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State of the energy market

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1 An overview of an energy market in transition

Australia's energy markets are in the midst of a major transition driven by decarbonisation, the decentralisation of energy services and new technologies.

This chapter describes recent developments across our evolving markets, providing an overview of the key issues and outcomes explored in further detail in chapters 2 to 6.

1.1 Context

Concerns about the impact of coal and gas generation on carbon emissions have led Australian governments to set renewable energy targets and offer incentives and support for low-emissions power generation. As the market for these technologies continues to grow, scale economies and technological improvements have strengthened their cost advantages over coal and gas plants. Generation businesses responded to these incentives by investing in wind and solar farms. Energy consumers also responded by installing rooftop solar panels and, to a lesser extent, batteries.

In contrast, Australia's coal plants are aging and increasingly costly to operate. Many require high levels of maintenance and refurbishment to keep them running. They are also prone to unplanned outages, sometimes prolonged outages, which make them increasingly unreliable. As these plants near the end of their economic lives, many are earmarked for closure over the next decade. Meanwhile, no energy business has invested in new coal-fired generation in Australia since 2013 and no coal plant proposals are currently being considered. There has also been relatively little recent investment in gas generation, except for Tallawarra B, a new gas peaking plant in New South Wales that added 320 megawatts (MW) of capacity in early 2024.

Almost all grid-scale generation investment since 2012 has been in renewable sources, initially mostly in wind farms but more recently in solar farms as well. The level of renewable energy injected into the grid regularly sets new records. On 6 November 2024, renewable sources supplied 75.6% of total generation during the half-hour interval ending at 1 pm, marking the highest share recorded to date.¹ In the future, the power system will at times be fully supplied by renewable energy.

Alongside this, while the wholesale market has been changing, energy customers have responded by consuming less electricity from the grid across the middle of the day, being more energy efficient and generating their own power through rooftop solar systems and installing batteries for storage.

While electricity consumption in the National Electricity Market (NEM) rose by 3.4% in 2024, about one-third of this increase was met by increased rooftop solar generation rather than being supplied through the grid.

The growth in solar generation has further deteriorated the economics of coal generation. When rooftop solar generation peaks in the middle of the day, the demand for grid-sourced electricity collapses (at times falling to zero in some regions). Coal plants are not engineered to run at low levels of output, so may offer negative prices to maximise the likelihood of being dispatched. Prolonged periods of negative spot prices, and potentially having to shut down during the day, makes it harder for coal plants to operate profitably.

The transition to a low emissions energy system can deliver significant benefits to consumers. Renewable energy has a very low marginal cost and relatively low investment cost compared with traditional generation and, if integrated efficiently into the power system, will deliver low-cost sustainable energy. For customers, resources such as rooftop solar and battery systems can help them save on power bills and manage energy use in ways to suit their needs, while also empowering them to take initiative on environmental concerns.

But the rapid transformation of Australia's energy system poses numerous challenges, which have become a central focus for governments, energy businesses, market bodies and regulators. These challenges include:

- ensuring enough generation and firming capacity, such as storage, is being built to offset the closure of coal-fired plants
- ensuring new generation capacity is located efficiently so it can be connected to the grid and delivered to customers at lowest cost
- ensuring new transmission network investment to support the transition is efficient and timely
- managing the safety and technical security of the grid as the generation mix changes
- efficiently integrating consumer energy resources into the system in the long-term interests of consumers
- ensuring all consumers benefit from the transition
- optimising the role of gas in the transition to firm the renewables.

Managing these challenges is complex. It requires reform to market design and regulatory frameworks, coordinated planning, the rollout of supporting technologies, changes in the way energy businesses operate and new protections for consumers.

Increased electrification is an inherent part of the transition; if we can decarbonise our electricity sector by moving to renewables, we can then decarbonise other parts of the economy. AEMO forecast that future energy consumption from the grid will grow by around 108% between now and 2050 as the economy moves towards more intensive electrification of industry and transport. Business and industry consumption is forecast to more than double from today's 145 terawatt hours (TWh) to almost 345 TWh in 2050.²

1 AEMO, [Quarterly Energy Dynamics Q1 2025](#), Australian Energy Market Operator, 7 May 2025, accessed 6 June 2025. For this figure, renewable generation includes grid-scale wind and solar, hydro generation, biomass, battery generation and distributed PV, and excludes battery load and hydro pumping. Total generation is defined as NEM generation plus estimated PV generation.

2 AEMO, [2024 Integrated System Plan](#), Australian Energy Market Operator, June 2024.

Current projections indicate that while households will also consume more energy, they are unlikely to draw much more from the grid in 2050 than they do now. Higher energy needs will be mostly met from their own investments in rooftop solar and counteracted by improved energy efficiency. Consumers will also play a vital role in meeting future grid demand for industry. Integrating rooftop systems, home batteries and other consumer energy resources into the system will allow households to export rooftop solar and stored energy into the system when it is needed.

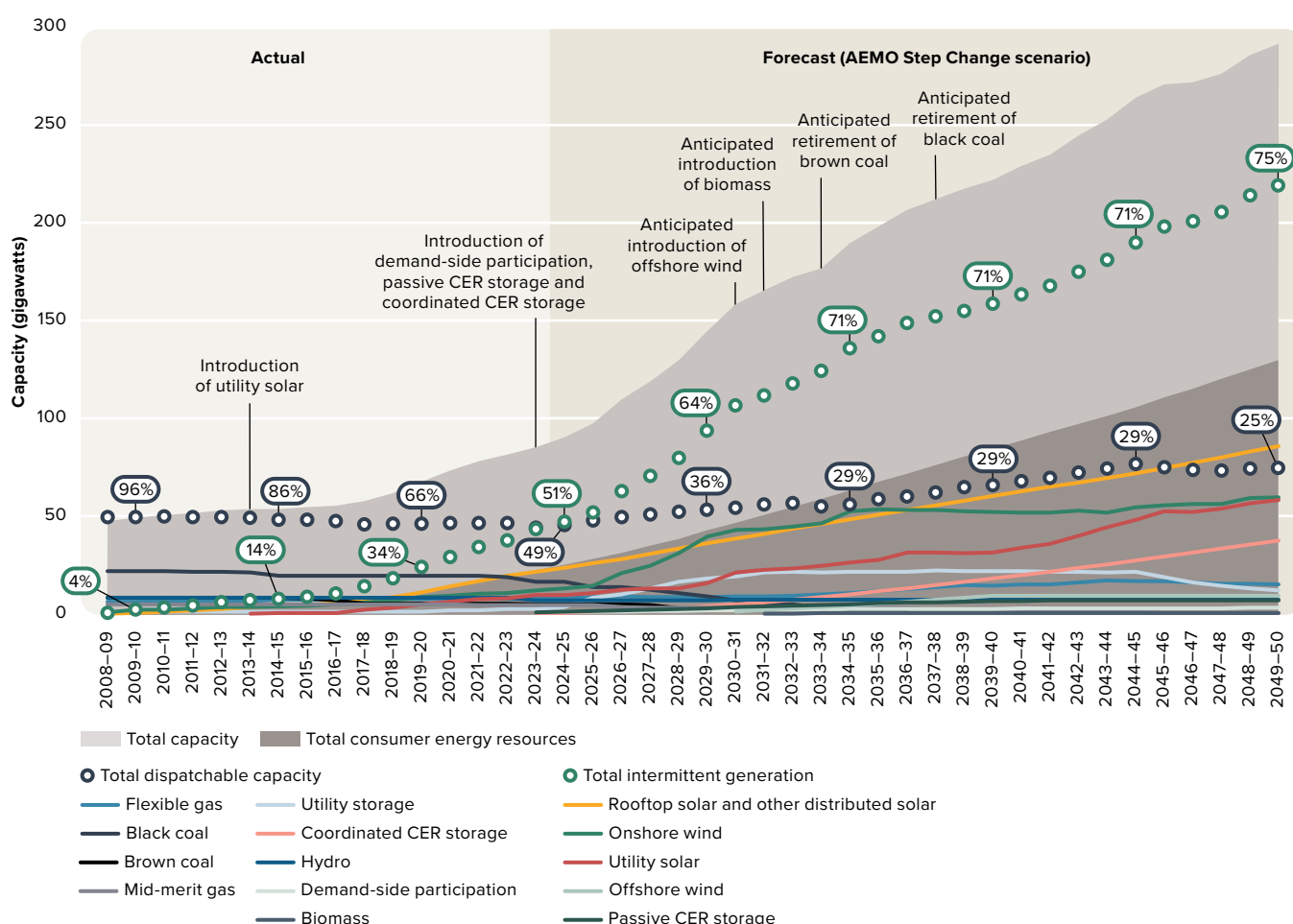
1.2 National Electricity Market (NEM)

Over the last decade, the profile of energy generation in Australia has changed significantly, and forecasts in AEMO's 2024 Integrated System Plan (ISP) highlight the significant amount of change that is still to come.

2024 was a notable year in many regards. New records were set for rooftop solar output, the highest number of negative-priced 30-minute periods, minimum daily electricity demand and entry of new registered generation capacity.

Increased price volatility is evidence that the wholesale electricity market is now increasingly driven by the complex relationship between weather conditions, shifting demand profiles and the diverse shifting mix of generation types in the NEM.

Figure 1.1 NEM capacity, by generation type



Note: CER: consumer energy resources. % reflects the proportion of total capacity.

Source: AEMO, 2024 Integrated System Plan, June 2024.

Between 2014 and 2024, more than 6.6 GW of coal-fired and gas-powered generation left the market. Over this same period, around 18.5 GW of large-scale wind and solar capacity and 18.2 GW of rooftop solar capacity came online.

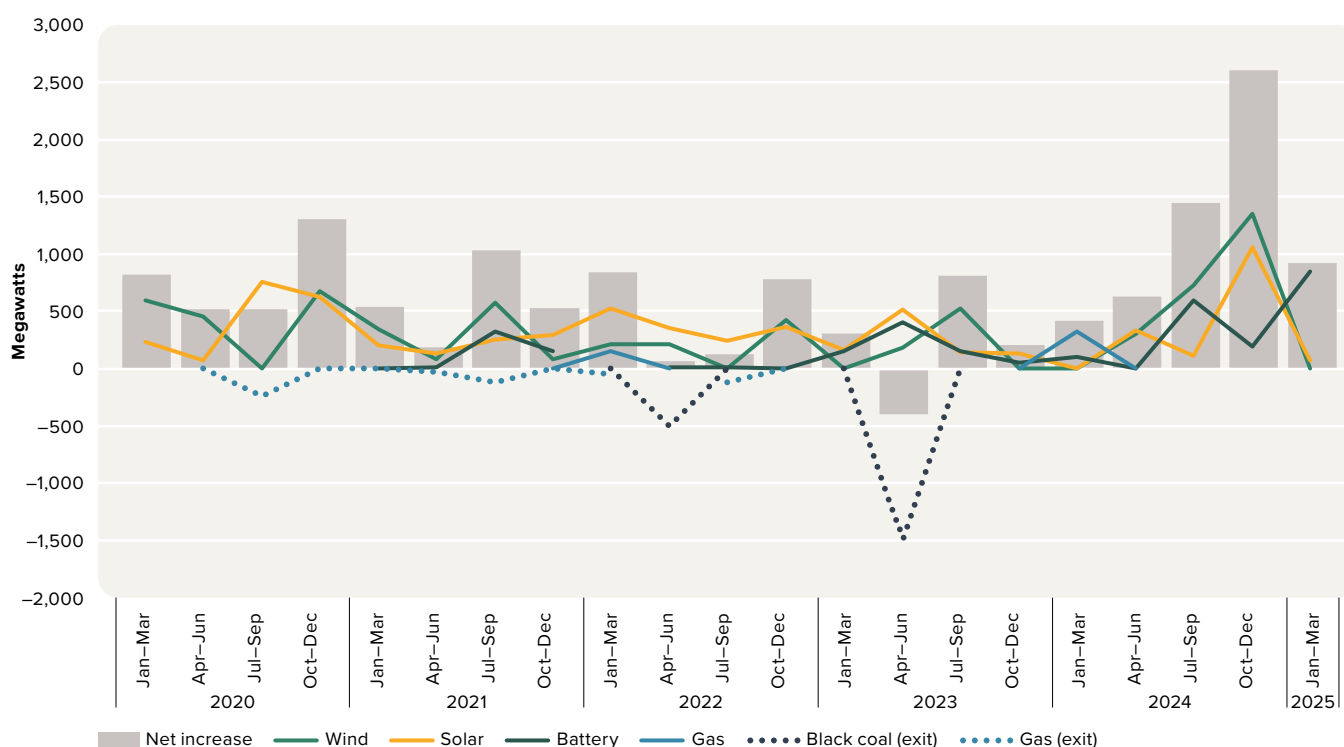
By the end of 2024, renewable technologies (rooftop solar, solar farms, wind, hydro and battery) made up 60% of the NEM's generation capacity, up from around 14% in 2014. The change is less pronounced for generation output because renewable energy is weather dependent and, unlike coal and gas plants, cannot run continuously. Therefore, it produces electricity at a lower rate relative to capacity. Renewable technologies (rooftop solar, solar farms, wind and hydro) met 39% of electricity demand in 2024, compared with 14% in 2015.

Around 90% of the NEM's coal generators are scheduled to retire by 2035 as plants reach the end of their economic lives.³ Coal-fired generators expected to retire in the next decade include remaining units of Eraring (NSW – August 2027), Callide B (Queensland – 2031), Yallourn (Victoria – 2028) and Vales Point B (NSW – 2033).⁴

By 2030, the share of electricity requirements met by coal-fired generation is forecast to decline to 17% of the grid and 14% of total electricity. By 2050, there is forecast to be zero coal-fired generation in the NEM.⁵

Grid-scale wind and solar are forecast to meet 65% of grid electricity requirements by 2030 and 88% by 2050.⁶ Gas-powered generation, hydro-generation, battery storage and consumer energy resources are forecast to meet the balance of demand.

Figure 1.2 Generator entry and exit



Note: This chart illustrates entry, exit and expected new entry. Solar and batteries are maximum capacity. Other plants are registered capacity. New entry date is the first day the station receives a dispatch target. Solar reflects large-scale solar and does not include rooftop solar.

Source: AER analysis using AEMO Generator Information.

Market conditions from July to September 2024 illustrate how the system is becoming more vulnerable to volatility caused by infrastructure outages and variable weather. Compared to the same quarter in 2023, wind generation was 21% higher, which drove a then record number of negative prices for the NEM. However, there were some periods of very low wind generation with output less than 7%

³ AEMO, [2024 Integrated System Plan](#), Australian Energy Market Operator, June 2024, p. 6.

⁴ AEMO, [Generating Unit Expected Closure Year April 2025](#), Australian Energy Market Operator, 15 April 2025, accessed 6 June 2025.

⁵ AEMO, [2024 Integrated System Plan](#), Australian Energy Market Operator, June 2024, pp. 49–50.

⁶ AEMO, [2024 Integrated System Plan](#), Australian Energy Market Operator, June 2024, p. 30.

of installed capacity, which contributed to high price events throughout the period. Network outages also played a role, with the Heywood interconnector being constrained during the majority of events occurring in South Australia and Murraylink offline for both planned and unplanned outages for some of the quarter.

Since 2020, the frequency of both negative prices and prices above \$300 per megawatt hour (MWh) has increased significantly. In 2024, across the NEM, negative prices accounted for 15% of all prices, up from 3.5% in 2020. Prices above \$300 per MWh rose from 0.4% to 1.8% over the same period. Despite their greater frequency, negative prices have a relatively modest impact on average spot prices compared with high prices. This is partly because when high prices do occur, they are often much more extreme than negative prices (which are often only slightly below \$0 per MWh) and they tend to occur when system demand is greater. This means high prices apply to a greater proportion of the electricity that is dispatched and therefore have a larger impact on volume weighted average electricity prices.

Orchestrating the timing and location of this investment with the timing and location of new generation is critical to a successful energy market transition.

1.3 Electricity networks

New solar and wind plants are being constructed in windy or sunny parts of the grid, where network capacity tends to be limited. Investment in new transmission capacity is needed to meet this challenge. Orchestrating the timing and location of this investment with the timing and location of new generation is critical to a successful energy market transition. Increases in the value of regulatory asset bases (RAB), that is, the total value of transmission network assets, are expected to continue as more major transmission network projects enter development and these networks grow.

AEMO in 2024 reported that the market needs around 5,000 km of new transmission lines by 2034 and 10,000 km by 2050.⁷ In preparing the 2025 Integrated System Plan, AEMO assessed that these projects are critical to unlocking new sources of renewable energy to replace our aging and increasingly unreliable coal plant. It forecasts that these transmission projects will repay their investment costs, save consumers \$18.5 billion in avoided costs and deliver emission reductions now valued at \$3.3 billion.

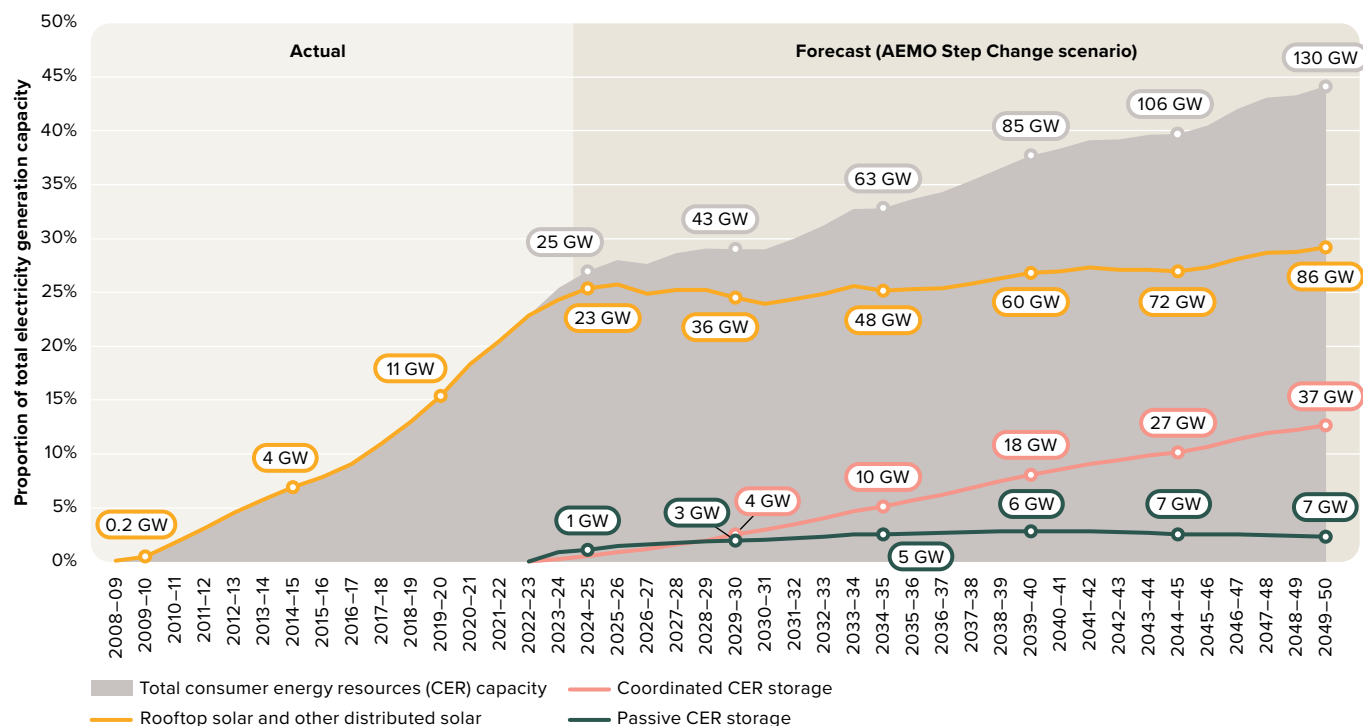
However, many key projects have faced delays and additional costs linked to social license and supply chain issues on equipment, materials and labour shortages which have resulted in challenges for transmission networks. Delays not only impede efficient delivery of transmission upgrades but may also impede timely delivery of generation that is reliant on them. In May 2025 AEMO estimated real costs for overhead transmission projects had increased 25% to 55% compared with equivalent cost estimates prepared for the 2024 ISP, and approximately 10% to 35% increase in real costs for transmission substation projects.

1.3.1 Consumer resources and distribution networks

Alongside major shifts in the energy market at the grid level, a raft of changes are occurring at the customer level. Energy customers are investing in consumer energy resources (CER) that can generate or store electricity to reduce their energy costs and support renewable energy. By far the most common form of CER in Australia is rooftop solar photovoltaic (PV) systems, but interest is also growing in batteries and electric vehicles.

⁷ AEMO, [2024 Integrated System Plan](#), Australian Energy Market Operator, June 2024.

Figure 1.3 Consumer energy resources share of total electricity generation (output)



Source: AEMO, 2024 Integrated System Plan, June 2024.

Australia has the largest per capita investment in rooftop solar in the world. As at December 2024, over 4 million households owned more than 22 GW in rooftop solar capacity connected to the grid, equivalent to 25% of all generation capacity in the market.

Total capacity of rooftop solar across Australia as at May 2024 was 7 times higher than capacity in May 2014. Output from rooftop solar systems has also more than tripled in the 7 years to 2023–24 and is now capable of meeting over half of underlying energy demand across the NEM in the middle of a sunny day.

Rooftop solar systems contributed 14.7% of the NEM's total generation in the first quarter of 2025, more than utility-scale solar (9.3%), wind power (13.7%), hydro (4.9%) and gas (3.5%).

As technologies mature and costs come down, more consumers will store surplus energy from solar systems in batteries to draw from when needed and, with the right incentives, export it into the grid when needed. In coming years, electric vehicle batteries are expected to play a similar role.

The rate of home battery installations in Australia is rising, albeit from a low base. Installations surged in 2024, with 74,582 home batteries installed, up from 46,127 in 2023 and marking a 62% year-on-year increase.⁸ In July 2025, 19,592 home batteries were installed across Australia, with a total nominal capacity of 356.6 MWh.⁹ Electric vehicle (EV) uptake in Australia has been slower than in other developed countries but new purchases continue to increase to and totalled more than 114,000 in 2024.¹⁰

⁸ Clean Energy Council, [Rooftop solar and storage biannual report](#), 17 March 2025, accessed 6 June 2025.

⁹ Data is as at 4 August 2025 and is subject to change – it includes installations with applications that have claimed or had small-scale technology certificates approved. Data includes residential and small business installations. See Clean Energy Regulator, [Strong solar battery uptake in first month](#), 4 August 2025.

¹⁰ Electric Vehicle Council, [2024 sets new record for EV sales in Australia](#), 6 January 2025, accessed 6 June 2025.

1.3.2 Orchestrating CER

Consumer energy resources are among the cheapest ways of meeting the projected growth in energy demand over time. If rooftop solar and batteries are orchestrated with the power system, they can deliver benefits to all consumers by mitigating price spikes and reducing the need for future grid-scale investment in generation, transmission and distribution.

However, when large amounts of CER are added to the power system it can lead to network congestion and make grid operation more difficult. For this reason, effective integration and coordination or orchestration of CER will be an important part of achieving a lowest-cost energy transition.

AEMO's market projections to 2050 factor in a substantial contribution from CER in meeting the NEM's energy requirements. It estimates coordinated CER storage will need to rise from today's 0.2 GW to 3.7 GW in 2029–30 and then 37 GW in 2049–50 to maintain system reliability. This coordinated storage would make up 66% of the NEM's storage capacity by 2050, or 36% of all coordinated capacity in the market (including generation). By 2050, this would make CER the largest energy source meeting grid demand. These coordinated resources could include virtual power plants, community batteries, vehicle-to-grid and other storage.¹¹

Analysis published by the Energy and Climate Change Ministerial Council forecasts that successful integration of CER could offset up to \$11 billion in network augmentation costs by 2040, along with \$8 billion in saved generation and storage costs.¹²

These benefits are not guaranteed but require the right policy settings and market incentives, and consumer trust to make effective orchestration a success.

1.3.3 Role of distribution networks

Alongside the need for significant transmission investments to rewire the nation, the energy market transition is changing the role of distribution networks. In the past, distribution networks provided a one-way delivery service to energy customers. However, now they can host two-way flows of consumer energy resources (CER) as well as some larger-scale renewable and storage projects.

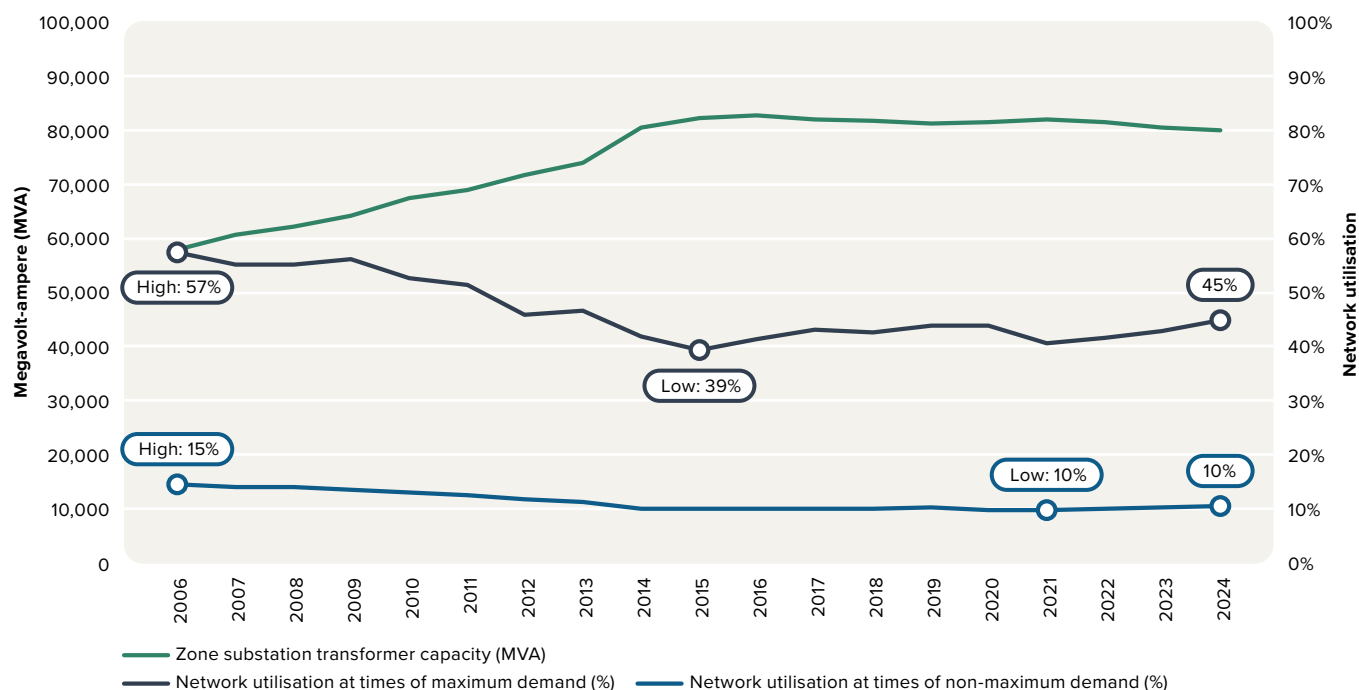
Utilisation rates on most networks in relation to maximum demand have been relatively stagnant in recent years, although has increased slightly (Figure 1.4). However, electrification of household heating and cooking appliances, use of electric vehicles and demand from data centres are expected to increase electricity consumption and peak demand on networks.

One method to deal with this expected demand is to use price signals and encourage certain consumption behaviour to shift this demand to periods of the day when there is lower network utilisation and greater availability of CER generation. This would also assist in flattening future peak demand and avoiding or minimising future capital investment into distribution networks.

11 AEMO, [2024 Integrated System Plan](#), Australian Energy Market Operator, June 2024.

12 Australian Government, [National consumer energy resources roadmap – Powering decarbonised homes and communities](#), Department of Climate Change, Energy, the Environment and Water, 19 July 2024, accessed 28 July 2025.

Figure 1.4 Network utilisation



Note: Network utilisation at times of maximum demand is calculated using non-coincident, summated raw system annual maximum demand divided by total zone substation transformer capacity. Network utilisation at times of non-maximum demand is the average energy delivered over the year less the energy delivered during the 'peak' 30-minute interval divided by total zone substation transformer capacity. The changes identified in the labels refer to the relative change in utilisation in percentage points over previous years.

Source: Economic benchmarking RIN responses.

1.3.4 Role of incentives

Successful orchestration requires well-designed incentives to bring on CER when it is needed and ease it off when too much is entering the system. Using some form of flexible network tariff is one pathway. Flexible tariffs typically set network usage charges lower when the network has spare capacity (typically during the day when rooftop solar generation eases demand from the grid) and higher when the network is under strain (typically later in the day when solar generation falls and customer demand is high).

These price signals are intended to encourage customers to shape their energy demand for services like hot water heaters and pool pumps around available capacity on the network. Network determinations require networks to design tariffs that consider periods of the day when there is high peak demand and network constraints. These flexible tariffs aim to be reflective of the costs to provide network services, while also achieving equity among customers. Other flexible pricing models include two-way tariffs, which adjust charges based on energy export times, controlled load tariffs for managing specific high-consumption devices, and wholesale pricing that reflects real-time market conditions.

An alternative way of orchestrating consumer resources is through some form of direct control supported by financial reward, using technology to control appliances such as water heaters, pool pumps and air conditioning, so they can be operated when demand is low or curtailed when the grid is under stress.

The AEMC released a draft determination in July 2024 allowing CER to compete in the wholesale electricity market by pooling resources through mechanisms such as virtual power plants and community batteries.¹³

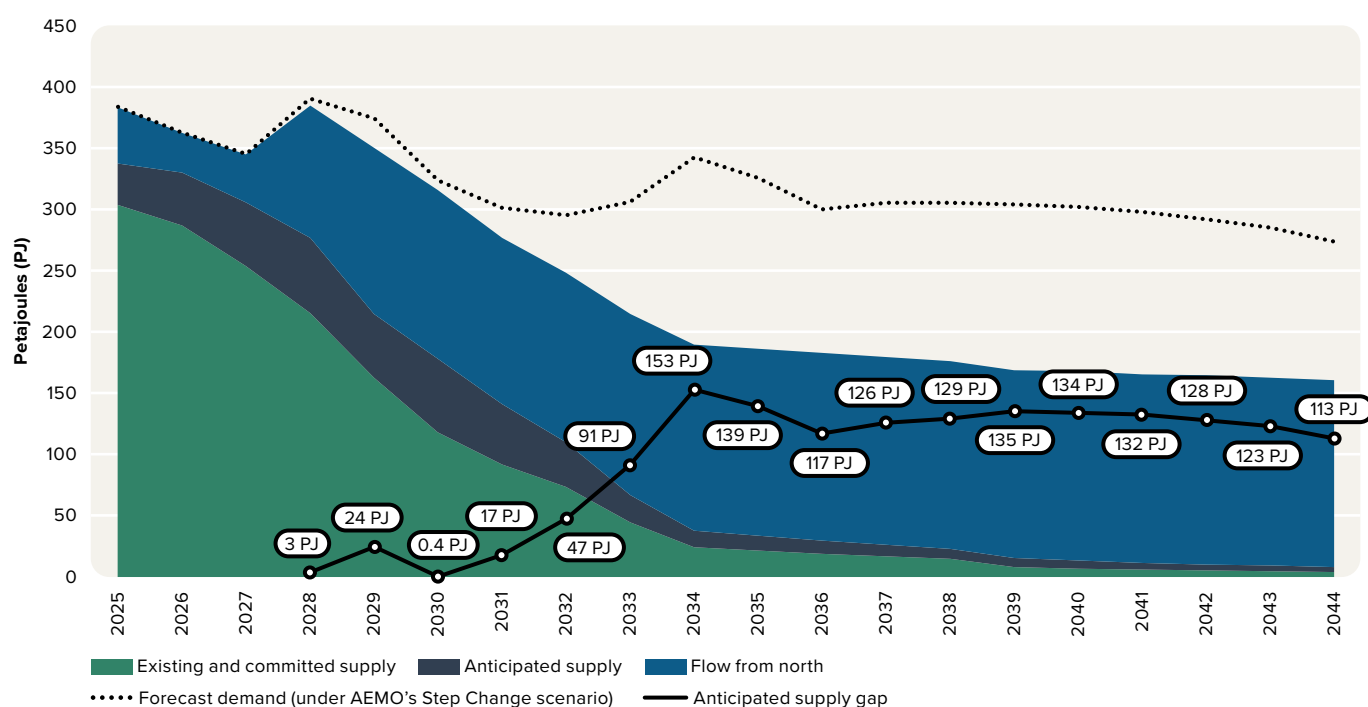
¹³ AEMC, [Integrating price-responsiveness resources into the NEM](#), Australian Energy Market Commission, 25 July 2024.

The AER welcomes creative proposals by network businesses and other market participants to trial innovative services or technologies. In February 2025, the AER signalled a new approach to testing and trialling new ideas in the energy market with the introduction of policy-led sandboxing. Our regulatory sandbox enables us to grant waivers from regulatory requirements that may be standing in the way of a trial. Our policy-driven approach is focused on overcoming barriers to access, deployment and orchestration of new energy resources, such as community batteries, electric vehicles and rooftop solar, that will benefit consumers in the long term.

1.4 Gas markets in eastern Australia

Alongside events in electricity markets, the gas market is undergoing its own transition. In many ways the gas transition interlinks with events in electricity, but gas supply and demand also face their own unique challenges.

Figure 1.5 Projected gas supply adequacy in southern regions



Source: AEMO, Gas Statement of Opportunities, March 2025.

1.4.1 Demand conditions

Domestic gas customers in eastern Australia include industrial businesses, electricity generators, commercial businesses and households. Industrial customers consumed 46% of gas sold to the domestic market in 2024. Households and small commercial customers accounted for 36% of domestic demand, but this share is as high as 60% in Victoria, where gas is widely used for heating and cooking.

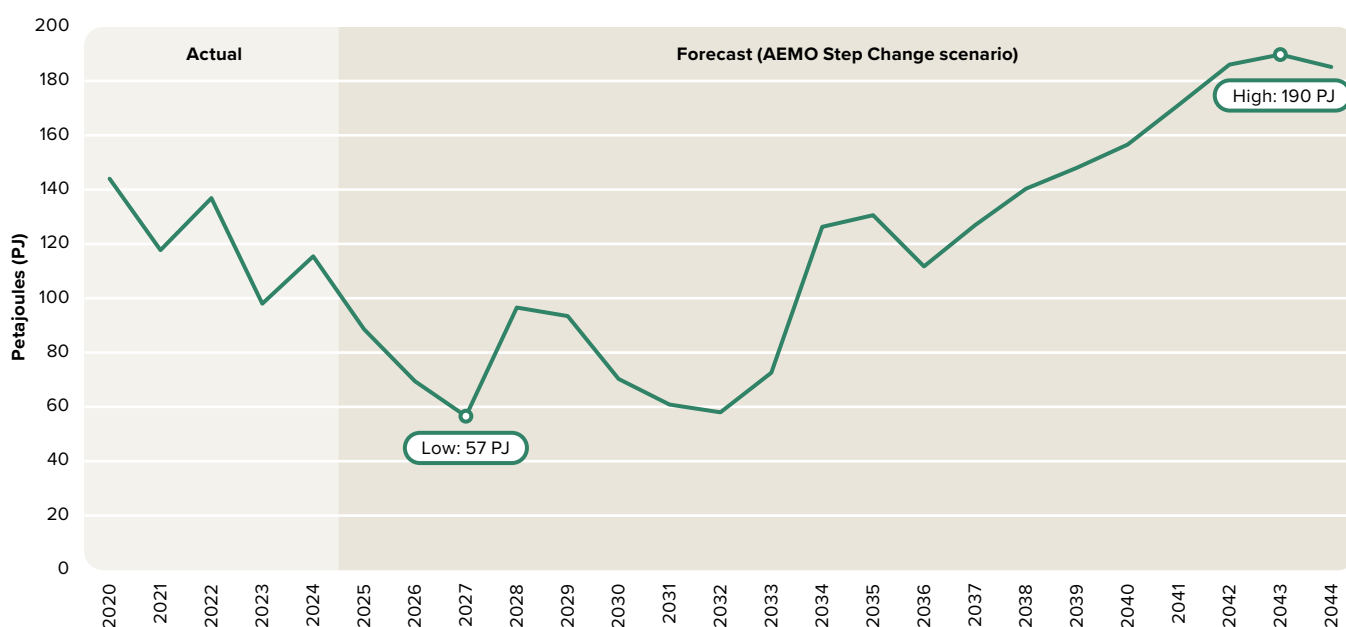
Gas consumption has been declining for many years, partly due to higher gas costs. This decline is forecast to continue as the economy continues its shift towards greater electrification to meet net zero targets. The Victorian and ACT governments are phasing out gas use in residential homes and are supporting research and investment in alternatives to achieve net zero targets. The impact of electrification on some parts of the industrial sector is likely to be less pronounced, due to the challenges in finding suitable substitutes for gas in processes such as for chemical feedstock production and heating at temperatures above 400°C.

1.4.2 Gas-powered generation

One source of demand that has fallen sharply in recent years is the use of gas for electricity generation. Around 19% of domestic gas demand in the NEM in 2024 was for power generation, down from 29% in 2017. Gas is more widely used for power generation in South Australia and Queensland (each supplied around 37% of gas-powered generation in the NEM in 2023).¹⁴

Higher gas fuel costs and relatively warmer winters contributed to the recent decline in gas-powered generation. Despite this, gas will remain a vital fuel for power generation during the energy market transition (section 1.2). Gas plants have the advantage of being able to start up and switch off quickly, providing fast dispatchability when cheaper plants are constrained by a lack of wind, sunshine or outages. This feature also makes gas plants an important provider of inertia and frequency stability as coal plants (the traditional supplier of these services) retire from the market. Reflecting these factors, AEMO projects that gas-powered generation demand will stabilise over the next decade and then rise from around 2033 (Figure 1.6). This growth is likely to be concentrated in winter, when solar generation is lower. The extent of this demand growth will depend on the timing of coal plant retirements and the capacity that replaces them.¹⁵

Figure 1.6 Gas demand for gas-powered generation



Note: Includes Northern Territory.

Source: AEMO, Gas Statement of Opportunities, March 2025.

¹⁴ AER, [State of the energy market 2024](#), Australian Energy Regulator, 7 November 2024, section 5.4.

¹⁵ AEMO, [2025 Gas Statement of Opportunities](#), Australian Energy Market Operator, March 2024.

1.4.3 Adequacy of gas supply

While the use of gas in electricity generation is forecast to rise beyond 2032, overall gas consumption is forecast to keep declining in the future as electrification gathers pace. But while gas demand will fall, domestic supply may decline faster.

Supply conditions are particularly uncertain in southern Australia, where Victoria's Gippsland Basin output is declining due to the depletion of legacy fields. Southern gas markets have become especially vulnerable in winter, when households use gas for heating. This has increased reliance on drawing gas from Queensland gas fields as well as storage facilities in Victoria. Supply into the Victorian market is limited by pipeline capacity, although recent upgrades have improved this capability.

Recent evidence of gas supply pressures in southern Victoria emerged in winter 2024, when unusually low wind generation drove high levels of gas demand for power generation. Higher demand combined with weaker southern gas production caused gas storage levels at Dandenong LNG and Iona – Victoria's only facilities providing storage services to third parties – to run down rapidly despite increased gas flows from northern sources.

AEMO forecast that these risks will recur from 2028 under extreme peak demand conditions, with annual supply gaps growing from 2029 onwards.

In its June 2025 Gas inquiry report, the ACCC forecast that the gas supply outlook has deteriorated and gas shortfalls are expected in the southern states in the fourth quarter of 2025 and throughout 2026.¹⁶ The ACCC also forecast the shortfalls will widen in future years without new supplies of gas coming online. In particular, the ACCC expects increased demand for gas-powered generation following the retirement of coal power generation, particularly post-2030, will coincide with substantial declines in forecast production in the Gippsland and Otway basins.

It noted new gas supplies and pipeline construction are facing delays due to long regulatory approval processes, technical factors (including uncertainties with geological and engineering) and making final investment decisions based on operational and market factors, some of which are beyond the control of producers.¹⁷ In several jurisdictions, community concerns around environmental risks associated with fracking led to legislative moratoria and regulatory restrictions on onshore gas exploration and development. Given the uncertainty around gas proposals being considered for government approval, investors are finding it difficult to obtain project finance.¹⁸

More gas supply and associated infrastructure will be needed to fill projected supply gaps. But getting the optimum amount of new investment is a challenge. The longer-term outlook for gas remains uncertain, both due to supply uncertainty and policies to meet Australia's net zero carbon commitments by 2050. This uncertainty creates a dilemma for policy makers.

Currently, low-emission gases such as hydrogen and biomethane make a small contribution to Australia's energy mix. Once commercialised, the use of low-emission gases could grow to complement or potentially replace natural gas, especially in industry and power generation when their production costs match or outcompete the incumbent fuels.¹⁹ Presently, there are significant challenges in supplying these gases economically at the scale required for their potential use; however, this may change as the methods of their production improve and become more efficient.

During Australia's transition to net zero, gas will continue to be used by households, businesses and industry, and to support reliability and security in the grid. But this role will decline over time. Therefore, the need for additional gas resources is temporary, which limits payback periods. In this context, identifying the least cost way of balancing gas supply and demand through to 2050 is challenging.

16 ACCC, [Gas inquiry 2017–2030, June 2025](#), Australian Competition and Consumer Commission, 30 June 2025.

17 ACCC, [Gas inquiry 2017–2025, interim report, June 2024](#), Australian Competition and Consumer Commission, July 2024, p. 36.

18 ACCC, [Gas inquiry 2017–2030, interim report, January 2023](#), Australian Competition and Consumer Commission, January 2023, p. 125.

19 Department of Industry, Science and Resources, [Finding new sources of gas to meet demand](#), accessed 14 July 2025.

1.5 Gas pipelines in eastern Australia

As the electrification of domestic gas applications continues, the number of gas customers will fall. In consequence, gas networks will face declining economies of scale. As network costs are spread over fewer and fewer customers, retail gas bills will escalate and threaten to drive more customers away from gas. This scenario could progress into a situation where some networks cannot maintain financial viability and become stranded assets. It also raises equity issues because consumers least able to afford the conversion costs of electrifying their energy supply are likely to be those most exposed to higher gas prices.

The AER is taking steps to manage the ongoing costs of maintaining gas networks over a declining customer base. Our aim is to ensure regulated businesses can invest where necessary to provide safe and reliable gas services while protecting consumers from unnecessary cost burdens now and in the future. For example, in Victoria, the AER allowed for some accelerated depreciation of assets, noting that bringing forward the recovery of assets while pipeline use remains relatively high spreads the increased costs among a larger pool of customers.²⁰

The gas market transition also poses safety issues if disconnection results in leaving live unused assets in place. We are working with pipeline businesses to manage this risk by sharing costs between disconnecting users and all gas consumers in the network.

While the current regulatory framework allows us to take these steps to manage uncertainty over the next 5 years, the framework targets efficient growth of the service rather than an environment of declining demand.

In the longer term, the current regulatory framework based around gas access arrangement reviews may not be sufficient to deal with the scale and scope of equity and safety issues likely to arise in a scenario of sharply eroding domestic gas use.

1.6 Retail energy markets and energy consumers

The transition is also driving innovation and change in the retail energy markets. While Origin Energy, AGL and EnergyAustralia remain the largest energy retailers in Australia, Tier 2 retailers²¹ have continued to grow their customer numbers and new retailers have entered the market with innovative business practices and product offerings. Some of these offers make renewable technologies accessible to a broader range of customers and include leases for batteries and solar, bundling batteries and solar with energy plans, virtual power plant plans, and peer-to-peer community trading.

The transition in Australia's energy market is being driven by consumers and affects them in a number of ways. Many consumers already benefit through self-production of rooftop solar energy, batteries to draw on when electricity is expensive, opportunities to earn income from exporting solar and battery discharge into the grid, savings from demand response and, where needed, access to cheap renewable power from the grid.

But not all consumers will benefit. Many people do not own a home, so cannot make their house more energy efficient or fit solar panels to the roof. Many cannot afford home batteries, an electric car or smart appliances they can use to respond to price signals. These customers will continue to draw electricity from the grid as they always have.

Ensuring that consumers don't get left behind and vulnerable customers are provided with the support they need now and in the future is important. It is also important that consumer protections give all customers confidence in the energy transition, as this will improve outcomes for everyone in the long term.

²⁰ AER, [State of the energy market 2024](#), Australian Energy Regulator, 7 November 2024, boxes 6.2 and 6.3.

²¹ Tier 2 retailers include any retailer that is not Origin Energy, AGL Energy, EnergyAustralia, nor one of the primary regional government-owned retailers – Ergon Energy (Queensland), ActewAGL (ACT) and Aurora Energy (Tasmania).

Over the past few years, initiatives outlined in the AER's *Towards energy equity strategy*²² and Review of consumer protections for future energy services²³ have progressed. The Energy and Climate Change Ministerial Council's Better Energy Customer Experience reform program announced in March 2025 is progressing many of the AER's recommendations and intends to ensure the right consumer protections are in place through the energy transition and beyond. The Department of Climate Change, Energy, the Environment and Water (DCCEEW) is leading consultation that is considering whether the National Energy Customer Framework (NECF)²⁴ is appropriate for new energy products and services and customers in different market settings, such as embedded networks, off-grid and pre-payment services. Consideration is also being given to whether the current framework supports customers to easily navigate the complexity of the energy market.

The AEMC also announced rule changes to better protect energy customers experiencing vulnerability and ensure that households can access better energy deals.²⁵ The reforms will take effect on 1 July 2026 and are intended to restrict energy retailers from raising prices more than once per year, remove unfair fees for vulnerable customers, and ensure customers on hardship programs are receiving their retailer's best offer.

Recent developments are a step in the right direction, but there are more opportunities to improve consumer outcomes. In the 12-month period to 31 March 2025, the total number of residential customers (combined electricity and gas) and the proportion of customers with energy debt increased. The average debt among this cohort of customers was also higher. Alongside this, retailers reported that fewer customers were receiving assistance through hardship programs; however, both the average level of hardship program debt and the average level of debt on entry to hardship programs increased. These results highlight the need to address how customers experiencing vulnerability are supported and how those in hardship programs can be better supported.

The AER's Review of payment difficulty protections in the National Energy Customer Framework²⁶ identified more specific opportunities to ensure customers experiencing payment difficulty are identified early, engaged proactively and supported appropriately with assistance that is tailored to their individual circumstances. Recommended changes include:

- eliminating the distinction between 'hardship customers' and 'other' customers experiencing payment difficulty and introduce a single, inclusive definition
- introducing Tier 1 civil penalties for retailers that fail to uphold the principle that disconnection due to inability to pay energy bills should be a last resort option
- requiring retailers to proactively engage with customers in ways that meet their needs and provide information about assistance that is easy to access and understand
- banning retailers from requiring customers to provide proof of circumstances to access payment difficulty assistance and introducing minimum assistance for all customers
- strengthening protections to make payment plans more affordable and introducing minimum assistance (including assistance to lower energy costs) for customers experiencing payment difficulty
- banning reconnection fees, strengthening requirements for communication in the disconnection process and strengthening minimum disconnection protections.

As the energy sector continues to evolve, it is critical that the market maintains consumer agency and promotes consumer trust in the energy transition.

22 AER, [Towards energy equity strategy](#), Australian Energy Regulator, 20 October 2022.

23 AER, [Review of consumer protections for future energy services](#), Australian Energy Regulator, November 2023.

24 The National Energy Customer Framework is a suite of legal instruments. For further information see AEMC, [National Energy Customer Framework](#), Australian Energy Market Commission, accessed 28 July 2025.

25 DCCEEW, [New rules for energy retailers help more Australians access better deals](#), Department of Climate Change, Energy, the Environment and Water, 26 June 2025.

26 AER, [Review of payment difficulty protections in the National Energy Customer Framework](#), Australian Energy Regulator, 15 May 2025.



2 National Electricity Market

Electricity generated in eastern and southern Australia is traded through the National Electricity Market (NEM). Generators make offers to sell electricity into the market and the Australian Energy Market Operator (AEMO) schedules the lowest-priced generation available to meet demand. The amount of electricity generated needs to match demand in real time, which means the amount being generated is continuously monitored and adjusted by AEMO. The market covers 5 regions – Queensland, New South Wales (NSW) including the ACT, Victoria, South Australia and Tasmania, and services around 11 million customers. The NEM is one of the world's longest interconnected power systems, stretching from Port Douglas in Queensland to Port Lincoln in South Australia and across the Bass Strait to Tasmania.

