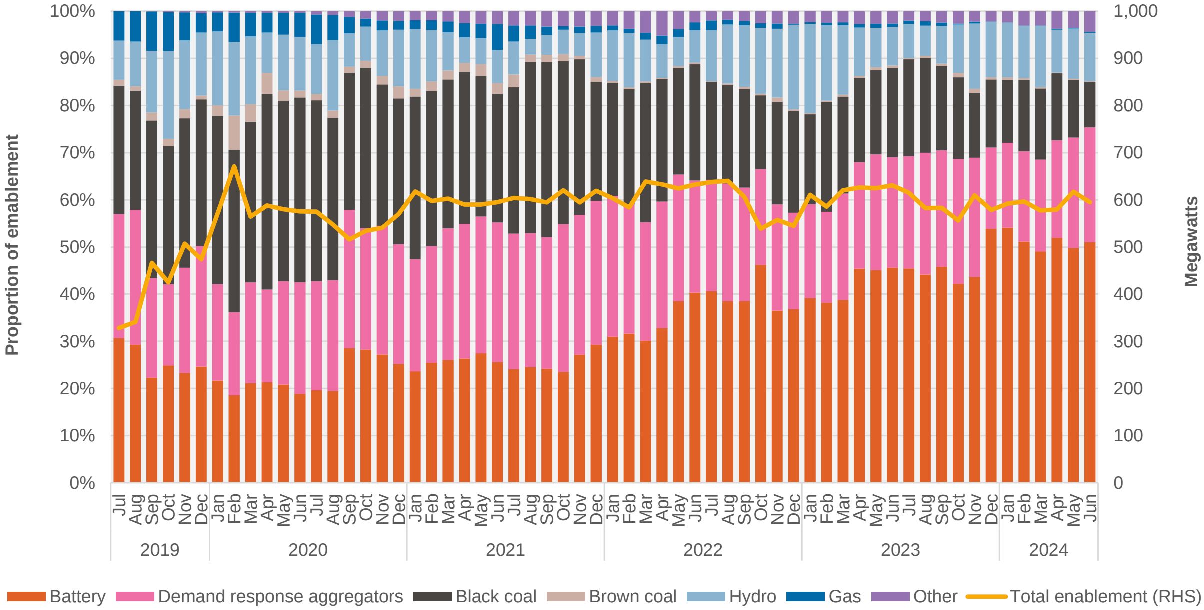
Prices and costs for these new services were initially much higher than for other FCAS services but started to fall in Q2 2024. For lower services, the 1-second contingency service averaged $23 per MW in its first quarter, while the next most expensive service was lower regulation at $8 per MW. For raise services, the 1-second service averaged $20 per MW, while the next most expensive was raise regulation at $10 per MW (Figure 2.21). Prices for the lower 1-second service had dropped significantly in Q1 2024 to $1 per MW but prices for the raise 1-second service have remained elevated compared with other services. In Q3 2024, prices for the new 1-second services fell to similar levels as other services.

2.4.2 Battery and demand response aggregators continue to displace coal and gas generation

Battery and demand response participants of FCAS services differ from traditional providers of FCAS like coal or gas generators in that they can provide FCAS without needing to provide energy as well. This makes them more flexible and responsive. Importantly, the efficiencies inherent in these technologies, such as lower marginal cost to operate and lower capital costs, allow them to offer at mostly low prices. This appears to have encouraged some incumbent participants, such as black coal generators, to shift FCAS capacity to lower prices to compete when it was economical to do so.

FCAS services sourced from grid-scale batteries have continued to increase over the past 2 years, surpassing those sourced from coal and gas generators in a number of FCAS services. In the case of raise 6-second services, the services provided by batteries increased from 40% in June 2022 to over 51% in June 2024 (Figure 2.22). This displaced thermal generation, where the services provided by coal and gas decreased from 27% to 10% over the same period.

Figure 2.22 Raise 6-second service enablement, by fuel type



Note: Enablement is monthly average of all units raise 6-second target grouped by fuel type. Total enablement represents the target (megawatts) of all units providing the service, averaged for each month. Other category includes virtual power plants, solar and wind.

Source: AER analysis of NEM data.

3 Contract markets

Key findings

- ASX contract traded volumes have increased considerably in the past 5 years, mostly driven by swaption contracts.
- Despite higher volumes, the total number of outstanding contracts that have not been settled (Open Interest) is falling. One possible explanation for this trend is that an increased proportion of the recent trades may be more speculative in nature. Speculative options trades typically involve short-term trades aimed at capitalising on price movements or volatility rather than holding positions over a long period of time.
- Contract price movements are less volatile than in 2022 but remain more volatile than pre-2022. This may indicate a tighter supply demand balance within the contract market.
- Swaptions are now the most widely traded contract and they are being traded earlier, have higher premiums and are being exercised and converted into base futures at a higher volume. For a premium, swaptions reduce buyers' exposure to volatility and cash flow risk compared with a standard base future. The willingness of buyers to pay option premiums illustrates the cost of increased volatility.
- The liquidity ratio is at an all-time high in all regions except in South Australia.

Prices in the wholesale electricity spot market can be volatile, rising as high as $17,500 per megawatt hour (MWh)[12] or falling as low as −$1,000 per MWh. This volatility poses risks for market participants. Generators face the risk of low settlement prices reducing their earnings. Retailers risk paying high wholesale prices that they cannot pass on to their customers.

Most wholesale electricity market participants use contract markets to manage at least some of their exposure to price risk. Contract (futures or derivatives) markets operate parallel to the wholesale market and every megawatt hour of electricity is traded multiple times in these secondary markets. Contract prices also tend to reflect market expectations of future wholesale prices. 'Speculative traders', who are neither generators nor retailers, also participate in these markets.

The wholesale electricity market is supported by 2 distinct financial markets:

- Over-the-counter (OTC) markets, in which 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.
- Exchange traded markets, in which electricity futures contracts are traded on the Australian Securities Exchange (ASX) or FEX Global. Electricity futures contracts are available on these markets for Queensland, New South Wales (NSW), Victoria and South Australia. At this stage, most of the trade is conducted on the ASX.

12 The wholesale electricity market price cap was set at $17,500 on 1 July 2024.

Box 3.1 Contract types

Various products are traded in electricity contract markets. Exchange traded products are standardised to encourage liquidity, while OTC products can be uniquely sculpted to suit the requirements of the counterparties. There are several products typically traded:

- **Futures contracts** allow a party to lock in a fixed price (strike price) to buy or sell a given quantity of electricity at a specified time in the future. Each contract relates to a nominated time of day in a particular region. Available products include quarterly base contracts (covering all trading intervals) and peak contracts (covering specified times of generally high energy demand). Futures contracts can also be traded monthly or as calendar or financial year 'strips' covering all 4 quarters of a year. Futures contracts are settled against the spot price in the relevant region – that is, when the spot price exceeds the strike price, the seller of the contract pays the purchaser the difference, and when the spot price is lower than the strike price, the purchaser pays the seller the difference. In OTC markets, futures contracts are known as **swaps** or **contracts for difference**.
- **Caps** are contracts that set an upper limit on the price that a holder will pay for electricity in the future. Cap contracts on the ASX have a strike price of $300 per MWh. The buyer pays the cap seller an upfront premium. In return, when the spot price exceeds the strike price, the seller of the cap must pay the buyer 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).

Two types of standard options are available through either the ASX or FEX Global.

- **Swaptions (also called base strip options)** are traded for either a calendar year or financial year. The buyer pays a premium up-front to have the opportunity, in the future, to buy/sell a set of 4 quarterly base futures contracts at a set price (the strike price). They must exercise their options (convert into the underlying base futures contracts) before the expiry date (swaptions expire 6 weeks before the start of the calendar or financial year). The price of a swaption is intrinsically linked to the price of the underlying base future contracts.
- **Average rate options (also called Asian options)** are bought/sold for a quarter. The payout for this type of option is based on the average spot price for the quarter measured at the end of the quarter. The buyer of an average rate option pays a premium up-front and the option is automatically exercised at the end of the quarter only if the option is 'in-the-money' (that is, the buyer will receive a payout). An average rate option can be bought and sold until the last day of the quarter.

Definitions for the terminology used in this report are as follows:

- **Block trades** refers to a large-volume trade with a minimum size of 25 MW. These trades are negotiated directly between participants and entered on the ASX via the block trade facility.

- **Hedge trading** refers to strategies employed to mitigate risks arising from positioning in the NEM spot market.
- **Hedging horizons** refers to a calculation conducted by the AER to indicate the average time from the date of trade to the start of the delivery period for contracts.
- **Margin payments** act as a security to cover any shortfall if the market participant is unable to pay at contract settlement. The individual clearing service providers manage their own risk by imposing their own margin requirements on the retailers and generators, on top of those margins paid to the ASX Clearing House. In the OTC markets, counter party risks are managed by participants demonstrating creditworthiness rather than margin payments. In times of high contract prices and increased volatility, the credit requirements are likely to be more onerous.

  There are 2 types of margins:

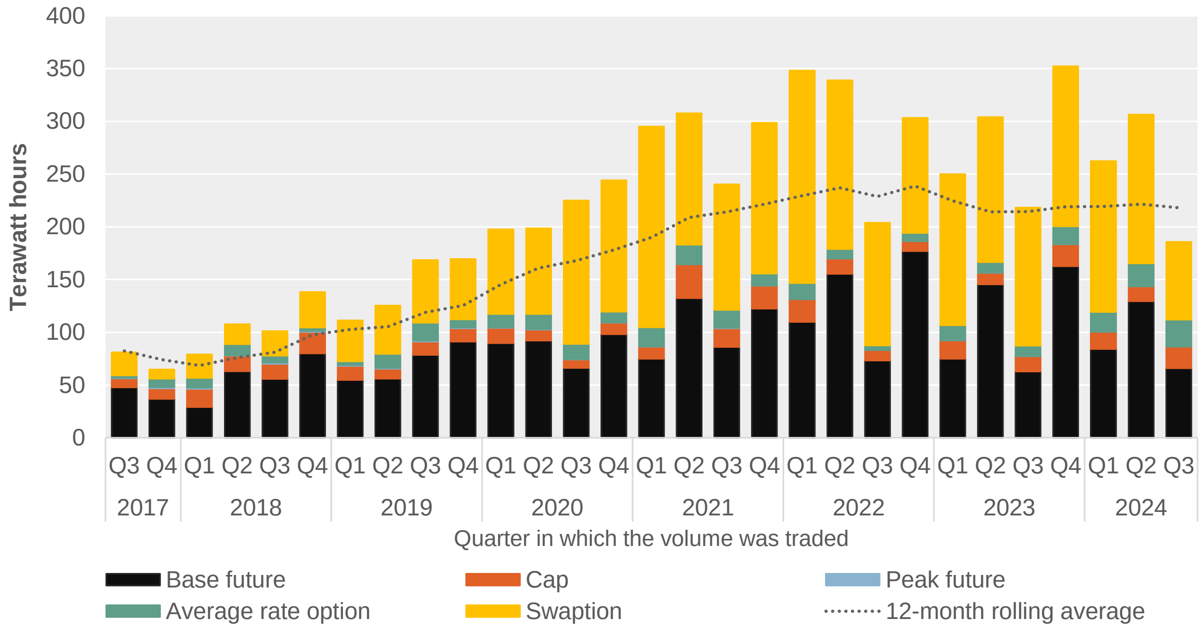
1) Initial margins are paid on entering into the contract and provide security to cover any reasonable price changes that can occur in a 3-day window. This gives the ASX 3 days to find a buyer for any contracts in the case that a participant can't afford to continue holding the contract. The initial margin is based on historical percentage movement in prices but is linked to the current contract price. If the price of the contract increases, the associated initial margin increases. The initial margin can be either cash, collateral or a guarantee.
2) Variation margins are based on the daily changes to the settled price for each contract. When a futures contract increases in price, the seller must pay the difference between yesterday's price and today's price in the form of a variation margin. The buyer of the contract will receive the variation margin. The opposite is true when the price of the contract falls. The variation margin must be paid in cash within a day of the price movement.

- **Open Interest** is the total number of contracts that have been opened but are not closed or delivered as at close of business on the previous day. Open Interest is an indicator of market activity, representing the number of contracts still open or active, where each contract reflects an agreement between a buyer and seller.
- **Speculative trading** refers to the practice of buying and selling contracts with the expectation of making a profit from price movements. Speculation takes on additional risk to hedge trading because the intention is to capitalise on market fluctuations.

3.1 ASX-traded volumes peaked in 2022, remain steady post-2022 at historically high levels

ASX activity shows traded volumes increased significantly in the years up to 2022 (Figure 3.1). Over the past 2 years, volumes have remained steady and are trading around historically high levels, with 1,139 terawatt hours (TWh) traded in 2023–24. The increase is mostly due to increased swaptions trading, which now comprises 50% of total volume (up from 22% in 2017–18). Base futures volume also increased significantly over the same period (148%), but their market share fell from 53% to 39%.

Figure 3.1 Traded volumes in ASX electricity contracts



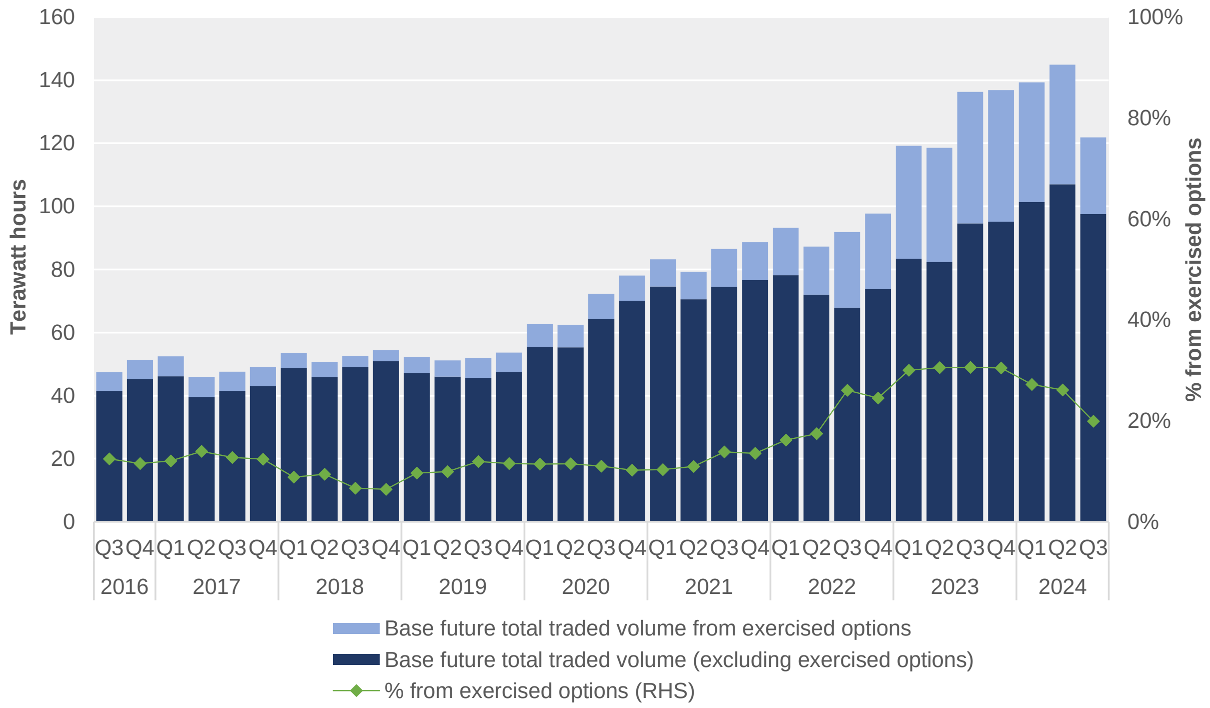
Note: Volume of trades that occurred during the quarter across ASX Energy futures. The x-axis represents the quarter in which the trades occurred.

Source: AER analysis using ASX data.

3.1.1 Base futures are trading at historically high levels

Consistent with the overall trend described above, the volume of traded base futures has been steadily increasing since 2019. Base futures traded for the financial year 2023–24 (traded over a 3 to 4-year horizon) were the highest volumes on record at 559 TWh. One driver of this increase is the impact of swaptions being exercised and converted into base future contracts. In 2023–24, 29% of all traded base future volume was the direct result of exercising of swaptions, up from 11% in 2017–18. In addition, speculative traders can manage option positions by buying or selling the relevant base future contracts, further increasing base future traded volumes.

Figure 3.2 Base future volumes[13]



Note: Base future volumes that occurred during the quarter across ASX Energy futures. The x-axis represents the period of the contract.

Source: AER analysis using ASX data.

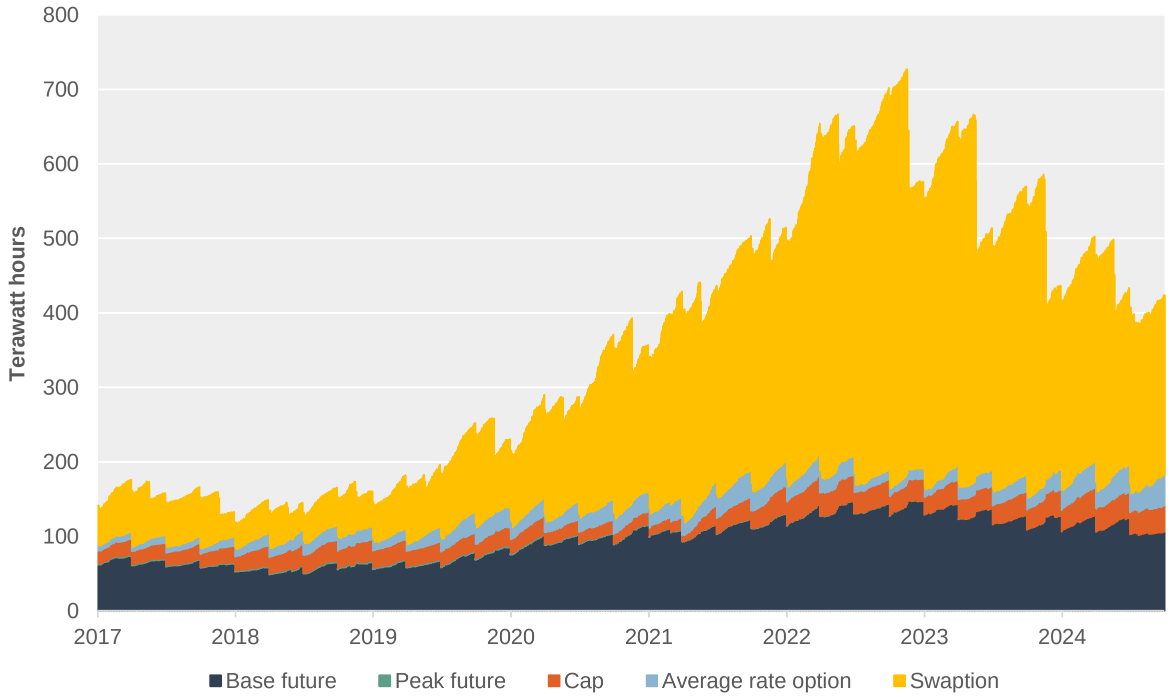
3.1.2 ASX Open Interest is falling

Despite higher volumes, the total number of outstanding contracts that have not been settled (Open Interest) is falling. Open Interest peaked in November 2022 at 727 TWh. It has fallen steadily since, reaching 424 TWh on 30 September 2024. This drop has been driven by a fall in Open Interest for swaption contracts, which have decreased from 544 TWh (November 2022) to 241 TWh (September 2024).

As swaption contracts expire every 6 months, in May and November, Open Interest will naturally fall, creating a saw-tooth pattern. While some of the decline in Open Interest is due to the routine contract expiry, the overall trend is downwards as less option contracts are being opened to replace those as existing contracts expire.

13 The shape of base future volumes in Figures 3.1 and 3.2 are different due to the distinct x-axes. The x-axis of Figure 3.1 is the quarter in which the trades occurred, while the x-axis of Figure 3.2 is the period of the contract.

Figure 3.3 Daily Open Interest



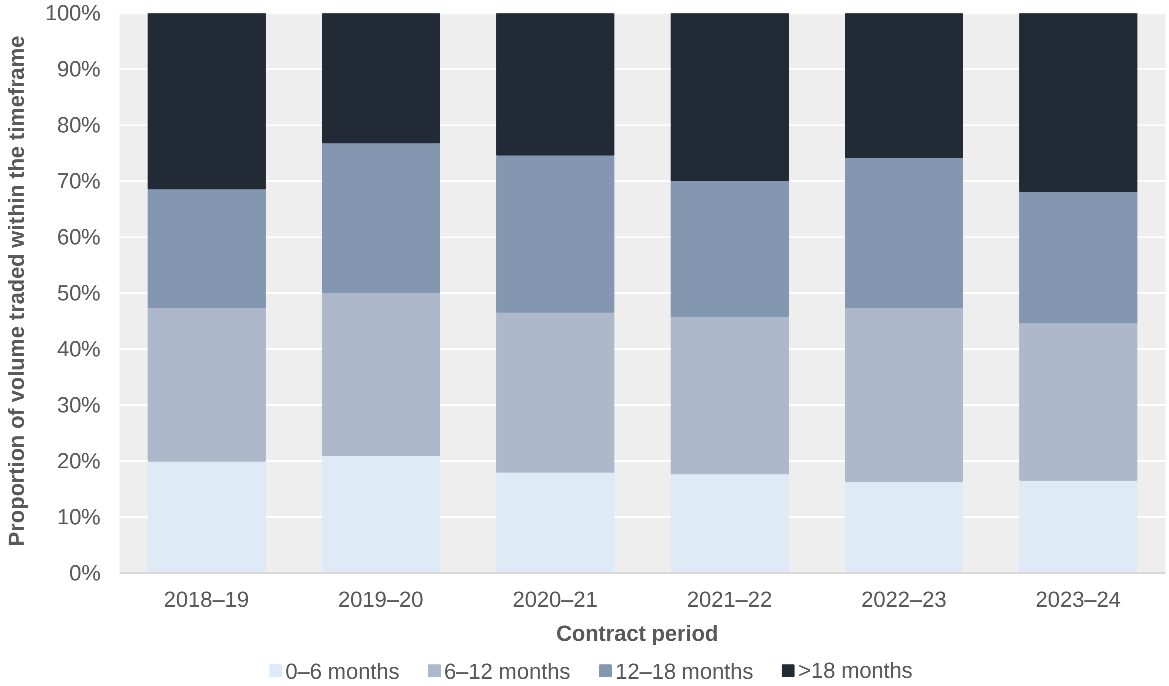
Note: Daily Open Interest for all ASX Energy contracts.
Source: AER analysis using ASX data.

One explanation for falling Open Interest while traded volumes remain high could be there is an increased volume of speculative trading. A speculative trade is motivated by financial goals. They are generally held for shorter periods and are purchased and sold with the intention of profiting off price fluctuations. This is in contrast with a hedge trade, which is purchased or sold to mitigate risks associated with spot market positions (see Box 3.1). The open interest movements suggest that there has been an increase in speculative trading. The extreme events of 2022, and the risks they exposed, are likely a part of the catalyst of these changes.

3.1.3 Hedging horizon of base futures remains stable

While the volume of base futures has been increasing, the hedging horizon has remained stable over the past 5 years. In 2023–24, 68% of traded volume was traded in the 18 months before contract expiry (Figure 3.4).

Figure 3.4 Base futures hedging horizon

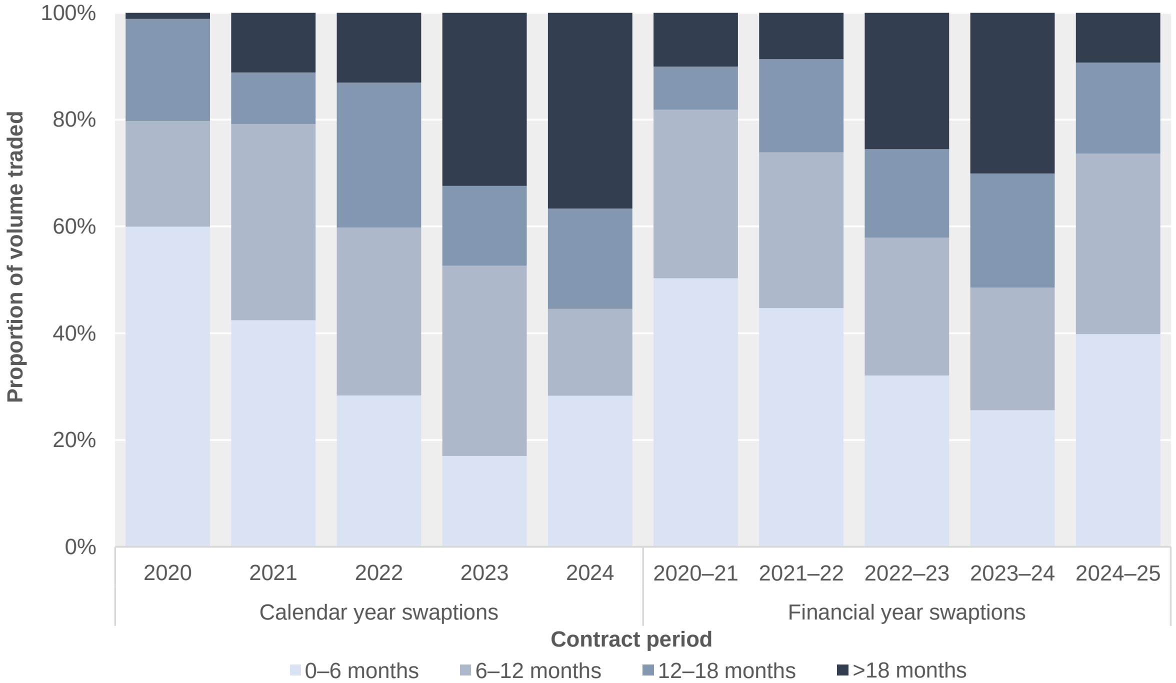


Source: AER analysis using ASX data.

3.1.4 Swaptions are being traded earlier than ever

As swaptions have become increasingly popular in the past 5 years, the trading of these options has been happening earlier. The proportion of calendar swaptions traded more than 18 months prior to expiry has increased from less than 10% before 2022 to 37% in 2024. Financial year swaptions were also traded earlier in the 2021–22 and 2023–24 financial years compared with previous years.

Figure 3.5 Swaptions hedging horizon



Source: AER analysis using ASX data.

The attractiveness of swaptions to buyers lies in their ability to manage the risks accentuated in 2022. Swaptions allow buyers to hedge further in the future without the cash flow risks of margining, in exchange for a fixed up-front cost. Capping prices further in advance helps guard against unforeseen future shocks. If market conditions become more favourable, buyers can simply let the swaption expire. Sellers have been willing to take on more of the risk, in exchange for higher premiums.

Retailer use of options to hedge their spot market positions appears to be growing, yet ASX data indicates that activity is likely concentrated among the large market participants, both physical energy participants and large financial participants. The majority of swaptions, approximately 95% of those transacted in the financial year 2023–24, were traded via the block trade facility, which has a sizable minimum lot size of 25 MW. This high minimum lot size limits their accessibility for small retailers, suggesting that hedging activities using swaptions remain predominately the domain of large participants. Smaller retailers may still access swaptions, though in small volumes, through brokers OTC or via on-screen ASX trading.[14]

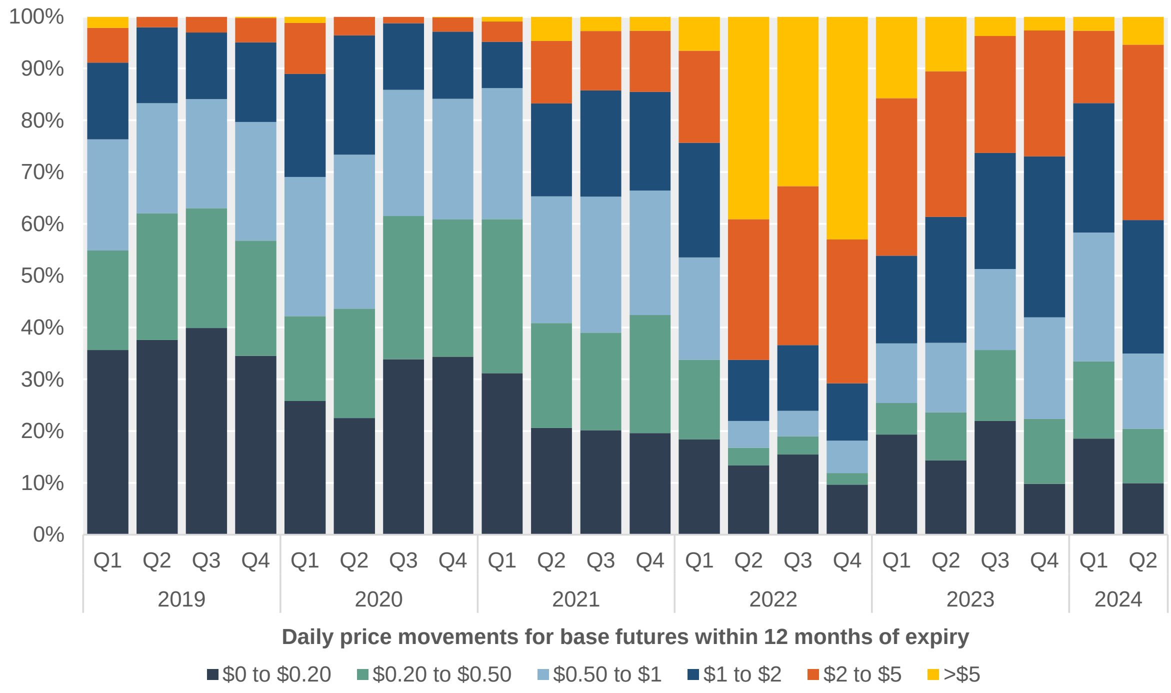
3.2 ASX base futures experiencing bigger price movements than pre-2022

In 2023–24, 28% of daily price movements for base futures within 12 months of expiry were greater than $2 per MWh (absolute value), compared with just 5–7% in the financial years 2018–19, 2019–20 and 2020–21. This indicates that, while daily price movements have settled since the unprecedented movement of 2022–23 (when 45% were greater than $2 per MWh), they are still more volatile than pre-2022. The higher daily price movements could indicate a tighter supply demand balance within the contract market combined with a response to higher spot market prices.

The increase in price movements impacts market participants – each time the contract price moves, either the buyer or seller is required to make a variation margin payment. Generators posting large variation margins can make back this money when they sell their generation into the spot market at a higher than expected price. But they still face cash flow issues because margins are paid daily on contracts for generation that won’t be sold into the spot market for months or years in the future.

[14] “On-screen” is where the trade is the result of being matched up 'on the screen'. A bid or offer is put in and then is matched up by the ASX platform. These bids and offers are visible to other parties (compared to off screen, where you find your own party to trade with and then move the trade onto the ASX).

Figure 3.6 Daily price movements for base future contracts within 12 months of expiry



Note: Count of the absolute values, as a percentage. Prices used are for Queensland, New South Wales and Victoria. South Australia was excluded due to the lack of liquidity in the region resulting in contract prices not reflecting the value of the underlying asset. Values are in nominal dollars without adjusting for inflation.

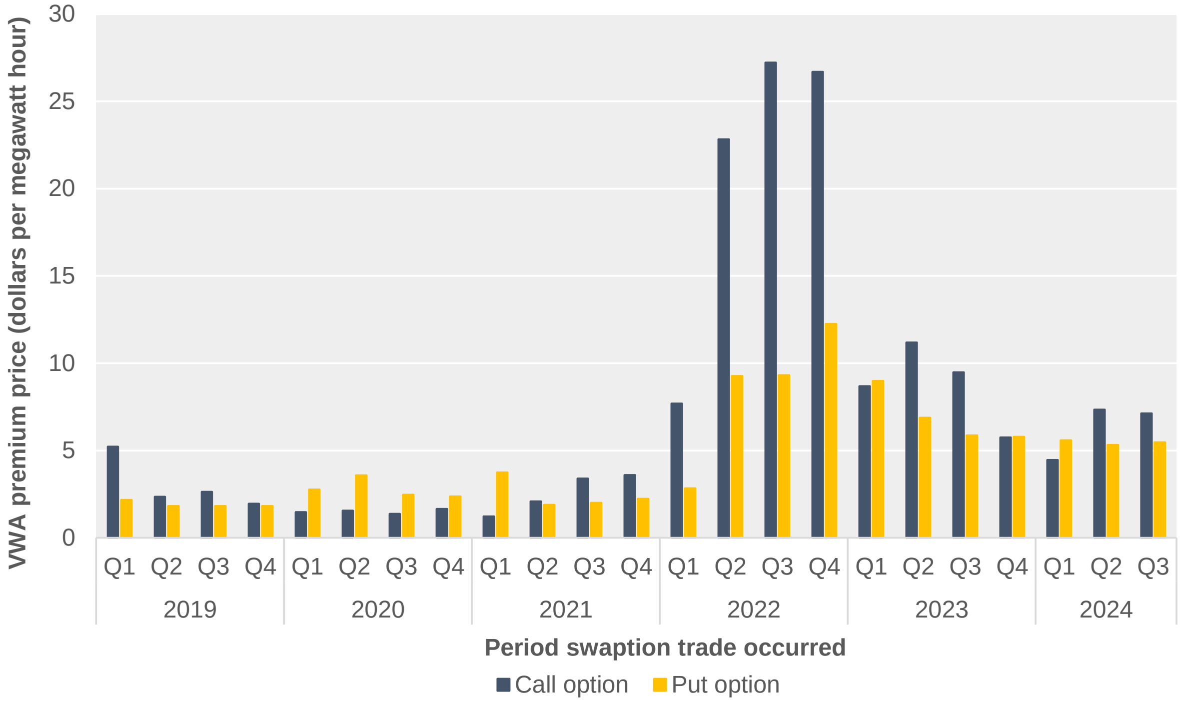
Source: AER analysis using ASX data.

3.2.1 Cost of swaptions has increased

Swaption premiums have increased in the past 5 years. The volume weighted average (VWA) premium price paid for swaptions was typically less than $3 per MWh before 2022. The extreme market events of 2022 saw premium prices increase, with VWA premium prices reaching greater than $25 per MWh for call options transacted in Q3 and Q4 2022. Put option premiums were not as high but did increase to greater than $10 per MWh during the same period. In recent years, VWA premium prices have remained elevated compared with pre-2022 prices, averaging $6 per MWh for swaptions transacted in the 2023–24 financial year.

Option pricing is based on models that account for factors including the strike price value, intrinsic value and time value. Swaptions are being traded earlier. The longer horizon combined with market volatility is impacting the time value, contributing to higher premium prices. The more volatile the market, the higher the time value will be to account for the unknown. The upward trend in VWA premium price paid for swaptions, coupled with their increased popularity, points to an increase in the time value of options driven, in part, by higher volatility.

Figure 3.7 Volume weighted average swaption premium price



Source: AER analysis using ASX data.

3.3 Liquidity in contract markets at record high in all regions except South Australia

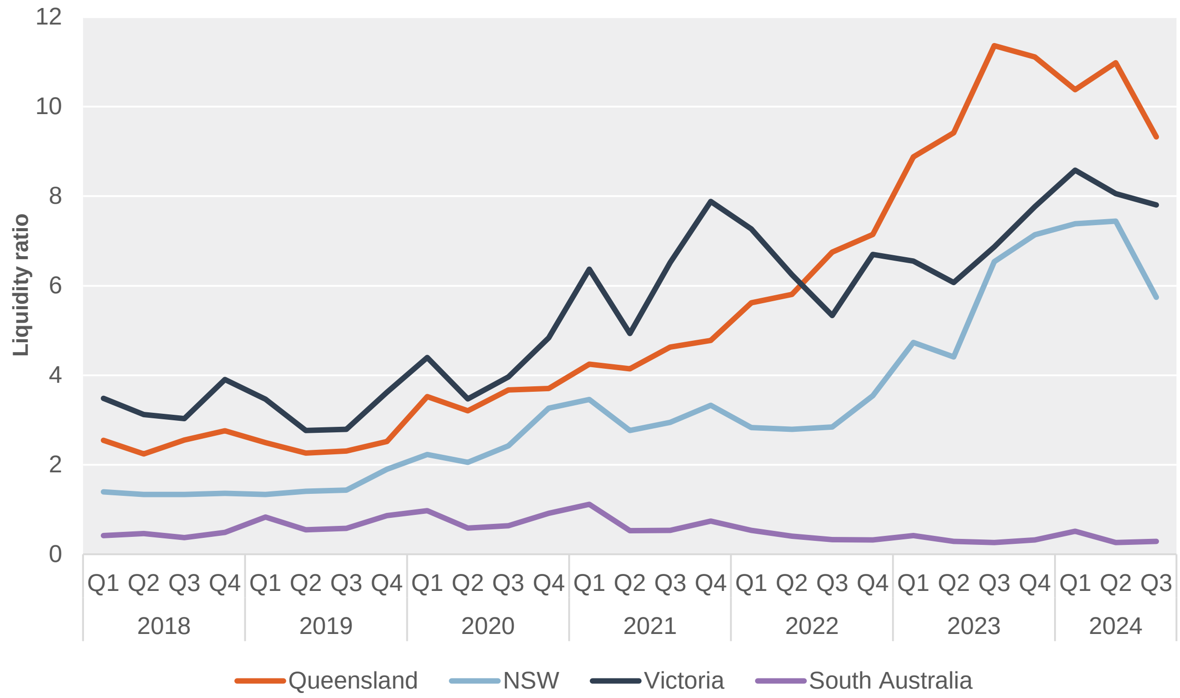
Liquidity is important in contract markets because it enables participants to buy or sell a contract within a reasonable price range, without that trade moving the price unreasonably. It facilitates ease of entry and exit of contracting positions, allows for more rapid integration of new information into prices, and allows for better risk management because participants can adjust positions quickly in response to changing market conditions. Overall, liquidity enhances the overall functioning and attractiveness of contract markets.

In our *Wholesale electricity market performance report 2022*, we reported that the liquidity of exchange traded contracts was declining. Access to clearing services had tightened, while increased margin payments had impacted the cost of trading and holding of contracts.

The liquidity ratio is one way to measure liquidity. It is a calculation of electricity contracts traded volumes divided by spot market native demand. Since 2022, the liquidity ratio has significantly improved in NSW, Queensland and Victoria, and is currently at an all-time high in all regions except South Australia (Figure 3.8). While the liquidity ratio is a rudimentary tool, the increased figures indicate that participants in NSW, Queensland and Victoria have greater opportunities to hedge their risks. Increased liquidity is primarily being driven by the increased volumes in options and base futures. Another factor may be increased contribution by speculative traders. Speculative traders increase the volume of trades, improving liquidity.

Contract volumes have fallen across all contract types in South Australia. Chapter 7 will dive deeper into the market conditions in South Australia.

Figure 3.8 Liquidity ratio for all contract types



Note: Contract traded volumes used to calculate the liquidity ratio are traded volumes for the period specified in the contract (not the period in which the contract was traded). Demand volumes are native demand.

Source: AER analysis using ASX data and AEMO data.

3.4 Interaction with government schemes

Generators want to recover their long-run marginal costs. Normally this would be done through a mixture of contracting and spot market revenue, with contracting used to manage price risk. In recent years governments have implemented ‘contract for difference’ schemes to help drive new investment. These schemes are designed to de-risk a project. There is a trade-off between the level of support and the incentive for the generator to contract.

The closer the support is to long-run marginal cost, the lower the risk the generator faces. If a generator received a contract for difference set at their long-run marginal cost, they would be able to recover their costs just by ensuring they were dispatched (that is, the generator is fully insulated from price risk). Removing risk for one participant is not the same as removing it for the market. Retailers still need to manage wholesale market price risk. Every generator that is insulated from risk is one less counterparty, making it more challenging for retailers to manage risk in the future. This could see the cost of contracting rise and smaller retailers struggle to find counterparties, which would affect retail competition.

There are ways in which generators can still have some incentives to contract, while participating in a contract for difference scheme. Generators will still be exposed to some risk if they are not compensated for negative wholesale prices (that is, set a lower limit at $0 per MWh). An alternative approach is a revenue guarantee. Depending on the level of the guarantee, it is more likely to ensure generators retain an incentive to contract. Recent government schemes have adopted design elements to try to encourage contracting.

3.5 Future contract analysis

Limited public information is available on the contracting arrangements in the NEM. The ASX publishes some information on trading, including the price and volumes traded, but not the parties to transactions.

Activity in OTC markets is even more opaque because it is not publicly disclosed. In the past, 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. In 2021–22 AFMA ceased this reporting.

In May 2024, the AER's wholesale market monitoring and reporting functions were expanded to include electricity contract markets (among other markets). These enhanced powers will allow the AER to collect contracts and contract-related information, including OTC trades, from market participants. This will provide greater visibility of the underlying drivers influencing how and why market participants behave the way they do, whether the outcomes in wholesale markets reflect effective competition in those markets and whether wholesale markets are operating efficiently. Chapter 7 provides an in-depth analysis of the South Australian market. In this WEMPR we exercised our new contract market monitoring powers for the first time. We anticipate that we will be able to incorporate more information in future WEMPR reports.

4 Market structure

Key points

- New entry since 2021–22 has led to lower market concentration in NSW, Victoria and South Australia. Market exit also contributed to declining concentration in NSW and South Australia, with AGL closing and mothballing units.
- Diverse ownership of large-scale renewables means that concentration is lowest when these assets are generating. As a result, concentration is now lowest during the middle of the day when solar output is highest, particularly in Queensland and NSW.
- Ownership of dispatchable generation, including flexible capacity, remains concentrated and a few large participants are often needed to meet demand. But the reliance on the largest participants has decreased across the National Electricity Market (NEM) over the past 2 years, except in Victoria.
- Interconnectors can provide competitive pressure by forcing local generation to compete with generation from other regions. Interconnectors have continued to experience congestion, but interconnector projects in the works may increase interregional competition.
- Network outages can create opportunities for the exercise of market power at times. Network providers should be incentivised to schedule planned outages when the market impacts are likely to be less significant. The AER has proposed suspension of the market impact component (MIC) of the service target performance incentive scheme (STIPS), because it is not working as intended, and is exploring alternatives.

Competition is influenced by the structure of the market. A generator has more opportunity to exercise market power in a market with few participants, especially during periods of limited interconnector capacity, when demand is high or when supply is constrained. That said, the ability to exercise market power is distinct from incentives to exercise that power. A participant's incentives will be influenced by a range of factors, including the extent to which it has hedged against spot prices, the extent to which it is vertically integrated and government direction or regulation.

4.1 Concentration of ownership

Despite new entry, a few large participants continue to control a significant portion of generation capacity in the NEM. This is most pronounced in coal and flexible generation. This continues to provide opportunities for certain participants to exercise market power during periods of supply stress and at certain times of the day.

We used standard market concentration metrics (Box 4.1) to assess market concentration in each region of the NEM and the extent to which this has changed.

Box 4.1 How we assess market concentration

Market concentration refers to the number and size of participants in a market. A concentrated market has a high proportion of capacity controlled by a small number of generators and is more susceptible to outcomes that are not competitive. Market concentration can be measured using various metrics. A more detailed description of our metrics can be found in our methodology document, which sets out revisions we have made to our method in 2023–24.

Market share

Market share is the simplest measure of concentration. This report uses 2 measures of market share – market share by registered capacity and market share by generation output.

Market share by registered capacity measures a market participant's share of total registered capacity on a given date. It is a good overall measure of total market capacity but does not account for outages or how different types of plant are offered into the market. This measure does not capture factors that may affect a participant's ability to generate, such as network constraints, fuel availability, plant conditions and seasonal variations in operational capacity.

Market share by generation output measures a participant's share of annual energy delivery. It better reflects the nature of a market participant's generation fleet and contribution to market outcomes. It may under-represent market participants with flexible generation portfolios who use their units to respond to peak prices and so operate them infrequently.

Herfindahl Hirschman Index (HHI)

HHI provides an indication of market concentration and allows for comparisons across regions and over time.

The index is calculated by summing squared market shares of all firms in the market. HHI can range from almost zero (a market with many small firms) to 10,000 for a monopoly. By squaring market shares, HHI highlights the impact of large firms. The higher the HHI, the more concentrated the market.

Other regulators also use HHI thresholds to assess concentration. The Australian Competition and Consumer Commission's (ACCC) merger guidelines indicate it is generally less likely to identify competition concerns when the post-merger HHI is less than 2,000.[15] The US Federal Trade Commission recently updated its guidelines to categorise markets with a HHI above 1,800 as highly concentrated.[16] In this analysis, we considered HHI scores above 2,000 to be highly concentrated but we may review this threshold in the future.

While the market may not be highly concentrated overall, subcomponents of the market (such as the market for flexible, dispatchable capacity) can be more concentrated.

We calculated the index using participant market share based on 5-minute bid availability. Unlike measures based on capacity or output, bid availability accounts for outages, fuel availability and bidding behaviour. This provides a more dynamic assessment of the levels of concentration in the market based on changing market conditions.

Pivotal supplier test (PST)

The PST measures the extent to which one or more participants is 'pivotal' to clearing the market. A participant is pivotal if market demand exceeds the capacity of all other

---

15 ACCC, Merger Guidelines, Australian Competition and Consumer Commission, November 2008 (amended November 2017), accessed 1 November 2024.

16 U.S. Department of Justice and the Federal Trade Commission, 2023 Merger Guidelines, 18 December 2023, accessed 1 November 2024.

participants, accounting for possible imports. In these circumstances, the participant must be dispatched (at least partly) to meet demand. The PST gives an indication of the risk of the exercise of market power.

4.1.1 A few participants control most of the generation in the NEM

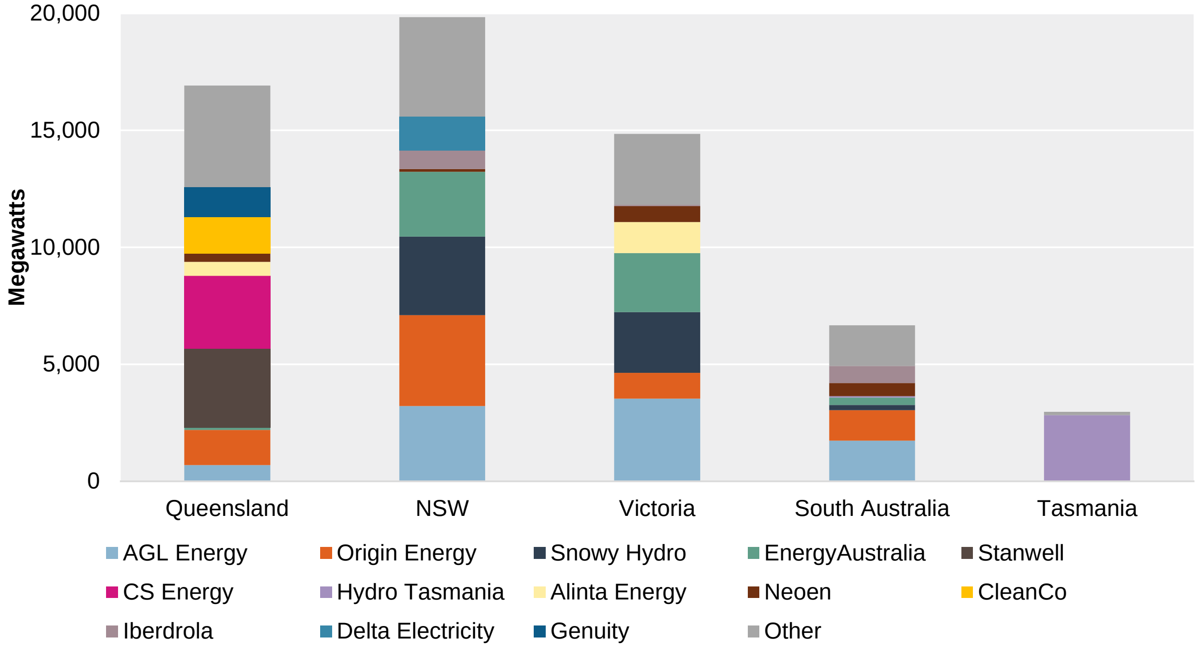
Similar to 2021–22, a few large participants control a significant portion of generation capacity and output in each region of the NEM in 2023–24 (Figure 4.1 and Figure 4.2).

- In Queensland, state government-owned participants Stanwell Corporation, CS Energy and CleanCo controlled 48% of the region's generation capacity and 65% of its output.[17] Each of these companies have signed offtake power purchase agreements with some of the approximately 1,000 MW of new generation that came online in 2022–23 and 2023–24.
- In NSW, Origin Energy, Snowy Hydro and AGL controlled 53% of registered capacity. AGL's share of registered capacity has fallen significantly since our 2021–22 report due to the closure of the final 3 units of the Liddell power station in April 2023. Meanwhile, over 2,000 MW of new capacity with diverse ownership has come online in NSW. AGL and Origin continue to have the largest share of the region's generation output – 27% each in 2023–24.
- In Victoria, AGL, Snowy Hydro and EnergyAustralia controlled 58% of total generation capacity, while brown coal owners AGL, EnergyAustralia and Alinta Energy controlled 75% of output. This was despite all new entry in Victoria being owned by smaller players.
- In South Australia, AGL, Origin Energy and ENGIE controlled 57% of the region's generation capacity and 60% of its output. In September 2022, a Torrens Island A unit (120 MW) owned by AGL closed, but this was offset by the entry of the 250 MW Torrens Island Battery. The remaining 450 MW of new capacity that entered the market was owned by smaller players.
- Tasmania is the most concentrated region, where state government-owned Hydro Tasmania owns almost all generation. The Tasmanian Government's regulated contract pricing arrangement (Box 4.2) reduces the incentive for Hydro Tasmania to exercise market power in wholesale markets.

---

[17] This is lower than we reported in our 2022 report largely due to revisions we have made to our method. 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. This method is applied regardless of whether a participant owns generation assets. In Queensland, half of the output of Gladstone power station has been allocated to Boyne Island Aluminium Smelter, which purchases the power from CS Energy. See, for example, CS energy, Thermal Generation, accessed 19 Nov 2024, and Financial Review "Rio Tinto's Boyne Island smelter slashes jobs and production as power bites", updated 19 January 2017, accessed 19 November 2024; that Boyne Island receives 810 MW per year from a long-term agreement with CS Energy. Accounting for ownership in this way leads to reduced market share for CS Energy and lower HHI and PST values for Queensland. More detail is provided in our methodology document.