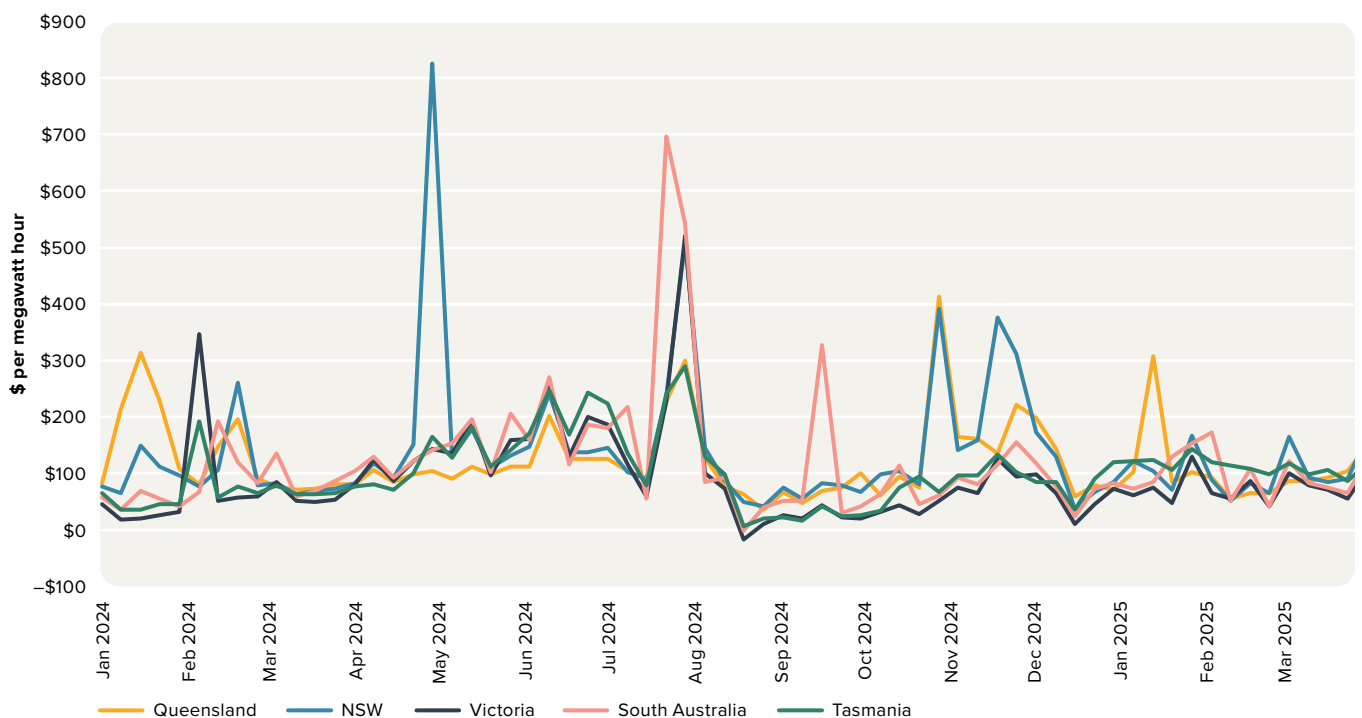
2.1 Snapshot

In the 2024 calendar year:

- Average wholesale spot prices across all regions of the NEM were higher than in 2023. Drivers included weather-related price spikes, network and generator outages and higher average demand levels. While prices were lower than the record levels reached in 2022, they were higher than pre-2022 levels.
- The proportion of prices below \$0 per megawatt hour (MWh) and above \$300 per MWh was slightly higher than in 2023. Compared with 2020, a significantly higher proportion of prices were at either end of the price spectrum. This trend has been driven by greater fluctuations in intra-day demand and by a decrease in mid-priced electricity offers.
- Demand was higher than in 2023 at all times of day, but especially during the evening peak and overnight. Before 2023, electricity demand in the NEM had declined significantly during the middle of the day, mostly due to widespread adoption of rooftop solar and the consequent reduced reliance on grid electricity during daylight hours. In contrast, demand had increased during early morning and evening peak hours, when solar output is usually low and household electricity use is high.

- The increase in electricity demand compared with 2023 was met by increased generation from a range of fuel types. Wind and solar generation increased, reflecting new entry of generation capacity. This was partly offset by a decrease in NEM hydro output, driven by the dry conditions in Tasmania. The remaining gap was filled by increased coal (helped by reduced outages) and gas-powered generation. Due to the higher use of fossil fuels, greenhouse gas emissions from electricity generation were slightly higher in 2024 than in 2023.
- Over 5 gigawatts (GW) of new solar, wind, battery and gas capacity entered the market, mostly in the second half of the calendar year. This was the largest annual new entry of capacity of the energy transition to date. A significant number of fossil fuel generators are scheduled to exit the market by the end of 2027. One new gas and one hydro power station are scheduled to come online during that time, but for the most part the closures will be replaced with new solar and wind generation and with battery storage. There were no generator closures in 2024.

Figure 2.1 Weekly average wholesale electricity prices



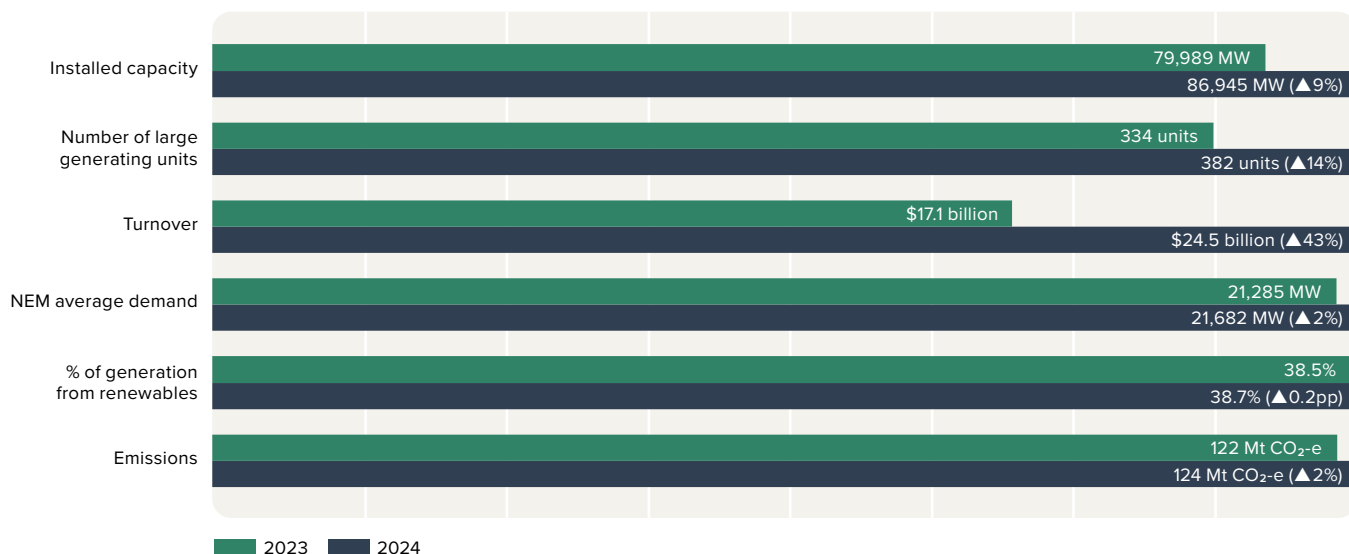
Note: Volume-weighted weekly average prices. Price is weighted against native demand in each region. The AER defines native demand as the sum of initial supply and total intermittent generation in a region.

Source: AER; AEMO (data).

2.2 NEM overview

Nearly 400 generating units produce electricity for sale into the NEM (Figure 2.2). A transmission grid carries most of this electricity along high-voltage power lines to industrial energy users and local distribution networks (chapter 3, section 3.3). Energy retailers complete the supply chain by purchasing electricity from the NEM and packaging it with transmission and distribution network services for sale to residential, commercial and industrial energy users.

Figure 2.2 NEM key statistics



Note: MW: megawatts; B: billion; Mt CO₂-e: millions of tonnes of carbon dioxide equivalent. The change in renewable generation percentage share is expressed as a percentage point (pp) change (which is the absolute difference between 2 percentages) rather than as a per cent change. Data period is calendar year. Installed capacity and number of generating unit metrics are as at the last day of the relevant calendar year.

Source: AER; AEMO (data); Clean Energy Regulator (data); Department of Climate Change, Energy, the Environment and Water (data).

Box 2.1 How the NEM works

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

Power stations make offers to supply quantities of electricity in different price bands for each 5-minute dispatch interval. Bidirectional units, such as pumped hydro and batteries, make offers both to consume power and to provide power to the market. Similarly, scheduled loads, such as smelters, may offer to reduce their consumption as a substitute for generation. Since 2021, consumers (either directly or through aggregators) have also been able to do this (demand response).²⁷ Electricity generated by rooftop solar systems is not traded through the NEM – except for when it is offered as demand response – but it does lower the demand that market generators need to meet.

A separate price is determined for each of the 5 NEM regions. When interconnectors between regions are free-flowing, prices will be very similar across regions (with minor differences caused by transmission losses). When interconnectors are constrained (or reach their full capacity), substantial price differences between regions can emerge.

Prices in the market have a price cap and floor. In 2022 the market price cap was reviewed and set to increase year on year until reaching \$22,800 in 2027–28 (in 2022 dollars).²⁸ The market price cap is adjusted annually in line with inflation. In 2024–25, a market price cap of \$17,500 per megawatt hour (MWh) applied, along with a price floor of –\$1,000 per MWh. The price cap rose to \$20,300 on 1 July 2025.²⁹ The market floor price remains unchanged for now but the Reliability Panel will consider it as part of the 2026 Reliability Standard and Settings Review, which commenced on 19 June 2025.³⁰

As the power system operator, AEMO uses forecasting and monitoring tools to track electricity demand, generator offers and network capability to determine which generators should be dispatched to produce electricity in 5-minute blocks for every region. It dispatches the cheapest generator bids first, then dispatches progressively more expensive offers until enough electricity can be produced to meet demand.

²⁷ Large customers can participate through the wholesale demand response mechanism and small customers can participate through their retailers in virtual power plants (VPPs).

²⁸ AEMC, [Amendment of the Market Price Cap, Cumulative Price Threshold and Administered Price Cap, Rule determination](#), Australian Energy Market Commission, 7 December 2023.

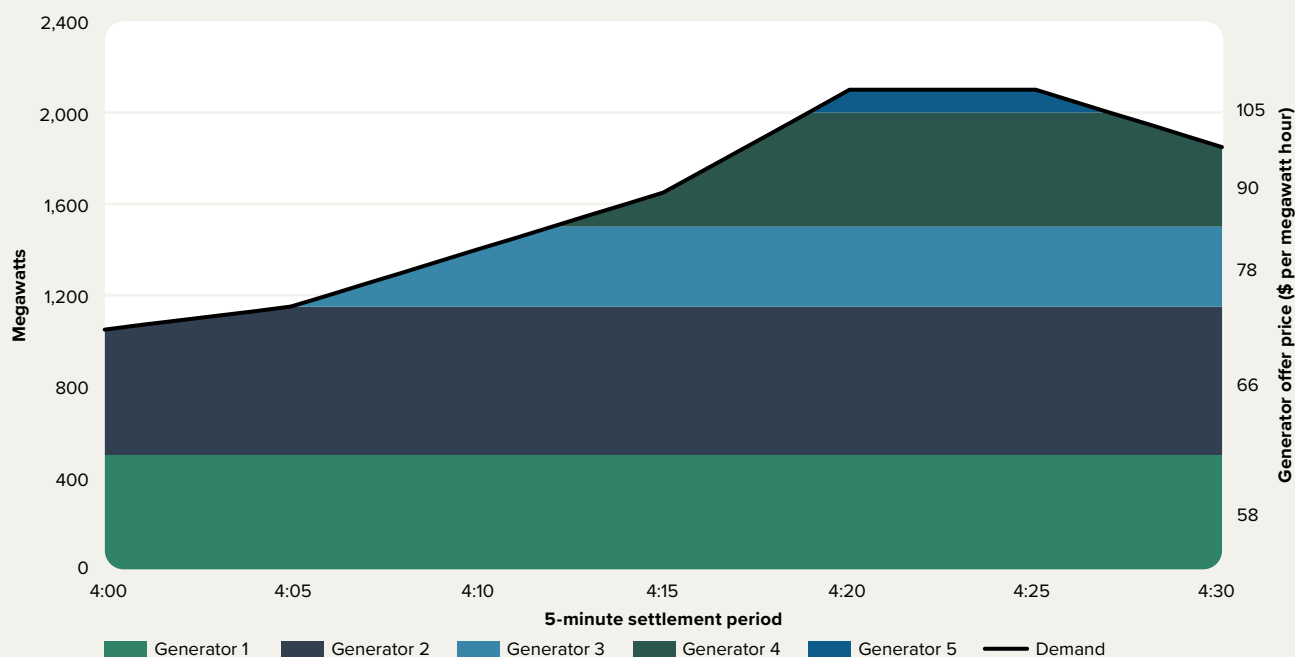
²⁹ AEMC, [AEMC updates market price cap for 2025–26](#), Australian Energy Market Commission, 27 February 2025.

³⁰ AEMC, [2026 Reliability Standard and Settings Review](#), Australian Energy Market Commission, accessed 26 June 2025.

The highest-priced offer needed to meet demand sets the 5-minute price in each region and is the price paid to each generator that is dispatched, regardless of their individual bids.

The Box Figure 2.1 illustrates how prices are set. In this example, 5 generators offer capacity in different price bands between 4:00 pm and 4:30 pm. At 4:15 pm the demand for electricity is 1,650 MW. To meet this demand, generators 1, 2 and 3 must be fully dispatched and generator 4 is partly dispatched. The dispatch price is \$90 per MWh. By 4:20 pm demand has risen to the point where a fifth generator is needed. This generator has a higher offer price of \$105 per MWh, which becomes the dispatch price for that 5-minute interval. That price is paid to all dispatched generators, regardless of their offers. This process is repeated for all 5-minute intervals.

Box Figure 2.1 Setting the price



Source: AER.

Generators can change their offers by rebidding capacity to higher or lower prices, or by increasing or decreasing the amount of capacity offered. Generators may do this right up until dispatch but must provide AEMO with a reason for each rebid.

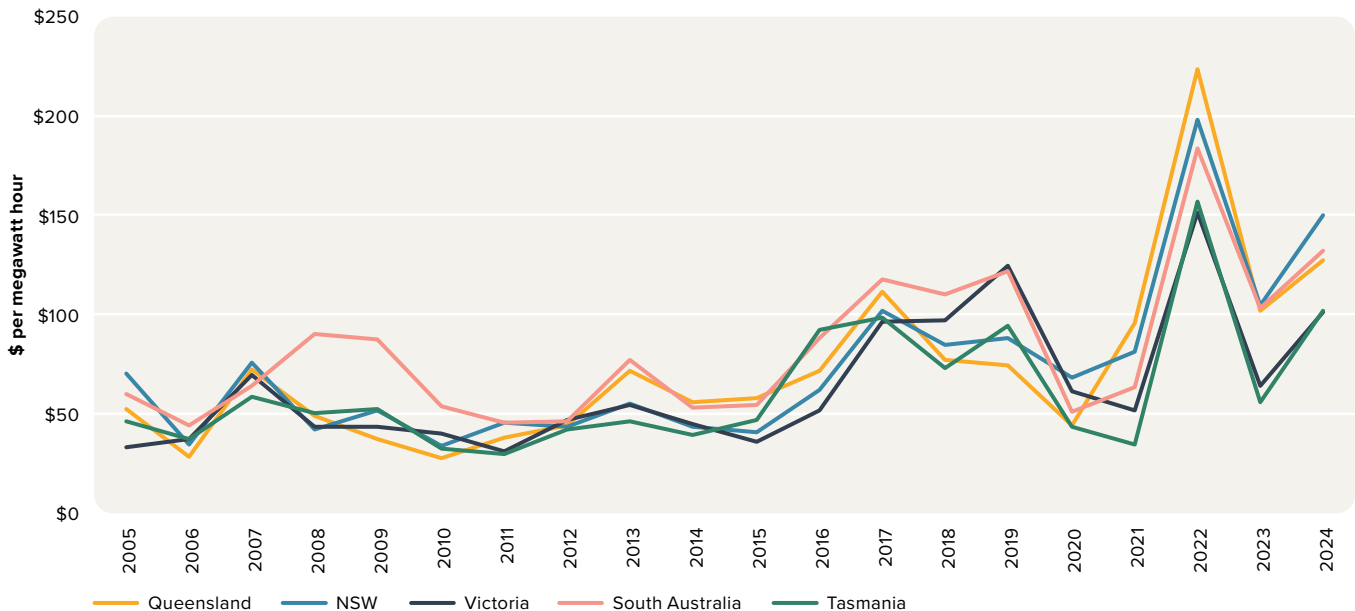
While the market is designed to meet electricity demand in a cost-efficient way, other factors can intervene. At times, dispatching the lowest-cost generator may overload the network or risk system security, so AEMO dispatches more expensive (out of merit order) generators instead.

Retailers buy electricity from the wholesale market and package it with network services to sell as a retail product to their customers. They manage the risk of volatile prices in the NEM in several ways, such as entering into hedging contracts (derivatives) that lock in a firm price for electricity supplies in the future, by ownership of generators or entering into demand response contracts with their retail customers.

2.3 Wholesale prices and activity

Wholesale electricity prices in 2024 were higher than in the previous year in all regions. Prices remained lower than the record levels reached in 2022 (Box 2.2) but were high compared with pre-2022 levels (Figure 2.3).

Figure 2.3 Annual wholesale prices



Note: Volume-weighted annual average prices, by calendar year. 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; AEMO (data).

Comparing average annual prices across the NEM in 2024:

- Queensland – prices averaged \$128 per MWh, up 26% from 2023, and were affected by high demand in the summer months driving many high price events.³¹
- NSW – prices averaged \$150 per MWh, up 43% from 2023, and were affected by many high price events in late autumn and late spring.³² Generator and network outages factored in many of these price events, as did rebidding by market participants.
- Victoria – prices averaged \$101 per MWh, up 58% from 2023. Colder weather driving higher demand was a factor in the price increases during winter and coincided with a period of lower wind output. Heading into spring and early summer, prices remained higher than the previous year amid a higher rate of brown coal outages.
- South Australia – prices averaged \$132 per MWh, up 28% from 2023. Prices were particularly high in the July to September 2024 quarter, driven by many high price events.³³ Low wind output, network outages and rebidding by participants were key drivers of the high prices.
- Tasmania – prices averaged \$102 per MWh, up 82% from 2023. A key driver was hydro generators offering into the market at higher prices, which reflects lower storage levels at major dams caused by the lower-than-average rainfall in the region.

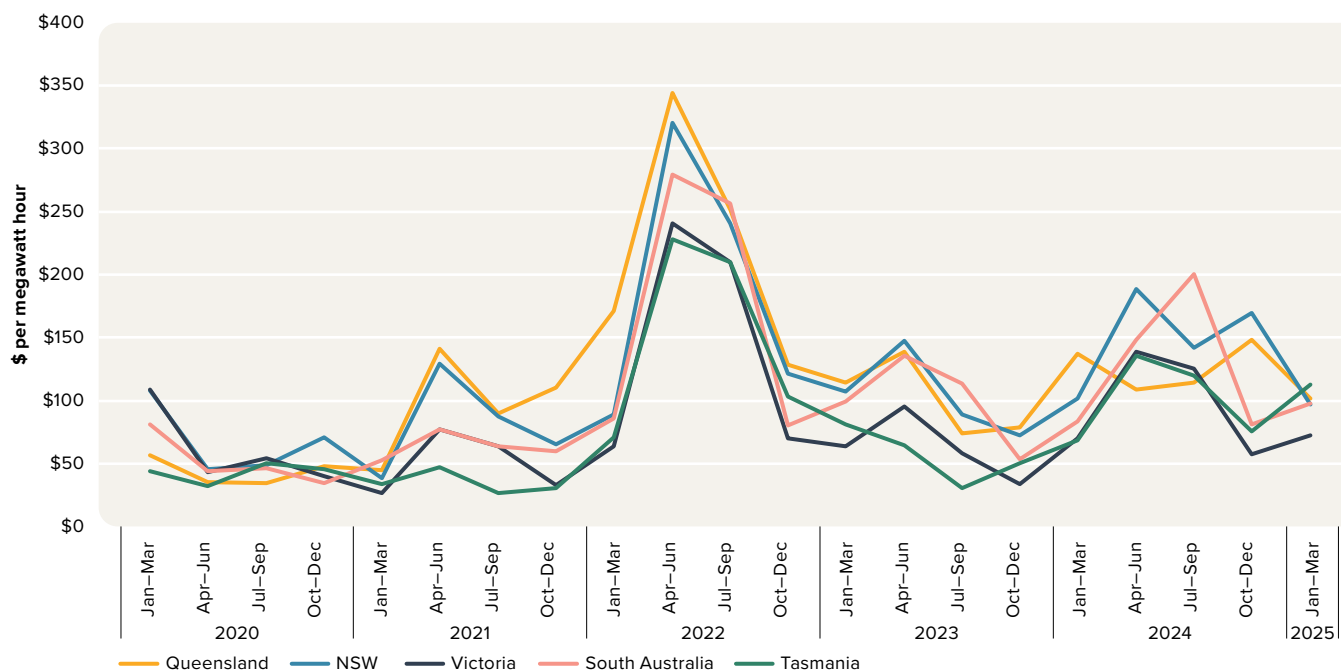
31 AER, [Prices above \\$5,000/MWh – January to March 2024](#) and [Prices above \\$5,000/MWh – October to December 2024](#), Australian Energy Regulator, May 2024 and February 2025.

32 AER, [Prices above \\$5,000/MWh – April to June 2024](#) and [Prices above \\$5,000/MWh – July to September 2024](#), Australian Energy Regulator, July 2024 and November 2024.

33 AER, [Prices above \\$5,000/MWh – July to September 2024](#), Australian Energy Regulator, November 2024.

Prices across the year varied from quarter to quarter due to typical seasonal changes as well as other factors. Prices in most regions were highest during the April to June and July to September quarters, when periods of network and generator outages combined with periods of cold weather with high demand for heating (Figure 2.4). Prices in Queensland and NSW were also high in the October to December 2024 quarter when earlier than usual warm weather combined with the usual planned generator outages that take place in the shoulder season.

Figure 2.4 Quarterly wholesale electricity prices



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

Box 2.2 Wholesale electricity prices in 2022

Wholesale electricity prices rose sharply in 2022 to reach record levels in all regions. A key driver of these prices was a dramatic increase in international prices for coal and gas, which are key fuels for electricity generation. Coal and gas-powered generators needing to source additional fuel were exposed to these high prices. These fuel cost issues were compounded by fuel supply problems, with many coal mines and rail routes impacted by heavy rain. Further, a large number of planned and unplanned coal generator outages in May and June coincided with unusually cold weather and high demand.

The increase in spot prices led to very high prices and considerable price volatility for electricity hedge contracts. It also led to an increase in the popularity of swaptions, which allow holders to lock in a price at which they may buy a hedge contract in the future. Section 2.5 includes a discussion of these dynamics.

Following the winter of 2022, the conditions that caused the high prices eased and both spot and hedge contract prices fell back to lower levels. However, given the ongoing evolution of the market, prices and market dynamics have not fully returned to pre-2022 'normal'.

2.3.1 Price volatility

Price volatility is a natural feature of energy markets that can signal to the market that investment in new generation or storage is needed or demand should be shifted to cheaper times. Price volatility in the NEM has increased significantly compared with 2020 in response to the interplay between intermittent generation sources and fluctuating demand.

Price volatility can involve instances of high prices, but it can also involve negative prices. Generators in the NEM may offer capacity as low as the market floor price of $-\$1,000$ per MWh. Our analysis in this section focuses on prices below $\$0$ per MWh and above $\$300$ per MWh.

Generators offer capacity at negative prices for a range of reasons. Generators whose capacity is dispatched by AEMO will receive the market price for that capacity, rather than the price they offer. Because AEMO usually dispatches the lowest-priced capacity first, a generator that bids capacity at negative prices is less likely to have its bid rejected and bidding at the market floor can 'guarantee' being dispatched.

Coal generators typically have high startup costs, so having to pay to continue generating for a limited period of time is usually more cost-effective than being switched off and restarting. Additionally, if a generator has entered into contracts that ensure a fixed price for the electricity it sells into the market, its exposure to negative prices may be lower.

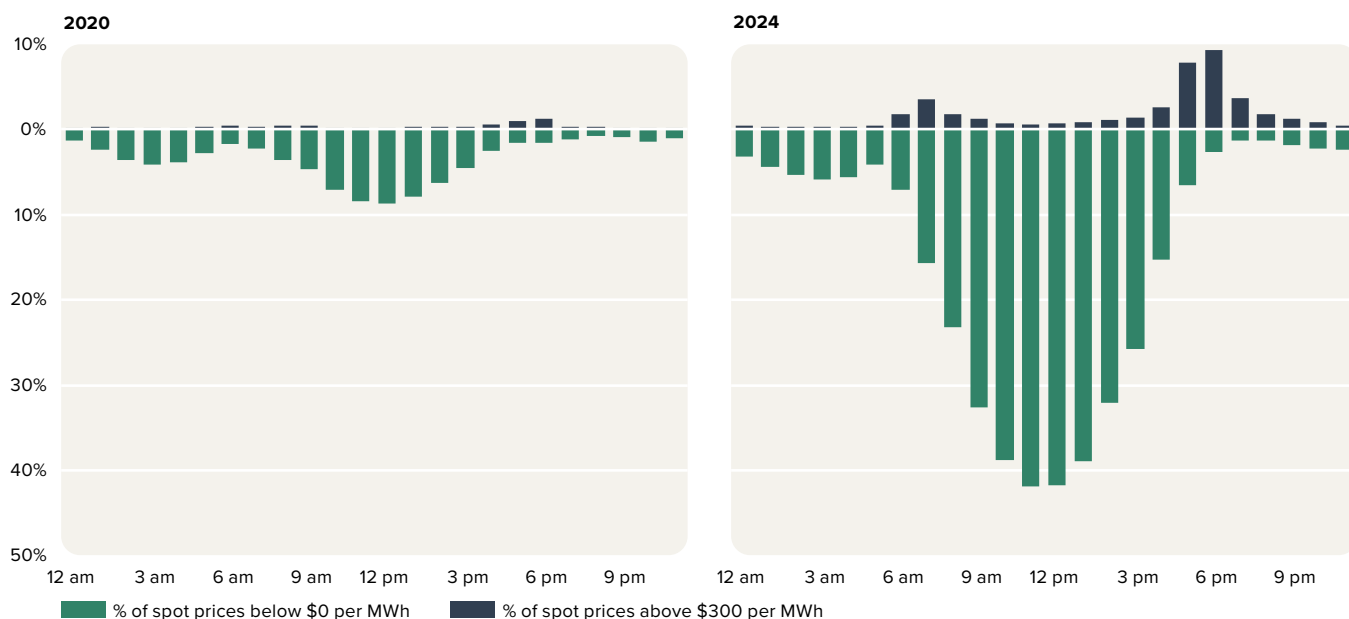
Negative prices have been more frequent since intermittent generation entered the market. Wind and solar generators have marginal costs close to zero. If wind and solar generating conditions are optimal, they may need to bid capacity at negative prices to guarantee dispatch. Some wind and solar generators also source revenue from power purchase agreements and the sale of renewable energy certificates. As such, they may operate profitably even when wholesale prices are negative. Instances of negative spot prices are highest when these technologies, alongside rooftop solar, are generating.

If electricity demand is low, the market has surplus capacity and the chances of the market settling at a negative price are higher. With multiple low-cost generators all competing for dispatch, the likelihood of negative prices increases. In recent times, negative prices have been most common in the middle of the day when large-scale solar resources are producing maximum output and the generation of rooftop solar reduces net electricity demand.

Generators may also offer capacity at high prices for a range of reasons. Generators with higher running costs, or with a need to ration limited fuel, will tend to offer at higher prices. Similarly, some generators have high start-up costs and may offer at very high prices when they do not plan to run, to avoid needing to switch on for short periods. Some gas generators have been doing this more often as more intermittent renewables have entered the market – likely because fluctuations in wind and solar output can require other generators to come on for short periods to fill gaps.

Since 2020, the frequency of both negative prices and prices above $\$300$ per MWh has increased significantly (Figure 2.5). Negative prices made up 15% of all prices in 2024, up from 3.5% in 2020. Prices above $\$300$ per MWh increased from 0.4% to 1.8% of all prices over the same period.

Figure 2.5 Percentage of prices below \$0 per MWh and above \$300 per MWh



Note: The upward y-axis shows, for each hour of the day in the chosen year, the percentage of 5-minute prices across all NEM regions that were greater than \$300 per MWh. The downward y-axis similarly shows the percentage of prices that were below \$0 per MWh. Prices were not settled in 5-minute intervals until October 2021, although prior to this dispatch was determined on a 5-minute basis using 5-minute prices. The figure presents outcomes in NEM time (Australian Eastern Standard Time).

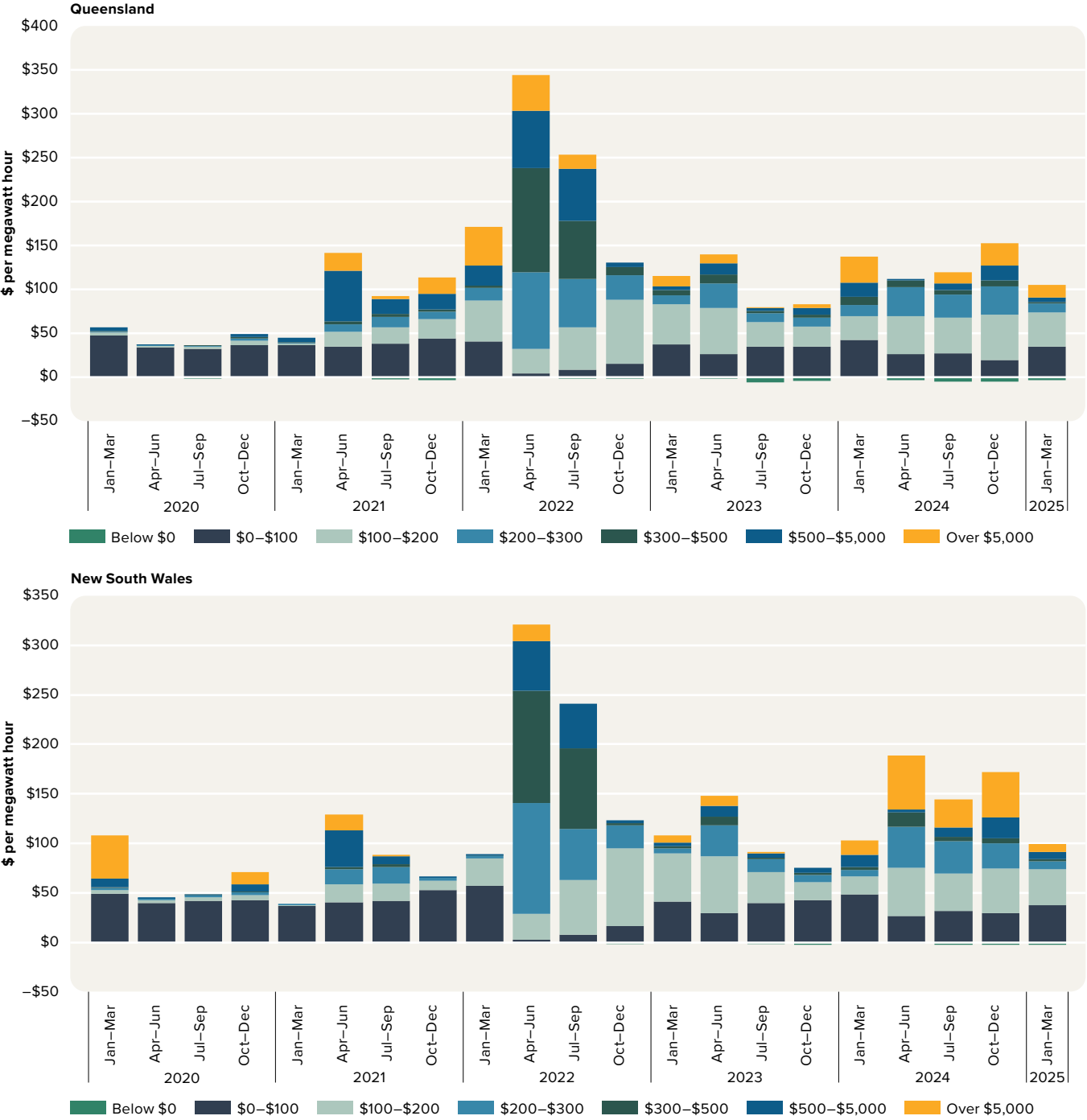
Source: AER; AEMO (data).

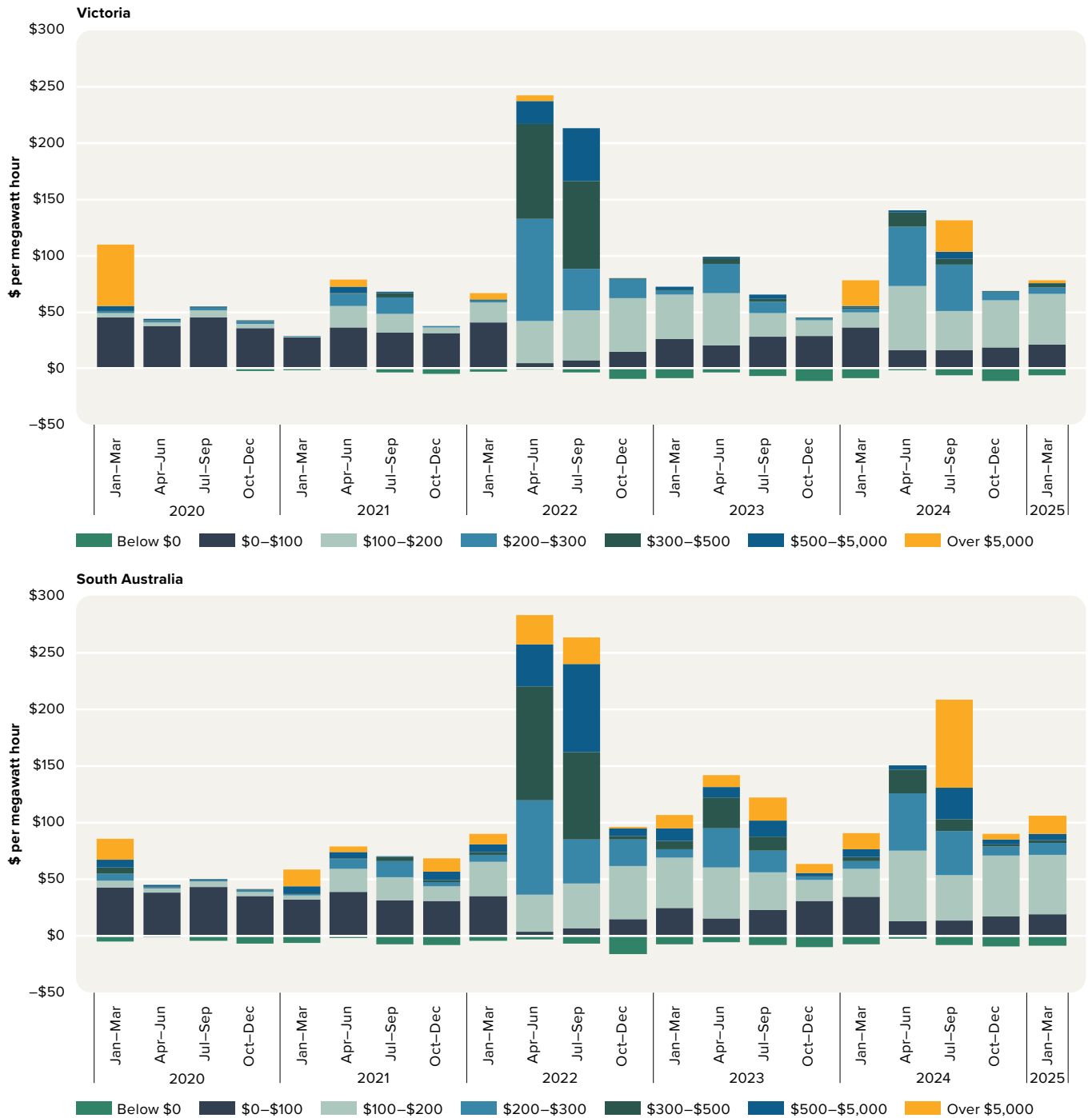
There have also been changes in the timing of these prices. The frequency of negative prices between 3 am and 4 am has increased only slightly – from 4.1% of the time in 2020 to 5.8% in 2024. By contrast, the frequency of negative prices between 11 am and noon has increased significantly – from 8.5% to 41.9% of the time. Meanwhile, the frequency of prices above \$300 per MWh increased at all times of day but especially during the evening peak. Between 6 pm and 7 pm, the frequency of prices above \$300 per MWh rose from 1.3% to nearly 10%.

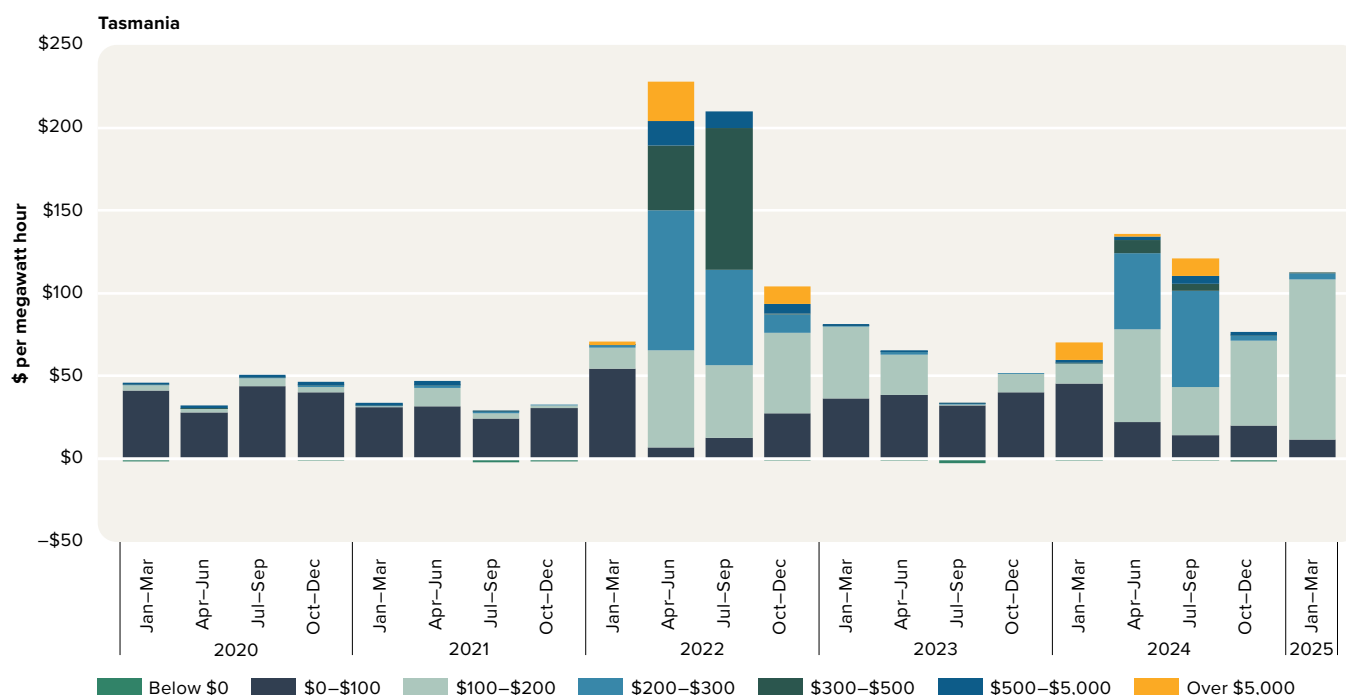
The frequency of high and low prices differed between regions. South Australia and Victoria, the regions with the highest proportion of intermittent renewable generation (Figure 2.18), accounted for most negative price occurrences in 2024, representing a combined 62% of negative prices in the NEM. South Australia and Queensland were the regions with the highest frequency of prices above \$300 per MWh. These regions represented 53% of prices above \$300 per MWh in 2024.

Despite their greater frequency, negative prices have a relatively modest impact on average spot prices compared with high prices (Figure 2.6). For example, in January to March 2025 in South Australia, negative prices reduced the quarterly average price by \$8.33 while prices above \$300 per MWh increased it by \$23.68. In the July to September quarter, the contribution from high prices was more extreme, with negative prices reducing the quarterly average price by \$7.79 while prices above \$300 per MWh added \$115.81. This is partly because when high prices do occur, they are often much more extreme than negative prices (which are often only slightly below \$0 per MWh). It is also partly because higher prices tend to occur when system demand is greater, meaning that high prices apply to a greater proportion of the electricity that is dispatched.

Figure 2.6 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; AEMO (data).

2.4 Generator fuel costs

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 with independent suppliers. NSW black coal generators typically acquire their fuel through contracts. Black coal producers supply domestically as well as exporting to the international market. Short-term supply contracts for coal are likely to align more closely with the prevailing international black coal price, but it is also common for the price of long-term domestic supply contracts to be set by reference to international coal price benchmark indices. 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 purchase coal for flexible levels of generation
- long-term contract negotiations coincide with fluctuating prices.

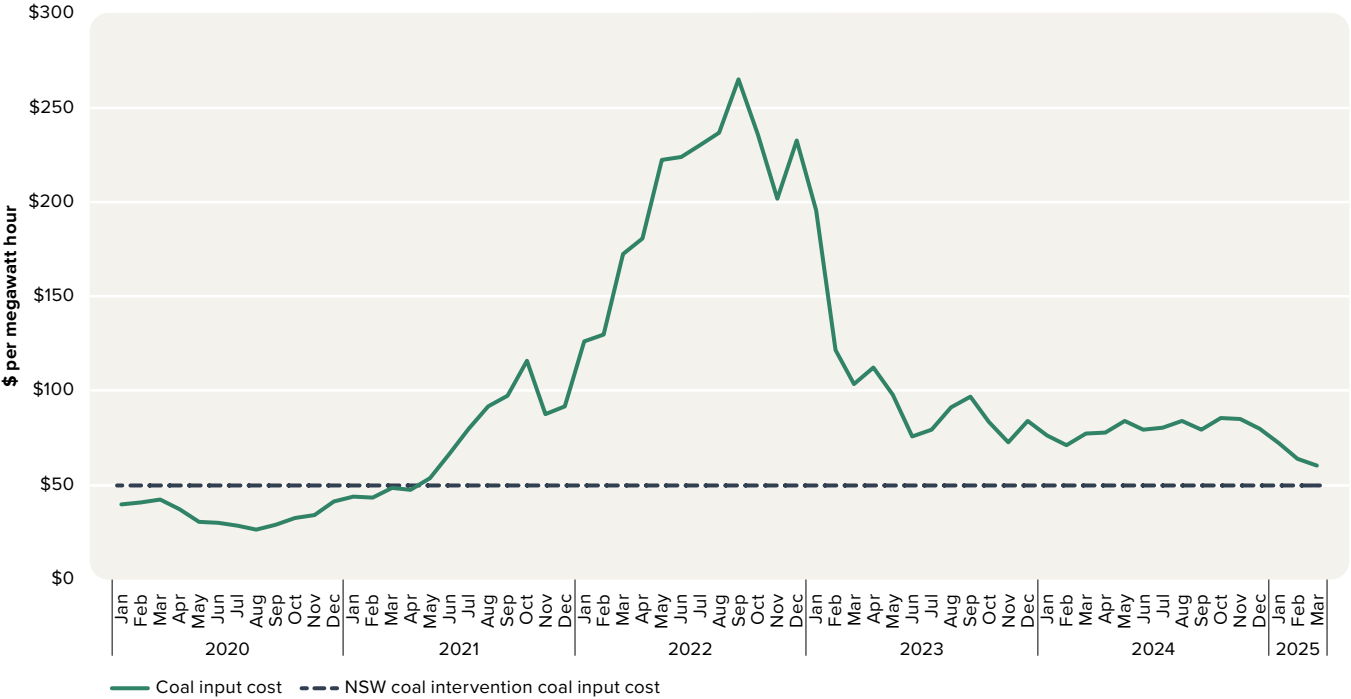
Coal generators in Victoria use brown coal rather than black coal. Brown coal is plentiful in the Gippsland region and is very low cost. It is also low quality and unsuitable for export, so its cost is not influenced by export market coal prices.

In 2024 the international export price for black coal averaged \$204.60 per tonne, which equates to a cost of generation of around \$80 per MWh (Figure 2.7). In 2024, the export price of coal was more stable than in 2022 and 2023.

As at the end of March 2025, the cost of generation based on the export price of black coal had dropped to around \$60 per MWh. Despite this drop, the generation cost remains higher than it was under the market intervention prices that were in place throughout 2023 and the first half of 2024 (about \$49 per MWh).³⁴ As such, it is likely that NSW generators are still facing higher coal costs than they were during the market intervention period.

34 AER, [NSW coal market price emergency](#), Australian Energy Regulator, accessed 30 May 2025.

Figure 2.7 Cost of producing electricity from coal



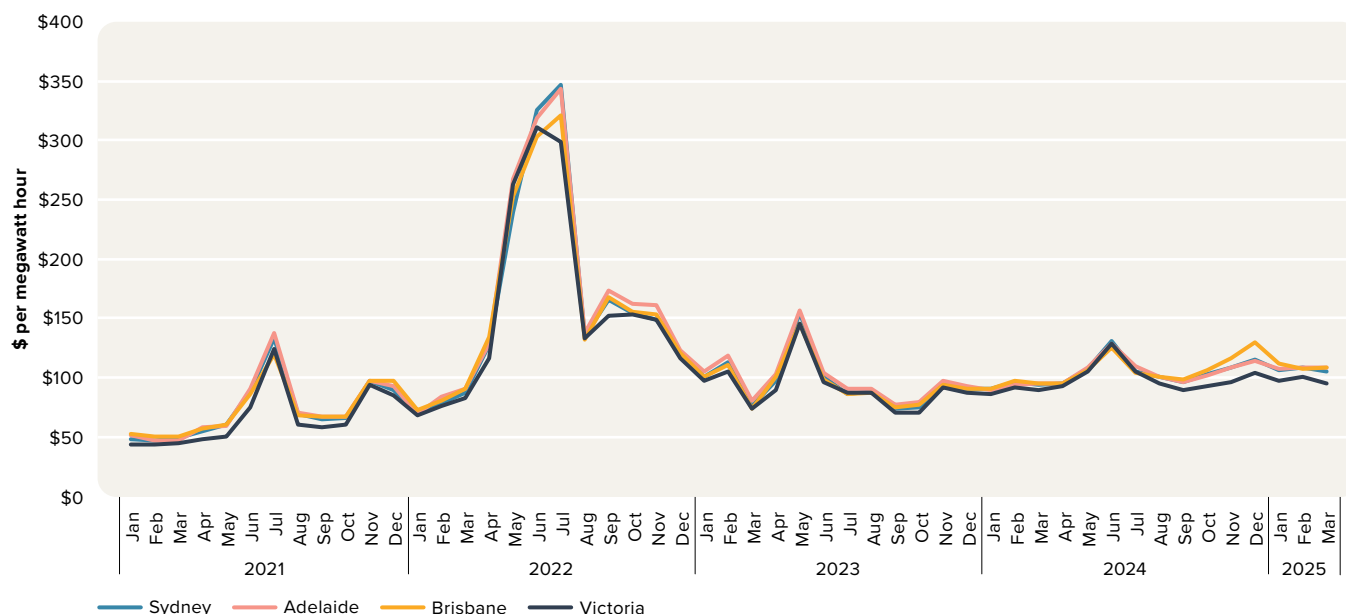
Note: To produce this analysis, we used an international reference price of coal (the NEWC index) as a proxy. To convert coal prices from US\$ per tonne to A\$ per MWh, we used the formula: \$ per MWh equals coal cost (US\$ per tonne) divided by the exchange rate (monthly average) multiplied by the heat rate (gigajoule [GJ] per MWh) divided by the 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; GlobalCoal (data).

Like black coal generators, gas-powered generators source their fuel from a variety of sources. Gas may be sourced from spot markets or through short-term or long-term contracts with suppliers. 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, or exporting it as LNG. These markets are covered in section 4.2.2 in chapter 4.

In 2024, the cost of producing electricity using gas sourced from domestic markets averaged around \$100 per MWh (Figure 2.8). This was much lower than the record prices reached in 2022, but higher than pre-2022 prices.

Figure 2.8 Cost of producing electricity from gas



Note: Analysis based on domestic spot gas prices. 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 equals gas cost multiplied by 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 – because they operate less efficiently than CCGT, they have higher heat rates and a higher cost of gas in \$ per MWh.

Source: AER; AEMO (data).

2.5 Electricity derivatives market

Derivative contract markets play a pivotal role in protecting energy consumers from price volatility by enabling proactive risk management. They also influence generator behaviour by shaping investment and dispatch decisions. A liquid, accessible and adaptable contract market is integral to competitive and sustainable wholesale market outcomes.

Derivative (exchange-traded or over-the-counter) markets operate parallel to the wholesale electricity market. Prices in the wholesale market can be volatile, posing risks for market participants. Generators face the risk of low settlement prices reducing their earnings, while retailers risk paying high wholesale prices that they cannot pass on to their customers. A retailer may expand its operation and contract with many new customers at a set retail price, only to incur unexpectedly high prices in the wholesale market, ultimately leaving the retailer substantially out of pocket.