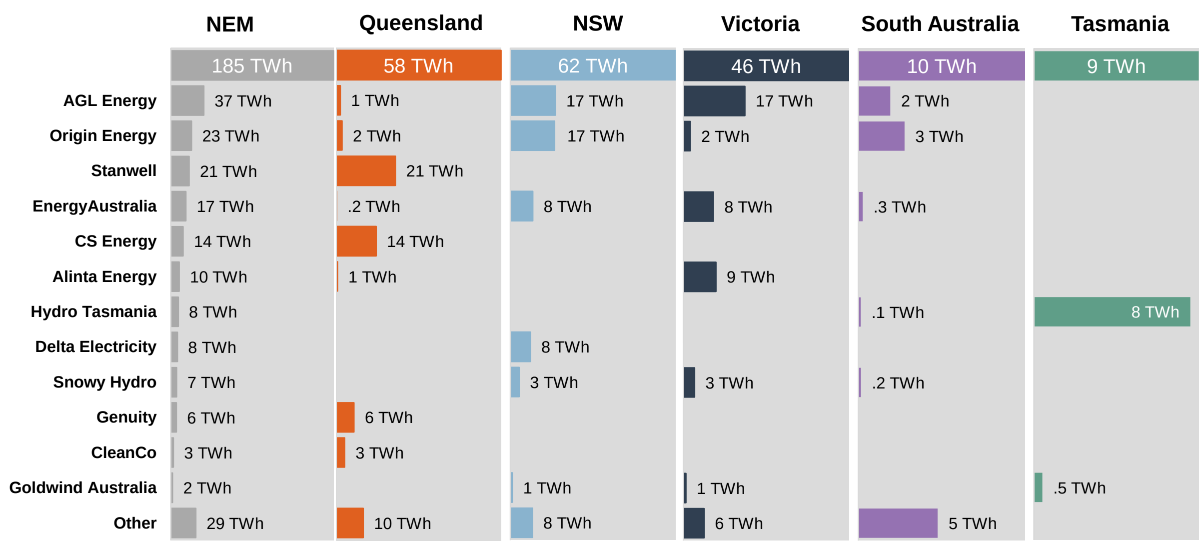
Figure 4.1 Market share by registered capacity, by region, 30 June 2024



Note: Registered capacity share uses registered capacity of all market scheduled and semi-scheduled generation (excluding market loads) registered as at 30 June 2024. 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.

Source: AER analysis using NEM data.

Figure 4.2 Market share by generation output, by region, 2023–24



Note: Output in 2023–24. Market shares are determined based on ownership of each unit's output. Where we were 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 analysis using NEM data.

There are 4 participants that have significant presence across multiple regions of the NEM and sizeable market shares in NSW, South Australia and Victoria.

AGL has the largest market share across the NEM, controlling 20% of output and 15% of registered capacity in 2023–24. Registered capacity was down from 19% in 2021–22, continuing a decline that we noted in our 2022 report. The closure of the remaining 3 units of Liddell power station drove most of the decline in AGL's market share and means it is no longer the largest participant in NSW. It does remain the largest participant in Victoria and South Australia, despite the closure of its one remaining Torrens Island A unit in South Australia.

Origin Energy is the second largest generator across the NEM, controlling 13% of both registered capacity and output. Snowy Hydro is the third largest generator by registered capacity (10% market share) but only the ninth largest by output (4% market share). This is because Snowy Hydro has significant market share of flexible dispatchable generation, particularly hydro, which does not run all the time but provides peaking capacity.

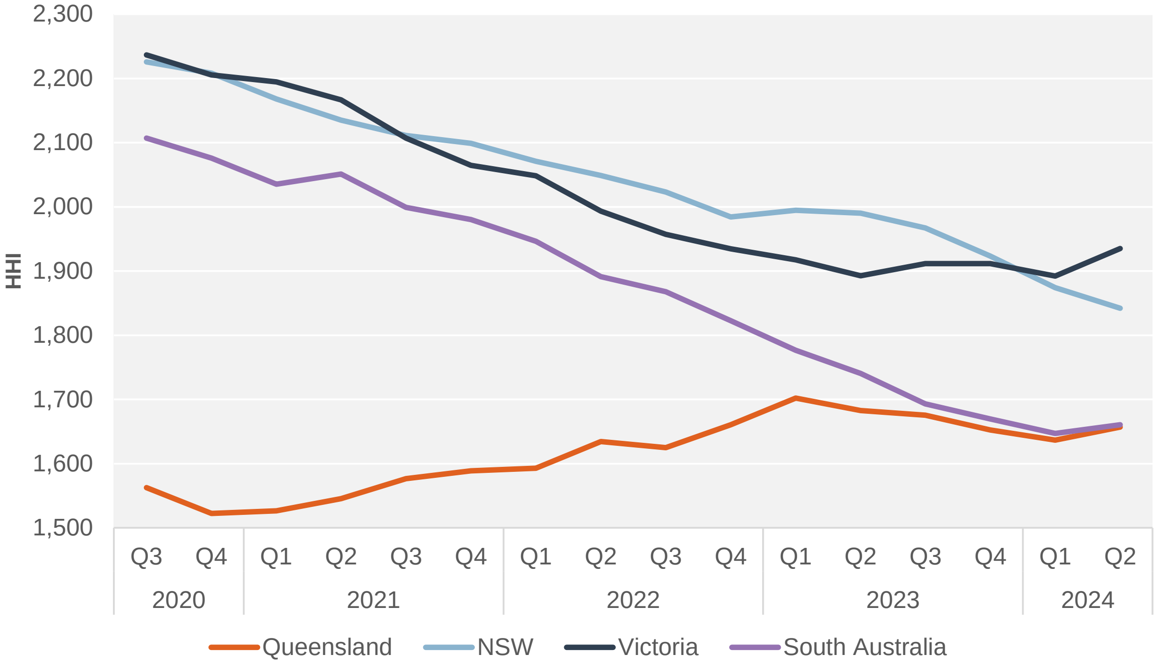
EnergyAustralia is the fourth largest NEM generator by both registered capacity and generation output, with 9% market share of both. The third largest generator by output was Queensland's Stanwell Corporation, with 11% of NEM output.

In the last 2 financial years, 4.5 GW of new capacity entered the market. About two-thirds of this was wind and solar generation, while about one-third was dispatchable generation (batteries or gas). While most new wind and solar is controlled by smaller participants, most of the new dispatchable generation is controlled by one of the 4 largest NEM generators. This has reduced concentration overall but has still left the largest NEM generators with significant market share at peak times.

4.1.2 The NEM is becoming more competitive on average but still has periods of very high concentration

As well as using market share, we used the Herfindahl Hirschman Index (HHI) to assess the market concentration of the NEM (Box 4.1). Over the past 2 years, concentration has reduced, on average, in all mainland regions except Queensland (Figure 4.3). All mainland regions are below the threshold that would class them as highly concentrated.

Figure 4.3 Quarterly rolling average HHI by bid availability



Note: Calculations of HHI exclude market suspension periods as well as administered pricing intervals where prices would have otherwise been higher than the administered price cap. Quarterly rolling averages were calculated by averaging HHI values across 4 quarters. For example, the rolling average for Q2 2024 is calculated by summing the average HHI values for Q3 2023, Q4 2023, Q1 2024 and Q2 2024, and dividing by 4.

Source: AER analysis using NEM data.

The rate of new entry impacted the level of concentration in each region. NSW and South Australia have had more new entry over the past 2 years relative to existing capacity than Queensland or Victoria. Most of this new entry is owned by smaller participants.

Market exit also contributed to declining concentration in NSW and South Australia. In NSW, AGL closed the Liddell power station across 2022 and 2023. AGL's lower market share drove the decrease in concentration in NSW.[18] In South Australia, AGL mothballed a Torrens Island B unit in October 2021 before decommissioning its last remaining Torrens Island A unit in September 2022. About two-fifths of the reduction in South Australian HHI was attributed to AGL.[19]

In Queensland, the increase in concentration since 2022 is partly driven by outages of Callide C power station's 2 units, which are co-owned by CS Energy and Genuity.[20] These

[18] The average NSW HHI score in 2023–24 was 1,842, down from 2,049 in 2021–22. Meanwhile, AGL's squared market share (that is, its contribution to the regional HHI score) averaged 426 in 2023–24, down from 678 in 2021–22. While AGL's smaller contribution more than accounted for the total decline in HHI, some of the change in AGL's market share would have reflected factors other than Liddell's exit, such as increased renewable penetration in the region and changes in Bayswater power station's offers.

[19] The average South Australian HHI score in 2023–24 was 1,661, down from 1,892 in 2021–22. AGL's average squared market share fell from 601 to 504 over the same period. Again, some of the change in AGL's market share reflects factors other than Torrens Island's exit.

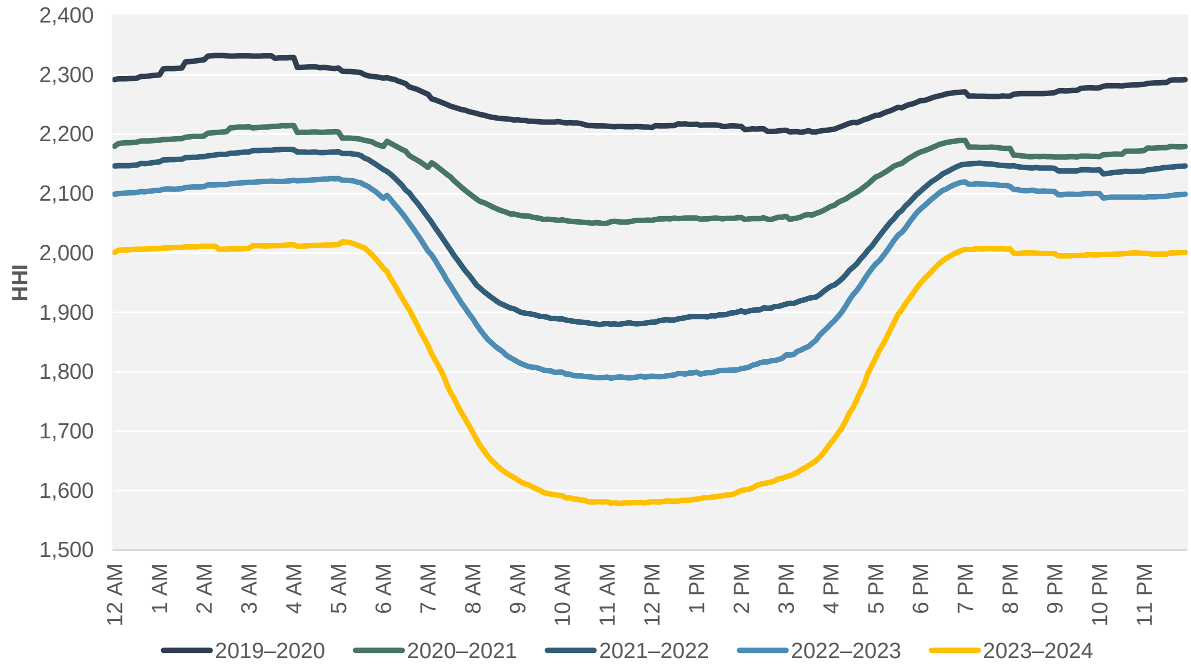
[20] Callide C4 went offline in May 2021 due to catastrophic failure of the unit. Callide C3 went offline in October 2022, due to the failure of its cooling tower.

outages increased the market share of Queensland's largest generator, Stanwell. With Callide C3 coming back online in April 2024 and Callide C4 in August 2024, Queensland's HHI score has declined in Q3 2024.

The entry of wind and solar generators has reduced market concentration. The market is least concentrated when these assets are generating and more concentrated at other times. The time-of-day profile of market concentration reflects this, with lower concentration in the middle of the day due to higher solar output. This is clearest in Queensland and NSW, which have more large-scale solar capacity. For example, in NSW the average HHI score overnight has fallen modestly since 2021–22 – from about 2,150 to about 2,000 (Figure 4.4), but has fallen significantly in the middle of the day, from about 1,900 to about 1,600 on average.

Victoria and South Australia have relatively less large-scale solar and more wind capacity, meaning that market concentration is more closely linked to wind conditions.

Figure 4.4 NSW financial year average HHI by time of day, 2019–20 to 2023–24



Note: Calculations of HHI exclude market suspension periods as well as administered pricing intervals where prices would have otherwise been higher than the administered price cap. HHI for each time of day is averaged across all dispatch intervals for that time of day in that year. Figure presents outcomes in NEM time.

Source: AER analysis using NEM data.

On average, market concentration levels are moderate in mainland NEM regions. However, the market can still be highly concentrated at times – particularly in South Australia and Victoria (Figure 4.5). The median HHI score was under 2,000 in every region in 2023–24, but at times of low wind and solar output Victorian HHI scores reached as high as 2,800 and South Australian scores reached 2,600.

Figure 4.5 Variability in bid HHI by region

Note: Calculations of HHI exclude market suspension periods as well as administered pricing intervals where prices would have otherwise been higher than the administered price cap.
Source: AER analysis using NEM data.

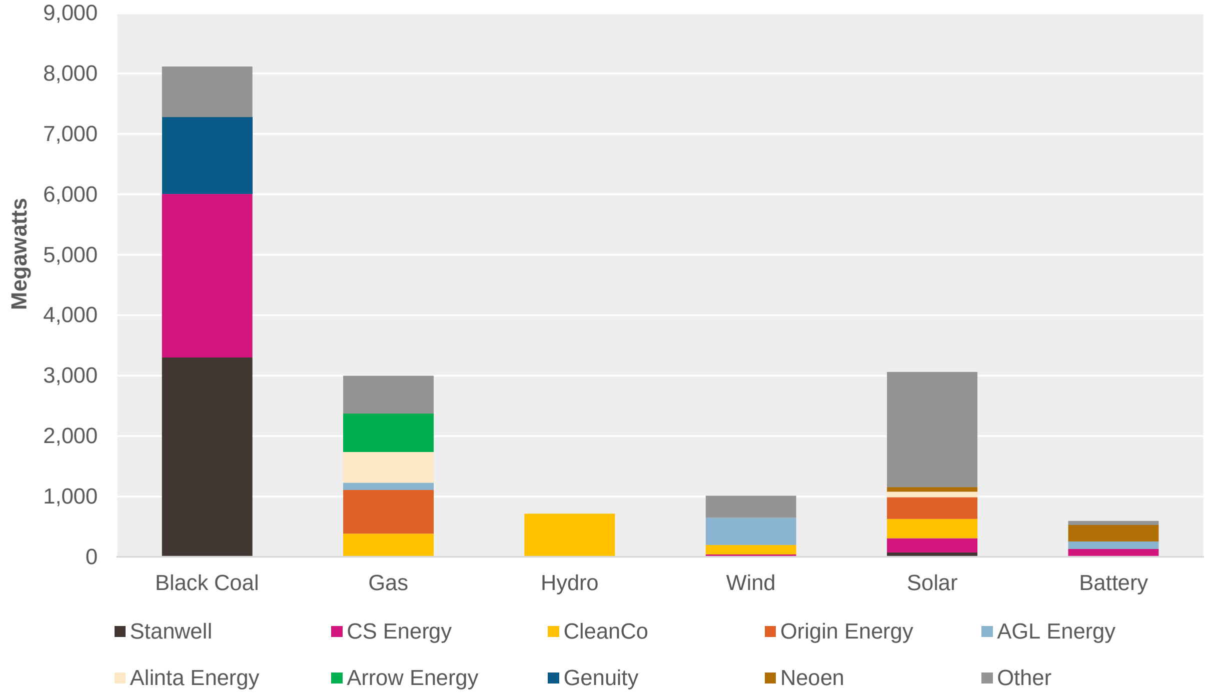
4.1.3 Ownership of dispatchable generation remains concentrated

While HHI scores are calculated based on all available generation in a region, the level of concentration may vary by generation type. Solar and wind, which have diverse ownership, are usually the first to be dispatched, along with the minimum generation capacity of coal-fired power stations.[21] When these are the only fuel types required, there is a high level of competition for marginal generation. Above this point in the offer stack, there will typically be discretionary coal capacity (which can only ramp up slowly), and then flexible fuel types such as hydro, gas and, finally, battery capacity. This higher priced capacity is only dispatched when needed to meet demand. Concentration of ownership currently tends to be greater for these higher priced generation types. As a result, at times when flexible generation is needed, a smaller number of participants may control the available marginal generation.

In Queensland, dispatchable generation is highly concentrated with half being owned by government-owned CS Energy and Stanwell (Figure 4.6). This figure rises to 69% for the top 4 generators. Stanwell and CS Energy own three-quarters of coal capacity, which is the region's dominant dispatchable fuel source. Flexible dispatchable capacity (which excludes coal) is more diversified, with the largest generator (CleanCo) controlling 26% of capacity and the second largest (Origin) a further 17%. Large-scale solar is highly diversified and now represents 19% of Queensland's capacity.

21 Coal-fired power stations take longer than other forms of generation to turn on and off, and repeated starts and shutdowns can be costly and lead to additional wear and tear. To avoid this, coal units generally bid some of their capacity at or below $0 per MWh to ensure a minimum amount is always dispatched and they can remain on.

Figure 4.6 Queensland market share by registered capacity, by fuel type, 30 June 2024



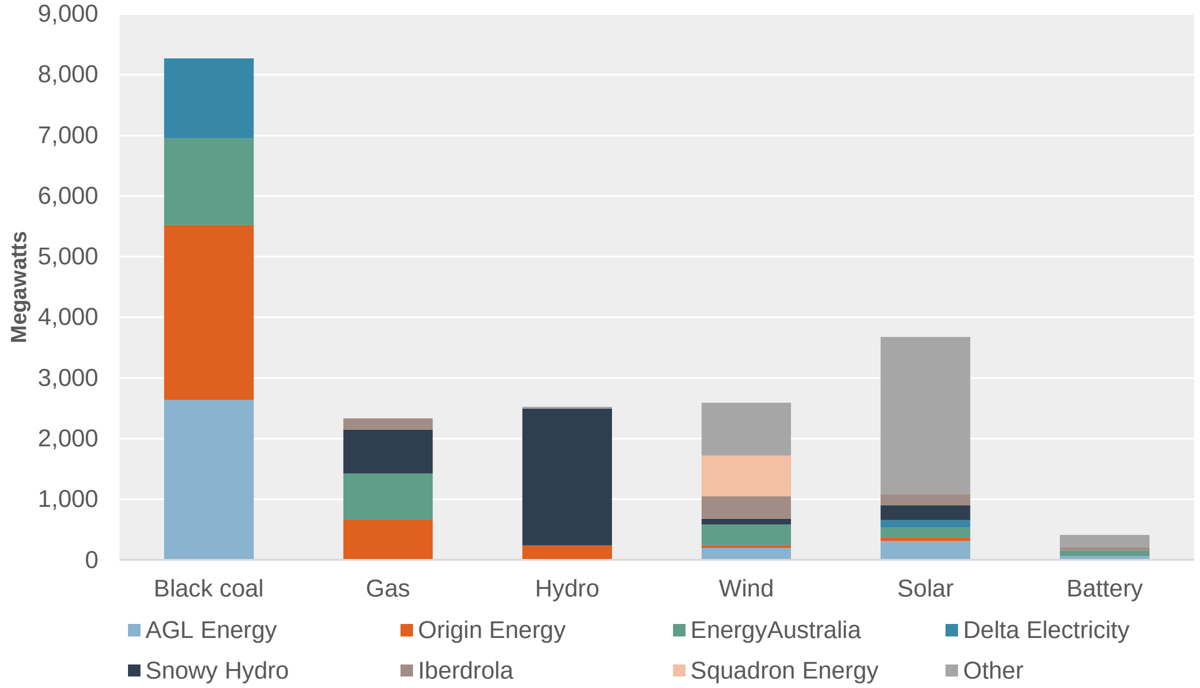
Note: Fuel type capacity share uses registered capacity of all market scheduled generation (excluding market loads) registered as at 30 June 2022. Market shares are determined using ownership declared to AEMO for each dispatchable unit identifier (DUID). Where an intermediary operates on behalf of the owner, the market share for that capacity is attributed to the intermediary.

Source: AER analysis using NEM data.

In NSW, 4 participants control 87% of dispatchable generation capacity. Like in Queensland, the major dispatchable fuel source in NSW is black coal, which is controlled by just 4 participants (Figure 4.7). Snowy Hydro has a 57% share of flexible generation capacity.[22] In contrast, wind and solar ownership is very diversified in NSW – the largest 4 participants control just 36% of capacity across the 2 generation types.

22 Gas, hydro and batteries.

Figure 4.7 NSW market share by registered capacity, by fuel type, 30 June 2024

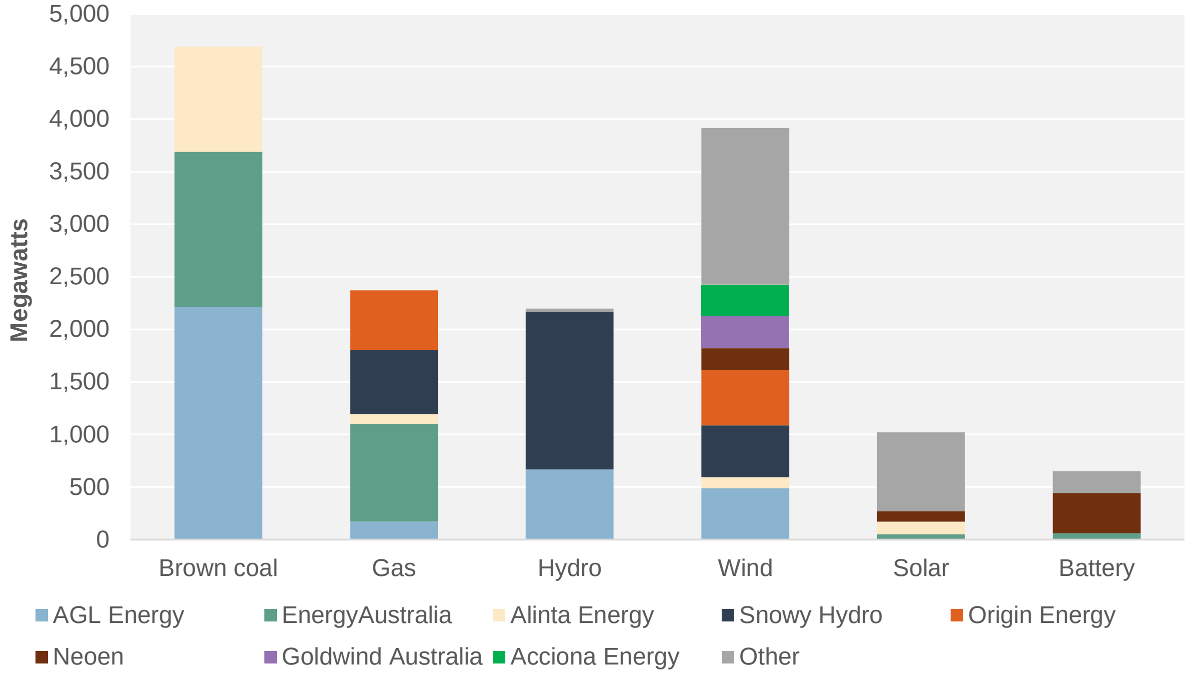


Note: Fuel type capacity share uses registered capacity of all market scheduled generation (excluding market loads) registered as at 30 June 2022. Market shares are determined using ownership declared to AEMO for each dispatchable unit identifier (DUID). Where an intermediary operates on behalf of the owner, the market share for that capacity is attributed to the intermediary.

Source: AER analysis using NEM data.

In Victoria, 77% of dispatchable capacity is controlled by AGL, EnergyAustralia and Snowy Hydro. These 3 participants also control 79% of flexible generation capacity (Snowy Hydro controls 40%). Although brown coal is the dominant fuel type in Victoria, other generation types are more significant in Victoria compared with NSW and Queensland (Figure 4.8). Wind capacity with highly diverse ownership now makes up over one-quarter of registered capacity in the region.

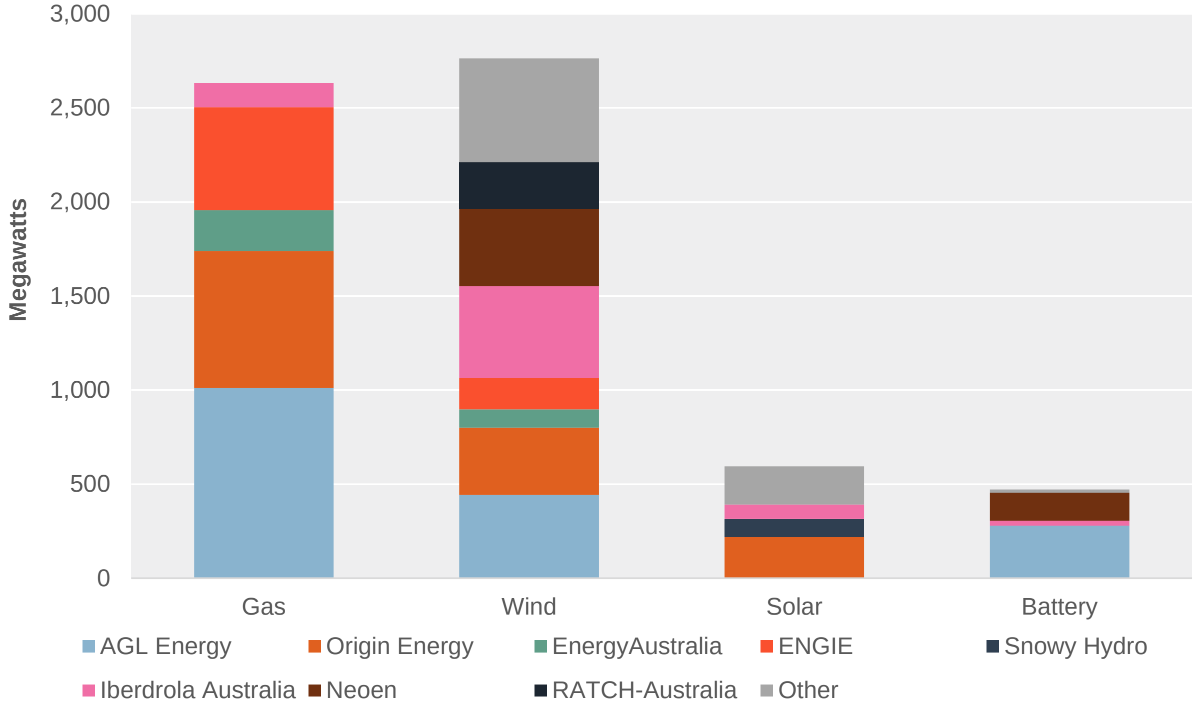
Figure 4.8 Victoria market share by registered capacity, by fuel type, 30 June 2024



Note: Fuel type capacity share uses registered capacity of all market scheduled generation (excluding market loads) registered as at 30 June 2022. Market shares are determined using ownership declared to AEMO for each dispatchable unit identifier (DUID). Where an intermediary operates on behalf of the owner, the market share for that capacity is attributed to the intermediary.
Source: AER analysis using NEM data.

Unlike the rest of the mainland, South Australia has significant renewable capacity and relies primarily on dispatchable gas to firm this generation (Figure 4.9 South Australia market share by registered capacity, by fuel type, June 2024). Ownership of flexible capacity is highly concentrated, with 80% (including 87% of gas) controlled by AGL, ENGIE and Origin Energy. These 3 generators also own 35% of wind and solar output in the region.

Figure 4.9 South Australia market share by registered capacity, by fuel type, June 2024



Note: Fuel type capacity share uses registered capacity of all market scheduled generation (excluding market loads) registered as at 30 June 2022. Market shares are determined using ownership declared to AEMO for each dispatchable unit identifier (DUID). Where an intermediary operates on behalf of the owner, the market share for that capacity is attributed to the intermediary.

Source: AER analysis using NEM data.

Tasmania remains the most concentrated region in the NEM, where all dispatchable generation is operated by government-owned Hydro Tasmania. However, a few small wind generators in the region are owned by smaller participants.

4.1.4 Output of one or 2 large participants is required to meet demand a significant proportion of time

As a result of the high concentration of dispatchable generation (section 4.1.3), output from a few large participants was often needed to meet demand in most regions, even after accounting for the availability of imports from neighbouring regions. At these times, the large participants are considered jointly pivotal to meeting demand. This gives them an increased ability to exercise market power.

The pivotal supplier test (PST) evaluates the potential for a participant or participants to exercise market power based on whether they are needed to meet demand. The PST accounts for generation ownership, outages and changing market conditions such as demand and interconnector availability. We have examined the extent to which the largest participant (PST-1) or 2 largest participants (PST-2) are pivotal for each mainland NEM region.

In the past 2 years, the proportion of time some generation from the largest (PST-1) or 2 largest (PST-2) generators were required to meet demand has decreased in all regions except Victoria (Figure 4.10). Queensland had the highest percentage of the time required for the largest one or 2 participants to meet demand, materially higher than the other states.

The largest supplier was required to meet demand 17% of the time in 2023–24, down from 25% in 2021–22. There was also a significant drop in PST-2, reducing from 89% in 2021–22 to 79% in 2023–24. PST-2 was always Stanwell Corporation and CS Energy. Stanwell Corporation was needed the most often (17% of the time) to meet the demand in 2023–24.

Figure 4.10 Proportion of time some generation from the largest one or 2 participants was needed to meet demand in 2021–22 and 2023–24

Note: PST-1 measures the period during which the available generation of the largest participant was required to meet market demand, while PST-2 measures the period where the 2 largest participants were required to meet demand. Data excludes the administered pricing periods when the price is capped, as well as market suspension periods.

Source: AER analysis using NEM data.

Queensland has the highest PST-1 and PST-2 percentages despite market concentration (HHI) being lower than in some of the other regions. One reason for this is the size of the 2 largest generators relative to the overall regional market. Stanwell and CS Energy are much larger than other generators in Queensland, contributing 961 and 411 points respectively to Queensland's average HHI score in 2023–24. The next highest were CleanCo (55 points) and Origin (54 points). In NSW, the third largest participant, AGL, contributed 426 points for 2023–24. Another reason for Queensland's higher PST percentages is the scale of regional demand compared with its ability to import generation from other regions. Total import capacity for the region is a maximum 957 MW, while demand is typically around 6,000 MW. NSW and Victoria have higher import capacity while South Australia and Tasmania have much lower demand.

In 2023–24 the largest supplier in NSW was required to meet demand 1.9% of the time, down from 2.4% of the time in 2021–22. Some generation from one of the largest 2 suppliers was needed to meet demand 34% of the time, down from 58% in 2021–22. The smaller market share of AGL following the exit of Liddell power station was a key driver of this, combined with the continued new entry of diversely owned renewable energy. Some generation from either Snowy Hydro or Origin was required (PST-2) 32% of the time to meet demand in 2023–24, down from 38% in 2021–22. AGL was a major pivotal supplier in 2021–22 but was needed less frequently than Origin or Snowy Hydro in 2023–24.

In Victoria, there was a small increase in both PST-1 (up from 1% to 2%) and PST-2 (up from 33% to 34%) from 2021–22 to 2023–24. AGL was most often the pivotal supplier in Victoria and was needed 2% of the time to meet demand in 2023–24, while Snowy Hydro was the second most frequent pivotal supplier. Some generation from either AGL or Snowy Hydro was needed to meet demand 33% of the time.

In South Australia, the percentage of time the largest one or 2 suppliers was needed to meet demand was lowest of all NEM regions and falling. Some output from the largest supplier was needed to meet demand less than 1% of the time in both 2021–22 and 2023–24. Output from one of the largest 2 suppliers was needed 7% of the time, down from 11%. While other mainland regions rely heavily on the output of a few large generators, South Australia has considerable renewable capacity firmed by gas generators. When renewable output is high, the gas generators are not needed to meet demand. At the same time, South Australia's high import capacity relative to regional demand also contributes to less frequent reliance on output from the largest participants.

4.2 Vertical integration and government intervention affect participant behaviour

Section 4.1 indicates that some larger participants may have opportunities to exercise market power in certain circumstances. However, the extent to which a participant is hedged against spot prices, and the influence of government intervention or direction, affects how participants behave in the market.

4.2.1 Vertical integration and contracting enables participants to manage risk

While vertical integration continues to be a feature of the NEM, the incentives that vertically integrated participants face vary depending on how much generation they control against their retail load. A participant with just enough generation to cover its retail position (a neutral portfolio) is unlikely to profit from raising spot prices because any additional revenue in its wholesale business would be offset by higher costs in its retail arm. The same may apply if it has less generation than retail load (that is, 'short' in generation). However, a participant that has more generation than retail load (that is, 'long') may be able to profit from raising spot prices because the additional revenue earned in its wholesale business would be only partly offset by increased retail costs.[23]

The extent to which a participant is vertically integrated provides a natural hedge against spot price volatility and will influence its hedging strategies, but it is unlikely to be the only tool participants would use to reduce exposure to spot prices. In chapter 3, we explain how participants use contract markets to manage at least some of their exposure to price risk.

---

[23] In theory, a contracted generator can also benefit from withholding capacity if influencing spot prices in the short run allows it to negotiate higher priced contracts in the future. In these cases, it is possible that a generator that is short or neutral to the spot may be (temporarily) willing to take losses in the spot market.

While our analysis in chapter 3 is based on public information, the expansion of the AER's wholesale market monitoring powers in May 2024 (section 3.5) allows us to collect confidential contracts and contract-related information from participants. We used these powers for the first time in 2024 to collect contract market information from South Australian energy businesses. This information has allowed us to assess the extent of vertical integration in the region, strategies participants use to manage their risk, and the extent to which some participants have an incentive to take advantage of market power and push prices higher. We anticipate that we will be able to incorporate more information in future WEMPR reports.

4.2.2 Government regulation can influence a participant's behaviour

In addition to a participant's exposure to spot prices, government direction and regulation can influence behaviour.

In Tasmania, state-owned Hydro Tasmania controls all nearly generation capacity. Since 2014 the Tasmanian Government has required Hydro Tasmania to offer wholesale contracts to retailers at regulated prices (Box 4.2). Currently, the regulated contract price is linked to the Victorian contract price, as a competitive price. This arrangement limits Hydro Tasmania's incentive to exercise market power to increase wholesale prices in the Tasmanian market because it must still meet obligations under regulated contracts.

Box 4.2 Regulated contract pricing arrangement in Tasmania

In 2014 the Tasmanian Government started regulating wholesale electricity contracts as a mechanism to reduce Hydro Tasmania's incentive to exercise market power to increase prices.

The Wholesale Contract Regulatory Instrument (WCRI) requires that Hydro Tasmania provides Tasmanian retailers access to regulated contracts at prices linked to ASX-traded Victorian electricity futures contract prices. The WCRI is determined by the Office of the Tasmanian Economic Regulator (OTTER). Since 2014 OTTER has periodically published updates to the WCRI, most recently in June 2024.[24]

On 22 December 2022, the NSW Premier declared a coal market price emergency. The NSW Government capped the price of black coal sold to generators at $125 per tonne. This is the equivalent of $49 per MWh. The Queensland Government moved simultaneously to direct its coal generators. The directions to the Queensland coal generators are not public, but the AER understands Queensland has a mechanism in place to achieve a similar effect to NSW. These directions had impacts on generator behaviour, as discussed in section 5.3.1.

---

24 OTTER, Wholesale Contract Regulatory Instrument pricing investigations, Office of the Tasmanian Economic Regulator, accessed 30 October 2024.

4.3 Interconnectors provide some competitive pressure to neighbouring regions

Each region in the NEM is connected by high voltage transmission lines that enable energy to flow between neighbouring regions (Box 4.3). Trade between regions over the interconnectors allows lower priced generation in adjoining regions to compete with higher priced local generation. As a result, strong interregional flows provide some competitive pressure on participants within a region.

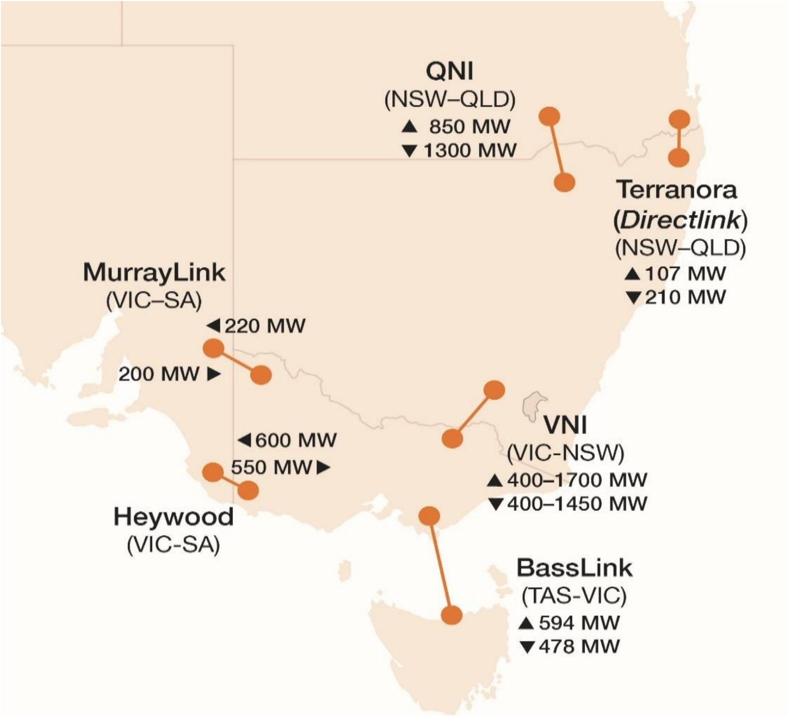
Box 4.3 Interconnectors in the NEM

Interconnectors enable energy transfers between the NEM's 5 regions (Figure 4.11). 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 the Australian Energy Market Operator (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 distinct markets. This is referred to as 'price separation'.

Figure 4.11 Interconnection in the NEM[25]



Note Arrows on the figure show the nominal capacity of each interconnector for each direction of flow.
Source: AER analysis using NEM data.

4.3.1 Flows were typically constrained below interconnector's nominal capacity

The ability of interconnectors to improve market efficiency and competition is impeded when flows over the interconnectors are constrained by physical or system limitations.[26] This congestion affects market outcomes by distorting the economic dispatch of generators and hence prices. Despite these impacts, a certain level of congestion is expected in an efficient market where the cost of expanding the network to eliminate congestion is greater than the cost of congestion.

Our congestion analysis examines how long each interconnector is bound as well as the capacity of each interconnector when binding. If an interconnector is binding, its flows are at the maximum level for that point in time.

- The Queensland-NSW Interconnector (QNI) has bound 18% of the time when flowing into NSW and 6% of the time flowing into Queensland over the past 5 years. This is a relatively low frequency of congestion and has facilitated frequent price-alignment

---

25 AEMO provides a nominal capacity range in each direction for VNI, rather than a single value. It explains that "the nominal capacity of VIC1-NSW1 is highly dependent on the output of Murray generators (for New South Wales to Victoria) and Lower/Upper Tumut generators (for Victoria to New South Wales)". See Interconnector Capabilities, April 2024 (accessed 21 Nov 2024), p. 8.

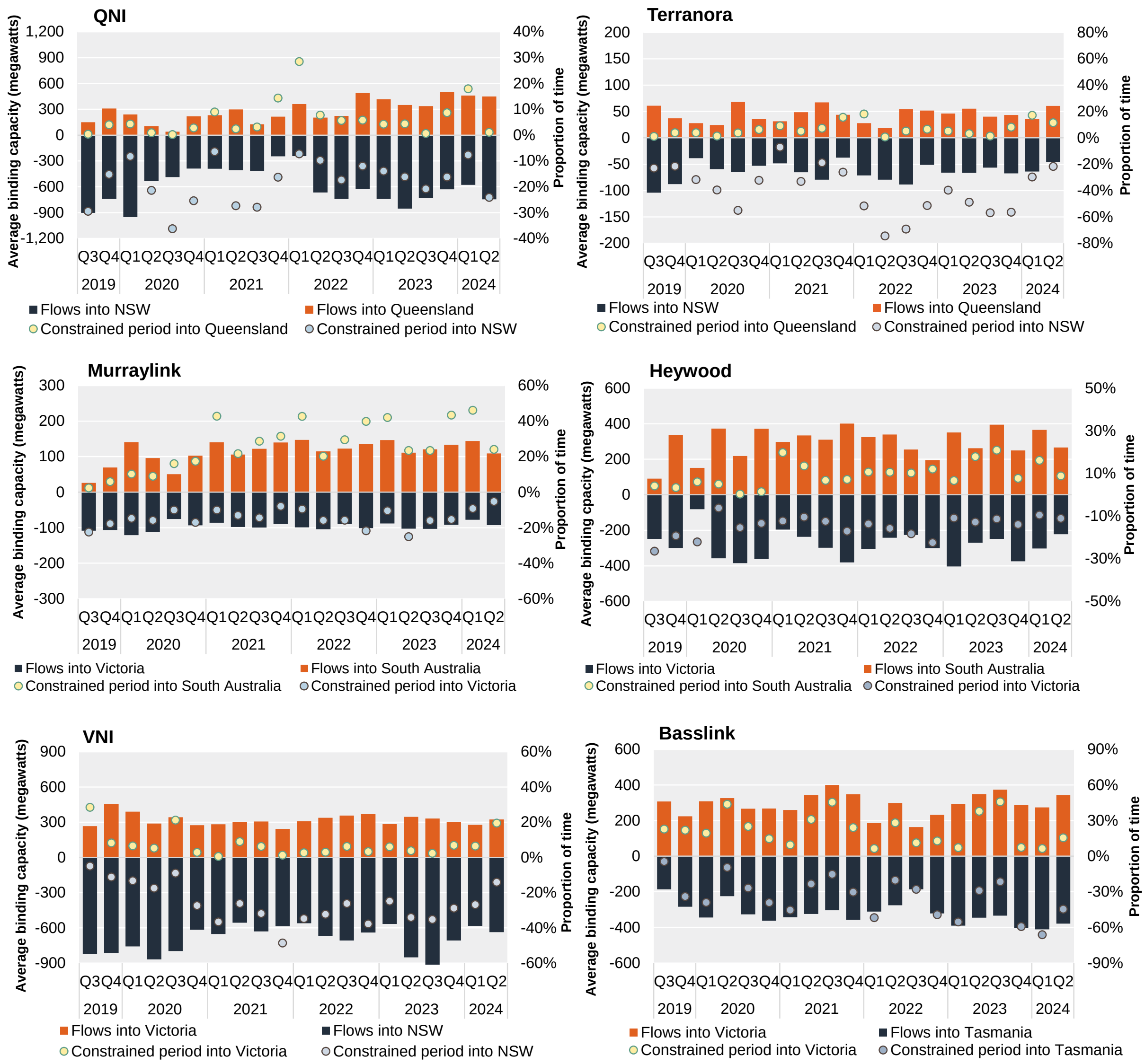
26 There are 2 types of congestion – 'system normal' and 'outage'. System normal is when the network is limited by the normal operation of the grid, while outage congestion is when the network is limited by line outages. Outage congestion often results in the network operating at less capacity compared with that of system normal conditions.

between the regions. QNI underwent upgrade works from 2020 to 2022 to improve the interconnector’s capacity. Since completion of the upgrade, the average binding level of flow into Queensland has improved as expected and is now typically above 400 MW. But this is still well below the interconnector’s nominal northwards capacity of 850 MW, and flows into NSW have been binding at a similar level to pre-upgrade.

- Terranora, the smaller interconnector linking Queensland and NSW, typically binds at well under 100 MW in either direction. Across 2022 and 2023 it bound more than half the time when flowing toward NSW – though this has improved in Q1 and Q2 2024.
- The Victoria to NSW Interconnector (VNI) tends to bind at around 700 MW flowing into NSW and around 300 MW flowing into Victoria. However, this interconnector has been subject to increasingly frequent instances of energy flowing ‘counter price’ from a high-priced to a low-priced region due to network congestion (see section 4.3.2). Counter-price flows diminish the efficiency of the market and the extent to which a lower priced region can provide a competitive constraint.
- Heywood, the larger of the 2 interconnectors linking Victoria and South Australia, bound on average 10% of the time flowing into South Australia and 15% of the time flowing into Victoria over the past 5 years. As a result, prices in the 2 regions are aligned most of the time. In both directions, the quarterly average binding level has typically been between 200 MW and 400 MW.
- Murraylink, the smaller of the Victoria-South Australia interconnectors, binds more frequently. It tends to bind between 100 and 150 MW on average when flowing toward South Australia and at around 100 MW when flowing toward Victoria.
- Basslink is the only market network service provider and unlike other (regulated) interconnectors it offers into the market like a generator. As a result, Basslink’s flow capacity may be impacted by price in addition to technical or system characteristics. In practice, there has usually been an agreement in place between Basslink and Hydro Tasmania to govern Basslink’s bidding behaviour. In February 2022, this agreement was terminated and during that year, the average binding capacity declined for both directions of energy flow. In October 2022, Hydro Tasmania and Basslink’s new owner APA reached a network service agreement which set out that APA would make Basslink available to the market at its safe continuous capacity at a low price.[27] Since then, Basslink’s performance has improved again.

[27] Hydro Tasmania, Update regarding Basslink contract arrangements, 24 October 2022 (accessed 4 December 2024).

Figure 4.12 Average binding capacity and duration by interconnector



Source: AER analysis of AEMO data.

Overall, the average binding level on each interconnector was significantly below the nominal interconnector limit. When interconnectors are constrained, there may be greater opportunities for generators to exercise market power. Investment in interconnectors is important for supporting competition. As they build these new projects, transmission network service providers (TNSPs) should be incentivised to conduct works in such a way as to limit the impact of planned network outages, which can create opportunity for generators to take advantage of the constrained network (section 4.3.5).

4.3.2 The impact of negative settlement residue management constraints has reduced from its 2021 peak

Interregional settlement residues occur when there are energy flows between neighbouring regions and the prices between those regions differ. In the normal course of events, electricity will flow from low-priced regions across interconnectors into higher price regions. Counter-price flows occur when electricity flows in the opposite direction to price to manage congestion. This occurs when the NEM dispatch engine determines that the optimal outcome to manage congestion located in one region is to force the flow of electricity into an adjoining region.

When counter-price flows occur, AEMO pays out more money to the generators in the exporting region than it has received from customers/retailers in both the exporting and importing regions. This is known as negative interregional settlement residue. Several inefficiencies are associated with this, including customers paying for energy at a higher price than the marginal generator in their region, and reductions in the value of settlement residue auction units used to manage price risk between regions.

AEMO manages the accumulation of negative interregional settlements by using constraints to limit or ‘clamp’ exports from the higher priced exporting region into the adjoining region. The binding duration and marginal binding impact of these constraints provide an indication of the inefficiencies associated with negative settlement residues.

The binding duration and binding marginal impact both increased markedly in 2021, driven by constraints used to manage QNI flows during the QNI upgrade (Figure 4.13).[28] Following completion of the upgrades in 2022, these fell considerably. At the same time there was a steep increase in the binding hours of the constraint to manage counter-price flows from NSW to Victoria. This constraint was responsible for 90% of negative settlement residue management constraint binding hours in 2023, up from 11% in 2021.

Overall, the marginal binding impact of negative interregional settlement constraints has reduced, but the number of binding hours has continued to climb. Multiplying the marginal binding impact by the number of binding hours suggests that the net impact of these constraints has likely fallen overall since 2021.[29]

Project Energy Connect (PEC), a new interconnector being constructed linking NSW to South Australia (section 4.3.3), may lead to increased interregional settlement residues on its completion. PEC will create the first interregional transmission loop in the NEM.[30] Interregional transmission loops are likely to drive higher interregional settlement residues compared with existing ‘radial’ interconnectors that simply link 2 regions and do not involve a transmission loop. This is due to the interaction between power flows in a transmission loop and the NEM’s regional pricing model. AEMO has proposed new method for allocating

---

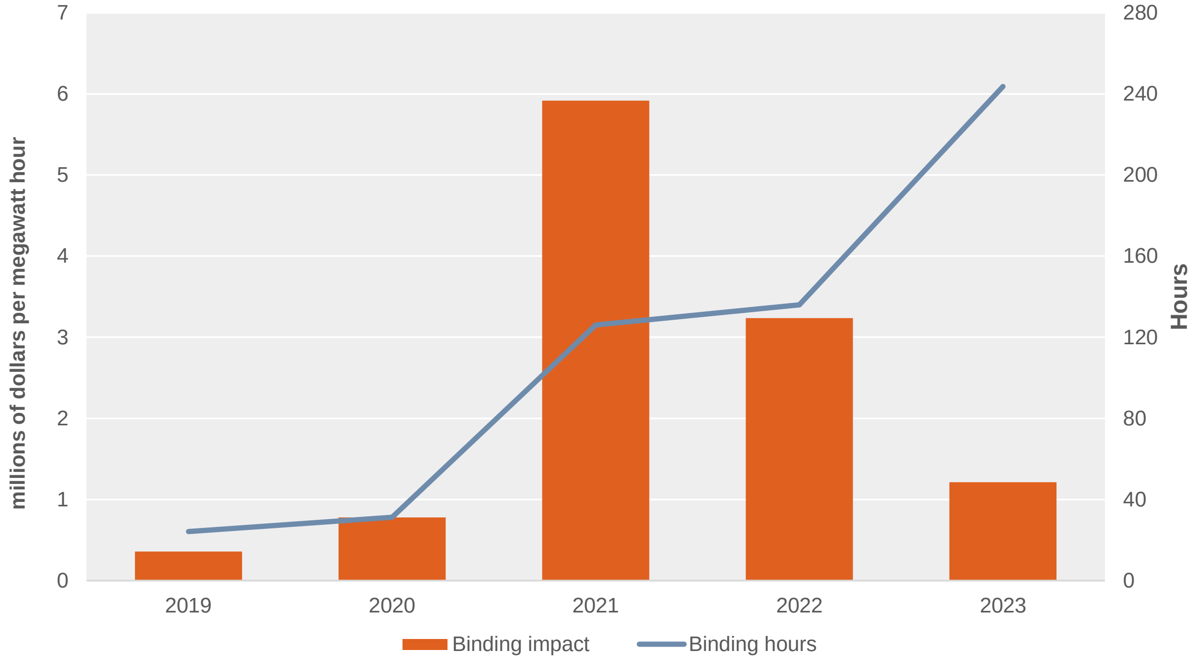
28 AEMO report congestion information annually, generally publishing in March for the previous year. For more detail see AEMO, Statistical Reporting Streams.

29 The binding impact of a constraint is derived by summarising the marginal value for each dispatch interval from the marginal constraint cost re-run over the period considered. The marginal value is a mathematical term for the market impact arising from relaxing the right-hand side of a binding constraint by one MW. Binding impact represents the financial cost associated with that binding constraint equation and can be a good way of picking up congestion issues. However, it is only a proxy (and always an upper bound) of the value per MWh of congestion over the period calculated. Hence, we cannot be sure of the net impact of constraints.

30 The completion of PEC will mean that NSW, South Australia and Victoria will be connected in a triangle, with each of the regions directly linked to the other 2 regions.

interregional settlements residues in transmission loops and has submitted a rule-change request, which is underway.[31]

Figure 4.13 Negative settlement residue management impact



Note: The binding impact of a constraint is derived by summarising the marginal value for each dispatch interval from the marginal constraint cost re-run over the period considered. The marginal value is a mathematical term for the market impact arising from relaxing the right-hand side of a binding constraint by one MW. Binding impact represents the financial cost associated with that binding constraint equation and can be a good way of picking up congestion issues. However, it is only a proxy (and always an upper bound) of the value per MWh of congestion over the period calculated. Further details can be found at AEMO congestion information.

Source: AER analysis of AEMO data.

4.3.3 New interconnectors have the potential to change interregional competition

Several major interconnector transmission projects are currently planned or underway. These projects may improve the reliability and security of the power system and may provide an increased competitive constraint on large participants in neighbouring regions. In some circumstances, they may provide an alternative to generation investment or may enable more cost-effective sources of generation to meet the needs of a neighbouring region.

To minimise the risk of overinvestment in transmission (where consumers pay more than is efficient) or underinvestment (where consumers experience lower reliability or higher than necessary wholesale prices), interconnector investment decisions currently undergo cost-benefit analyses by network service providers.

There are 3 new major interconnector projects currently planned or underway:

31 AEMC, Inter-regional settlements residue arrangements for transmission loops, Australian Energy Market Commission, accessed 15 November 2024.

- PEC is an interconnector to directly link South Australia and NSW for the first time. The project is being delivered in 2 stages, with stage 1 expected to be complete in December 2024 and stage 2 in July 2027.[32] The interconnector aims to deliver greater security and competitive constraint but will increase the complexity of interregional power flow (see section 4.3.2).
- In October 2022 the Australian, Tasmanian and Victorian governments agreed to joint ownership of Marinus Link, a new interconnector connecting Tasmania and Victoria. This will enable an increase in trade between the regions, which should improve the competitive landscape as well as system security. The interconnector will be delivered in two stages. Construction of Stage 1 is expected to begin in 2026 with completion in 2030.[33] Completion of Stage 2 is expected in 2032.[34]
- VNI West is a proposed high-capacity transmission line between Victoria and NSW. The VNI West regulatory investment test for transmission (RIT-T) was jointly undertaken by AEMO Victoria Planning (AVP) and Transgrid (NSW) for the respective Victorian and NSW parts of the project. In May 2024, the AER published its decision to approve Transgrid's contingent project application for capital expenditure to undertake early works related to the NSW portion of the project.[35]

The costs of new interconnectors can extend beyond direct construction costs to include, for example, higher energy and FCAS prices resulting from the network outages required for construction. These costs are ultimately borne by consumers. TNSPs should be incentivised to conduct upgrades in a way that limits these costs as much as possible (section 4.3.5).

4.3.4 Intraregional network constraints can also impact competition

As Box 4.3 explains, interconnector constraints can impact competition by limiting access to generation from other regions. Network constraints within a region can also impact competition in a similar way if they occur on important lines, limiting the flow of power from a region's generators to its load centres. In these cases, the constraint may lead either to generation being curtailed or forced counter-price into another region. Meanwhile, the remaining unconstrained generation may have more ability to exercise market power by offering at higher prices and still being dispatched.

We identified network outages as being a factor in 22 of the 36 high price events we reviewed between the start of 2023 and mid-2024.[36] In some cases, these outages limited access to cheap generation from other regions and in other cases from within the region. Outages can create conditions that enable participants to commercially rebid to spike the

---

32 AEMO, 2024 Integrated System Plan, Australian Energy Market Operator, 26 June 2024, p. 14.

33 Marinus Link, Project Timeline, accessed 15 November 2024.

34 AEMO, 2024 Integrated System Plan, Australian Energy Market Operator, 26 June 2024, p. 14.

35 AER, Transgrid VNI West contingent project application stage 1 early works, Australian Energy Regulator, May 2024.

36 We considered a high price event to be a calendar day in which our significant price reporting criteria for spot prices was breached at least one region (see Significant price reporting guidelines).

spot price. Out of the 22 high price events where network outages were a factor, commercial rebidding by participants was also a factor in 13.

One example was the events in NSW in May 2024.[37] During this month, a planned network outage on the Collector to Yass line in southern NSW resulted in up to 1,400 MW of low-priced generation being unable to reach key load centres, including Sydney. During some of the high price intervals, unconstrained NSW coal power stations – particularly AGL's Bayswater and EnergyAustralia's Mt Piper – rebid capacity above $5,000 per MWh, which contributed to the high prices. Without the network limitations (as well as some unplanned coal unit outages), the power stations would not have been able to offer this way with the same result.

4.3.5 Network providers should be incentivised to minimise the market impacts of planned outages

The May 2024 events were an example of a planned outage contributing to high prices. Networks have some discretion with the scheduling of planned outages, unlike unplanned outages, which are by nature unpredictable.

Ideally, outages should be scheduled at times when market impacts are likely to be less significant. However, market conditions are often unpredictable, and outages can have greater impacts than expected if conditions change from what was anticipated.

The transmission service target performance incentive scheme (STIPS) incentivises TNSPs to improve service standards. It aims to offset incentives for TNSPs to reduce expenditure at the expense of network performance. The market impact component (MIC) of the STIPS provides incentives for TNSPs to minimise the impact of planned outages.

On 6 November 2024, the AER published its proposed positions on the STIPS incentive components for consultation.[38] Our proposed position on the MIC was that it is not working as intended – with most TNSPs receiving maximum penalties – and should be suspended. We proposed to instead exercise our information gathering powers to collect new data measuring the impact of transmission outages and report on this annually. This will allow us to reinstate the MIC (or a variant thereof) should we identify a better metric that could be applied as an incentive mechanism. We have also said that we will explore the option of a rule change to introduce a conduct obligation on TNSPs into the National Electricity Rules.

Overall, planned network outages are unavoidable and necessary to maintaining a reliable electricity network. However, it is important that TNSPs are incentivised to conduct this maintenance at times when it they are likely to have less impact on the market.

---

37 AER, Prices above $5,000/MWh – April to June 2024, Australian Energy Regulator, 17 July 2024.

38 AER, Review of electricity transmission service standards incentive schemes, Australian Energy Regulator, 6 November 2024, accessed 12 November 2024.

5 Participant conduct

Key points

- In our 2022 report, we observed that rising fuel costs, fuel supply issues, weather events and significant outages had caused many participants to shift offers to higher prices or offer less capacity into the market.
- Since 2022, the volume of low to mid-priced offers has improved, reflecting that fuel costs have eased. This chapter explores case studies across regions and fuel types. A number of these illustrate that some of the capacity remaining at high prices may not be priced efficiently, suggesting a lack of competitive pressure in some areas. We will continue to monitor this behaviour.
- In 2022, we reported that coal generators were shifting some capacity to high prices in the middle of the day to avoid uneconomic dispatch. In this chapter, we show that some intermittent renewables generators are now also doing this.
- Battery storage systems have continued to enter the market and change market dynamics. These units help reduce volatility and set price both as generators and as loads.

When assessing effective competition, the National Electricity Law requires us to consider the extent to which market power is sustained. Instances of transient market power alone are not sufficient to conclude that competition in the National Electricity Market (NEM) is not effective. Participants can exercise market power in several ways. They may use strategies within a trading day to spike prices or they may engage in longer term strategies. These strategies may in turn affect contract prices. The strategies we assess in this chapter include:

- offering capacity at prices materially higher than efficient costs to increase prices (economic withholding) – this activity could include shadow pricing; for example, where a participant reprices capacity to just under the costs of the next highest price unit
- reducing the amount of capacity offered to the market or not offering capacity at all (physical withholding) – this can create an artificial shortage, pushing up prices and leading to higher revenues for the participant's remaining generation fleet
- rebidding capacity from low to high prices close to dispatch – this type of behaviour can limit the ability of other participants to respond to price signals competitively
- restricting the ramp rates of generation units to be dispatched in place of cheaper generation or demand response to benefit from high prices.

Some behaviours that appear to be a potential exercise of market power may instead be efficient responses to changing market conditions or a plant's technical requirements. We assess participant conduct in each region over the long term to see if changes in offers can be explained by underlying supply conditions or whether market power has been exercised.

Generator conduct is shaped by opportunities and incentives. Even if market power has not been exercised, behaviour may not lead to efficient market outcomes. If participants are offering or rebidding capacity in a way that prevents the lowest cost generation from being dispatched, this can cause allocative inefficiency regardless of intent to influence the price.[39]

Our analysis in this chapter explores patterns of conduct in the market to produce case studies that exemplify market dynamics or showcase notable shifts in behaviour. We include case studies that highlight:

- Queensland gas generators, which have reduced the capacity they offer to market and shifted capacity to higher prices (section 5.2.1)
- NSW and Queensland coal generators since the coal market interventions (section 5.3.1)
- battery storage units and the new dynamics they introduce to the market (section 5.4.1)
- intermittent renewables that have offered capacity at high prices (section 5.5.1).

Participant conduct in South Australia is covered in more detail in chapter 7.

5.1 Generators offered more capacity between $0 and $100 per MWh in 2023–24 reflecting lower fuel costs

We consider offers in the $0 to $100 per MWh range to be low to mid-priced. The volume of offers in this range partly recovered in 2023–24 after decreasing over the previous 3 financial years (Figure 5.1). This was most evident in NSW, where offers between $0 and $100 per MWh fell from 31% to just 12% of total offers from 2019–20 to 2022–23, before rebounding to 21% in 2023–24. The proportion of low to mid-priced offers also increased in Victoria and South Australia in 2023–24 and remained flat in Queensland. The increase in low to mid-priced capacity mostly resulted from capacity being shifted down from higher price bands.

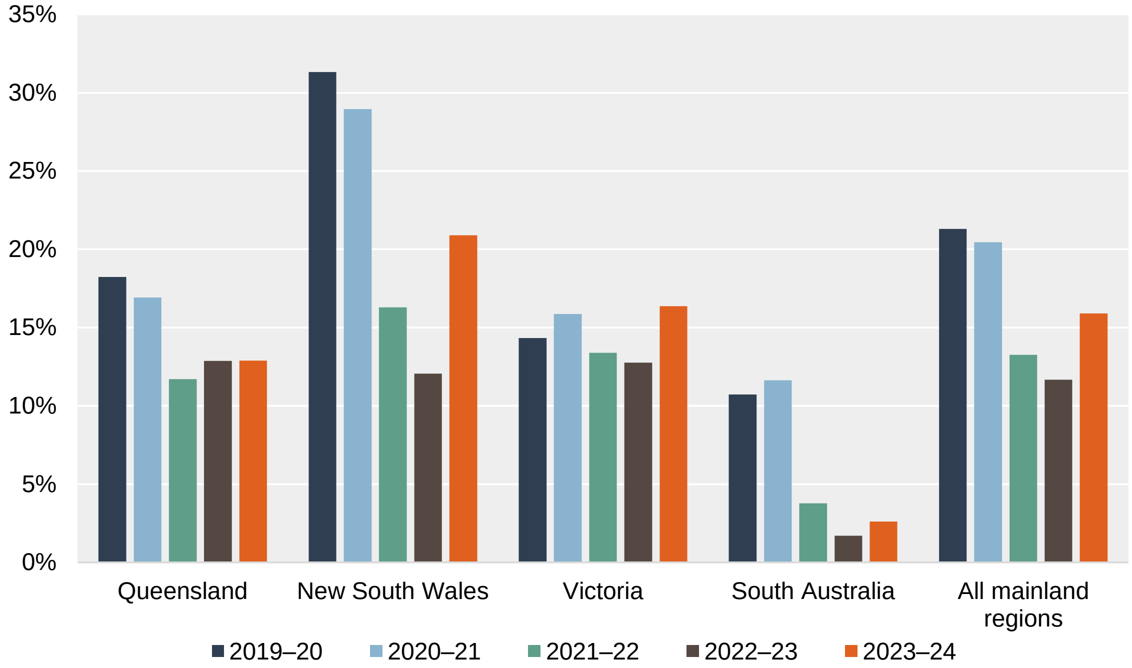
Significant volumes of capacity are offered below $0, principally by coal and renewable generators. At times of low demand these offers may be sufficient to meet demand. At other times, higher priced offers are required. Low to mid-priced offers are important because they reduce price volatility. If there is a low level of capacity offered at these prices, spot prices will more often jump significantly due to changing demand. Greater price volatility increases risk and cost for market participants. Low to mid-priced offers also lead to lower prices overall compared to the capacity being offered at higher prices.

Generally, a large portion of low to mid-priced capacity is offered by coal generators. Black coal still sets the price a significant proportion of the time. Hydro generation is also an important price setter. However, it tends to offer above black coal generation to manage water storage levels. Gas sets the price a small proportion of the time and usually at the highest cost of all technologies. It currently plays a critical role in the market during peak

39 Allocative efficiency means that resources are allocated to their highest value uses. In electricity markets, this means the electricity that consumers demand is provided by the lowest cost supply and demand-side options.

demand events or other constrained periods. This merit order is important to understanding market dynamics.

Figure 5.1 Percentage of financial year offers between $0 and $100 per MWh, by mainland region



Note: Average percentage of capacity offered between $0 and $100 per MWh, by financial year and mainland region.
Source: AER analysis using NEM data.

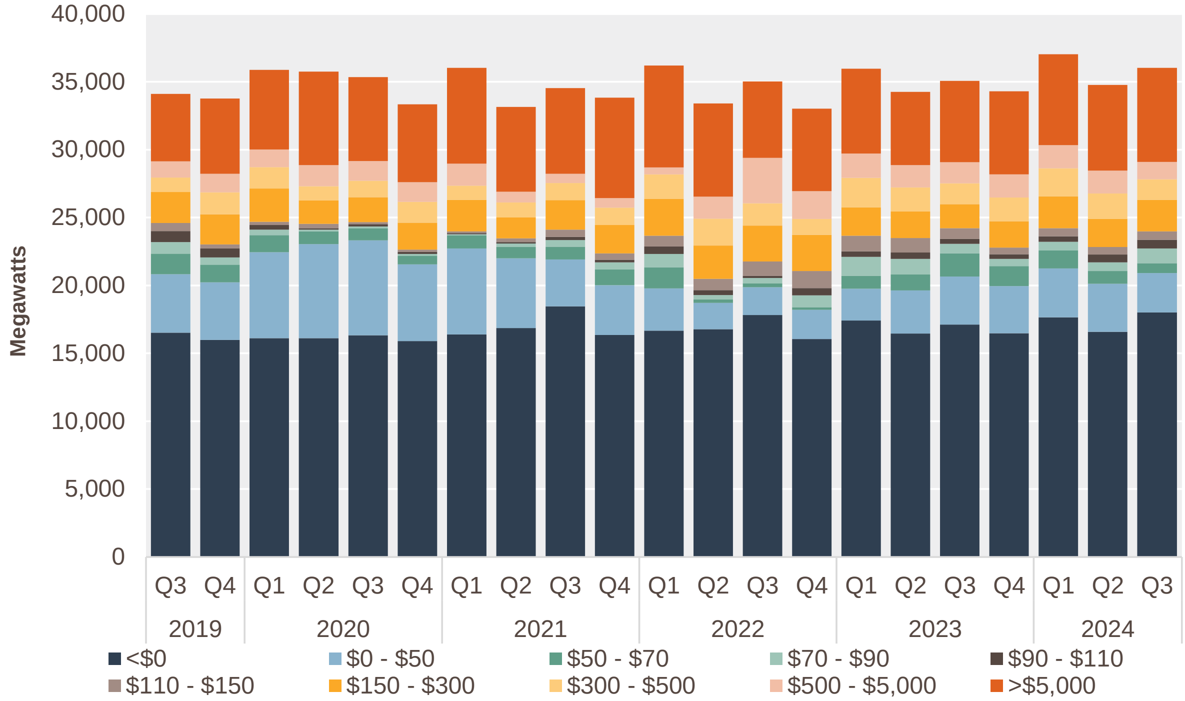
Black coal offers in NSW and, to a lesser extent Queensland, significantly contributed to both the squeezing and subsequent recovery of low to mid-priced offers. In 2022, the higher cost and reduced availability of fuel meant many coal generators repriced discretionary capacity from mid to higher prices. This was to avoid uneconomic dispatch and in some cases to ration fuel. Fuel price and supply constraints have since eased. These dynamics are discussed in more detail in section 5.3.1.

Gas offers contributed to the reduction in $0 to $100 per MWh offers in 2021–22 but not to the subsequent recovery in 2023–24. In South Australia, the closure of intermediate gas generation units in 2020–21, 2021–22 and 2022–23, which tend to offer capacity at lower prices than gas peaking plant, led to some low to mid-priced capacity being removed. Meanwhile gas peakers, which can turn on quickly but incur high start-up, running and maintenance costs when they run, offered less in these bands in Victoria over the past 5 years. This was likely to avoid switching on for short periods, in part due to increasing penetration of renewables. Queensland gas-powered stations (both intermediate and peaking) have also been offering less capacity over the past 5 years, including between $0 and $100 per MWh (this is explored further in section 5.2.1).

Finally, hydro power stations offered less in mid-price bands in earlier years before offering more again in 2023–24. Hydro stations may need to ration their water and are observed to adjust their offers in line with the offers of other generators to do this at times. When coal and gas offer prices were higher in 2022, hydro dispatch levels increased and hydro offers shifted to higher prices. When coal offers shifted back down in 2023–24, hydro offers partly followed.

While low to mid-priced offers have fluctuated over the past 5 years, offers below $0 per MWh remained mostly steady (Figure 5.2). Coal and gas stations have been offering slightly less at negative prices, but solar and wind generators have offered more. This means that the capacity offered below $100 per MWh fell in 2021–22 but has partly recovered in 2023–24. This is reflected in prices, as discussed in section 2.1.

Figure 5.2 NEM quarterly offers by price band

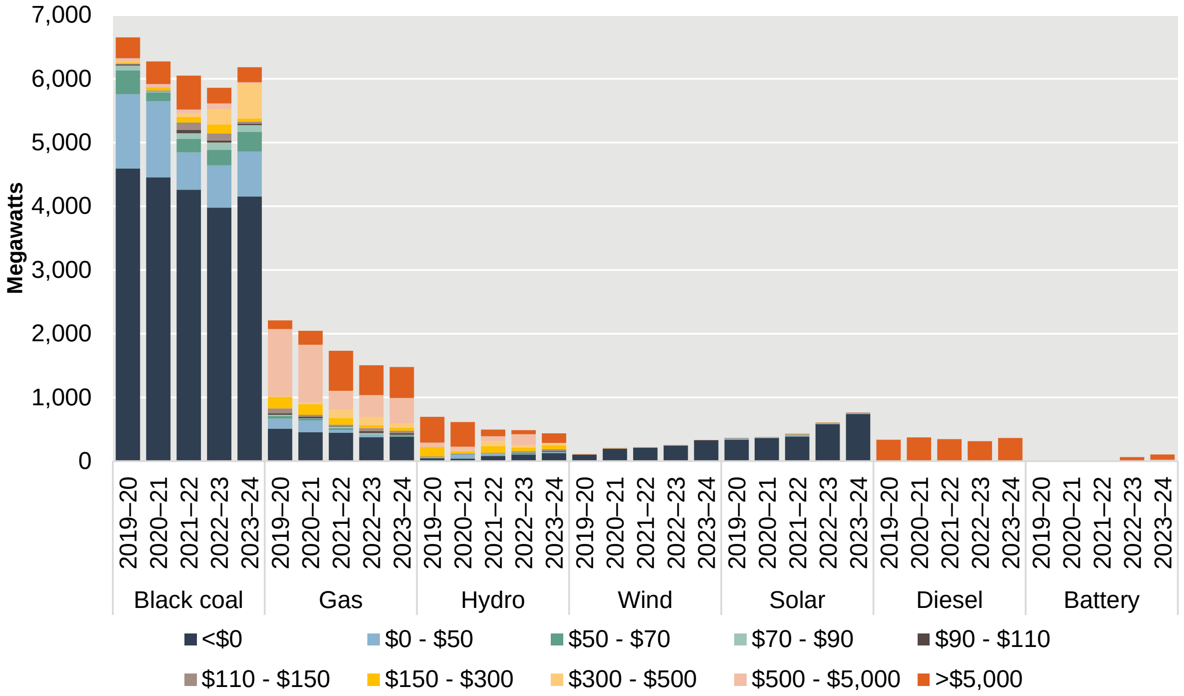


Note: Quarterly average offered capacity by NEM generators within price bands.
Source: AER analysis using NEM data.

5.2 Queensland thermal generation capacity offers increased in 2023–24 after trending downward

Queensland continues to depend heavily on black coal generation (Figure 5.3). In 2023–24, the amount of black coal capacity offered increased after trending downwards since 2019–20.

Figure 5.3 Queensland offers, by fuel type

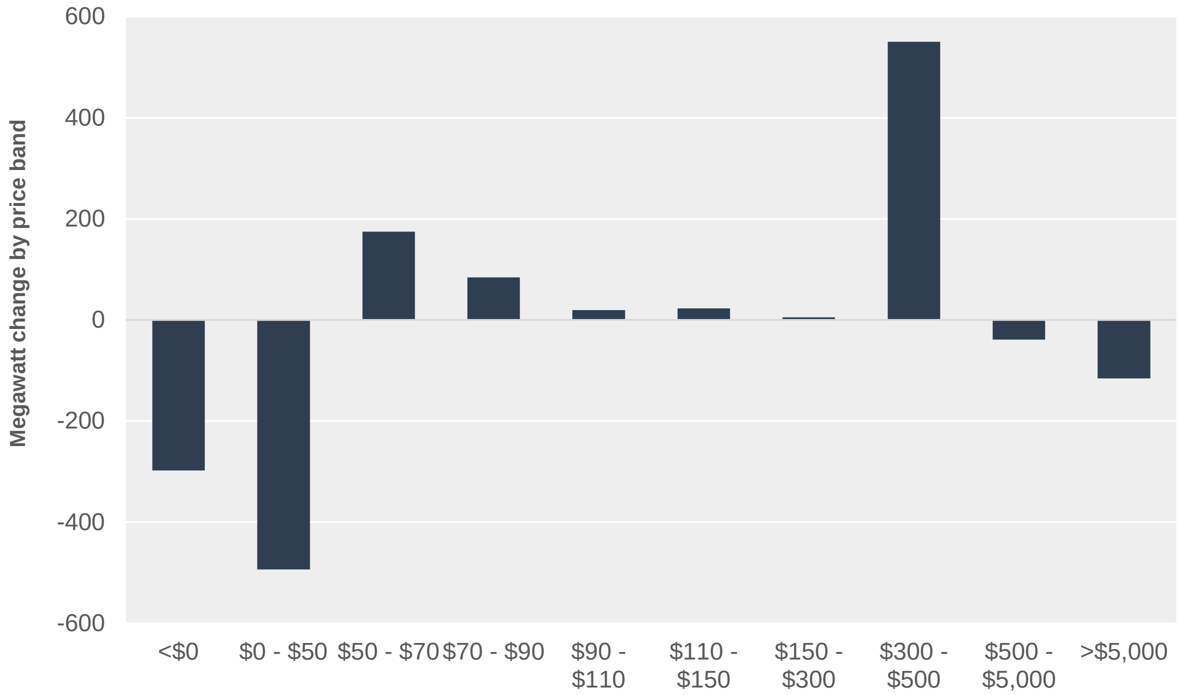


Note: Financial year average offered capacity by Queensland generators within price bands.
Source: AER analysis using NEM data.

In 2022, we reported that outages, heavy rainfall and black coal fuel price increases had all impacted on black coal offers. These factors have all since improved, facilitating the increase in black coal offers including at lower prices. Government interventions may also have had an impact (section 5.3.1).

Despite the recent improvement in low-priced coal offers, there is still less offered at low prices than pre-2022, while the amount offered between $300 and $500 per MWh has increased (Figure 5.4). Most of the increase in $300 to $500 per MWh offers occurred in 2023–24 and was shifted up from below $300 per MWh.

Figure 5.4 Change in Queensland coal capacity offered within each price band, 2020–21 compared with 2023–24



Note: Change in financial year average offered capacity by Queensland generators within price bands, 2020–21 compared with 2023–24.

Source: AER analysis using NEM data.

Queensland's black coal generation had been impacted in recent years by long-term outages at CS Energy's Callide power station, which have now resolved. Callide C3 returned to service in April 2024 following a 17-month outage caused by the failure of its cooling tower. Meanwhile Callide C4, which had been offline since the catastrophic failure of the unit in May 2021, returned to service at half-capacity in August 2024 (reaching full capacity in November). The return of these units did not significantly impact 2023–24 offers, because C3 was only available for April to June and C4 returned after the financial year ended. However, Queensland coal offered an extra 450 MW of capacity in Q3 2024 than in the previous Q3, with the majority of this being the result of Callide power station's offers.

Gas offers in Queensland have trended downward over the past 5 years. At the same time, the amount of high price capacity offered has increased. The decrease in low-priced gas offers has been offset by a corresponding increase in low-priced solar, wind and hydro offers. This, combined with the increase in low-priced coal offers, meant that Queensland enjoyed an overall increase in low-priced offers in 2023–24. This contributed to reduced volume-weighted average spot prices in the region (see section 2.1). Despite recent improvements, there is still less low-priced capacity offered in Queensland compared to pre-2022 and average spot prices remain higher.

5.2.1 Case study – Queensland gas generators are offering less capacity to market and are offering at higher prices

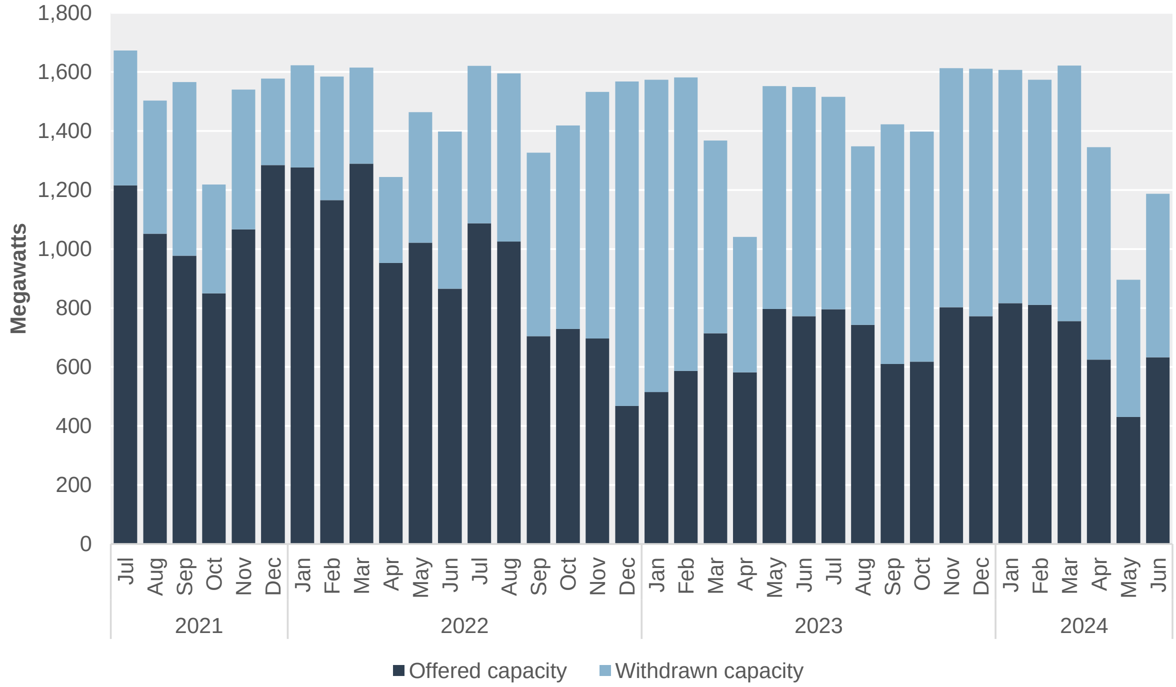
Queensland gas generators offered about 1,500 MW into the market on average in 2022–23 and 2023–24, down from about 1,700 MW in 2021–22 and over 2,000 MW before then

(Figure 5.3). Until 2021–22 only a small amount of capacity was offered at prices higher than $5,000 per MWh, because several of Queensland's gas generators are more efficient combined cycle generators that have lower costs than fast start peaking plant.[40]

In 2021–22, most of the drop in availability was driven by a 9-month outage at CleanCo's Swanbank E power station. At around the time or soon after Swanbank E returned to service in September 2022, Shell's Oakey, AGL's Yabulu and Origin's Darling Downs power stations all reduced the capacity they offered to market. Arrow Energy's Braemar 2 gas power station also reduced the capacity it offered to market in 2021–22 and 2022–23 before partly increasing it again in 2023–24.

The reduction in capacity offered by these power stations primarily represents withdrawal of capacity from the market, rather than outages (Figure 5.5).[41]

Figure 5.5 Average capacity offered and average capacity withdrawn by Darling Downs, Yabulu, Braemar 2 and Oakey power stations



Note: The chart shows the monthly average offered capacity and monthly average withdrawn capacity by Darling Downs, Yabulu, Braemar 2 and Oakey power stations. Capacity withdrawn is defined as the difference between bid PASA and bid maximum availability.

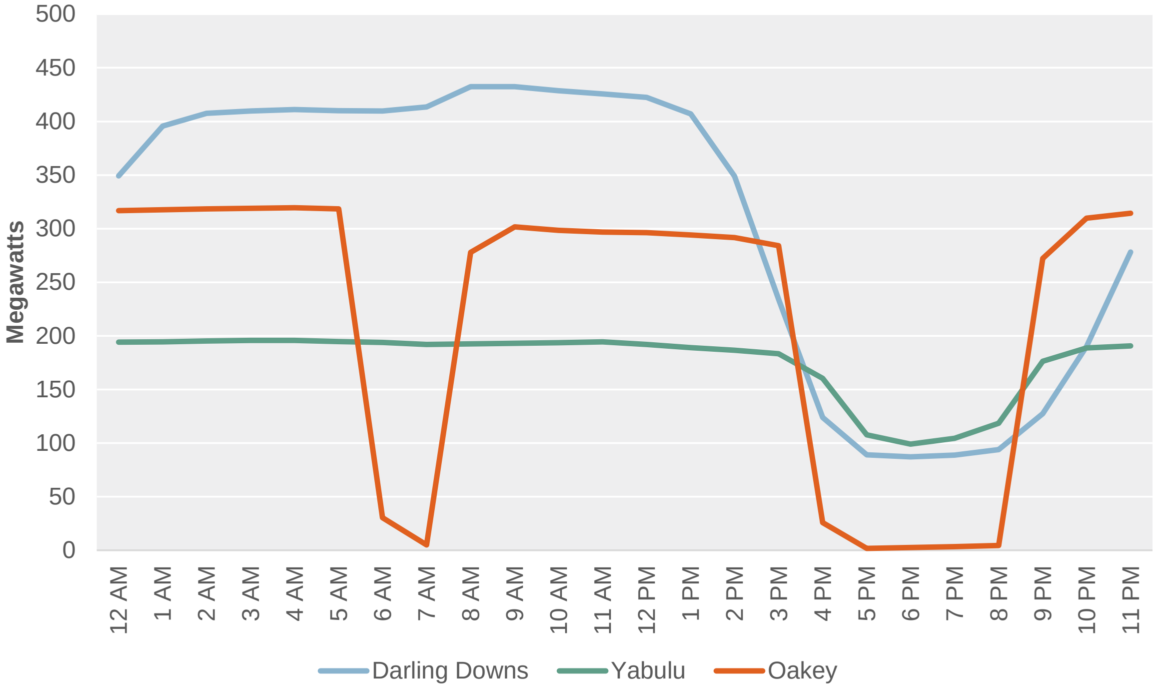
Source: AER analysis using NEM data.

These stations generally retain capacity in the market during the evening peak (and in Oakey's case, also the morning peak), but withdraw it at other times (Figure 5.6).

40 Of the generators discussed in this case-study, Swanbank E, Yabulu and Darling Downs are intermediate combined cycle gas generators. Braemar A, Braemar 2 and Oakey are open cycle peaking power stations.

41 Withdrawn capacity is defined as the difference between bid PASA and bid maximum availability. It is intended to represent capacity that a participant could supply but chooses not to.

Figure 5.6 Average capacity withdrawn by time of day in 2023–24, Darling Downs, Yabulu and Oakey power stations



Note: The chart shows the average capacity withdrawn by time of day in 2023–24 for Darling Downs, Yabulu, and Oakey power stations. Capacity withdrawn is defined as the difference between bid PASA and bid maximum availability.

Source: AER analysis using NEM data.

Given the owners of these power stations each have only a small portfolio in the region relative to other participants, it is unlikely the withdrawal of capacity represents a strategy to push up prices.[42] The time of day that capacity is withdrawn, and the fact that the whole station is typically withdrawn, suggests these stations are trying to avoid uneconomic dispatch. Peaking plant offering capacity into the market must quickly turn on when the dispatch price reaches their offer price. But a spike lasting only one or 2 dispatch intervals may not be sufficient to recover the costs of turning on. These stations may be withdrawing from the market outside of peak times to mitigate this risk. Regardless of the reason, withdrawal of capacity can reduce the market's efficiency if participants are not incentivised to offer the capacity that enables the Australian Energy Market Operator (AEMO) to operate the market securely and reliably at the lowest cost.

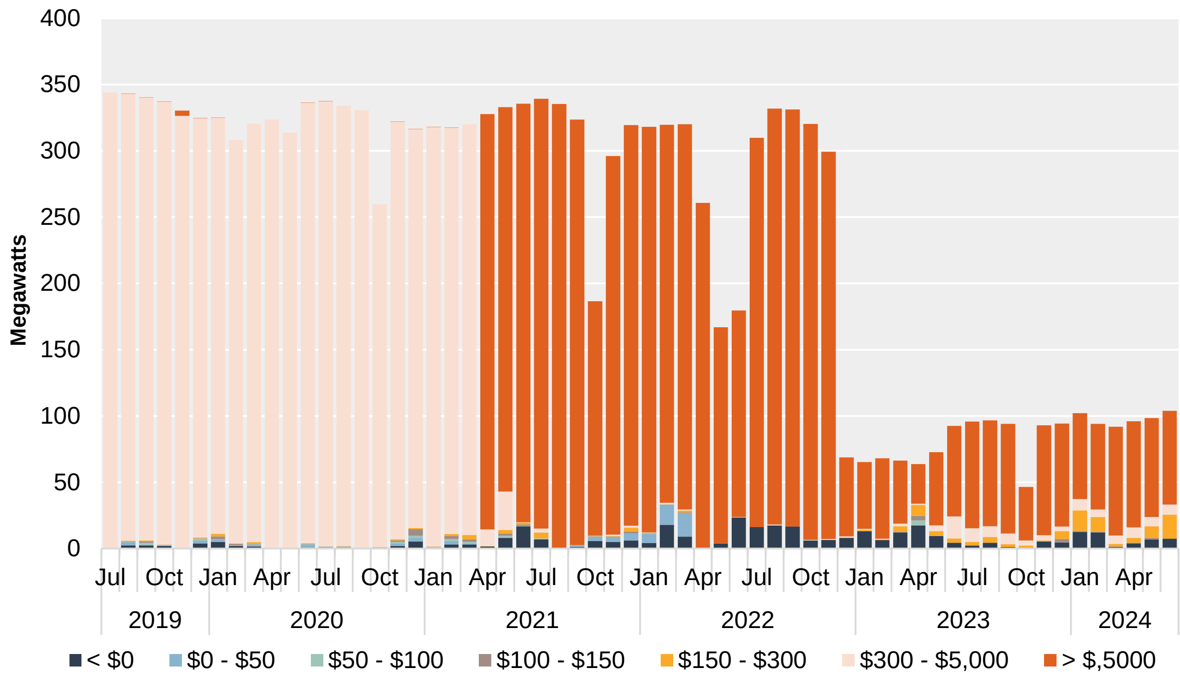
Over the past 3 financial years, Queensland gas generators have also offered more capacity above $5,000 per MWh than prior to 2021–22. Alinta's Braemar A power station has increased the percentage of its capacity offered above $5,000 per MWh year on year since 2019–20. Meanwhile, Arrow Energy's Braemar 2 repriced about half of its capacity from below to above $5,000 per MWh in 2021–22 (much of this was then withdrawn completely from May 2022 to September 2023). Shell's Oakey repriced most of its capacity from below

---

42 To benefit from a high price, a generator would need to have (uncontracted) generation that is being dispatched at the time of the price. The additional revenue from this would need to more than offset the losses from the withdrawn capacity not being dispatched.

to above $5,000 per MWh from April 2021 (Figure 5.7), before withdrawing most of its capacity for large parts of each day from late 2022. Similarly, AGL's Yabulu repriced most of its capacity from below to above $5,000 per MWh from May 2022 until late 2023 when it too withdrew most of its capacity for large parts of each day (but returned most of the remainder to lower prices). Queensland's gas generators rarely set price above $5,000 per MWh in 2023–24.

Figure 5.7 Average capacity offered within price bands, Oakey power station



Note: The chart shows the monthly average capacity offered within price bands by Oakey power station.
Source: AER analysis using NEM data.

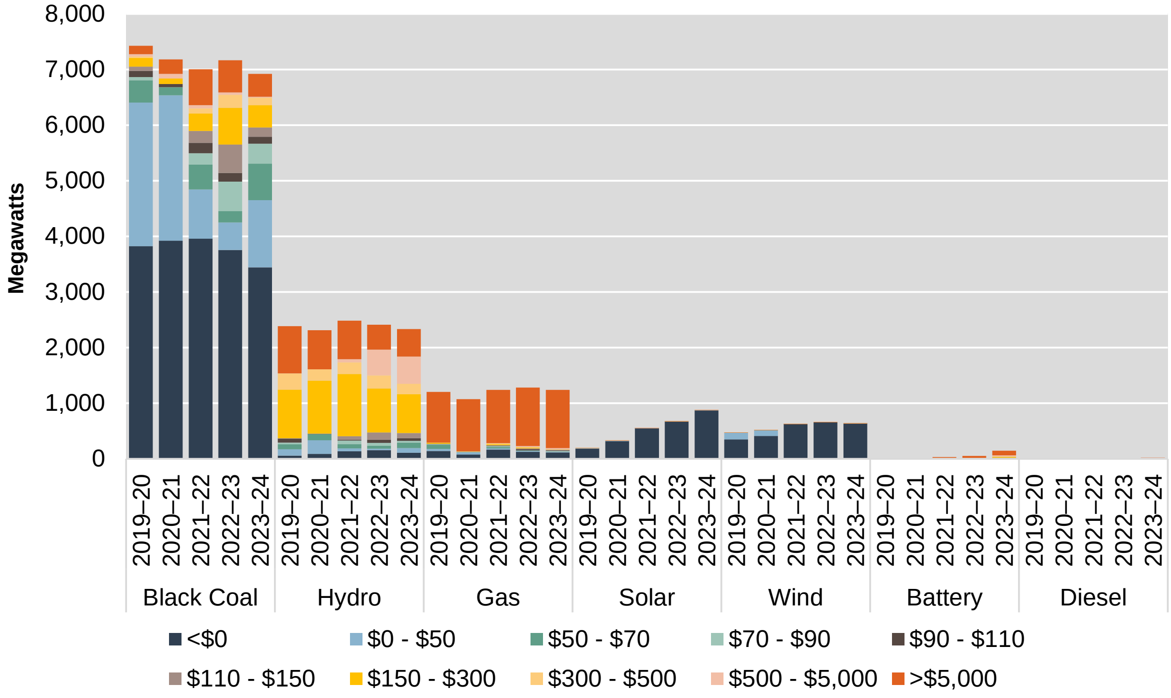
Some of this repricing of capacity likely reflects the increase in gas costs in 2021 and 2022. Gas prices are now much lower than their peak in winter 2022 (section 2.2.1) but remain elevated compared to pre-2021. Nevertheless, the increase in fuel costs may not fully explain the repricing of capacity.

The pricing of large amounts of capacity at high prices can contribute to higher volatility and if it does not reflect costs, it can reduce the efficiency of the market. We will continue to monitor this behaviour.

5.3 NSW coal generators are offering more low to mid-priced capacity again

Like Queensland, NSW is heavily reliant on black coal. Total coal capacity offered in the region has remained relatively flat despite the closure of AGL's Liddell power station in April 2023, mostly due to increased offers by AGL's other coal station Bayswater and EnergyAustralia's Mt Piper. Low to mid-priced coal offers were significantly squeezed in 2021–22 and 2022–23 amid high fuel prices and low fuel availability. These factors have now mitigated and the volume of offers between $0 and $100 per MWh has partly recovered (section 5.3.1). The coal market intervention, which capped the price of coal at $125 per MWh, remained in place until the end of 2023–24.

Figure 5.8 NSW offers, by fuel type



Note: Financial year average offered capacity by NSW generators within price bands.
Source: AER analysis using NEM data.

Most gas capacity in NSW is offered above $5,000 per MWh, because most gas stations in NSW are expensive peakers. They only offer at lower price bands when they wish to turn on, such as during the evening peak. There has been little change in offers in recent years.

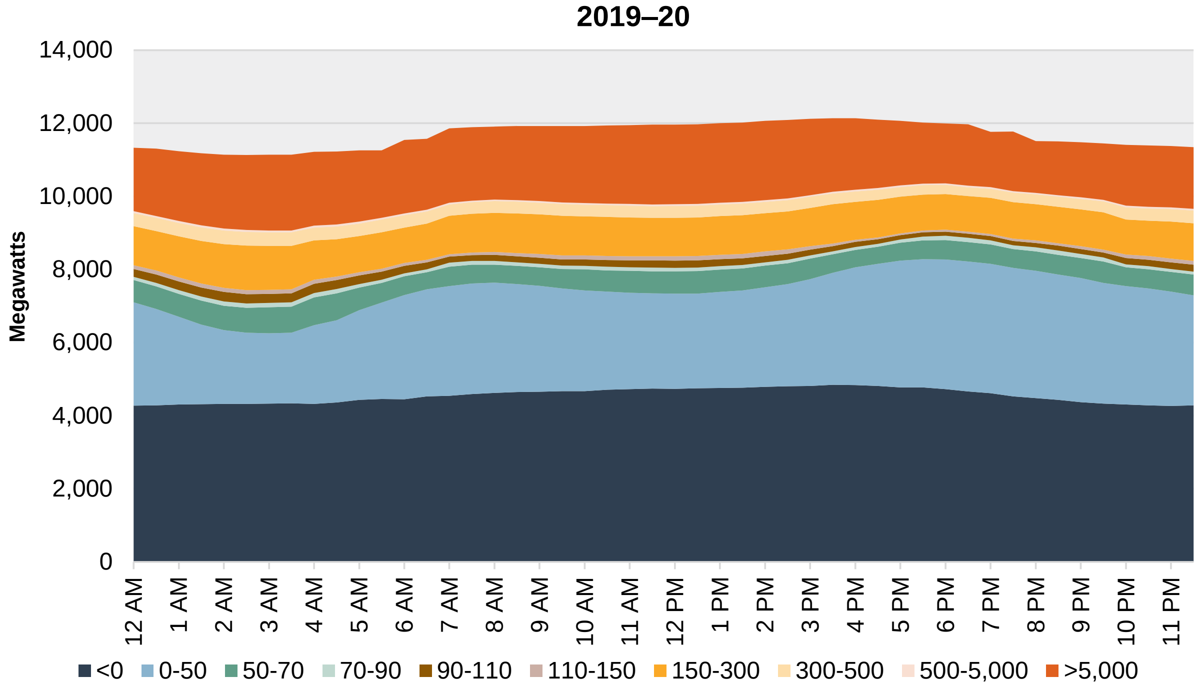
Hydro power stations in NSW, which are mostly owned by Snowy Hydro, predominantly offer their capacity between coal and gas in the bid-stack. During winter 2022, NSW hydro generators shifted nearly 1,000 MW of capacity from below $300 per MWh up into the $500 to $5,000 per MWh price band driven by a need to manage water levels and avoid running too hard. By Q4 2022, about half of this high-priced capacity was shifted back to lower price levels – but the remainder was left at higher prices as discussed below. Despite this, NSW hydro dispatch levels remain higher than in 2020 and 2021.

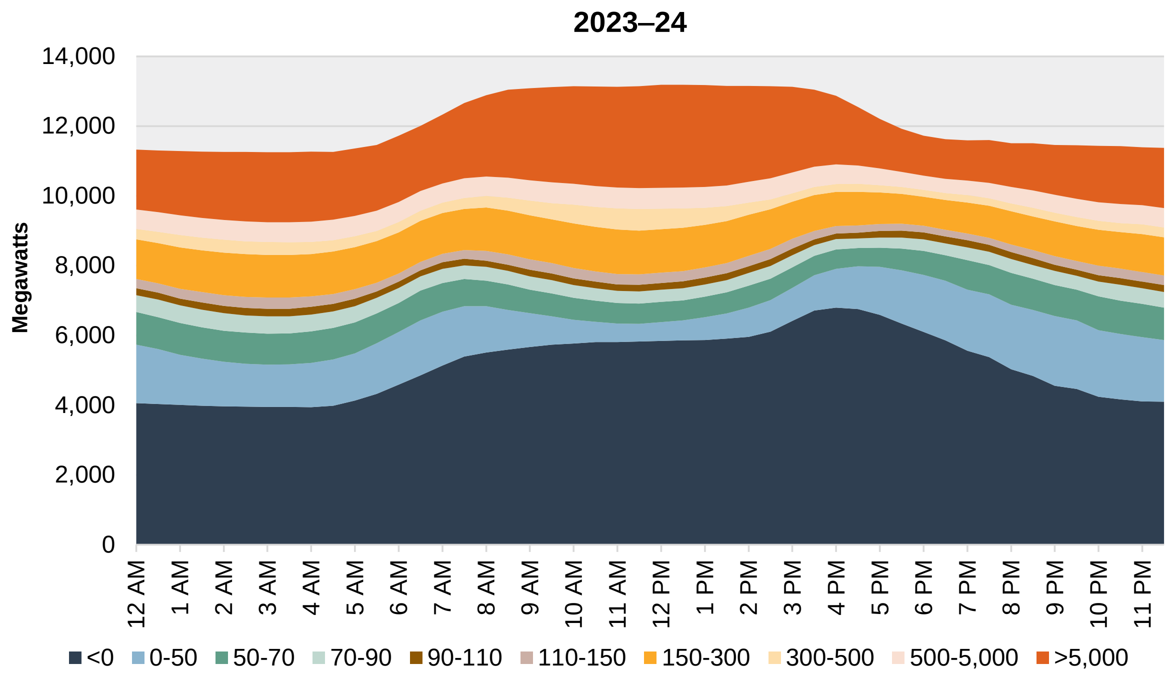
Intermittent renewables, while still a relatively small component of the NSW energy mix, have been steadily increasing the capacity they provide to the market. In recent years growth has been stronger in large-scale solar offers, which now represent 7% of total offers. Wind offers have plateaued for the past 2 years, representing a slowdown in new entry and less windy conditions in 2023–24.

Increased solar penetration has changed the time-of-day profile of NSW offers. In 2019–20, nearly all negatively priced capacity was offered by coal and there was little systematic variation by time-of-day. By 2023–24 the pattern was very different, with substantially more low-priced capacity being offered during daylight hours (and less offered overnight). There is also now more negatively priced capacity offered in the evening peak, when scheduled generation is bidding more capacity at low prices to be dispatched into higher peak spot prices.

There has also been an increase in capacity offered between $500 and $5,000 per MWh, including at peak times, mostly offered by Snowy Hydro's hydro power stations. Based on current market conditions, we consider some of this capacity may be priced above the marginal cost of generation and could be shifted to lower price bands without significantly impacting dispatch levels. This may suggest a lack of competitive pressure on these power stations.

Figure 5.9 NSW average capacity offered within price bands by time of day, 2019–20 and 2023–24





Note: Average capacity offered across selected financial years by time of day, by Queensland generators within price bands. The charts are presented at 30-minute level granularity and use NEM time.

Source: AER analysis using NEM data.

5.3.1 Case study – Queensland and NSW coal bidding behaviour changed following market interventions

Generator fuel costs reached an all-time high early in mid-2022, driven by high international prices for coal and gas. This affected domestic generators. NSW black coal generators typically acquire their fuel through contracts. Short-term supply contracts for coal are likely to align more closely with the prevailing international coal price, but it is common for long-term domestic supply contracts to also set prices by reference to international coal price benchmark indexes.

In addition, some participants faced an undersupply of contracted coal in mid-2022 due to transportation and weather challenges. This undersupply meant some NSW generators were more exposed to international prices. These costs remained high throughout 2022 and were reflected in ongoing higher offer prices by coal generators and high spot electricity prices. Future prices also remained well above historical levels.

In response National Cabinet decided on 9 December 2022 it would intervene to limit gas and coal prices, to shield consumers from energy price spikes.[43] Then on 22 December the NSW Premier declared a coal market price emergency. The NSW Minister for Energy was granted the power to give directions to respond to the emergency while the declaration is in place, with these issued the following day. The Queensland Government moved simultaneously to direct its coal generators.