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

Typically, vertically integrated gentailers are imperfectly hedged – their position in generation may be ‘short’ (small relative to their retail load) or ‘long’ (large relative to their retail load). For this reason, gentailers also participate in contract markets to manage outstanding exposures, but to a lesser extent than standalone generators and retailers.

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

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

- In exchange-traded markets, electricity futures products are traded on the Australian Securities Exchange (ASX). Electricity futures products are available for Queensland, NSW, Victoria and South Australia.

- In over-the-counter (OTC) markets, 2 parties contract with each other directly (often assisted by a broker). The terms of OTC trades are usually set out in International Swaps and Derivatives Association (ISDA) agreements.

Exchange-traded products are standardised to encourage liquidity. OTC markets contain standardised products as well, but also offer products that can be tailored to the bespoke requirements of counterparties. Exchange-traded contracts are settled through a centralised clearing house, which acts as a counterparty to all transactions and requires daily cash margining to manage credit default risk. In OTC trading, counterparty 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.

Standardised derivative products include:

- Futures contracts – these allow a party to lock in a fixed price (strike price) to buy or sell a given quantity of electricity at a specified time in the future. Available products include quarterly base contracts (covering all trading intervals within a quarter) and peak contracts (covering specified times of generally high energy demand). As at April 2025, the ASX planned to list new Peak Load Electricity Futures Contracts that better reflect key NEM demand periods, with separate morning and evening contracts to begin listing from 30 June 2025 (section 2.5.6).³⁵ Futures can also be traded as calendar or financial year strips covering all 4 quarters of a year. Futures contracts are settled against the spot market price in the relevant region – that is, when the spot price exceeds the strike price, the seller of the contract pays the purchaser the difference; when the spot price is lower than the strike price, the purchaser pays the seller the difference. In OTC markets, futures are known as swaps or contracts for difference.
- Caps – these are contracts setting an upper limit on the price that a holder will pay for electricity, with the seller paying the difference between the cap (strike price) and the spot price. Cap contracts on the ASX have a strike price of \$300 per MWh. When the spot price exceeds the strike price, the seller of the cap (typically a generator) must pay the buyer (typically a retailer) the difference between the strike price and the spot price. Alternative (higher or lower) strike prices are available in the OTC market.
- Options – these are like futures contracts, but they 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 the ASX.

- 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.

35 ASX, [New Australian Peak Load Electricity Futures Contracts go live dates](#), Australian Securities Exchange, 22 May 2025, accessed 5 June 2025.

Trade volumes and prices of derivative products are publicly reported for exchange trades, but trading activity in OTC markets is confidential and not disclosed publicly. Under national electricity law amendments passed in May 2024, the AER received enhanced powers to collect contracts and contract-related information, including OTC trades, from market participants.³⁶ In 2024, the AER used these powers for the first time and collected contract market information, including OTC trades, pertaining to the South Australian contract market. Analysis of this information was included in the *Wholesale electricity market performance report 2024* and supported our assessment of market performance, competition and efficiency in the region.³⁷

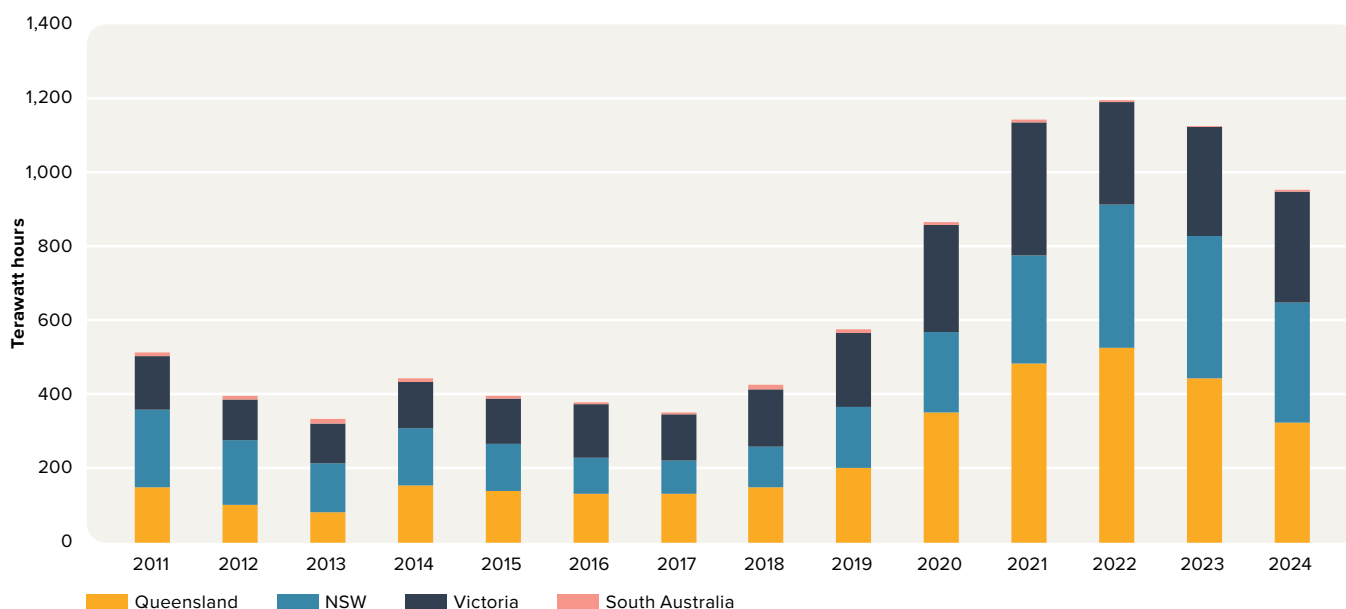
2.5.1 Exchange-traded market activity

Until 2021, the ASX was the sole futures exchange operating in the NEM, facilitating regular trades across Queensland, NSW, Victoria and South Australia. FEX Global launched a separate futures exchange in March 2021 offering a similar range of products. However, FEX Global recently halted trading in all contract markets.³⁸

Exchange-traded liquidity has historically been high in Queensland, NSW and Victoria, but low in South Australia. Liquidity in South Australia increased slightly in 2024 – albeit from very low historic levels and is still well below other regions. In 2024, Queensland, NSW and Victoria each accounted for roughly one-third of ASX-traded volume, while South Australia contributed just 0.5% of contract market trades. ASX contracts in South Australia are likely less attractive for hedging than in other NEM regions, due to the region’s unique demand and generation profiles compared with other regions. A detailed analysis of South Australia’s unique market conditions is available in the South Australia deep dive chapter of the AER’s *Wholesale electricity market performance report 2024*.

ASX annual trading volume has increased materially since 2017, more than tripling by 2021 and peaking in 2022 (Figure 2.9), coinciding with the period of record-breaking high wholesale electricity prices in the NEM (Box 2.2). Annual ASX-traded volumes decreased by 15% in 2024 compared with 2023 but remained elevated relative to pre-2021 levels. NSW and Queensland drove the decrease, recording year-on-year declines of 16% and 27% in 2024, respectively. Victoria experienced a 2% increase, while South Australia saw its trade volume rise by 121% from a very low base.

Figure 2.9 Traded volumes in ASX electricity contracts



Note: Volumes are exchange trades that occurred across the calendar year across ASX Energy futures. The axis shows the year the trade occurred rather than the period of the contract.

Source: AER; ASX Energy (data).

³⁶ AER, [Enhanced wholesale market monitoring guideline \(2024\)](#), Australian Energy Regulator, 5 November 2024.

³⁷ AER, [Wholesale electricity market performance report 2024](#), Australian Energy Regulator, 20 December 2024.

³⁸ FEX Global, [FEX Global transition in Clearing and Settlement Arrangements](#), accessed 17 July 2025.

Growth in ASX trading between 2018 and 2022 was primarily driven by increased swaption activity and, to a lesser extent, by increased base futures volumes. Since exercised swaptions result in trades of the underlying base futures contracts, the rise in swaption activity contributed to the increase in base future trading volumes. A more detailed discussion of the shift towards swaptions is available in Chapter 3 of the AER's *Wholesale electricity market performance report 2024*.

Base futures contracts are typically traded in higher volumes during the April to June and September to December quarters. This pattern reflects market participants exercising options contracts, which are converted into base futures as they approach the start of the financial and calendar years.

The trade of both swaptions and quarterly base futures contracts peaked in 2022 when they represented 49% (587 terawatt hours [TWh]) and 43% (516 TWh) of total ASX trade volume, respectively. Since then, ASX base quarterly futures trading has declined by 14% in 2023 and a further 16% in 2024. Swaptions fell by 4% in 2023 and 27% in 2024 but remained the most traded contract type on the ASX, comprising 43% of traded volume in 2024. Swaptions have been the most traded product since overtaking base quarter futures in 2020. Quarterly base futures followed with a 39% share, while average rate options (10%) and caps (7%) were traded at lower levels. Monthly base futures and peak contracts were rarely traded, together making up just 0.1% of total volume.

2.5.2 Contract market liquidity ratio

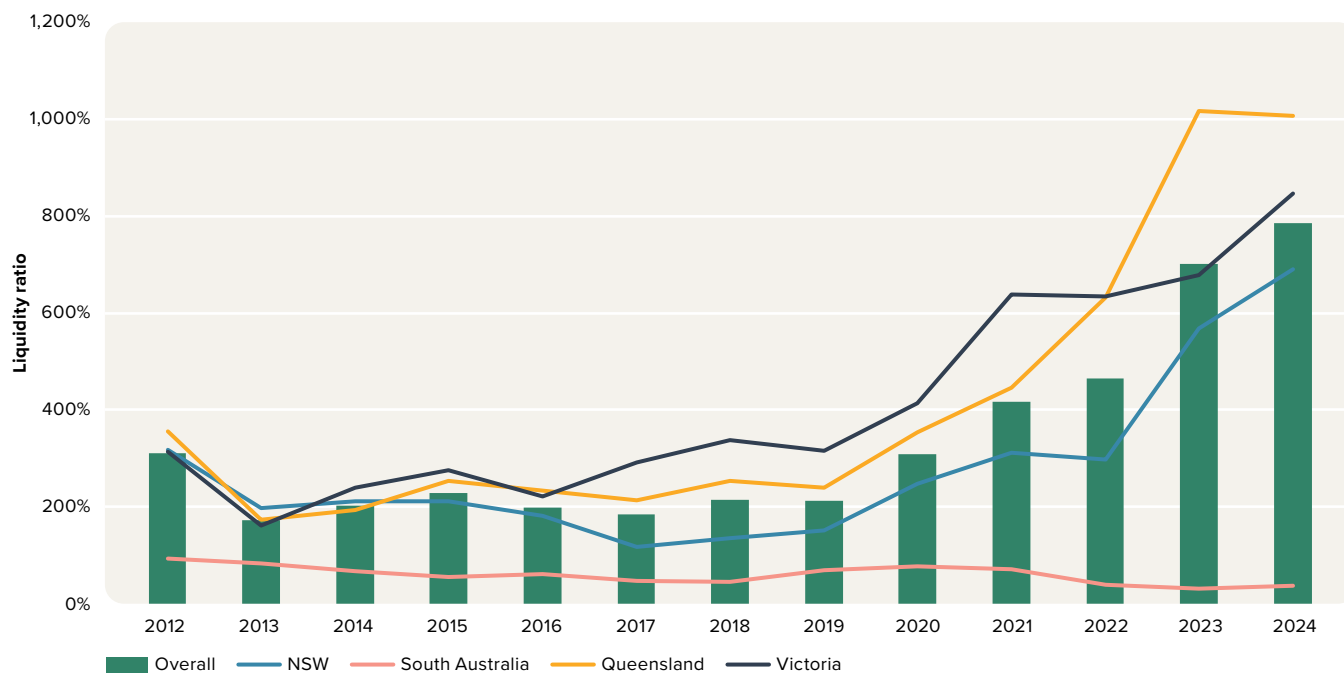
The liquidity ratio is one way to measure market liquidity. It is calculated by dividing the volume of ASX electricity contracts traded (in MWh) for a given delivery year by the spot market's native demand (also in MWh) in that same year. Higher liquidity allows market participants to trade contracts more readily and can contribute to greater price certainty.

The liquidity ratio for the mainland NEM regions has been steadily increasing since 2017, rising from 184% in 2017 to 786% in 2024 (Figure 2.10). Since 2022, the liquidity ratio has improved significantly in NSW, Queensland and Victoria, and is now at an all-time high in all regions except South Australia. In these 3 regions, total ASX contract trade volumes significantly exceeded underlying electricity demand. Given the extent of vertical integration in Victoria and NSW, this suggests substantial trading and re-trading of capacity made available for contracting.

South Australia has also seen an increase in contract liquidity in 2024, but it remains relatively low compared with other NEM mainland regions. Traded volumes are still below underlying electricity demand, with ASX contracts for 2024 representing only 37% of the region's demand – up from 32% in 2023. The region's high proportion of intermittent renewable generation, high degree of vertical integration and relatively concentrated ownership of dispatchable generation have contributed to this weaker liquidity because intermittent generation is less suited to underwriting the standard ASX-listed contracts.

ASX trades can be initiated up to 4 years in advance of delivery. Therefore, the current high liquidity ratio partly reflects elevated trading activity in previous years. With total traded volumes declining in both 2023 and 2024, the elevated liquidity ratio is unlikely to be sustained in future years.

Figure 2.10 ASX Liquidity ratio



Note: The liquidity ratio compares traded volumes to electricity native demand in each region. For this metric, trade volumes are listed for the period of the contract rather than the year the trade occurred. The AER defines native demand as the sum of initial supply and total intermittent generation in a region.

Source: AER; ASX Energy (trade data); AEMO (demand data).

2.5.3 Open interest

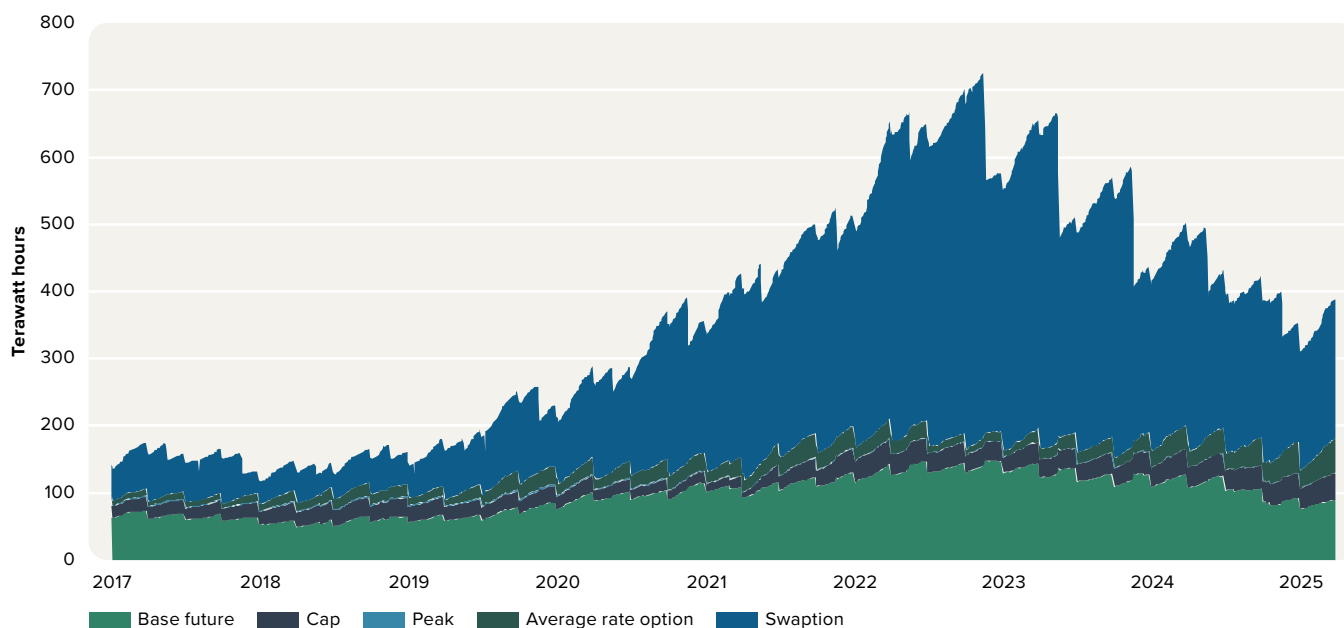
Open interest is the total number of contracts that are still active. These are contracts that have not been closed, exercised or expired as at the end of the previous trading day. Open interest serves as an indicator of market activity, as each active contract reflects an agreement between a buyer and a seller.

Open interest volumes have continued to fall through 2024 after peaking at 727 TWh on 16 November 2022 (Figure 2.11). Since then, open interest has trended downwards and was 389 TWh on 31 March 2025. This trend aligns with the overall decline in trading volumes since the 2022 peak and highlights the continued cooling of market activity. The sharper fall in open interest relative to volume indicates that a larger share of recent trades has involved closing existing positions rather than opening new ones.

This decline has been largely driven by a reduction in open interest for swaption contracts, which have dropped from a peak of 544 TWh on 14 November 2022, amid elevated market volatility in mid-2022, to 207 TWh (a reduction of 62%) as at 31 March 2025. As swaption contracts expire every 6 months, in May and November, open interest naturally decreases, creating a saw-tooth pattern. While some of this decline reflects routine contract expiry, the broader trend is downward, as fewer new option contracts are being opened to replace those expiring.

Base futures, the next most significant contract type after swaptions, have also followed a downward trend. Open interest in these contracts has fallen from a peak of 148 TWh on 28 November 2022 to 90 TWh as at 31 March 2025.

Figure 2.11 ASX daily open interest volumes, by contract type



Note: Daily open interest for all ASX energy contracts.

Source: AER analysis using ASX data.

2.5.4 Contract prices

A calendar year base futures contract covers all 4 quarters of a calendar year and allows a party to lock in a fixed (strike) price to buy or sell a constant number of megawatts per hour throughout the year. We use calendar year base futures prices to indicate overall wholesale electricity market trends and price expectations.

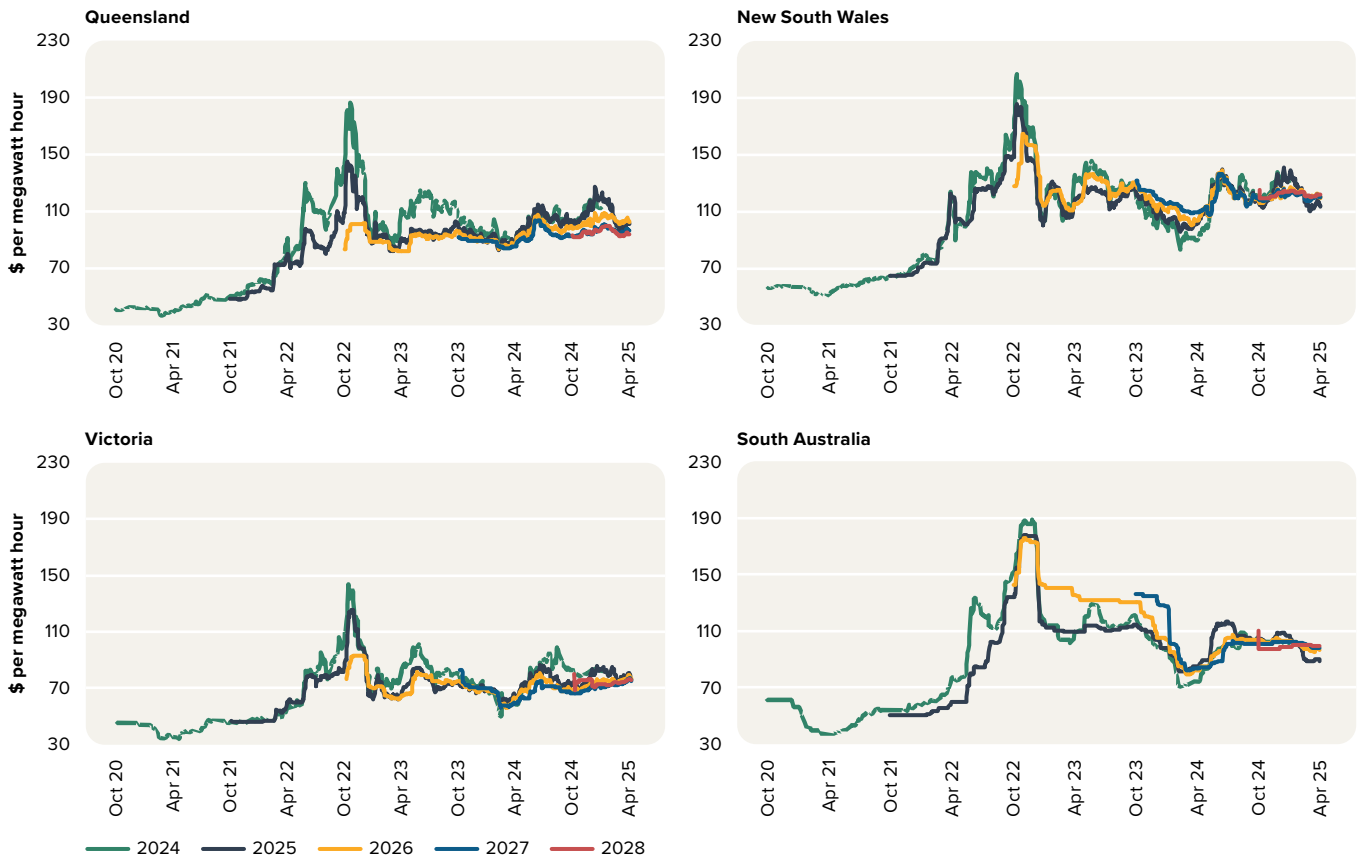
Calendar year base futures prices have fallen considerably from their 2022 peak but have remained relatively stable from early 2023 onwards. In mid-2024, prices rose modestly across all mainland regions before easing again, resulting in little net change during the 2024 calendar year (Figure 2.12). Daily price volatility also declined over the year, returning to levels last seen before 2022.³⁹

As at 1 April 2025, prices for 2025 contracts ranged between \$76 per MWh in Victoria and \$114 per MWh in NSW. Futures contracts for later years mostly traded in line with 2025 prices, ranging between \$77 per MWh in Victoria and \$120 per MWh in NSW for 2026 and between \$75 per MWh in Victoria and \$121 per MWh in NSW for 2027.

The prices of these futures contracts indicate that the market expects electricity prices to remain elevated compared with pre-2022 levels, but not to reach the record levels of 2022 (Box 2.2).

³⁹ Daily price volatility was calculated as the standard deviation of the percentage daily price changes in calendar year base futures prices.

Figure 2.12 Prices for calendar year base futures

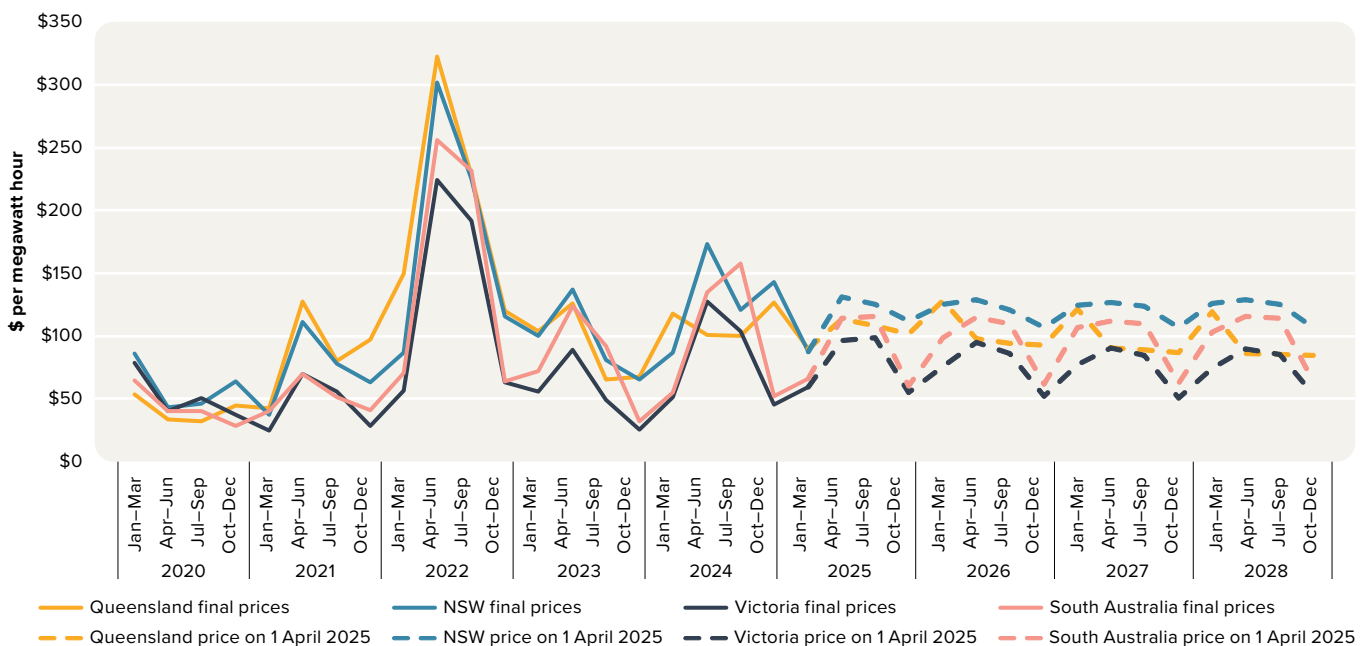


Note: Calendar year prices have been calculated by averaging the prices across the 4 base quarter products within each calendar year (calendar year base futures products do exist, but they are thinly traded). Prices are calculated based on daily settled prices at the end of each trading day.

Source: AER; ASX Energy (data).

Quarterly base futures exhibit a seasonal profile, with prices for future quarters lowest for the October to December quarter when demand is usually at its lowest (Figure 2.13).

Figure 2.13 Prices for quarterly base futures



Note: Prices for quarterly base futures up to and including the January to March quarter 2025 are finalised (as they are no longer traded). Prices for quarterly base futures for the April to June quarter 2025 and beyond (which are still being traded) are as at 1 April 2025.

Source: AER; ASX Energy (data).

2.5.5 Access to contract markets

Access to contract markets, either via an exchange (ASX) or in OTC electricity markets, can present a significant barrier to retailers and generators looking to enter or expand their presence in the market. Limited access restricts their ability to manage costs (for retailers) and secure revenue streams (for generators). This lack of access poses a material risk because contracts provide price certainty and revenue stability.

In the ASX market, the cash requirements for counterparties through initial and daily margining of contract positions can impose significant cash-flow constraints on retailers. Additionally, the use of standardised products with a minimum trade size of 1 MW can be prohibitive for smaller retailers, restricting them to the use of 'load following' hedges only accessible through the OTC market. OTC load following hedge contracts remove volume risk and are particularly sought by smaller or new retailers without extensive wholesale market expertise or capability.

However, credit risk can present further challenges in the OTC market. Smaller retailers may face stringent credit support requirements from counterparties, making access more difficult. Before entering into an OTC contract, counterparties typically need to establish an ISDA agreement, which is costly to set up. Furthermore, each OTC relationship requires a separate agreement, adding to administrative and financial burdens.

Access to clearing services was a key issue raised by participants following the withdrawal of Bell Potter as an ASX clearing participant amidst the significant volatility in 2022. To transact on the ASX, a market participant requires a clearer to clear and settle the transaction. The Exchange Clearing House manages its risk by imposing margin requirements on its contracting counterparties – the clearing participants – who in turn pass on these margin requirements to their clients, including retailers and generators.

In April 2024, a seventh clearing service provider (StoneX) entered the ASX electricity contracts market,⁴⁰ following the entry of Marex in October 2023.^{41 42}

2.5.6 Developments in contract markets

The increasing penetration of intermittent renewable generation has significant implications for contract markets. Unlike coal-fired generation, which historically suited the sale of standard contracts due to its steady output, renewables are weather-dependent and variable. 'Firming' this generation with energy storage and gas-powered plant could support more active and effective market participation. In response to these structural shifts, the ASX introduced new Morning and Evening Peak Load Electricity Futures Contracts in June 2025.⁴³

The existing peak load futures contracts cover 7 am to 10 pm on business days and were developed for a coal-dominated grid. These contracts no longer reflect evolving demand patterns and accounted for just 0.0005% of total ASX electricity trades in 2024. Following industry consultation in 2024, the ASX has redesigned its peak products to better reflect current operational demand patterns in the NEM.⁴⁴ The new products define morning peak as 6 am to 9 am and evening peak as 4 pm to 9 pm, from Monday to Sunday. These updated time blocks align more closely with actual periods of high net system demand and the operational needs of a grid increasingly shaped by solar during the day and higher consumption in the early morning and evening.

The new peak load contracts will be introduced progressively across NEM regions, starting with NSW on 30 June, followed by Queensland on 7 July, Victoria on 21 July and South Australia on 28 July.⁴⁵ Each regional contract will be listed quarterly out to the April to June quarter 2029, beginning with the July to September quarter 2025. This initiative aims to provide market participants with more relevant and effective tools for managing price exposure and hedging risks in a rapidly transforming energy landscape.

40 StoneX, [StoneX Obtains ASX Derivatives Clearing and Trading Membership](#), StoneX, 30 April 2024, accessed 5 June 2025.

41 Marex, [Marex becomes newest ASX futures clearing participant](#), Marex, 12 October 2023, accessed 5 June 2025.

42 ASX, [ASX Commodities Clear Contacts November 2024](#), Australian Stock Exchange, accessed 2 May 2025.

43 ASX, [ASX to list New Morning and Evening Peak Futures Contracts](#), Australian Stock Exchange, 14 April 2025.

44 ASX, [Response to consultation on ASX Australian Peak Load Electricity Futures contract redesign](#), Australian Stock Exchange, 30 September 2024.

45 ASX, [New Australian Peak Load Electricity Futures Contracts go live dates](#), Australian Stock Exchange, 22 May 2025.

2.6 Electricity demand and consumption

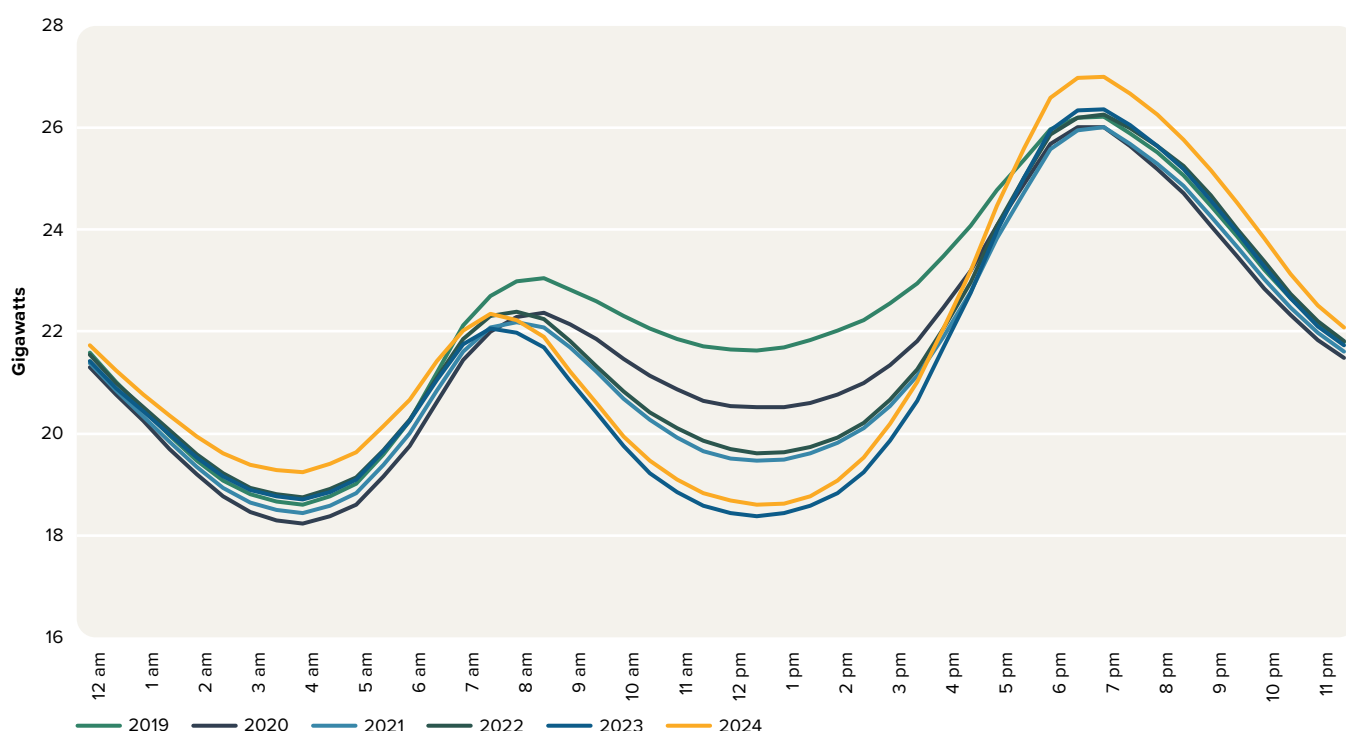
Grid demand refers to electricity sourced from large-scale generators and sold through the NEM. Electricity consumption refers to the total amount of electricity consumed and includes electricity produced by consumer energy resources, such as rooftop solar and home storage batteries. Consumer energy resources reduce grid demand because they replace electricity that would otherwise be supplied by large generators.⁴⁶

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

Between 2019 and 2024, the NEM experienced a noticeable decline in demand during the middle of the day (Figure 2.14). This trend has been driven by the significant growth in rooftop solar installations across residential areas. As more households have installed rooftop solar, a substantial portion of daytime electricity consumption is now being met by their own onsite solar generation. This self-generation reduces the amount of electricity required from the grid during daylight hours, particularly around midday when solar output is at its peak.

Conversely, grid demand has increased during the early morning and early evening periods, commonly referred to as peak hours, in part due to population growth. During these times, residential electricity usage tends to be high – due to activities such as heating, cooling, lighting and appliance use – while solar generation is minimal or non-existent due to the lack of sunlight. As a result, households rely more heavily on the grid during these periods. With population growth contributing to higher overall consumption, peak demand has risen despite the overall decline in midday demand.

Figure 2.14 NEM average demand, by time of day



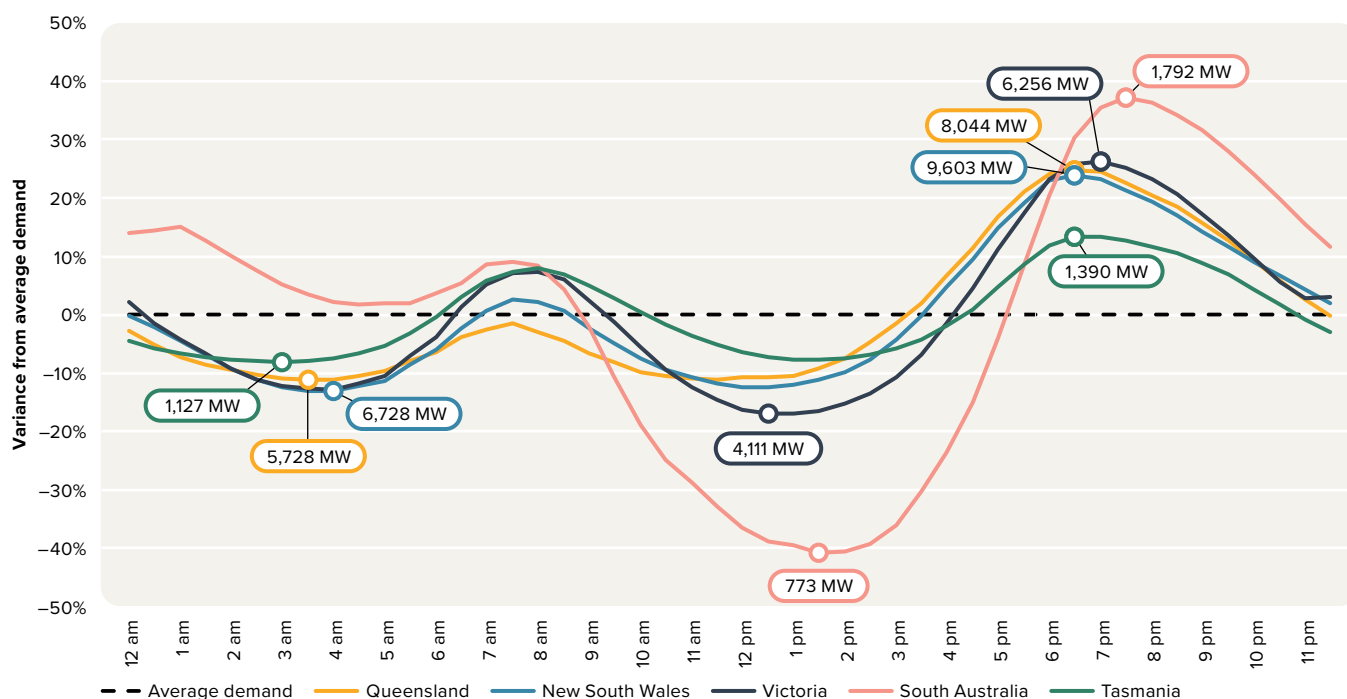
Note: The AER defines native demand as the sum of initial supply and total intermittent generation in a region. This figure presents outcomes in NEM time (Australian Eastern Standard Time). Values of y-axis do not start at zero to highlight the changes in demand.

Source: AER; AEMO (data).

⁴⁶ Consumer energy resources are distributed energy resources that are owned or leased by residential and small business consumers (or groups of consumers) that generate or store electricity or can alter demand in response to external signals. These resources include consumer loads that are flexible and efficiently optimised either through automation or direct behavioural response.

The gap between minimum and maximum demand varies considerably between regions. South Australia has the largest variation (approximately 80%), followed by Victoria, NSW and Queensland (ranging from 34% to 41%), and Tasmania has the smallest (21%) (Figure 2.15). The variability of grid demand is influenced by factors such as the level of rooftop solar uptake (which increases variability) and the proportion of electricity demand coming from heavy industry (which decreases variability).

Figure 2.15 Average demand by time of day in 2024, by region



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). Data labels show the average daily minimum and maximum demand in each region.

Source: AER; AEMO (data).

AEMO modelling shows that residential customers in the NEM currently consume around 60 TWh of electricity each year – around 40 TWh of this comes from the grid and 20 TWh is supplied by rooftop solar. Annual electricity consumption from business and industry in the NEM is around 150 TWh, almost all of which comes from the grid. Residential grid demand accounts for around 21% of total grid demand.⁴⁷

AEMO's modelling forecasts that NEM consumption will rise by around 108% by 2050.⁴⁸ Residential electricity use is forecast to increase due to uptake of electric vehicles and greater use of electricity for heating, cooling and cooking. Business and industry consumption is forecast to increase due to economic growth, the emergence of hydrogen and electrification of transport and industrial processes.

As households increasingly meet their own electricity needs through CER, residential grid demand will likely stay about the same. However, business and industry grid demand is forecast to increase by nearly 70% by 2050, reaching around 260 TWh.⁴⁹

47 AEMO, [2024 Integrated System Plan](#), Australian Energy Market Operator, 26 June 2024.

48 AEMO, [2024 Integrated System Plan](#), Australian Energy Market Operator, 26 June 2024.

49 AEMO, [2024 Integrated System Plan](#), Australian Energy Market Operator, 26 June 2024.

2.7 Market generation sources and ownership

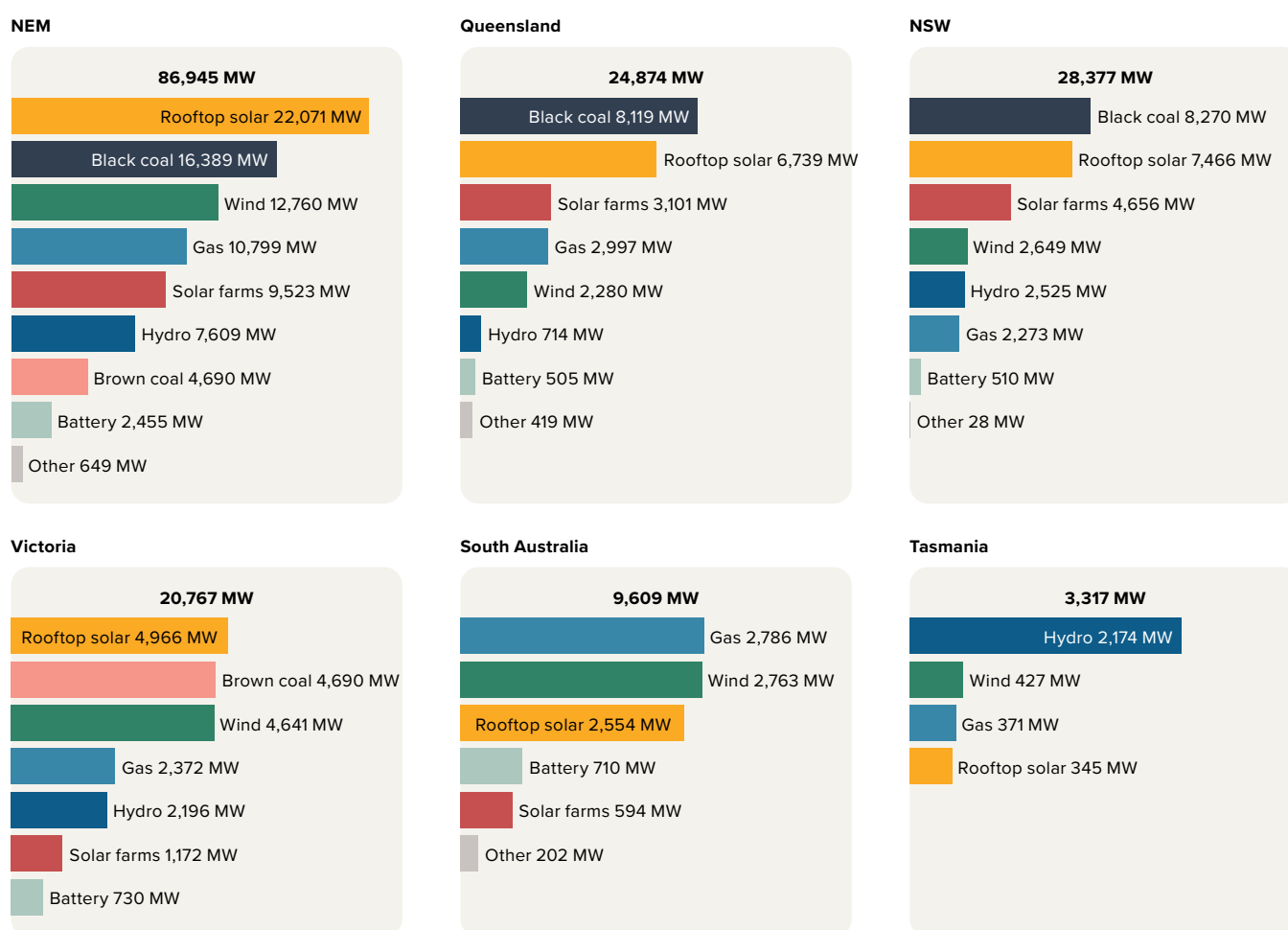
The NEM's generation fleet uses a mix of technologies to produce electricity. The NEM's generation mix can be measured in 2 ways – based on the registered capacity of each generating unit or based on their total generation output.

Registered capacity refers to the highest amount of electricity a generator has been registered to produce per hour. A typical generator will produce electricity at a rate lower than its registered capacity most of the time, with different generation technologies able to produce electricity at different rates of their capacity. Coal generators typically produce at a high rate relative to capacity because they can generate continuously throughout the day. Wind and solar generation are intermittent and produce electricity at a lower rate relative to their capacity. Gas and hydro generators may also produce electricity at a lower rate relative to capacity, depending on a range of factors including fuel costs and availability.

2.7.1 Sources of generation

By the end of 2024, total generation capacity in the NEM was 86,945 MW. Rooftop solar had the highest capacity, totalling 25% of registered capacity, followed by black coal at 19% (Figure 2.16). The installed capacity of renewable technologies (rooftop solar, solar farms, wind and hydro) represented 60% of total capacity in 2024.

Figure 2.16 Generation capacity, by fuel source

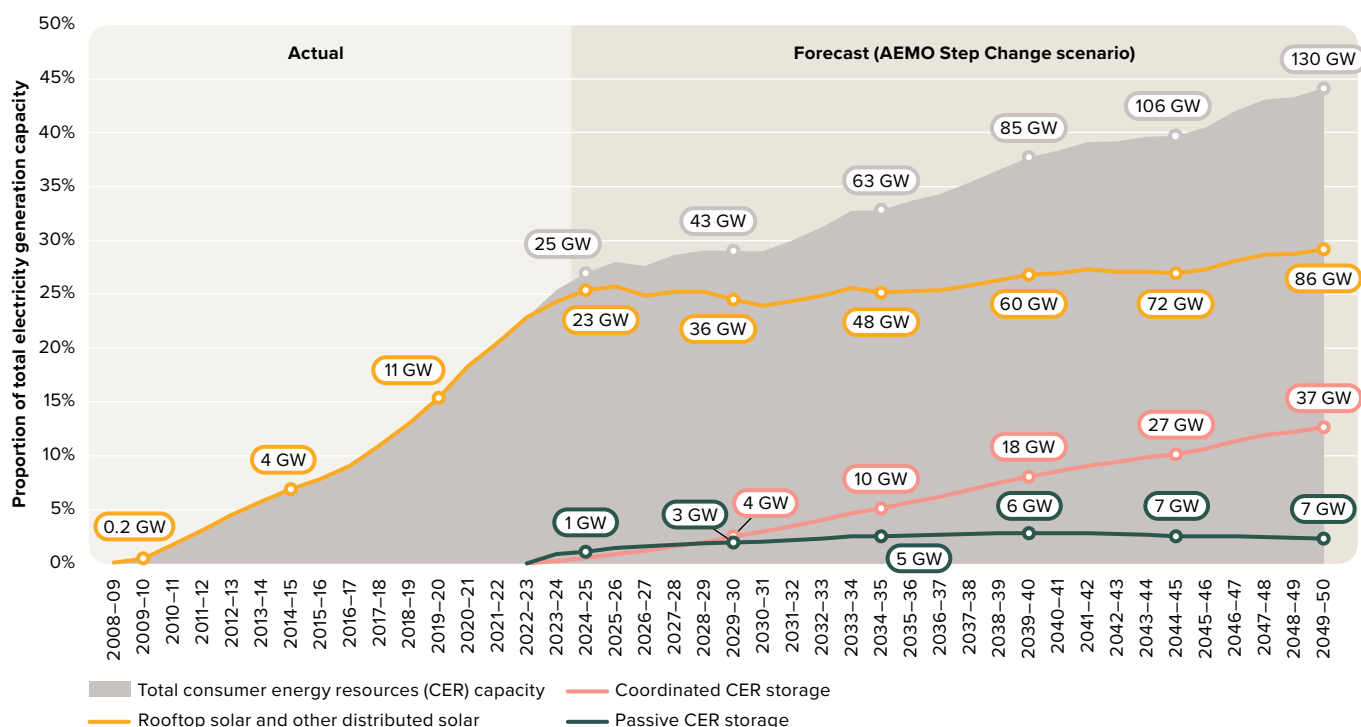


Note: Generation capacity as at 31 December 2024. Other dispatch includes biomass, waste gas, diesel and liquid fuels. Loads and non-scheduled generation have been excluded. For solar and battery units, we used the maximum capacity metric rather than registered capacity because inverter constraints may prevent these units from dispatching their full registered capacity.

Source: AER; AEMO (grid capacity data); Clean Energy Regulator (rooftop solar capacity data).

CER's share of generation capacity is expected to increase over time and AEMO forecasts it to reach 130 GW of capacity by 2050 (Figure 2.17). This is expected to represent about 45% of total NEM generation capacity.

Figure 2.17 Electricity generation capacity through consumer energy resources



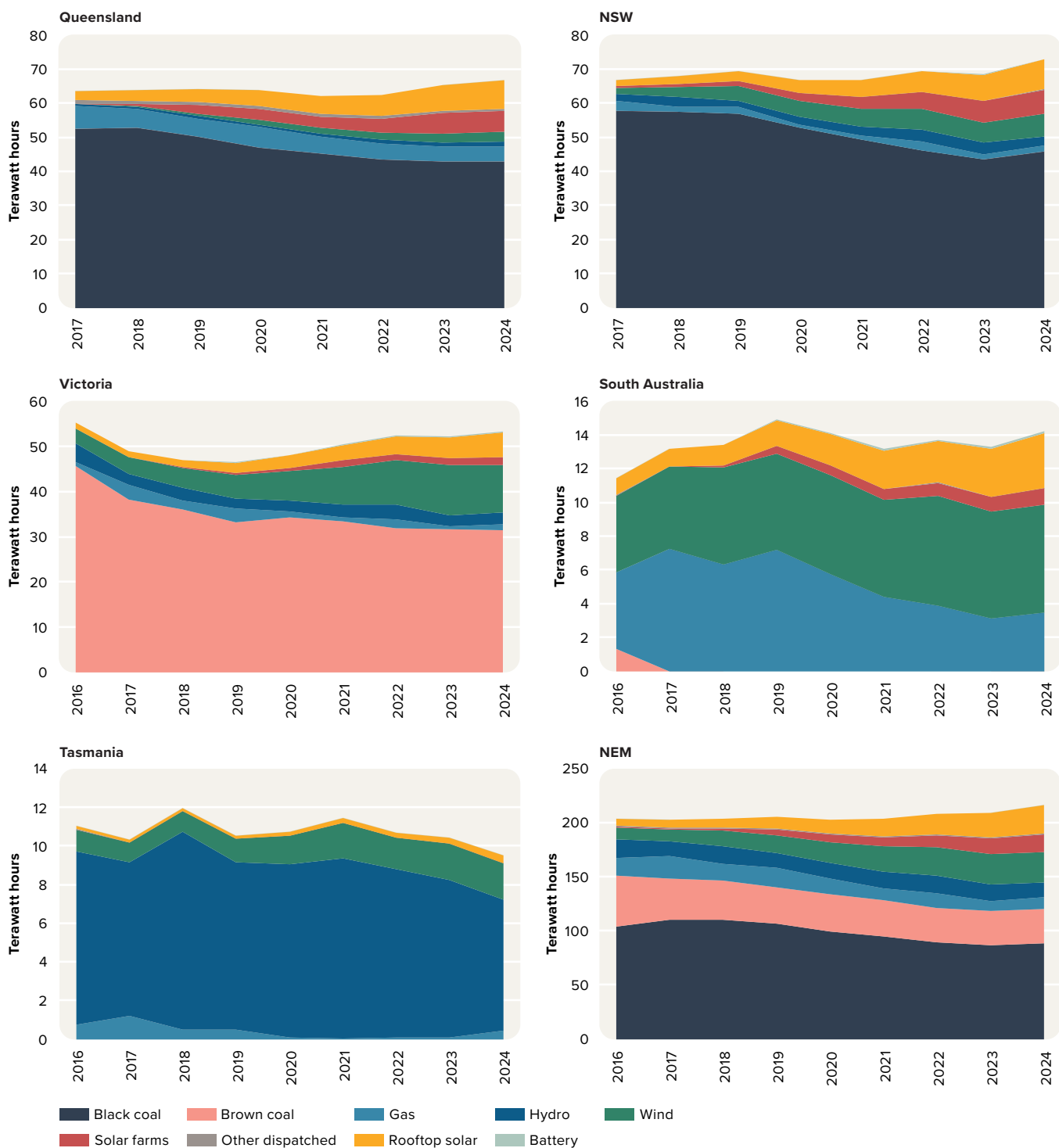
Source: AEMO, 2024 Integrated System Plan (ISP), Australian Energy Market Operator, 26 June 2024.

Generation output refers to the total amount of electricity produced over a given period. In 2024, 217 TWh of electricity was generated – 191 TWh by grid-scale generators and 26 TWh by rooftop solar systems (Figure 2.18). Compared with 2023, this represented a 2% increase in grid-scale generation output and a 13% increase in rooftop solar output (a 3% increase in generation output overall).

Coal and gas generators produced 61% of generation output, which was a slightly lower proportion than the previous year but represented a slight increase in total output. This in turn drove a 2% increase in carbon emissions from electricity generation. Renewable generators (rooftop solar, large-scale solar, wind and hydro) contributed 39% of electricity generation output, up from 38% in 2023. This modest increase was due to a 7% increase in solar and wind output being offset by an 11% decrease in hydro output. Hydro output is influenced by rainfall levels – Tasmanian hydro generation, in particular, has been impacted recently by a period of extremely low rainfall.⁵⁰

50 See for example, Hydro Tasmania, [Tasmanians to benefit from \\$122m Hydro dividend](#), Hydro Tasmania, 17 October 2024.

Figure 2.18 Generation output, by fuel source



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

Source: AER; AEMO (data).

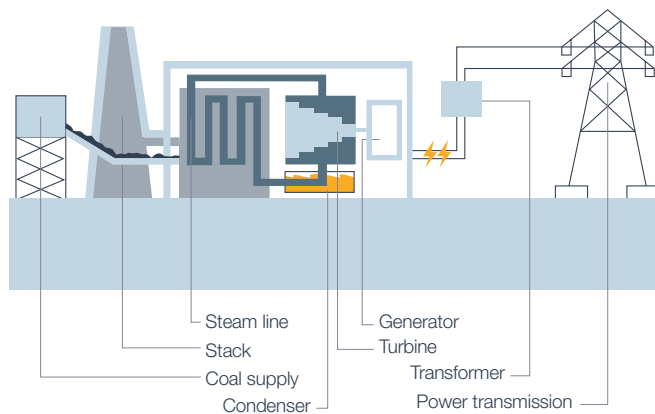
2.7.2 Characteristics of technology types

The various generation technologies (Figure 2.19) have differing characteristics that drive generator behaviours and have implications for price outcomes, as well as reliability and security of the energy system. Differences in startup, shutdown and operating costs influence each fuel type's bidding and generation strategies. Technology types also have different implications for power system security, including system strength and frequency.

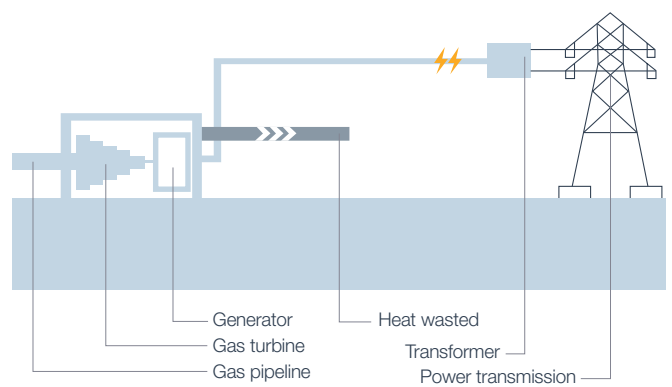
Renewable generation in the NEM has increased significantly over the past decade as Australia progresses towards carbon emissions reduction targets. By contrast, output from emissions-intensive black and brown coal generators has generally been declining, despite an uptick in 2024. Since new wind and solar generation has very different characteristics to the coal it is replacing, there are significant implications for the power system.

Figure 2.19 NEM generation technologies

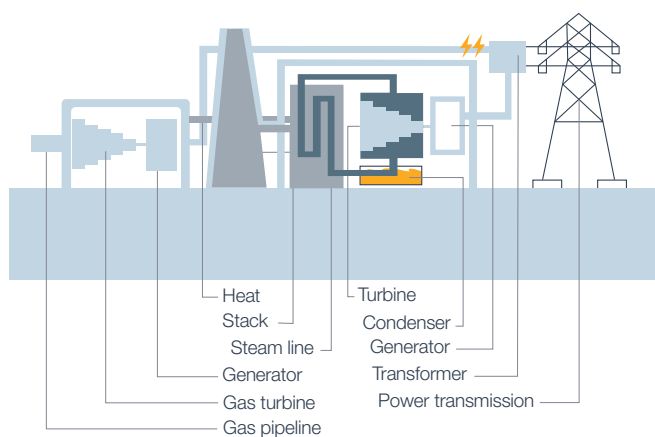
Coal-fired generation



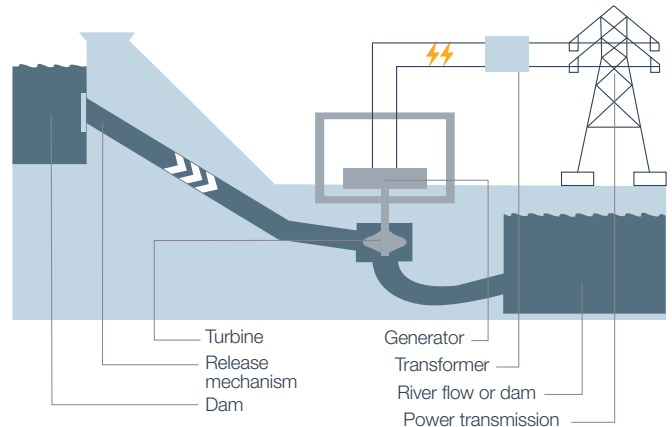
Open cycle gas-powered generation



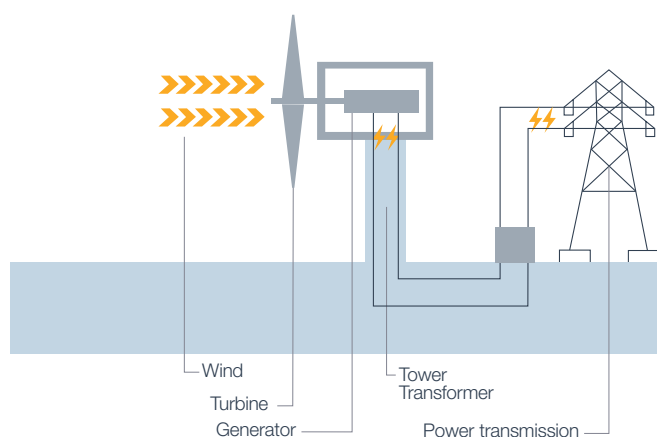
Combined cycle gas-powered generation



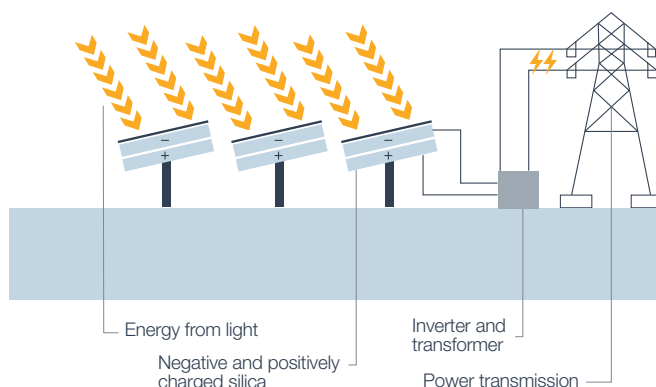
Hydroelectric generation



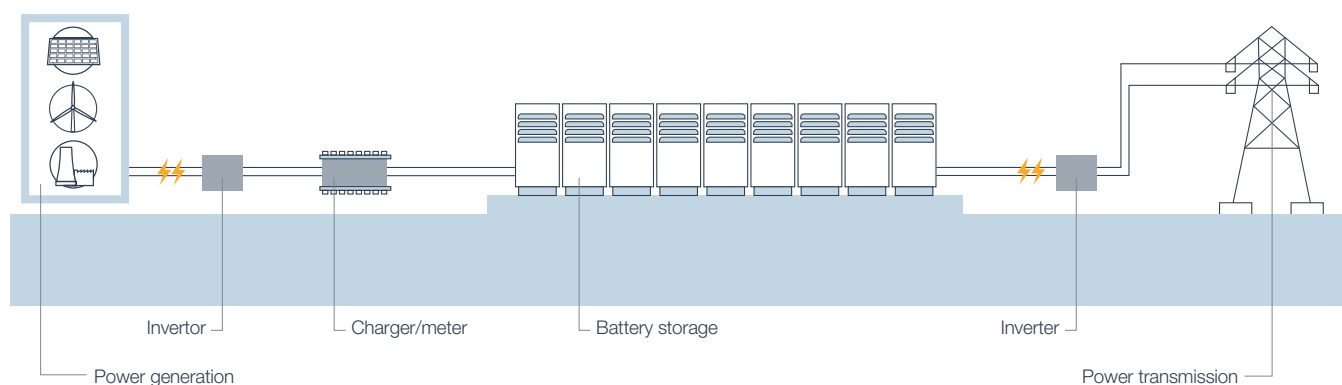
Wind-powered generation



Solar PV generation



Battery energy storage system



Traditional power sources, such as coal, gas and hydro, are dispatchable. This means they can be turned on and off as required – although some generation technologies can do this faster than others. By contrast, wind and solar generators are intermittent and can only provide energy when weather conditions are suitable. Battery storage and pumped hydro can provide further dispatchable generation output by storing the power generated by intermittent sources and supplying it back to the market when required.

An important characteristic of dispatchable generation is how quickly it can be turned on and off or ramped up and down. The output of intermittent renewables changes quickly based on the conditions and the flexibility of dispatchable generation impacts how quickly it can respond to this. Coal generators take many hours to turn on and can only ramp up and down slowly. This makes them less suited to balance out the fluctuations of intermittent renewables. Gas and hydro power stations can turn on in a matter of minutes and ramp up and down much faster than coal. Meanwhile, batteries can adjust their output up and down almost instantly, which enables them to help maintain the power system in a secure state faster than other technologies. For the transition to renewables to be successful, there must be sufficient flexible generation – such as gas, hydro and batteries – to balance out the volatility in intermittent generation output and continuously meet demand for electricity in real time.

Different generation sources also face very different operating costs. Once solar and wind capacity has been installed, there is essentially no marginal cost of producing power. On the other hand, the cost of producing electricity using coal or gas is linked to the underlying fuel costs and the consistency in fuel supply. These costs can vary, but gas is typically much more expensive than coal. Hydro generators do not usually pay an explicit cost for their water but can face limited supply and may experience a high opportunity cost of generation. Similarly, a battery's cost of generation depends on the price it paid to recharge and the opportunity cost of discharging later. Changes in operating costs will influence a generator's decision on how much generation to offer into the market and at what price.

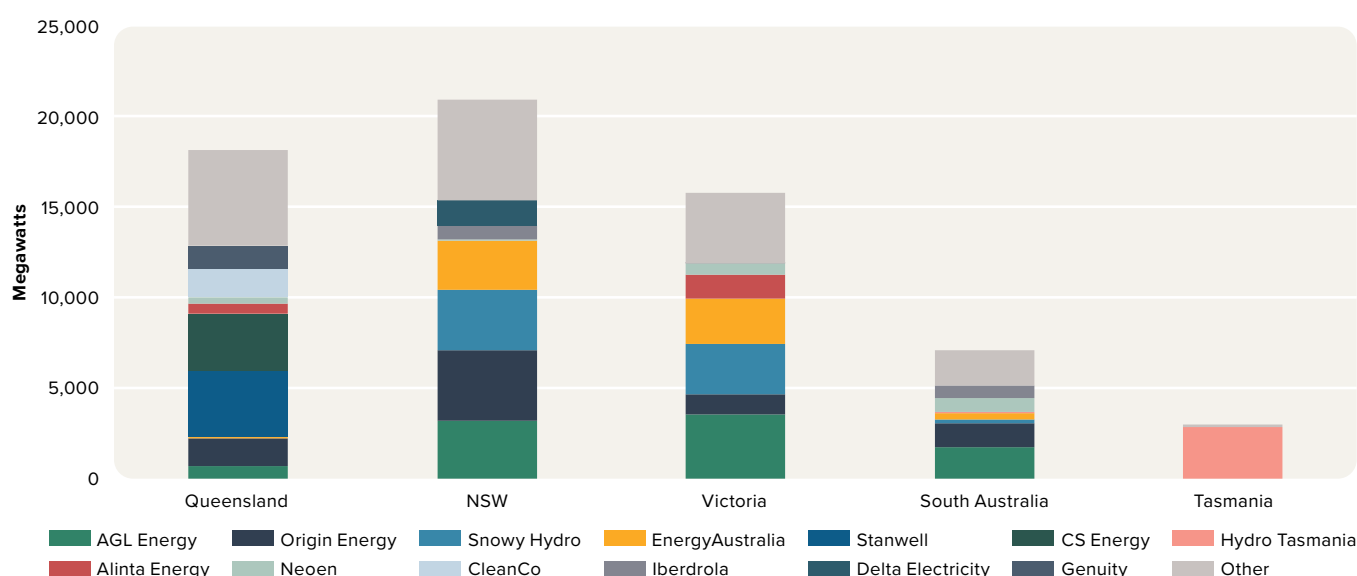
2.7.3 Market ownership and concentration

Nearly 400 generators sell electricity into the NEM. Despite significant diversity in new entry ownership in recent years, a few large participants still control a significant proportion of generation in each NEM region. Figure 2.20 shows the regional market share of the NEM's 13 largest generation companies. In each region, the top 3 companies control:

- 46% in Queensland (Stanwell Corporation, CS Energy and CleanCo)
- 50% in NSW (Snowy Hydro, Origin Energy and AGL)
- 56% in Victoria (AGL, Snowy Hydro and Energy Australia)
- 54% in South Australia (AGL, Origin Energy and ENGIE).

Tasmania has the most concentrated electricity market in the country. The state-owned entity Hydro Tasmania controls approximately 95% of the state's generation capacity.

Figure 2.20 Market share, by registered capacity



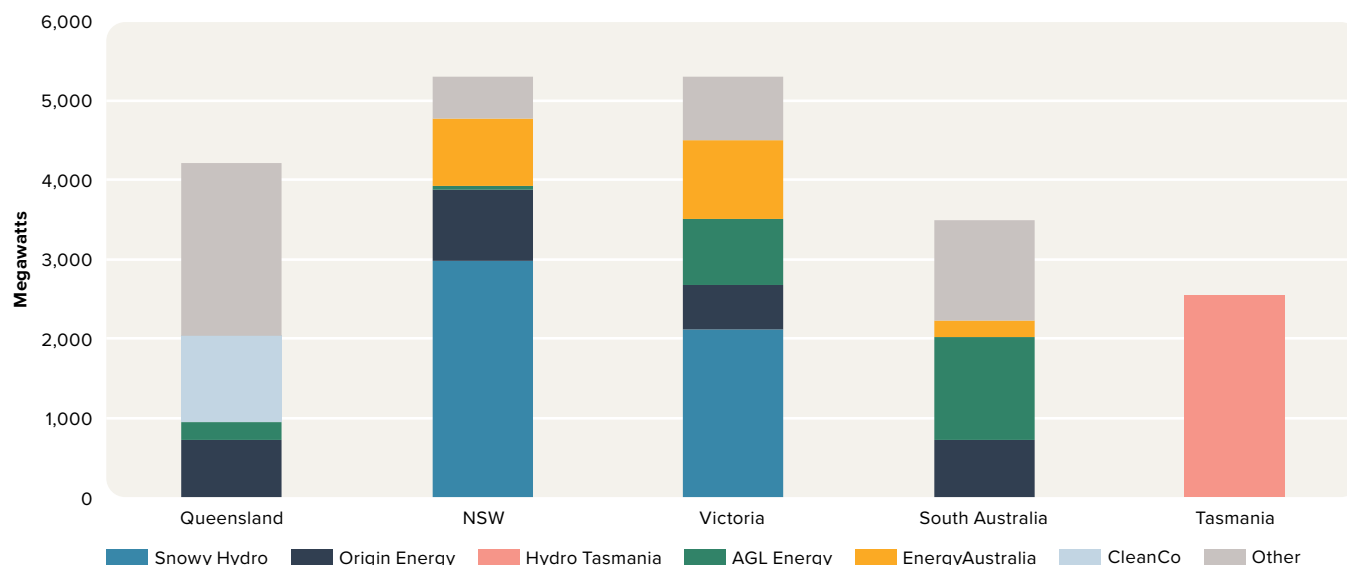
Note: This chart shows the registered capacity in each region of all market scheduled and semi-scheduled generation units (including bidirectional units but excluding market loads) registered as at 31 December 2024. For solar and battery units, we used the maximum capacity metric rather than registered capacity because inverter constraints may prevent these units from dispatching their full registered capacity. 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; AEMO (data); various online sources (ownership information).

Market concentration by share of generation output varies considerably between the periods of highest and lowest concentration in each region. Concentration tends to be lowest in the middle of the day when diversely owned renewable generation is at its peak, reducing reliance on conventional generation sources. At peak times, when conventional generation sources form a greater share of total generation, all regions are highly concentrated.

Ownership of flexible generation, which can quickly respond to changing market conditions, is particularly concentrated because a few participants control significant flexible generation capacity in NSW, Victoria, South Australia and Tasmania.

Figure 2.21 Market share of flexible generation



Note: This chart shows the registered capacity in each region for hydro, gas and batteries registered as at 31 December 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; AEMO (data); various online sources (ownership information).

Snowy Hydro controls more than 5,000 MW of registered flexible generation capacity. Most of these assets are in NSW and Victoria and, as a result, Snowy Hydro controls 56% of flexible generation in NSW and 40% in Victoria. In addition, Snowy Hydro is developing Snowy 2.0, which would add a further 2,200 MW of flexible capacity to its portfolio and its 750 MW gas-fired power station near Kurri Kurri will start generating shortly. Origin Energy is the second-largest provider of flexible generation, with significant capacity across the mainland regions. Collectively, Snowy Hydro and Origin Energy control 62% of all flexible capacity across NSW and Victoria.

As coal stations close and the market depends more heavily on renewable generation, flexible generation will play an increasingly important role in the market at peak times. Detailed analysis of market structure and competition, including concentration and competition in the supply of flexible capacity, in addition to broader market outcomes, are addressed in the AER's Wholesale electricity market performance report, most recently in December 2024.

2.8 Trade across regions

Interconnectors enable energy transfers between the NEM's 5 regions. 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 and the capacity of the interconnector. This capacity can change depending on the direction of flow, outages on the network or other physical constraints, and limits that AEMO imposes to manage system security.

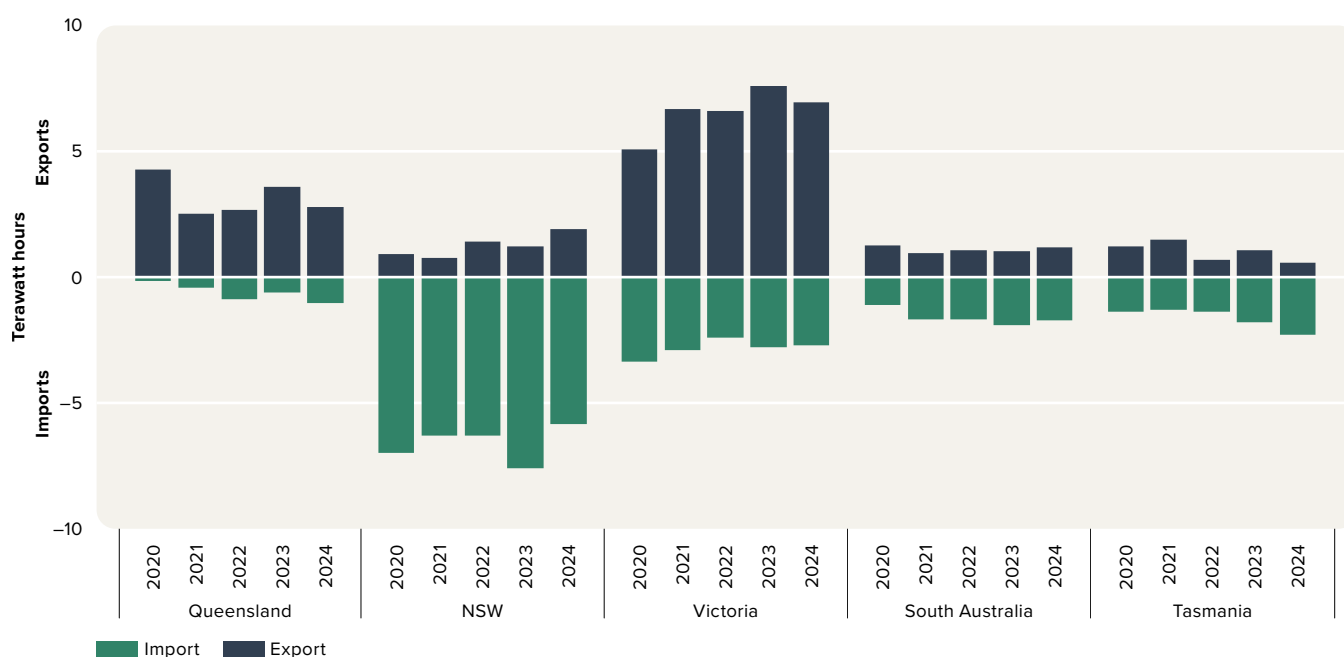
An interconnector is constrained when the volume of electricity flowing across it reaches its technical limit. Each interconnector has a nominal limit, which represents its capacity in optimal conditions, but its technical limit at any given time could be lower – for example, due to outages or grid congestion on nearby transmission lines.⁵¹ When an interconnector is constrained, cheaper sources of generation in one region cannot replace more expensive generation in another, effectively separating those regions into separate markets (price separation). Interconnector constraints are often a factor in high price events.

⁵¹ AEMO, [Interconnector capabilities](#), Australian Energy Market Operator, April 2024.

To support the transition to renewable generation, new transmission infrastructure will be needed. AEMO's 2024 Integrated System Plan provides a coordinated whole-of-system plan for efficient development of the power system in the NEM to ensure needs are met in the long-term interests of consumers. As part of this transition, several major interconnector transmission projects are planned or underway. More information on transmission projects is set out in section 3.13.7 in chapter 3.

Queensland and Victoria tend to be net exporters of energy, providing surplus electricity to NSW and South Australia. This was the case in 2024, when Queensland and Victoria were net exporters of energy and NSW, South Australia and Tasmania were net importers (Figure 2.22). Tasmania's trade position varies with environmental and market conditions; throughout 2023 and 2024 it was a net importer of electricity. In 2023 and 2024, Hydro Tasmania experienced a substantial decline in hydro generation due to below-average rainfall.⁵² It also ran its gas-fired assets at the Tamar Valley Power Station more frequently to manage the generation shortfall, including the Combined Cycle Gas Turbine, which operated from 6 June 2024 to 23 August 2024.

Figure 2.22 Inter-regional trade



Note: Gross amount of energy imported and exported by each region.
Source: AER; AEMO (data).

⁵² Office of the Tasmanian Economic Regulator, [Energy In Tasmania Report 2023–24](#), Executive Summary, March 2025, p. i.

2.8.1 Market alignment and network constraints

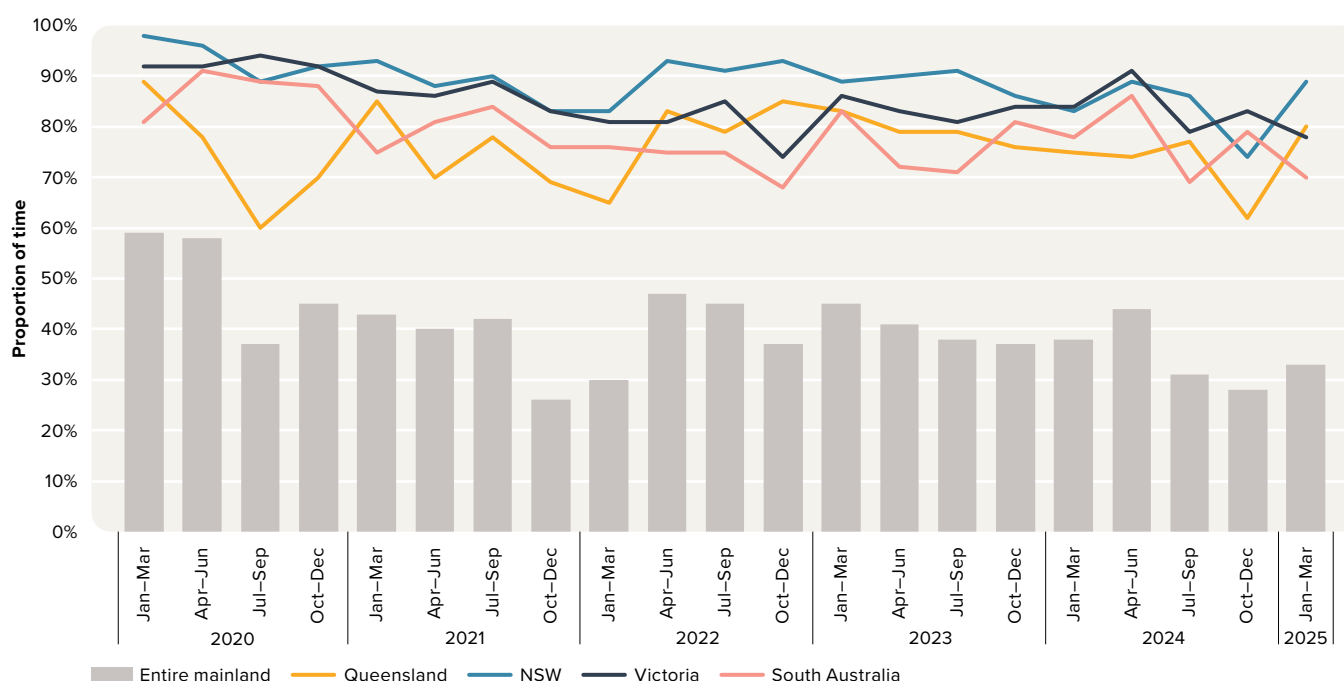
The market sets a separate spot price for each NEM region. When interconnectors are unconstrained, competitive pricing pressure from neighbouring regions brings prices into alignment across the NEM (with slight variations caused by physical losses that occur when transporting electricity). At these times, the NEM functions more like a single market than a collection of regional markets, because generators are exposed to competition from generators in other regions.

As coal-fired generators retire and new generation sources are developed in different locations, new areas of network constraint are emerging – often due to line capacity limitations or system security considerations. These constraints can affect electricity prices by limiting the flow of cheaper power to the market and may also influence inter-regional trade dynamics in the future.

For example, we reported in the *Wholesale electricity market performance report 2024* that the Victoria to NSW interconnector has been subject to increasingly frequent instances of energy flowing ‘counter price’ from a high-priced region to a low-priced region. Counter-price flows occur when electricity flows in the opposite direction to price to manage network congestion. These flows diminish the efficiency of the market and the extent to which a lower priced region can provide a competitive constraint.⁵³

In recent years, price alignment across regions has been falling. This overall trend continued in 2024 in all regions, with a particularly sharp drop during the October to December quarter in Queensland and NSW. In the January to March quarter 2025, alignment increased in Queensland and NSW but decreased in Victoria and South Australia (Figure 2.23).

Figure 2.23 Price alignment in mainland NEM regions



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

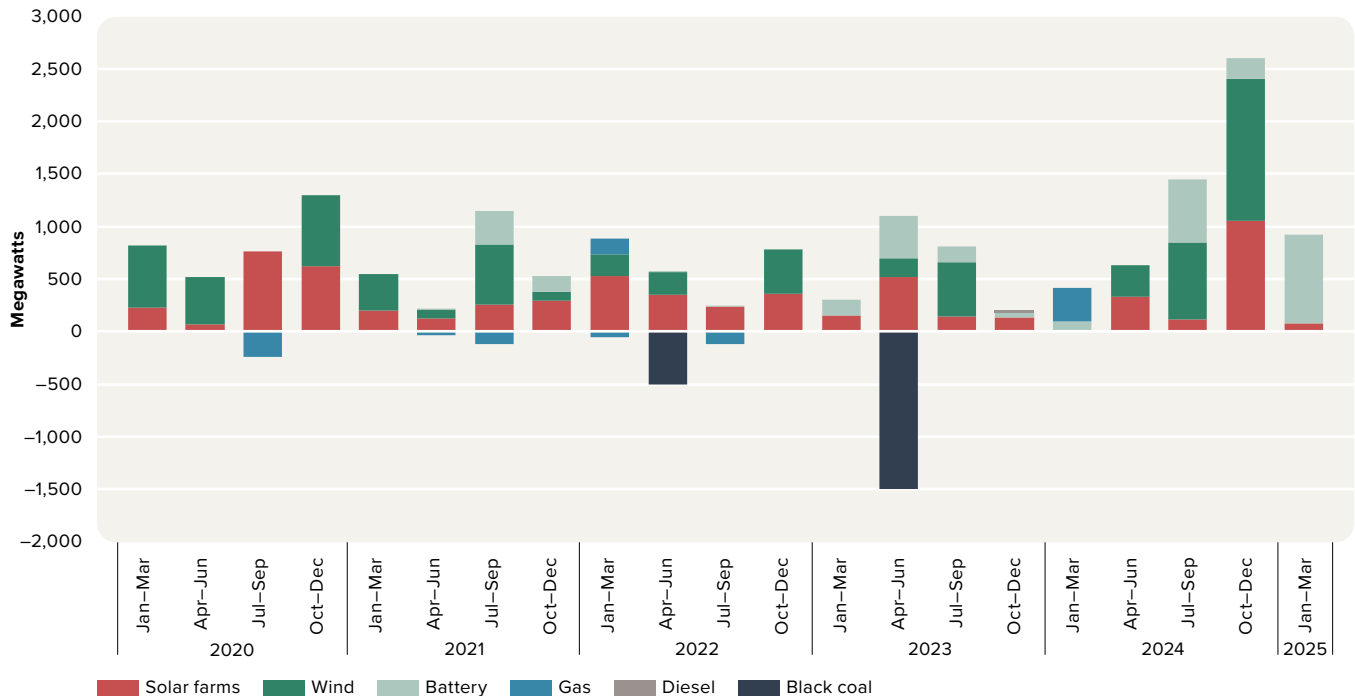
Source: AER; AEMO (data).

53 AER, *Wholesale electricity market performance report 2024*, Australian Energy Regulator, 20 December 2024. p. 67.

2.9 Generation investment and plant closures

Over 16 GW of new grid-scale solar, wind and battery investment has been added to the NEM since the beginning of the 2020, with around 5.1 GW entering in 2024 (Figure 2.24).

Figure 2.24 New generation investment and plant withdrawal



Note: This chart illustrates market entry and exit. For solar and battery units, we used the maximum capacity metric rather than registered capacity because inverter constraints may prevent these units from dispatching their full registered capacity. The new entry date is taken as the first day the station receives a dispatch target. Solar reflects large-scale solar and does not include rooftop solar.

Source: AER; AEMO (data).

The new capacity that entered during 2024 included:

- 2,381 MW of wind capacity, located in all regions except Tasmania
- 1,501 MW of solar capacity, located in NSW, Victoria and Queensland
- 891 MW of battery capacity, located in all regions except Tasmania
- 320 MW of gas capacity from Tallawarra B, a new gas peaking plant in NSW.

In addition to this, 921 MW of new capacity entered the market in the January to March quarter 2025, which included 845 MW of new battery capacity located in NSW, Queensland and Victoria, and a 76 MW solar farm in Victoria.

Large volumes of fossil fuel generators are scheduled to close by the end of 2027, including 2,892 MW of black coal and 980 MW of gas. AEMO's Generation information workbook lists 6,773 MW of committed projects⁵⁴ that are not active and are expected to come online during this period, including:

- 2,363 MW of solar
- 1,094 MW of wind
- 750 MW of gas
- 250 MW of hydro
- 2,316 MW of batteries, with an energy storage capacity of 5,997 MWh.

⁵⁴ Projects that will proceed, with known timing, satisfying all 5 of AEMO's commitment criteria (which are around land rights, contracts finalisation, planning applications, finance and construction dates). The [generation information workbook](#) (accessed 19 May 2025) was last updated 15 April 2025. We have removed projects that have commenced dispatching generation. For more information on the commitment criteria, see AEMO's [Reliability Forecasting Consultation Paper](#), October 2022, accessed 30 May 2025.

Projects have been taking longer to reach the commissioning stage in recent years. This might be caused by a range of factors, including financial market volatility, supply chain constraints, construction challenges, and environmental and planning approvals.⁵⁵ On-time delivery of new projects will be important to ensure the ongoing reliability of the NEM.

2.10 Power system reliability and security

Reliability is about the power system being able to consistently supply enough electricity to meet consumers' demand. Security refers to the power system's technical stability in terms of frequency, voltage, inertia and similar characteristics. System reliability and security both need to be carefully managed through the energy market transition.

2.10.1 Power system reliability

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

Reliability risks are typically highest over summer, particularly at times of peak demand. But they may also emerge at other times in the year, when solar or wind output is low, or there are transmission or plant outages.

The Retailer Reliability Obligation (RRO) is a mechanism that was designed to be a longterm solution to ensure reliability at the lowest cost. It facilitates the market to prepare for and eliminate forecast reliability gaps before they occur.

AEMO makes reliability forecasts under the RRO, which are incorporated into its annual Electricity Statement of Opportunities (ESOO) report.⁵⁶ When AEMO identifies a material reliability gap 3 years and 3 months out, it will apply to the AER to trigger the RRO by making a reliability instrument. Each Minister for Energy in a NEM region can also trigger the RRO by making an instrument directly.

Where a reliability instrument is made, liable entities (retailers and other parties that purchase electricity directly from the wholesale energy market) are on notice to enter into sufficient qualifying contracts with generators to cover their share of a once in 2 years peak demand event and report their net contract position to the AER.⁵⁷

In its 2024 ESOO, AEMO identified reliability gaps for NSW and Victoria for the summer of 2028–2029. In response, the AER triggered the RRO on 22 October 2024 and made reliability instruments for these regions.

⁵⁵ AEMO, [Integrated System Plan](#), Australian Energy Market Operator, June 2024.

⁵⁶ AEMO, [NEM Electricity Statement of Opportunities \(ESOO\)](#), Australian Energy Market Operator.

⁵⁷ For more information on the RRO, see AER, [Retail Reliability Obligation](#), Australian Energy Regulator, accessed 30 May 2025.

Box 2.3 How reliability is measured

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

While the 0.002% target is used to assess market performance and the appropriateness of reliability settings such as the market price cap, a stricter interim reliability measure of 0.0006% was introduced in 2020 and is currently scheduled to run until 30 June 2028.⁵⁸ The interim reliability measure is used as a trigger for 2 mechanisms to prevent forecast supply shortages from occurring. If it forecasts unserved energy will exceed the 0.0006% threshold, AEMO can:

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

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

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

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

Reserves procured under the RERT must be ‘out of market’. Any generator or load that participated in the wholesale market in the previous 12 months may not provide emergency reserves through the RERT. AEMO maintains a panel of RERT providers that can provide short notice and medium notice reserve if required. Panel members for short notice RERT agree on prices when appointed to the panel, whereas panel members for medium notice RERT negotiate the price when reserves are required. AEMO may procure long notice reserve through invitations to tender, where it has 10 weeks or more notice of a projected shortfall, as well as interim reliability reserves if the stricter reliability target is forecast to be exceeded.

Market participants that provide short notice reserves are compensated if the reserves are activated, or pre-activated, but are not compensated based on availability. In contrast, participants that provide long run or interim reliability reserves are compensated for making generation available. The RERT should only be activated if necessary to avert load shedding or other risks to reliability and system security. The capacity activated under the RERT scheme is typically more expensive than that acquired through the market; this is a cost that is ultimately borne by customers.

The cost incurred by AEMO for these standby services should be less expensive than the projected cost of load shedding for customers. The values of customer reliability (VCR) are thresholds set by the AER.⁵⁹ VCR seek to reflect the value different types of customers place on reliable electricity supply under different conditions and are usually expressed in dollars per kilowatt hour of unserved energy. A guiding principle of RERT payments is that they should not exceed the VCR, but doing so is not prohibited.⁶⁰

58 AEMC, [Final rule to extend Interim Reliability Measure](#), Australian Energy Market Commission, September 2023.

59 AER, [Values of customer reliability](#), Australian Energy Regulator, accessed 2 April 2025.

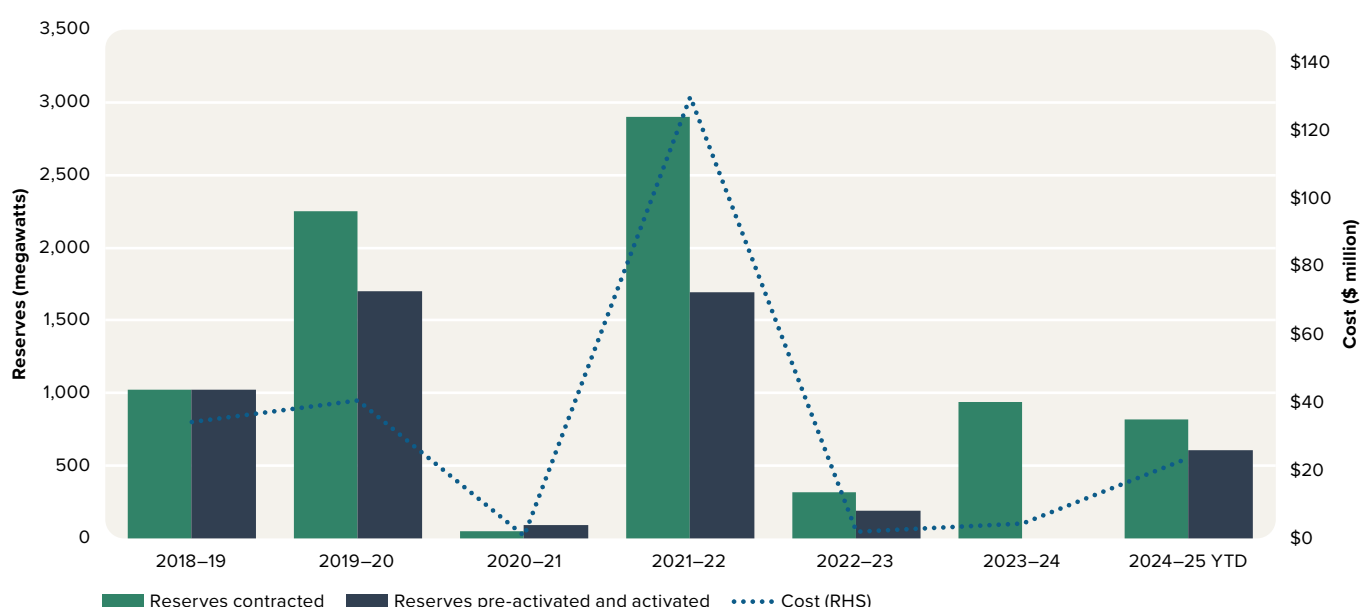
60 AEMC, [National Electricity Amendment \(Enhancement to the Reliability Emergency Reserve Trader\) rule 2019](#), Australian Energy Market Commission, May 2019.

AEMO entered into interim reliability reserve (IRR) contracts for the first time in 2023, following reliability shortfalls identified in its 2023 Electricity Statement of Opportunities. In preparation for the summer period, AEMO contracted a total of:

- 100 MW of IRR in Victoria and 10 MW in South Australia for the period 1 December 2023 to 31 March 2024
- 19 MW in Victoria for the period 1 January 2024 to 31 March 2024.⁶¹

These contracted interim reliability reserves were not activated or pre-activated but incurred an availability cost totalling \$4,252,685 for the 2023–24 financial year. AEMO also entered into several short notice contracts in response to forecast lack of reserve 2 conditions on 14 December 2023, 27 January 2024 and 13 February 2024, totalling 807 MW. Unusually, AEMO did not pre-activate or activate any of the contract capacity, but the total cost of RERT was still higher than the previous year (Figure 2.25) due to the IRR contracts.

Figure 2.25 Interim reliability reserves and short notice contracted costs



Note: Reliability and Emergency Reserve Trader (RERT) costs include costs for availability, pre-activation, activation and other costs (including compensation costs). 2024–25 YTD includes data to the end of March 2025.

Source: AER analysis of AEMO's RERT reporting.

Following shortfalls identified in its 2024 ESOO, AEMO's preparation for the 2024–2025 summer period included contracting a total of:

- 127 MW of IRR in South Australia, covering the period from 1 January 2025 to 31 March 2025. The total amount payable by AEMO was \$19,089,765.⁶²
- 85 MW of IRR in NSW, covering the period from 1 December 2024 to 31 March 2025. The total amount payable by AEMO was \$1,201,336.⁶³

AEMO also entered into several contracts in response to a forecast lack of reserve level 2. Of these, 605 MW were pre-activated and 65 MW were activated. The total amount payable was \$3.55 million. The cost per MWh was \$56,359.⁶⁴

61 AEMO, [Reliability and Emergency Reserve Trader \(RERT\) Quarterly Report Q4 2023](#), Australian Energy Market Operator, February 2023.

62 AEMO, [Reliability and Emergency Reserve Trader \(RERT\) Quarterly Report Q1 2025](#), Australian Energy Market Operator, 15 May 2025, accessed 20 June 2025.

63 AEMO, [Reliability and Emergency Reserve Trader \(RERT\) Quarterly Report Q4 2024](#), Australian Energy Market Operator, February 2025, accessed 1 May 2025.

64 AEMO, [Reliability and Emergency Reserve Trader \(RERT\) Quarterly Report Q4 2024](#), Australian Energy Market Operator, February 2025, accessed 1 May 2025.

The RERT has averted multiple instances of load shedding since the initiative began, but doing so comes at significant cost to the consumer. Typically, RERT costs have been calculated in reference to the MWh usage of activated contracted capacity. The average cost of the RERT in the previous 5 financial years has been just over \$36,000 per MWh, nearly double the current market price cap of \$20,300 per MWh.

AEMO's 2024 ESOO stated that 'If further investment beyond current committed and anticipated projects is delayed or does not materialise, AEMO forecasts reliability gaps will exist over the coming years in some NEM regions.'⁶⁵ Increased volumes of interim reliability reserves or long notice reserves may be required in the future to meet reliability shortfalls. This cost will ultimately be borne by customers.

2.10.2 Security performance in the NEM

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

Frequency control markets

As part of AEMO's market operations, it is required to maintain system frequency within a secure range (between 49.85 and 50.15 hertz). Any deviations from this range should not exceed more than 1% of the time over any 30-day period. Maintaining system security during the energy transition has been a key focus of the NEM market bodies. Frequency control ancillary services (FCAS) are used to maintain the frequency of the power system close to 50 hertz. The NEM has 10 FCAS markets, which are either regulation services or contingency services.

- Regulation services operate continuously to balance minor variations in frequency caused by small changes in demand or supply during normal operation of the power system.
- Contingency services manage large frequency changes from sudden and unexpected shifts in supply or demand, they are used less often, and are purchased as either raise or lower services.

Historically, regulation services costs were recovered from participants that contributed to frequency deviations (causer pays).

- Raise contingency services costs were recovered from generators.
- Lower services costs were recovered from market customers (usually retailers).

From 8 June 2025, the NEM implemented frequency performance payments (FPP), a double-sided incentive that rewards or charges participants based on their impact on system frequency. Building on the existing 'causer pays' model, FPP applies to all generation and load units with appropriate metering. Units that help stabilise frequency receive payments, while those that worsen deviations incur charges. Participants without suitable metering (the 'residual') are assigned a share of total FPP and regulation FCAS costs, based on their proportion of energy consumed or sent out within each dispatch interval.

AEMO acquires FCAS through a co-optimised market that coordinates offers from generators and other participants in both energy and FCAS markets to minimise overall cost.

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

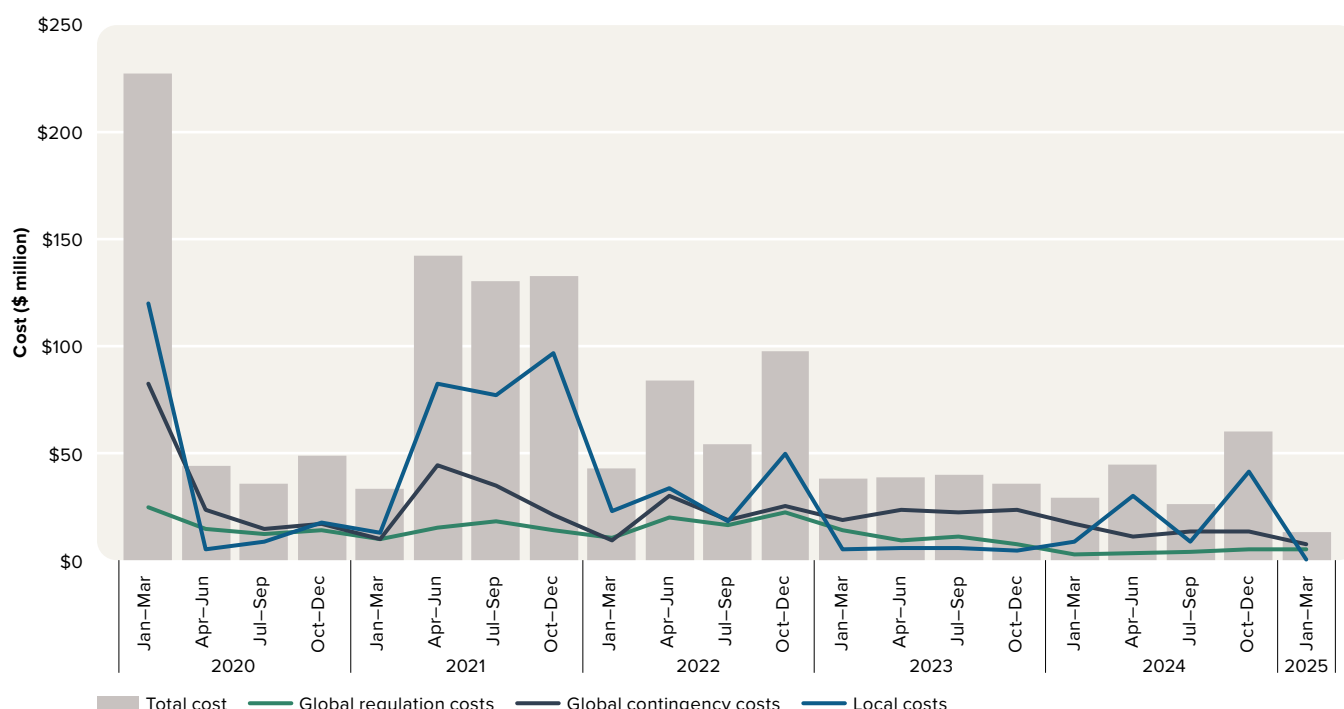
Fewer participants operate in FCAS markets than in the wholesale electricity market, but participation is growing – as at 1 January 2025, 46 participants were registered to provide services across the NEM, with some participants providing services in multiple regions. Of the 46 participants, 17 participants were providing FCAS in Queensland, 19 in NSW, 20 in Victoria, 18 in South Australia and 3 in Tasmania. New generation technologies, such as batteries, demand response and virtual power plants, can offer FCAS services and in some cases have been displacing incumbent providers (coal, gas and hydro).