---

43 Australian Government, [Energy Price Relief Plan](), 9 December 2022, accessed 5 November 2024.

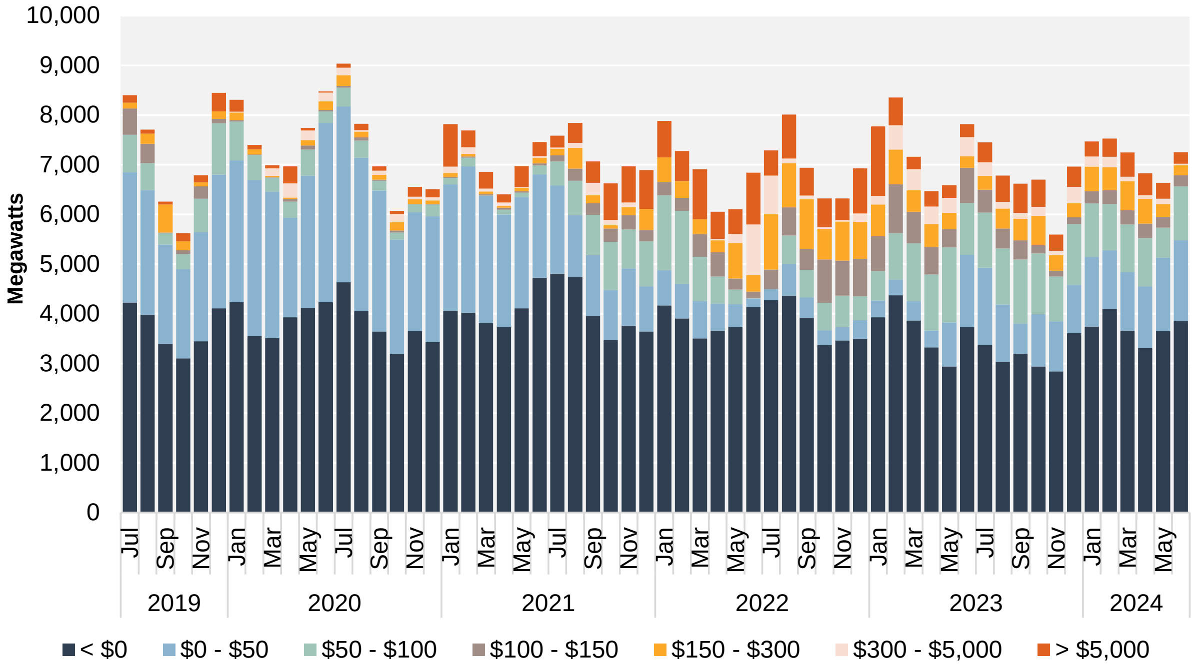
As a result of the directions given, the price of black coal sold to coal generators was capped at $125 per tonne in NSW. While the directions to Queensland coal generators were not public, the AER understands Queensland implemented a mechanism to achieve a similar effect. Additionally, coal generators in NSW were required to plan to maintain a stockpile sufficient to meet 30 days of projected demand. Coal mines in NSW were required to reserve a proportion of future coal production to supply NSW coal generators and were to prioritise delivery to generators with low stockpiles. The NSW intervention remained in effect until 30 June 2024.

Following the market interventions, we observed a change in offer behaviour by NSW and Queensland coal generators.

NSW

In 2021 and the first half of 2022, NSW coal generators shifted most of the capacity that had been offered between $0 and $50 per MWh to much higher prices (Figure 5.10). By Q4 2022, 1,493 MW was priced between $100 and $300 per MWh, nearly all of which was previously offered below $50 per MWh.

Figure 5.10 NSW monthly coal offers by price band



Note: Monthly average offered capacity by NSW generators within price bands.
Source: AER analysis using NEM data.

After the market intervention, much of this capacity shifted back to lower price bands. By June 2023, 1,452 MW was offered between $0 and $50 per MWh, with another 1,044 MW between $50 and $100 per MWh. This was particularly driven by Origin Energy shifting significant capacity into the $0 to $50 per MWh range at its Eraring power station and Delta Electricity shifting capacity to the $50 to $100 per MWh range at Vales Point. AGL and EnergyAustralia also increased the lower priced capacity offered at their Bayswater and Mt Piper power stations.

There is still less capacity offered below $50 per MWh than prior to 2022. Most of this was priced between $50 and $100 per MWh in 2023–24 and reflects the fact that even with market interventions in place, coal prices faced by generators are likely higher than a few years ago when international prices were much lower and translated to lower fuel costs for domestic generators (section 2.2.1). A fuel cost of $125 per tonne (the market intervention price cap) translates to around $49 per MWh.

With the market intervention now ended, NSW coal generators may again face fuel costs above $125 per tonne. Export prices equated to around $84 per MWh in November 2024. Since black coal continued to set the price nearly half the time in Queensland and NSW in 2023–24 (and nearly one-quarter of the time in Victoria and South Australia), international coal prices will continue to have a significant impact on energy market prices.

Some capacity that was repriced in 2022 remained at much higher prices and does not appear to reflect fuel costs. Several hundred MW of Mt Piper capacity remained priced above $150 per MWh, some of which may reflect an ongoing need to ration fuel in the face of supply constraints. A similar amount (though a smaller percentage) of Bayswater's capacity remained priced above $5,000 per MWh.

Capacity priced above $5,000 per MWh may in part be a response to increased renewable penetration. Coal generation is designed for continuous operation. Ramping output up and down (and particularly turning off and on) can stress the units requiring increased maintenance. More capacity was offered at these higher prices in the middle of the day when renewable output tends to be higher and demand lower.

Higher priced offers at these power stations may also reflect that these participants are not always constrained by competitive pressures. In Q2 2024, these power stations rebid capacity from low to high prices, contributing to high NSW spot prices. Our report into prices above $5,000 per MWh for the quarter identified market conditions had created the opportunity for AGL and EnergyAustralia to put upward pressure on prices and maximise profits by rebidding capacity at Bayswater and Mt Piper power stations.[44]

This behaviour was enabled by market conditions such as planned network outages (section 4.3.4) and unplanned coal outages, which prevented significant amounts of lower priced capacity from being dispatched into the market. These events resulted in spot prices exceeding the cumulative price threshold and, for only the second time in the history of the NEM, the introduction of an administered price cap. They also likely contributed to an increase in futures prices (Figure 5.11). For example, the daily average settled price of Q2 2025 base futures contracts rose from $103 per MWh as at 31 March 2024 to $137 per MWh by 30 June 2024. During the same period, cap contracts followed a similar trend.

---

44 AER, Electricity prices above $5,000 MWh – April to June 2024, Australian Energy Regulator, July 2024, accessed 12 November 2024.

Figure 5.11 NSW daily settled base futures prices in Q1 and Q2 2024 mapped against days when commercial rebidding contributed to high prices

Note: Average daily settled price for Q3 2024, Q2 2025 and Q2 2026 NSW quarterly base futures contracts, mapped against days when AER significant price reports identified commercial rebidding as a contributor to 30-minute prices above $5,000 per MWh in the region.

Source: AER analysis using ASX data.

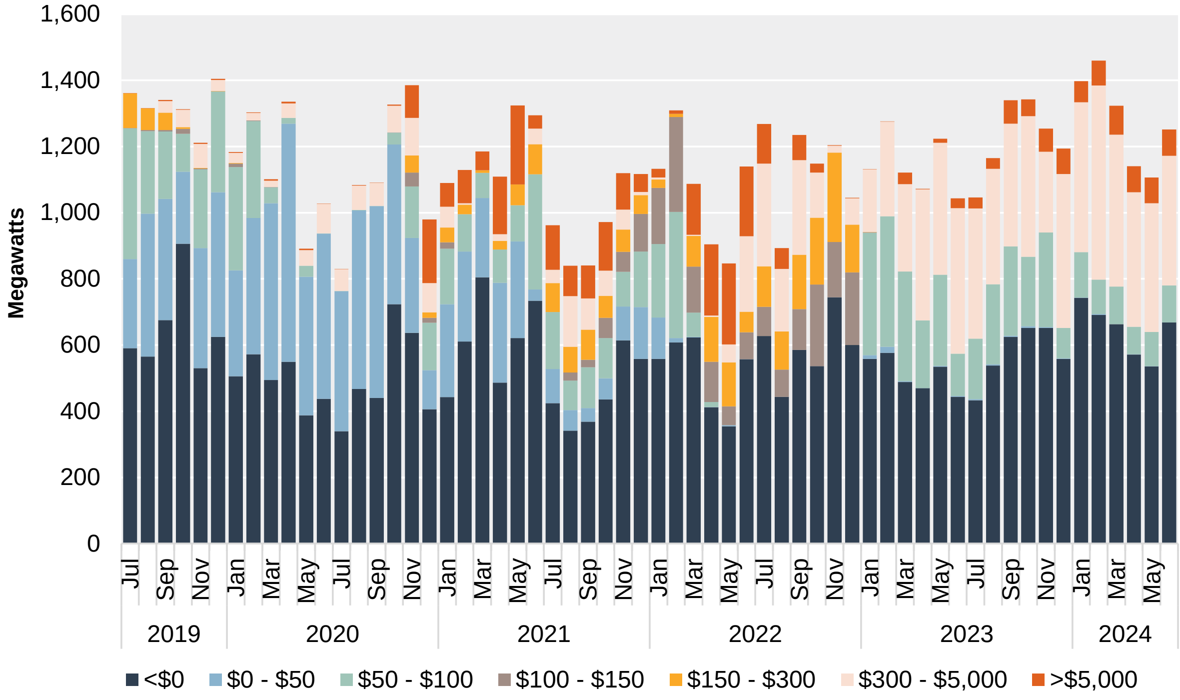
Overall, while we generally observed coal offers moving in line with costs, the high price events in May highlight that when the opportunity arises, coal generators do sometimes offer at prices well above costs. We will continue to monitor coal offer behaviour, with a particular focus on changes post intervention, using our new contract data collection powers to support this.

Queensland

In Queensland, the effect of market intervention on coal offers was less dramatic. In part, this may reflect that more of Queensland's coal generators are 'mine-mouth', which allows them to receive most of their coal directly from an on-site mine. These generators tend to have lower fuel costs and be less exposed to international price movements. While some of these generators were impacted by wet coal or outages in winter 2022, high fuel costs were generally less of an issue.

While Queensland coal offers shifted less than NSW coal offers overall, what matters is changes to the marginal generator that sets price. Following the Queensland Government's intervention into coal markets in December 2022, we observed offer changes at some power stations that set price frequently. Most notably, Gladstone immediately repriced capacity from the $100 to $300 per MWh range into $50 to $100 per MWh price bands, although some of this capacity was subsequently moved to above $300 per MWh (Figure 5.12).

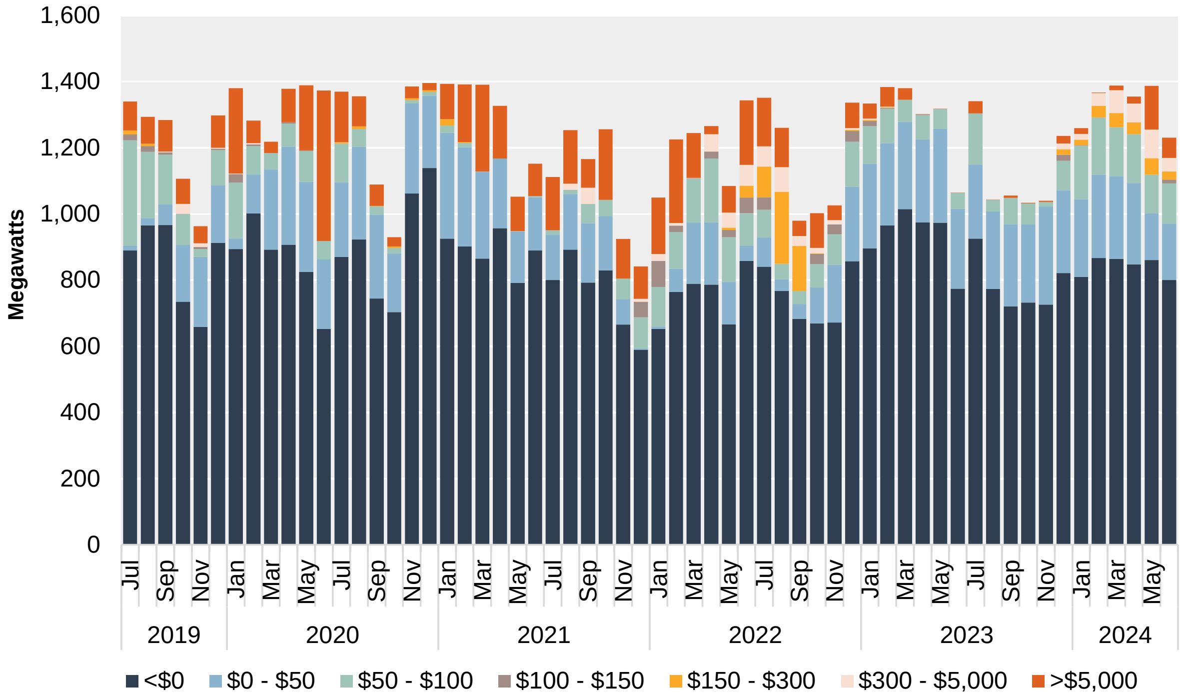
Figure 5.12 Gladstone power station monthly offers by price band



Note: Monthly average offered capacity by Gladstone power station within price bands.
Source: AER analysis using NEM data.

Tarong power station also changed its offers following the market intervention, moving some capacity from above $100 per MWh to between $0 and $100 per MWh (Figure 5.13).

Figure 5.13 Tarong power station monthly offers by price band



Note: Monthly average offered capacity by Tarong power station within price bands.
Source: AER analysis using NEM data.

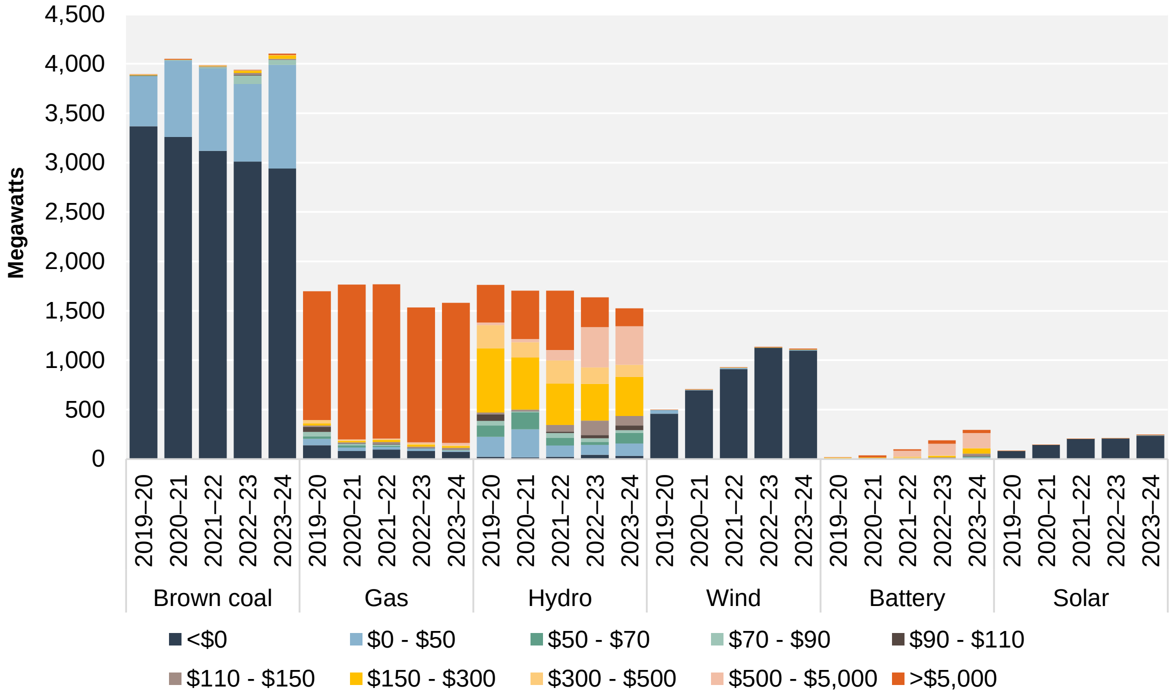
As with NSW, we will continue to monitor changes in Queensland coal generator behaviour now that the interventions have come to end.

5.4 Victorian brown coal has set lower prices since 2022 despite more capacity offered above $0 per MWh

Victoria has significant brown coal capacity, which did not face the same supply issues that impacted black coal in Queensland and NSW. Brown coal is low quality and not suitable for export, which means it is not exposed to international prices and did not face the same cost pressures in 2022. This also means that brown coal costs have not declined in 2023–24.

Brown coal offers most of its capacity below $50 per MWh, with about 3 quarters of this being priced below $0 per MWh in 2023–24 (Figure 5.14). There has been an increase in capacity priced between $0 and $50 per MWh in recent years, driven by gradual changes in offers by AGL's Loy Yang A and Alinta's Loy Yang B power stations. A small amount of capacity was offered above $50 per MWh at these power stations.

Figure 5.14 Victoria offers, by fuel type



Note: Financial year average offered capacity by Victorian generators within price bands.
Source: AER analysis using NEM data.

In 2022, we reported on higher offer prices and higher prices set by Victorian brown coal generators. We said this could suggest a lack of competitive pressure on these stations. Since then, despite continuing to offer some capacity above $50 per MWh, brown coal has tended to set lower average prices again. The monthly average price set by these stations has typically been below $20 per MWh over the past 2 years. This likely indicates the offers are not significantly impacting market efficiency.

In contrast to brown coal generators, Victorian gas and hydro generators faced similar issues to other regions in 2022 and shifted capacity to higher prices. This capacity has largely remained at higher prices in 2023–24 despite gas prices declining and prices being generally lower.

Wind has been the largest source of new entry in Victoria over the past 5 years, more than doubling the capacity it offered from 2019–20 to 2022–23. However, in 2023–24 wind offers declined slightly amid a slowdown in new entry combined with less windy conditions. At the same time solar and battery offers continued to increase. More battery capacity was offered in Victoria in 2023–24 than any other region, albeit batteries capacity made up a larger relative share of the smaller South Australian market.

5.4.1 Case study – battery storage units are changing market dynamics

By the end of June 2024, 24 battery storage units had entered the market representing 2,130 MW of capacity. In absolute terms, Victoria has the highest penetration of battery storage (651 MW). These units alternate between soaking up generation as a load and discharging into the market as a generator. At first, battery storage units predominantly operated in FCAS markets. Because market penetration has increased, they have increasingly begun to operate in the energy market.[45]

Battery storage units make a profit from arbitrage. The wider spread between the price they pay to charge and what they receive to dispatch generation, the more revenue they earn. As more batteries enter the market, we expect them to put downward pressure on peak prices and upward pressure on minimum prices, helping reduce market volatility. In this way they complement intermittent renewables and have the potential to improve market efficiency. To date though, we have observed batteries setting higher prices than other fuel types.

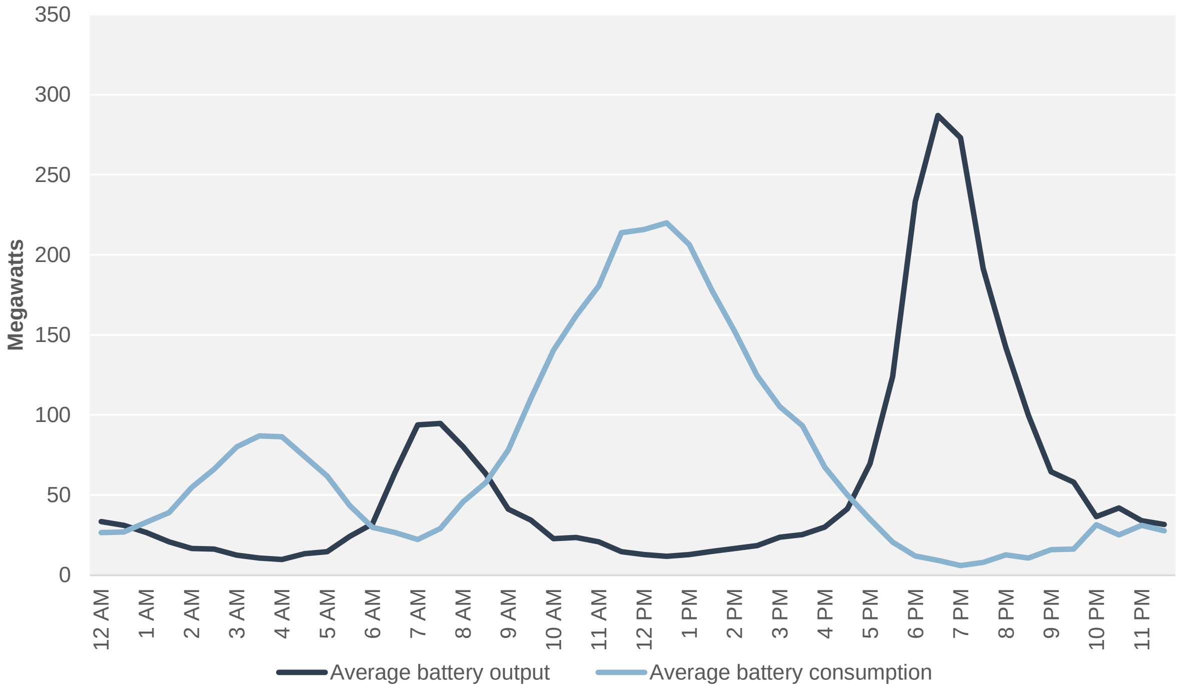
Vertically integrated generators may incorporate batteries into their portfolio to help balance their generation against their retail load requirements. Batteries' fast response time make them ideal for helping to manage price volatility and sharp increases in peak prices. Vertically integrated participants may also use batteries to help reduce spot price risk and associated hedging costs.

Batteries tend to offer energy into the market at relatively high prices – typically above $500 per MWh, while offering to charge at much lower prices. Given NEM prices are usually highest in the evening and lowest in the middle of the day, battery charge and discharge patterns follow this same time of day pattern (Figure 5.15).

---

45 AEMO, Quarterly Energy Dynamics Q3 2024, Australian Energy Market Operator, 30 October 2024 page 40.

Figure 5.15 Time of day profile of NEM battery load consumption and output, 2023–24



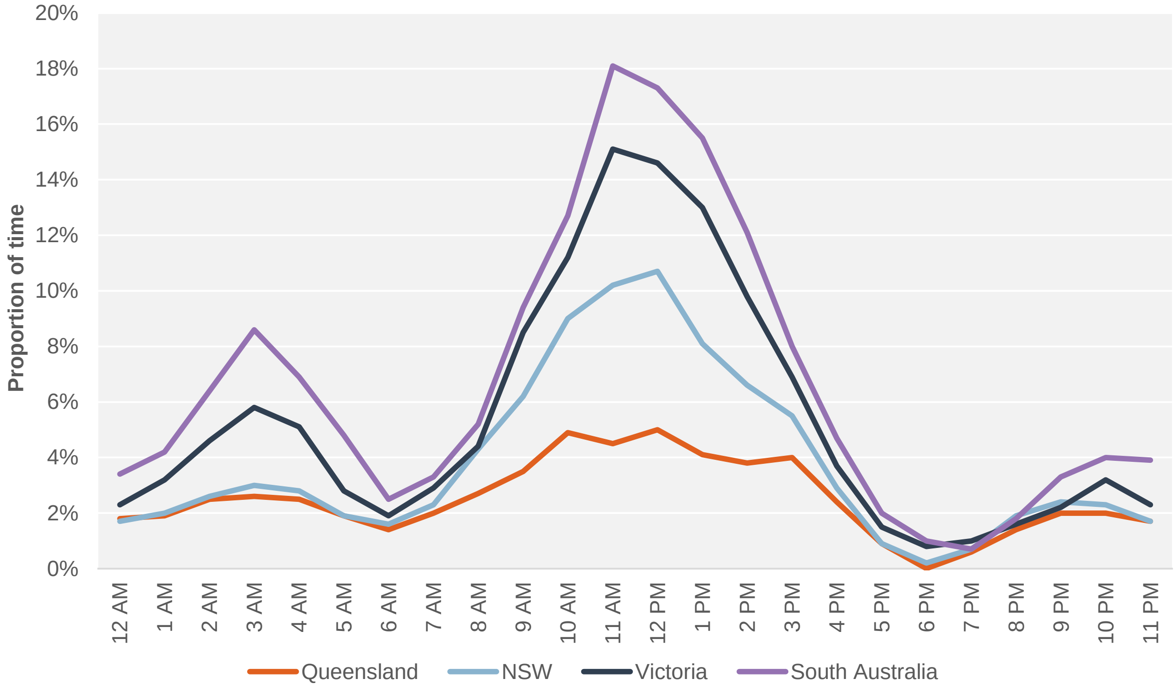
Note: Average generation output and consumption by time of day by scheduled NEM battery storage units in 2023–24. The chart is presented at 30-minute level granularity and uses NEM time.

Source: AER analysis using NEM data.

Typically, the AER's price setter analysis has focused on generators, but loads can set price too. For example, loads can set price when it is more cost effective to reduce load consumption by 1 MW than to increase generation by a MW. Reducing load consumption can lead to reduced generation requirements, which can mean that more expensive generation is not required to meet demand.

Loads, including pumped hydro storage units and scheduled industrial loads, have always set price in the market at times. The increased penetration of battery storage systems now means that loads set price much more frequently, particularly in South Australia and Victoria (Figure 5.16).

Figure 5.16 Percentage of intervals where load sets price, by time of day in 2023–24

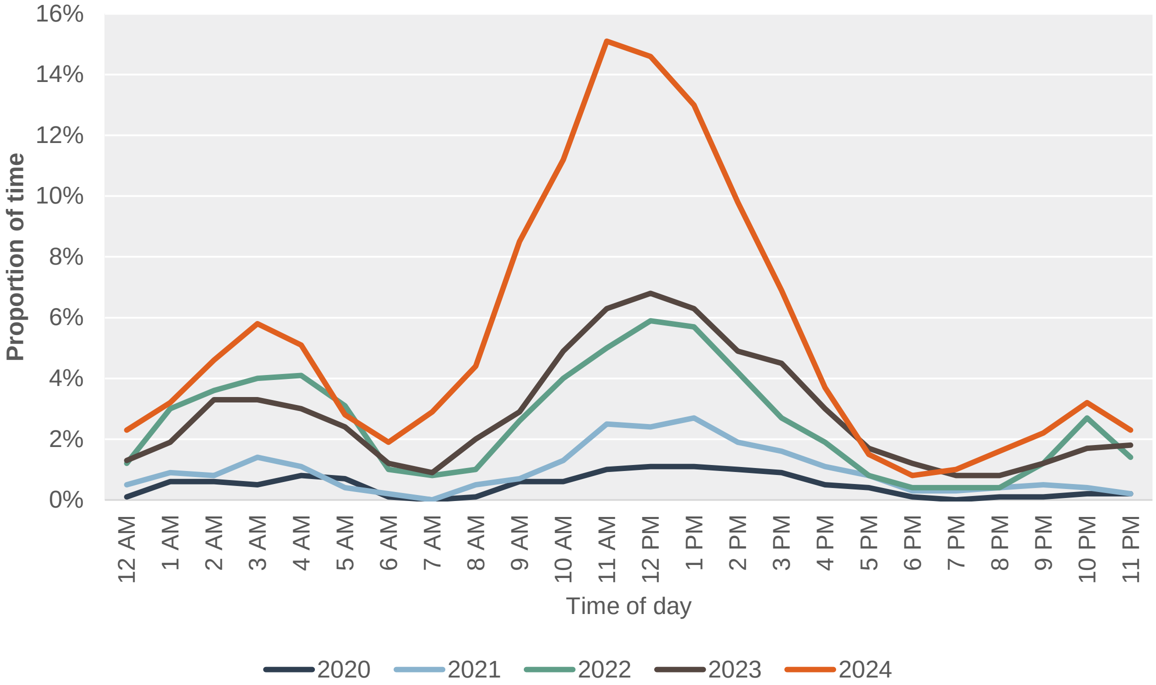


Note: Occurrences of a scheduled load setting price as a percentage of all dispatch intervals, by time of day in 2023–24. The chart is presented at hourly granularity and uses NEM time.

Source: AER analysis using NEM data.

In Victoria, loads set price 15% of the time in the middle of the day in 2023–24, up from 7% in 2022–23 (Figure 5.17). Other regions have shown a similar trend, though loads still set price less frequently in Queensland and NSW. When setting price as a load, batteries set lower prices on average to what they set as a generator. However, battery loads do usually set prices above $0 per MWh and occasionally above $1,000 per MWh.

Figure 5.17 Percentage of intervals when load sets price in Victoria, by time of day



Note: Occurrences of a scheduled load setting price in Victoria as a percentage of all dispatch intervals, by time of day in 2023–24. The chart is presented at hourly granularity and uses NEM time.

Source: AER analysis using NEM data.

Batteries can respond quickly to changing conditions and will often make hundreds of rebids in a day, relying on auto-bidding software. This may involve rebidding to higher prices when price forecasts change. In some cases, we have identified battery units contributing to high price events through rebidding from low to high prices. For example, on 1 March 2023, AGL's Wandoan BESS in Queensland submitted a late rebid shifting 65 MW from $279 per MWh to $14,999 per MWh, contributing to a high 5-minute price.

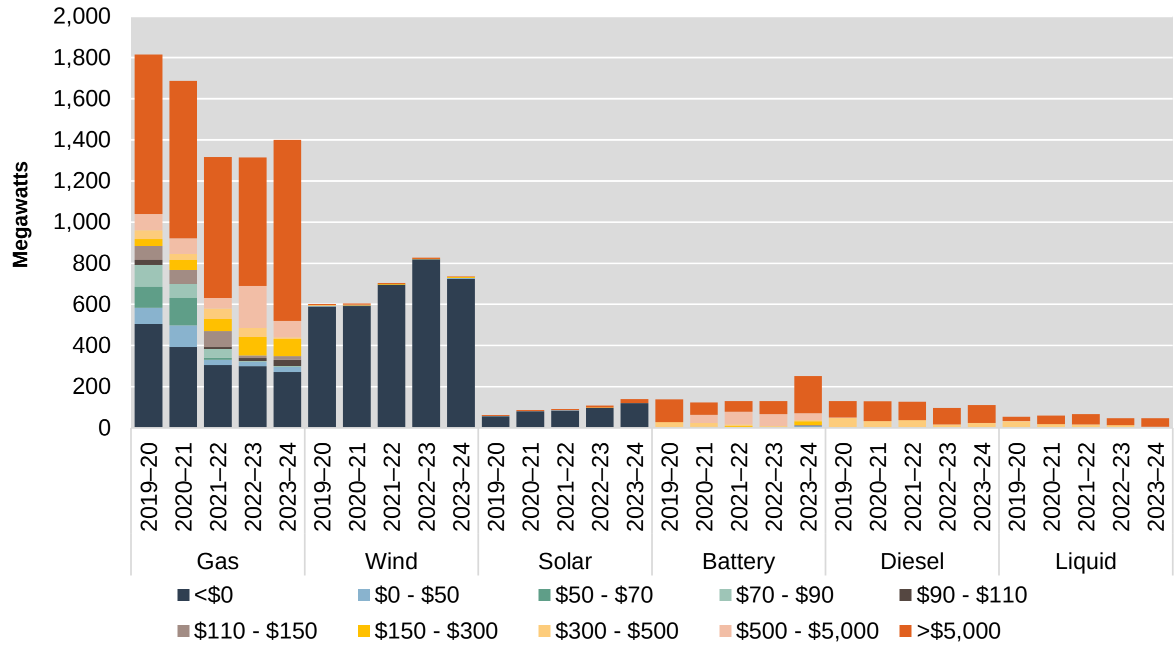
It can be difficult to distinguish between battery rebids that reflect changing costs and those that reflect a lack of competitive constraint or exercise of market power to put upward pressure on prices. Since batteries are energy limited, the cost of generation is the opportunity cost of discharging later. If a battery discharges too early and prices subsequently rise, this not only reduces the unit's revenue but also the allocative efficiency of the market. In this respect, auto-rebidding to reflect changing conditions can improve the market's efficiency. On the other hand, rebids close to dispatch can reduce the efficiency of the market if they do not give other generators sufficient time to respond.

In determining the efficiency of the market, we are interested in whether prices in the long run reflect costs, rather than periods of transient market power. We will continue to monitor the behaviour of batteries to assess whether they act competitively over the longer term.

5.5 Less South Australian gas capacity is offered at low prices

Unlike other mainland regions, South Australia has no coal-fired generation. Its predominant dispatchable fuel source is gas. It also has high levels of renewable penetration. In 2020–21 and 2021–22, gas offers declined due to AGL closing its Torrens Island A power station. Since then, total gas offers have remained steady, but the proportion of capacity offered at low prices has declined (Figure 5.18). Higher gas prices have played a role in this by driving up the cost of generation.

Figure 5.18 South Australia offers, by fuel type



Note: Financial year average offered capacity by South Australian generators within price bands.
Source: AER analysis using NEM data.

The economics of gas-powered generation in South Australia are complicated by high renewable penetration in the region and declining minimum system demand. This can make it uneconomic for gas generators to operate, and AEMO intervenes by directing power stations in the region to generate to protect the security of the power system. These dynamics are explored in more detail in chapter 7.

Like in other regions, wind generators in South Australia offered less capacity in 2023–24 than the preceding year. Nevertheless, wind remained the primary source of low-priced capacity in the region.

Solar and battery offers continued to increase in 2023–24, reflecting new entry into the market. Solar generators, which typically offer most of their capacity at the price floor, offered a larger share of their capacity at the price cap, reflecting it was sometimes not economic for them to dispatch into the market.

5.5.1 Case study – South Australian solar generators offering capacity at the price cap

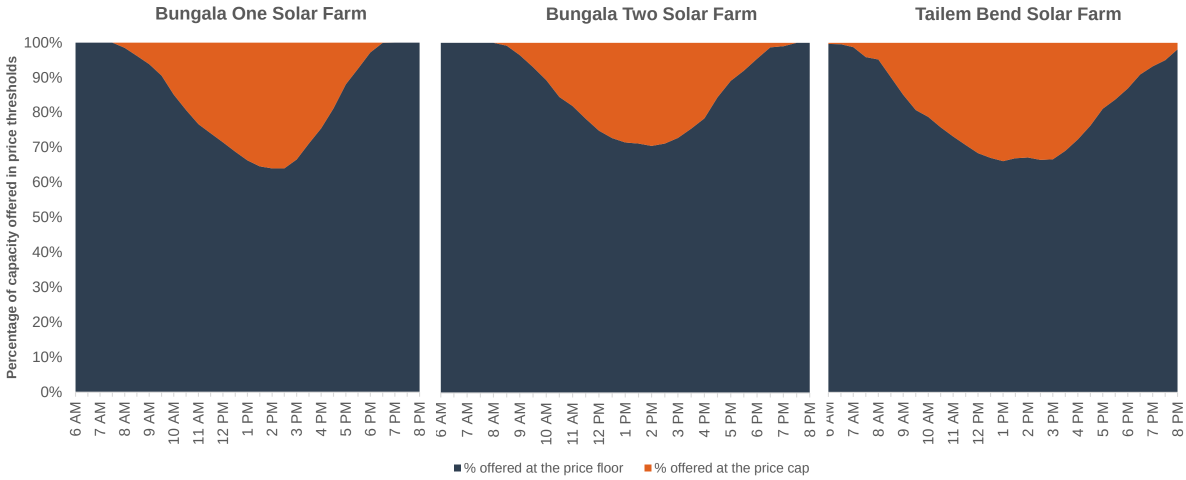
In South Australia, solar offers at the price cap reflect the phenomenon of intermittent renewable generators bidding themselves out of the market to avoid uneconomic dispatch. Renewable generators, like any generator, want to avoid losing money.

Typically, generators wish to dispatch into the market when the marginal revenue from doing so exceeds the marginal cost. Since the marginal cost of producing solar and wind power is essentially $0 per MWh, one would expect these units to generate when prices are higher than this. However, a variety of factors impact revenue for these generators. Renewable generators obtain revenue from Large-scale Generation Certificates, which can make it economic to offer capacity below $0 per MWh. In addition, generators selling their output via power purchase agreements may be incentivised to dispatch at even lower prices, depending on the terms of the agreement. On the other hand, stations may incur costs via the FCAS causer pays framework if their output leads to higher FCAS requirements.[46]

In South Australia, the intermittent renewables offering the most capacity at high prices are Bungala One, Bungala Two and Tailem Bend Solar Farms. The Bungala Solar Farms have power purchase agreements with Origin Energy while Tailem Bend has a power purchase agreement with Snowy Hydro.

Across 2023–24, each of these 3 solar generators were offering capacity at the price cap about a third of the time in the middle of the day (Figure 5.19). Typically, on a low-priced day, these solar generators would move capacity from the floor to the cap partway through the morning. This capacity would then remain at the cap until sometime in the afternoon. This occurred most frequently in spring and summer.

Figure 5.19 Percentage of capacity offered at the floor vs at the cap by time of day in 2023–24



Note: Percentage of capacity offered at the price floor and at the price cap by Bungala One, Bungala Two and Tailem Bend Solar Farms, by time of day in 2023–24. The chart is presented at a 30-minute granularity and uses NEM time, showing the percentage offered from 6 am to 8 pm only (very little capacity is offered outside of these times).

Source: AER analysis using NEM data.

For example, on 24 October 2023, Bungala One and Two Solar Farms rebid capacity at 7:26 am and 8:10 am respectively from the price floor to the price cap referencing 'CHANGE IN FINANCIAL POSITION – SL'. Both rebids were applied until late that afternoon. Similarly, Tailem Bend Solar Farm rebid all its capacity from the price floor to the price cap at 7:37 am

46 For more information on the FCAS causer pays framework see AEMO, Ancillary services contribution factors, Australian Energy Market Operator.

referencing ‘Negative predispatch prices’. On the day in question, prices were almost exclusively negative, and often below −$50 per MWh, until 7:00 pm.

These solar generators mostly offered capacity at high prices when the market price was very low. But on occasion, this capacity remained at high prices when the market price was above $0 per MWh. For the Bungala Solar Farms, this represented about 0.3% of dispatch intervals in 2023–24 rising to about 0.5% of intervals in Q3 2024. They did not set price at these times except for 2 dispatch intervals on 22 October 2024, when Bungala 1 Solar Farm set price at the market price cap of $17,500 per MWh. The solar generator did not rebid to lower prices in response to the high price event. Tailem Bend Solar Farm also set price for one of these 2 dispatch intervals, due to rebidding from low to high prices to avoid incurring high FCAS costs. We consider that during such instances, electricity demand was not provided by the lowest cost of supply, resulting in allocative inefficiency in the market.

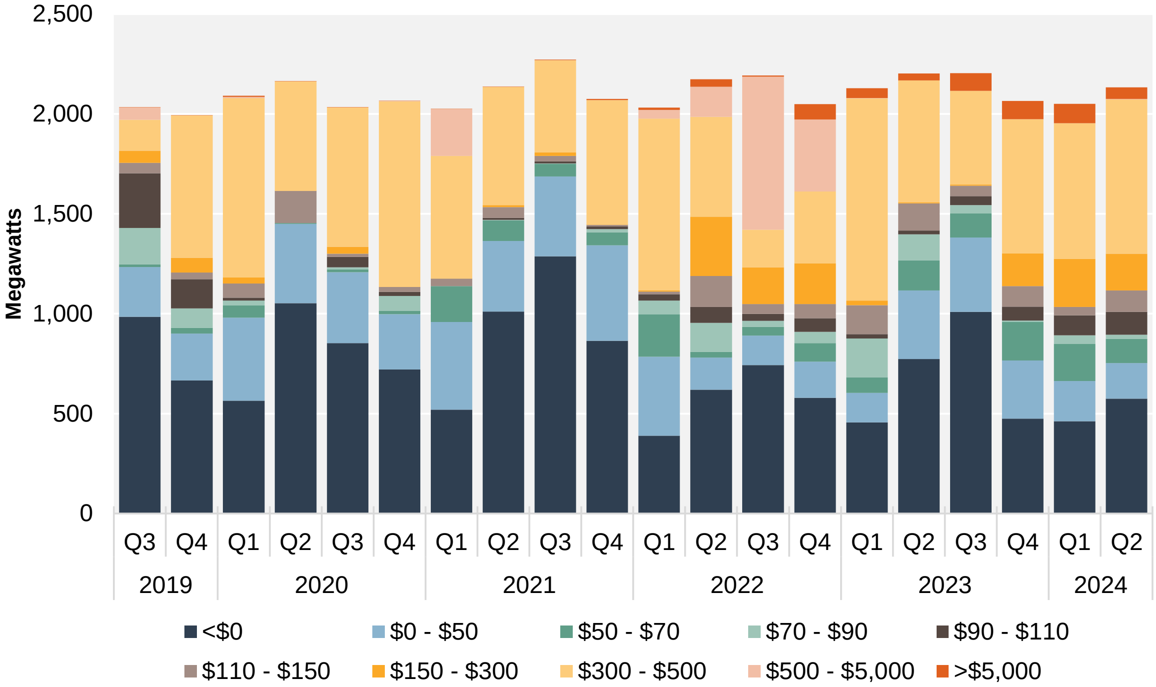
5.6 Higher Tasmanian offer prices in Q2 2024 likely driven by reduced water availability

In contrast to the other regions, most generation in Tasmania is controlled by one participant (Hydro Tasmania). Hydro Tasmania’s behaviour determines offers in the region. The prices at which Hydro Tasmania may offer wholesale contracts are regulated, which may limit its incentive to exercise market power (Box 4.2).

The majority of Hydro Tasmania’s portfolio consists of hydro generation. This is supplemented by wind and gas-fired generation, which comprise about one-quarter of Hydro Tasmania’s capacity.

Tasmanian offers typically follow a cyclical pattern based on the season, experiencing peak demand over winter because milder summers mean there is less need for cooling (Figure 5.20). The greatest volume of low-priced capacity tends to be offered over the colder winter months and the least low-priced capacity offered in the warmer months.

Figure 5.20 Tasmanian average quarterly offers, by price band



Note: Financial year average offered capacity by Tasmanian generators within price bands.
Source: AER analysis using NEM data.

This pattern changed slightly in Q2 2024, with only about the same amount of low-priced capacity being offered as in Q4 2023 and Q1 2024. This likely reflects low rainfall (the lowest inflows in 90 years) and Hydro Tasmania's subsequent management of water storage levels,[47] rather than a strategy to push up prices. Hydro Tasmania ran its gas-fired assets much harder in the winter of 2024, recalling the mothballed unit of its Tamar Valley gas power station which it operated from 6 June to 23 August. This unit had not been used since 2019 and its recall further suggests that Hydro Tasmania faced supply constraints over the winter, which likely explain its repricing of capacity.

---

47 Hydro Tasmania, Tasmanians to benefit from $122m Hydro dividend, 17 October 2024, accessed 6 November 2024.

6 Entry and exit

Key findings

- The National Electricity Market (NEM) requires significant new investment over the next decade as part of a successful transition to net zero emissions. In the last 2 financial years, 4.5 GW of new large-scale generation entered the market. This is 22% lower compared with the previous 2 financial years.
- Direct and indirect government support continues to be a key driver of new generation investment. Given the scale of government programs this appears likely to be the case for the near future.
- We have analysed price signals to understand the prospects for entry of different technologies. In circumstances where governments are supporting a large proportion of new entry, where the price signal is already consistent with new entry it suggests the cost of government support may be low. For generation with a weak price signal proponents may not bid them into government schemes and/or governments may not choose to fund them. In the event they are funded, the gap is indicative of the cost to deliver governments' policy objectives.
- New wind and solar generation appears commercially viable but may face declining wholesale market revenue due to saturation. This problem is most notable with large-scale solar. In most regions there is a positive commercial case for investment in grid-scale batteries, while investment in new commercial gas has been improving but remains challenging.
- The remaining Liddell units exited in 2023. The NSW Government intervened to extend the operation of Eraring by 2 years, due to reliability concerns. There is nearly 1 GW of gas scheduled to exit South Australia in the next 2 years.
- The exit of thermal generators and increased dispatch of inverter-based technologies,[48] which to date don't have the grid-forming properties of synchronous machines, has required the electricity market rules to quickly evolve to ensure system security services are still provided. However, the pace of change comes with the risks of creating inefficiencies and new opportunities for the exercise of market power.
- The rising costs of network congestion highlight inefficiencies arising from current transmission access arrangements for generators. Recent policy changes will help address some of the problems relating to the location of new generation but will have limited impact on improving operational efficiency. Increased transmission capacity will also help, but there remain elements of market design which lead to inefficient use of this capacity by generators.

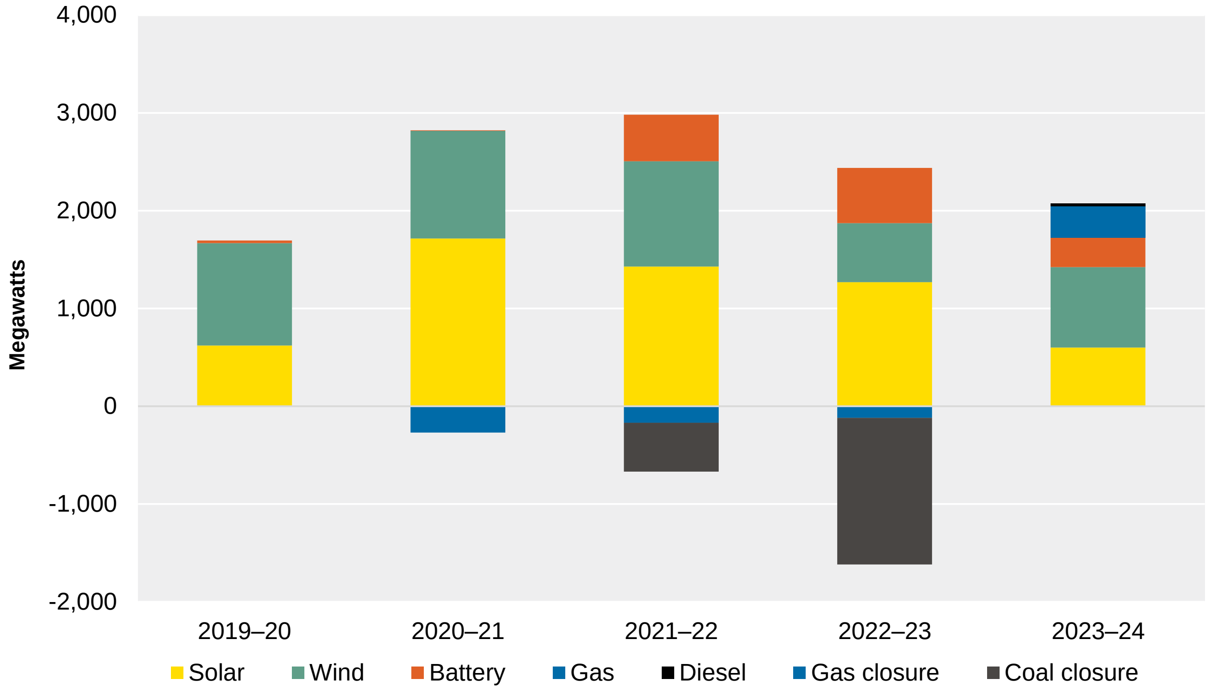
[48] The term inverter-based technologies is generally considered to cover wind and solar generation technologies, battery energy storage systems and direct current network links.

6.1 Prospects for new investment

6.1.1 New entry has primarily been in large-scale wind and solar

Since our 2022 report, new entry has been predominately intermittent renewables and batteries. Across 2022–23 and 2023–24, around 1,871 MW of solar capacity, 1,424 MW of wind and 867 MW of battery capacity entered the market. In addition, the 320 MW Tallawarra B gas power station came online Q1 2024.

Figure 6.1 Entry and exit of capacity in the NEM



Note: Capacity includes scheduled and semi-scheduled generation but does not include rooftop solar capacity. Figure uses registered capacity for every fuel type except for solar, which is based on maximum capacity, to reflect its different technical constraints. Generators are marked as having entered from their first dispatch date and this chart does not reflect stages of commissioning.

Source: AER analysis using NEM data.

New entry for the financial years 2022–23 and 2023–24 was 22% lower compared with 2020–21 and 2021–22 (5.8 GW to 4.5 GW). Delays in committed projects coming online contributed to the decrease. Between 2021–22 and 2023–24, committed projects had an average difference of approximately 8 months between the advised and actual date of commissioning completion.[49] Accounting for capacity exit (see section 6.2.1), there has been a net gain of 2.9 GW capacity over the 2022–23 and 2023–24 financial years compared with 4.9 GW over 2020–21 and 2021–22; a decrease of 40%. In Q3 2024 approximately 1,445 MW of capacity was added through wind (729 MW), batteries (600 MW) and solar (116 MW); however, it will take some time before these units reach full output.

[49] AEMO, 2024 Electricity Statement of Opportunities, Australian Energy Market Operator, August 2024.

The pipeline of upcoming new entry is mostly renewables and storage

The Australian Energy Market Operator's (AEMO's) 2024 Integrated System Plan (ISP) *Step Change* scenario estimates the NEM must almost triple its capacity to supply energy by 2050 to replace retiring coal capacity and to meet increased electricity consumption as other sectors decarbonise through electrification.[50] Based on this scenario the NEM will need 56 GW/660 GWh of storage capacity in 2049–50 and 12.8 GW of new gas generation. Timely delivery is critical to avoid a tighter market through the transition, limiting opportunities for generators to exercise market power.

Based on AEMO's classification,[51] at present an additional 20.2 GW of scheduled or semi-scheduled generation and storage developments are forecast to be operational by the end of 2033–34[52]. These developments include:

- Hunter Power Station (750 MW) in NSW from December 2024
- Kidston Pumped Hydro Energy Storage (250 MW/2,000 MWh) in Queensland from February 2025
- Snowy 2.0 (2,200 MW/350,000 MWh) in NSW by December 2028
- Borumba Pumped Hydro (1,998 MW/48,000 MWh) in Queensland from September 2031
- a 204 MW hydrogen generator as part of the South Australian Hydrogen Jobs Plan from December 2025
- more than 8,500 MW/22,500 MWh of utility-scale batteries, including Eraring Big Battery, Liddell Battery Energy Storage System (BESS), Orana BESS, Richmond Valley BESS, Swanbank BESS and Wooreen BESS
- numerous renewable energy developments across the NEM, including more than 4,000 MW of wind generation and 4,500 MW of utility-scale solar generation.