65 AEMO, [2024 Electricity Statement of Opportunities](#), Australian Energy Market Operator, August 2024, accessed 2 June 2025.

Total FCAS costs increased by 5% in 2024 compared with 2023 (Figure 2.26). Global FCAS costs decreased by 45% and local FCAS costs increased by 315%, compared with 2023.

The decline in global costs in 2024 continued a longer-term trend and reflected lower costs for both regulation and contingency services. This likely reflects increased competition, due to the increase in the number of participants registered to provide FCAS services. While local FCAS costs were higher in 2024 than in 2023, they were lower than costs in 2020 to 2022. Of the \$89 million in local costs incurred in 2024, \$71 million was incurred in the April to June and October to December quarters of 2024. \$64 million of the local costs incurred during these quarters were for Queensland services, and mostly 6-second services.

Figure 2.26 Total FCAS costs



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

Source: AER; AEMO (data).

Other system security market features

Security performance can be impacted by changing system conditions (including extreme weather events) and uncertain supply demand balance. AEMO now reports annually on system security needs across the NEM for the coming 10-year period. Its 2024 system strength report identified that all regions except South Australia are expected to experience system strength shortfalls over the next 3 years unless investment or services are provided by the relevant system strength service provider in each region.⁶⁶

System security services have historically been provided by synchronous generators (coal, gas and hydro).⁶⁷ These services can be replicated by other technologies, with appropriate market settings. Options can include synchronous condensers, retrofitting of clutches to existing/future gas turbines and grid-forming inverter-based resources solutions (such as batteries). System strength service providers are currently undertaking the process to plan for and procure system strength ahead of the first binding requirements starting on 2 December 2025.

⁶⁶ AEMO, [2024 System Strength Report](#), Australian Energy Market Operator, February 2025, p. 3.

⁶⁷ Synchronous generators are large spinning units that have turbines that spin at the same speed as the frequency of the power system. As a result, there is an electro-mechanical 'link' between the mechanical energy of the generator and the electrical frequency of the power system. Asynchronous generators are those that connect to the power system using inverters, such as wind and solar.

AEMO use of directions

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

The energy transition is necessitating more frequent directions from AEMO to maintain power system security. In South Australia, directions to market participants to take action to maintain or restore power system security have been in place for a substantial amount of time for the past several years.⁶⁸

In May 2025, AEMO published plans to reduce the requirement for the number of synchronous generators required to operate in South Australia from 2 to 1, assuming certain criteria are met.

2.11 Market reforms and policy developments

Market reform and policy development through 2024 and into 2025 focused on the NEM's transition towards a low-emissions energy system. These efforts build on the Australian Government's legislated Net Zero Plan⁶⁹ and the rollout of the Capacity Investment Scheme (CIS),⁷⁰ and seek to evolve market design to reflect the changing dynamics of the electricity system.

The Australian Government has completed 2 CIS tender rounds for the NEM. The successful projects for the South Australia–Victoria Dispatchable Tender were announced on 4 September 2024 and for the CIS Tender 1 – NEM Generation on 11 December 2024.⁷¹ Together, these tenders approved 25 projects, expected to begin operation from 2027, delivering 6.4 GW of wind and solar generation capacity and 2.1 GW (7.2 gigawatt hours [GWh]) of storage capacity. CIS Tender 3 – NEM Dispatchable (targeting 4 GW or 16 GWh) and CIS Tender 4 (targeting 6 GW) are expected to announce successful bids in September and October 2025, respectively.⁷² This continued rollout supports Australia's 2030 target of 82% renewable electricity and 32 GW of new capacity.

In November 2024, the Australian Government launched a review of the NEM wholesale market settings, led by an independent expert panel and supported by the Department of Climate Change, Energy, the Environment and Water. The review aims to recommend settings that will encourage investment in firmed renewable generation and storage post-CIS, and to deliver a roadmap for reform aligned with Australia's National Electricity Objectives.⁷³

In December 2024, the AEMC made a final rule determination to better integrate price-responsive resources – such as community batteries, virtual power plants and flexible loads – into the NEM.⁷⁴ This rule was prompted by a 2023 rule-change request made by AEMO.

Demand response was already able to register to participate in the NEM via the wholesale demand response mechanism, which was implemented in October 2021. Participation rates in the mechanism have been low, with the AEMC reporting in March 2025 that only 74 MW of capacity had been registered and 1,258 MWh dispatched since the mechanism's inception.⁷⁵ Most of this was offered into the market at very high prices. Meanwhile, there has been continued entry of price-responsive resources that are unscheduled and not fully integrated into market operations.

Not accounting for price-responsive resources in the operation of the electricity system can lead to higher energy prices, which drive inefficient investment in generation, storage and demand response. It can also lead to greater demand forecast errors, which increase FCAS requirements and prices. The new rule attempts to address these problems. It enables price-responsive resources to become dispatchable, introduces short-term incentives to drive participation and establishes monitoring to improve forecast accuracy. AEMO is progressing implementation through its NEM Reform Program.⁷⁶

68 AEMO, [Quarterly Energy Dynamics Q2 2024](#), Australian Energy Market Operator, July 2024.

69 DCCEEW, [Net Zero](#), Department of Climate Change, Energy, the Environment and Water, accessed 23 April 2025.

70 DCCEEW, [Capacity Investment Scheme](#), Department of Climate Change, Energy, the Environment and Water, accessed 23 April 2025.

71 DCCEEW, [Closed CIS tenders](#), Department of Climate Change, Energy, the Environment and Water, accessed 23 April 2025.

72 DCCEEW, [Open CIS tenders](#), Department of Climate Change, Energy, the Environment and Water, accessed 23 April 2025.

73 DCCEEW, [National Electricity Market wholesale market settings review](#), Department of Climate Change, Energy, the Environment and Water, accessed 23 April 2025.

74 AEMC, [Integrating price-responsive resources into the NEM](#), Australian Energy Market Commission, accessed 23 April 2025.

75 AEMC, [Review of the Wholesale Demand Response Mechanism](#), Australian Energy Market Commission, accessed 12 June 2025.

76 AEMO, [Integrating Price Responsive Resources into the NEM \(IPRR\)](#), Australian Energy Market Operator, accessed 23 April 2025.

2.12 Compliance and enforcement activities

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

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

Each year, the AER identifies and publishes a set of compliance and enforcement priorities, some of which relate to participants in the NEM.

In 2025–26, the AER's key compliance priority for wholesale electricity markets is supporting power system security and market efficiency. This includes a focus on:

- network service providers' compliance with network outage and generation connection obligations
- generator performance standards
- generator availability obligations.⁷⁷

Since July 2024, the AER's compliance and enforcement work in the NEM has included:

- **Court-ordered penalty for Callide Power Trading:** On 25 May 2021, a catastrophic failure at the Callide C4 unit caused widespread supply disruptions. Although the unit's prolonged outage was due to unrelated incidents, it remained offline until 30 August 2024. On 9 February 2024, the AER commenced proceedings in the Federal Court against Callide Power Trading Pty Ltd (Callide Power Trading) for failing to comply with performance standards at the Callide C power station.⁷⁸ On 4 February 2025, the Federal Court ordered Callide Power Trading to pay a \$9 million penalty – the highest ever imposed for a breach of performance standards under the National Electricity Rules.⁷⁹
- **Retailer Reliability Obligation (RRO):** On 8 August 2024, the AER finished its review of the RRO Auditors Panel. As a result of the review, the AER published a revised version of the Auditors Panel Handbook, launched the Auditors Panel Conflict of Interest Register and updated the current Auditors Panel membership and contact details.⁸⁰ On 23 August 2024, the AER also published 4 guidance notes to help participants understand their obligations under the RRO.⁸¹
- **Industry guidance:** The AER issued industry correspondence outlining expectations for the accurate use of self-forecasting by semi-scheduled generators.

Further detail on the AER's compliance and enforcement work was outlined in the Annual compliance and enforcement report 2024–25, released in July 2025.⁸²

77 AER, [AER compliance and enforcement priorities 2025–26](#), Australian Energy Regulator, June 2024.

78 AER, [Callide Power Trading: alleged breaches of the National Electricity Rules](#), Australian Energy Regulator, February 2024.

79 AER, [Callide Power Trading: breaches of the National Electricity Rules](#), Australian Energy Regulator, February 2025.

80 AER, [Review of Retailer Reliability Obligation Auditors Panel](#), Australian Energy Regulator, August 2024.

81 AER, [AER published Retailer Reliability Obligation Guidance](#), Australian Energy Regulator, August 2024.

82 AER, [Annual compliance and enforcement report 2024–25](#), Australian Energy Regulator, 23 July 2025.



3 Electricity networks

Australia's electricity infrastructure consists of transmission and distribution networks, as well as smaller standalone regional systems. Together, these networks have traditionally transported electricity from generators to residential, commercial and industrial customers. However, Australia's energy system is rapidly changing and affecting how electricity networks are used. Technological developments and consumer preferences are leading us away from a supply-side orientated system to one that needs to support two-way flows of electricity, and away from centralised generation to distributed generation.

This chapter covers the 21 electricity network service providers regulated by the Australian Energy Regulator (AER). These service providers are located in all Australian states and territories except Western Australia.

3.1 Snapshot

In April 2025, the AER finalised revenue determinations for distribution network service providers Energex (Queensland), Ergon Energy (Queensland) and SA Power Networks (South Australia) as well as the Directlink interconnector.⁸³ These determinations set target revenue controls through to 30 June 2030.

Across all electricity network service providers, over the 12-month period to 30 June 2024:

- \$12.7 billion in revenue was collected for delivering core regulated services,⁸⁴ \$270 million (2.1%) less than in the previous year (section 3.9.1).
- \$7.4 billion was invested in capital projects, \$545 million (8%) more than in the previous year and the most since 2014 (section 3.13.1).
- Regulated asset bases increased by \$2.4 billion (2%), driven by investment on Transgrid's (NSW) transmission network and Powercor's (Victoria) and Jemena's (Victoria) distribution networks.
- \$4.6 billion was spent on operating costs, \$307 million (7%) more than in the previous year and the most since 2016 (section 3.14.1).

83 Directlink is an electricity transmission interconnector between Queensland and NSW.

84 Prescribed transmission services for transmission network service providers and standard control services for distribution network service providers.

- The average customer experienced 1.26 unplanned interruptions to supply, 15% more than in the previous year (section 3.16.5).⁸⁵
- The average customer experienced 294.5 unplanned minutes off supply, 82% more than in the previous year (section 3.16.5).⁸⁶
- Increases in the number of unplanned interruptions to supply and the duration of unplanned minutes off supply were driven by the impact of several severe storm events across Queensland and Victoria, compared with the relatively low number of severe weather events in the previous year (section 3.16.5).

3.2 Electricity network characteristics

Transmission networks transport high-voltage electricity from large-scale generators located away from population centres to consumers situated in major load centres. Electricity is injected from points along the transmission grid into the distribution networks, where the voltage is stepped down to safely deliver electricity to residential homes and commercial and industrial premises. Distribution networks consist of poles and wires, substations, transformers, switching equipment, and monitoring and signalling equipment. In addition to the electricity delivered by transmission networks, electricity from small-scale local generation is increasingly being injected directly into the distribution grid to supply consumers.

Network service providers transport and deliver electricity to consumers, but they do not sell it. Instead, retailers purchase electricity from the wholesale market and package it with network services to sell to customers (chapter 6).

Electricity networks traditionally provided a one-way transportation service to consumers. However, the role of electricity networks has evolved, and technology continues to change how and where electricity is generated and used. Consumers are adopting innovative ways to reduce and manage demand from the grid, investing in what the industry collectively refers to as consumer energy resources. Many small-scale generators such as rooftop solar systems are now embedded within distribution networks, resulting in two-way electricity flows along the networks. Consumers with rooftop solar systems can source electricity from the distribution network when they need it and sell the surplus electricity they generate at other times (section 3.13.4). Electricity generated using rooftop solar systems is also increasingly being stored using battery storage systems. Due to the versatility and falling cost of battery technology, and the need to make use of excess solar generation for use later in the day, the use of batteries is expected to continue to grow. Installing storage options closer to the locations where excess solar is generated could reduce electricity transport costs and make better use of existing infrastructure.

Box 3.1 Cheaper Home Batteries Program

Since 1 July 2025, the Australian Government's Cheaper Home Batteries Program – applicable to customers with existing solar or those wanting to invest in a new solar-plus-battery set-up – has offered a 30% discount on batteries for households, businesses and community facilities such as sports centres or town halls.

The Cheaper Home Batteries Program can be used in conjunction with jurisdictional battery incentives and is directly funded by the Australian Government to ensure no extra costs are passed on to consumers.⁸⁷ This means customers could be eligible for support under multiple schemes.

⁸⁵ After removing the impact of interruptions to supply deemed to be beyond the control of the network service providers.

⁸⁶ After removing the impact of interruptions to supply deemed to be beyond the control of the network service providers.

⁸⁷ Depending on the conditions established by state and territory governments.

3.3 Geography

Electricity networks in Queensland, New South Wales (NSW), Victoria, South Australia, Tasmania and the Australian Capital Territory (ACT) create an interconnected grid forming the National Electricity Market (NEM). The NEM transmission grid has a long, thin, low-density structure, reflecting the dispersed locations of electricity generators and demand centres. The 5 state-based transmission networks⁸⁸ are linked by cross-border interconnectors. Three interconnectors (Queensland–NSW, Heywood (Victoria–South Australia) and Victoria to NSW) are owned by the state governments and 3 interconnectors (Directlink, Murraylink and Basslink) are privately owned (Figure 3.2). The transmission network also directly supplies electricity to large industrial customers, such as rail companies, mines and mineral processing facilities.

The transmission grid connects with 13 distribution networks.⁸⁹ Consumers in Queensland, NSW and Victoria are served by multiple distribution network service providers, each of which owns and operates its network within a defined geographic region. Consumers in South Australia, Tasmania and the ACT are served by single distribution network service providers operating within each jurisdiction (Figure 3.1 and Figure 3.3).

The Northern Territory has 3 separate distribution networks – the Darwin–Katherine, Alice Springs and Tennant Creek systems – all owned by Power and Water. The 3 networks are classified as a single distribution network for regulatory purposes but do not connect to each other or the NEM.⁹⁰ The AER regulates all major network service providers in the NEM as well as the Northern Territory's distribution network.

Electricity networks in Queensland, New South Wales, Victoria, South Australia, Tasmania and the Australian Capital Territory create an interconnected grid forming the National Electricity Market.

In June 2025, the AER accepted APA Group's application to convert the Basslink interconnector – a high-voltage cable linking Victoria and Tasmania's electricity grids – from a market network service to a prescribed transmission service. The AER determined that converting Basslink to a regulated transmission service is more likely to promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers. A fully regulated Basslink will ensure that the interconnector operates as an open link, enabling the market and consumers to benefit from generation in both the Tasmanian and mainland regions of the NEM.⁹¹

Several other interconnectors have regulatory approval and are either currently under development or highly likely to proceed. These include:

- Project EnergyConnect – a new 330 kilovolt double-circuit interconnector between South Australia and NSW, with a new 220 kilovolt double-circuit line to Victoria
- incremental upgrades to the transfer capacities of the existing Victoria to NSW (VNI Minor) and Queensland–NSW (QNI Minor) interconnectors (section 3.13.6).

88 Transgrid operates the high voltage transmission network in both NSW and the ACT.

89 Some jurisdictions also have small networks that serve regional areas.

90 For this reason, any text or charts within this chapter that refer to 'whole of NEM' do not include Power and Water (NT).

91 AER, [Basslink – Determination 2025–30, Final decision: Basslink conversion](#), Australian Energy Regulator, 26 June 2025.

Permission to transmit or distribute electricity must be granted by the relevant jurisdictional regulator. In September 2024, distribution network service provider Powercor was granted a licence by the Essential Services Commission (Victoria) to plan, design and build transmission infrastructure within its current distribution footprint across western, central and northern parts of Victoria. Powercor can now deliver transmission infrastructure, including new terminal stations and 220 kilovolt powerlines, to connect customer-related projects to the grid.⁹²

In February 2025, the Essential Services Commission (Victoria) granted Transmission Company Victoria (TCV) a licence to operate transmission infrastructure and transmit electricity in Victoria. As a licensee, TCV – a wholly owned subsidiary of the Australian Energy Market Operator (AEMO) created to progress VNI West⁹³ – must comply with all legal requirements of the licence. Any breaches will be subject to the Essential Services Commission's compliance and enforcement powers, including breaches of the Land Access Code of Practice.⁹⁴

The aggregated value of the regulatory asset bases for the electricity networks regulated by the AER is around \$123.2 billion.

In May 2025, AusNet Infrastructure No. 2 Pty Ltd⁹⁵ applied to the Essential Services Commission (Victoria) for a licence to transmit electricity through the connection and extension assets associated with a new 220kV electrical transmission station in northern Victoria.⁹⁶ The decision to grant, or not grant, the licence had not been made at time this report was published.

The aggregated value of the regulatory asset bases (RABs) for the electricity networks regulated by the AER is around \$123.2 billion.⁹⁷ This comprises 7 transmission networks valued at \$28.3 billion and 14 distribution networks valued at \$94.9 billion. In total, the networks consist of more than 800,000 kilometres of line and deliver electricity to more than 11 million customers.

The AER does not regulate electricity networks in Western Australia, where the Economic Regulation Authority (ERA) administers state-based arrangements. Western Power (owned by the WA Government) is the state's principal network, covering the populated south-west region, including Perth. Another state-owned corporation – Horizon Power – services Western Australia's regional and remote areas.⁹⁸

92 Powercor, [New transmission provider to deliver more choice and better service to Victoria](#), media release, 25 September 2024, accessed 24 April 2025.

93 A project to build a new transmission line between Victoria and NSW.

94 The Land Access Code of Practice introduced enforceable rules that TCV must comply with, including how and when it provides information to landowners and when it engages with them. The Land Access Code of Practice also requires transmission companies to be open, honest and respectful in their communication with landowners.

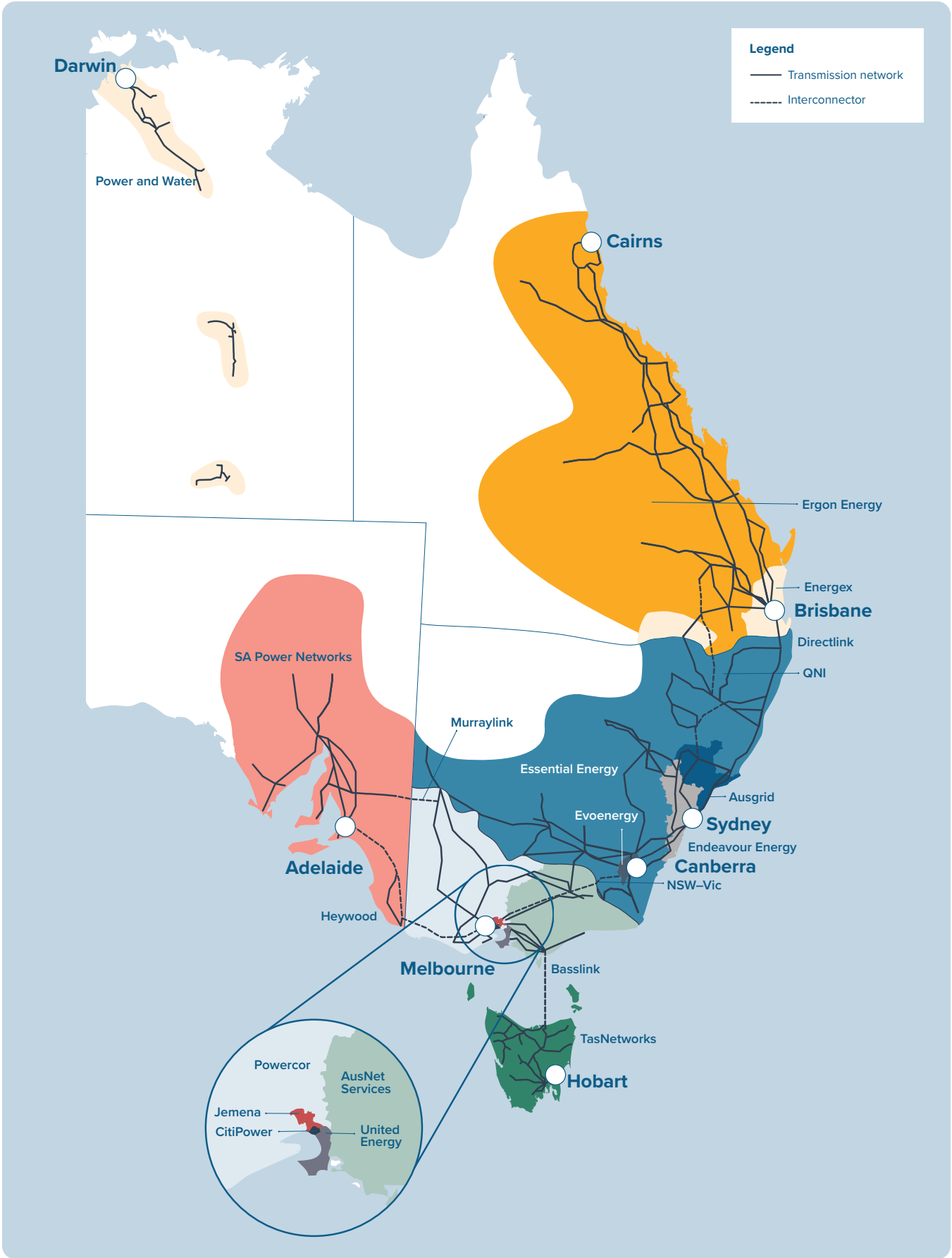
95 As trustee for the AusNet Infrastructure No. 2 Trust.

96 ESC, [AusNet Infrastructure No. 2 Pty Ltd as trustee for the AusNet Infrastructure No. 2 Trust – Application for electricity transmission licence](#), Essential Services Commission (Victoria), 1 May 2025, accessed 2 May 2025.

97 RABs capture the total economic value of assets that are providing network services to customers. These assets have been accumulated over time and are at various stages of their economic lives.

98 For further information, see the [WA Department of Treasury](#) and [ERA](#) websites.

Figure 3.1 Electricity networks regulated by the AER



Note: QNI is the Queensland–NSW Interconnector.
Source: AER.

Figure 3.2 Electricity networks regulated by the AER – transmission

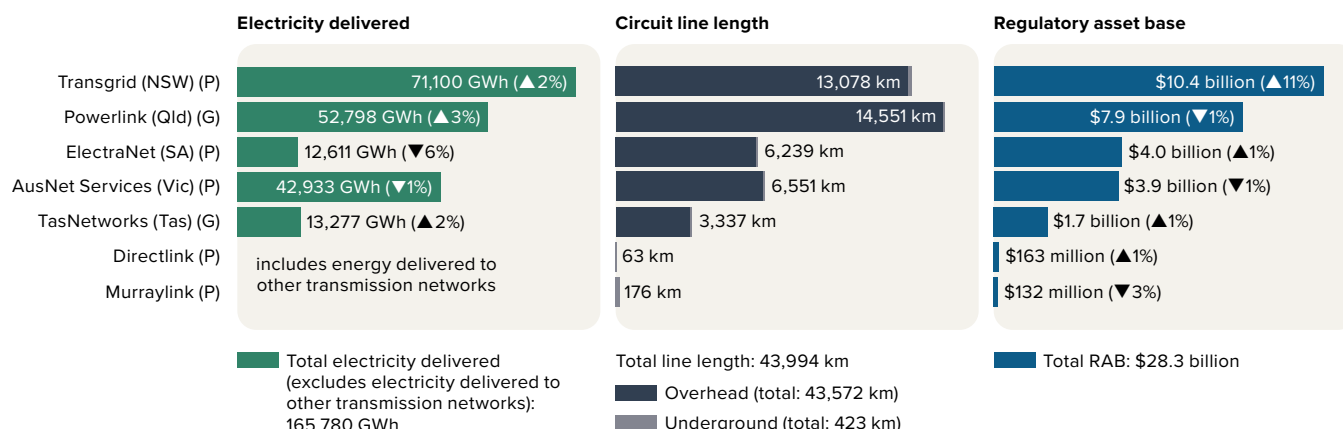
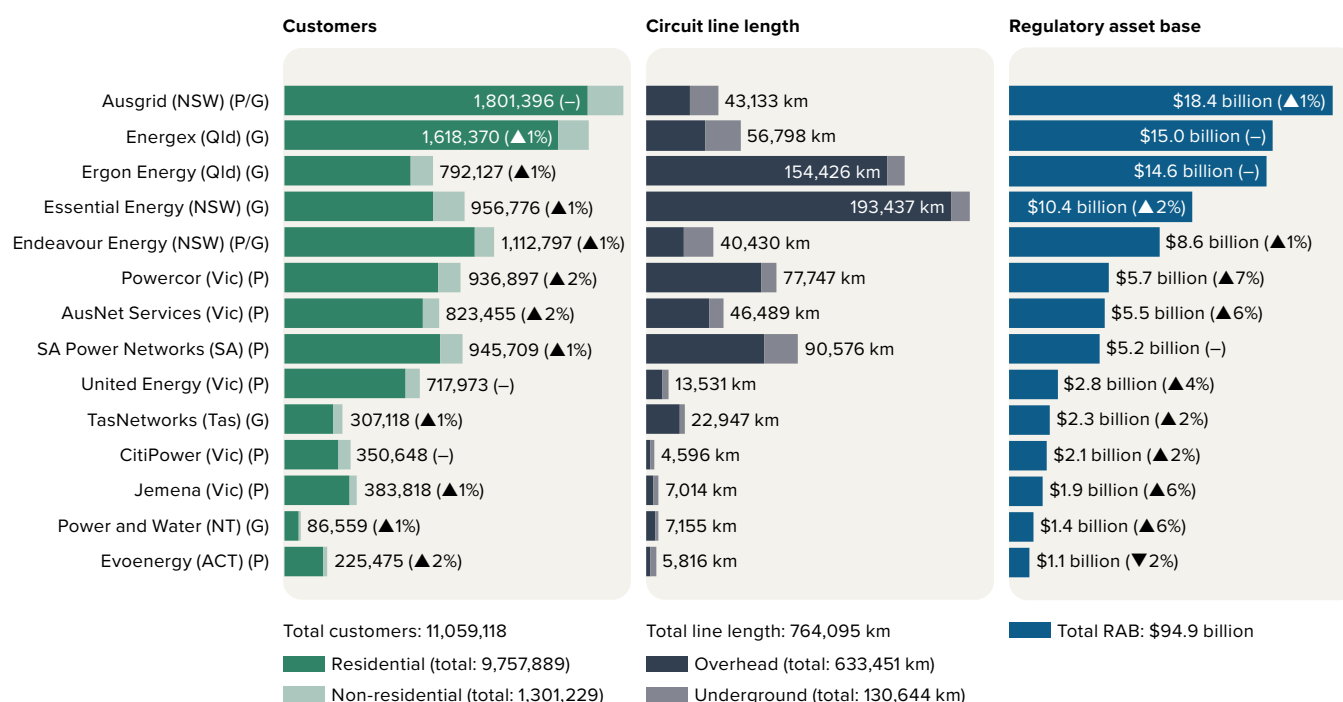


Figure 3.3 Electricity networks regulated by the AER – distribution



Note: (G): state government owned. (P): privately owned. GWh: gigawatt hours. km: kilometres. % values represent change from previous year. Regulatory asset base is adjusted to June 2024 dollars. Line length and regulatory asset base are as at 30 June 2024 (31 March 2024 for AusNet Services transmission). Electricity delivered is for the 12-month period to 30 June 2024 (year to 31 March 2024 for AusNet Services transmission). Electricity delivered is a measure of total energy transported through the transmission networks. The information reported includes electricity transmitted to distribution networks, pumping stations and directly connected end users. Electricity delivered to other transmission networks is included in the data for individual transmission networks but has been excluded from the total. Customer numbers, line length and asset base are as at 30 June 2024 for the distribution networks. For regulatory purposes, Northern Territory transmission assets are treated as part of the distribution system.

Source: AER revenue determinations and economic benchmarking regulatory information notices (RINs).

3.4 Network ownership

Australia's electricity networks were originally government owned, but 3 jurisdictions have now either partly or fully privatised the assets. Ownership of the partly or fully privatised networks in NSW, Victoria and South Australia is concentrated among relatively few entities. These entities include Hong Kong's Cheung Kong Infrastructure Holdings (CKI Group) and Power Assets Holdings, Singapore Power International and State Grid Corporation of China.

Electricity networks in Queensland, Tasmania, the Northern Territory and Western Australia remain wholly government owned, as does Essential Energy (NSW). In 2016, the Queensland Government merged the state-owned distribution network service providers Energex and Ergon Energy under a parent company, Energy Queensland.

In May 2025, transmission network service provider Transgrid (NSW) underwent its third ownership change since the beginning of the year with Australia's Future Fund agreeing to buy a 10% stake from Canadian pension fund OMERS.⁹⁹ Transgrid owns and operates the largest electricity transmission network in the NEM, with a regulated asset base of more than \$10 billion (Figure 3.2). This is forecast to more than double over the next 5 years. Transgrid continues to play a crucial part in facilitating Australia's energy transition and is responsible for delivering several key projects by 2030 (section 3.13.6).

In some jurisdictions, ownership of electricity networks overlaps with other electricity industry segments. For example, Queensland's state-owned Ergon Energy provides both distribution and retail services in regions outside South East Queensland. In such cases, ring-fencing arrangements are in place to ensure the network service providers do not use revenue from regulated services to cross-subsidise their unregulated retail products (section 3.8.3).

3.5 How network prices are set

Electricity networks are capital intensive and require significant investment to build and operate the necessary infrastructure. This gives rise to a natural monopoly industry structure, where having a single network service provider is more efficient than having multiple providers offering the same service. Because monopolies face no competitive pressure, they have opportunities and incentives to charge higher prices than they could charge in a competitive market. This monopolistic environment poses risks to consumers, given network charges currently make up as much as 46% of a residential electricity bill (Figure 6.2 in chapter 6). To counter these risks, the role of the AER as the economic regulator is to administer the regulatory framework effectively by replicating the incentives that network service providers would face in a competitive market (that is, to control costs, invest prudently and efficiently and not overcharge consumers).

3.5.1 Regulatory objective and approach

One of the AER's key objectives is to deliver efficient regulation of monopoly electricity and gas infrastructure while incentivising networks to become platforms for energy services (section 3.13.4).¹⁰⁰ This objective relates to the transformation of traditional power grids into open systems that facilitate a variety of energy services beyond just delivering electricity to retail customers. The transformation enables interactions between multiple energy producers, consumers and third parties such as retailers or other service providers. Examples of open systems include consumer energy resources (integrating rooftop solar and battery storage), demand response programs, peer-to-peer energy trading and electric vehicle charging solutions. Open systems allow for more flexible, decentralised energy services.

In February 2025, the AER signalled a new approach to testing and trialling new ideas in the energy market with the introduction of policy-led sandboxing. Innovation is crucial to accelerating access, deployment and orchestration of distributed energy resources (including consumer energy resources) and delivering a least-cost energy system to all consumers.¹⁰¹

99 Future Fund, [Future Fund and OMERS complete transaction for 9.995% of Transgrid](#), media release, 20 May 2025, accessed 3 July 2025.

100 AER, [AER Strategic Plan 2020-2025](#), Australian Energy Regulator, 14 December 2020, accessed 21 May 2025.

101 AER, [Innovative trials welcomed as AER introduces policy-led sandboxing approach](#), Australian Energy Regulator, 13 February 2025, accessed 5 June 2025.

The National Electricity Law and the National Electricity Rules set out the framework that the AER administers when regulating electricity networks.

In May 2023, Energy Ministers agreed to amend the national energy laws to incorporate an emissions reduction into the National Electricity Objective.¹⁰² The amended National Electricity Objective seeks to promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers of electricity with respect to:

- price, quality, safety, and reliability and security of electricity supply
- the reliability, safety and security of the national electricity system
- the achievement of targets set by a participating jurisdiction
 - for reducing Australia’s greenhouse gas emissions, or
 - that are likely to contribute to reducing Australia’s greenhouse gas emissions.

In February 2024, the National Electricity Rules were amended to include ‘changes in Australia’s greenhouse gas emissions’ as a class of market benefit to be considered as part of the Integrated System Plan (ISP) (section 3.13.6) and the regulatory investment tests for transmission (RIT-T) and distribution (RIT-D) (section 3.13.5).¹⁰³

The amended National Electricity Rules also enable electricity network service providers to include expenditure that contributes to achieving emissions reduction targets in their revenue proposals. Together, these amendments to the National Electricity Law and National Electricity Rules provide greater clarity to Australia’s energy market bodies¹⁰⁴ with regards to transitioning Australia’s energy system to net zero by 2050.

In February 2025, the AER signalled a new approach to testing and trialling new ideas in the energy market with the introduction of policy-led sandboxing. Innovation is crucial to accelerating access, deployment and orchestration of distributed energy resources (including consumer energy resources) and delivering a least-cost energy system to all consumers.

The AER uses a wide range of tools to meet its objectives under the regulatory framework (Box 3.2). One of the AER’s main roles is to set the maximum revenue that a network service provider can collect from customers for delivering a safe, reliable and secure electricity service. The AER fulfils this role via a periodic revenue determination process, in which it assesses the amount of revenue a prudent network service provider would need to cover its efficient costs and address emerging issues such as network cybersecurity, climate resilience, integration of consumer energy resources, and digitalisation. Network revenues are capped at the determined level for the duration of the regulatory period, which is typically 5 years.¹⁰⁵

102 The National Electricity Objective (NEO), National Energy Retail Objective (NERO) and the National Gas Objective (NGO) govern and guide the Australian Energy Market Commission (AEMC) in all of its activities under the relevant national energy legislation.

103 AEMC, [Harmonising the national energy rules with the updated national energy objectives \(electricity\)](#), Australian Energy Market Commission, 1 February 2024, accessed 12 July 2025.

104 The Australian Energy Market Commission (AEMC), the Australian Energy Market Operator (AEMO) and the Australian Energy Regulator (AER) and Western Australia’s Economic Regulation Authority (ERA).

105 While a 5-year regulatory period helps to create a stable investment environment, it poses risks of locking in inaccurate forecasts. The National Electricity Rules include mechanisms for dealing with uncertainties – such as cost pass-through triggers and a process for approving contingent investment projects – when costs were not clear at the time of the revenue determination.

As part of the determination process, a network service provider submits a proposal to the AER setting out the amount of revenue it considers necessary to cover the costs of providing a safe and reliable supply of electricity. The National Electricity Rules set out specific requirements to ensure the AER assesses expenditure proposals and makes draft and final determinations in accordance with the National Electricity Law. When assessing a network service provider's proposal, the AER must decide if the proposed capital expenditure and operating expenditure forecasts reasonably reflect:

- the efficient costs of achieving the expenditure objectives
- the costs that a prudent operator would require to achieve the expenditure objectives
- a realistic expectation of the demand forecast, and cost inputs, and other relevant inputs required to achieve the expenditure objectives.

If the AER is not satisfied the network service provider's proposal is in the long-term interests of consumers, it will request further information or a more transparent business case. Subsequently, the AER may amend the proposed revenue to ensure the approved cost forecasts are efficient. Proposals that are developed through genuine engagement with consumers and meet the AER's expectations for forecast expenditure, depreciation and tariff structure statements are more likely to be largely or wholly accepted at the draft determination stage.

In conducting its assessment of a network service provider's proposal, the AER draws from a range of inputs, including expenditure forecasts, benchmarking and revealed costs from past expenditure. It engages closely with network service providers and stakeholders early in the process, including before the network service provider lodges a formal proposal (section 3.7).

Capital expenditure – the money required to build, maintain or improve the physical assets needed to provide core regulated services – generally accounts for the most significant component of a network service provider's revenue requirement. To form a view on the reasonableness and efficiency of a network service provider's capital expenditure forecast, the AER assesses the drivers of the proposed expenditure. Although the AER is responsible for determining the total capital expenditure forecast, it does not determine forecasts for individual capital expenditure drivers, programs or projects. Once the total capital expenditure forecast has been determined, the network service provider must prioritise their program and deliver services at the lowest possible cost.

Unlike capital expenditure, a network service provider's operating expenditure is largely recurrent and predictable. As such, the AER begins its assessment by reviewing the actual operating expenditure incurred in the (then) current regulatory period. The AER uses several assessment techniques to determine whether this 'base' expenditure is efficient before applying a rate of change to account for forecast changes in prices, productivity and the outputs the service provider is required to deliver. The AER may also add (or subtract) step changes for any other efficient costs not captured in the base expenditure or the rate of change.

The AER publishes guidelines on its approach to assessing capital and operating expenditure and applying incentives.¹⁰⁶

¹⁰⁶ AER, [Networks guidelines, schemes, models and reviews](#), Australian Energy Regulator, accessed 12 July 2025.

Box 3.2 The AER's role in electricity network regulation

All electricity network service providers are regulated under revenue caps. Every 5 years we determine the total allowed revenue a network service provider can collect from its customers. Each year network service providers set their prices to target earning the maximum revenue allowed under the revenue cap. Alongside this central role, we undertake broader regulatory functions, including:

- assessing distribution network charges each year to ensure they do not breach the determined revenue cap
- providing incentives for network service providers to improve their performance in ways that customers value
- assessing whether any additional costs not anticipated at the time of our final determination should be passed on to customers (section 3.9.3)
- publishing information on the performance of network service providers, including benchmarking and profitability analysis
- assessing whether network service providers properly evaluate the merits of new investment proposals
- promoting and enforcing compliance with regulations, including connections policies and ring-fencing (section 3.8.3).

We also help implement reforms to improve the quality of network regulation and achieve better outcomes for energy customers, such as:

- adopting a more consumer-centric approach to setting network revenues (section 3.7)
- reviewing and refining our guidelines and incentive schemes to ensure they remain relevant and fit for purpose
- reviewing how rates of return and taxation allowances are set for energy networks (section 3.12).

We also carry out state-level regulatory functions in both Queensland and NSW. State-based arrangements aim to coordinate the timing of building network infrastructure with renewable generation while simultaneously managing issues associated with social licence, employment and supporting First Nations people. The newly conferred functions allow us to use our expertise to support this aim and promote the long-term interests of consumers in those states. Under the *Electricity Infrastructure Investment Act 2020* (NSW), we make revenue determinations for network projects procured through contestable and non-contestable processes.

Under the *Energy (Renewable Transformation and Jobs) Act 2024* (Qld), the responsible ministers may ask for our advice about priority transmission investments. This can include assessing whether Queensland transmission network service provider Powerlink's proposed expenditure for a network project is prudent and efficient.

3.5.2 Building blocks of network revenue

The AER uses a 'building block' approach to assess a network service provider's revenue needs. Specifically, it forecasts how much revenue the service provider will need to cover:

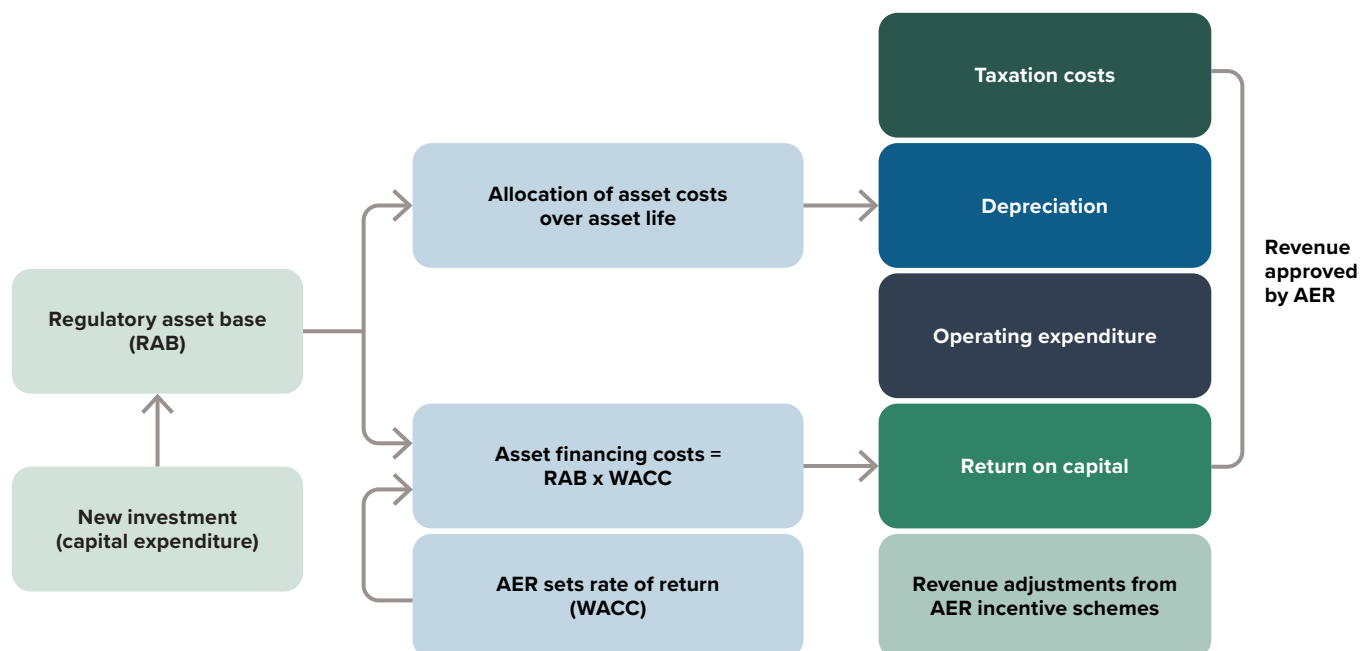
- a return to the investors that fund its assets and operations
- efficient operating and maintenance costs
- asset depreciation costs
- taxation costs.

The AER also makes revenue adjustments for rewards or penalties earned through any applicable incentive schemes.

Network service providers are entitled to collect revenue to cover their efficient costs each year, but this revenue does not include the full cost of investment in new assets installed throughout the year. Network assets generally have long lives and investment costs are recovered over the economic lives of the assets, which may be several decades. The amount recovered each year is called depreciation, and it reflects the lost value of network assets each year through wear and tear and technical obsolescence (Figure 3.4).

The regulatory asset base (RAB) represents the total remaining economic value of the assets that are used to provide network services to customers, to be recovered through depreciation over time. Depreciation is the amount provided so capital investors recover their investment over the economic life of the asset (return of capital). All things being equal, a higher RAB would increase both the return on capital and depreciation (return of capital) components of the maximum allowed revenue calculation.

Figure 3.4 Forecasting electricity network revenues



Note: AER: Australian Energy Regulator. RAB: regulatory asset base. WACC: weighted average cost of capital. Revenue adjustments from incentive schemes encourage network service providers to efficiently manage their operating and capital expenditure, improve services provision to customers and adopt demand management schemes that avoid or delay unnecessary investment.

Source: AER.

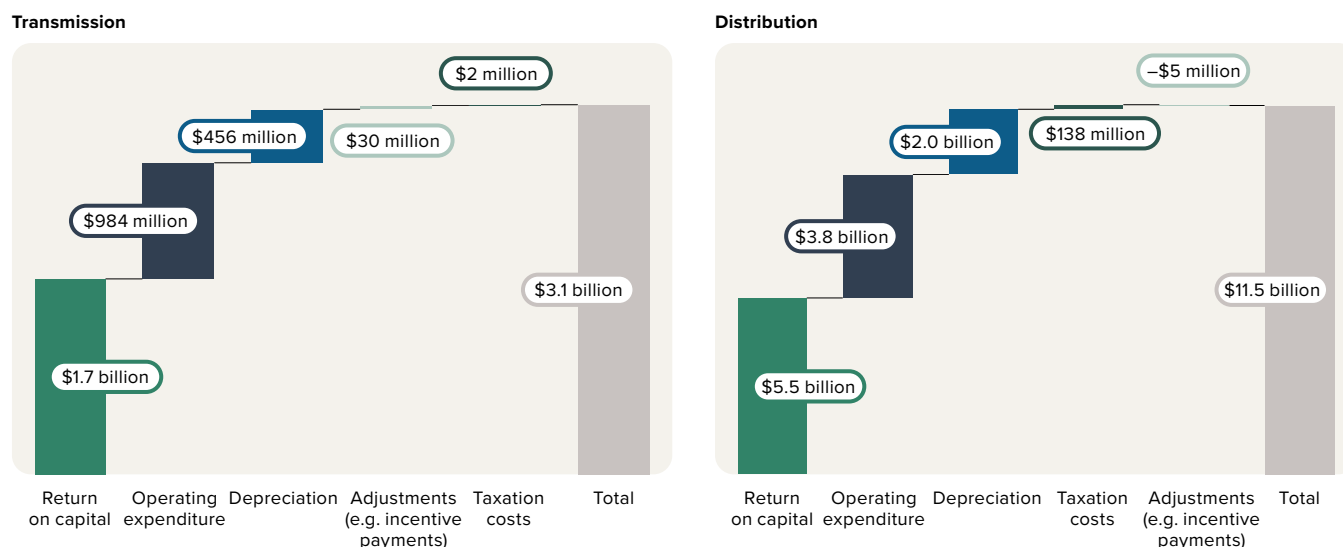
Additionally, the shareholders and lenders that fund these assets require a return on their investment. The AER sets the allowed rate of return (also called the weighted average cost of capital [WACC]) (section 3.12). The size of this return depends on:

- the value of the network service provider's RAB
- the allowed rate of return that the AER allows based on the forecast cost that a benchmark efficient entity would incur in funding those assets through equity and debt.¹⁰⁷

Overall, the return on capital takes up the largest share of network revenue, accounting for around 49% of total revenue across all networks (Figure 3.5). Sections 3.11 to 3.14 examine major cost components in more detail.

¹⁰⁷ The return on equity is the return that shareholders of the business will require for them to continue to invest. The return on debt is the interest rate that the network business pays when it borrows money to invest.

Figure 3.5 Composition of average annual electricity network revenue



Note: Composition of average annual electricity network revenue – current periods as at 1 July 2025. All data are adjusted to June 2024 dollars.
Source: Post-tax revenue modelling used in AER determination process.

3.6 Recent AER revenue determinations

In April 2025, the AER finalised revenue determinations for distribution network service providers Energex (Queensland),¹⁰⁸ Ergon Energy (Queensland)¹⁰⁹ and SA Power Networks (South Australia)¹¹⁰ and the Directlink interconnector.¹¹¹

The determinations set target revenue controls for the 5-year period through to 30 June 2030 and seek to balance affordability and efficient and prudent investment that delivers a safe and reliable network to meet the long-term needs of consumers. In making the determinations, the AER addressed emerging issues such as network cybersecurity, mitigating the risks of the increasing frequency of extreme weather events and the integration of consumer energy resources. The AER also recognised that electricity networks must adhere to safety regulations and technical standards and supported the network service providers to efficiently improve network resilience and maintain safety standards.

Network costs are increasing due to economy-wide factors of higher interest rates and a higher inflationary environment. For example, Energex and Ergon Energy's cost of capital increased from 4.73% to 6.09% and SA Power Networks' cost of capital increased from 4.75% to 6.12% in the 5 years since the AER's 2020–25 revenue determinations (section 3.12). Over the same period, inflation increased from 2.27% to 2.72%. This effectively means the cost for network service providers to obtain the capital needed to make the required investments and operate their businesses has increased.¹¹²

¹⁰⁸ AER, [Energex - Determination 2025–30](#), Australian Energy Regulator, 30 April 2025.

¹⁰⁹ AER, [Ergon Energy - Determination 2025–30](#), Australian Energy Regulator, 30 April 2025.

¹¹⁰ AER, [SA Power Networks - Determination 2025–30](#), Australian Energy Regulator, 30 April 2025.

¹¹¹ AER, [Directlink - Determination 2025–30](#), Australian Energy Regulator, 30 April 2025.

¹¹² The rate of return is a nominal rate of return unless stated otherwise.

These were all key inputs in the AER's regulatory determinations, which are summarised in Table 3.1.