More projects are likely to be commissioned within the next 5 years, especially in generation types with relatively short construction lead-times.

Offshore wind in Australia

Offshore wind generators have the potential to generate more energy than their onshore counterparts with fewer installations, as the turbines can be larger and benefit from stronger, more consistent winds.[53] They currently have higher costs than onshore wind. In the future, their higher capacity factor and access to different wind patterns may be advantageous.

There are 5 offshore wind sites in NEM regions, all in the early stages of development. The most advanced is Gippsland, where feasibility licenses have been granted. This area has the potential capacity of 25 GW. The Hunter Region off NSW (5.2 GW) and the Southern Ocean

50 AEMO, 2024 Integrated System Plan, Australian Energy Market Operator, 26 June 2024.

51 For more information about AEMO's classification and forecasting of generation projects, see AEMO, Generation information, Australian Energy Market Operator, accessed 14 November 2024..

52 AEMO, 2024 Electricity Statement of Opportunities, Australian Energy Market Operator, August 2024, accessed 14 November 2024.

53 DCCEEW, Building an offshore wind industry, Department of Climate Change, Energy, the Environment and Water, accessed 14 November 2024.

off Victoria (2.9 GW) are in the process of finalising feasibility licenses. Two additional zones have been proposed: Illawarra in NSW (2.9 GW) and Bass Strait in Northern Tasmania (28 GW).[54] Victoria has set ambitious offshore wind targets of 2 GW by 2032, 4 GW by 2035 and 9 GW by 2040.[55]

6.1.2 Direct and indirect government support is key driver of new investment

Governments have been supporting investment in new generation. This will increase over the coming years, as they have significantly expanded the scale of their direct and indirect support. This has been driven by a combination of the need to meet emissions targets as part of Australia's net zero commitment and the need to replace a rapidly aging coal fleet. Under the *Step Change* scenario of the ISP, 6 GW of new renewable generation is needed each year until 2030. The investment task is both vast and urgent.

Under the current market design, revenue streams are generally based on spot and contract market prices. With exchange-traded contracts only generally traded 3 years out, price signals are relatively short-term compared with the life of a generation asset and are insufficient to underwrite long-term investments.[56] Investors can secure revenues through contracts with longer terms such as power purchase agreements, but these are more bespoke and can be challenging to access. It is also difficult to provide revenue confidence in an environment of market volatility and technological change. If there is an expectation of a significant fall in technology costs, investment may be deferred to avoid being stranded by lower cost future generation.[57]

Governments have adopted different approaches to support new generation. Recently, schemes have used underwriting to de-risk projects. Governments share the risk with the project proponent through a price or revenue guarantee. The cost of the scheme is either met by taxpayers or recovered from electricity consumers. The Queensland Government has remained committed to direct government investment, with Victoria shifting towards increased public ownership. Profits from fully or partially owned generators are a source of revenue for governments. Since the 2022 WEMPR, new schemes include:

- the Australian Government's Capacity Investment Scheme to support investment in 23 GW of renewable capacity and 9 GW of clean dispatchable capacity[58]

---

54 DCCEEW, Australia's offshore wind areas, Department of Climate Change, Energy, the Environment and Water, accessed 14 November 2024.

55 Victorian Government, Offshore Wind Energy, accessed 14 November 2024.

56 ESB, Post 2025 Market Design – Capacity mechanism – High-level design consultation paper, Energy Security Board, 20 June 2022, p 13.

57 AER, Wholesale Electricity Market Performance Report 2022, Australian Energy Regulator, 15 December 2022, page 105.

58 There is currently 21.2 GW of large-scale intermittent renewables and 2.1 GW of batteries in the NEM. DCCEEW, Capacity Investment Scheme, Department of Climate Change, Energy, the Environment and Water, accessed 14 November 2024.

- the Victorian Government re-establishing the State Electricity Commission with $1 billion of funding and a mandate to add 4.5 GW of new renewable energy generation and storage[59]
- the Queensland Government providing direct investment for 1,455 MW of wind and 900 MW of batteries.[60]

This builds on the existing schemes including:

- the Victorian Renewable Energy Target, which across 2 auctions has committed to 1,430 MW of renewables and 365 MW of storage[61]
- the NSW Energy Infrastructure Roadmap, which across 4 auctions to date has committed to 2,452 MW of renewables and 1,649 MW of storage[62]
- funding from the Clean Energy Finance Corporation (CEFC) and the Australian Renewable Energy Agency (ARENA)[63]
- the Australian Government Large-scale Renewable Energy Target (LRET).[64]

6.1.3 Price signals

We analyse price signals for different technologies to understand the prospects for new entry. In circumstances where governments are supporting a large proportion of new entry, if the price signal is already consistent with new entry it suggests the cost of government support may be low. For generation with a weak price signal proponents may not bid them into government schemes and/or governments may not choose to fund them. In the event they are funded the gap gives an indication of the cost of delivering on governments' policy objectives.

For this report, we have compared the levelised cost of electricity (LCOE) for new generation to the spot revenue that type of plant has earned over the last 5 years. For each region we have calculated volume weighted average prices (VWAP), by fuel type. If that price exceeds the costs, it indicates there is an incentive for new entry. Consistent with the 2020 and 2022 WEMPR, we chose LCOE for its simplicity, which makes it accessible, transparent and comparable. For WEMPR 2024, we used the LCOE analysis conducted by CSIRO as part of the 2023–24 GenCost report.[65]

---

59 Victorian Government, The SEC is back for good, media release, 15 October 2024.

60 The State of Queensland (Queensland Treasury), 2023–24 Queensland Budget, Capital Statement (Budget Paper 3), 11 June 2024.

61 See Victorian Government, Victorian Renewable Energy Target auction (VRET1), and Victorian Renewable Energy Target auction (VRET2), accessed 14 November 2024.

62 AEMO Services, Market Briefing Note, June 2024.

63 ARENA provides grant funding and the CEFC provides concessional finance to support investment in renewable and storage generation.

64 The LRET is part of the Renewable Energy Target. The LRET provides a financial incentive to generate electricity from renewable sources by establishing a market for creating and selling large-scale generation certificates (LGC).

65 CSIRO, GenCost: cost of building Australia's future electricity needs, Commonwealth Scientific and Industrial Research Organisation, 22 May 2024.

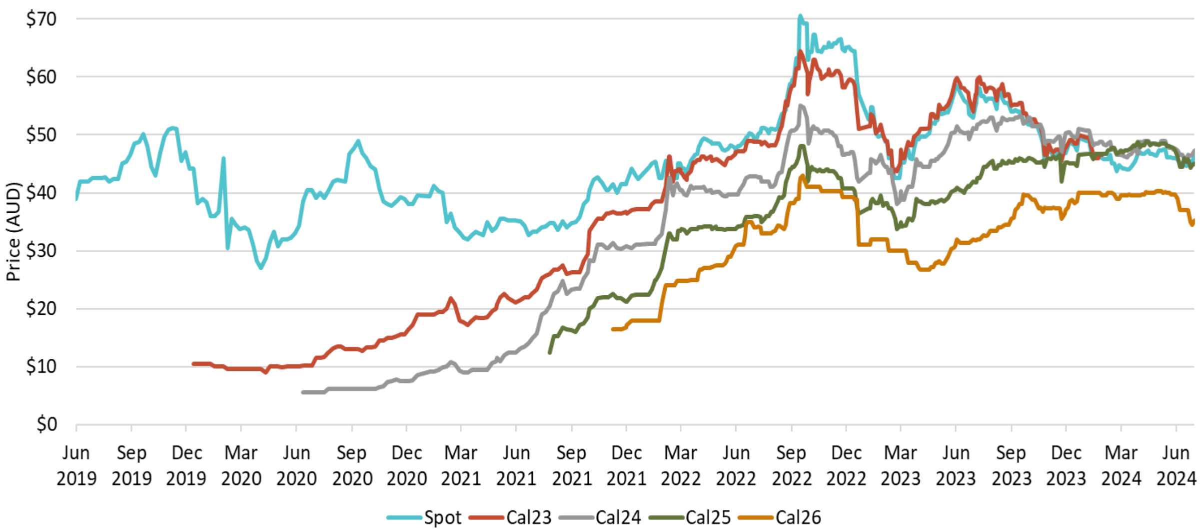
For storage, we have compared the levelised cost of storage (LCOS) and volume-weighted average discharging prices. LCOS measures the average cost per unit of energy stored over the lifetime of an energy storage system. We have used CSIRO's LCOS analysis conducted as part of the 2023 Energy Storage Roadmap.

This analysis is only intended to be a proxy. Real-world investment decisions will be based on a range of factors including future expected revenue, contract arrangements, other market- and non-market sources of revenue, as well as overall market conditions and confidence.

New entry of solar and wind is viable with LGCs, but faces headwinds

Our analysis indicates that in most regions, the wholesale market revenue for utility scale solar and wind projects would not have covered costs over the last 5 years (Figure 6.3). However, projects would have been viable when revenue from Large-scale Generation Certificates (LGCs) is taken into account. In recent years LGCs have been trading around $40 (Figure 6.2).

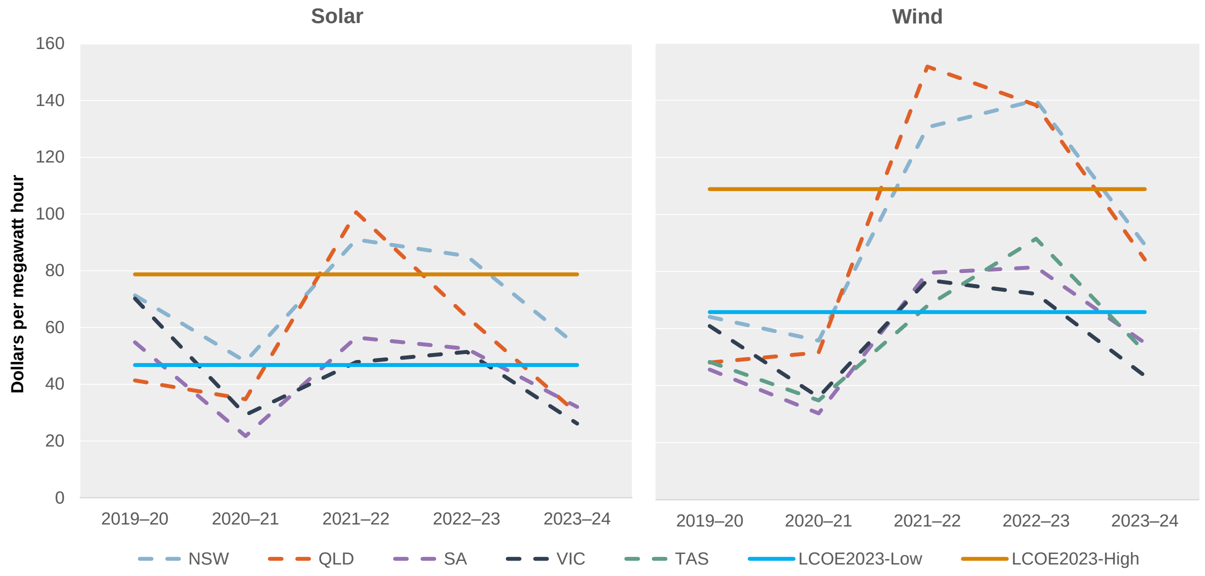
Figure 6.2 Large-scale generation certification (LGC) reported spot and forward prices



Source: Clean Energy Regulator

While solar costs less than wind to build, it earns less wholesale market revenue compared with wind generation. Supply tends to be at its highest and demand at it its lowest when solar is operating, resulting in lower prices when it is generating compared with the regional VWAP. Wind prices are less affected as it operates throughout the day.

Figure 6.3 Likelihood for new entrant cost recovery for 2020–24, solar and wind technology



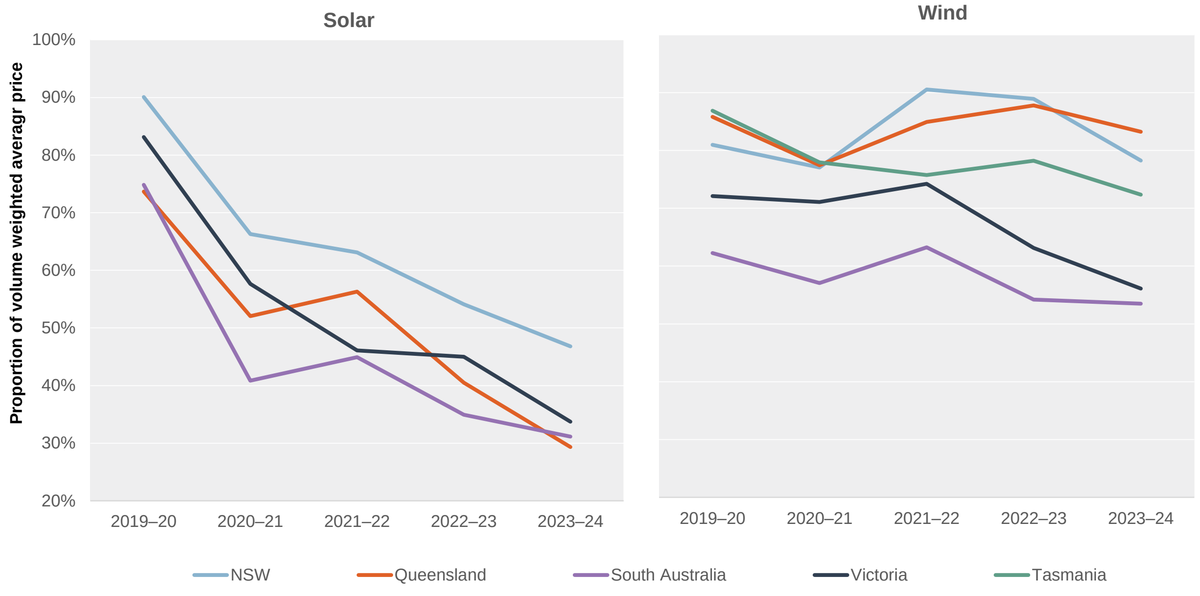
Note: Volume weighted average fuel price, by region, the last 5 financial years. Compared to CSIRO 2023–24 GenCost report LCOE estimates.
Source: AER analysis using NEM and CSIRO data.

Our analysis of the 5-year trend indicates that increased saturation of renewables will affect future business cases, as increased renewable capacity further suppresses the wholesale market revenue renewables can receive (Figure 6.4). Compared to wind generation, grid-scale solar has been more affected to date, as it is competing against rooftop solar and doesn't generate at peak times.

Wind generation will increasingly face the same issues as new capacity enters the market. This can already be seen in regions with larger amounts of wind generation, such as South Australia and Victoria. The loss of LGC revenue in 2030 when the Renewable Energy Target ends may further impact the business case for future renewables projects. Diminishing wholesale market revenue can be offset by increasing demand during periods of excess renewable generation, such as during the day when solar generation is optimal, either through increased storage or demand shifting. Future renewables projects could also be built on complementary renewable resource sites. For example, wind projects in Queensland, which have different with wind patterns compared with South Australia and Victoria.[66]

[66] WattClarity, Insights: How do weather patterns impact wind REZ correlations?, 6 November 2019.

Figure 6.4 Increasing renewable penetration reduces wholesale market revenue



Note: Volume weighted average fuel price, as a share of volume weighted average fuel price, by region. Last 5 financial years.
Source: AER analysis using NEM data.

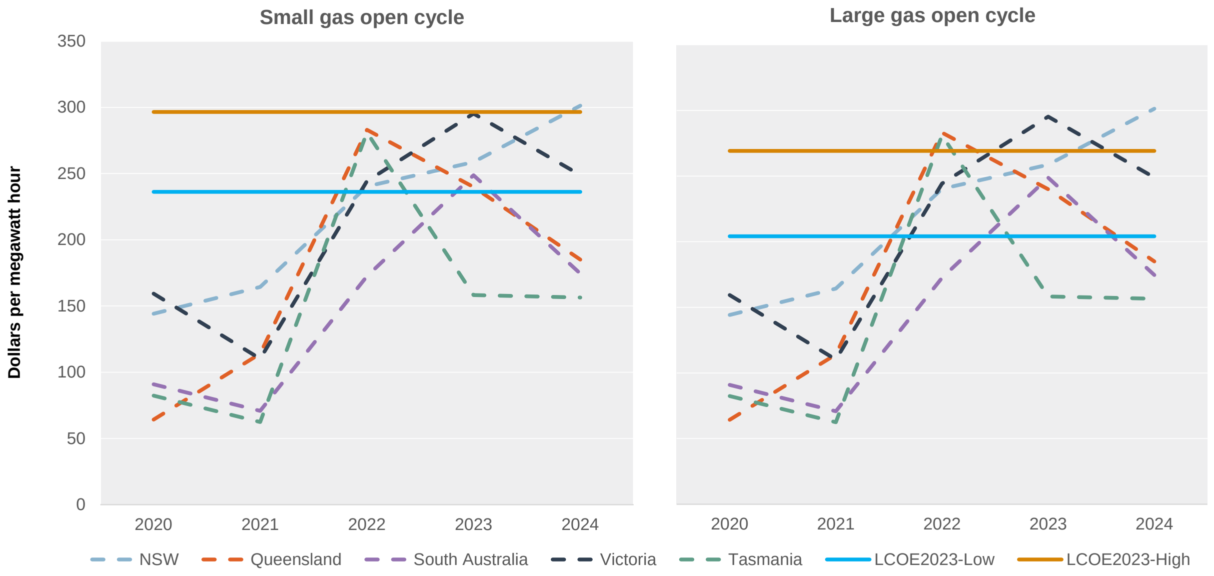
The case for new gas has been improving

Our analysis shows the signal for new entrants in large and small open-cycle gas turbines (OCGT) has been improving, but new projects would still face challenges in consistently covering their costs. This has been driven by higher electricity prices. Recent market volatility could further support investment, as OCGT units typically operate during periods of high prices and derive revenue from selling cap contracts. As part of the transition, there will be an increasing need for fast-start, flexible generation to provide firming services to support the growing share of intermittent renewable generation.

In response to concerns about a potential shortfall of 1,000 MW of dispatchable generation when the Liddell power station closed, the Australian Government supported 2 gas plants in NSW in its 2021–22 Budget:[67] [68] It supported the Kurri Kurri power station directly, providing all the funding and provided a grant to deliver Tallawarra B. Kurri Kurri is currently expected to start operation in Q4 2024, while Tallawarra B started operation in Q1 2024.

[67] Minister Angus Taylor, Protecting families and businesses from higher energy prices, 19 May 2021.
[68] The NSW Government contributed funding to Tallawarra B.

Figure 6.5 Likelihood for new entrant cost recovery for 2020–24, large and small gas open cycle technology

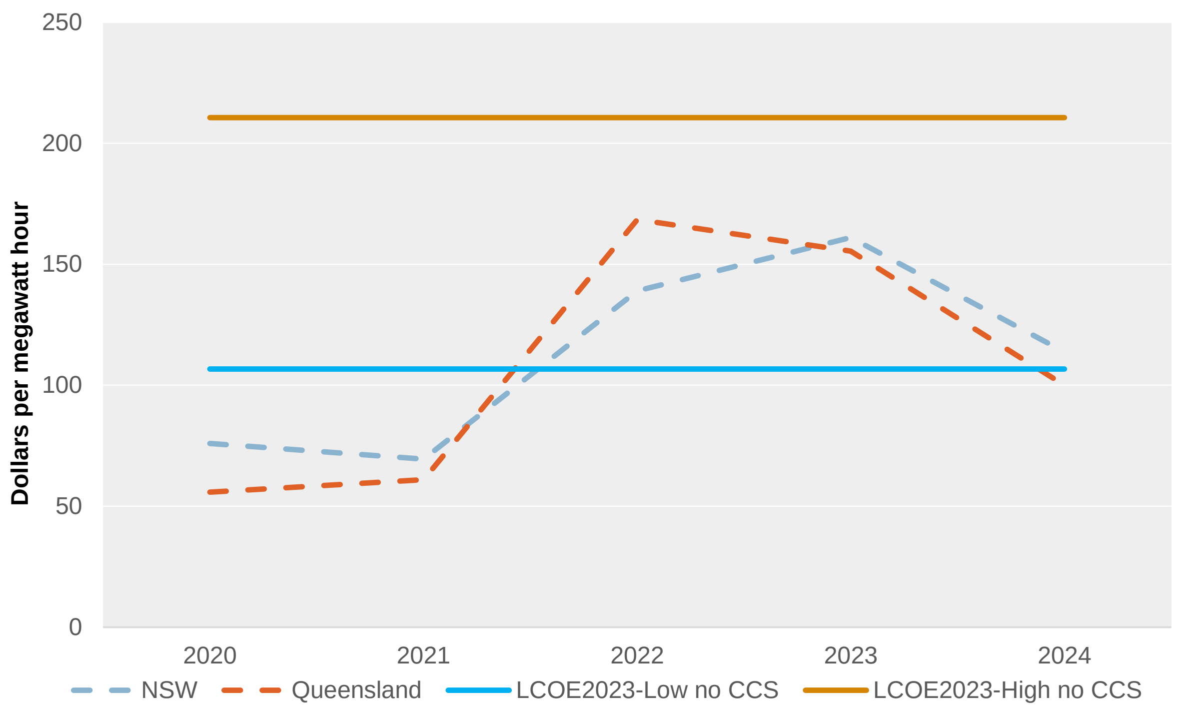


Note: Volume weighted average fuel price, by region, last 5 financial years. Compared to CSIRO 2023–24 GenCost report LCOE estimates.
Source: AER analysis using NEM and CSIRO data.

Coal with carbon capture and storage is unlikely to be viable

Typically, coal-fired generators are large units with high fixed costs that need to be recovered over many years. Coal generation is designed for continuous operation, preferably at a high-capacity factor. Unabated coal would have covered its costs in the last 3 years (Figure 6.6).

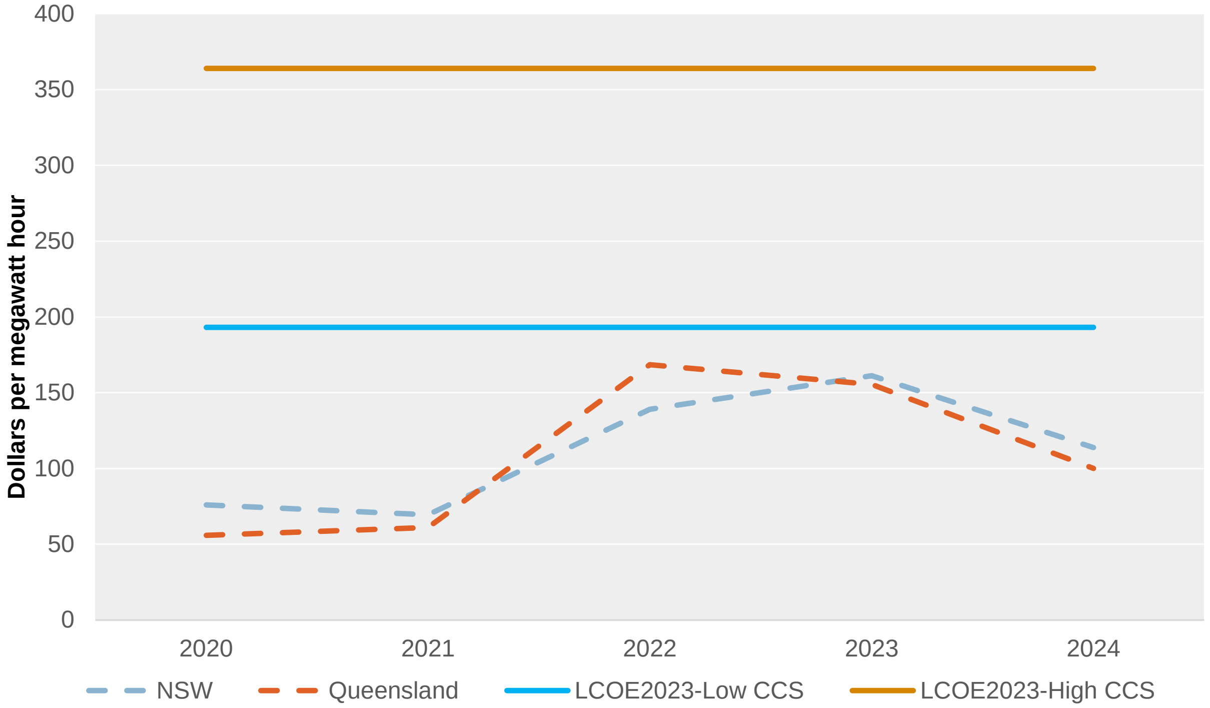
Figure 6.6 Likelihood for new entrant cost recovery for 2020–24, black coal



Note: Volume weighted average fuel price, by region, last 5 financial years. Compared to CSIRO 2023–24 GenCost report LCOE estimates.
Source: AER analysis using NEM and CSIRO data.

To be consistent with Australia's Net Zero Plan, any new coal investment would need to include Carbon Capture and Storage (CCS).[69] Our analysis for black coal with CCS suggests it is unlikely to recover its cost (Figure 6.7). It has lower VWAP than other dispatchable technologies as it is running all the time, not just at the peak. Currently there is no proposed new investment in coal-fired generation.

Figure 6.7 Likelihood for new entrant cost recovery for 2020–24, black coal with CCS technology



Price signals for new entry are positive for short duration batteries

Battery investment was initially driven by frequency control ancillary services (FCAS) revenue. This has shifted over time, with energy market revenue through arbitrage now playing a key role.[70] The ability of storage technologies to recover their costs is influenced by daily price fluctuations, which have intensified in recent years due to increased market volatility. The increasing number of negative price events, caused by renewables, has also helped by lowering charging costs. In most regions, the price signal is consistent with market-driven investment. Battery revenue is a function of peak prices in the region.[71] Recent investment in batteries has been market driven, such as the Hazelwood and Torrens Island

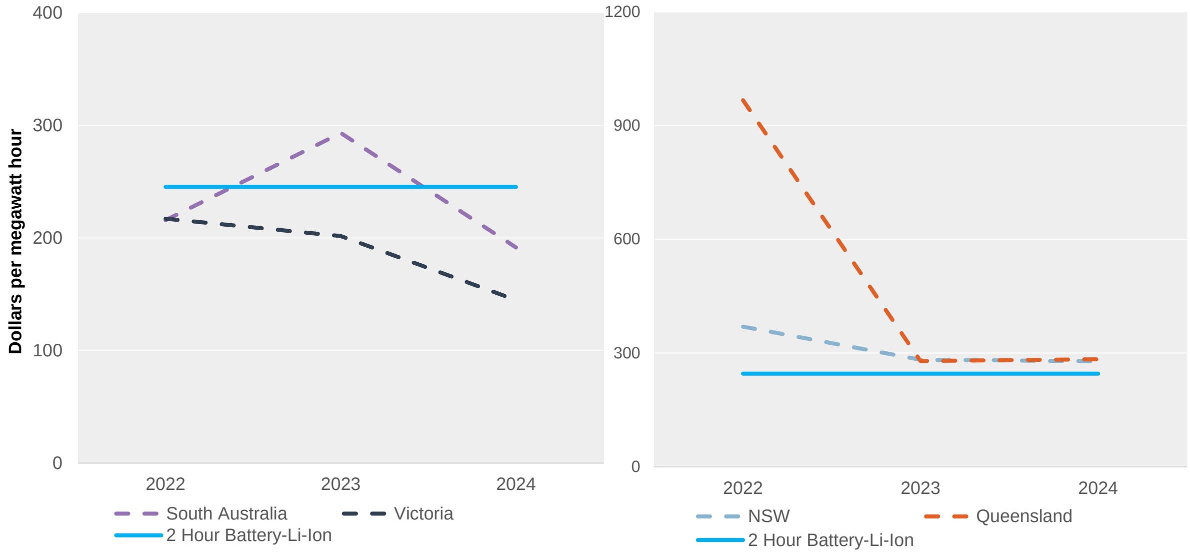
69 DCCEEW, Net Zero, Department of Climate Change, Energy, the Environment and Water, accessed 14 November 2024.

70 AEMO, Quarterly Energy Dynamics Q3 2024, Australian Energy Market Operator, 30 October 2024 page 40.

71 If there is a a small number of generators, like batteries in Queensland and NSW, the method used to estimate generator revenue can produce volatile results.

BESS. A significant amount of future investment will be supported by various government programs.

Figure 6.8 Likelihood for new entrant cost recovery for 2023–24 for 2-hour battery



Note: Volume weighted average fuel price, by region, last 5 financial years. Compared to CSIRO 2023 Energy Storage Roadmap LCOS estimate.
Source: AER analysis using NEM and CSIRO data.

Future of long duration storage in Australia

Deep storage systems can continuously dispatch electricity for over 12 hours, shift energy over weeks or months (seasonal shifting) or cover long periods of low sunlight and wind (renewable droughts).[72] The existing deep storage assets in the NEM are pump hydro facilities. New transmission projects like HumeLink and Project Marinus will enhance access to these deep storage assets. New pumped hydro generation is very capital intensive. This is a function of the size and complexity of the projects.[73]

Several government programs are in place to support the development of new deep or medium-duration storage solutions. The main support mechanism remains direct investment from the government. At present, only Snowy 2.0 (NSW), Borumba and Kidston (both in Queensland) have confirmed or anticipated development. Hydro Tasmania is evaluating a new pumped hydro initiative called Battery of the Nation at Cethana and NSW has set a legislative target of 2 GW of storage with at least 8 hours of duration by 2030.[74]

6.1.4 Post 2030

Most government programs are designed to deliver new investment this decade. Significant investment is required from 2030 to 2050. AEMO's *Step Change* scenario requires 27 GW of

---

72 AEMO, 2024 Integrated System Plan, Australian Energy Market Operator, 26 June 2024, p. 67.

73 CEC, Hydropower: Backbone of a Reliable Renewable Energy System, Clean Energy Council, 17 November 2024.

74 AEMO, 2024 Integrated System Plan, Australian Energy Market Operator, 26 June 2024, p. 68.

storage and 72 GW of wind and large-scale solar.[75] The Australian Government has recently announced a review into the wholesale market. For the market signals to drive investment following the conclusion of the current government schemes, there will need to be a credible mechanism within the market for delivering investment in new zero emission and dispatchable generation that can recover its long run marginal cost. Understanding what this signal will be is also important to managing the cost of government schemes, as generators supported by the schemes will operate for many years after the schemes are closed to new entry.

6.2 Exit

6.2.1 Thermal capacity will continue to exit the market over the next decade

Thermal generation comprises a substantial portion of generation capacity in the NEM and continues to be concentrated (section 4.1.3). Given the lumpy nature of thermal exit, there could be more market volatility as the supply-demand balance tightens at certain times. How this generation is replaced will affect the competitive landscape.

In the last 2 financial years the remaining 3 units at AGL's Liddell power station in NSW (April 2023) and the final unit at AGL's Torrens Island A in South Australia (September 2022) have closed. This removed 1.5 GW of black coal and 120 MW of gas generation from the NEM. Over the next decade around 11.2 GW of thermal power stations are expected to close. This consists of 7.6 GW of black coal, 1.45 GW of brown coal, 1.75 GW of gas and 429 MW of diesel-powered generation.[76]

Since our last report the closure of Osborne (180 MW) in South Australia has been pushed back 3 years to 2026. Vales Point's (1,320 MW) closure was pushed back by 4 years to 2033. The closure of 3 South Australian diesel-powered plants (Port Lincoln Gas Turbine units 1 and 3 and Snuggery, with a combined total of 136.5 MW) has been brought forward from 2030 to 2027.

Eraring power station was scheduled to close in 2025. In its 2023 annual Electricity Statement of Opportunities AEMO found that NSW would face a reliability shortfall from 2025–26 that aligned with the planned shutdown of Eraring.[77] The NSW Government subsequently entered into an agreement with Origin Energy, whereby the company would continue operating Eraring until August 2027. In return, the government would underwrite a portion of Origin's potential financial losses, with Origin agreeing to share any profits with the government.[78]

The generators cited the transition to lower cost and low-carbon renewable technology as the reason for their exits, with Origin noting that the transition has put unsustainable pressure on

---

75 AEMO, 2024 Integrated System Plan, Overview, Australian Energy Market Operator, 26 June 2024.

76 Discrepancies in figures are due to rounding conventions.

77 AEMO, 2023 Electricity Statement of Opportunities, Australian Energy Market Operator, 21 May 2023, pp. 9 and 70.

78 NSW Government, Summary of agreement between the State and Origin on its plans for Eraring power station, 22 May 2024.

coal-fired power stations.[79] Renewables have reduced the need for thermal assets during the day and overnight. Coal plants have responded by reducing minimum generation levels.[80]

Table 6.1 Expected thermal generator closure to 2034

Expected closure year	Region	Station	Fuel type	Registered capacity (MW)
2026	SA	Torrens Island B units 1, 2, 3, and 4	Gas	200 each
		Osborne	Gas	180
2027	SA	Port Lincoln Gas Turbine unit 1	Diesel	50
		Port Lincoln Gas Turbine unit 3	Diesel	23.5
		Snuggery	Diesel	63
	NSW	Eraring units 1, 2, 3, and 4	Black coal	720 each
2028	QLD	Callide B units 1 and 2	Black coal	350 each
	VIC	Yallourn W units 1 and 2	Brown coal	360 each
		Yallourn W units 3 and 4	Brown coal	375 each
2030	SA	Dry Creek Gas Turbine units 1, 2 and 3	Gas	52 each
		Mintaro Gas Turbine	Gas	90
2032	SA	Hallett Power Station	Gas	217
2033	NSW	Vales Point units 5 and 6	Black coal	660 each
		Bayswater units 1, 2, 3, and 4[81]	Black coal	660 each
	QLD	Mt Stuart units 1 and 2	Diesel	146 each
	VIC	Somerton	Gas	170
2034	QLD	Barcaldine	Gas	37
	QLD	Roma units 7 and 8	Gas	40 each

In terms of ownership, 97% of the capacity that exited in the last 5 years was owned by AGL and all closures expected within the next 5 years are owned by Origin, EnergyAustralia, CS Energy or AGL.

79 Origin Energy, Origin proposes to accelerate exit from coal-fired generation, 17 February 2022.

80 See WattClarity, A look into minimum generation levels at various coal plants, using the GSD2023, and Origin Energy drops Minimum Generation levels at Eraring Power Station to 180MW, accessed 14 November 2024.

81 Bayswater will be closed between 2030 and 2033.

Energy Ministers developed the Orderly Exit Management (OEM) Framework due to concerns such as those surrounding the retirement date for Eraring power station.[82] The OEM Framework will enable governments to extend power stations beyond their closure dates through either voluntary agreement or mandatory notice. Jurisdictional governments will need to opt in to the OEM Framework for it to apply in their jurisdiction. If it is activated, for example, due to concerns that an exit could lead to reliability gaps, it will follow a staged process of independent assessment, exploration of options, and engagement with generators.

The funding mechanism for the OEM Framework is designed to encourage commercial operation of any generator that is required to postpone its exit. When triggered, the framework uses a financial contract to incentivise the generator to participate in the market when needed by compensating them with reference to market pricing. The cost of any contract will be recovered from consumers via increased transmission charges within the generator's region.

While the OEM Framework will help manage reliability and security risks as plants exit, there remain price and competition impacts arising from risks of unplanned outages and fuel market prices and supply constraints (sections 2.1.2, 2.2.2 and 5.3.1). In our 2022 report we recommended governments consider options to manage the exit of coal generators, including to ensure they withdrew from the market at a rate consistent with the entry of new generation and in light of the maintenance requirements and coal supply exposure they face.

6.3 Changing system needs

6.3.1 System services

The exit of thermal generators has implications for system security. Many essential system services that support the stability and security of the grid, such as frequency response, system strength and inertia, were intrinsic by-products of synchronous generation such as coal and gas. The pace of change comes with the risk of creating inefficiencies as the market evolves. This is evident in the recent costs of directions to maintain system security (section 7.2.8). It can also create new opportunities for the exercise of market power. The electricity market rules have been playing catch up with the changing technology mix, establishing new markets and rules to ensure critical services are still provided.

System strength

The NEM can no longer rely on the full level of system strength to be provided by synchronous generation as a by-product of their operation. In 2021, the Australian Energy Market Commission (AEMC) made significant changes to the regulatory framework for system strength through the *Efficient management of system strength on the power system rule change*.[83] The National Electricity Rules now require certain transmission network service providers (TNSPs), known as system strength service providers (SSSPs), to procure sufficient system strength to meet forecast needs at localised nodes within each region.

---

82 ECMC, Orderly Exit Management Framework Draft Exposure Bill and Rule - June 2024

83 AEMC, Efficient management of the system strength on the power system, Australian Energy Market Commission, 21 October 2024.

Recently, the AEMC made further changes to the system strength framework as part of the *Improving security frameworks for the energy transition rule change*.[84]

In general, there are 3 ways to provide system strength: contract with existing synchronous generators, procure synchronous condensers, and contract with batteries with grid-forming inverters. Each method has its own benefits and drawbacks.[85]

System strength is a highly locational service and cannot be provided at a system-wide level. If SSSPs rely solely upon the existing synchronous generators, this limits the pool of potential providers giving rise to potential market power concerns. In the future, batteries with grid-forming inverters could add competitive tension by increasing the number of providers in certain locations. However, the ability of batteries with grid-forming inverters to provide system strength, in particular the provision of fault current, is still being proven.

Synchronous condensers require significant capital outlay to procure. There is a risk they could be underutilised, as system strength requirements can vary from year to year, and synchronous condensers, unlike generators or batteries with grid-forming inverters, cannot be used for another purpose. Use of synchronous condensers is further complicated by high demand globally with long lead times. AEMO’s system security strength report indicates that the lead time for large synchronous condensers may now exceed 5 years.

SSSPs are currently undertaking the process to plan for and procure system strength ahead of the first binding requirements starting on 2 December 2025. The AER recently released guidance on how SSSPs might best comply with their obligations at least cost and in the long-term interests of consumers.[86]

Increased directions for system security have compromised market efficiency

At times, AEMO issues directions to market participants to manage and stabilise the electricity grid. Directions can include instructions to either increase or decrease generation, offer FCAS services, or dispatch instructions. When directions are made, operation of assets is driven by AEMO rather than participants. As directions increase, so does AEMO’s impact on asset operation, which impedes efficient dispatch based on offers. Although directed participants can recover the costs of directions, stakeholders report that directions make effective management of assets and fuel much more challenging (see section 7.2.8 for more detail).

6.3.2 Network congestion will continue to evolve as the market transitions

The power system is transitioning from one engineered for a small number of large capacity generators with relatively consistent output to one with more decentralised, diverse and dynamic low-emission generation technologies. In the 2022 WEMPR, we noted pricing

---

84 AEMC, Improving security frameworks for the energy transition, Australian Energy Market Commission, 28 March 2024.

85 AER, Efficient management of system strength framework, Australian Energy Regulator.

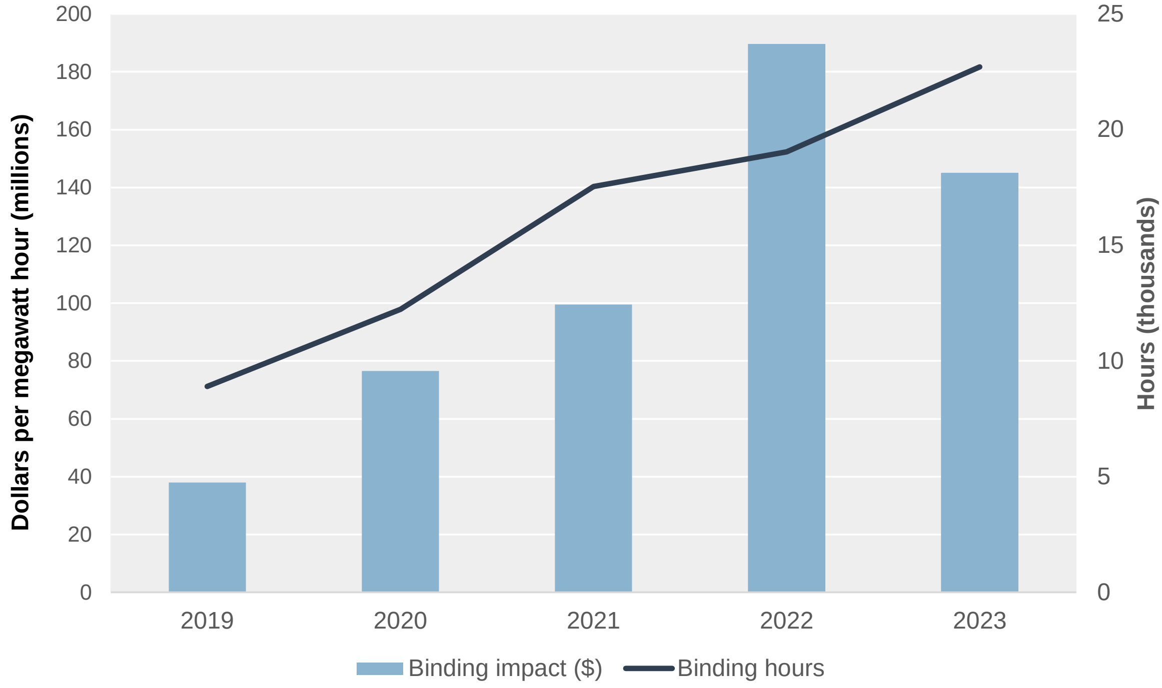
86 AER, Efficient management of system strength framework, Australian Energy Regulator.

signals in the transmission access framework needed to be reconsidered. This need remains.

Some level of congestion is a normal feature of an efficient network, but excessive congestion, if sustained, suggests insufficient or absent locational price signals. A lack of locational signals risks over-investment in both generation and network infrastructure. Participants can connect in areas of the grid with limited hosting capacity and limited incentives to coordinate with large-scale storage, leading to transmission congestion and curtailment of generation. It also contributes to operational inefficiencies as higher priced generation may be dispatched (and may be able to bid strategically to drive up prices) where otherwise more competitive generation is constrained, and participants (especially storage) are not rewarded for their ability to reduce congestion.

Over the 5 years up to and including 2023, network congestion has increased significantly, with parts of the network continuing to be used more heavily. This is linked to new entrants clustering to certain parts of the grid in an uncoordinated and inefficient way, increasing congestion in those areas. While costs decreased in 2023, the general trend has been up over recent years (Figure 6.9).

Figure 6.9 Hours and impact from network congestion



Note: Data excludes impacts from FCAS, outages, network support and commissioning constraints. Further details can be found at [AEMO congestion information](). The binding hours and impact of system normal constraints provides an indication of network congestion. The binding impact of a constraint is derived by summarising the marginal value for each dispatch interval from the marginal constraint cost re-run over the period considered. The marginal value is a mathematical term for the market impact arising from relaxing the right hand side of a binding constraint by 1 megawatt (MW). Binding impact represents the financial pain associated with that binding constraint equation and can be a good way of picking up congestion issues, however it is only a proxy (and always an upper bound) of the value per MW of congestion over the period calculated.

Source: AER analysis of AEMO congestion information.

The rising costs of congestion highlights the importance of coordination of transmission and generation investments to minimise system costs and costs to consumers.[87] Recent government interventions such as Renewable Energy Zones (REZ) and the CIS help to address some of the problems relating to the location of new generation. However, these interventions are time-limited and rely on continued active involvement of governments in markets. These schemes also have limited effectiveness in improving operational efficiency due to non-cost-reflective bidding or incentivising congestion relief from storage and demand-side technologies. There remains a need for an enduring solution to transmission access. The status quo requires continued government direction and coordination of investments. Reform is necessary to return to effective market-led investment and operation of generation beyond the horizon of government programs.

6.3.3 Emergency reserves needed less often to maintain system reliability and security

The Reliability and Emergency Reserve Trader (RERT) is an intervention that allows AEMO to contract for emergency reserves, such as generation or demand response, that are not otherwise available in the market. AEMO uses RERT as one of a number of mechanisms in the event that a critical shortfall in reserves is forecast. RERT is used as an emergency backstop after other market options have been exhausted, typically during periods when the supply demand balance is tight.

Initially the RERT was rarely needed, only being used 3 times between 1998 and 2016. From 2017–18 to 2022–23, the RERT was called on by AEMO every financial year. But in 2022–23 AEMO only activated RERT twice, a significant drop from 2021–22 (5 times).[88] For 2023–24, AEMO did not activate RERT.[89] However, AEMO incurred $4.2 million in costs in relation to availability payments for Interim Reliability Reserve contracts.[90]

---

87 AEMC, Transmission access reform consultation paper, Australian Energy Market Commission, April 2024.

88 AEMO, Reliability and Emergency Reserve Trader (RERT) End of Financial Year 2022-23 Report, Australian Energy Market Operator, August 2023.

89 AEMO, Reliability and Emergency Reserve Trader (RERT) Quarterly Report Q1 2024, Australian Energy Market Operator, May 2024.

90 AEMO, Reliability and Emergency Reserve Trader (RERT) End of Financial Year 2023-24 Report, Australian Energy Market Operator, August 2024.

7 South Australia deep dive

Key findings

- In South Australia, increased large-scale renewable investment and rooftop solar generation have increased the occurrence of negative prices. These low prices during the middle of the day signal a reduced need for generation at that time. Other periods have also experienced downward price pressure due to increased renewable generation. However, higher fuel costs, network congestion, rebidding by participants and lower wind conditions have meant, overall, wholesale electricity prices have been slightly higher than pre-2022 levels in 2023 and 2024.
- Consistent with the transition to low emissions generation, the share of low-cost renewable generation has increased. Over time, the economics of higher cost thermal generation has become less favourable. Some thermal generators are forecast to exit the market over the next 5 years, including AGL's Torrens Island B gas power station (2026) and ENGIE's Port Lincoln and Snuggery diesel stations (2028). Following these exits, 10 gas-fired power stations remain in the South Australian market.
- Australian and South Australian government backed investment has supported a pipeline of new solar, wind and hydrogen energy systems.
- A higher proportion of offers in South Australia are at prices below zero or above $5,000 per MWh, with increasingly fewer offers in the middle of the price range. This is driven by increased renewable generation and thermal plants making high offers to avoid uneconomic dispatch. The resulting steepening of the offer curve increases price volatility and the incentive to economically withhold.
- Price volatility has continued to increase over the past 2 years. This may increase prices for consumers by making it more costly for smaller retailers to hedge their price risk. The Australian Securities Exchange (ASX) is considering new contract types that may assist participants in managing this price risk.
- Standard contracts are increasingly less suitable for managing market risk and are consequently traded infrequently. Low contract volumes combined with high price volatility have resulted in some price risks, and businesses with significant vertical integration are likely to be better placed than other retailers to manage those risks.
- We have examined 5 market events suggestive of economic withholding. During these events the relevant participant shifted capacity from low to high prices with the objective of increasing revenue for its portfolio. The participant was successful and made significant returns in the wholesale electricity market.
- The South Australian market is at the forefront of the energy transition and provides insights for other regions undergoing the same transition. This chapter highlights the complexities of the South Australian market and the insights this provides for future market design.

7.1 Background

South Australia is at the forefront of the energy transition and has more renewable penetration than other mainland NEM regions.

While South Australia has made significant strides in adopting renewable energy, it is also faced with unique challenges. It is at the end of a long, thin network connection to the rest of the NEM and has often relied on system security directions to maintain grid stability. Increased rooftop solar installations have also meant that there is increasingly lower minimum demand in the middle of the day, accompanied by negative prices. These prices have made the economics for some gas generation with minimum operational requirements more challenging. In addition, the contract market plays an important role in facilitating investment and is used to manage wholesale price risk. The South Australian contract market is thinly traded with prices that are at times comparatively higher than several NEM regions, potentially making it more difficult for smaller retailers to enter the market.

For these reasons we have conducted a deeper analysis of the South Australian market. In this chapter, we examine market conditions, market structure (including market share and concentration) and the conduct of market participants.

We have also used our newly enhanced wholesale market monitoring and reporting powers to collect information from selected participants to inform our assessment. We obtained marginal cost data, lists of cost drivers for thermal plants and information on the impacts of renewable generation on participant portfolios and operations. We also collected information on contracts to better understand contract market dynamics and participants' incentives.

The chapter is divided into 3 sections:

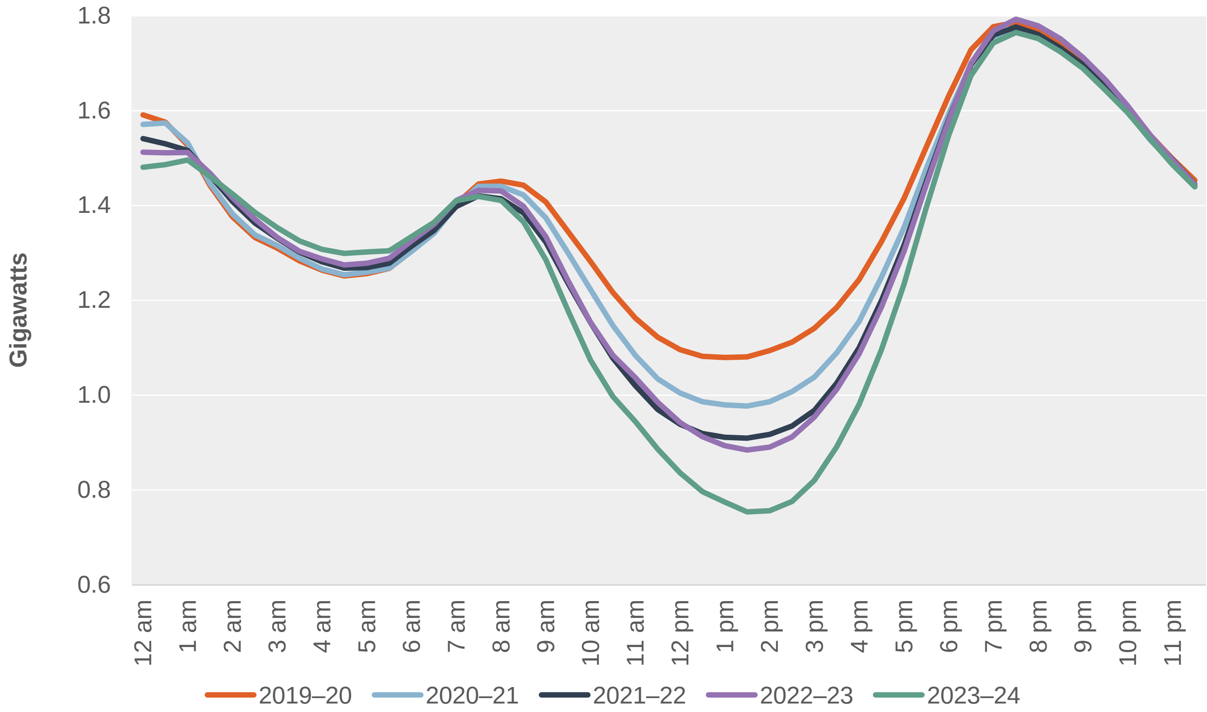
- **Section 7.2 examines the market conditions** in South Australia. This includes the demand and supply conditions, spot price outcomes and the South Australian contract market. This section also assesses the cost of security directions and the role of various technology in the frequency ancillary services markets.
- **Section 7.3 examines the market structure** in South Australia, including participant market share, market concentration, pivotal supplier analysis as well as an assessment on the incentives of vertically integrated participants in South Australia. The section also examines inter-regional trade and government-supported investment.
- **Section 7.4 examines the conduct of market participants.** This includes a review of generation offers made by market participants, an assessment of potential economic withholding conduct and a case study on a participant's conduct.

7.2 Market conditions in South Australia

7.2.1 Demand continues to decrease during daylight hours

Average electricity demand decreased slightly in South Australia in 2022–23 and 2023–24, partly driven by the growth in rooftop solar installations. Increased rooftop solar generation has resulted in a significant deepening of the demand 'duck curve' over the past 5 years. The duck curve is a graph illustrating that demand decreases during daylight hours while solar is generating and peaks during the morning and evening (Figure 7.1). It doesn't reflect a reduction in electricity consumed during the day, rather an increase in electricity generated by rooftop solar installations. The average demand at 2 pm in 2019–20 was 1.09 GW, while in 2023–24 it decreased to 0.76 GW.

Figure 7.1 Wholesale electricity demand in South Australia



Source: AER analysis using NEM data.

7.2.2 Renewables continue to displace thermal generation

South Australia has a unique generation profile and is at the forefront of the energy transition, with a significant proportion of its generation coming from renewables. In 2023–24, 52% of generation came from wind and large-scale solar, with 25% generated by gas and 1% from batteries. For 2,477 hours in 2023–24, 100% of demand in South Australia was supplied by renewable generation. Wind has contributed more generation than gas every year since 2020–21.

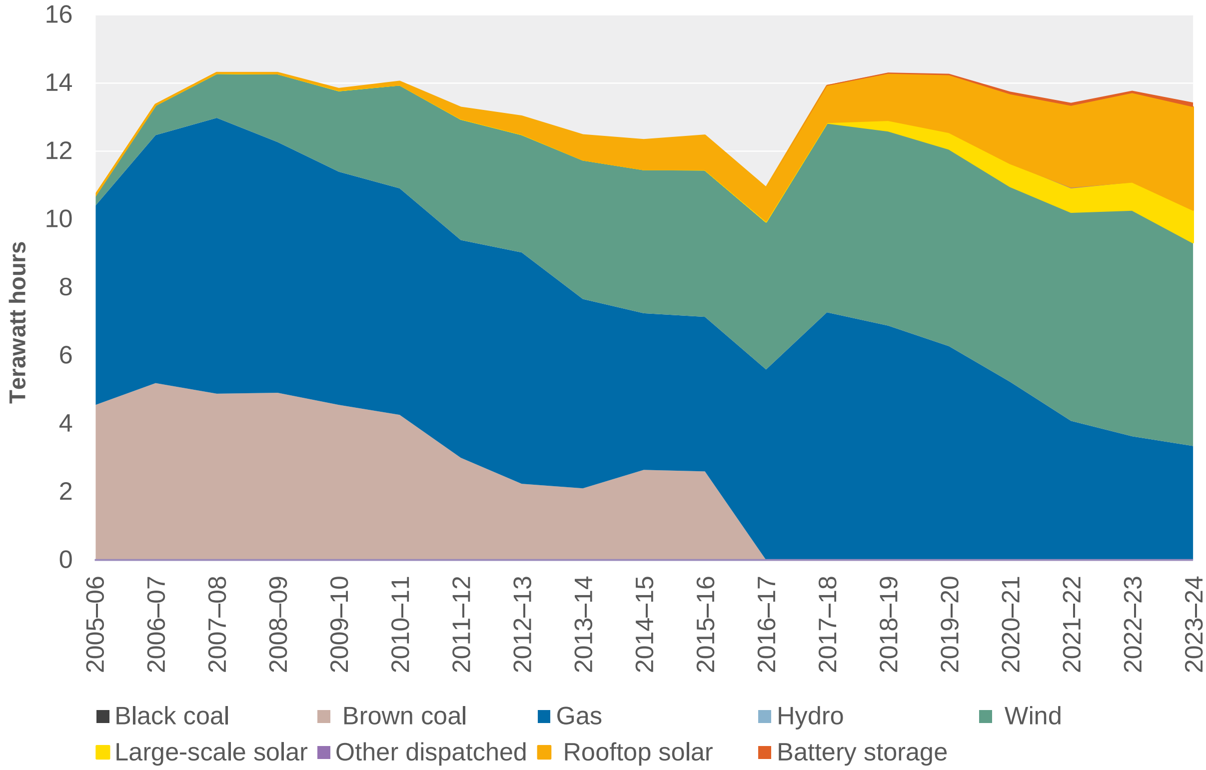
The contribution of gas has been decreasing since 2017–18 and this trend is likely to continue. Several gas units are expected to close over the next 8 years, with a total 1.58 GW of capacity being permanently removed from South Australia.[91] However, some of these units have already been mothballed prior to their scheduled closures, including AGL's Torrens Island B and ENGIE's Snuggery.

Over the past 5 years gas generation has predominantly been displaced by solar generation, which is now the fastest growing generation source. Rooftop solar generation increased by 81% over this period and large-scale solar generation increased by 97%. While rooftop solar generation occurs behind the meter, its contribution to the overall generation profile reduces the need for thermal generation to operate during the day. The role of batteries has also

91 Torrens Island B units 1, 2, 3 and 4 and Osbourne are expected to close in 2026. Port Lincoln Gas Turbines 1 and 3 and Snuggery are expected to close in 2027. Dry Creek Gas Turbine units 1, 2 and 3 and Mintaro are expected to close in 2030. Hallett is expected to close in 2032.

increased over the past few years. However, batteries remain a small percentage of total generation, contributing 133.4 TWh (1%) in 2023–24. While still relatively small, battery penetration is higher in South Australia than in other NEM regions. The NEM has a total battery capacity of 497.1 TWh (0.2% of all generation).

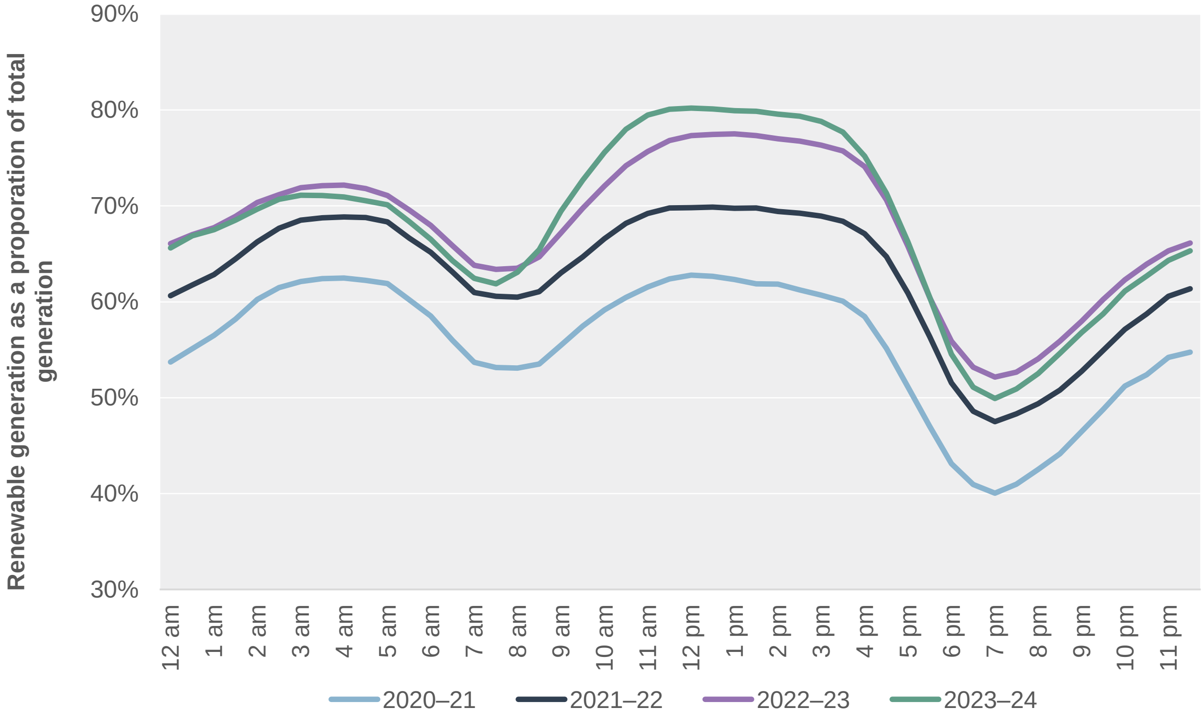
Figure 7.2 Yearly average generation in South Australia, by fuel type (financial year)



Source: AER analysis using NEM data.

Electricity generated in South Australia from renewable sources has consistently increased year on year. As of 2022–23, renewable energy (wind and solar) makes up most of the electricity generated in South Australia across all hours of the day (Figure 7.3). This is likely to increase with the South Australian Government's target of net 100% renewable generation by 2027. Investment price signals will be explored in greater depth in section 7.2.5.

Figure 7.3 Renewable generation as a percentage of total generation



Note: This chart illustrates the percentage of electricity generation made up by wind and solar generator generation by time of day. This chart does not include rooftop solar generation. As can be seen in the chart, renewable generation has increased from around 60% to 80% of total generation, on average, during the middle of the day.

Source: AER analysis using NEM data.

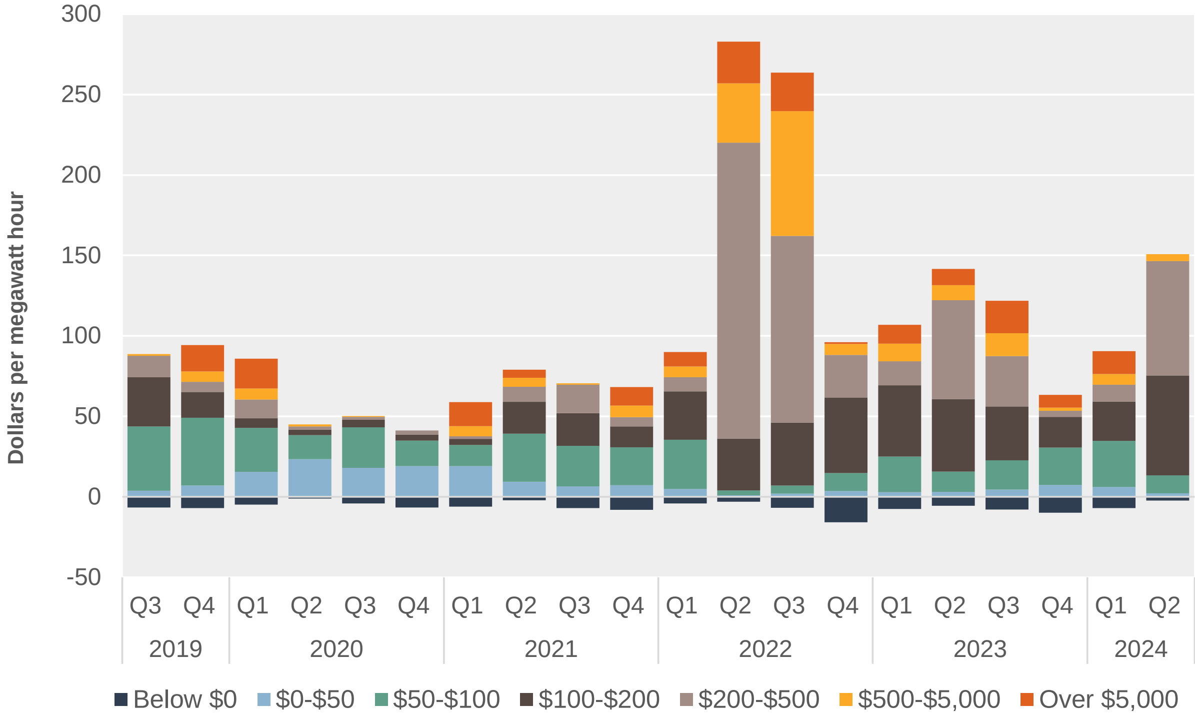
7.2.3 Contribution to price bands

Average prices can be driven by a general movement in prices or a more limited number of price events. In Q2 and Q3 2022, average quarterly prices in South Australia significantly increased due to increased offers resulting from fuel supply constraints and higher fuel costs. In 2022–23 and 2023–24, offers between $100 to $500 per MWh significantly contributed to the average price, more so than in previous years, indicating a general upwards movement in participant offers (Figure 7.4).

In Q4 2022, there was a marked increase in negative prices. These negative prices reduced the quarterly average price by $15.88 per MWh.

Periods of very high prices have also had an impact on average prices. In Q3 2024, there were 27 30-minute periods where the price exceeded $5,000 per MWh. These high price periods increased the average price by $77.

Figure 7.4 Contribution of different price bands to quarterly wholesale prices



Note: Shows the extent to which different spot prices within defined bands contributed to the volume weighted average wholesale prices in each region.

Source: AER analysis using NEM data.

7.2.4 Average prices are influenced by extreme highs and lows

Wholesale electricity prices are impacted by a multitude of factors, such as plant availability, gas prices, weather condition, network congestion, rebidding and demand response.

In South Australia, volume weighted average (VWA) prices hit unprecedented levels in Q2 2022 due to high gas prices. The estimated cost to fuel gas generation reached a record of $347 per MWh in July 2022. In early 2024, fuel costs reduced to around $89 per MWh, then increased to $128 per MWh in June 2024. The wholesale price followed the same trend, reducing to $86 per MWh in Q1 2024, then increasing to $150 per MWh in Q2 2024 and $201 per MWh in Q3 2024.

Prices in Q3 2024 were influenced by more high price periods (30-minute periods where the price exceeded $5,000 per MWh) occurring in the first half of the quarter, brought on by low wind generation during high demand periods, rebidding and network outages.[92] A total of 27 high price periods occurred in South Australia, 18 of which occurred between the end of July and the beginning of August. These high price periods increased quarterly prices by $77 in South Australia.

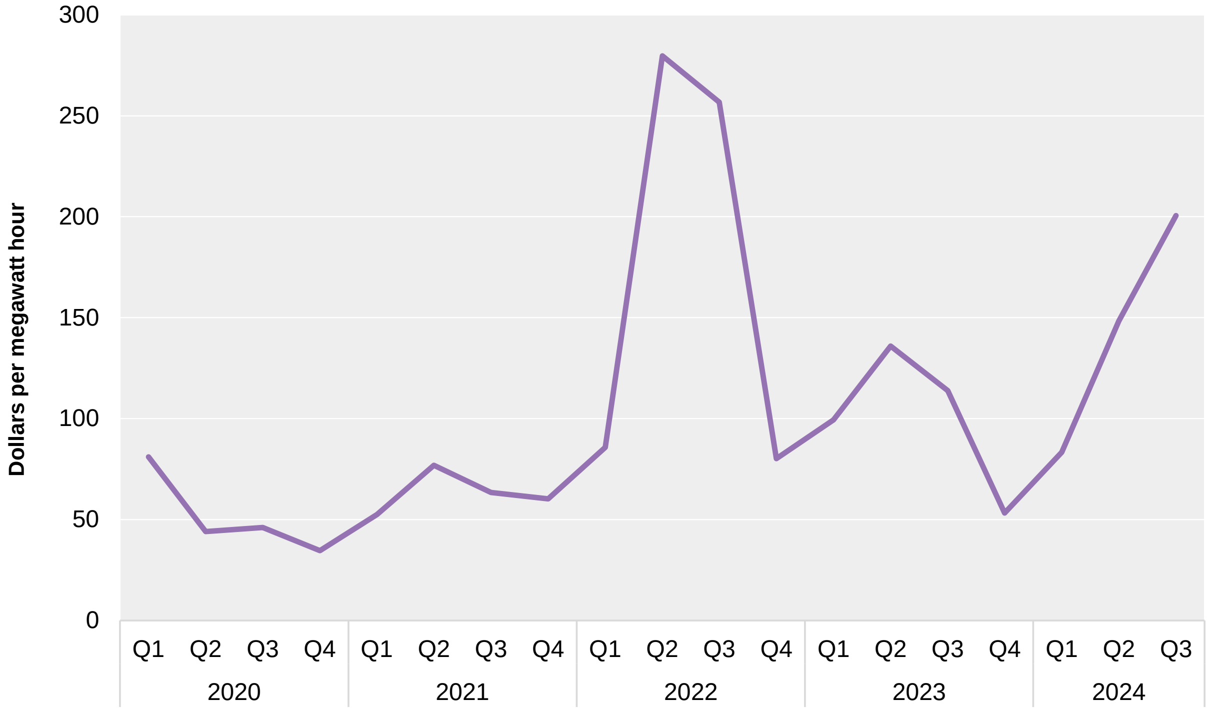
As more renewable generation enters the South Australian market, so does the region's dependency on weather conditions for supply. When renewable generation reduces due to low wind or solar conditions, the region becomes more dependent on expensive gas

---

92 AER, [Prices above $5,000/MWh - July to September 2024 | Australian Energy Regulator (AER)](), 22 November 2024.

generation to meet demand, causing prices to rise. However, as the generation mix continues to evolve, market dynamics may change. Technologies such as batteries and virtual power plants are responding to high prices by releasing energy or reducing demand, putting downward pressure on prices. Increases in wind generation capacity can be partially used to meet demand when solar is not generating. In the future, South Australian generation is likely to be less sensitive to the cost associated with using and transporting gas.

Figure 7.5 Quarterly volume weighted average prices in South Australia

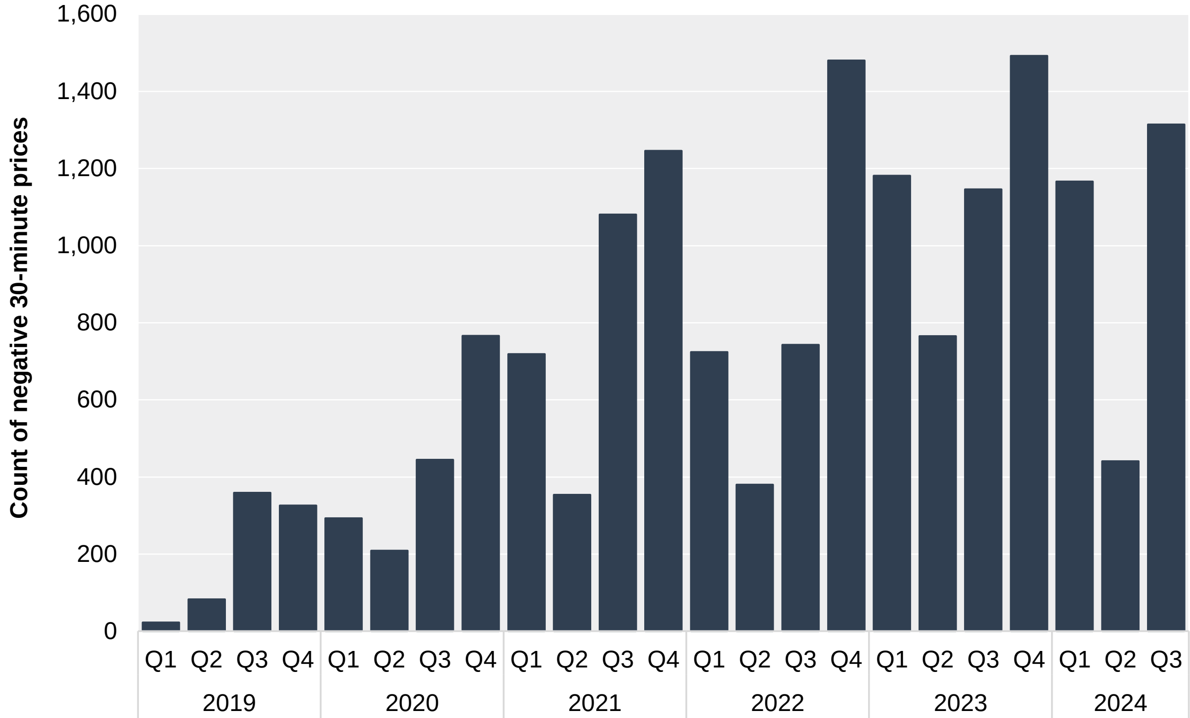


Note: This chart illustrates volume weighted average quarterly prices, meaning prices are weighted against native demand in each region. The AER defines native demand as the sum of initial supply and total intermittent generation in a region.
Source: AER analysis using NEM data.

Negative prices are a feature of the South Australian market, particularly during daylight hours

Instances of negative prices in South Australia have increased significantly since 2019, rising from 719 30-minute intervals to 4,584 (15% of annual intervals) in 2023 (Figure 7.6). During the first 3 quarters of 2024, there were 2,129 negative intervals. Q3 and Q4 generally have the most instances of negative prices due to lower demand and higher solar output.

Figure 7.6 30-minute prices below $0 per MWh

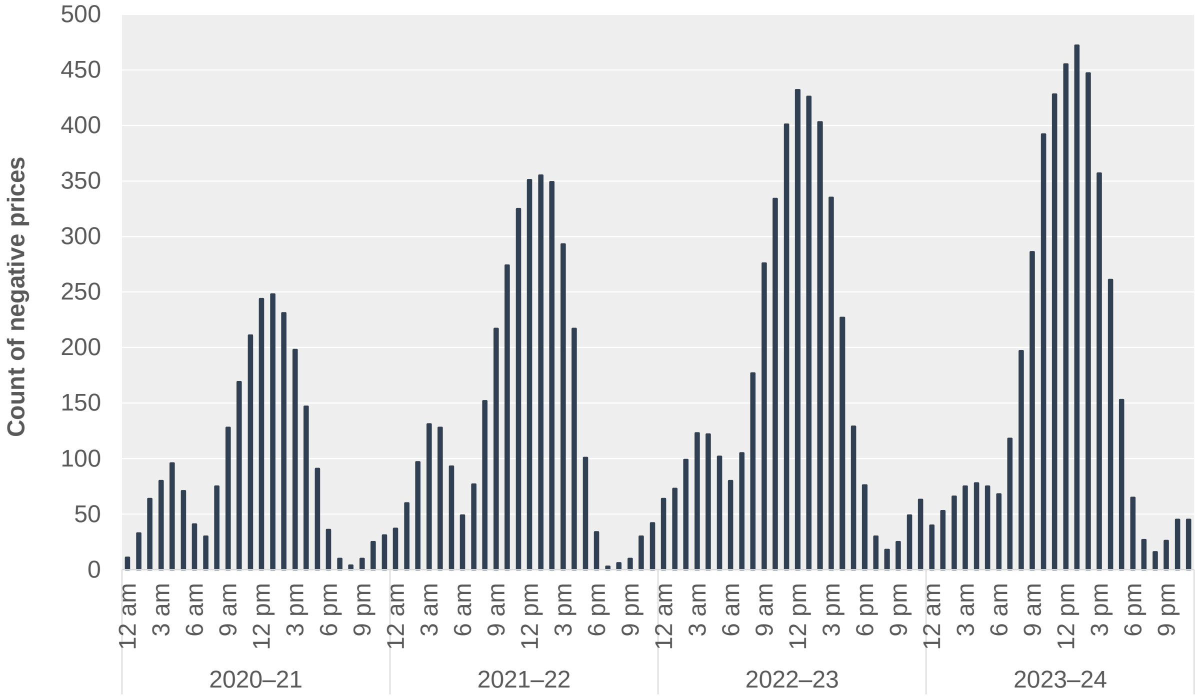


Note: This chart illustrates the number of 30-minute intervals that had prices under $0 for each quarter.
Source: AER analysis using NEM data.

Instances of negative prices mostly occur between 8 am and 5 pm, when solar generation is high (Figure 7.7). Over 2023–24, the count of negative prices was highest at 1 pm (472 negative prices). The value of these negative prices was also more severe over the middle of the day, reaching an average of −$61.90 per MWh at 1 pm over the same financial year. However, the more significant change is that over the past 2 financial years – negative prices have been more negative in non-peak periods (outside of daylight hours), driven by an increase in low-cost wind generation.

Increased instances of negative prices and the depths these prices reach (how negative they are) have implications for competition and the exit of thermal generation. Gas generators are generally more sensitive to operating at negative prices due to the cost of the gas they use to generate, while renewable generators may still earn revenue from other sources such as power purchase agreements (PPAs) and renewable energy certificates (RECs).

Figure 7.7 Count of negative prices by time of day, 2020–21 to 2023–24



Source: AER analysis using NEM data.

Price setter

Overall, coal (black and brown) is setting price less frequently over 2023–24 than it was in 2021–22. However, when black coal sets price, it is at higher levels than in 2021. South Australia doesn't have coal generation, so when coal sets price in South Australia it is due to coal generation flowing in from other regions.

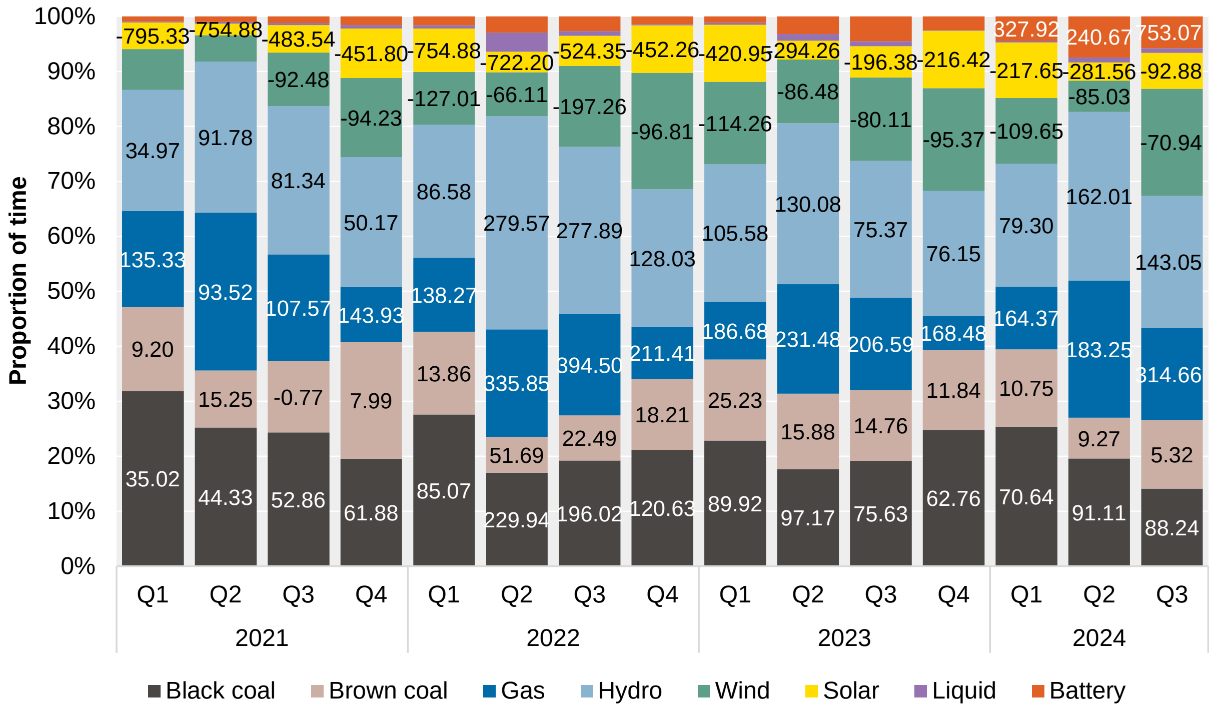
Solar generators continued to set the price a similar proportion of the time to previous years between 10 am and 4 pm. However, while solar continues to set negative prices, the prices are closer to $0 than previously. In 2021 solar set price at between −$452 (Q4) and −$795 (Q1). In 2024, solar has set prices between −$93 (Q3) and −$282 (Q2).[93] This could be due to the observed trend of solar generators removing their generation from the market by either switching off or bidding themselves high to avoid being dispatched at negative prices. The removal of cheap generation means that more expensive generation must be dispatched to meet demand, which effectively raises prices.

As illustrated in Figure 7.8, gas generators set price at much higher levels on average in 2023 and 2024, compared with 2021. In 2021 gas generators set prices on average between $94 (Q2 2021) and $144 (Q4 2021), whereas over 2023–24 gas generators set prices on average between $164 (Q1 2024) and $315 (Q3 2024). Batteries are also having a larger impact in South Australia due to the commissioning of new storage, such as the Torrens Island battery, which came online in August 2023. We have observed an increase in both the

93 Data is not currently available for Q4 2024.

percentage of time batteries set price and the prices they set it at. In Q3 2024 batteries set price on average at $753.

Figure 7.8 Quarterly price setter by fuel type in South Australia

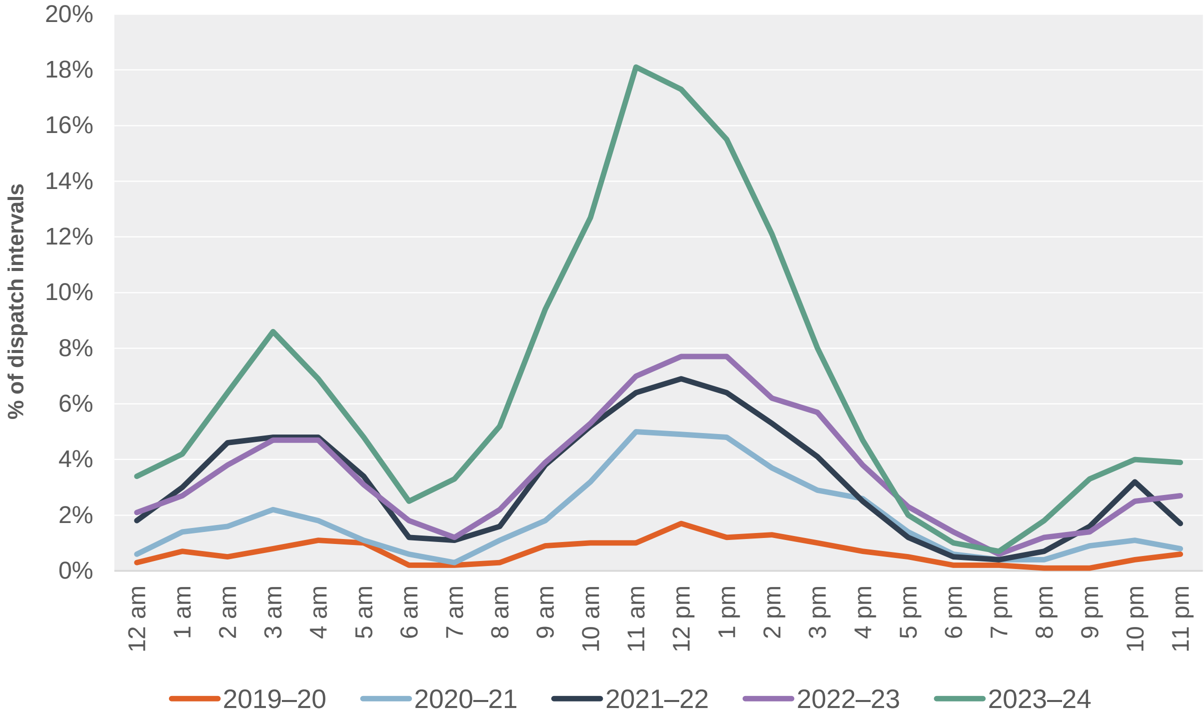


Note: The height of each bar is the percentage of time each fuel type sets the price and the number within each bar is the average price set by the fuel type when it is marginal (that is, setting the price).

Source: AER analysis using NEM data.

As well as setting price through dispatch, batteries can set price as load. Loads set price when it is more cost effective to reduce load than to increase generation. The increased penetration of battery storage systems has resulted in load setting price more frequently than it did in previous years.

Figure 7.9 Percentage of intervals when load sets price in South Australia, by time of day



Source: AER analysis using NEM data.

7.2.5 Changing competition dynamics stemming from renewable penetration

As renewable energy generators are becoming the dominant suppliers, particularly during midday hours, spot prices are being driven down due to the lower marginal cost of these generators. This low-cost supply puts increasing pressure on legacy thermal generators that face lower dispatch prices and revenue. Reduced profitability for thermal generators at times may incentivise them to seek higher revenues (within the limits of competitive constraints) during the shrinking morning and evening price peaks.

Higher prices during the morning and evening peaks may incentivise new entry and innovation

Prices spike in the morning around 7 am – 9 am and evening around 6 pm – 9 pm. These peak prices may incentivise new entry and innovation from fast response systems such as batteries or demand response solutions. Dispatch of battery capacity has increased over the past 4 years, contributing 1% in 2023–24, with most of that being over the morning and evening peaks. The price fluctuations observed in South Australia, where prices are low during the day and high during peak periods, may create additional incentives for battery entry noting that batteries profit from arbitraging this price differential.

Conversely, consistent low and negative prices may act as a barrier to entry for some renewable generation. These prices may not be sufficient to incentivise investment in new generation and may make it difficult to recover the capital cost of new investment (section 6.1.3).

Like many other regions in the NEM, investment in storage and renewable generation in South Australia is being underwritten by both state and Australian Government programs (section 7.3.6).

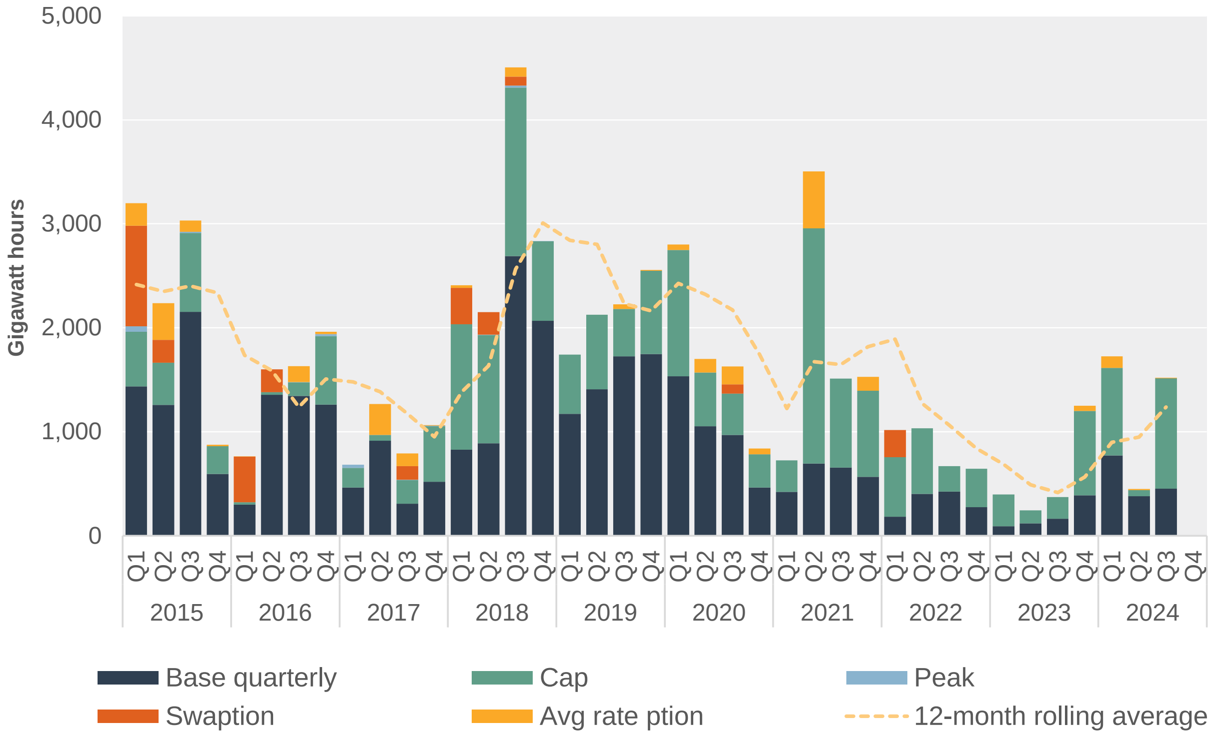
7.2.6 South Australian contract market diverges from markets across the rest of the NEM

The unique aspects of South Australia's generation market also impact South Australia's wholesale electricity contract market. This section derives insights predominantly from reviewing futures contracts.

Volumes continue to decrease

Traded contract volumes have always been lower relative to total regional demand in South Australia than in other regions of the NEM. However, over recent years volumes have further declined, reaching an all-time low in 2023 when they fell to just 451 GWh in Q2 2023 (Figure 7.10).

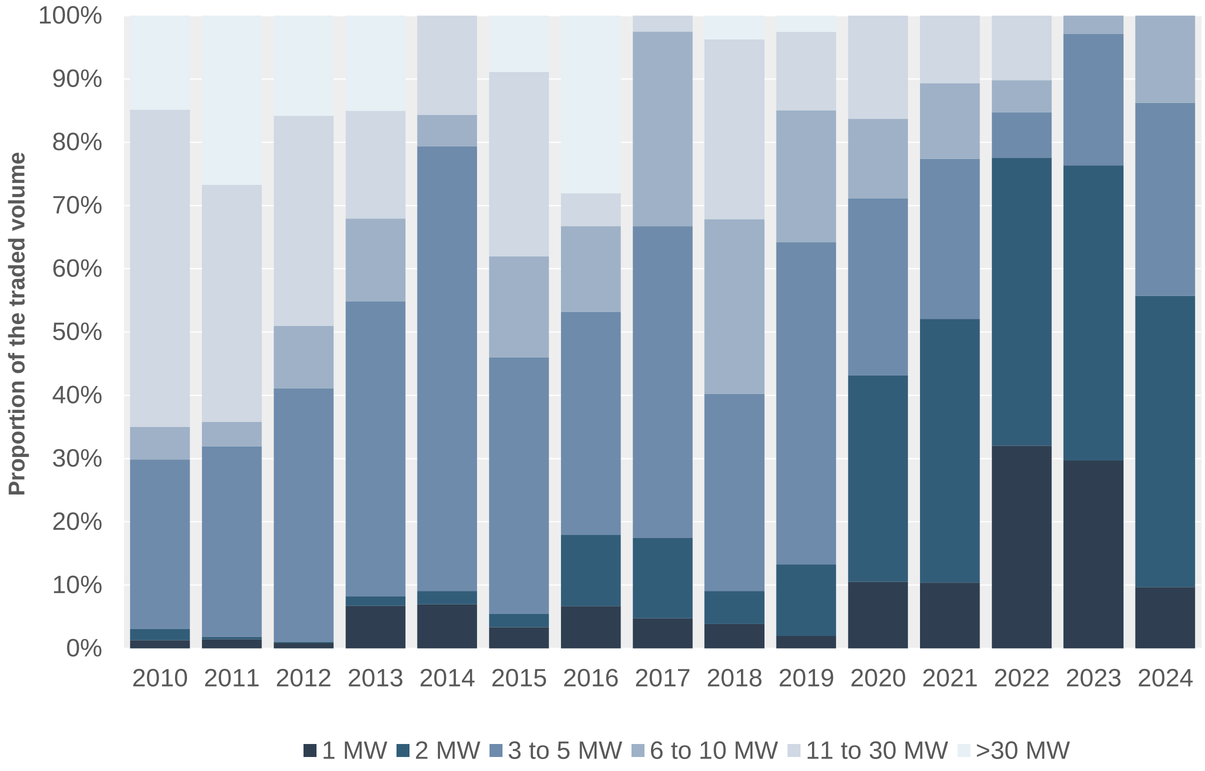
Figure 7.10 Traded volumes



Notes: Volume of trades that occurred during the quarter across ASX Energy futures. The x-axis represents the quarter in which the trades occurred.
Source: AER analysis using ASX data.

Over the past 2 years, both the number and volume of trades have reduced. In 2023, there were no base future trades with a volume greater than 10 MW. This is a significant shift – over the decade from 2010 to 2019, approximately one-third of all traded volume came from individual trades with a volume greater than 10 MW (Figure 7.11 and Figure 7.12).

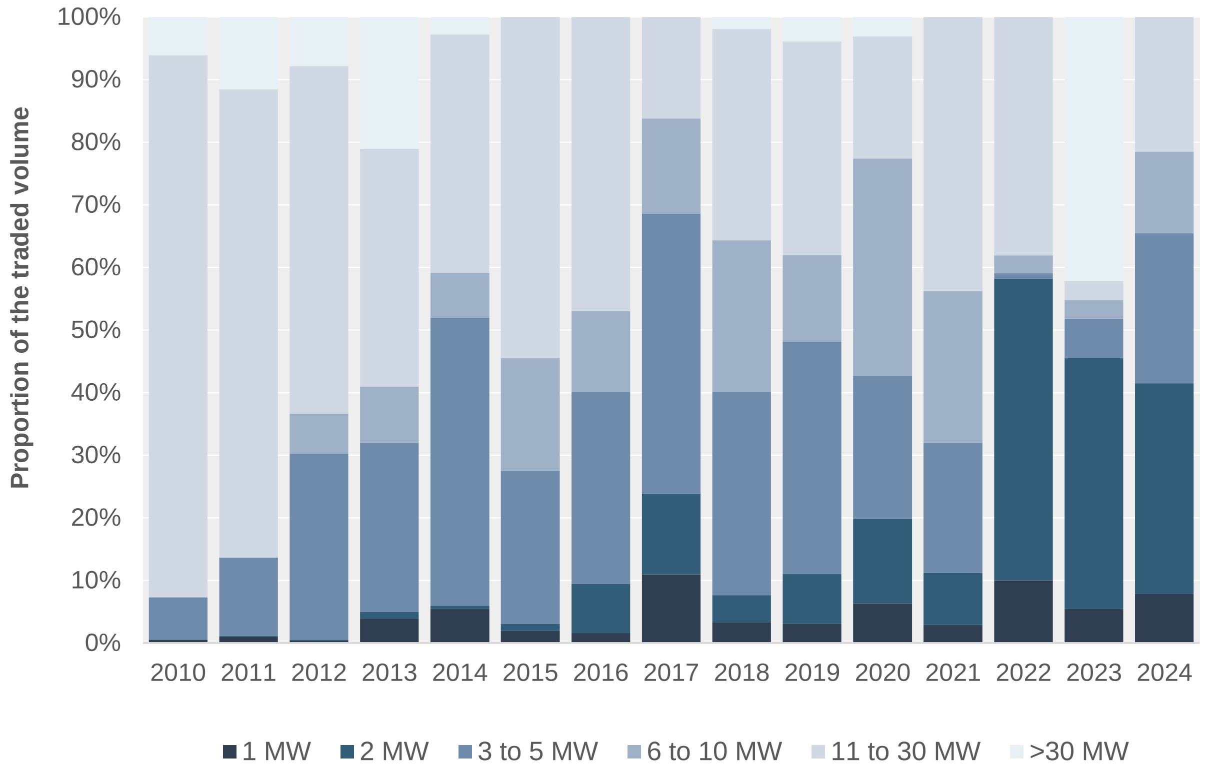
Figure 7.11 Base futures, trade size



Note: This chart measures the size of base future trades in the year they were traded. 2024 is calculated up until 30 September 2024.

Source: AER analysis using ASX data.

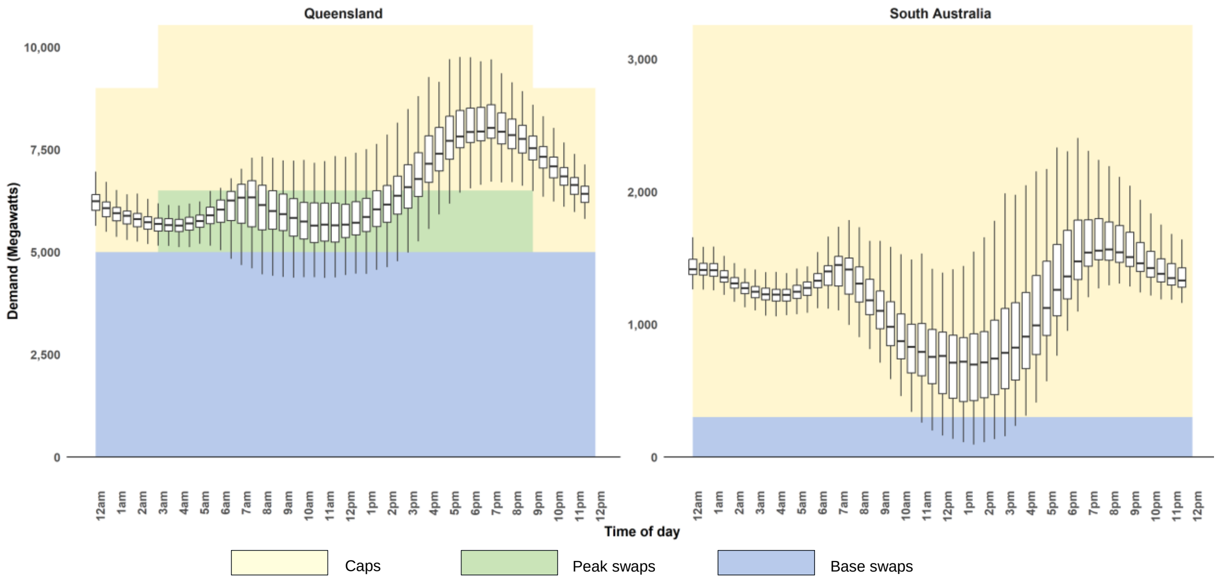
Figure 7.12 Caps, trade size



Note: This chart measures the size of cap trades in the year they were traded. 2024 is calculated up until 30 September 2024.
Source: AER analysis using ASX data.

The decrease in contract volumes and the contract size (that is, volume per trade) is likely because standard ASX contracts are less attractive for hedging in South Australia compared with other NEM regions, due to South Australia's unique demand and generation profiles. Contracts that cover a 24-hour period are increasingly less suited for the South Australian market. In Figure 7.13 the demand profile in Queensland shows a smaller drop in demand compared with South Australia. This less marked load profile means that a combination of base and peak contracts could be used and better suited in managing the price risk for load. In South Australia large base and peak contracts are less suited to manage the demand profile, as holding a large volume of swaps risks over contracting during hours around midday. Caps are insurance against high price volatility. Each contract ensures that the buyer pays no more than an agreed price ('strike price') for a quantity of electricity over a specified period. Hence, some retailers' preference is to use caps to manage price risks, particularly during the morning and evening peaks.

Figure 7.13 Performance of different contract products relative to load shape



Note: The boxplot shows the distribution of regional demand data. The box itself represents the interquartile range, containing the middle 50% of the data. The top edge of the box marks the upper quartile (Q3), indicating that 75% of the demand values lie below this point. The bottom edge represents the lower quartile (Q1), meaning 25% of the values fall below this level. The line within the box represents the median (50th percentile), which reflects the central value of the demand data. The whiskers extend to the maximum and minimum demand values, excluding outliers. The top of the upper whisker corresponds to the highest non-outlier value, while the bottom of the lower whisker indicates the lowest non-outlier value.
Source: Frontier Economics analysis for the AER, using ASX data.

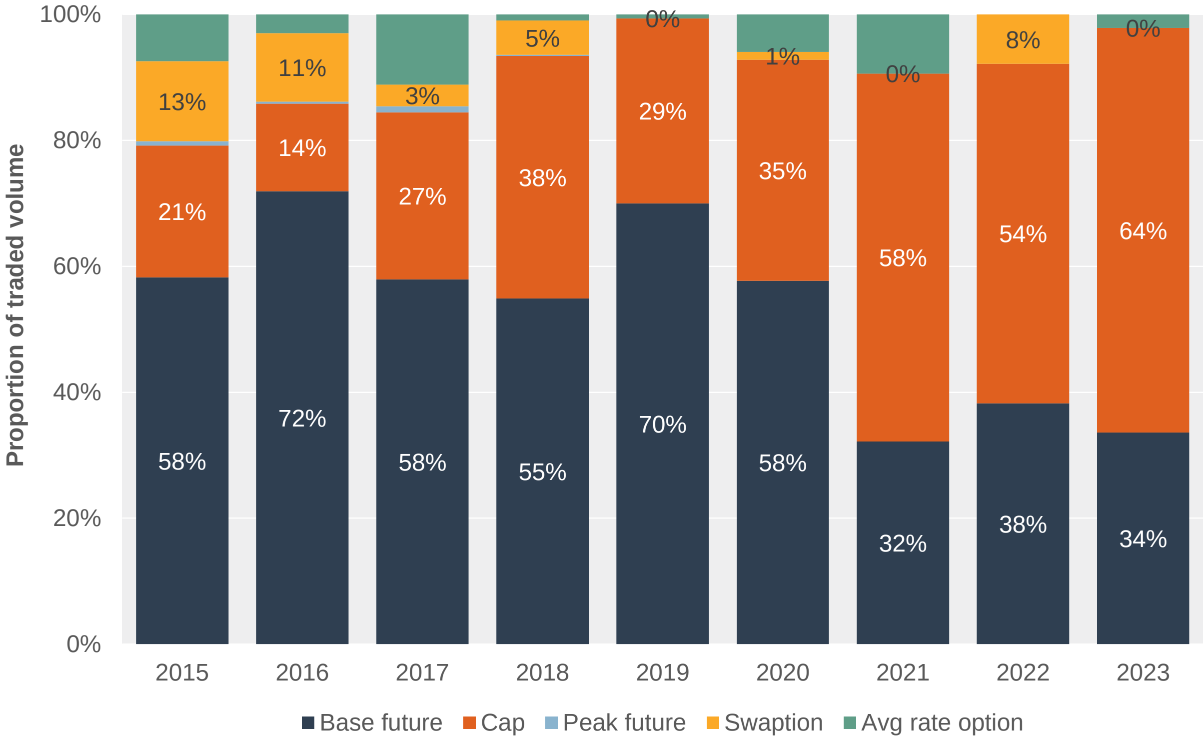
OTC trades have not been publicly reported since AFMA ceased their voluntary surveys of market participants in 2021–22. For WEMPR 2024, the AER collected contracts and contract-related data from selected South Australian market participants and found that the total volume of OTC contracting typically varies from quarter to quarter and is subject to seasonal effects. OTC base swaps declined at the end of 2021 but increased from mid-2022 and have remained relatively stable, while OTC caps declined at the end of 2022 before increasing from early 2023 and remaining stable thereafter.