Table 3.1 Recent AER electricity network revenue determinations

Network service provider	Revenue (forecast)	Capital expenditure (forecast)	Operating expenditure (forecast)
Energex (Queensland)	\$7.7 billion (▲16%)	\$3.1 billion (▲30%)	\$2.4 billion (▲12%)
Ergon Energy (Queensland)	\$7.3 billion (▲13%)	\$4.3 billion (▲62%)	\$2.3 billion (▲6%)
SA Power Networks (South Australia)	\$4.4 billion (▲6%)	\$2.2 billion (▲11%)	\$2.0 billion (▲19%)

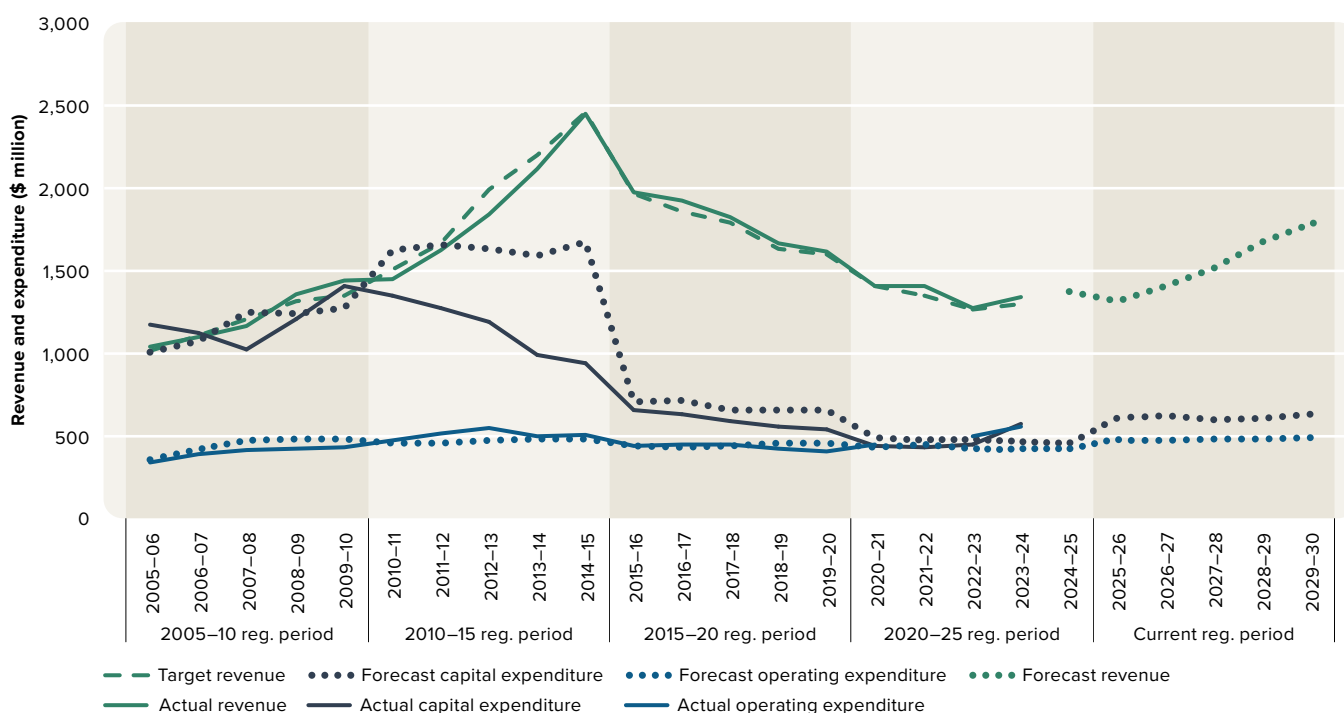
Note: All revenue and expenditure data are adjusted to June 2024 dollars. Changes in revenue and expenditure are in relation to forecasts from the previous regulatory periods.

Source: AER estimates.

3.6.1 Energex (Queensland)

The AER's final determination was that Energex can collect \$7.7 billion in revenue from its customers over the 2025–30 regulatory period, \$1.0 billion (16%) more than the revenue forecast for the previous regulatory period (2020–25). The AER estimates that approximately 55% of the increase was driven by higher capital and operating expenditure, with the other 45% driven by higher inflation and interest rates (Figure 3.6).

Figure 3.6 Revenue and key drivers – Energex (Queensland)



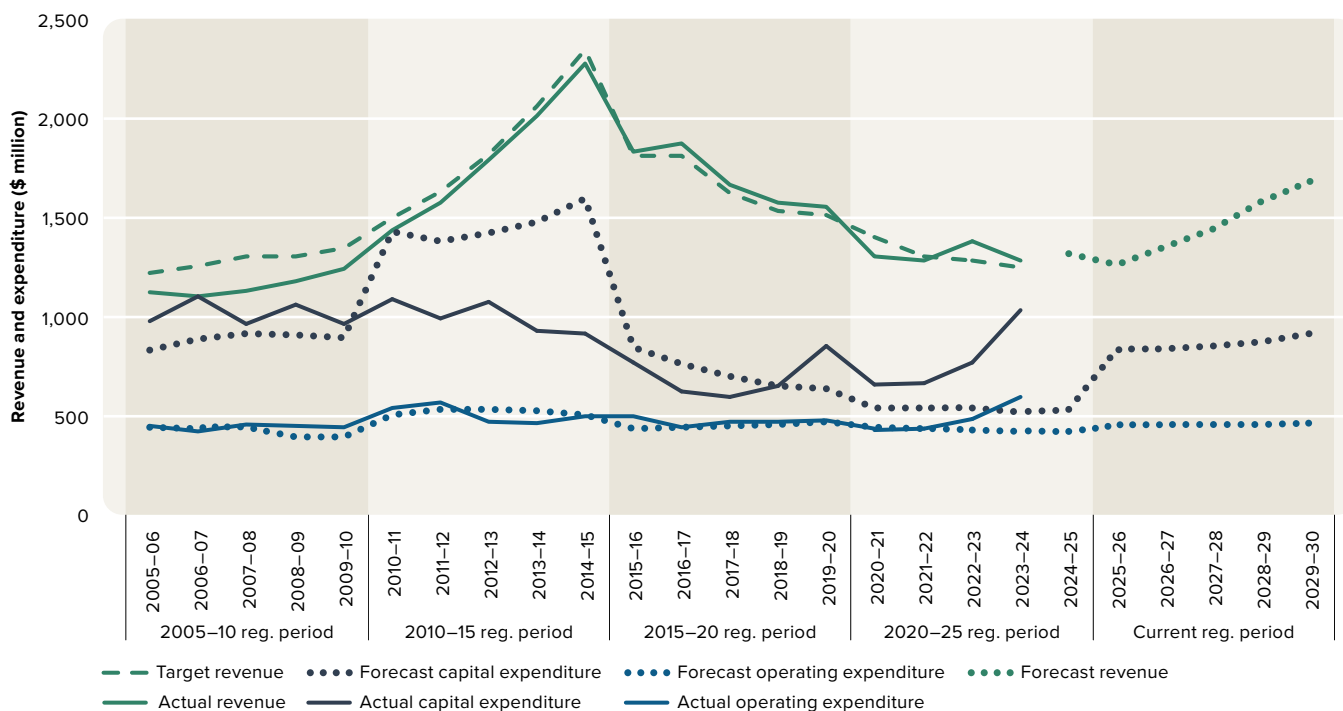
Note: All data are adjusted to June 2024 dollars.

Source: AER modelling; annual reporting RIN responses.

3.6.2 Ergon Energy (Queensland)

The AER's final determination was that Ergon Energy can collect \$7.3 billion in revenue from its customers over the 2025–30 regulatory period, \$832 million (13%) more than the revenue forecast for the previous regulatory period. The AER estimates that approximately 57% of the increase was driven by higher inflation and interest rates, with the other 43% driven by higher capital and operating expenditure (Figure 3.7).

Figure 3.7 Revenue and key drivers – Ergon Energy (Queensland)



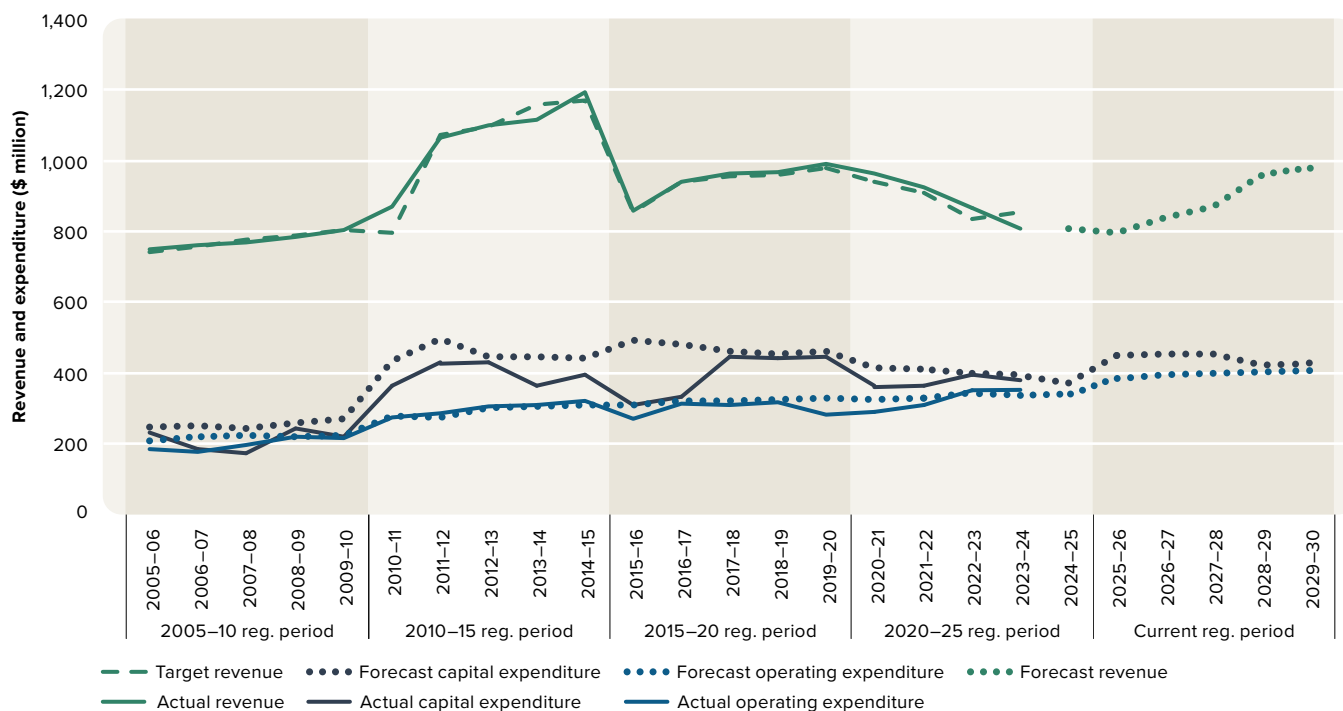
Note: All data are adjusted to June 2024 dollars.

Source: AER modelling; annual reporting RIN responses.

3.6.3 SA Power Networks (South Australia)

The AER's final determination was that SA Power Networks can collect \$4.4 billion in revenue from its customers over the 2025–30 regulatory period, \$259 million (6%) more than the revenue forecast for the previous regulatory period. The AER estimates that approximately 54% of the increase was driven by higher capital and operating expenditure, with the other 46% driven by higher inflation and interest rates (Figure 3.8).

Figure 3.8 Revenue and key drivers – SA Power Networks (South Australia)



Note: All data are adjusted to June 2024 dollars.

Source: AER modelling; annual reporting RIN responses.

For Energex (Queensland) and Ergon Energy (Queensland) the drivers of higher forecast revenues were partially offset by negative revenue adjustments, mainly due to the impacts of large efficiency benefit sharing scheme (EBSS) (Box 3.4) and capital expenditure sharing scheme (CESS) (Box 3.3) penalties applied in the final determinations.

If the AER considers over-expenditure against the approved capital allowance to be efficient, the excess spending, or a proportion thereof, may be added to the RAB (section 3.11). Conversely, if the AER considers over-expenditure to be inefficient, the excess spending may not be added to the RAB and the network service provider would bear the cost by taking a cut in profits. This condition protects consumers from funding inefficient expenditure.

In 2024, Ergon Energy materially overspent against forecast capital expenditure for the fifth consecutive year. Ergon Energy submitted that overspends were driven by the need to address priority network safety programs, including defect rectifications and remediation works.¹¹³

In its draft determination, the AER recommended a 50% reduction in the amount of capital expenditure¹¹⁴ to be included in Ergon Energy's opening RAB at 1 July 2025.¹¹⁵ The AER found that Ergon Energy did not provide sufficient supporting material to demonstrate prudent and efficient decision-making for some of its capital expenditure. Instead, there were information gaps and reliance on poor-quality data. In its final determination, the AER reiterated its concerns made in the draft determination regarding Ergon Energy's asset management practices, particularly its practice of retrospectively applying new standards to existing assets and its approach to opportunistically replacing pole top structures and service lines when replacing poles.¹¹⁶

Ergon Energy acknowledged its increasing operating costs over the previous regulatory period (2020–25) and identified key drivers including flood and storm costs in 2023–24, increasing vegetation management costs resulting from newly negotiated contracts, a general increase in costs driven by the COVID-19 pandemic and an increase in labour and overhead costs associated with growth in its capital program.¹¹⁷

¹¹³ Ergon Energy, [2021-22, 2022-23 and 2023-24 Annual reporting RINs](#), 31 October 2022, 2023 and 2024.

¹¹⁴ Outlaid by Ergon Energy over the 5-year period from 2018 to 2023.

¹¹⁵ AER, [Ergon Energy - Draft determination 2025–30](#), Australian Energy Regulator, 23 September 2024.

¹¹⁶ AER, [Ergon Energy - Determination 2025–30](#), Australian Energy Regulator, 30 April 2025.

¹¹⁷ Ergon Energy, [Response to AER Information request, IR#047 – actual base year opex, Q.1 and workbook](#), 12 July 2024.

3.7 Refining the regulatory approach

The regulatory framework is not static. The regulatory process is increasingly focusing on how network service providers engage with their customers in shaping proposals.

In May 2024, the AER published an update to its *Better Resets Handbook – Towards consumer-centric network proposals* (the Handbook) as part of reflecting the addition of the emissions reduction objective to the existing National Energy Objectives (section 3.5.1).¹¹⁸

Regulatory proposals that are developed through genuine engagement with consumers and meet the AER's expectations for forecast expenditure, depreciation and tariff structure statements are more likely to be largely or wholly accepted at the draft determination stage, creating a more efficient regulatory process for all stakeholders.

The Handbook provides many benefits, including improved relationships and understanding between network service providers and the consumers they serve, greater trust between all parties in regulatory processes, and the creation of new ideas and regulatory approaches that benefit both consumers and service providers.

Another key resource in promoting the interests of consumers is the AER's Consumer Challenge Panel. The Panel – comprising experienced and highly qualified individuals with consumer, regulatory and/or energy expertise – provides independent input on issues of importance to consumers. It advises the AER on:

- whether the revenue proposals submitted by network service providers are in the long-term interests of consumers
- the effectiveness of network service providers' engagement with their customers
- how consumer views are reflected in the development of network service providers' proposals.¹¹⁹

The AER was satisfied that both Energex's (Queensland) and Ergon Energy's (Queensland) stakeholder engagement plans for the 2025–30 revenue determination process were well targeted and provided meaningful input into their revised proposals. Both Energex and Ergon Energy engaged with their Voice of Customer Panel, Customer and Community Council and Network Pricing Working Group to obtain consumer views on the AER's draft determinations on capital investment, network tariffs and the customer service incentive scheme (CSIS) (Box 3.6), and to gain support for the direction of their revised proposals.¹²⁰

However, Energex and Ergon Energy presented an unbalanced picture to consumers about the AER's draft determinations on capital expenditure and some tariff elements. Both Energex and Ergon Energy suggested the AER's draft determination on capital expenditure would lead to worsening reliability and compromise safety goals. Energex and Ergon Energy also implied their two-way tariff proposals were rejected by the AER and encouraged consumers to support postponing its implementation.

The AER was satisfied that SA Power Networks' (South Australia) stakeholder engagement following the 2025–30 draft determination was effective in gathering feedback for the revised proposal. SA Power Networks held targeted engagement with its consumer groups to address issues raised by the AER in the draft determination and held information sessions to provide an overview of their proposed response, and the expected revenue and bill impacts of their revised proposal. SA Power Networks' collaborative approach to refine the innovation fund with consumers was a standout in its post-draft determination engagement process.¹²¹

The AER noted that Energex, Ergon Energy and SA Power Networks all failed to fully address the issue of affordability in their revised proposals despite the issue being raised by several stakeholders.

118 AER, [Better Resets Handbook – Towards consumer centric network proposals](#), Australian Energy Regulator, 30 July 2024.

119 AER, [Consumer Challenge Panel](#), Australian Energy Regulator, accessed 3 February 2025.

120 AER, [Energex – Determination 2025–30 – Final decision](#) and [Ergon Energy – Determination 2025–30 – Final decision](#), Australian Energy Regulator, 30 April 2025.

121 AER, [SA Power Networks – Determination 2025–30 – Final decision](#), Australian Energy Regulator, 30 April 2025.

3.7.1 Changes to revenue setting approaches

The AER frequently reviews and updates key aspects of its revenue setting approaches to ensure they remain fit for purpose.

In February 2023, the AER released its latest rate of return instrument (the 2022 Instrument). The rate of return is a key component used to determine the amount of revenue network service providers can recover from customers. The AER sets the rate of return to cover the cost of capital of an efficient service provider.

In March 2024, the AER released an updated version of the February 2023 Instrument, which binds all access arrangements from 25 February 2023 until the next revision of the Instrument.¹²² The instrument sets out the approach by which the AER will estimate the rate of return and comprises the return on debt and the return on equity, as well as the value of imputation credits (section 3.12).

In March 2025, as a first step toward making the 2026 Rate of Return Instrument, the AER published a paper setting out the high-level review process it will undertake to produce the Instrument.¹²³

The AER also continues to review and incrementally refine elements of its benchmarking methodology and data. The aim of this work is to continually improve the reliability of the benchmarking results it publishes and uses in its network revenue determinations (section 3.15).

3.8 Electricity pricing for a renewable future

The amount of electricity generated by consumer-owned or controlled devices continues to grow. This growth in consumer energy resources – such as rooftop solar panels, home batteries, electric vehicles and smart devices that can interact with the grid – presents both opportunities and challenges as technological advances constantly shifts the way in which electricity is supplied, stored and used.

As we transition to a renewable future – in particular, the increase in consumer energy resources – it is important that individual consumers can make informed choices about their electricity usage to avoid increasing costs for all consumers. Sending signals via network prices is one way to incentivise consumers to use electricity in ways that minimises the need for future network investment.

Distribution network service providers set network tariffs to recover the costs of owning and operating the electricity network. Cost-reflective network tariffs – which means charging different prices for different periods of the day – send broad and consistent signals to energy retailers that sourcing electricity from the grid during periods of peak demand, or exporting it during periods of minimum demand, contributes to network costs in the long run. As such, cost-reflective network tariffs can incentivise retailers to encourage customers to consume energy when there are fewer constraints on the grid and electricity is cheaper to distribute.

Conversely, ‘static’ or ‘flat’ network tariffs see distribution network service providers charge retailers the same price per unit of electricity regardless of when the electricity is used. These types of network tariffs do not reflect that consuming electricity during periods of peak or minimum demand can contribute to network costs.

Network assets generally have a long life span and are paid for by customers. Distribution network service providers are best placed to develop network tariffs that signal the impact demand will have on network costs. Managing network demand and supply imbalances to increase capacity utilisation (section 3.15.2) could mitigate future costs by reducing the need for network augmentation, thereby lowering future network bills for all consumers. When network service providers pass broad and consistent price signals to retailers, it incentivises retailers to then facilitate alternative ways to align consumers’ energy use with efficient use of network infrastructure through innovative energy services and retail tariffs.

¹²² AER, [Rate of Return Instrument 2022](#), Australian Energy Regulator, accessed 20 March 2025.

¹²³ AER, [Rate of Return Instrument – 2026 review process paper](#), Australian Energy Regulator, 28 March 2025.

3.8.1 Smart meters, new technologies and network pricing

Smart meters are advanced digital electricity meters that provide accurate real-time information about electricity usage. Smart meters measure and record electricity usage every 30 minutes and automatically send the data to the customer's distribution network service provider. This enables distribution network service providers to develop cost-reflective network tariffs, and for retailers to pass on these tariffs (via the retail contract), to customers who are willing and able to respond to time-variable tariffs and make informed decisions in managing both their electricity usage and exports.

Smart meters play an essential role in supporting the energy transition. The provision of accurate real-time usage data is vital to the development and implementation of demand management strategies and enables distribution network service providers to better balance the variable supply of renewable electricity. For example, facilitating time-varying retail pricing and supporting the orchestration of consumer energy resources can reward customers for using electricity when there is ample network capacity.

The penetration of smart meters has increased over the past decade. However, the proportion of network customers outside of Victoria with access to smart meters remains relatively low. Outside of Victoria, most households still have accumulation meters that need to be manually read. As such, most households still only have access to flat retail offers. Accelerating the deployment of smart meters means that customers and the broader energy system can get faster access to the benefits offered by these devices.

In August 2023, the Australian Energy Market Commission (AEMC) released its final report supporting the accelerated rollout of smart meters.¹²⁴ The report set out several recommendations and options to achieve universal penetration of smart meters across the NEM by 2030. Following this, the AEMC published a final determination and final rule seeking to efficiently accelerate the deployment of smart meters to all customers, commencing December 2025.¹²⁵

The AER demonstrated its support of the AEMC's proposed acceleration of the rollout by approving the cost recovery of old network-delivered meters in the quickest, lowest cost way to all customers.¹²⁶ The AER has signalled through its recent revenue determinations that the transitioning of legacy meters may require it to consider different classifications and/or price/revenue control settings for distribution network service providers.¹²⁷ While the AER will look to maintain a consistent approach in assessing legacy metering services, consideration of the individual circumstances of each distribution network service provider will be required to ensure it provides outcomes that are in the long-term interests of consumers.

The AEMC's *Accelerating smart meter deployment* final rule determination includes customer protections prohibiting up-front costs and requiring retailers to obtain a customer's explicit informed consent before moving them to a new (cost-reflective) retail tariff for the 2-year period after the installation of a smart meter. This reflects the risk that some customers could be worse off under time-varying or demand tariffs.¹²⁸ The AEMC determination also enables jurisdictions to implement a requirement that designated retailers continue to offer flat retail tariffs. To date, Queensland is the only jurisdiction to require designated retailers to offer a flat standing offer as an alternative tariff to customers with smart meters.¹²⁹

The AEMC is currently consulting on a rule change, initiated by Energy Consumers Australia (ECA), to enable consumers to access real-time data from their smart meters.¹³⁰ Having access to real-time energy usage data has the potential to enhance the consumer's benefits of having a smart meter. Currently, consumers and third parties seeking access to real-time energy usage data need to install separate digital meter readers or current transformers, with consumers paying to gain the additional access.

124 AEMC, [Final report – Review of the regulatory framework for metering services](#), Australian Energy Market Commission, 30 August 2023.

125 AEMC, [Final rule determination – Accelerating smart meter deployment](#), Australian Energy Market Commission, 28 November 2024.

126 AER, [Final revenue decisions balance affordability and required investment](#), media release, Australian Energy Regulator, 30 April 2024.

127 AER, [Final Decision – Endeavour Energy electricity distribution determination 2024 to 2029 – Overview](#), Australian Energy Regulator, 30 April 2024, p. 27.

128 A demand tariff is a network tariff that includes a charge based on the customer's maximum power usage during a specified period, typically a 30-minute interval within a defined peak period.

129 *National Energy Retail Law (Queensland) Amendment Regulation (No. 2) 2024*.

130 AEMC, [Directions paper – Real time data for consumers rule 2025](#), Australian Energy Market Commission, 30 January 2025.

3.8.2 Regulatory reforms that support changing energy flows

Network tariff design, under the network tariff reform program, continues to evolve as the pace of the energy transition accelerates. Network tariffs are designed to signal to electricity retailers the varying costs of the network, over time of day, time of year and potentially by location.

Tariff structure statement process

The AER's role is to approve, or not approve, network tariffs proposed by distribution network service providers based on whether they comply with the network pricing principles of the National Electricity Rules and contribute to the achievement of the Network Pricing Objective and the National Electricity Objective. With each subsequent tariff structure statement, distribution network service providers are required under the National Electricity Rules to progressively move towards more cost-reflective network tariffs.¹³¹

The AER makes its decisions on tariff structure statements by assessing whether network tariff design is progressing towards cost reflectivity.¹³² This includes considering the impact network tariffs have on customers, retailers' ability to incorporate tariffs in their retail offers and whether customers will understand their network tariffs. This has been an important consideration for the AER in assessing the default network tariffs that distribution network service providers assign to customers.¹³³

The AER's role is to approve, or not approve, network tariffs proposed by distribution network service providers based on whether they comply with the network pricing principles of the National Electricity Rules and contribute to the achievement of the Network Pricing Objective and the National Electricity Objective.

Distribution network service providers are required to submit tariff structure statements to the AER every 5 years as part of the wider revenue determination process. Tariff structure statements set out proposed network tariff structures for the forthcoming 5-year period, policies on how network tariffs are assigned and information on how network tariffs are set. The 5-year tariff structure cycle was imposed to place weight on certainty for electricity retailers and consumers, because distribution network service providers cannot modify approved network tariffs within a 5-year period unless exceptional circumstances have been met. Given the pace of the energy transition, a 5-year cycle may no longer be fit for purpose. Increased flexibility in the tariff structure statement process is being considered as part of the AEMC's *Electricity pricing for a consumer-driven future* review.¹³⁴

¹³¹ Most distribution network service providers have completed their third round of tariff structure statements. The AER will make a final determination on the Victorian distribution network service providers' third round of tariff structure statements in April 2026.

¹³² To signal to energy retailers, then to customers via their energy retail, periods of network capacity and periods of network congestion.

¹³³ The 'default network tariff' is the initial tariff a customer is assigned to, unless the customer's retailer chooses an alternative tariff made available by the distribution network service provider.

¹³⁴ AEMC, [The pricing review: Electricity pricing for a consumer-driven future](#), Australian Energy Market Commission, accessed 5 June 2025.

Increasing network utilisation through tariffs

Distribution network service providers reward customers for behaving in ways that better utilise the existing network, potentially reducing the need for future network investment. Some innovative approaches include:

- designing tariffs that more closely reflect network costs, including introducing ‘solar soak’ periods – tariffs that have low charges during the day to encourage consumers to use electricity in this time (most distribution network service providers have or will soon include these tariffs)
- introducing export rewards or two-way tariffs in recognition of the need to manage the significant levels of electricity now being exported back into the grid from consumer energy resources, such as small-scale solar and batteries.

The introduction of two-way tariffs is one example of tariff reform and follows a rule change made by the AEMC in August 2021 to integrate consumer energy resources more efficiently into the electricity grid.¹³⁵ Export reward tariffs – which offer rewards to customers for exporting electricity at times when it is most needed (in addition to retailers’ solar feed-in tariff payments) and apply charges for exporting large amounts of solar into the grid at times when it is not needed – better reflect the costs and benefits to the network from solar-exporting customers and incentivise behaviours that benefit all customers. Export reward tariffs are intended to help customers who generate solar decide when to consume the solar electricity themselves and when to export it.¹³⁶

The AER first approved the use of export reward tariffs in April 2024. Export reward tariffs were introduced by distribution network service providers in NSW on 1 July 2024, followed by South Australia on 1 July 2025. Network service providers are not required to introduce export reward tariffs and any proposed export reward tariff is subject to the AER’s approval as part of the tariff structure statement process.

Some distribution network service providers have also introduced flexible export limits, a connection that allows the service provider to limit solar exports when needed to protect local power supply. This allows customers to export more than the static (fixed) limit at other times. For example, Endeavour Energy (NSW) announced a flexible exports service that will allow eligible customers to increase the amount of energy they can export to the grid from 5 kilowatts (kW) up to 10 kW for 95% of the year. Endeavour Energy will only limit exports if grid stability is at risk.¹³⁷

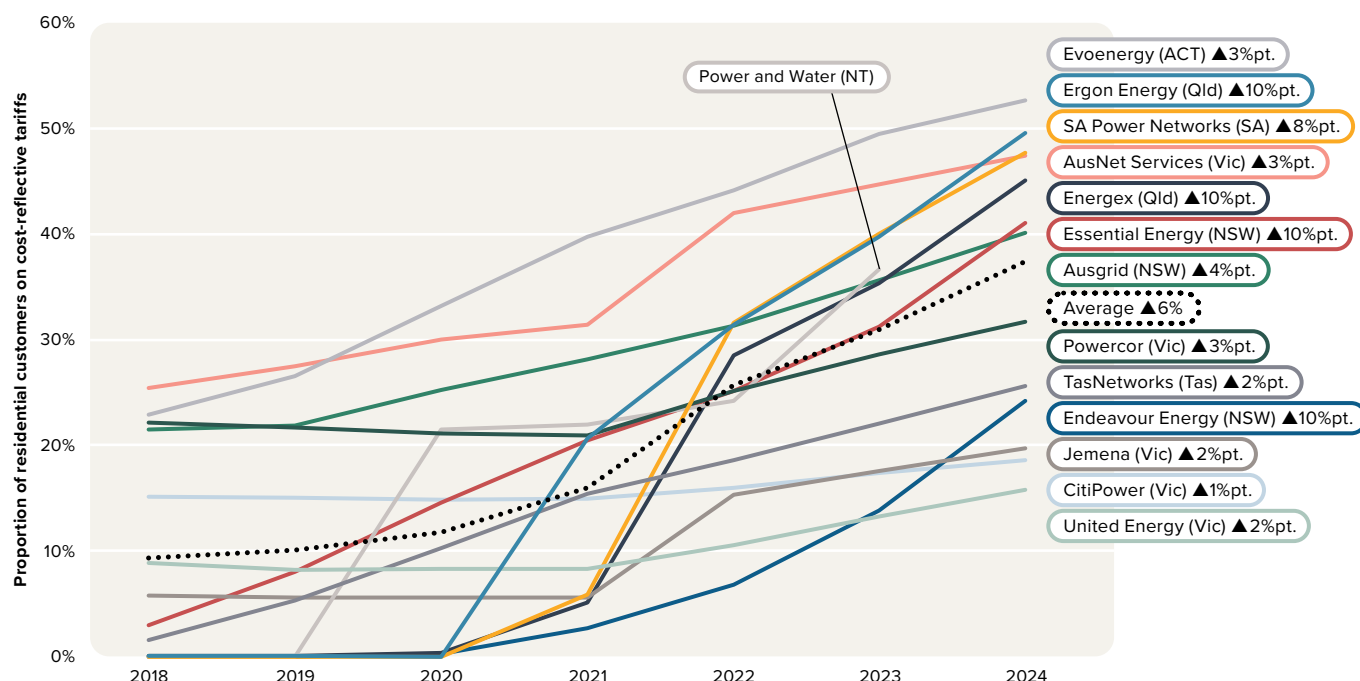
As at 30 June 2024, approximately 37% of residential consumers in the NEM were assigned to a cost reflective network tariff that was charged to their retailer (Figure 3.9). This proportion will likely increase in response to the accelerated rollout of smart meters. However, it is important to recognise that the direct impact on a customer’s electricity bill from any network tariff, two-way or otherwise, will still depend on how it is passed on by the retailer in a customer’s retail contract.

¹³⁵ AEMC, [Access, pricing and incentive arrangements for distributed energy services](#), Australian Energy Market Commission, 12 August 2021, accessed 2 June 2025.

¹³⁶ AER, [Export reward tariffs and you](#), Australian Energy Regulator, April 2024.

¹³⁷ Endeavour Energy, [World-leading AI technology to unlock electricity bill savings and double rooftop solar](#), media release, 25 February 2025, accessed 25 February 2025.

Figure 3.9 Residential customers on cost-reflective tariffs



Note: 2024 data for Power and Water (NT) was not available.
Source: Annual RIN responses.

The AER encourages collaboration between distribution network service providers, retailers and industry to trial alternative tariff structures (sub-threshold tariffs) during a regulatory period to support the introduction of innovative tariff structures, and to develop other mechanisms to shift both demand and solar exports to more cost-efficient times of the day. Examples of trials include:

- Energex and Ergon Energy (Queensland) – storage tariff trials (dynamic flex and dynamic pricing) to trial dynamic pricing and dynamic connections for storage consumers. Energex and Ergon Energy will (subject to developing the necessary billing capabilities) use the outcomes of the trials to inform storage tariffs for introduction from 2025.
- Endeavour Energy (NSW) – a flexible controlled load tariff trial with specific focus on hot water and electric vehicle solar soaking.
- SA Power Networks (South Australia) – a residential ‘electrify’ tariff trial with a targeted peak window and solar sponge, designed to encourage consumers with flexible load to shift electricity use to during the day or overnight. SA Power Networks aims to introduce this tariff to all residential consumers from 2025.

Unlike tariff structures introduced through the 5-year regulatory proposals, tariff trials do not need to be approved by the AER but are subject to other safeguards:

- distribution network service providers are required to notify the AER of proposed tariff trials
- tariff trials are not allowed to recover more than 5% of a distribution network service provider’s revenue.

With the need for innovative solutions to support changes in consumers’ energy use more urgent than ever, the AER may look for rule amendments around sub-threshold tariffs to be less restrictive as part of the AEMC’s *Electricity pricing for a consumer-driven future*.¹³⁸

138 AEMC, [The pricing review: Electricity pricing for a consumer-driven future](#), Australian Energy Market Commission, accessed 5 June 2025.

Network tariffs for EV users and EV charging point operators

The network tariff reform program, administered by the AER, is a long-term micro-economic reform program aimed at reducing future network costs through more efficient use of the network. This is particularly important for the emerging electric vehicle (EV) load on the network. Most distribution network service providers now have default cost-reflective tariffs that signal to retailers when there is abundant network capacity, making it cheaper for consumers to charge their EVs. This generally occurs in the middle of the day when solar generation is high and overnight when fewer customers are using appliances. Customers with EVs with vehicle-to-grid capability may also benefit from export reward tariffs and be rewarded for exporting electricity into the grid when it is needed.

Trials have demonstrated that consumers have responded well to EV load price signals, with even greater benefits from blending price signals with external control over a consumer's EV chargers. For example:

- AGL's Electric Vehicle Orchestration Trial found that EV customers on time-of-use retail offers (that reflect cost-reflective network tariffs) respond strongly to price signals and move EV charging to off-peak periods.¹³⁹
- Origin Energy's trial demonstrated that providing incentives to participants through time-varying offers reduced charging consumption at peak times by 20%.¹⁴⁰

There has also been an emergence of non-tariff mechanisms employed by distribution network service providers to help manage EV-related demand. For example, customers in Queensland can install equipment that allows their distribution network service provider to dynamically control an EV fast charger, limiting electricity supply in close to real-time when the network is congested.¹⁴¹ Together, cost-reflective tariffs, external control and smart devices could increase network capacity utilisation and mitigate potential adverse network efficiency outcomes as Australia's road transport electrifies.

The AER supports a consistent approach to network tariffs for EV charge point operators – the entities responsible for building, operating and maintaining EV charging infrastructure – across the NEM to facilitate the expansion of Australia's EV charge point network. Following the AER's 2025–30 revenue determinations for Energex (Queensland), Ergon Energy (Queensland)¹⁴² and SA Power Networks (South Australia),¹⁴³ customers with 'peaky load profiles' (relatively high demand but low utilisation) – such as new/small charge point operators – will be able to opt in to either a 'time-of-use' or 'demand' tariff in all distribution networks in the NEM.¹⁴⁴

The AER considers the access to similar network tariff structures for EV charge point operators NEM-wide could further support uptake and use of EVs, consistent with the Australian Government's National Electric Vehicle Strategy, to 'make it easy to charge EVs across Australia' and 'reduce road transport emissions'.¹⁴⁵

¹³⁹ Australian Government, [AGL Electric Vehicle Orchestration Trial](#), Australian Renewable Energy Agency, May 2023, accessed 5 July 2025.

¹⁴⁰ Australian Government, [Origin Energy Electric Vehicles Smart Charging Trial Lessons Learnt 2](#), Australian Renewable Energy Agency, May 2022, accessed 5 July 2025.

¹⁴¹ Energex, [EV charging & connections](#), accessed 6 June 2025.

¹⁴² AER, [Final Decision Attachment 19 – Tariff structure statement – Ergon Energy and Energex – 2025-30 Distribution determination revenue proposal](#), Australian Energy Regulator, 30 April 2025.

¹⁴³ AER, [Final Decision Overview – SA Power Networks – 2025-30 Distribution determination revenue proposal](#), Australian Energy Regulator, 30 April 2025.

¹⁴⁴ Prior to the Energex/Ergon Energy/SA Power Networks determinations, consistency had already been achieved in other NEM jurisdictions. Across NSW, Victoria, Tasmania and the ACT, EV charge point operators could already access time-of-use tariffs while consumption is less than 160 MWh.

¹⁴⁵ Australian Government, [The National Electric Vehicle Strategy](#), Department of Climate Change, Energy, the Environment and Water, accessed 2 June 2025.

3.8.3 Ring-fencing

Ring-fencing refers to the separation of the regulated and competitive business activities of an electricity network service provider.

The objective of ring-fencing is to provide a regulatory framework that promotes the development of competitive markets. It does so by creating a level playing field between natural monopoly and third-party service providers in new and existing markets for contestable services.¹⁴⁶ Effective ring-fencing arrangements are important for promoting an increased choice of service providers for consumers and more competitive outcomes in markets for electricity services without losing the cost efficiencies of natural monopolies.

Ring-fencing should not be regarded as a barrier to innovation or a barrier to the emerging role of electricity networks as platforms for new energy services. The aim of ring-fencing is to prevent network service providers from using revenue from regulated services to cross-subsidise their unregulated products or services, and/or discriminate in favour of affiliated businesses. Before a network service provider offers services in a competitive market, robust ring-fencing arrangements must be in place to ensure it competes fairly with other service providers.

The AER has developed separate ring-fencing guidelines for transmission and distribution networks. Under the guidelines, network service providers must identify and separate the costs and business activities attributed to the provision of regulated network services from those attributed to the delivery of services in competitive markets. Network service providers are required to report to the AER any breaches of the guidelines within 15 business days of becoming aware of the breach. In addition, network service providers must annually report to the AER on their compliance with the guidelines. When breaches have occurred, network service providers have generally communicated promptly with the AER, acted quickly to remediate any potential harms and put plans in place to prevent breaches from recurring. The introduction of civil penalties for ring-fencing breaches has further encouraged improved compliance.

The guidelines allow the AER to grant waivers for network service providers from some ring-fencing obligations. The AER encourages network service providers to submit waiver proposals that demonstrate consumer benefits through increased choice or reduced future capital spending.

In the 12-month period to 30 December 2024, 2 transmission and 6 distribution network service providers reported breaches related to the protection of ring-fenced information. The AER did not consider these breaches had a material impact on competition within contestable markets.

The guidelines allow the AER to grant waivers for network service providers from some ring-fencing obligations. The AER encourages network service providers to submit waiver proposals that demonstrate consumer benefits through increased choice or reduced future capital spending.

On 27 February 2025, the AER amended the ring-fencing guidelines for distribution network service providers to remove the maximum length of waivers and provide the AER with discretion to determine the duration of waivers.¹⁴⁷

¹⁴⁶ The 2015 Power of Choice reforms required the AER to develop the distribution ring-fencing guideline.

¹⁴⁷ AER, [Ring-fencing guideline \(electricity distribution, version 4\)](#), Australian Energy Regulator, 27 February 2025.

Table 3.2 provides a summary of the waivers granted by the AER in the 12-month period to 30 June 2025. In addition, the AER has previously granted waivers – some of which specifically target new and innovative services – for distribution network service providers to install and operate community-scale batteries to further test and trial how locally based storage can benefit consumers.

Table 3.2 Recent AER waiver approvals

Network service provider	Waiver description	Waiver commencement date	Waiver end date
Ergon Energy (Qld)	Allows Ergon Energy to continue to use a similar brand name and branding as Ergon Energy Retail.	27 June 2025	30 June 2035
Ergon Energy (Qld)	Allows Ergon Energy to continue to classify the Mareeba and Charters Towers depots as regional offices for the purposes of ring-fencing.	10 June 2025	30 June 2045
Ergon Energy (Qld)	Allows Ergon Energy to continue to provide connection from its mainland network to Hayman Island via undersea cable.	21 May 2025	30 June 2040
Ergon Energy (Qld)	Allows Ergon Energy to continue to provide other services to and on behalf of transmission network service provider Powerlink (Qld).	2 April 2025	30 June 2040
Ergon Energy (Qld)	Allows Ergon Energy to act as the metering coordinator for 3 communities in regional Queensland.	19 September 2024	31 December 2027
Ergon Energy (Qld)	Allows Ergon Energy to provide generation services in Queensland's isolated networks using behind-the-meter generation assets.	22 August 2024	30 June 2030
Transgrid (NSW)	Allows Transgrid to continue to provide telecommunication services not associated with the transmission network to one customer.	17 April 2025	12 April 2026
AusNet Services (Vic)	Allows AusNet Services to install, own and operate 10 pole-top batteries.	19 November 2024	31 December 2035
Power and Water (NT)	Allows Power and Water to address an inconsistency between the ring-fencing guidelines and the NER (Northern Territory) about the publishing of registers.	1 July 2024	30 June 2034

Note: The waivers listed in Table 3.2 refer to those granted by the AER in the 12-month period to 30 June 2025. As at 30 June 2025, the AER was assessing a number of ongoing ring-fencing waiver applications, including a ring-fencing waiver application by CitiPower (Victoria), Powercor (Victoria) and United Energy (Victoria) to install and maintain kerbside electric vehicle charging infrastructure in their collective distribution areas.

3.9 Revenue

Electricity network businesses collect revenue for providing services to customers. Some services are regulated, while others are provided through competitive markets. These core regulated services include electricity transportation, connections and metering services and represent most of a network service provider's revenue. This report focuses exclusively on revenues collected for providing core regulated services.

For transmission network service providers, 'regulated services' include revenues associated with delivering prescribed transmission services. For distribution network service providers, it includes revenues associated with providing standard control services.¹⁴⁸

All electricity network service providers are regulated under revenue caps. Under this form of control, the AER determines each network service provider's total allowed revenue. Each year, network service providers set their prices to target earning the maximum revenue allowed under the revenue cap.

¹⁴⁸ Regulated services include electricity transportation, connections and metering services and represent most of a network service provider's revenue. For transmission network service providers, 'regulated services' includes revenues associated with delivering prescribed transmission services. For distribution network service providers, it includes revenues associated with providing standard control services.

The AER updates the revenue targets each year to account for actual inflation, changes in network service providers' allowed returns on debt, cost pass-throughs (section 3.9.3) and other factors. Interest rates and inflation are factors outside both network service providers' and the AER's control.¹⁴⁹

3.9.1 Revenue in 2024

Over the 12-month period to 30 June 2024, network service providers earned \$12.7 billion for delivering core regulated services,¹⁵⁰ \$270 million (2.1%) less than in the previous year.

Table 3.3, Figure 3.10 and Figure 3.11 provide a summary of the revenue that network service providers collected for serving customers in 2024 and how it compared with previous years' targets and actuals.

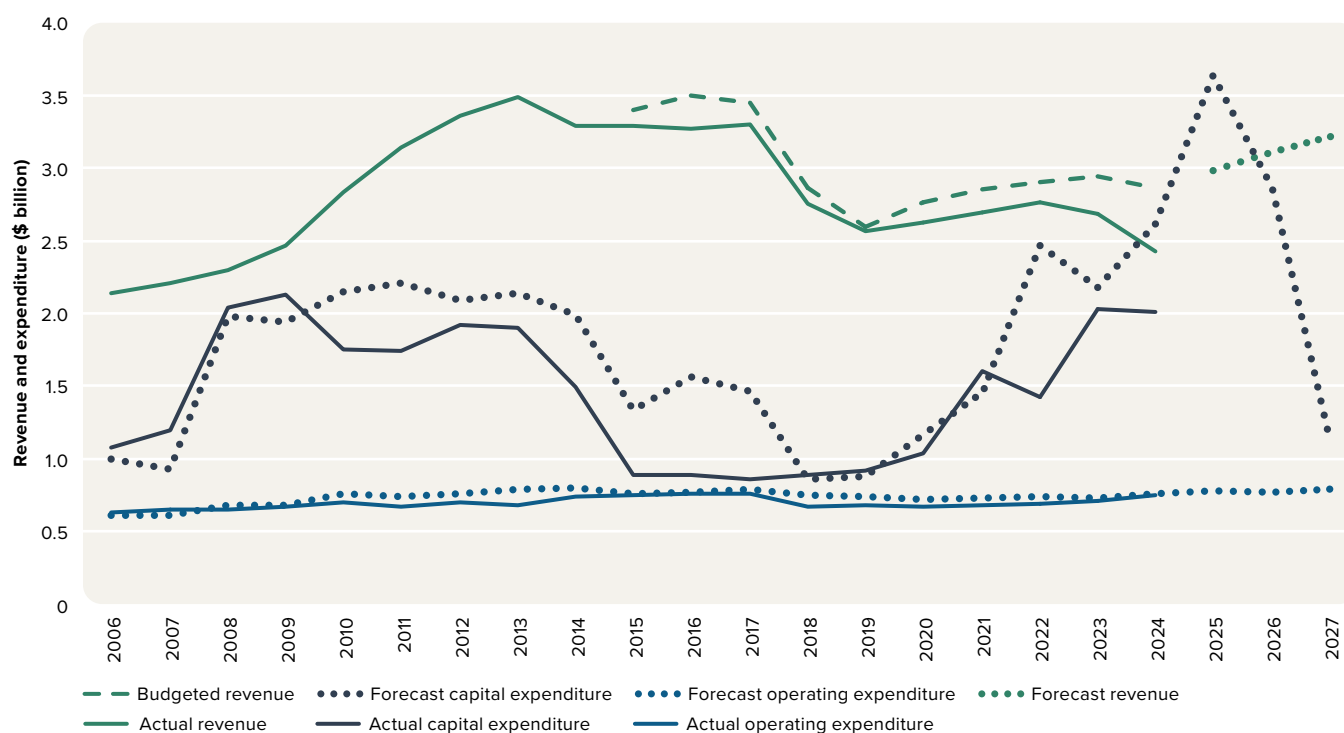
Table 3.3 Revenue in 2024 – key outcomes

Service type	Revenue (actual) (2024)	Revenue (actual) (compared with 2023)	Revenue (actual) (compared with peak)
Transmission	\$2.4 billion	▼\$256 million (▼10%)	▼\$1.1 billion (▼31%) (2013)
Distribution	\$10.3 billion	▼\$14 million (▼0.1%)	▼\$4.9 billion (▼32%) (2015)
Total	\$12.7 billion	▼\$270 million (▼2.1%)	▼\$5.7 billion (▼31%) (2015)

Note: All data are adjusted to June 2024 dollars.

Source: AER estimates.

Figure 3.10 Revenue and key drivers – electricity transmission networks (aggregate)



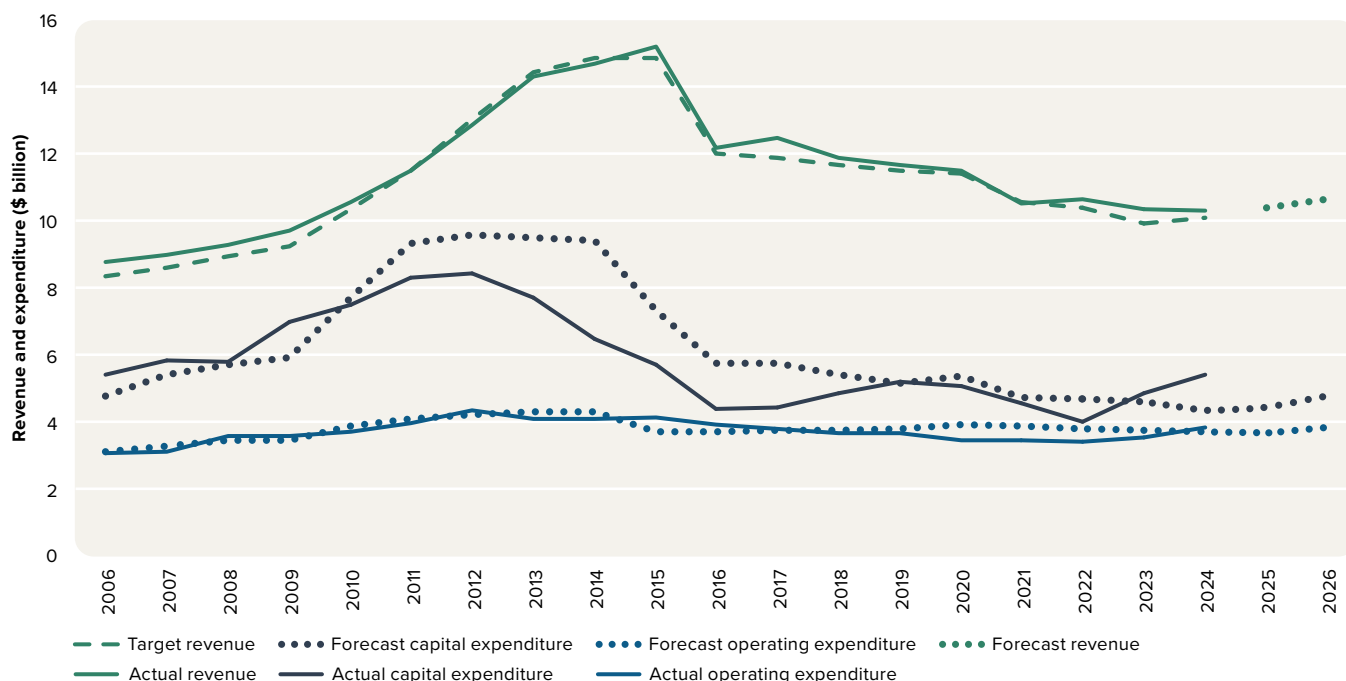
Note: All data are adjusted to June 2024 dollars. Most network service providers report on a 1 July to 30 June basis. The exception is AusNet Services (Victoria), which reports on a 1 April to 31 March basis. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Transmission network service providers earn revenues for delivering prescribed transmission services, some of which comes directly from customers and some from sources such as inter-regional and intra-regional settlements residues or inter-regional settlements auction proceeds. Budgeted revenue reflects the revenues transmission network service providers budgeted to be collected from customers.

Source: Revenue: economic benchmarking RIN responses; capital expenditure: AER modelling, category analysis RIN responses; operating expenditure: AER modelling, economic benchmarking RIN responses.

149 AER, [Rate of return – overview for consumers](#), Australian Energy Regulator, February 2023.

150 Prescribed transmission services for transmission network service providers and standard control services for distribution network service providers.

Figure 3.11 Revenue and key drivers – electricity distribution networks (aggregate)



Note: All data are adjusted to June 2024 dollars. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). The exception is the Victorian networks, which until year end 2020 reported on a 1 January to 31 December basis. Target revenue for the Victorian distribution networks for the 2021 year has been derived from the transitional year (1 January to 30 June 2021). To enable reporting on equivalent terms, these values have been doubled. The adjustments include rewards and penalties from incentive schemes, cost pass-throughs and other factors that are considered in determining the target revenues used to set prices each year.

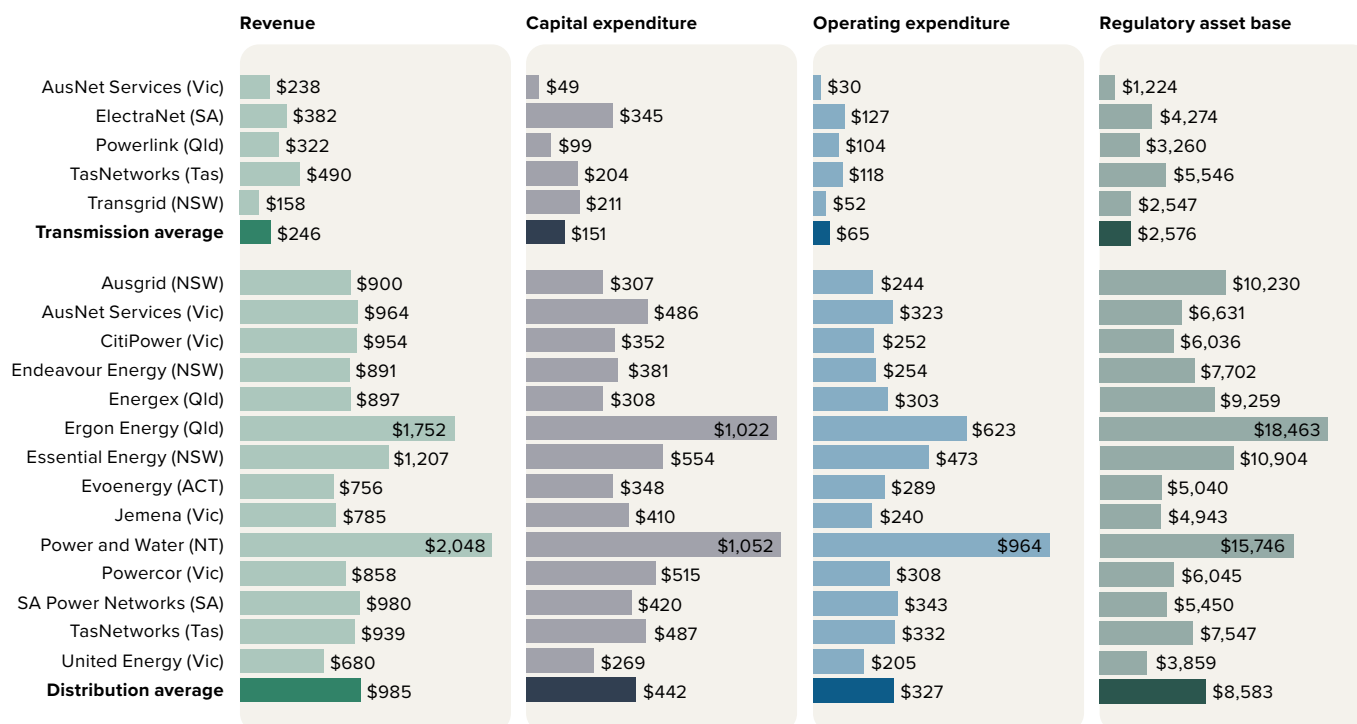
Source: Revenue: economic benchmarking RIN responses; capital expenditure: AER modelling, category analysis RIN responses; operating expenditure: AER modelling, economic benchmarking RIN responses.

When assessing financial indicators for network service providers, it is often more useful to view the outputs on a ‘per customer’ basis. This allows for easier comparison between networks of different sizes and structures. However, multiple factors other than customer numbers – such as line length and terrain – can impact these outputs.

Figure 3.12 summarises key ‘per customer’ financial indicators related to the delivery of core regulated services.¹⁵¹

¹⁵¹ Transmission network service providers do not report customer numbers. Per customer metrics for the transmission networks were calculated using the total number of distribution customers in the relevant jurisdictions.

Figure 3.12 Average per customer metrics – 2020 to 2024 (5 years)



Note: All data are adjusted to June 2024 dollars. In 2024, residential customers (a customer who purchases electricity principally for personal, household or domestic use) accounted for 88% of total customers on the distribution network. While the proportion differed across network service providers – for example, 91% residential for Endeavour Energy (NSW) and 83% for CitiPower (Victoria) – the differences do not materially affect the ‘per customer’ metric. Revenue, capital expenditure and operating expenditure are the annual averages over the 5 years to 30 June 2024. RAB is the actual closing regulatory asset base at 30 June 2024. For regulatory purposes, Northern Territory transmission assets are treated as part of the distribution system.

Source: AER revenue determinations and economic benchmarking RINs.

We note the ‘revenue per customer’ output for Ergon Energy (Queensland) shown in Figure 3.12 does not reflect the amount Ergon Energy’s network customers actually paid. The Queensland Government supports customers in regional Queensland (served by Ergon Energy) by ensuring they pay similar prices for their electricity to customers in South East Queensland (served by Energex). This is done by subsidising – through the Community Service Obligation payment – additional costs involved in supplying electricity to regional Queenslanders through payments to Ergon Energy Retail.¹⁵²

Forecast revenue is translated into a path of ‘X-factors’, which are locked in at the beginning of the regulatory period and updated annually to account for changes in cost of debt. These X-factors – alongside changes in inflation, incentive schemes and other factors – control the change in the maximum revenue that network service providers can recover each year. Under this model, network service providers are incentivised to provide services at the lowest possible cost because their returns are determined by the actual costs of providing services. If network service providers reduce their costs to below the estimate of efficient costs, the cost savings are shared with consumers in future regulatory periods.

152 Queensland Government, [Electricity prices](#), Business Queensland, accessed 5 June 2025.

Table 3.4 provides a summary of the AER's revenue determinations for all electricity network service providers for their respective current regulatory periods.

Table 3.4 AER electricity network revenue determinations – current regulatory periods

Service type	Revenue (forecast)	Capital expenditure (forecast)	Operating expenditure (forecast)
Transmission	\$15.4 billion (▲4%)	\$11.1 billion (▲36%)	\$3.9 billion (▲7%)
Distribution	\$55.7 billion (▲7%)	\$25.0 billion (▲4%)	\$19.2 billion (▲1.8%)
Total	\$66.8 billion (▲7%)	\$36.1 billion (▲12%)	\$23.1 billion (▲2.6%)

Note: The current regulatory period is the period in place at 1 July 2025. All revenue and expenditure data are adjusted to June 2024 dollars. Changes in revenue and expenditure are in relation to forecasts from the previous regulatory periods.

Source: AER estimates.

The key drivers behind increased revenues for most of the network service providers have been changes in the return on capital, regulatory depreciation and operating expenditure building blocks (section 3.5.2).

In the most recent round of regulatory determinations,¹⁵³ the allowed rate of return increased from the rate applied in the previous period due to the increase in interest rates. This created significant upward pressure on network revenue. However, some of the regulatory determinations currently in place were made before 2024, when lower interest rates saw the allowed rate of return decrease from the previous regulatory period, which led to downward pressure on revenue for some network service providers.

In 2019, the AER reviewed how it calculates the cost of corporate tax and made changes to its approach to align with the rulings of the Australian Taxation Office. The impact of the changes generally resulted in the cost of corporate tax for regulatory periods beginning between 2020 and 2024 being lower than it was in the past. In contrast, the network service providers that took part in the most recent round of regulatory determinations saw an increase in the estimated cost of corporate income tax, primarily due to a higher return on equity determined in the current regulatory period (2025–30) compared with the 2020–25 period.

3.9.2 Trends in network revenue

Aggregated revenues for network service providers increased by around 6% per year from 2006 to 2015, when network charges included:

- rapid growth in regulatory asset bases (RABs) caused in part by stricter reliability standards imposed by state governments, which required new investment and increased operating expenditure
- higher costs of capital during the global financial crisis.

These increases were more pronounced in Queensland and NSW than in other jurisdictions. Cost pressures began to ease when demand for electricity from the grid plateaued, causing new investment to be scaled back from 2013. The changing demand outlook coincided with government moves to allow network service providers greater flexibility in meeting reliability requirements. The financial environment also improved after 2012, easing borrowing and equity costs. After peaking at more than 10% between 2009 and 2013, allowed rates of return for some network service providers fell to around 4.9% in 2023 (section 3.12).

Reforms phased in from 2015 also helped offset the increasing network revenues. The reforms, which explicitly linked network costs to efficiency factors, encouraged network service providers to better control their operating costs.

A combination of these factors reduced the revenue needs of network service providers. Decreasing investment and rates of return lowered revenue requirements as network service providers entered a new 5-year regulatory cycle. However, consumers will continue to pay for the relatively high investment in network assets from 2006 to 2013 for the remainder of the economic lives of those assets, which in some cases may be up to 50 years.

¹⁵³ In April 2025, the AER finalised revenue determinations for distribution network service providers Energex (Queensland), Ergon Energy (Queensland) and SA Power Networks (South Australia) and the Directlink interconnector. These determinations set target revenue controls through to 30 June 2030.

Since 2017 network revenues have generally decreased, driven by a 22% reduction in target revenue for the NSW-based networks in the 2015–19 regulatory period, followed by an 11% reduction for the Queensland based networks in the 2016–20 regulatory period.

Consumer groups and some industry observers remain concerned that the regulatory framework enables network service providers to earn excessive profits. In response to calls for greater transparency around the actual returns earned by network service providers, the AER now publishes information on network profitability in an annual network performance report. The AER's network performance report provides detailed analyses of key operational and financial trends as well as key profitability measures.¹⁵⁴ The network performance report provides key insights to enable stakeholders to make more informed assessments of the returns earned by each network service provider.

Operating, maintenance and other costs are relatively stable in comparison to the investment in capital projects. While operating expenditure has always been lower than capital expenditure, the contrast between the 2 has fluctuated over time. From 2009 to 2013, expenditure on capital projects was more than twice that of operating costs. However, by 2016 capital (53%) and operating (47%) expenditure had almost reached parity due to weakening investment (section 3.14).

3.9.3 Pass-through events

The AER is responsible for assessing cost pass-through applications, in which a network service provider may apply to recover additional costs incurred during a regulatory period. The application is assessed against a list of predefined events that are specified in either the National Electricity Rules or in the network service provider's revenue determination.

Table 3.5 summarises the cost pass-through applications approved by the AER in the 12-month period to 30 June 2025.¹⁵⁵ The number of cost pass-through applications assessed by the AER in recent years has grown, largely due to more frequent severe natural disaster events causing damage to network assets, as well as the accelerating pace of regulatory change associated with the energy transition.

Table 3.5 Cost pass-throughs

Network service provider	Pass-through event	AER approved (\$ nominal)	Recovery period
Powerlink (Qld)	Network support	\$0.9 million	2025–26
Energex (Qld)	Natural disaster (storm)	\$11.5 million	2025–27
Ergon Energy (Qld)	Natural disaster (storm)	\$24.6 million	2025–27
Ergon Energy (Qld)	Natural disaster (storm)	\$15.3 million	2025–27
AusNet Services (Vic)	Easement land tax	\$61.3 million	2025–26
AusNet Services (Vic)	Natural disaster (storm)	\$12.9 million	2025–27
AusNet Services (Vic)	Natural disaster (storm)	\$30.1 million	2025–28
AusNet Services (Vic)	Victorian Emergency Backstop Mechanism (VEBM)	\$17.2 million	2025–26
Jemena (Vic)	Victorian Emergency Backstop Mechanism (VEBM)	\$8.3 million	2025–28
Powercor (Vic)	Victorian Emergency Backstop Mechanism (VEBM)	\$11.5 million	2025–26
United Energy (Vic)	Victorian Emergency Backstop Mechanism (VEBM)	\$6.5 million	2025–26
ElectraNet (SA)	Network support	–\$7.2 million	2025–26
TasNetworks (Tas)	Network support	\$0.4 million	2025–26

Note: Approved under clauses 6.6.1, 6A.7.2, 6A.7.3 or 11.6.21 of the National Electricity Rules.

Source: AER, [Cost pass throughs](#).

¹⁵⁴ AER, [Networks performance reporting](#), Australian Energy Regulator, accessed 13 July 2025.

¹⁵⁵ AER, [Cost pass throughs](#), Australian Energy Regulator, accessed 4 July 2025.

3.10 Network charges and retail bills

Electricity network charges made up as much as 46% of a residential customer's electricity bill in 2024 (Figure 6.2 in chapter 6). Distribution network services accounted for most of the costs (63% to 92%), with transmission network service costs (up to 27%), jurisdictional scheme costs¹⁵⁶ (up to 15%) and metering costs (up to 8%) making up the balance.

A customer's electricity bill reflects the combined costs of all the electricity supply chain components – wholesale electricity generation, transmission and distribution network costs, metering and jurisdictional scheme costs, and retail costs. The estimated impact of the AER's current revenue determinations on residential customer bills represents the impact of the network costs (defined as prescribed (transmission) services and standard (distribution) control services) components of the bill.

The AER's revenue determinations for the current regulatory periods are estimated to increase residential electricity bills by an average of 0.7% per year across all states and territories (Figure 3.13). The estimated bill impact is based on average annual electricity usage for a residential customer. As such, customers with different usage will experience different changes in their bills. In the past, the most significant changes to network charges generally arose in the first year of a regulatory period. However, in the most recent revenue determinations, the most significant changes (increases) often occur later in the period. For example, residential customers on Energex's (Queensland) and Ergon Energy's (Queensland) distribution networks have been allocated an estimated 3.2% increase in the fourth year of the current regulatory period, compared with an estimated average 2.2% increase per year over the whole period.

The AER's revenue determinations for the current regulatory periods are estimated to increase residential electricity bills by an average of 0.7% per year across all states and territories.

To minimise price shocks, network revenues are smoothed across the regulatory period. Revenue smoothing involves reallocating some of the forecast costs to adjacent years within the regulatory period to minimise the potential of large revenue variances at the start of the following regulatory period.

Distribution network service providers submit annual pricing proposals to the AER, outlining proposed prices to take effect in the following year. These proposed prices must be consistent with the service provider's approved revenues but can account for additional costs associated with transmission and jurisdictional schemes.

The transition from a network service providers' initial revenue proposal to the AER's final determination, which happens over a 15-month period, is illustrated in Figure 3.13. In the most recent round of revenue determinations, the AER approved higher revenues than were indicated in the draft decisions. This was primarily driven by a lower-than-expected inflation rate, which increases the value of regulatory depreciation and a higher rate of return, increasing the return on capital.

Among other factors, the annual process updates prices for changes in the consumer price index (CPI). Over the 12 months to December 2024, applying to network prices over 2025–26, CPI increased by 2.4%. In May 2025, the Reserve Bank of Australia announced that inflation had eased and was now within its target range (2–3%). While the unemployment rate was low, the global outlook had worsened and was more unpredictable than usual.¹⁵⁷

¹⁵⁶ Jurisdictional scheme costs are costs related to jurisdictional regulatory obligations that are passed through to customers by distribution network service providers. These schemes generally relate to historical premium feed-in tariff schemes, as well as emerging renewable energy zones, such as the NSW Electricity Infrastructure Roadmap.

¹⁵⁷ RBA, [Statement of Monetary Policy](#), Reserve Bank of Australia, May 2025.

Figure 3.13 Impact of AER revenue determinations on residential customer electricity bills



Note: Estimated impact of latest AER determination on the network component of a residential electricity bill based on AER estimates of retail electricity prices and typical residential consumption in each network. Revenue impacts are nominal and averaged over the life of the current determination. Annual change amounts and percentages are indicative. They are derived by varying the network component of the estimated bill amount in the final year of the previous regulatory period in proportion to yearly expected revenue divided by AEMO's forecast electricity delivered on the transmission network and forecast electricity for distribution as submitted by the relevant distribution network service provider. Actual bill impacts will vary depending on electricity consumption and tariff class. The data account only for changes in network charges, not changes in other bill components. Outcomes will vary among customers, depending on electricity use and network tariff structures.

Source: AER revenue determinations; additional AER modelling.

3.11 Regulatory asset base

The regulatory asset base (RAB) represents the total economic value of the assets that provide network services to customers.¹⁵⁸ The value of the RAB substantially impacts a network service provider's revenue requirement and the total cost a customer ultimately pays. Given some network assets have a life of up to 50 years, network investment will impact electricity bills long after the investment is made.

Network service providers receive a guaranteed return on their RAB. For this reason, they have an incentive to overinvest if their allowed rate of return exceeds their actual financing costs. Previous versions of the National Electricity Rules enabled significant overinvestment in network assets, which partly drove the sharp rise in network revenue from 2006 to 2015 (section 3.9). Under reforms introduced in 2015, the AER may remove inefficient investment from a network service provider's RAB if the service provider overspent its capital allowance, to ensure customers do not pay for it.

The AER may remove inefficient investment from a network service provider's RAB if the service provider overspent its capital allowance, to ensure customers do not pay for it.

As part of the revenue determination process, the AER forecasts a network service provider's efficient investment requirement over the forthcoming regulatory period. Efficient investment approved by the AER is added to the RAB on which the network service provider earns returns, while depreciation on existing assets is deducted. As such, the value of a network service provider's asset base will grow over time if approved new investment exceeds depreciation. The RAB is adjusted at the end of the regulatory period to reflect actual investment.

Escalating investment inflated the value of the total electricity network RAB from \$65.8 billion in 2006 to \$109.4 billion in 2013 – an increase of around 8% per year. Since then, network investment has steadied, as has the growth in the value of the total network RAB. Since 2014, the value of the total network RAB has continued to grow but at a considerably slower rate of around 1% per year.

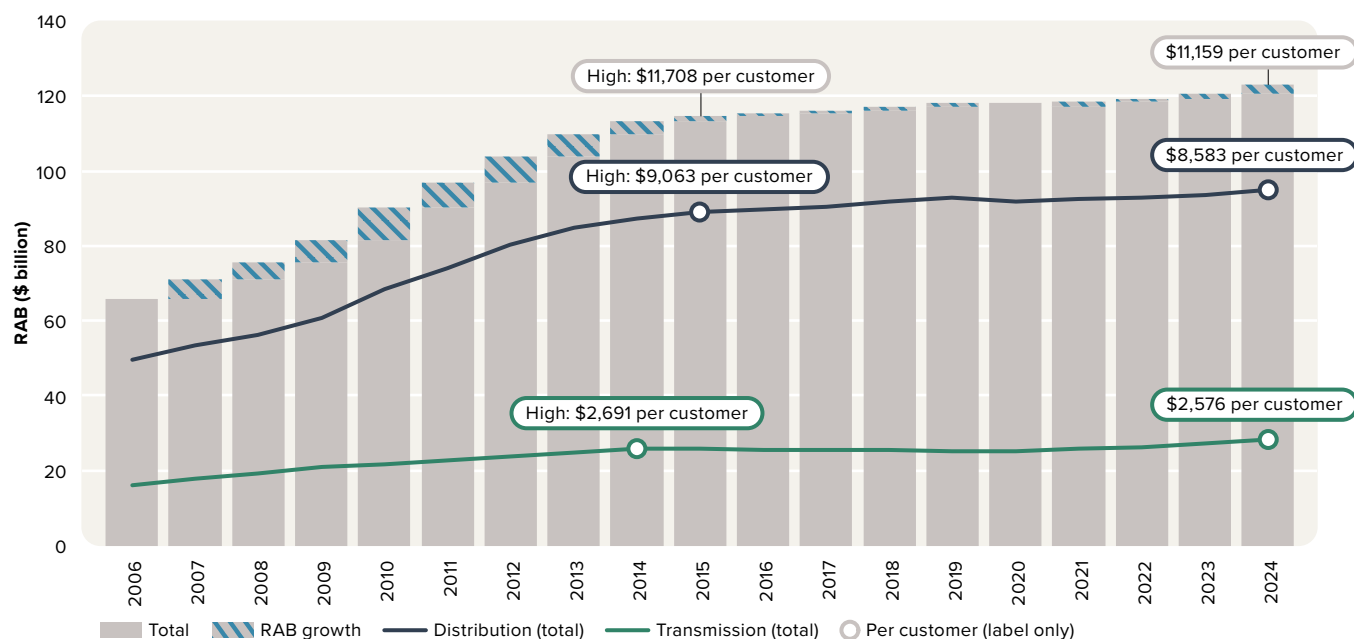
3.11.1 Regulatory asset base in 2024

As at 30 June 2024, the aggregated value of the RABs for the electricity networks regulated by the AER was around \$123.2 billion, an increase of \$2.4 billion (2%) from the previous year (Figure 3.14).¹⁵⁹ This comprises 7 transmission networks valued at \$28.3 billion and 14 distribution networks valued at \$94.9 billion.

¹⁵⁸ To the extent that they are used to provide such services.

¹⁵⁹ RABs capture the total economic value of assets that are providing network services to customers. These assets have been accumulated over time and are at various stages of their economic lives.

Figure 3.14 Value of electricity network assets (regulatory asset base)



Note: All data are adjusted to June 2024 dollars. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). This figure includes the RAB values for the Directlink and Murraylink transmission interconnectors. The Directlink and Murraylink RABs are immaterial and have not been used in the 'per transmission customer' calculation.

Source: AER modelling; economic benchmarking RIN responses.

Recent RAB growth has been most pronounced for the Transgrid (NSW) and ElectraNet (South Australia) transmission service providers. Several major capital project investments in the previous period (2018–23) – Project EnergyConnect, HumeLink, Queensland–NSW Interconnector and Victoria–NSW Interconnector Minor – have driven the increase in Transgrid’s RAB. Current period investment in these projects has already been scrutinised through contingent project assessments.¹⁶⁰

Transgrid’s RAB growth is expected to slow over the current regulatory period (2023–28). However, it is possible that investment projects, such as those relating to AEMO’s ISP (section 3.13.6) and triggered contingent projects, could significantly increase Transgrid’s RAB over the period.¹⁶¹

For ElectraNet (South Australia), large ISP-driven projects – including Project EnergyConnect and the Main Grid System Strength project – were added to regulated revenue during the previous regulatory period (2018–23). As these new assets are added to ElectraNet’s RAB, the return on that capital investment will continue to be a significant contributor to the increase in ElectraNet’s revenue and tariffs over the current (2023–28) regulatory period.

Increases in the value of the RABs of Australia’s electricity grid are expected to continue as more major transmission network projects enter development. These projects are necessary to enable the reliable supply of low carbon energy as part of Australia’s energy transition (section 3.13.6).

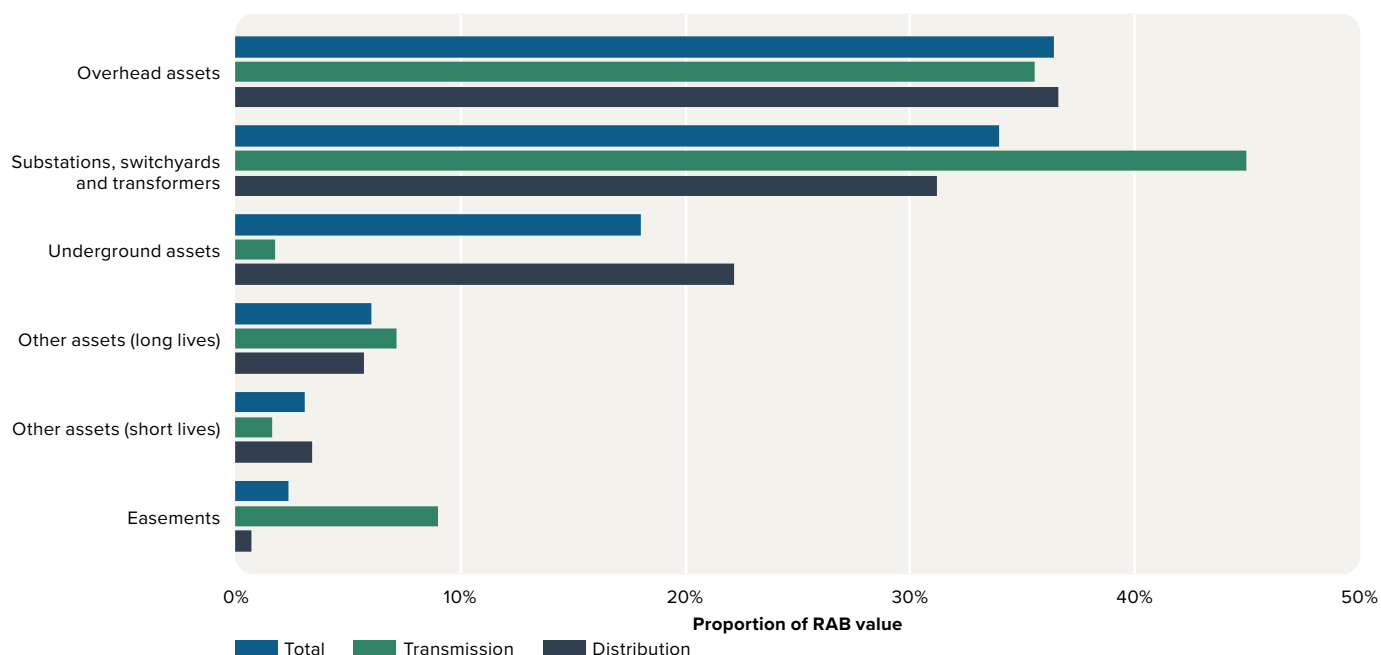
3.11.2 Overhead support structures

A network service provider’s RAB is made up of many assets, which can be broken down into several categories. Overhead network assets represent the most observable component of electricity network infrastructure and account for the greatest proportion (around 36%) of the total aggregated network RAB. This is not surprising given the combined transmission and distribution networks include more than 800,000 kilometres of line, 84% of which is above ground (Figure 3.15).

¹⁶⁰ The AER is required by the National Electricity Rules (NER) to assess applications by network service providers to amend their regulatory revenue determination to include the revenue required for a contingent project. Contingent projects are major network infrastructure assets that have been flagged in long-term investment plans. When a network service provider has met the requirements to request cost recovery from consumers for one of these projects, it submits a contingent project application to the AER for approval. The AER then undertakes a rigorous assessment process to ensure that consumers pay no more than is needed to build the new infrastructure.

¹⁶¹ For example, the AER has approved 5 contingent projects with a combined value of \$365 million.

Figure 3.15 Disaggregated value of electricity network assets (regulatory asset base)



Source: Economic benchmarking RIN responses.

Network service providers install transmission towers and distribution poles to support overhead powerlines. Transmission towers are predominately made of steel, whereas distribution poles are made of wood, concrete, steel or composites like fibreglass. The differing environmental conditions faced by each network service provider can influence their choice of material. For example, in some parts of Australia, wooden poles are more quickly destroyed by termites, so metal poles are used instead. In its 2024–29 draft determination, the AER acknowledged Essential Energy’s (NSW) proposed use of composite poles (made from resin and fibreglass) to replace wooden poles as part of its ‘at-risk’ poles program.¹⁶²

Stobie poles – which are unique to South Australia – consist of 2 perpendicular lengths of steel-channel section held apart by bolts and the intervening space is filled with concrete, which protects the steel from corrosion. The poles – which were patented more than a century ago – came about as an engineering solution to South Australia’s lack of tall, termite-resistant hardwood for poles to carry powerlines and telephone wires.¹⁶³ SA Power Networks manufactures about 4,500 Stobie poles every year, which are used to replace poles when they have reached the end of their working life or when new overhead powerlines are being installed.¹⁶⁴

SA Power Networks’ distribution network consists of more than 70,000 kilometres of overhead powerlines.¹⁶⁵ However, overhead network assets only make up around 19% of the value of SA Power Networks’ RAB. This relatively low proportion of overhead assets in SA Power Networks’ RAB is uncommon among network service providers, especially given the extensive size of the network service area.

Because of the hard-wearing and near-indestructible nature of the poles used in South Australia, the average pole in SA Power Networks’ distribution network is considerably older than those found in any other network. Due to the relative age of the poles, a significant proportion of SA Power Networks’ overhead assets are no longer included in the RAB. This unique feature makes SA Power Networks somewhat of an anomaly in the NEM and has the impact of providing cost savings for its current customers.

¹⁶² AER, [Draft decision – Attachment 5 – Capital expenditure – Essential Energy 2024 to 2029](#), Australian Energy Regulator, September 2023.

¹⁶³ P Sumerling and W Prest, [Stobie Poles](#), SA History Hub, History Trust of South Australia, accessed 13 July 2025.

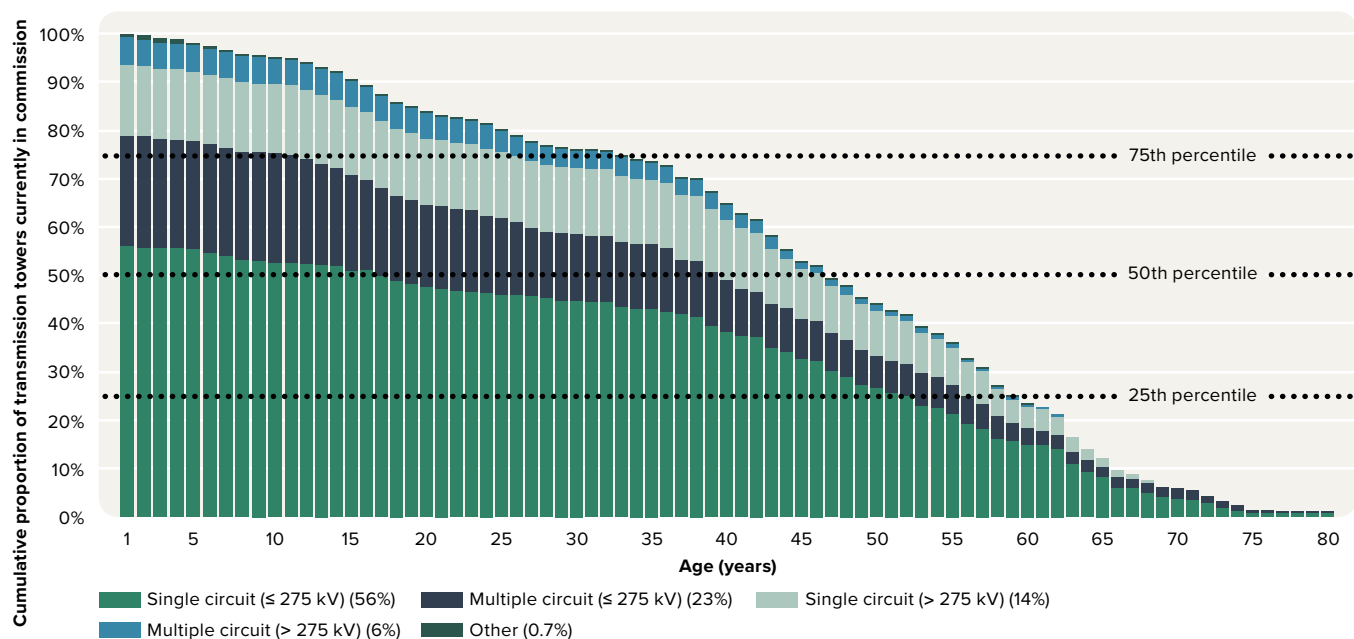
¹⁶⁴ ABC News, [Stobie poles are a South Australian icon, but how did they come about?](#), 31 March 2023, accessed 13 July 2025.

¹⁶⁵ Third only to Essential Energy (NSW) with 182,708 kilometres and Ergon Energy (Queensland) with 144,583 kilometres.

Some service providers, such as Essential Energy (NSW) and Ergon Energy (Queensland), operate larger, rural distribution networks that are almost entirely above ground. Conversely, CitiPower (Victoria) and Evoenergy (ACT) operate smaller, urban distribution networks that are predominately underground. Unsurprisingly, predominately rural networks are more reliant on overhead poles than the networks operating in more urban environments.

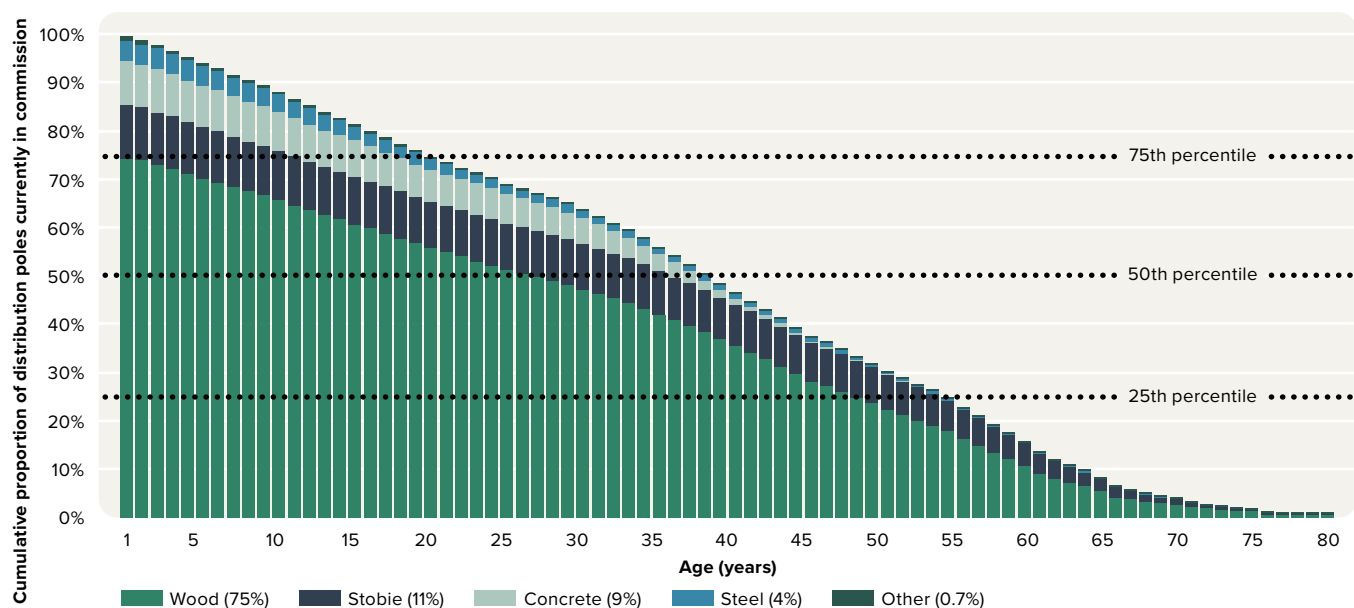
The asset age profiles shown in Figure 3.16 and Figure 3.17 provide an overview of the age of the towers and poles currently in commission across the collective electricity networks. However, we note the asset age, and the types of towers and poles, vary considerably between each network.

Figure 3.16 Overhead support structures – electricity transmission network towers



Note: kV: kilovolt.
Source: Category analysis RIN responses.

Figure 3.17 Overhead support structures – electricity distribution network poles



Note: Stobie poles, used almost exclusively in South Australia, are made up of 2 vertical steel posts with a slab of concrete between them.
Source: Category analysis RIN responses.

In May 2024, transmission network Transgrid (NSW) expressed that it aims to use as many Australian-made products as possible when constructing new transmission lines. However, due to considerable constraints on the availability of locally produced products, Transgrid has been forced to purchase equipment from overseas after it used up most of the existing capacity in Australia.

The increase in demand for the materials needed to construct energy infrastructure has been driven by the rollout of thousands of kilometres of new transmission lines to cater for the transition away from coal-fired energy.¹⁶⁶

In May 2025, AEMO published its *Draft 2025 Electricity Network Options Report*¹⁶⁷ to gather feedback on the electricity network options to inform the development of the 2026 ISP (section 3.13.6). In the report, AEMO states that transmission costs have risen, particularly for overhead lines, and that the Australian energy sector continues to be subject to ongoing supply chain issues associated with the delivery of materials and equipment, as well as workforce and skills shortages.

3.12 Rates of return

The shareholders and lenders that finance a network service provider expect a return on their investment. The rate of return estimates the financial returns that a network service provider's financiers require to justify investing in the business. It is a weighted average of the expected returns needed to attract equity and debt funding. Equity funding is provided by shareholders in exchange for part ownership of a network service provider, while debt funding is provided by an external lender such as a bank. Given this weighting approach, the rate of return is sometimes called the weighted average cost of capital (WACC).

The AER sets an allowed rate of return based on a benchmark efficient entity, but a network service provider's actual returns can vary from the allowed rate. The difference can be due to several factors, such as the impact of incentive schemes, efficiency improvements, forecasting errors or the network service provider adopting a different debt or tax structure to the benchmark efficient entity. Some differences may be temporary if caused by revenue over- or under-recovery under a revenue cap or the revenue smoothing process. The AER calculates allowed returns each year by multiplying the RAB (section 3.11) by the allowed rate of return.¹⁶⁸

If the AER sets the allowed rate of return too low, network service providers may not be able to attract sufficient funds to invest in the assets needed for a reliable power supply. Conversely, if the rate is set too high, service providers have a greater incentive to overinvest.

Because electricity networks are capital intensive, returns to investors currently make up around 49% (53% for transmission, 48% for distribution) of a network service provider's total revenue allowance. As such, a small change in the allowed rate of return can have a significant impact on both a network service provider's revenue and customers' electricity bills.

As an estimate, a one percentage point increase in the allowed WACC will increase revenues by around 8%, which would increase average household bills by around 4%.¹⁶⁹ For this reason, before limited merits review was abolished and the binding rate of return instrument was introduced, the allowed rate of return was often the most contentious part of the AER's individual revenue determinations.

Conditions in financial markets are a key determinant of the allowed rate of return. The AER's revenue determinations from 2009 to 2012 took place against a backdrop of the global financial crisis, an uncertain period associated with reduced liquidity in debt markets and high-risk perceptions. In revenue determinations made during this period the allowed rate of return was greater than 10%, reflecting the conditions in financial markets at the time. The Australian Competition Tribunal increased some allowed rates of return following appeals by network service providers.

166 Herald Sun, [Buying local has limitations, says Transgrid chief](#), 8 May 2024 (purchased article).

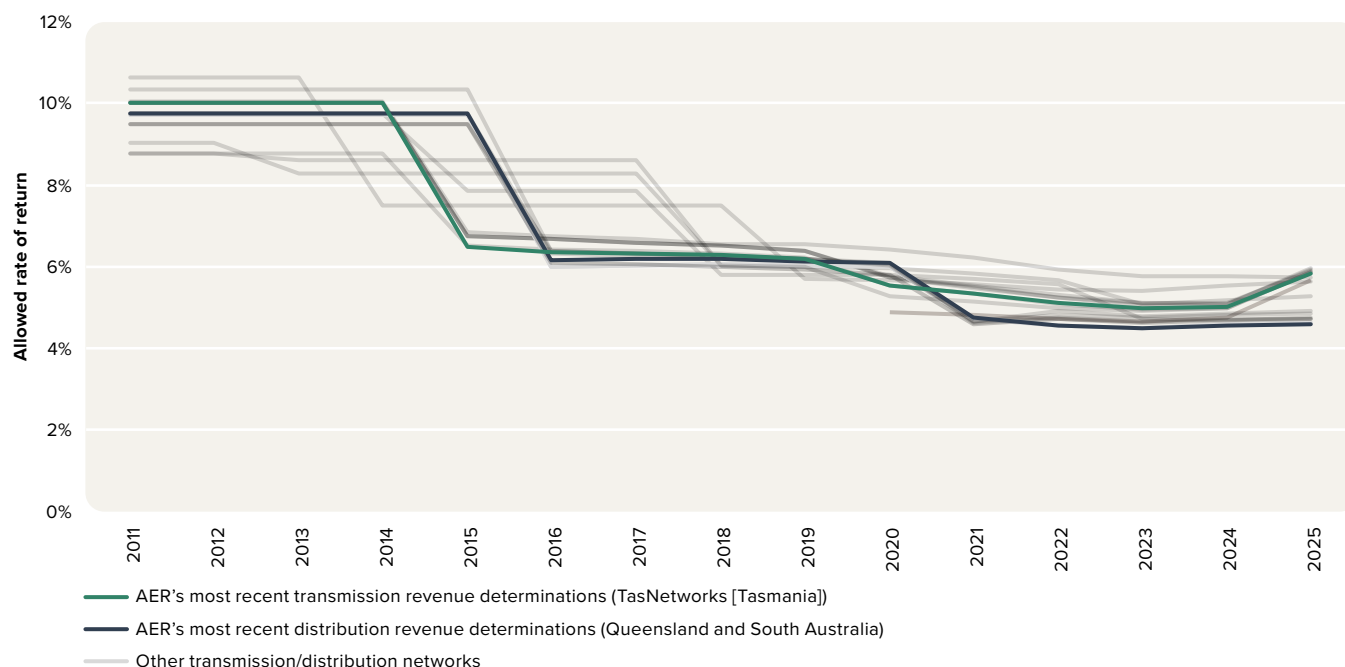
167 AEMO, [Draft 2025 electricity network options report](#), Australian Energy Market Operator, 22 May 2025, accessed 28 May 2025.

168 For example, if the rate of return is 5% and the RAB is \$50 billion, then the return to investors is \$2.5 billion. This return forms part of a network's revenue needs and must be paid for by energy customers.

169 Average household bill calculation assumes \$2,000 average household bill, 50% network component (transmission plus distribution) and ignores demand impacts.

Since 2015 the AER has updated the allowed rate of return annually to reflect changes in debt costs. More stable financial market conditions resulted in allowed rates of return averaging around 6% from 2016. These lower allowed rates became a key driver of lower network revenues and charges over the past few years (Figure 3.18).

Figure 3.18 Allowed rate of return



Note: Allowed rate of return is the nominal vanilla weighted average cost of capital (WACC).

Source: AER determinations on electricity network revenue proposals; AER determinations following remittals by the Australian Competition Tribunal or full Federal Court.

Recently, a key input into rates of return has increased. The risk-free rate is an important driver of allowed returns on equity and is estimated using required returns on Commonwealth Government Securities (CGSs), also known as Australian Government bonds. Since January 2020, annual yields on 10-year CGSs have ranged from 0.61% (March 2020) to 4.94% (November 2023). Over the 12-month period to 30 June 2025, annual yields on 10-year CGSs averaged around 4.29%.¹⁷⁰ If the risk-free rate continues to increase it will put upward pressure on network revenue over coming years.

In recent years the AER has estimated network service providers' actual returns to provide a comparison against their allowed returns. The outcomes suggest that actual returns often exceed the AER's allowed returns. This is not unexpected given that the premise of a revealed efficient cost framework is to encourage network service providers to become more efficient, allowing for short-term profits to be earned above the allowed rate.¹⁷¹

In March 2024, the 2022 Rate of Return Instrument was superseded by 'version 1.2'. This updated version binds all regulatory determinations from 25 February 2023 until the next revision of the Instrument.¹⁷² In March 2025, as a first step toward making the 2026 Rate of Return Instrument, the AER published a paper setting out the high-level review process it will undertake to produce the Instrument.¹⁷³

¹⁷⁰ RBA, [Capital Market Yields – Government Bonds – Daily – F2](#), Reserve Bank of Australia, accessed 6 July 2025.

¹⁷¹ The AER's [Electricity network performance reports](#) investigate network profitability and provide a more thorough analysis of actual returns than allowed/forecast returns.

¹⁷² AER, [Rate of Return Instrument 2022](#), Australian Energy Regulator, accessed 13 July 2025.

¹⁷³ AER, [Rate of Return Instrument – 2026 review process paper](#), Australian Energy Regulator, 28 March 2025.

3.13 Capital expenditure

Network service providers invest in capital equipment such as towers, poles, wires and other infrastructure needed to transport electricity to consumers. Investment drivers vary among networks and depend on each network's age and technology, load characteristics, the demand for new connections, and reliability and safety requirements. Substantial investment is needed to replace aging equipment as it wears out or becomes technically obsolete. Other investments may be made to augment (expand) a network's capability in response to changes in electricity demand.

3.13.1 Capital expenditure in 2024

Over the 12-month period to 30 June 2024, network service providers invested \$7.4 billion in capital projects, \$545 million (8%) more than in the previous year and \$455 million (7%) more than was forecast.

Table 3.6 provides a summary of the capital expenditure outlaid in 2024 and how this compared with previous years' expenditure and forecasts.

Table 3.6 Capital expenditure in 2024 – key outcomes

Service type	Capital expenditure (2024)	Capital expenditure (compared with 2023)	Capital expenditure (compared with peak)
Transmission	\$2.0 billion (▼23% than forecast)	▼\$11 million (▼0.5%)	▼\$113 million (▼5%) (2009)
Distribution	\$5.4 billion (▲24% than forecast)	▲\$556 million (▲11%)	▼\$3.0 billion (▼36%) (2012)
Total	\$7.4 billion (▲7% than forecast)	▲\$545 million (▲8%)	▼\$2.9 billion (▼28%) (2012)

Note: All data are adjusted to June 2024 dollars. Excludes AER determinations on transmission interconnectors. Numbers may not sum due to rounding.

Source: AER modelling; RIN responses.

Forecast capital expenditure increased for Transgrid (NSW) in 2024 primarily due to the forecast costs associated with Project EnergyConnect. Transgrid's actual capital expenditure from 2022 to 2024 was significantly lower than forecast due in large part to its reprofiling of expenditure on Project EnergyConnect (Figure 3.19).

In January 2025, Transgrid revised the net cost of Project EnergyConnect from \$2.1 billion to \$3.6 billion. It attributed the increase to several 'unforeseeable factors such as COVID-related global supply chain impacts on key equipment and materials, critical labour shortages, record inflation, the impacts of the war in Ukraine, flooding and the insolvency of [construction group] Clough'.¹⁷⁴

Investment in the transmission network is forecast to continue over the next few years. Although the estimated cost of actionable ISP projects under the 2024 ISP is around \$27.8 billion¹⁷⁵ (Figure 3.24), most of this estimated cost does not yet fall within the AER's approved forecast expenditure window. Further, AEMO has indicated that since the publication of its 2024 ISP, costs have risen by 25% to 55% for overhead transmission line projects and 10% to 35% for transmission substation projects.¹⁷⁶

HumeLink, a proposed 500 kilovolt transmission line that will connect Wagga Wagga, Bannaby and Maragle and expand Transgrid's transmission network in NSW, was identified as a staged actionable ISP project in AEMO's 2020¹⁷⁷ and 2022¹⁷⁸ ISPs and was confirmed to be actionable in AEMO's 2024 ISP.¹⁷⁹

In 2022 and 2023, the AER made determinations on Transgrid's HumeLink stage 1 contingent project application, which related to early works or preconstruction activities. These activities included project design, stakeholder engagement, land-use planning and approvals and acquisition, project management and procurement of long lead equipment. This allowed Transgrid to lock in prices, secure supply-chain availability for necessary equipment and refine its construction cost estimate for stage 2 of the project.

¹⁷⁴ Transgrid, [EnergyConnect update](#), media release, 8 January 2025.

¹⁷⁵ AEMO, [2024 Integrated System Plan](#), Australian Energy Market Operator, June 2024, pp. 61–63.

¹⁷⁶ AEMO, [Draft 2025 electricity network options report](#), Australian Energy Market Operator, 22 May 2025, accessed 28 May 2025.