One element of OTC trades that has developed in South Australia is the strike price of caps. Until recently, most OTC caps had a strike price of $300, in line with standard ASX caps. However, recently $100 caps have traded in South Australia. Trade in caps at a lower strike price indicates that buyers are willing to pay a premium for protection against smaller price increases. This may reflect increased price risk at lower price levels (driven by volatility) and challenges for buyers to manage this risk. Furthermore, the lower cap strike price and reduced base contracts level (Figure 7.11) may also indicate that participants prefer to use caps to insure against prices above $100 and bear the risks below this level.

The market is dominated by base futures and caps

The wholesale electricity market across most regions of the NEM is dominated increasingly by swaptions (section 3.1), but South Australia is dominated by base futures and caps. Since 2021, caps are the most traded contract in South Australia (Figure 7.14). This reliance on caps is likely due to the unique market conditions in South Australia, where spot prices are volatile and there is greater reliance on peak load generation due to the high proportion of wind generation. Negative prices have impacted the economics of operation for gas generators, which have minimum operational requirements. Some gas generators have offered their capacity at the price cap to avoid dispatch into negative prices. This dynamic has resulted in greater price volatility at times, increasing the market value of cap contracts. Furthermore, some retailers and commercial and industrial customers have opted to use PPAs with renewables to provide energy and purchase caps to manage the residual price exposures. While it is noteworthy that caps have overtaken base load contracts over the past few years, it is important to emphasise that the volume of caps is also falling – they are just decreasing at a slower rate than base contracts (Figure 7.15). The absence of swaptions in South Australia is likely due to swaptions volumes falling to such a degree that trading swaptions is unviable due to the lack of a liquid underlying contract.

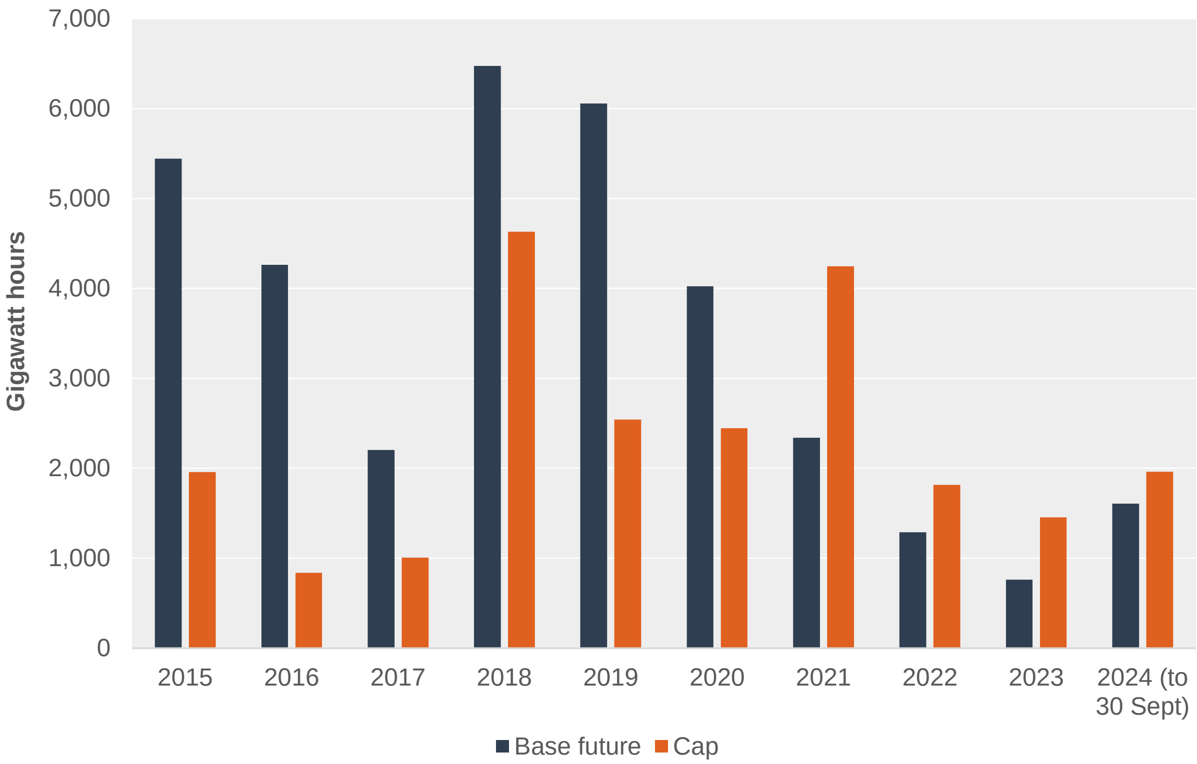
Figure 7.14 Composition of trades



Note: This figure illustrates the proportion of traded volume by contract type. They are calculated by years the contracts were traded.

Source: AER analysis using ASX data.

Figure 7.15 Traded volume, base futures and caps



Note: This figure illustrates the traded volume of base futures and caps. They are calculated by years the contracts were traded.
Source: AER analysis using ASX data.

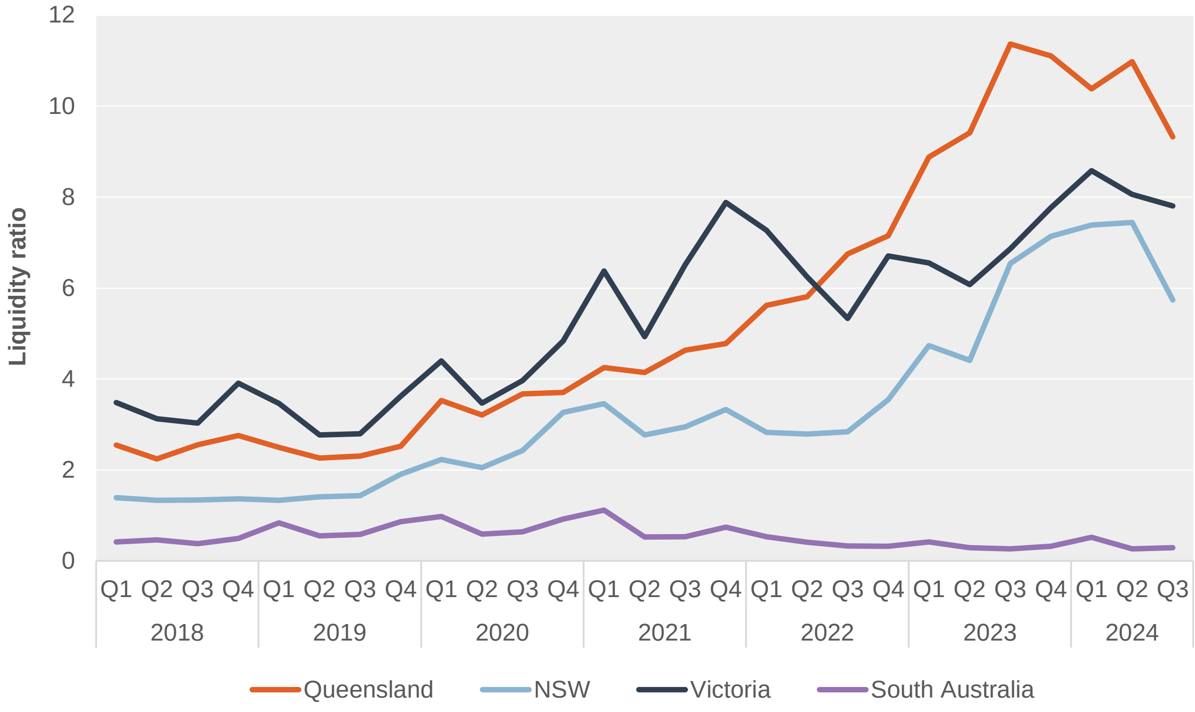
The contract market trades at low volume

The liquidity of a contract market refers to the ease with which contracts can be bought or sold. In a liquid market the sale price is independent of how quickly the sale is made. However, an illiquid market will not clear easily and buyers may have to pay more to purchase contracts quickly than if they purchased the same quantity over a longer period. The volume of trade and the liquidity of trading, while conceptually different, are often used synonymously. This is because markets with high trading volumes are often also very liquid. In this section, we examine measures of the volume of trade and whether price changes with the volume traded to gain insight into market liquidity.

In WEMPR 2022, we raised concerns about declining liquidity across the NEM and the likely implications for the functioning and attractiveness of contract markets if liquidity didn't improve. These concerns have reduced for most regions in the NEM because of an increase in contract trading over 2023 and 2024. In contrast, South Australian trading remains at low levels and indicators associated with liquidity are lower in South Australia than in other NEM regions (Figure 7.16).

South Australia's contract trade volumes have declined and the ratio of contract trades to electricity demand (liquidity ratio) remains low. While the liquidity ratio of other regions ranged from 7.2 to 10.9 in 2023–24, it was only 0.3 in South Australia. The divergence between the ratio trendlines for South Australia and all other regions illustrates that the South Australian contract market is being driven by different forces than those in the other regions.

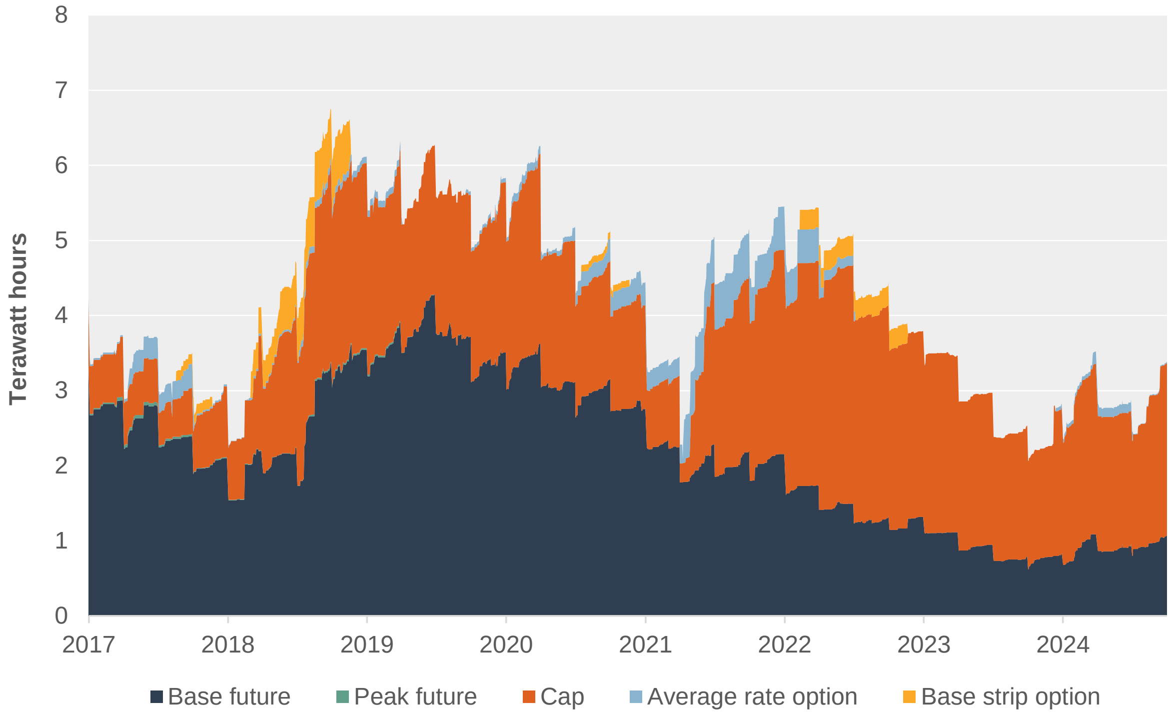
Figure 7.16 Liquidity ratio for all contract types



Note: Contract traded volumes used to calculate the liquidity ratio are traded volumes for the period specified in the contract (not the period in which the contract was traded). Demand volumes are native demand.
Source: AER analysis using ASX data and AEMO data.

'Open interest' refers to the total number of contracts held by market participants and can be an indicator of liquidity. It is more indicative than total trade of the extent to which participants are actually using contracts because the measure is less influenced by speculative trading. Since 2019, South Australian open interest declined from around 6 TWh in June 2019 to 3 TWh in September 2024.

Figure 7.17 Open interest

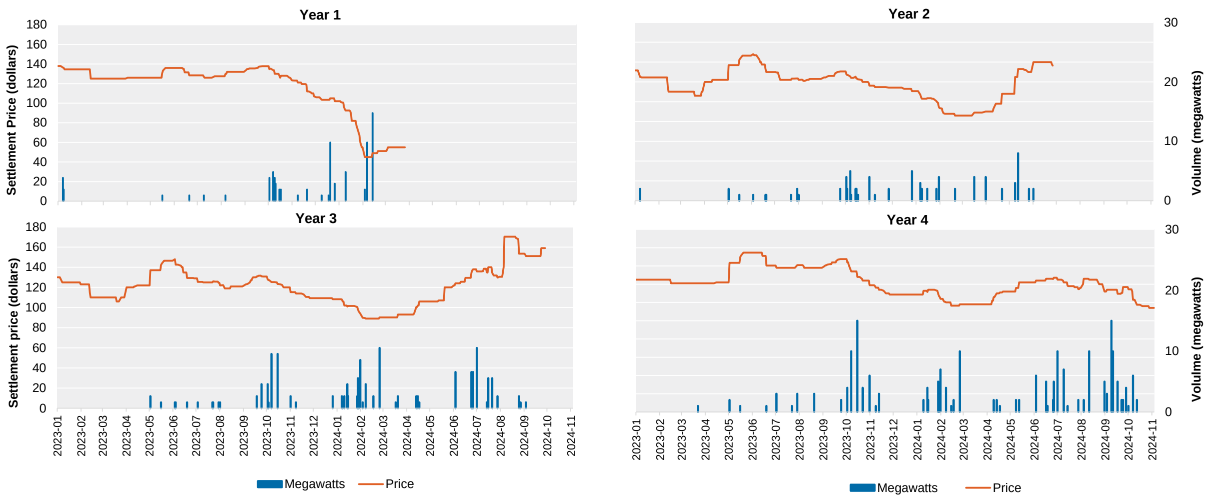


Source: AER analysis using ASX data.

Our examination of daily settlement price and daily volumes traded does not demonstrate a strong relationship between volume traded and contract prices for base products in South Australia (Figure 7.18). The absence of a relationship between volume traded and price is also observed for caps (Figure 7.19). In a very illiquid market, price is expected to fluctuate with the volume traded as supply and demand struggle to accommodate larger trades. In contrast to the liquidity ratio and open interest measures, the absence of a clear relationship between volume and price is a positive indicator of liquidity.

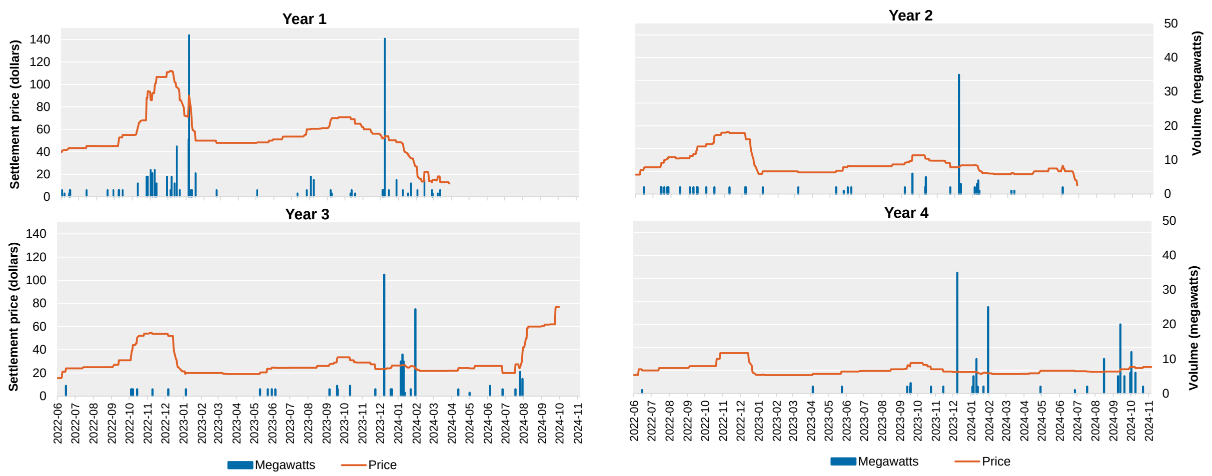
Development of market products that are more suited to hedging electricity price movements may improve trading in the future. Such contracts would allow retailers to specifically hedge the risk of higher prices during times when renewable generation is low and demand is high. Participants are likely to enter into bespoke agreements of this type. However, market trading has significant benefits over OTC trading due to better availability of market information for participants.

Figure 7.18 Liquidity in ASX contracts – base swaps



Source: Frontier Economics Analysis for the AER, using ASX data.

Figure 7.19 Liquidity in ASX contracts – caps



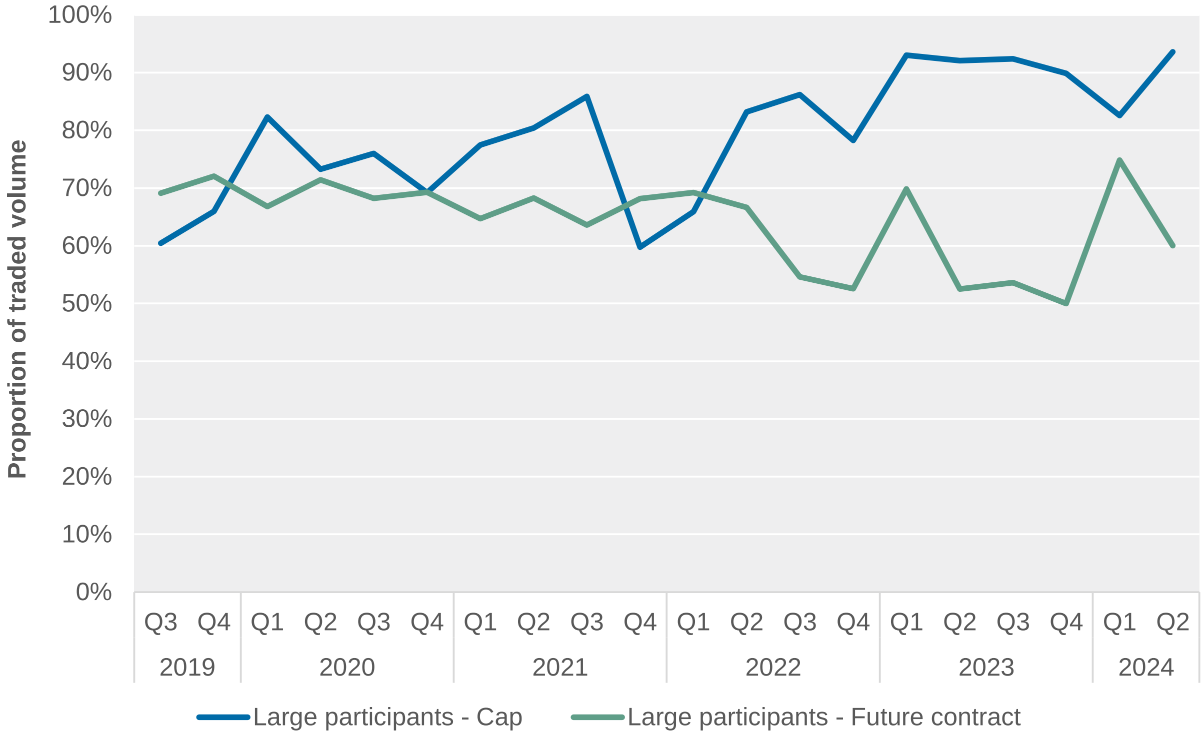
Source: Frontier Economics Analysis for the AER, using ASX data.

The majority of ASX trades conducted by large participants

Most of the contracts in South Australia are traded by large market participants. As in other regions, contracts are also traded by speculative traders, non-market participants and smaller electricity participants. However, between 50% and 75% of futures contracts and between 60% and 94% of cap contracts on the ASX were traded annually by large South Australian participants over the past 5 financial years (Figure 7.20).

We have only collected contract data from South Australian participants for this report. We will collect and report on contract trading across the NEM in future reports.

Figure 7.20 Proportion of volume traded by large participants in South Australia



Source: AER analysis using confidential contract data provided by the participants.

Hedging in South Australia internally and through PPAs and SRAs

Large South Australian participants hedge differently depending on their generation capability, load size and risk preference. However, some of them hedge through a combination of using their own generation capacity (if they have any), power purchase agreements (PPAs) and purchasing Settlement Residue Auctions (SRAs). We explore this structural feature of the market, and some of the conduct that arises from it, in section 7.3.4.

PPAs are used to facilitate investment in renewable energy projects. These provide long-term price certainty that makes it easier to secure financing.

SRAs are used to manage financial settlement related to congestion in the transmission network. When networks become congested, market participants can bid for the rights to financial settlement residues created by the congestion. The proceeds from the auctions are generally used to compensate affected participants, helping to balance the financial impacts of congestion. SRAs can be effectively used for hedging in South Australia as they reduce exposure to the risks associated with using the interconnector to Victoria. Some participants that are naturally long in Victoria can also use SRAs to shift their exposure into South Australia. SRAs are generally not considered firm hedges because they are dependent on interconnector flows and performance.

7.2.7 Cost of system security directions remains high

In South Australia, there are no coal plants, and gas units are uneconomic when demand is met by renewables. This has implications for system security and can result in AEMO requiring the operation of a minimum number of synchronous generators at times (also known as the minimum unit commitment or MUC). This requirement is used to mitigate potential system security risks associated with voltage control, frequency control, ramping, system strength or inertia.

Under 4.8.9 of the National Electricity Rules, AEMO has the power to intervene in the market to ensure system stability. AEMO has frequently directed participants in South Australia to operate their thermal plants to meet the MUC. Directed participants can recover the cost of directed generation through a compensation framework. Compensation is calculated based on direct cost, lost revenue and contract prices, minus any actual or potential revenue made, with any reasonable adjustment considered by the AEMC.

When directions are made, operation of assets is driven by AEMO rather than participants' offers. As directions increase it disrupts the economic dispatch order, which is otherwise based on offers.

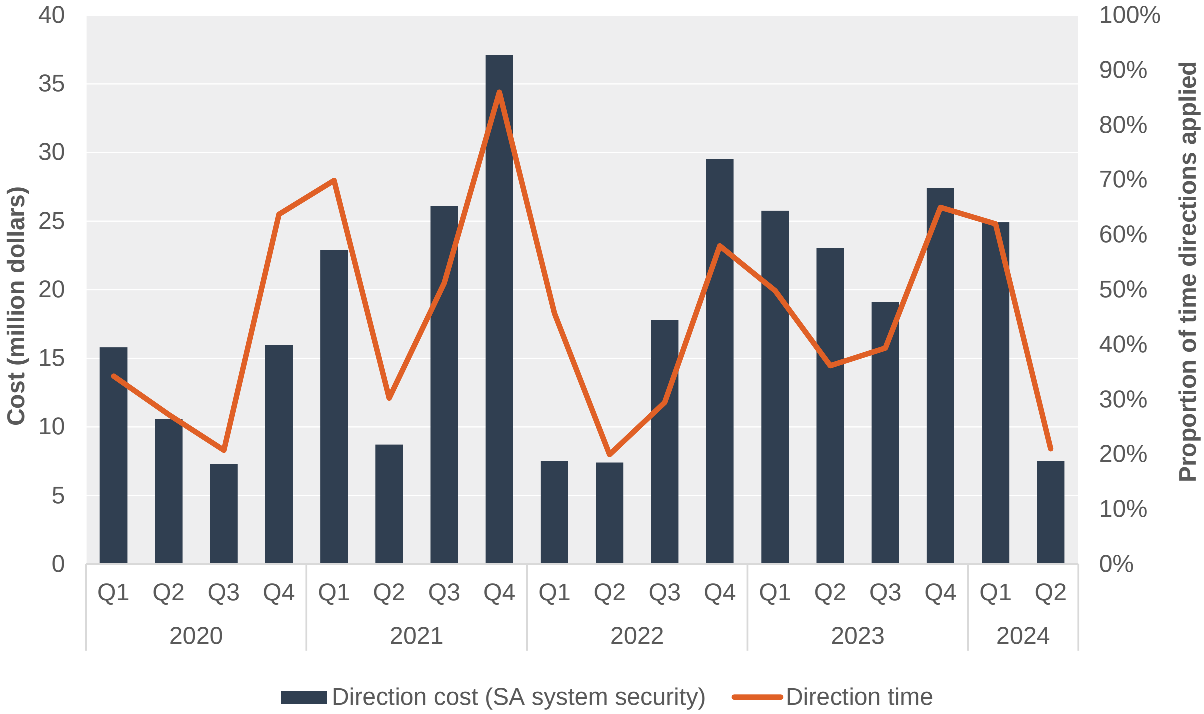
Before September 2022, there was a system strength requirement in South Australia for 4 units to operate. This decreased to a MUC of 2 units, when synchronous condensers were commissioned to address system strength needs.[94] However, this reduction did not have a significant impact on the proportion of time directions were applied or the costs of directions (Figure 7.21).

The costs of directions have fluctuated quarterly; over the past 2 financial years they have mostly remained between $17.8 million and $29.5 million. There were lower costs in Q2 2024 due to lower wind conditions and increased gas generation, meaning there were a minimum of 2 units online, driven by market conditions and a consequent reduced need for directions.

---

94 AEMO, SA synchronous generator requirements (Stakeholder update package), Australian Energy Market Operator, September 2022, accessed 22 November 2024.

Figure 7.21 Cost and proportion of time directions applied in South Australia



Note: Figure presents proportion of time in each quarter that direction(s) applied.
Source: AER analysis of AEMO data, Quarterly Energy Dynamics Q4 2023, Q3 2024.

7.2.8 System security directions affect market dynamics, costs and contracting

South Australian participants advised the AER that because directed units do not respond to spot price signals, directions can impact how non-directed generators are offered into the market by changing the competitive dynamics.

Directions have financial implications for participants that receive them. Participants have reported that directions make effective management of assets and fuel more challenging. Generating under direction means that fuel must be diverted from other intended uses, which can impact future fuel supply and future fuel costs. Switching on and off under directions increases unit wear and tear, which alters required maintenance dates and can, in some cases, damage or increase the risk of unexpected failure of plant components.

Participants noted their increased exposure to financial risk when directed, because it undermines their control over the economic allocation of their assets and resources across their portfolio.

The prevalence of directions in South Australia may also reduce incentives to contract. One participant told the AER that the impact of directions on market outcomes has the potential to disincentivise contracting because there is a general observation that free riding is a consistent challenge in South Australia. We understand this to mean that with a MUC there is less need for some retailers to hedge their load because prices are likely to be lower and less volatile in those circumstances. Another participant highlighted that the reduced control of economic allocation of resources limits their ability to optimise their use of contracting to manage customer load.

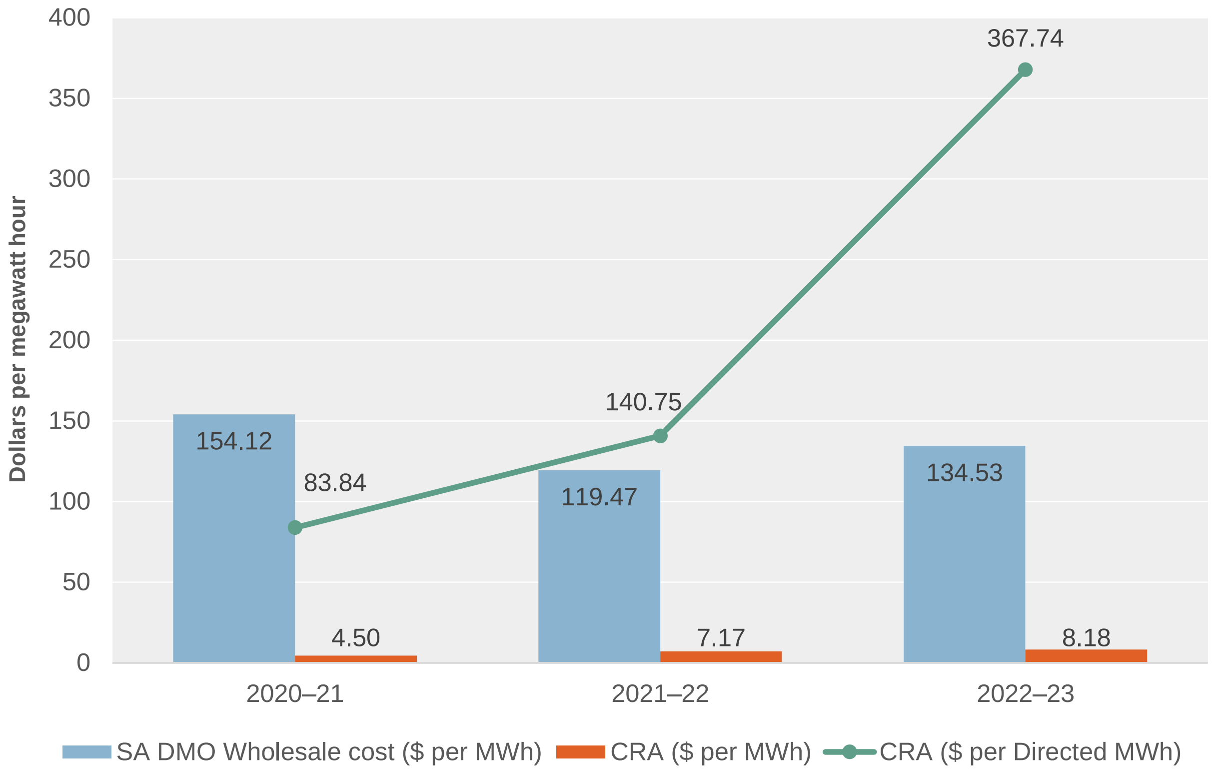
Cost per unit of directed capacity has more than doubled

The costs of directions have varied over time due to underlying generation costs. We have compared the cost of direction with the wholesale costs used to calculate the Default Market Offer (DMO) to better understand the potential impacts on consumers.[95]

The cost per directed MWh has increased from $84 per MWh in 2020–21 to $141 per MWh in 2021–22, and to $368 per MWh in 2022–23, likely driven by higher fuel costs for gas generators. The costs of these directions are included in the wholesale cost component of the respective annual DMO (Figure 7.22).

The Compensation Recovery Amount as a proportion of DMO wholesale costs for residential and small business customers has increased from 3% in 2020–21 to 5% in 2022–23.[96] This indicates that these directions, that are used to calculate the South Australian DMO, are contributing a material and growing proportion of the wholesale component of consumer bills when considered on a total and $-per-MWh basis.

Figure 7.22 Cost and directions as a proportion of the wholesale costs



Source: AER analysis using NEM data.

95 The Default Market Offer (DMO) is the maximum price that a retailer can charge a customer on standing offer in New South Wales, South Australia and South East Queensland.

96 The DMO wholesale costs per MWh is based on energy consumed by residential and small business customers and does not include large industrial load.

Outlook for system security in South Australia

In March 2024, the Australian Energy Market Commission (AEMC) introduced new requirements for procuring system security services.[97] This includes enhanced transparency of system security needs and AEMO's management strategies. In September 2024, AEMO released draft transitional services guidelines outlining the procurement process for these services, which may involve competitive tenders or direct requests for offers when feasible.[98]

AEMO's new public reporting obligations require detailed reporting on compensation paid to directed and affected participants. Additionally, AEMO's transition plan for system security will specify steps for managing security during the transition and track trends in issued directions, with the first plan published on 2 December 2024.

The new procurement framework may alleviate some of the concerns expressed by market participants.

7.2.9 Storage technology dominates provision of ancillary services

Frequency control ancillary services (FCAS) are services to keep the electricity system stable despite rapid fluctuations in demand or contingency events (Box 2.2). Section 2.4 highlights that FCAS costs across the NEM have reduced. In this section we examine the FCAS market in South Australia in more detail.

In South Australia there are 17 registered participants for the provision of FCAS. The revenue earned by South Australian participants for providing FCAS increased in 2022–23 (for 6 of the 8 services), before reducing in 2023–24 (Figure 7.23). The increase in 2022–23 was driven by increases in participant offers, resulting in higher FCAS prices.

In August 2023 AGL's Torrens Island battery commenced operation, with most of its FCAS offers made below $30 per MWh. This placed downward pressure on prices, with AGL becoming the largest supplier of FCAS in South Australia in 2023–24, surpassing Neon.

Storage technologies such as batteries are displacing thermal generators in FCAS markets due to better response times, efficiency and flexibility. Batteries also have lower operational costs than thermal generators, which require fuel and time to ramp up and down.

Since 2019–20, batteries have earned the largest proportion of FCAS revenue across all FCAS markets in South Australia. In 2023–24, the proportion of revenue earned by batteries was between 83-97%, whilst the proportion of revenue earned by thermal generators varied between 2% and 14%.

'Very fast' raise and 'lower 1-second' service markets were introduced in October 2023. In South Australia, 11 providers deliver these services. Prices for these services were initially much higher than for other FCAS services but started to fall in Q2 2024 (section 2.4.1).

---

97 AEMC, Improving security frameworks for the energy transition, Australian Energy Market Commission, 28 March 2024.

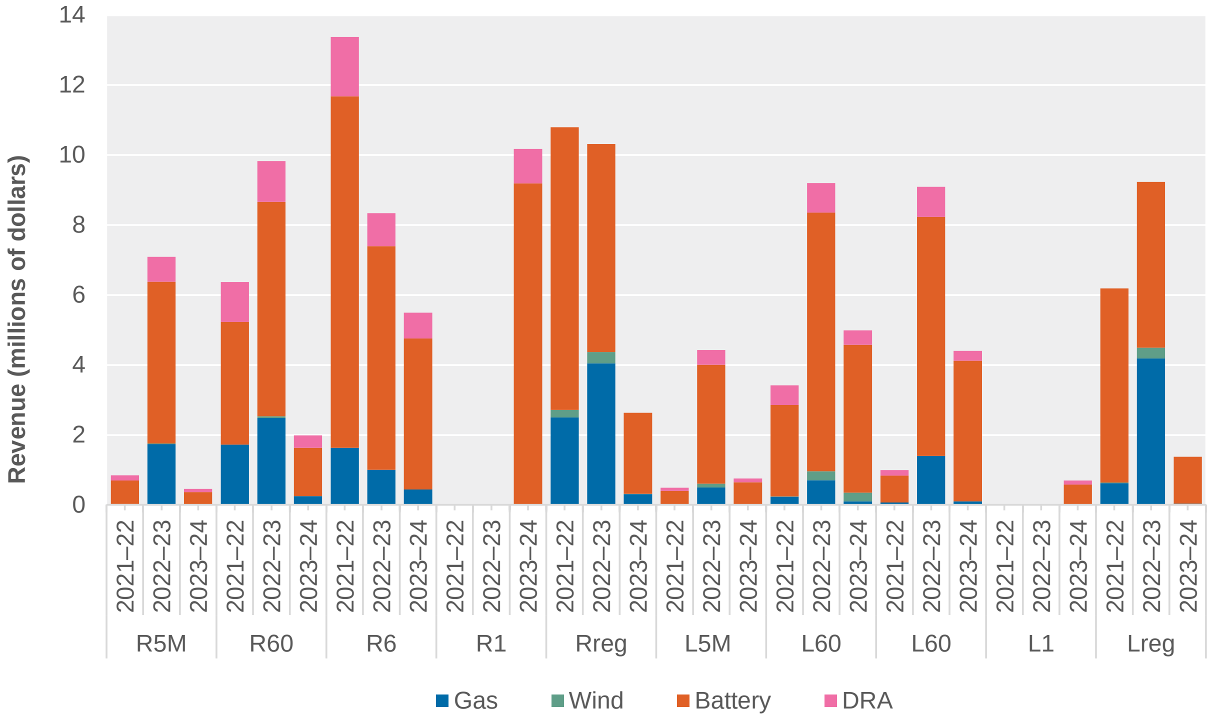
98 AEMO, Draft Transitional Services Guideline Consultation, Australian Energy Market Operator, 26 September 2024.

Batteries earn the largest proportion of revenue from providing very fast services – around 95% for raise 1-second and 99% for lower 1-second markets in 2023–24.

Demand response aggregators combine the demand response capabilities of multiple consumers to create a sizable resource that can be used to respond to price. Technologies with this capability include batteries, rooftop solar and solar heat pumps. Demand response aggregators in South Australia currently hold a market share of 8% to 16% across FCAS markets. The penetration of demand response aggregators has been facilitated by uptake of rooftop solar. Energy providers that have enrolled consumers to form part of an aggregated load can make use of residential rooftop solar with home batteries to provide a distributed network of energy that can then be used and treated as a single load.

Demand response aggregators contribute to contingency FCAS, which may require more energy than regulation FCAS. The market for raise 6-second FCAS earned the highest revenue across all markets at $13.83 million across 2022–23 and 2023–24. The raise 1-second market introduced in October 2023 earned $10.18 million in 2023–24 and was almost double the raise 6-second market's revenue for the same year. Most of the services are showing a downward trend in revenue with the same number of participants active in the market. The use of batteries for FCAS demonstrates that the advantages of new technology can lower costs to the benefit of consumers.

Figure 7.23 Global FCAS revenue by service type and by fuel type in South Australia



Source: AER analysis using NEM data.

7.3 Market structure in South Australia

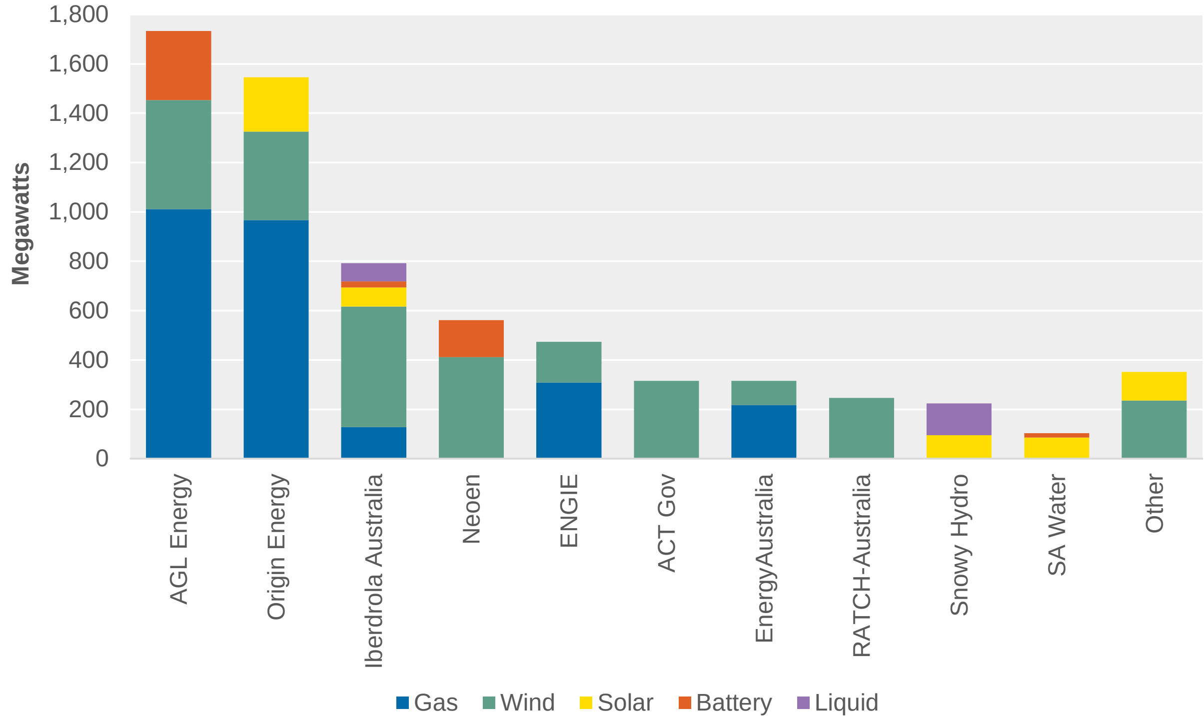
7.3.1 Market share

The South Australian market consists of 27 participants, most of whom have relatively small capacity. The 2 largest participants, AGL Energy and Origin Energy, own almost half of the region's capacity and have gas, wind, large-scale solar and battery assets (Figure 7.24).

AGL Energy had the greatest market share by capacity at 26%. Their generation fleet makes up 38% of gas capacity in South Australia, 16% of wind and 59% of battery. In 2023–24, AGL Energy supplied 19% of total generation in South Australia. For the same period, Origin Energy controlled 23% of market share by capacity and held 37% of the region's gas capacity, 12% of wind and 37% of large-scale solar. Origin Energy had the highest market share by output at 28%.

Ownership of intermittent renewable sources is less concentrated. Since the last report in 2022, almost 700 MW of renewable capacity was invested in the region, of which 64% was owned by smaller participants. This is explored further below.

Figure 7.24 South Australia market share by registered capacity, by participant, 30 June 2024



Note: Registered capacity share used registered capacity of all market scheduled generation (excluding market loads) registered as at 30 June 2024. Market share is determined using ownership declared to AEMO for each unit (DUID). Where an intermediary operates on behalf of the owner, the market share for that capacity is attributed to the intermediary.

Source: AER analysis using NEM data.

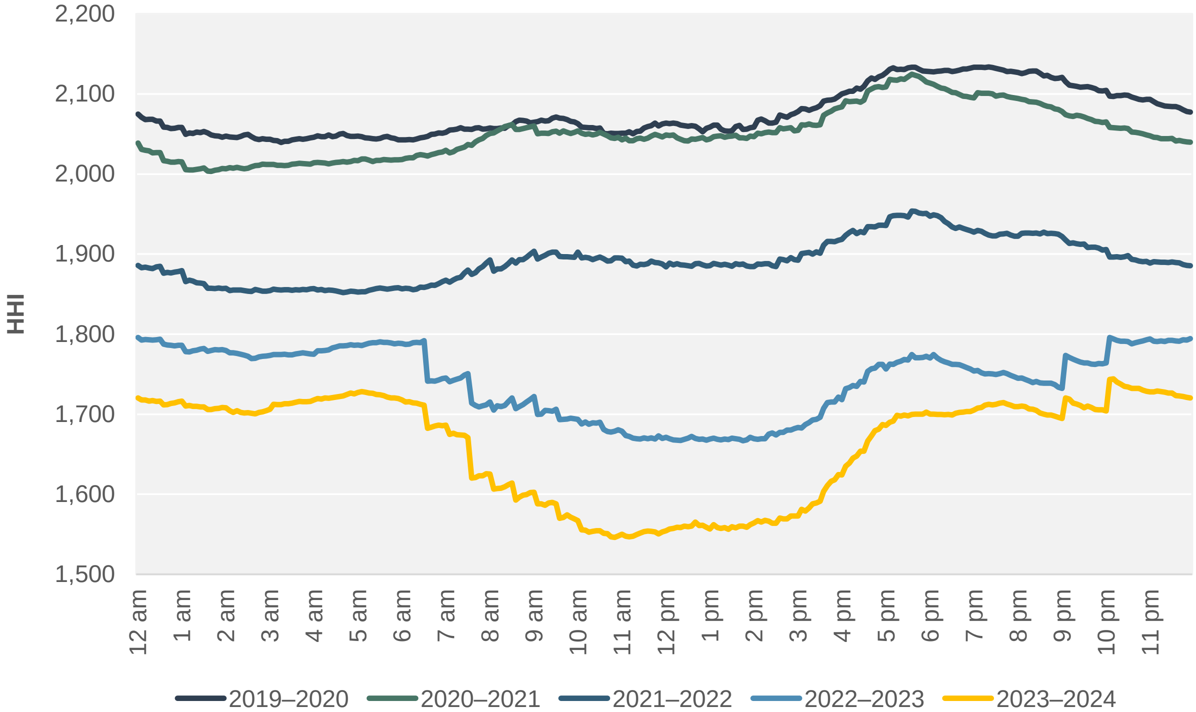
7.3.2 HHI

We use the Herfindahl Hirschman Index (HHI) to assess the market concentration of the South Australian market. We consider a HHI above 2,000 to be indicative of a highly concentrated market. In 2019–20 and 2020–21 South Australia had several participants with significant market share, resulting in a highly concentrated market. This concentration has reduced over time, as new entrants enter the market. Over the past 3 years, South Australia's HHI score has been below the 2,000 level. In 2023–24, renewable energy, on average, supplied 50% or more of demand throughout the day (Figure 7.3). However, the level of generation from renewable sources fluctuates, resulting in varying levels of concentration and thus competitiveness in the market.

In South Australia, the ownership of renewable generation is less concentrated compared with dispatchable generation. The concentration of available dispatchable generation – gas and batteries – may vary during the day due to plant availability. Ownership of dispatchable generation remains concentrated and plant is primarily dispatched during morning and evening demand peaks, when concentration can increase by up to 60%. Meanwhile, concentration reduces by up to 25% in the middle of the day (Figure 7.25).

Intermittent renewables have higher output during solar hours, leading to lower market concentration at these times. Despite the variable level of competition during the day, concentration in the region is showing a downward trend as more participants with renewable generation capacity enter the market.

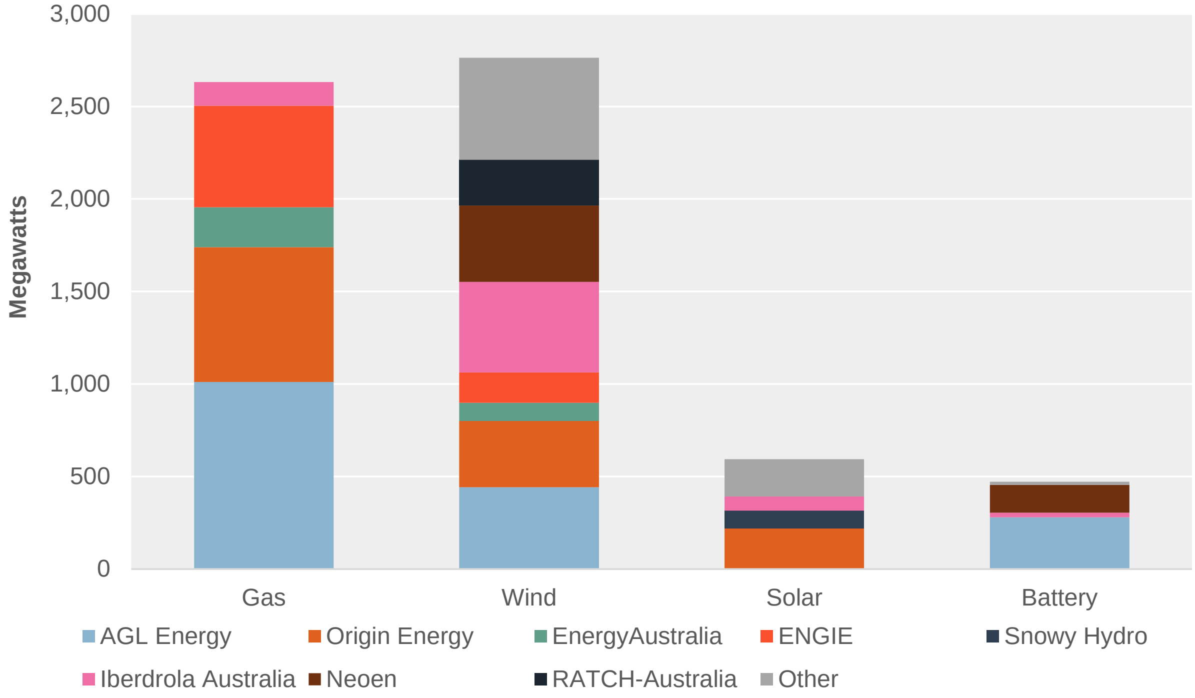
Figure 7.25 South Australia average bid availability Herfindahl Hirschman Index (HHI), by time of day, 2019–20 to 2023–24



Note: Calculations of HHI exclude the administered pricing period. HHI greater than 2,000 indicates the market is highly concentrated.

Source: AER analysis using NEM data.

Figure 7.26 South Australia market share by registered capacity, by fuel type, 30 June 2024



Source: AER analysis using NEM data.

7.3.3 Pivotal supplier

As outlined in section 7.3.2, the market can be highly concentrated during periods of low renewable output. During these times, the market must rely on dispatchable generation such as gas generators and battery storage. Ownership of these assets is highly concentrated in South Australia, with AGL Energy and Neoen owning 91% of registered battery capacity, while AGL Energy and Origin Energy own 75% of gas capacity. Also, some dispatchable capacity is either mothballed, under maintenance or it is uneconomic for them to generate due to minimum operational requirements. The absence of this capacity increases the market power of the remaining participants.

Based on a pivotal supplier test (PST), we observe that it is rare in South Australia for output from any particular generator to be necessary to meet demand. Output from the largest generator in the region was needed to meet demand less than 1% of the time in 2023–24, while output from the largest 2 generators was needed 7% of the time. As discussed in section 4.1.4, this reflects that South Australian generation comes from a multitude of renewable sources and typically has significantly more firming capacity available than needed to meet demand. Most of the time, the South Australian market has a large number of suppliers and a significant quantity of generation coming from low-cost renewables. However, when dispatchable generation is required, dispatchable units often have sufficient market power to influence prices. The lack of a pivotal supplier most of the time may indicate that when prices are elevated, multiple suppliers are offering at higher prices. Such instances of high prices may not be frequent nor predictable enough to act as a signal for new investment in dispatchable generation.

7.3.4 Vertical integration

Vertical integration is a key feature of the NEM. It occurs when a market participant combines ownership of generation with a retail customer base. In South Australia there is a high degree of vertical integration, which impacts incentives to contract and offers in the wholesale electricity market. In this section we examine the extent of vertical integration for several participants in South Australia and their incentives to contract.

A participant's incentives are impacted by both its level of vertical integration and its contracted position. Vertically integrated participants that are 'long in generation' have generation beyond what is required to meet retail load. These participants may sell contracts for their surplus generation or expose this surplus to the spot market. Where they choose to expose this to the spot market, generators will directly benefit from high market prices and have an incentive to try to push spot prices higher. Conversely, vertically integrated participants that are 'short in generation' have more retail load than generation capacity. These participants may buy contracts to hedge their load or expose this load to spot market outcomes. If unhedged, high spot market prices may result in losses for the participant and they have an incentive to bid their generation in a way that pushes down spot prices.

Contract prices are set based on the expectation of future spot prices. Spot price movements today can impact the current quarterly contract price, but also future contract prices. This provides an incentive for a participant to raise the spot prices, which potentially increase the participant's revenue from contracting.

Further, a participant's net position (generation minus retail load adjusted for their contract position) varies over time and so does the participant's interests in whether the spot price is high or low. The balance of the factors that influence a participant's position makes examining a participant's incentives complex.

Analysis in this section reviews standard contracts used by participants in the OTC and ASX markets. Bespoke contracts have not been reviewed as part of this analysis.

Some participants in South Australia use Settlement Residue Auctions (SRA) and/or OTC and ASX contracts to manage risk. We sought contract information from a selection of these participants.

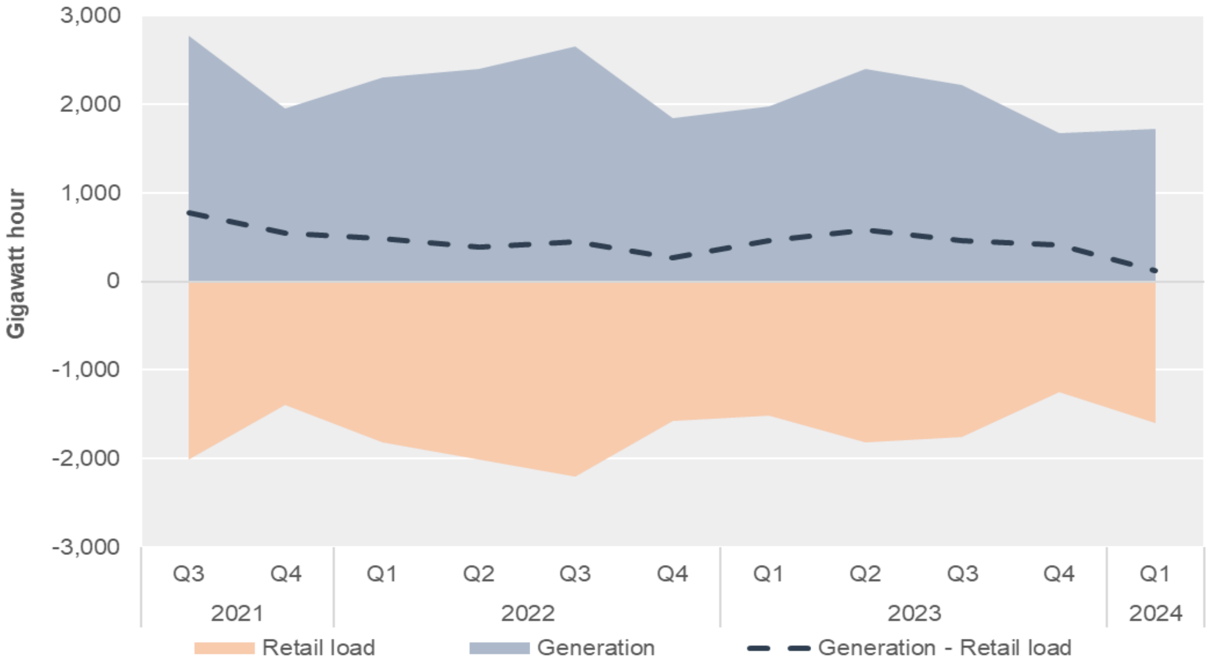
For confidentiality reasons we have not identified the participants but provide some insights on net generation positions and contract positions for the period between June 2021 and June 2024.

Over the past 3 years, at least one of these participants was either close to neutral or long generation. Each participant hedged differently, reflecting varying generation fleet (if any), portfolio across neighbouring regions, size of retail load and likely risk preferences. However, there was a notable shift in contract positions in 2022, likely driven by a change in participants' risk preferences as a result of tumultuous market events that year. In particular, some participants reduced their volume of contract trading, thereby reducing their exposure to the contract market. Some participants were also observed to switch from being net buyers of contracts to net sellers, while other participants switched from being net sellers to net buyers.

Over the past 3 years, changes in participants' preferences for different types of hedge products could have been driven by changes in a participant's load profile, the increasing role of PPAs in a participant's portfolio and market volatility. There has also been a reduction in contracting by these participants. This could be due to aging assets with reduced reliability, the changing role of the plant (with plant operating to firm capacity rather than as a base load), changes in risk preferences, or the inability of the market to clear at the desired volumes or price. Furthermore, the change in hedge positions around mid-2022 coincided with a time when wholesale prices in South Australia increased significantly due to high gas prices. Demand for caps during this time may have increased due to retailers wanting to reduce their exposure to high wholesale prices.

Figure 7.27 illustrates the combined net generation for several South Australian market participants. This shows the aggregate generation by those participants, including the generation from PPAs and is compared against their aggregate retail load. Over time the length of the participants' combined position has reduced, thereby reducing the incentive to sell contracts.

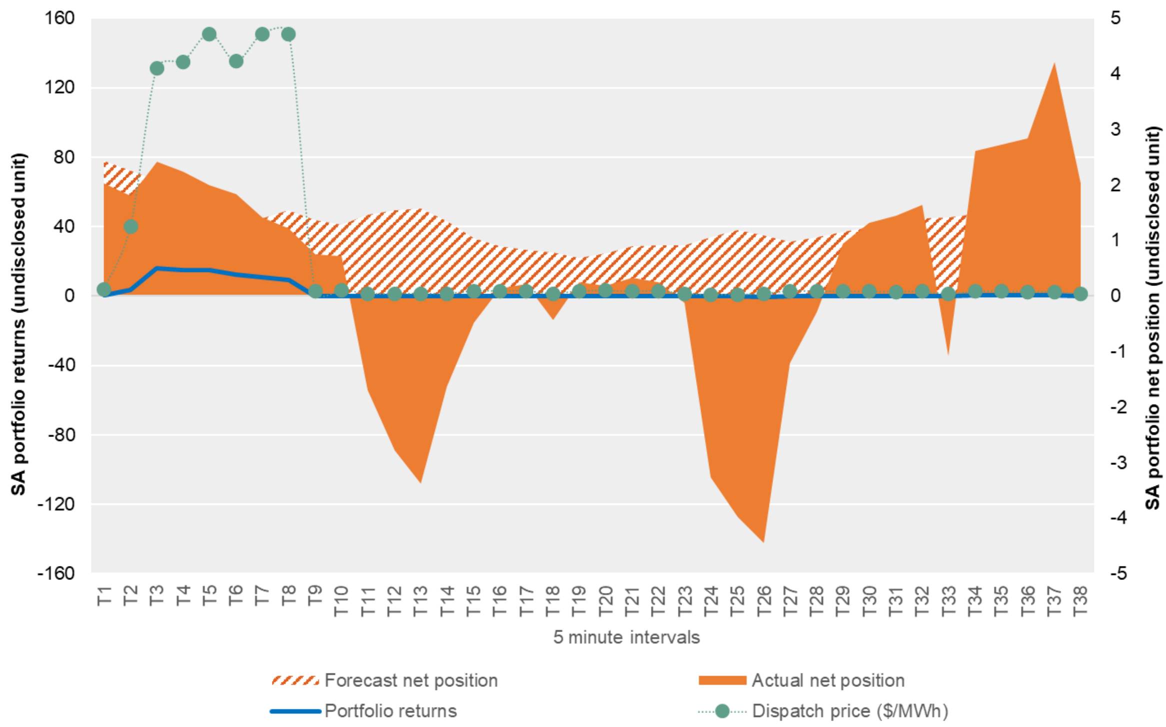
Figure 7.27 Total net generation of several vertically integrated participants in South Australia



Source: AER analysis using confidential data provided by participants.

The previous section assesses participants' net position on a quarterly aggregate level. However, a participant's net position is dynamic and could shift between long and short throughout a day and so does its incentive to influence price. For example, the AER analysed one instance where a participant had a forecast long position for the evening period. However, prevailing market conditions resulted in the participant significantly reducing its generation. The participant's net position shifted from long to short. While in this case the participant's overall returns did not appear to be significantly impacted by the shift from long to short over the evening period, this example illustrates the dynamic ability of participants to shift their net position.

Figure 7.28 Participant's net position shifts between long and short



Note: These values are not a true representation of the participant's net position and portfolio returns. The values are undisclosed for confidentiality reasons.
Source: AER analysis using confidential data provided by the participant.

7.3.5 Inter-regional trade

Inter-regional transfer is an important aspect of the market that promotes effective competition between regions. South Australia is connected to Victoria by 2 interconnectors – Murraylink and Heywood. Murraylink has a transfer capability of 220 MW into South Australia and Heywood has 600 MW transfer capability into the region.

When interconnectors are free flowing, generators in neighbouring regions can compete on price to supply energy. However, when transfers are impacted by congestion due to physical or system limitations, there is reduced competitive pressure across regions.

In 2023–24 the proportion of time that Heywood and Murraylink were congested was similar to previous years, with greater congestion typically in Q1 and Q4 when renewable output is greater (see section 4.3.1)

The construction of a new interconnector between South Australia and NSW, Project Energy Connect, is underway and expected to be completed in 2026–27. The completion of this 800 MW interconnector may change market dynamics in South Australia by facilitating the export of excess renewable generation and allowing the import of dispatchable generation when needed. It may also increase competitive constraints for large participants.

7.3.6 Australian and South Australian governments are supporting new investment

In February 2024, the South Australian Government announced it was adjusting its renewables target for net 100% renewables from 2030 to 2027; fast tracking it by 3 years.[99] Net 100% renewables means enough renewable generation over the course of a year to meet demand over the course of that year. At times, renewables will be surplus to demand and will be exported to other regions, while at other times electricity will be imported to meet demand and gas will still be used periodically to firm supply. While this is an ambitious target, it will be supported by South Australian and Australian Government investment. In July 2024, the Australian Government agreed to underwrite the development of a minimum of 1,000 MW of new wind and solar projects in South Australia and 400 MW of new storage capacity.[100]

The battery projects selected are Limestone Coast West, Solar River, Clements Gap and Hallett. These projects will be supported by the Australian Government's Capacity Investment Scheme (CIS).[101] In conjunction with various other battery projects currently under construction, South Australia's battery storage is forecast to increase to approximately 3,500 MWh by 2029–30.[102]

In addition, South Australia intends to increase generation with the commitment of more than half a billion dollars to the Hydrogen Jobs Plan to build a renewable hydrogen power plant by early 2026. The 200 MW hydrogen plant is intended to provide flexible dispatchable generation that could enhance grid security.[103]

The South Australian Government is also supporting the development of virtual power plants (VPP), including networks of thousands of home battery systems orchestrated to work together as one large battery to contribute to electricity reliability and stability.[104]

7.4 Participant conduct in South Australia

This section examines participant conduct in South Australia, focusing on the extent to which there may be exercise of market power. Isolated instances of transient market power are not sufficient to conclude that competition in the NEM is ineffective. When barriers to entry are low, temporarily higher prices provide a signal for new investment. However, the ability of participants to exercise market power may also indicate that the market is not workably competitive.

We assessed participant conduct in South Australia over the last 5 years to see if changes in offers can be explained by underlying supply conditions, whether participants' behaviour contributed significantly to price increases or market volatility, and whether market power

---

99 South Australian Government, New target for renewables, accessed 22 November 2024.

100 Minister for Climate Change and Energy, Joint media release: Delivering more reliable renewables in South Australia, 10 July 2024.

101 Department of Climate Change and Energy, the Environment and Water, Capacity Investment Scheme support 6 new projects in Vic and SA, 4 September 2024.

102 AEMO, 2024 ISP generation and storage outlook, Australian Energy Market Operator, 26 June 2024.

103 South Australian Government, Hydrogen jobs plan power plant project, accessed 22 November 2024.

104 South Australian Government, South Australia's virtual power plant, accessed 22 November 2024.

may have been exercised. We also explored how the transition towards lower emission, renewable generation has impacted the operation of different types of generation.

We have identified individual plants that may have exhibited economic and physical withholding behaviour between 2019 and 2023. Economic and physical withholding are not unlawful under the National Electricity Law or National Electricity Rules per se but can be both inefficient and harmful for consumers because it leads to higher prices that do not reflect costs. We have used new information collection powers to gather information and documents to examine this behaviour. In section 7.4.4 we closely examine the offer behaviour of a selected participant in South Australia.

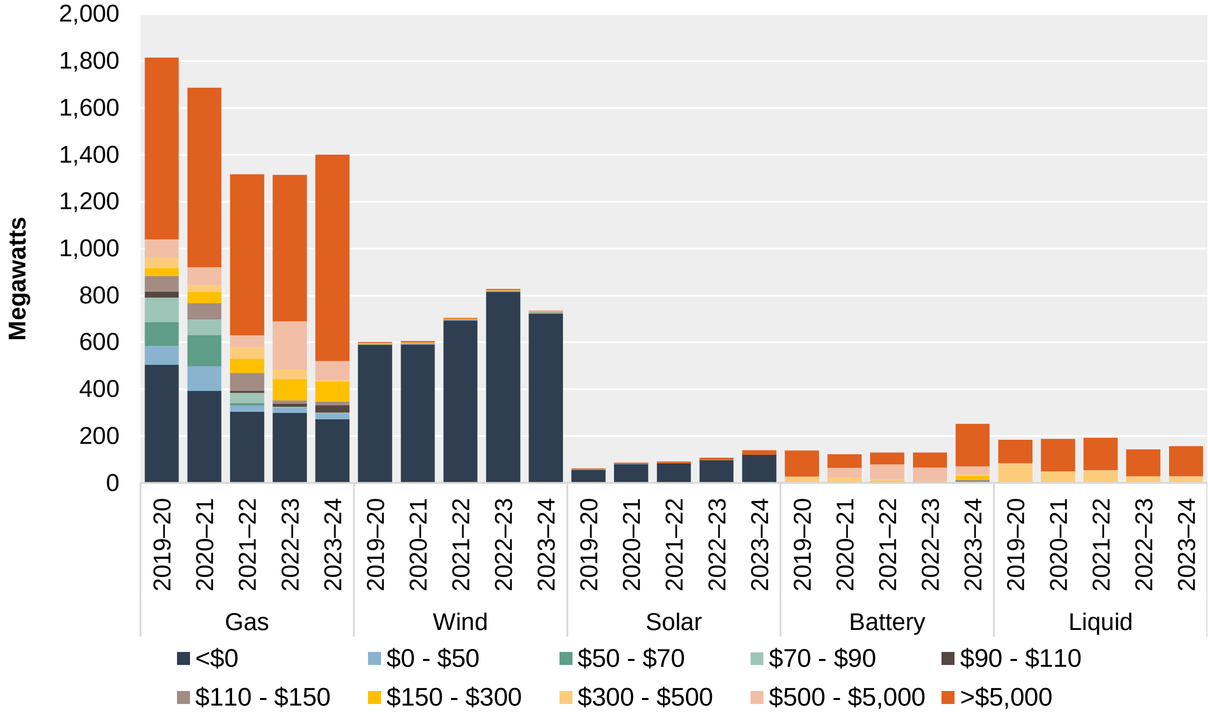
7.4.1 South Australia exhibits polarised energy offers driven by increased divergence in costs for energy production

Wind and large-scale solar offers accounted for 24% of total offers in 2019–20 and steadily increased to 37% in 2022–23. In 2023–24 large-scale solar and wind offers reduced slightly to 34%, predominately due to lower wind conditions. Almost all generation from wind and large-scale solar was offered at less than $0 per MWh, reflective of low operating costs. This dynamic put downward pressure on price during periods where renewable generation is high, particularly during the middle of the day.

Increases in negative prices have resulted in changes in generating and bidding behaviour by solar generators switching off their plants during daytime hours to avoid being dispatched at negative prices. An alternative to avoid being dispatched is to bid a plant at a high price when negative prices are anticipated. Such bidding practices may result in an inefficient price that is higher than necessary to meet demand if the anticipated negative prices do not actually occur. We examined instances of South Australian solar generators offering capacity at the price cap and found that, in some cases, the offers coincided with the South Australian price increasing to $17,500 per MWh (section 5.5.1).

Since our last report in 2022, AGL Energy’s 250 MW Torres Island Battery entered the market (August 2023). Unlike thermal plants, batteries can only discharge a limited amount of energy before their supply is depleted. Therefore, battery participants often offer their capacity at high prices to avoid uneconomic dispatch and tend to rebid their offers into lower prices when the price is sufficiently high. The new Torrens Island battery appears to have offered a significant amount of capacity into FCAS markets, as batteries are well suited to provide FCAS services, and secured a 14.3% proportion of the FCAS market share by output (section 7.2.9).

Figure 7.29 South Australia offers, by fuel type



Source: AER analysis using NEM data.

The proportion of gas capacity offered below $500 per MWh has steadily decreased from 53% in 2019–20 to 31% in 2023–24. This increase in offer price was partly driven by the worsening economics of operation of some types of gas generation assets, particular those with minimum commitment requirements and high startup costs. AGL Energy progressively closed its Torrens Island A power station in 2020 and 2021 and mothballed its Torrens Island B unit 1 in October 2021.[105] Most of the capacity removed through closures was previously offered at low prices. In 2022, AGL also announced the accelerated closure of Torrens Island B power station, which is now scheduled to exit in 2026 instead of 2035.[106] This closure is likely to further reduce the quantity of lower priced offers in South Australia, as these units currently offer 80 MW at less than $150 per MWh.

We have also observed a shift in gas offers from the mid-price range (between zero per MWh to $500 per MWh) to above $5,000 per MWh. We discuss this in more detail by reviewing the offers of several participants.

Origin Energy, AGL Energy, EnergyAustralia and ENGIE's offers account for 62% of market share by output. These participants have several dispatchable generation assets and the offered capacity by Origin Energy, AGL Energy and ENGIE has broadly increased during periods where there were lower levels of renewable generation (Q2 and Q3) and reduced during periods of higher renewable generation (Figure 7.30). EnergyAustralia's offers were more varied over time.

105 The first Torrens Island A units closed in September 2020 and the last unit closed in September 2022.

106 AGL Energy, Torrens Island 'B' Power Station to close in 2026, 24 November 2022.

We examined the offers of each of these participants.

- Origin Energy has 36% market share by output and its portfolio consists of gas, wind and solar generation. It has an agreement with ENGIE to access 240 MW of ENGIE's Pelican Point electricity production in exchange for Origin supplying gas to the station. Over the past 5 years, Origin's total offers have fluctuated seasonally. The proportion of offers between zero and $500 per MWh has reduced over time, from 10% in 2019–20 to 3% in 2023–24, while the proportion of offers above $5,000 per MWh has increased from 60% in 2019–20 to 80% in 2023–24.[107]
- AGL Energy has 19% market share by output and its portfolio consists of wind and gas generation and more recently battery storage. Over the past 5 years, AGL Energy's total offers have reduced significantly due to the shutdown of its Torrens A power station and the mothballing of one of its Torrens B units. Despite its reduced generation portfolio, AGL Energy's offers display a similar trend to those of other participants in South Australia. The proportion of offers between zero and $500 per MWh reduced from 41% in 2019–20 to 18% in 2023–24 and its proportion of offers above $5,000 per MWh increased from 23% in 2019–20 to 54% in 2023–24.
- ENGIE has 5% of market share by output and its portfolio consists of gas, diesel and wind generation.[108] In February 2024 ENGIE announced that its 2 diesel plants will be taken out of service from 1 July 2024 ahead of full closure in 2028. ENGIE's total offers have reduced from 765 MW in Q3 2019 to 491 MW in Q2 2022. Since Q2 2022, offers have varied with renewable output and seasonal effects. The proportion of offers between zero and $500 per MWh have also reduced over time, from 12% in 2019–20 to 10% in 2023–24, of which most were shifted to prices above $5,000 per MWh.
- EnergyAustralia has 2% of market share by output and its portfolio consists of gas and wind generation. There was a reduction in total offers in Q2 2021, but those offers increased slightly in Q4 2023. EnergyAustralia's proportion of offers between zero and $500 per MWh has been close to zero over the past 5 years and the proportion of offers above $5,000 per MWh increased from 53% in 2019–20 to 77% in 2023–24.

107 Offers between $0 per MWh and $500 per MWh.

108 This is inclusive of power purchase agreements, where the participants have trading rights over certain generation assets and the generation for these assets for an agreed price.

Figure 7.30 AGL, ENGIE, Energy Australia and Origin quarterly offers

Source: AER analysis using NEM data.

7.4.2 Access to fuel

We asked participants how access to fuel for gas-powered generation impacted their offer strategies for the period from 1 July 2022 and 30 June 2024. A participant reported that, while constraints on the supply of fuel forms part of the commercial optimisation of the participant's physical assets and contract positions, these constraints did not have a material impact on the participant's ability to offer their gas units into the wholesale electricity market.

Participants can access gas supply on the Short Term Trading Market (STTM), or through longer term bilateral gas contracts to hedge supply and demand risks. A participant reported that they did not enter into any longer-term contracts for gas supply in the last 2 financial years, given market dynamics and the liquidity of the STTM. Factors including gas supply, transportation and storage costs, and gas spot prices and contract positions, all contribute to decision-making on the pricing of gas-powered generation in South Australia. The tight supply and higher cost of gas contributed to higher fuel costs for some participants and reduced their access to additional short-term gas supply in the second half of 2022.

7.4.3 Price dynamics and economic withholding

In this section we screen for periods when market outcomes could be consistent with economic withholding. We explore the relationship between dispatch prices and surplus capacity (extra generation capacity that is not being used). This analysis allows us to identify periods when price may not be explained by market conditions and economic withholding may be occurring. While these observations provide a useful indication of market behaviour, the metrics used are indicative and a range of factors contribute to any specific market outcome.

The trends observed show that market behaviour, and the incentive to economically withhold, have evolved over time in response to the increase in negative prices in the middle of the day in the South Australian market. More detailed analysis of these observations is discussed below.

How we test for economic withholding

In 2022, we developed several metrics to help us assess economic withholding behaviour. This involved researching the approaches of other energy regulators and economists worldwide and adapting techniques to our context.

We developed a surplus capacity-price relationship metric to screen for periods when outcomes could be consistent with economic withholding. Surplus capacity (or supply cushion) is the capacity in a region that is available but not dispatched.

Our analysis focuses on the relationship between this surplus capacity and the dispatch price.[109] The surplus capacity-price relationship identifies 'outlier' periods when prices are higher than this relationship would typically predict. A low level of surplus capacity represents tight market conditions. In a competitive market, we would expect prices to be higher at these times because this is when higher cost generation is required to be dispatched. Periods when the price is higher than typical for the level of surplus capacity may indicate participants offering capacity strategically to raise prices, but these periods may be caused by other factors, such as network congestion.

We also developed a method to estimate the incentive for generators to withhold in any given period (returns from withholding capacity). This estimates a generator's potential gains from economic withholding behaviour. This measure is comprised of a 'price effect' multiplied by a 'portfolio effect'. The price effect estimates the impact on the price of reducing the supply of energy by a given amount. We calculate this based on the slope of the surplus capacity-price relationship, meaning that a steeper relationship implies a greater incentive. The portfolio effect represents the amount of energy the participant is generating in each period and thus the size of the portfolio that stands to benefit from an increase in the price. The returns from withholding capacity measure aims to provide an indication of the incentive to withhold and we refer to it as 'the incentive' in our analysis. This incentive to withhold is influenced by the contracts a participant enters into and may be reduced or increased depending on their overall contract position.

Shifting surplus capacity-price relationship has increased the incentive to withhold

We have analysed how surplus capacity-price dynamics have changed over the past 5 years and how this may have impacted the incentive to withhold capacity. This analysis allows us to identify periods when the price may not be explained by supply conditions and thus when economic withholding may be occurring. The balance of supply and demand is also influenced by renewable generation and changes in the amount of renewable generation are due to weather, which is outside participants' control. To account for this, we have also investigated how differing levels of renewable generation impact the relationship between surplus capacity and price.

---

109 See D P Brown and D E H Olmstead, [Measuring market power and the efficiency of Alberta's restructured electricity markets: An energy-only market design](http://www.jstor.org/stable/45172452), *The Canadian Journal of Economics*, 2017, 50(3): 888–870, http://www.jstor.org/stable/45172452.

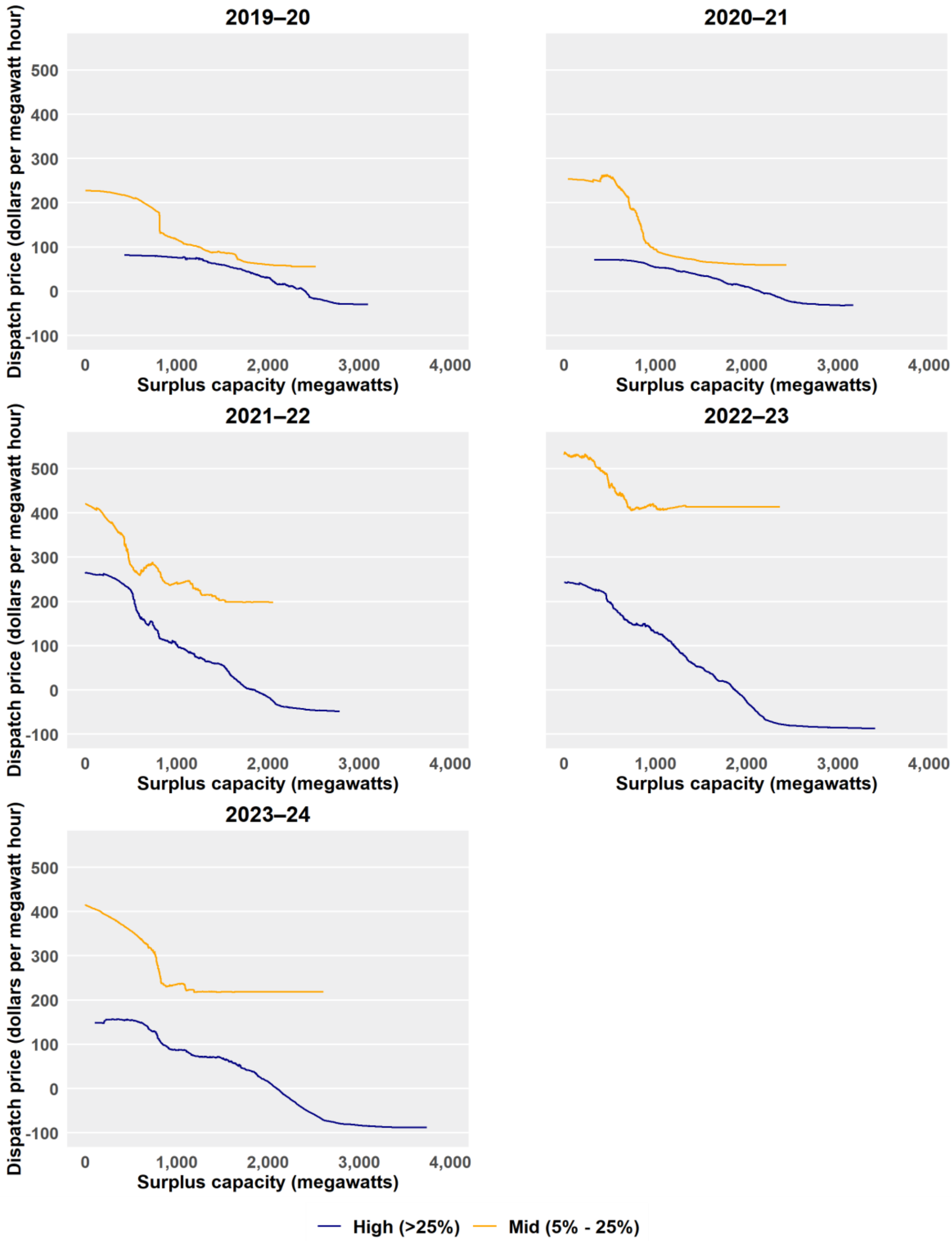
Figure 7.31 depicts the relationship between dispatch prices and surplus capacity over time. The blue line depicts the relationship between surplus capacity and price when renewable generation is greater than 25% of total capacity (high scenario) and the yellow line depicts the relationship when renewable generation is between 5% and 25% (mid scenario).

In 2019–20 and 2020–21 the mid scenario curve is steepest when the region's supply cushion is around 500 MW to 1,500 MW. This indicates that relatively small changes in market conditions could result in large changes in price. This sensitivity provides an increased incentive for generators to withhold capacity. In 2021–22 and 2022–23 the steepness of the mid scenario appears to reduce slightly and the whole curve shifted upward. While the reduced slope indicates less incentive to withhold, the upward shift indicates that overall market prices have increased. The upward shift of the curve could reflect dispatchable generators in South Australia moving offers to higher price bands.

Furthermore, the relative positions of the mid and high scenarios have changed over time. In 2019–20, the 2 curves were relatively close. This indicated that a sudden change in renewable output would result in a relatively small change in price. Between 2021–22 and 2023–24, the 2 curves moved further apart. This separation indicates that changes in renewable output results in more significant changes in price. For example, in 2023–24, when surplus capacity is around 2,000 MW, a change in renewable generation from greater than 25% of total output to between 5% and 25% of total output could result in a price rise from $15 per MW to $220 per MW.[110]

110 'High' levels of renewable generation occur when renewable generation constitutes more than 25% of total generation output.

Figure 7.31 Surplus capacity-price relationship in South Australia



Note: The figure plots the relationship between the dispatch price and the level of surplus capacity for every dispatch interval in a financial year. A steeper line indicates a more sensitive relationship between surplus capacity and price. 'Mid' refers to periods when wind and grid solar output is between 5% to 25% of total output in South Australia. 'High' refers to periods when wind and grid solar output is >25% of total output in South Australia.

Source: AER analysis using NEM data.

Price volatility has increased and is not always explained by the level of surplus capacity

We have observed increasing variability in prices that is not driven by changes in surplus capacity. For any given level of surplus capacity, we observe a much larger spread of prices than in the past. This price spread reflects a greater frequency of negative prices, due to renewable generation increasingly setting prices. Other contributing factors that may impact market outcomes independent of renewable energy are the reduction of mid-range offers, the presence of network congestion and variation in fuel costs and offers.

Increase in frequency of negative price events

Negative prices typically occur during periods of oversupply. In 2019–20 most negative prices occurred when surplus capacity exceeded around 1,500 MW. However, from 2020–21 to 2023–24, there is an increasing prevalence of negative prices when the surplus capacity exceeded around 500 MW. This implies that the increase in renewable penetration has resulted in negative prices at lower levels of surplus capacity.

During low supply conditions, thermal generators are sometimes needed to provide firming capacity. They often require higher prices to recover costs. The increased prevalence of negative prices during lower supply conditions present challenges for these generators, as it's difficult to avoid generating during negative prices. The occurrence of negative prices may fluctuate based on prevailing intermittent weather conditions and it may not be practical for some thermal plants to avoid dispatch into negative prices due to the plant ramping limit and/or minimum operating requirement. Unhedged generation could result in the participant generating at a loss. Some generators appear to have chosen to avoid this price risk by parking capacity at high prices. Others seem to have removed capacity from low prices in an attempt to avoid dispatch at times of low prices.

Increased renewable penetration may have reduced the profitability of some high-cost thermal generation. Orderly exit in response to market signals is appropriate and can lead to efficient market outcomes, as can adaptation to changing market conditions. However, these changed conditions may incentivise legacy thermal generation to push up the prices within the limits of their competitive constraints. If generators can successfully use market power in this way, it may indicate a lack of effective competition.

7.4.4 Case study – selected participant conduct analysis

In 2022, we developed new metrics to help assess the extent of economic withholding behaviour in the market.[111] For South Australia, we tested several dispatchable generators that submit higher bids during periods when prices are higher than expected given a level of surplus capacity and assessed the generator's profit incentive. We identified several participants in South Australia who increased their bids during such periods by more than $100 per MWh.

In addition to these metrics, we also reviewed participants' portfolio generation mix, market share and rebidding during significant pricing events.

---

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

Based on these results, we selected a participant in South Australia and examined the participant's conduct in more detail.

We used our new powers under the National Electricity Law to seek information in relation to offers between 2019–20 and 2022–23, including the motivation for selected rebids that coincided with wholesale prices exceeding $5,000 per MWh. The information provided sheds light on the reasons for the rebids as well as the financial and operational settings in which the identified power stations operated in South Australia. Market participants have assets across the various regions in the NEM and optimise their portfolios across those regions. Despite this, South Australia, has a state-based regional reference price, offers, contracts and retail load, which can be examined to provide insights into underlying price drivers and participants' incentives.

Long-term offer analysis

We reviewed the participant's net generation position (generation minus retail load) as well as its standard contracts held between 2019–20 and 2022–23. During this time, the participant had a significant presence in the South Australian energy market.

To the extent that a participant's load is hedged by its generation, there is less incentive for that participant to participate in the contract market. If a participant has excess generation above what is required to supply its load, it may contract this generation by making sales in the contract market. A net seller in general does not have an incentive to increase prices because it would be required to pay the difference of the price and the contract price to the counterparty. However, a participant may have an incentive to reduce prices, if the low spot price increases the value of its short position, by greater than its spot market loss.

In general, high prices increase costs to participants with retail load and are not desirable. However, if a participant held sufficient contracts to cover its retail load, they would be protected from the high prices. With its load protected, its generation would then benefit from high wholesale prices, providing an incentive to seek to achieve higher prices.

The participant bought and sold contracts, including caps. At times during this period, the participant held more contracts than it sold, with its net position therefore acting as a hedge against their retail load. While this means the participant stood to benefit from higher prices at those times, it also reflects the risk management the participant was undertaking on behalf of its retail customers.

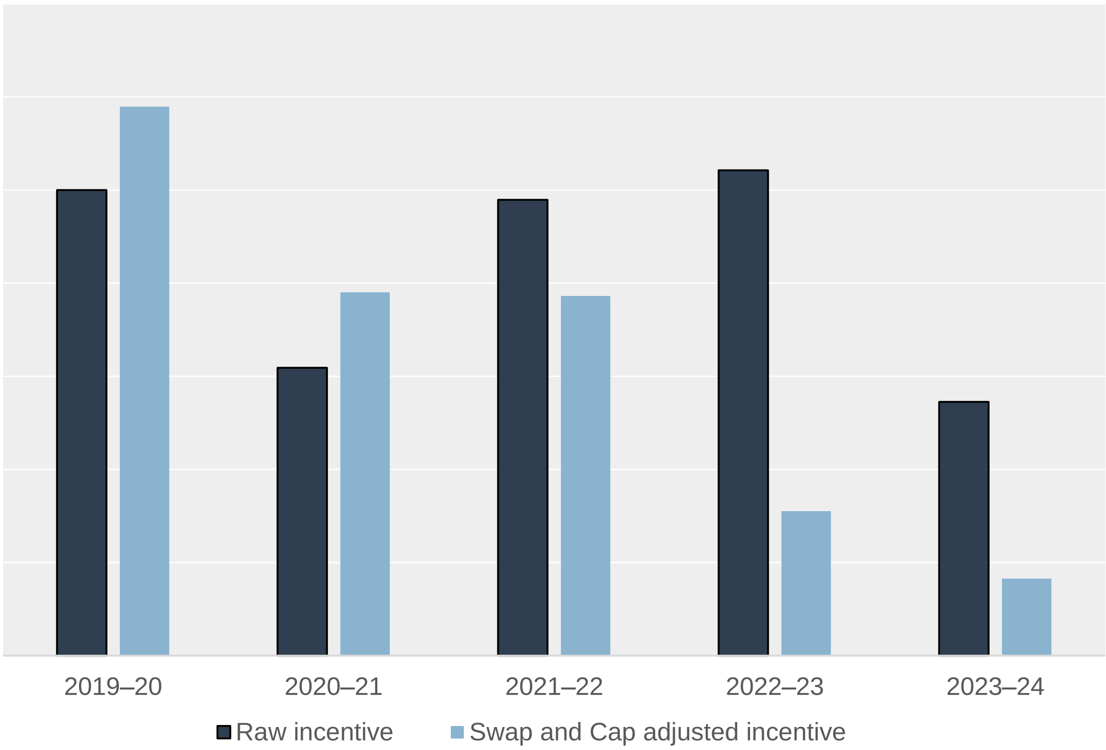
We note that bespoke contracts that have different terms to standard swap and cap contracts have not been considered in this assessment. We understand this is a small proportion of the participant's contracts.

Participant incentive to withhold has reduced in recent years

We also calculated the estimated incentive to withhold for the participant in South Australia. We derived our incentives estimate using 2 methods. The first method assumes the participant derived all revenue from the spot market and the participant's incentives are completely tied to spot prices. We call this the 'raw' incentive. The second method uses the participant's actual contract information to derive a contract-adjusted incentive. We consider the contract-adjusted incentive to be a better reflection of the participant's actual incentive.

The participant's raw incentive to withhold increased materially from 2020–21 to 2021–22 and reduced materially in 2023–24. After taking the participant's hedge contracts into account, the incentive to withhold was higher in 2019–20 and 2020–21, before reducing in 2022–23 and 2023–24. The fall in the adjusted incentive to withhold likely reflects various factors, including changes in the participant's contract position. Units are not disclosed on the chart for confidentiality reasons.

Figure 7.32 Selected participant's estimated average incentive to withhold



Note: The values are not disclosed for confidentiality reasons.
Source: AER analysis using NEM and confidential data.

Participant made significant returns from rebidding

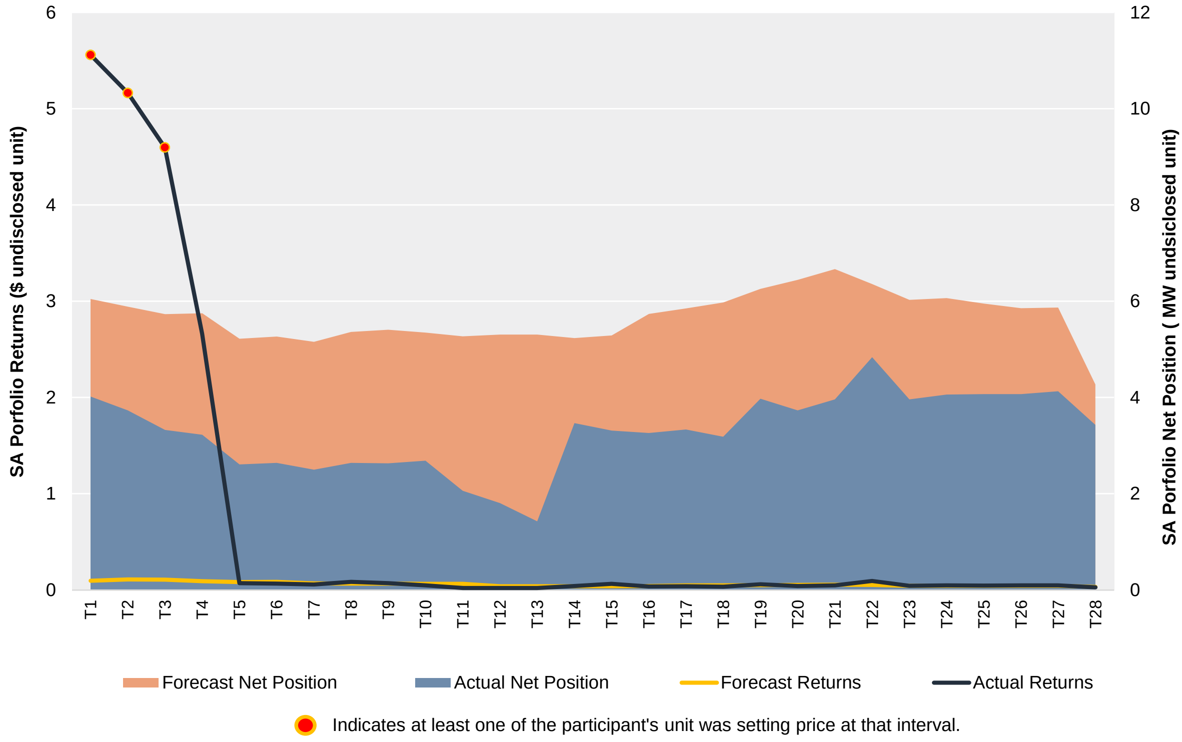
In addition to long-term offer analysis, we conducted discrete offer analysis to assess if economic withholding behaviour had occurred. We reviewed 14 rebids between 2019–20 and 2022–23 when prices exceeded $5,000 per MWh and the participant's rebids contributed to the high price events. We sought information on these rebids and gathered information on the participant's net position, forecast generation, forecast load and trader's logs. We examined which units were setting prices, the participant's forecast returns prior to the rebid and actual returns following the rebids. Figure 7.33 depicts an example of the information generated to assist us with our rebid analysis.

In this example, immediately after the rebid took place, the price increased, which also increased the participant's actual returns (black line) relative to the forecast returns (yellow line). The red dots in the chart indicate at least one of the participant's units was setting price at that interval. The participant's forecast net position considers the participant's contract position, retail load quantity and forecast generation and is shaded in orange in the chart, while its actual net position is shaded in blue.

By and large, we found that the participant made significant additional returns following the rebids and the primary motivation for the rebids was to optimise the participant's long position. That is, the participant had more generation than required to cover its retail and wholesale contractual obligations in these periods, and as such higher prices would benefit its portfolio. We consider the rebids that resulted in an increased return for the participant are examples of successful economic withholding behaviour. However, this analysis has been conducted on a small number of rebids between 2019–20 and 2022–23. We have not screened whether this participant had economically withheld outside these high price events.

The ability of generators to bid capacity at higher price bands is part of the design of the market and capacity bid at higher prices will not necessarily be dispatched. In an energy only market short periods of volatile prices, driven by tightened supply and demand conditions, may enable generators to recover their fixed costs and earn a return of their investments. Periods of high spot prices may also provide a signal for new generators to enter the market. However, to the extent that this leads to prices being sustained at a level higher than is necessary to meet demand, it can indicate a lack of competitive tension which can cause harm to consumers. As described in sections 6.1.2 and 7.3.6, significant new investment is also now being supported by government programs.

Figure 7.33 Example of a discrete rebid analysis



Source: AER analysis using NEM and confidential data.

We also examined the conditions prevalent when these rebids were made, such as surplus capacity conditions, the proportion of the participant's offers compared with total offers and the percentage of renewable generation. Participants may not always be able to generate at full capacity due to fuel constraints or plant outages. This analysis provides an indication of the extent to which opportunities for withholding behaviour could exist, noting that this does not necessarily mean that withholding has occurred. We also note this is likely to be a small subset of the broader opportunities for withholding. We also observe that high price events in South Australia are almost always associated with constraints on one or both of the 2 interconnectors between Victoria and South Australia. This is because it is difficult for prices to rise in South Australia when additional generation capacity in Victoria can be offered into the South Australian market. We observe that additional interconnection capacity between South Australia and other regions is currently being constructed.

We found that the frequency of conditions in which we assess there were the greatest opportunities for withholding in the market for this participant increased from 1.9% of the time in 2020–21 to 5.5% in 2021–22 and 2022–23 and then reduced to 1.9% in 2023–24. Average prices for the periods were $232 per MWh in 2020–21, $370 per MWh in 2021–22, $523 per MWh in 2022–23 and $550 per MWh in 2023–24. The prices are greater than the respective average annual price. The occasions also mostly coincided with the evening peak, between 6 pm and 9 pm. This indicates that opportunities for withholding appear to have increased between 2019–20 and 2022–23, and then moderated somewhat in 2022–23 and 2023–24.

7.4.5 South Australia provides insights for the energy transition

As South Australia transitions to a low carbon fleet, we observe changing incentives and drivers of generation, such as weather conditions for renewables, arbitrage opportunities for batteries and forecast prices for unit commitment of gas plants. The changes in incentives combined with changes in market dynamics have resulted in some emerging inefficiencies and costs.

- **Instances of allocative inefficiency:** The increase in renewable penetration has increased the frequency of negative prices in the region and has at times led to participants bidding capacity into high price bands to avoid dispatch. This conduct has been observed for a range of different generation types, including gas generators and by solar generators that have very low variable costs and should have no reason not to generate at any price above zero. These offers have in some cases resulted in high dispatch prices and allocative inefficiencies in the market because the electricity that consumers demand was not provided by the lowest cost supply at the time.
- **Increased costs due to volatility:** Offers in South Australia are becoming more polarised, with an increased proportion of offers priced below zero and above $5,000 per MWh. The offers above $5,000 per MWh are increasingly a reflection of operational decisions rather than a reflection of underlying cost. This dynamic has resulted in a steepening of the offer curve for South Australia, where small changes in demand or supply could result in large price changes. The combination of a steep offer curve and variable renewable generation has increased price volatility in the market. Price volatility imposes costs on retailers, which must manage and or mitigate this volatility. The associated costs are typically passed onto consumers. In addition, it appears to be more difficult to hedge price risk, as evidenced by a shrinking market for currently available hedging products.
- **Increased incentive to withhold and opportunity to exercise market power:** The reduction of mid-priced offers over time has created greater incentives to withhold, as a participant could trade a smaller proportion of their generation for the opportunity to earn higher returns. With more thermal plants due to exit the market, the remaining

participants' share of dispatchable generation will likely increase. As such, opportunities for economic withholding, when firming capacity is need, may also increase in the future.

The dynamics outlined above could impact market efficiency. However, the completion of the 800 MW interconnector between NSW and South Australia in 2026–27 may change market dynamics in South Australia by facilitating the export of excess renewable generation and allowing the import of dispatchable generation when needed. This further highlights the increasing importance of transmission performance in reducing opportunities for economic withholding and other conduct that could lead to inefficient wholesale price outcomes. When the connections between South Australia and the rest of the NEM are constrained, energy consumers are more exposed to the local dynamics of the South Australian market.

We have examined the conduct of market participants in the South Australian wholesale electricity market and have identified occasions when participants optimised their wholesale position to make additional returns.

While high price periods associated with market volatility may in and of themselves incentivise the market to evolve to efficiently provide low emissions energy to consumers, this dynamic is likely to be self-limiting. New technologies that substitute for thermal generation, such as battery storage, produce revenue from volatile price changes. A level of volatility is required in an energy only market for storage to operate profitably, and this level may need to be higher to support larger and deeper storage requirements. Alternatively, a compensation arrangement where generators do not have to rely on high spot market prices to recover their capital costs may be used to support new entry.

The market can be conceptualised as one market with 2 different sets of conditions that overlap to some degree. Either demand is being met by renewable energy or renewable energy is insufficient at a given moment and dispatchable supply is required. We can expect the overlap between these 2 sets of conditions to reduce in the future as the market continues to transition.

The revenue streams available from the current market design may not be optimal in such a future scenario. Highly volatile prices may create too much uncertainty for investors to support new generation. A highly volatile wholesale spot market also creates financial risk for retailers and subjects them to the cost of managing this risk on behalf of customers. A modified market design should not only enable generators to recover their long-run marginal costs, while meeting emissions objectives, but should also:

- enable market entry of technologies and products that can help manage intermittency of supply and volatility of demand, both intra-day and seasonal shifting
- enable innovation in risk management products to reduce the costs of volatility and support competition
- deliver competitive tension in the provision of energy, firming and of essential system services.

Glossary

Term	Definition
ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AFMA	Australian Financial Markets Association
ARENA	Australian Renewable Energy Agency
ASX	Australian Securities Exchange
AVP	AEMO Victoria Planning
BESS	Battery energy storage system
CCGT	Combined cycle power plant
CCS	Carbon capture and storage
CEC	Clean Energy Council
CEFC	Clean Energy Finance Corporation
CER	Consumer energy resources
CIS	Capacity Investment Scheme
DCCEEW	Department of Climate Change, Energy, the Environment and Water
DMO	Default market offer
DUID	Dispatch unit identifier
ESB	Energy Security Board
FCAS	Frequency control ancillary services
GJ	Gigajoule
GW	Gigawatt
GWh	Gigawatt hour
HHI	Herfindahl Hirschman Index
Hz	Hertz
ISDA	International Swaps and Derivatives Association
ISP	Integrated System Plan
LCG	Large-scale Generation Certificate

Term	Definition
LCOE	Levelised cost of energy
LCOS	Levelised cost of storage
LRET	Large-scale Renewable Energy Target
LRMC	Long run marginal cost
MIC	Market impact component
MUC	Minimum unit commitment
MW	Megawatt
MWh	Megawatt hour
NEM	National Electricity Market
NER	National Electricity Rules
OCGT	Open cycle gas turbine
OEM	Orderly Exit Management
OTC	Over the counter
PEC	Project Energy Connect
PPA	Power purchase agreement
PST	Pivotal supplier test
QNI	Queensland-NSW Interconnector
RERT	Reliability and Emergency Reserve Trader
REZ	Renewable Energy Zone
RIT-T	Regulatory investment test for transmission
SRA	Settlement Residue Auctions
SSSP	System strength service providers
STIPS	Service target performance incentive scheme
STTM	Short Term Trading Market
TNSP	Transmission network service providers
TWh	Terawatt hour
VNI	Victoria to NSW interconnector
VPP	Virtual power plant
VWA	Volume weighted average
VWAP	Volume weighted average prices

Term	Definition
WEMPR	Wholesale electricity market performance report