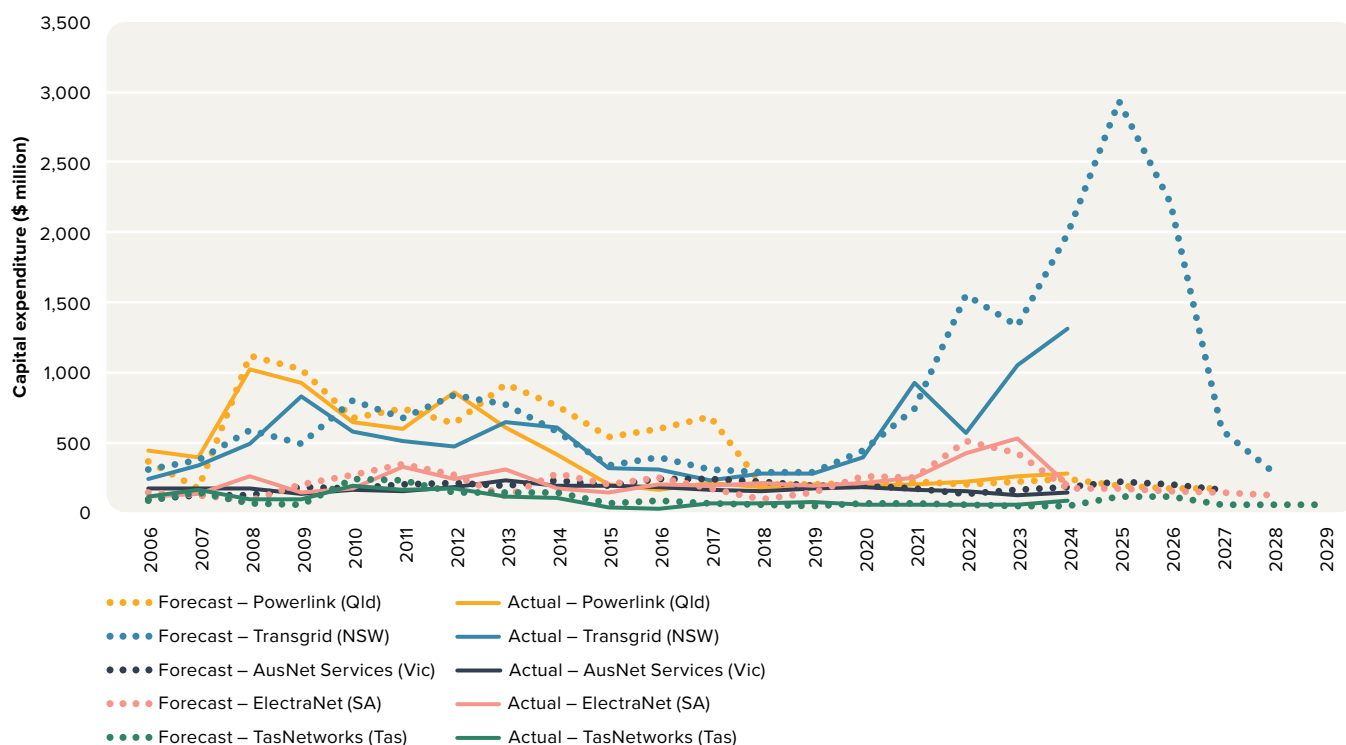
¹⁷⁷ AEMO, [2020 Integrated System Plan](#), Australian Energy Market Operator, July 2020.

¹⁷⁸ AEMO, [2022 Integrated System Plan](#), Australian Energy Market Operator, June 2022.

¹⁷⁹ AER, [Transgrid HumeLink contingent project stage 2](#), Australian Energy Regulator, 2 August 2024.

In August 2024, the AER approved \$4.0 billion (\$2023) in forecast capital expenditure for stage 2 of Transgrid's HumeLink project. The AER's role in the process was to assess Transgrid's contingent project application to determine the incremental revenues that are to be added to its revenue allowance. The AER did not accept Transgrid's proposed expenditure of \$4.3 billion (\$2023) because it did not consider the proposed amount reflected prudent and efficient capital expenditure required to deliver the project. Subject to a financial investment decision by the proponent, HumeLink is likely to be completed by 2026–27.

Figure 3.19 Capital expenditure – electricity transmission networks



Note: All data are adjusted to June 2024 dollars. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Assumptions are set out in the Figure 3.10 notes.

Source: AER modelling; annual reporting RIN responses.

3.13.2 Trends in capital expenditure

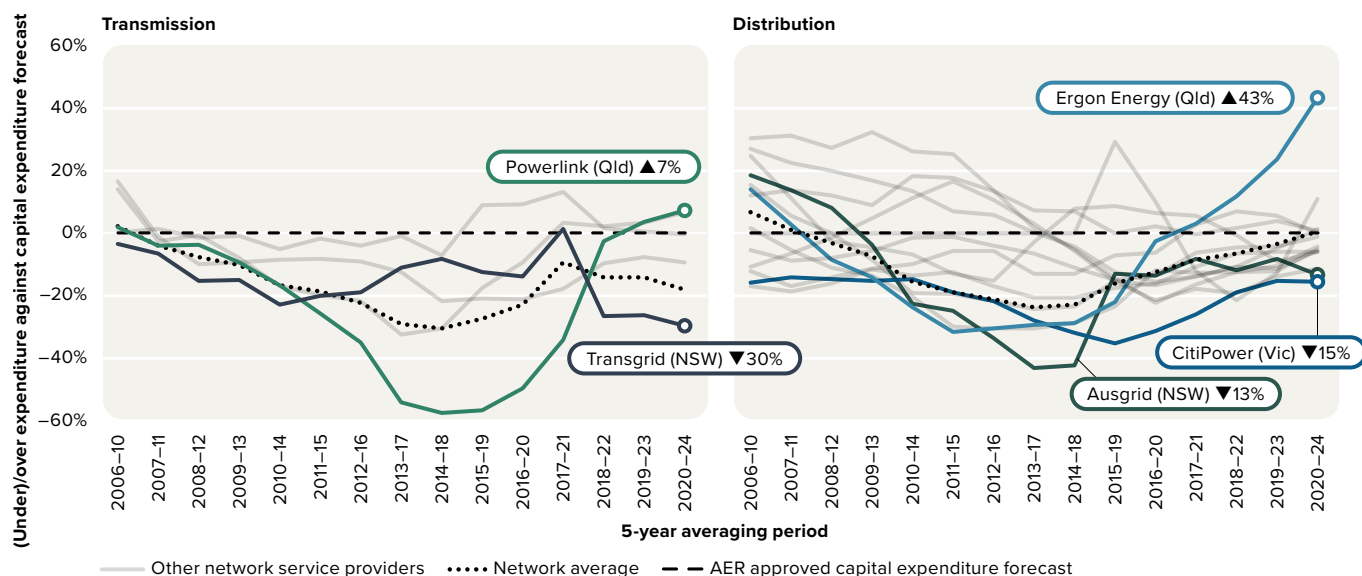
In 2006, governments and the AEMC changed the rules to incentivise greater investment to address concerns that network investment was not keeping pace with projected growth in electricity demand. More stringent reliability standards imposed by the NSW and Queensland governments also contributed to further growth by requiring new investment to meet the stricter targets.

Investment in electricity networks increased by an average of 8% per year in the 6-year period from 2006 before peaking at around \$10.4 billion in 2012 (Figure 3.10 and Figure 3.11).

Over the 4-year period from 2006 to 2009, network service providers invested \$2.8 billion (10%) more on capital projects than was forecast. However, the trend of overspending was soon to be reversed, with network service providers underspending by \$17.5 billion (16%) against forecast over the following 13 years (from 2010 to 2022). Over this time, many investment projects were either postponed or abandoned when it became clear that earlier projections of sustained demand growth would not eventuate. Further, a shift in government policy towards less stringent reliability obligations made some projects redundant, leading to several proposed projects being scaled back or deferred.

The disparity between forecast and actual investment has eased in recent years.¹⁸⁰ The timing of this change in behaviour aligns with the AER's reforms to protect consumers from funding inefficient network projects (Figure 3.20).

Figure 3.20 Capital expenditure against AER approved forecast



Note: All data are adjusted to June 2024 dollars.

Source: AER modelling; annual reporting RIN responses.

The AER assesses capital expenditure drivers when forming its view on the reasonableness of a network service provider's capital expenditure forecast. The AER does not determine which capital programs or projects a network service provider should or should not undertake. Once the AER sets a capital expenditure forecast, it is up to the network service provider to prioritise its investment program. However, all network service providers are required to undertake a cost-benefit analysis for new investment projects that meet specific cost thresholds.

In the AER's most recent revenue determinations,¹⁸¹ the most significant driver of forecast investment expenditure was the replacement of assets that are reaching the end of their life, along with infrastructure that supports the delivery of electricity transmission services.

In 2015 the AER introduced the capital expenditure sharing scheme (CESS), which offers financial incentives for network service providers to avoid undertaking investment above forecast levels (Box 3.3).

¹⁸⁰ Transmission network service provider Transgrid's (NSW) actual capital expenditure in 2022 was significantly lower than forecast due in large part to its reprofiling of expenditure on Project EnergyConnect.

¹⁸¹ In April 2025, the AER finalised revenue determinations for distribution network service providers Energex (Queensland), Ergon Energy (Queensland) and SA Power Networks (South Australia) and the Directlink interconnector. These determinations set target revenue controls through to 30 June 2030.

Box 3.3 Capital expenditure sharing scheme

Our capital expenditure sharing scheme (CESS) incentivises network service providers to keep new investment within the forecast levels approved in regulatory determinations. The CESS rewards efficiency savings (spending below forecast) and penalises efficiency losses (spending above forecast).

In its current form, the CESS allows a network service provider to retain underspending against forecast for the duration of the applicable regulatory period (which may be up to 5 years, depending on when the spending occurs). In the subsequent regulatory period, the network service provider must pass on 70% of underspends to its customers as lower network charges. The service provider retains the remaining 30% of the efficiency savings.

After the regulatory period has concluded, we conduct an ex-post review of the network service provider's spending. Approved capital expenditure is added to the regulatory asset base (RAB) (section 3.11). However, if a service provider overspends against its capital allowance, and we find the overspending was inefficient, the excess spending may not be added to the RAB. Instead, the service provider bears the cost by taking a cut in profits. This condition protects consumers from funding inefficient expenditure.

Following our 2023 review of incentive schemes,¹⁸² we elected to amend the CESS and implement the Bright-Line Tiered Test to apply:

- a 30% sharing ratio for any underspend up to 10% of the forecast capital expenditure allowance in the previous regulatory period
- a 20% sharing ratio for any underspend that exceeds 10% of the forecast capital expenditure allowance in the previous regulatory period
- a 30% sharing ratio for any overspend of the forecast capital expenditure allowance in the previous regulatory period.

The Bright-Line Tiered Test approach is designed to be asymmetric. Despite improvements in our capital expenditure assessment toolkit and stakeholder engagement, a level of information asymmetry remains between the regulator, consumers and the network service providers. The scheme poses risks that network service providers may inflate their original investment forecasts. To manage this risk, we assess whether proposed investments are efficient at the time of each revenue determination. Another risk is that the scheme may incentivise a network service provider to earn bonuses by deferring critical investment needed to maintain network safety and reliability.

To manage this risk, the CESS is balanced by separate incentives that focus on efficient operating expenditure (Box 3.4) and service quality (Box 3.5). This balancing of schemes encourages network service providers to make efficient decisions on their mix of expenditure to provide reliable services in ways that customers value (section 3.16.1).

For large transmission investments, we will consider whether the CESS is fit for purpose on a case-by-case basis.

The changes to the CESS are supplemented by transparency measures that will require network service providers to better explain the reasons for variations between operating and capital expenditure outcomes and forecasts. This will in turn assist stakeholders to better understand the extent to which genuine efficiency gains have driven expenditure outcomes, and the value of incentive payments.

In February 2025, we published a consultation paper on proposed amendments to the CESS Guideline.

The consultation paper initiated our review of the Guideline to accommodate the AEMC's amended rule on managing ISP project uncertainty through targeted ex-post reviews published in August 2024. This requires us to update our Guideline to enable us to carry out separate targeted ex-post review for ISP projects and non-ISP projects.¹⁸³ Our draft amendments to the CESS Guideline were published on 16 May 2025.¹⁸⁴

¹⁸² AER, [Review of incentive schemes for regulated networks](#), Australian Energy Regulator, April 2023, accessed 13 July 2025.

¹⁸³ AER, [Consultation opens on the Capital Expenditure Incentive Guideline amendments](#), Australian Energy Regulator, 21 February 2025.

¹⁸⁴ AER, [Capital Expenditure Guideline Review 2025](#), Australian Energy Regulator, 16 May 2025.

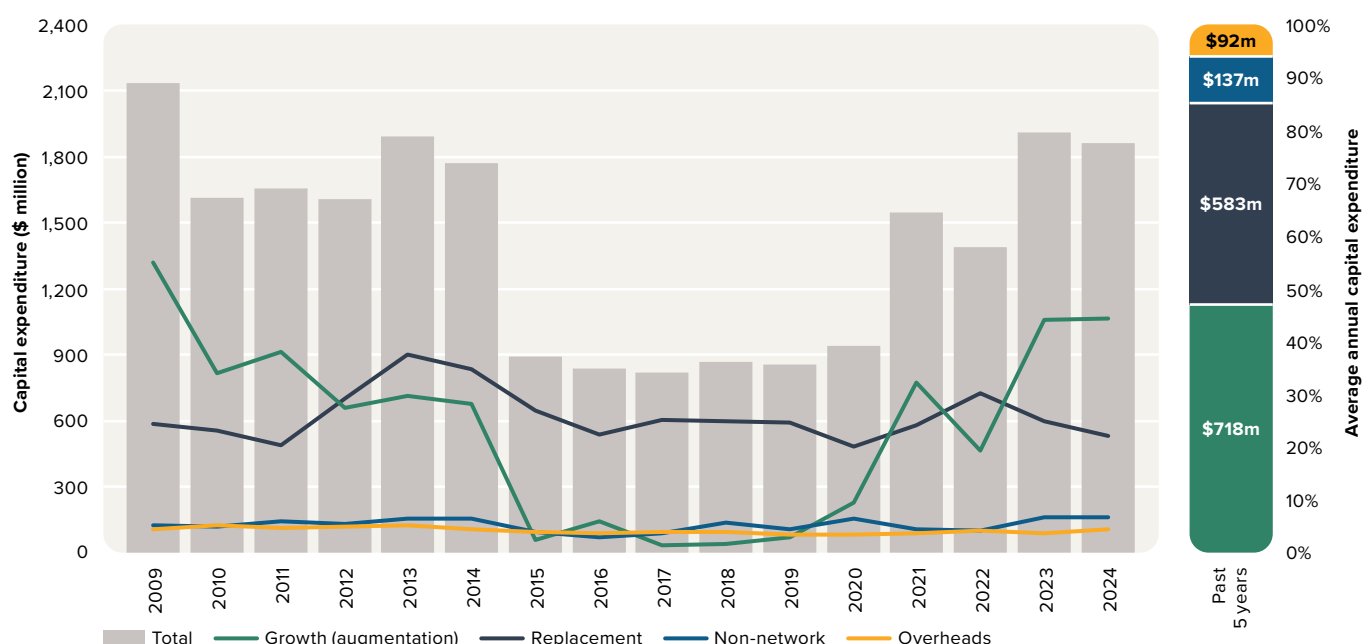
3.13.3 Changing composition of investment

Over the 12-month period to 30 June 2024, network service providers invested \$2.8 billion on replacing existing infrastructure on their respective networks (Figure 3.21 and Figure 3.22).

Over the same period, network service providers spent \$1.9 billion on growth-related projects, \$215 million (10%) less than in the previous year but still more than any other year since 2014. The recent increase in growth-related expenditure has been driven by Transgrid's (NSW) substantial investment in Project EnergyConnect.

Transgrid has also forecast substantial investment in developing HumeLink (section 3.13.1), which, among other roles, aims to connect Snowy 2.0 to the grid by 2026. In May 2024, Snowy Hydro stated that despite 'challenging' conditions the project is on schedule and is expected to be operational by December 2028.¹⁸⁵

Figure 3.21 Drivers of capital expenditure – electricity transmission networks (aggregate)

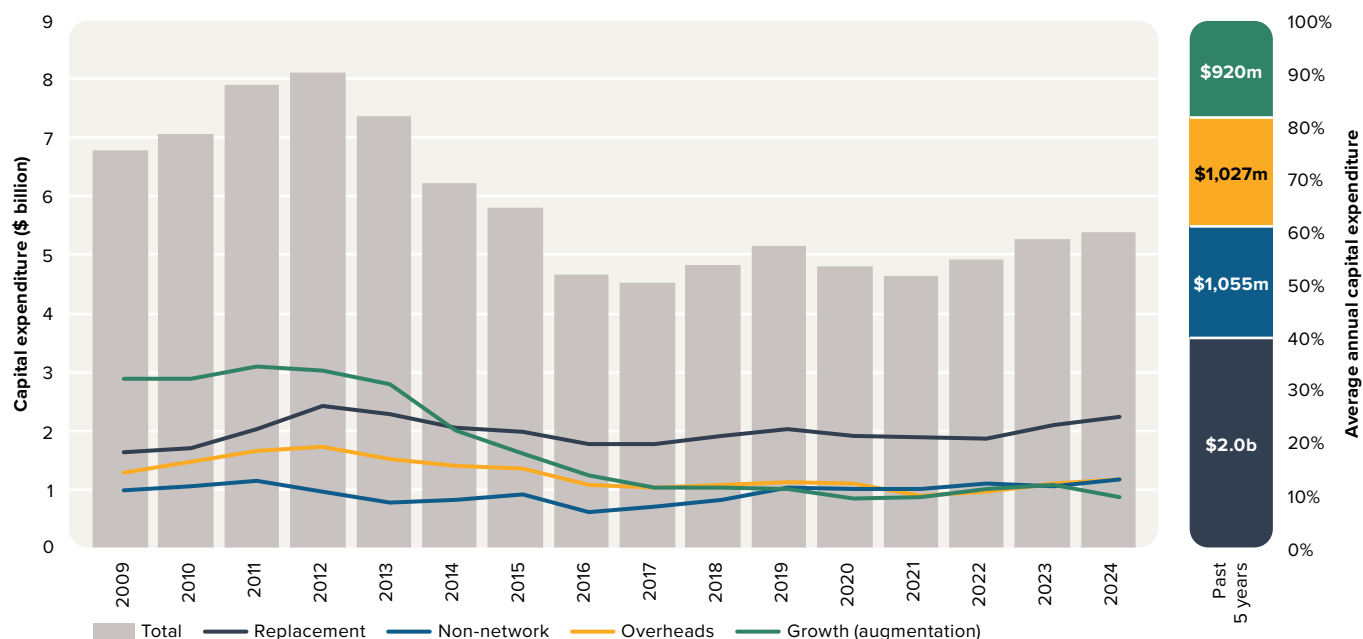


Note: All data are adjusted to June 2024 dollars. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Augmentation of the Victorian transmission network is carried out by AEMO; hence, AusNet Services reports \$0 expenditure for augmentation carried out on the transmission network.

Source: Category analysis RIN responses.

185 ABC News, [Snowy Hydro boss doubles down on project timeline despite slow progress and budget blow-out](#), 9 May 2024, accessed 8 August 2024.

Figure 3.22 Drivers of capital expenditure – electricity distribution networks (aggregate)



Note: All data are adjusted to June 2024 dollars. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: Category analysis RIN responses.

3.13.4 Valuing consumer energy resources

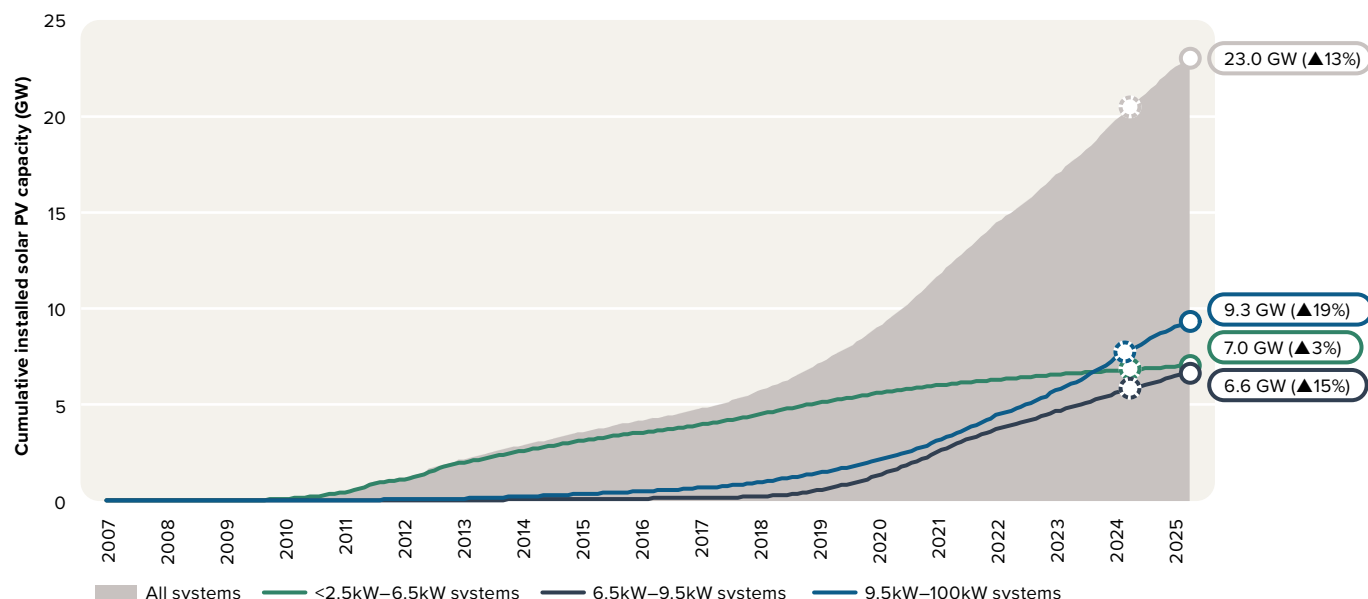
AEMO's 2024 ISP notes that effective integration of consumer energy resources has the potential to significantly reduce future grid-scale investment needed to support increases in electricity consumption. For example, recent analysis by the Institute for Energy Economics and Financial Analysis indicates that consumer energy resources (across the full range of possible sources) have the potential to deliver \$11 billion in avoided network costs if well integrated.¹⁸⁶

The uptake of rooftop solar photovoltaic (PV) systems has grown exponentially over the past decade. As a result of this rapid growth, integration of consumer energy resources such as solar PV, batteries and electric vehicles now presents a significant, emerging area of network expenditure.

As at 1 March 2025, the total installed capacity of small-scale solar PV systems – systems with a capacity of up to 100 kilowatts measured around 23 gigawatts, a 13% increase from the previous year (Figure 3.23).

186 Australian Government, [National consumer energy resources roadmap – Powering decarbonised homes and communities](#), Department of Climate Change, Energy, the Environment and Water, 19 July 2024, accessed 13 July 2025, p. 9.

Figure 3.23 Cumulative installation of small-scale solar



Note: GW: gigawatt. kW: kilowatt. PV: photovoltaic. Includes installations of PV systems up to 100 kW in size. Data covers all jurisdictions in Australia except Western Australia.

Source: AER analysis of postcode data from the Australian PV Institute, collected on 19 June 2025.

In November 2019, the AER began developing guidance around assessing proposed expenditure for integrating consumer energy resources. As part of this process, the AER sought stakeholder views on the current and predicted effects consumer energy resources are having on electricity networks and whether its current set of expenditure assessment tools are fit for purpose.

In 2020, the AER released a report (by the CSIRO and CutlerMerz) on potential methodologies for determining the value of consumer energy resources.¹⁸⁷ The preferred methodology compares the total electricity system costs from increasing hosting capacity with the total electricity system costs of not doing so. Electricity system costs include the investment costs, operational costs and costs on the system from environmental outcomes of large-scale generation, essential system services, network assets and consumer energy resources installed by customers. The findings and recommendations of the report were reviewed and considered as part of the AER's draft consumer energy resources integration expenditure guidance note published in July 2021.¹⁸⁸

The uptake of rooftop solar PV systems has grown exponentially over the past decade. As a result of this rapid growth, integration of consumer energy resources such as solar PV, batteries and electric vehicles now presents a significant, emerging area of network expenditure.

187 CSIRO and CutlerMerz, [Value of distributed energy resources: methodology study – final report](#), October 2020. The labels 'consumer energy resources' and 'distributed energy resources' are used interchangeably.

188 AER, [Draft DER integration expenditure guidance note](#), Australian Energy Regulator, 6 July 2021.

An environment that consists of increasing levels of consumer energy resources means that distribution network service providers need to alter aspects of their operation – facilitating electricity flows in multiple directions and enabling efficient access to markets for consumer energy resources so that they can provide the greatest benefits to the system as a whole.¹⁸⁹ In April 2023, the AER released its consumer energy resources strategy, which communicates the regulators goal of enabling consumers to own and use energy resources to consume, store and trade energy as they choose in support of the broader long-term interest of all energy consumers.¹⁹⁰

AEMO, in its 2024 ISP, stated that ‘renewable energy connected by transmission and distribution, firmed with storage and backed up by gas-powered generation is the lowest-cost way to supply electricity to homes and businesses as Australia transitions to a net zero economy’.¹⁹¹ New transmission networks and more modern distribution networks are needed to connect these diverse low-cost resources to homes, businesses and industry. Transmission networks will continue to transport electricity to where it is needed, when it is needed, and improve the power system’s resilience. Modernised distribution networks then facilitate the flow of electricity in multiple directions, delivering electricity to homes and businesses and taking back any surplus from consumers’ own assets, thereby enabling efficient access to markets for consumer energy resources and providing benefits to the system as a whole.

This is a monumental change from the traditional role of distribution networks, wherein the assets have been traditionally used to distribute energy received from transmission networks to end users. The transition to a modernised distribution network is already underway. In 2024, more than 14 million megawatt hours (10%)¹⁹² of the total energy delivered came from export customers with smart meters.¹⁹³

3.13.5 Regulatory tests for efficient investment

The AER assesses network service providers’ efficient investment requirements every 5 years as part of the regulatory process, but it does not approve individual projects. Instead, it administers a cost-benefit test called the regulatory investment test (RIT). The National Electricity Rules require a network service provider to apply the RIT for transmission projects that have an estimated capital cost of greater than \$8 million and for distribution projects that have an estimated capital cost of greater than \$7 million.¹⁹⁴

There are separate tests for transmission networks (RIT-T) and distribution networks (RIT-D). The AER publishes guidelines on how to apply the tests and monitors network service providers’ compliance with the tests. The AER also resolves disputes over whether a network service provider has properly applied a test. Civil penalties including fines apply to service providers that do not comply with some of the RIT requirements (including the required consultation procedures).

A network service provider must evaluate credible alternatives to network investment (such as generation investment or demand-side response) that may address the identified need at lower cost. The network service provider must select the option that delivers the highest net economic benefit, considering any relevant legislative obligations. This assessment requires public consultation.

189 AEMC, [Electricity network economic regulatory framework 2020 review](#), Australian Energy Market Commission, 1 October 2020.

190 AER, [Consumer energy resources strategy](#), Australian Energy Regulator, 3 April 2023.

191 AEMO, [2024 Integrated System Plan](#), Australian Energy Market Operator, June 2024, p. 55.

192 Data only captures energy exporting customers with smart meters. As 25% of exporting customers do not have smart meters, both the ‘14 million megawatt hours’ and ‘10%’ of the total energy delivered understate the true volume and proportion of energy exported by network customers.

193 AER, [Insights into Australia’s growing two-way energy system – Export services network performance report 2024](#), Australian Energy Regulator, 18 December 2024.

194 AER, [2024 cost thresholds review for the regulatory investment test – Final determination](#), Australian Energy Regulator, 12 November 2024.

In 2020, the AER published guidelines that prescribe the cost-benefit analysis framework, consultation processes and forecasting practices that AEMO must apply when developing its ISP. AEMO's 2022 ISP brought into effect the AER's guidelines to make the ISP actionable.¹⁹⁵ The guidelines include a cost benefit analysis guideline,¹⁹⁶ a forecasting best practice guideline and updates to the regulatory investment test for transmission (RIT-T) instrument¹⁹⁷ and application guidelines.¹⁹⁸ The guidelines are part of broader reforms that were led by the Energy Security Board,¹⁹⁹ with changes made to the National Electricity Rules to streamline the transmission planning process while retaining rigorous cost-benefit analyses.

In November 2024, the AER amended the cost benefit analysis guidelines, the RIT instruments and accompanying application guidelines to account for recent changes to the National Electricity Rules and changes raised in the AER's *Directions paper – Social licence for electricity transmission projects*. The amendments provide additional guidance on:

- valuing changes in Australia's greenhouse gas emissions as a class of market benefit
- enhanced community engagement by RIT-T proponents
- treatment of concessional finance benefits
- treatment of costs associated with early works that are undertaken concurrently with a RIT-T for an actionable ISP project
- timing and bases for ISP feedback loop assessments by AEMO in relation to final RIT-Ts for actionable ISP projects.

In January 2024, the AER published a report detailing the outcomes of its transparency review of AEMO's Draft 2024 ISP.²⁰⁰ The AER assessed the adequacy of AEMO's explanation of how key inputs and assumptions had been derived and how those inputs and assumptions contributed to the outcomes in the Draft 2024 ISP. The review was not intended to assess the merits of AEMO decisions; rather, it is to form an opinion on the adequacy of AEMO's explanations.

The AER identified some issues that required AEMO to provide further explanation in an addendum to the Draft 2024 ISP and to consult on these issues in the Final 2024 ISP. Transparency in understanding AEMO's approach is important because it promotes stakeholder understanding of key inputs and assumptions that impact the ISP, which in turn promotes confidence in the ISP itself.

3.13.6 AEMO's Integrated System Plan

AEMO's ISP provides a coordinated whole-of-system plan for efficient development of the power system in the NEM to ensure needs are met in the long-term interests of consumers. Through its ISP, AEMO identifies the transmission network options (or equivalent non-network solutions) that are most likely to optimise net market benefits through the electricity system's transition to a lower carbon future.

The 2024 ISP appeals for urgent investment in generation, storage and transmission to deliver secure, reliable and affordable electricity through the energy transition. The ISP's optimal development path sets out the needed generation, firming and transmission to transition to net zero by 2050 through current policy settings. The optimal development path includes 'actionable projects', which should be delivered urgently, and 'future ISP projects', which may require transmission network service providers to undertake preparatory activities. It also states that distribution networks will play a major role in the transition by hosting consumer energy resources and some utility-scale renewable and storage projects – facilitating coordinated two-way flow of electricity between grids.²⁰¹

195 AER, [Final decision – guidelines to make the Integrated System Plan actionable](#), Australian Energy Regulator, August 2020.

196 AER, [Cost benefit analysis guidelines](#), Australian Energy Regulator, August 2020.

197 AER, [Application guidelines – regulatory investment test for transmission](#), Australian Energy Regulator, August 2020.

198 AER, [Guidelines to make the integrated system plan actionable](#), Australian Energy Regulator, August 2020, accessed 29 March 2022.

199 The Energy Security Board has since been dissolved. Since 1 July 2023, the Energy Advisory Panel co-ordinates market body advice to governments on security, reliability and affordability of Australia's east coast energy system.

200 AER, [Transparency review of AEMO draft 2024 Integrated Systems Plan](#), Australian Energy Regulator, accessed 9 August 2024.

201 AEMO, [2024 Integrated System Plan](#), Australian Energy Market Operator, June 2024.

Significant investment in the transmission network is forecast over the next decade. The modelled cost of actionable ISP projects under the 2024 ISP is around \$27.8 billion²⁰² (Figure 3.24). However, AEMO has since indicated that transmission costs have risen by as much as 55% for overhead transmission line projects and 35% for transmission substation projects compared with the modelled costs used in the 2024 ISP.²⁰³ Transmission network service providers and other jurisdictional planning bodies have advised AEMO that the recently observed cost increases in tendering processes and project delivery are primarily driven by:

- sustained supply chain pressures on materials, equipment and workforce
- market competition driven by a high number of concurrent projects under development in the NEM
- project complexity, including an increased number of projects planned for remote areas
- social licence and additional community and landholder engagement along proposed transmission line routes
- additional contracting costs to account for risk allocation in engineering, procurement and construction contracts in response to pressures in the current market.

When preparing the 2026 ISP, AEMO will revisit transmission network projects previously identified as needing to proceed, with the exception of projects that have advanced to anticipated or committed status.

In December 2024, in response to a request from the Minister for Climate Change and Energy,²⁰⁴ the AEMC made rule changes requiring AEMO to consider how distribution network investments impact the development of consumer energy resources and other distributed resources, as well as the impact that both have on the optimal development path identified in the ISP.²⁰⁵

The ISP will now include greater consideration of the broad range of demand-side factors that influence the identification of the optimal development pathway, including the uptake and orchestration of consumer energy resources and distributed resources, demand flexibility, electrification and energy efficiency. The ISP will also provide more insight into AEMO's assumptions about distribution network development opportunities, where these are consistent with the efficient development of the power system.

The ISP will now include greater consideration of the broad range of demand-side factors that influence the identification of the optimal development pathway, including the uptake and orchestration of consumer energy resources and distributed resources, demand flexibility, electrification and energy efficiency.

The AER provides oversight of the ISP by ensuring that AEMO's processes are robust, credible and transparent. The requirements and considerations that are expected of AEMO's forecasting processes are specified in the AER's forecasting best practice guidelines²⁰⁶ and cost benefit analysis guidelines.²⁰⁷ The guidelines seek to provide AEMO with flexibility in how it identifies the optimal pathway for the NEM when developing the ISP based on a quantitative assessment of the costs and benefits of various options across a range of scenarios. The guidelines also apply to RIT-Ts for actionable ISP projects.²⁰⁸

202 2023 dollars (\$2023).

203 AEMO, [Draft 2025 electricity network options report](#), Australian Energy Market Operator, 22 May 2025, accessed 28 May 2025.

204 Australian Government, [Rule change request](#), Department of Climate Change, Energy, the Environment and Water, May 2024, accessed 2 June 2025.

205 AEMC, [Improving consideration of demand-side factors in the ISP](#), Australian Energy Market Commission, 19 December 2024, accessed 2 June 2025.

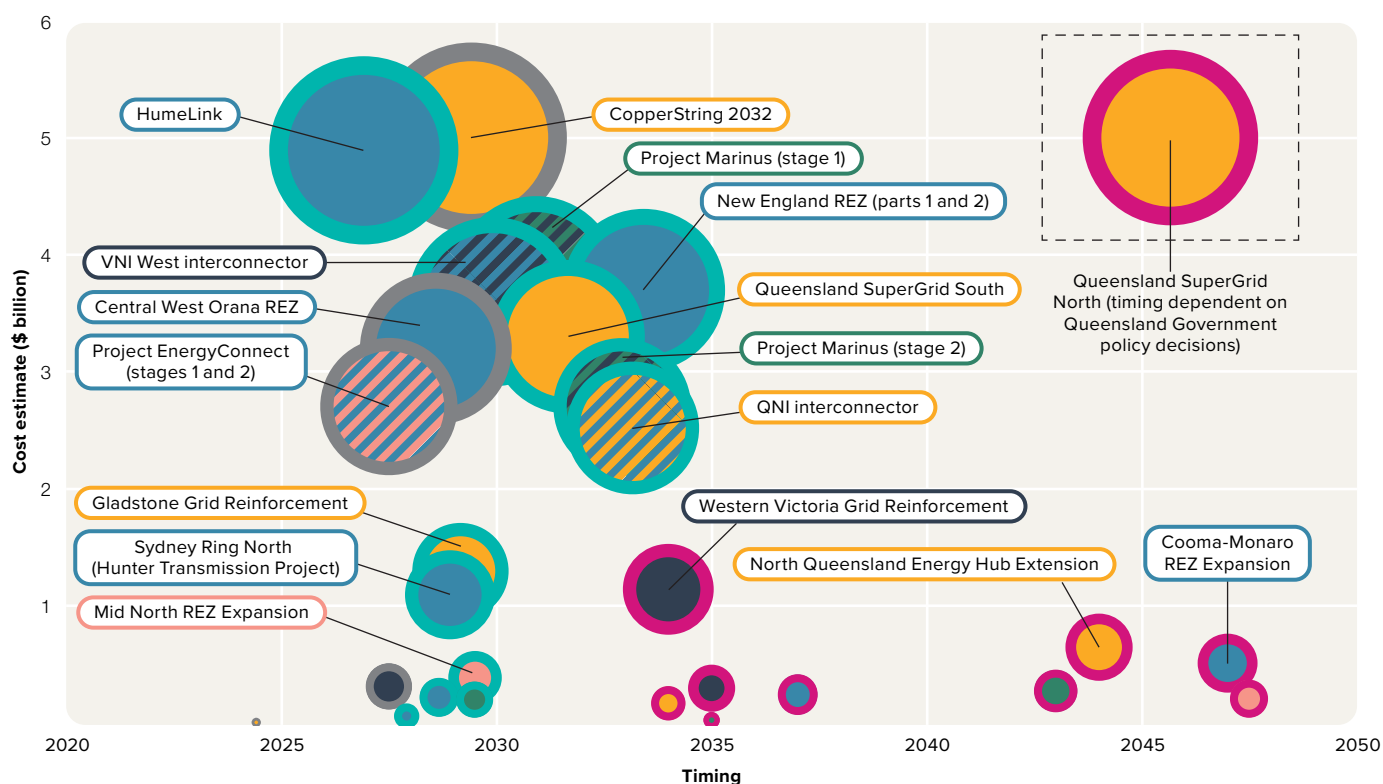
206 AER, [Forecasting best practice guidelines](#), Australian Energy Regulator, August 2020.

207 AER, [Cost benefit analysis guidelines](#), Australian Energy Regulator, August 2020.

208 Actionable ISP projects are identified in an ISP and trigger RIT-T applications for these projects. Under the RIT-T Instrument, RIT-T proponents must identify the credible option that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the market.

The distinction between ISP and non-ISP projects was introduced to avoid duplication of project assessments where analysis has already occurred in developing the ISP. The current transmission planning framework will remain largely unchanged for non-ISP projects, such as asset replacements.

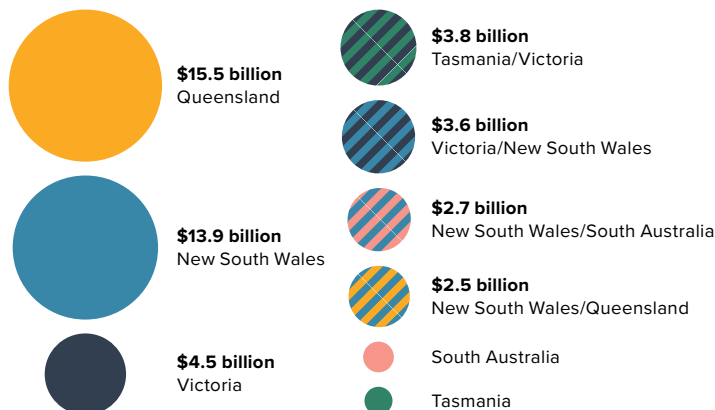
Figure 3.24 AEMO's 2024 Integrated System Plan



Project status



Jurisdiction



Note: The size of the bubble reflects the estimated costs, **not** the estimated construction time for each project.

Note: All data are adjusted to 2023 dollars unless otherwise stated. The ISP cost estimates in Figure 3.24 were published almost 12 months prior to AEMO's [Draft 2025 electricity network options report \(May 2025\)](#) wherein the costs are estimated to be approximately 25% to 55% higher for overhead transmission line projects and 10% to 35% higher for transmission substation projects (section 3.11.2).

Source: AER analysis; AEMO Integrated System Plan, June 2024.

3.13.7 Regulatory investment tests – recent activity

As at August 2025, several RIT-T processes were ongoing across the transmission networks. This section highlights major developments among actionable ISP projects.

Victoria to NSW Interconnector West (VNI West)

VNI West is a proposed high-capacity 500 kilovolt double-circuit overhead transmission line between Victoria and NSW. The VNI West RIT-T has been jointly undertaken by AEMO Victoria Planning (AVP) and Transgrid (NSW) for the respective Victorian and NSW parts of the project.

In February 2023, the Victorian Minister for Energy published a Ministerial Order under the *National Electricity (Victoria) Act 2005* to confer functions on AVP, which included assessing alternative additional options to the preferred options (as identified through the RIT-T) that would expedite the development and delivery of VNI West or otherwise better meet a crucial national electricity system need in Victoria.²⁰⁹

In May 2023, AVP and Transgrid published the project assessment conclusions report for VNI West. The project assessment conclusions report is a major milestone in the RIT-T process, representing the final stage in the RIT-T consultation process.²¹⁰

In May 2024, the AER published its determination to approve Transgrid's contingent project application for capital expenditure to undertake early works related to the NSW portion of the project.²¹¹ Early works will enable Transgrid to refine the project scope, identify and manage project risks, and progress pre-construction activities and community engagement.

Marinus Link

TasNetworks (Tasmania) completed a RIT-T for Marinus Link, a proposed project connecting Victoria and Tasmania through 2 new high voltage direct current cables, each with 750 megawatts of transfer capacity and associated alternating current transmission. Marinus Link will connect to the existing transmission networks in both states.

In October 2022, the Tasmanian, Victorian and Australian governments agreed on a funding arrangement to build Marinus Link. A loan scheme will make up the majority of financing for the estimated \$3.5 billion power cable, with the 3 governments also jointly contributing 20% equity.

In June 2023, the AER published its decision to commence a revenue determination process for Marinus Link. This decision allowed Marinus Link to progress the project and submit a regulatory proposal for costs associated with stage 1 early works and construction costs. The AER approved the proposed costs for early works in December 2023.²¹² The costs for early works and the construction of stage 1 will not be recovered from consumers until the Marinus Link Interconnector is commissioned.²¹³

Marinus Link Pty Ltd has shortlisted 2 engineering and construction consortiums – TasVic Greenlink and Empower – to complete the balance of works, covering onshore civil and installation works. This tender is the final major tender for stage 1 of Marinus Link.²¹⁴

In May 2025, the AER published its initial draft decision on Marinus Link's Stage 1, Part B (construction costs) revenue proposal.²¹⁵ The AER is taking a two-step approach in making its determination for this proposal, to support consumer engagement and the timely delivery of Project Marinus. This includes an initial draft decision limited to 2 market tested work programs, with the remaining cost elements assessed in a supplementary draft decision.

209 Victorian Government, [VNI West and Western Renewables Link Ministerial Order](#), Victorian Government Gazette, 20 February 2023.

210 AER, [AEMO Victoria Planning and Transgrid: VNI West PACR](#), Australian Energy Regulator, 21 June 2023.

211 AER, [Transgrid VNI West stage 1 early works contingent project](#), Australian Energy Regulator, 6 May 2024.

212 AER, [AER Determination – Marinus Link Stage 1 Part A \(Early works\)](#), Australian Energy Regulator, 19 December 2023.

213 AER, [Marinus Link – Intending transmission network application](#), Australian Energy Regulator, 1 June 2023.

214 Marinus Link Pty Ltd, [Victorian Community Update – Major construction contractors shortlisted](#), 1 April 2025.

215 AER, [Marinus Link – Intending transmission network application – Draft decision](#), Australian Energy Regulator, 16 May 2025.

The AER's initial draft decision is to accept Marinus Link Pty Ltd.'s forecast capital expenditure of \$1.6 billion (\$2023) for the 2 market tested work programs. This comprises converter station design and equipment supply of \$737 million (\$2023) and the high voltage direct current cable system of \$895 million (\$2023). The 2 market tested work programs account for 46% of the total proposed capital expenditure for the construction of the first Marinus Link cable. The AER expects to make its final decision on Stage 1, Part B (construction cost) in December 2025.

Actionable ISP projects proceeding under RIT-T framework

There were 4 actionable projects – Sydney Ring South, Waddamana to Palmerston transfer capability upgrade, Mid North South Australia REZ Expansion and QNI Connect – identified in the 2024 ISP. AEMO has stated that these projects will proceed under the RIT-T framework.²¹⁶ The RIT-T proponent responsible for each of these actionable projects will be required to initiate its RIT-T process by publishing a project assessment draft report by the relevant date specified in the 2024 ISP.

Actionable ISP projects not proceeding under RIT-T framework

The 2024 ISP identified 5 actionable projects that AEMO has stated will progress under NSW or Queensland frameworks.²¹⁷ These projects will not complete a RIT-T but will instead be subject to the requirements of their respective frameworks.

Two of these projects were previously identified as actionable in the 2022 ISP – Sydney Ring North (previously Sydney Ring) and New England REZ Network Infrastructure Project (previously New England REZ Transmission Link).

The other 3 actionable projects identified in the 2024 ISP that are outside of the RIT-T framework are Gladstone Grid Reinforcement, Queensland SuperGrid South and HunterCentral Coast REZ Network Infrastructure Project.

The Energy Corporation of NSW (EnergyCo) and Transgrid (NSW) have signed a commitment deed confirming Transgrid as the preferred network service provider to deliver the Hunter Transmission Project (Sydney Ring North).²¹⁸ Separately, EnergyCo has appointed Ausgrid (NSW) as the preferred distribution network service provider for the Hunter-Central Coast REZ Network Infrastructure Project.²¹⁹

In March 2025, EnergyCo commenced the competitive tender process for parties interested in becoming the network operator for the New England REZ Network Infrastructure Project. This tender process will run through 2025 with a formal request for proposal in late 2025.²²⁰

²¹⁶ AEMO, [2024 Integrated System Plan](#), Australian Energy Market Operator, June 2024, p. 14.

²¹⁷ *Electricity Infrastructure ACT 2020 (NSW) or Energy (Renewable Transformation and Jobs) Act 2024 (Queensland)*.

²¹⁸ NSW Government, [NSW Government partners with Transgrid to advance the Hunter Transmission Project](#), 29 January 2025, accessed 30 April 2025.

²¹⁹ NSW Government, [Hunter-Central Coast Renewable Energy Zones power ahead](#), media release, 31 January 2025, accessed 17 June 2025.

²²⁰ NSW Government, [EnergyCo seeks partner to deliver and operate New England Renewable Energy Zone](#), 17 March 2025, accessed 30 April 2025.

Table 3.7 shows the 12 network projects classified as actionable in AEMO's 2024 ISP.

Table 3.7 Network projects in the 2024 ISP optimal development path

Actionable project	Actionable framework
HumeLink	ISP
Sydney Ring North (Hunter Transmission Project)	NSW ^a
New England REZ Network Infrastructure Project	NSW ^a
Victoria – New South Wales Interconnector West (VNI West)	ISP
Project Marinus ^b	ISP
Hunter-Central Coast REZ Network Infrastructure project	NSW ^a
Sydney Ring South	ISP
Gladstone Grid Reinforcement	Qld ^c
Mid North South Australia REZ Expansion	ISP
Waddamana to Palmerston transfer capability upgrade	ISP
Queensland SuperGrid South	Qld ^c
Queensland – New South Wales Interconnector (QNI Connect)	ISP

Note:
a These projects will progress under the *Electricity Infrastructure Investment Act 2020* (NSW) rather than the ISP framework.
b Project Marinus is a single actionable ISP project without decision rules.
c These projects will progress under the *Energy (Renewable Transformation and Jobs) Act 2024* (Qld) rather than the ISP framework.

Source: AEMO Integrated System Plan, June 2024, p. 14.

The Australian Government has collaborated with states and territories to create the National Renewable Energy Priority List, which will provide coordinated support for regulatory planning and environmental approval processes for identified priority renewable energy projects across Australia. The Priority List adopts a 'faster to yes, faster to no' approach. Identified projects will receive additional support and facilitation through regulatory and environmental processes. They will still have the same scrutiny applied as any other project and continue to be required to meet all statutory requirements.²²¹

The ISP-listed Powerlink-led CopperString 2032 project is also on the Priority List. In April 2025, the Queensland Government revealed the full cost of the project – an 840 kilometre new double-circuit line to connect Queensland's North-West Minerals Province to the NEM near Townsville – to be almost \$14 billion, nearly \$12 billion more than originally announced.^{222 223} The Queensland Government stated it will leverage the infrastructure expertise of Queensland Investment Corporation – an Australian investment manager and sovereign investor – to deliver CopperString 2032, the biggest energy project in North Queensland's history.

CopperString 2032 will be built and owned by the Queensland Government, under the Queensland Energy and Jobs Plan commitment to public ownership of the state's transmission assets. It was not actioned through the ISP framework.²²⁴

221 Australian Government, [National Renewable Energy Priority List](#), Department of Climate Change, Energy, the Environment and Water, accessed 9 May 2025.

222 Queensland Government, [Crisafulli Government saves CopperString](#), media release, 8 April 2025.

223 ABC News, [Queensland Premier Anastacia Palaszczuk announces more support for outback mega-power line](#), 7 October 2020, accessed 8 April 2025.

224 AEMO, [2024 Integrated System Plan](#), Australian Energy Market Operator, June 2024, p. 60.

3.13.8 Annual planning reports

Network service providers must publish annual planning reports identifying new investments they consider necessary to efficiently deliver network services. The reports identify emerging network pressure points and options to alleviate those constraints. In making this information publicly available, the reports enable non-network providers to identify and propose solutions to address network needs.

The AER publishes guidelines and templates to ensure the annual planning reports provide practical and consistent information to stakeholders.²²⁵ This results in network service providers providing data on network constraints to assist third parties in offering non-network solutions and to inform connection decisions at the transmission level.²²⁶

The NSW Government is conducting a review into transmission planning arrangements in the state. The Transmission Planning Review, which was a recommendation of the *Electricity Supply and Reliability Check Up* report, will consider transmission planning arrangements in NSW to reduce duplication and ensure coordination between relevant entities, and make recommendations for reform. The review is set to conclude by September 2025.²²⁷

On 22 January 2025, Energy Consumers Australia (ECA) submitted a request to the AEMC to amend the National Electricity Rules to improve the existing distribution system planning processes.²²⁸ ECA noted that the existing distribution annual planning reports are not required to include an analysis of consumer energy resources hosting capacity, and that the analysis undertaken every 5 years through the existing expenditure proposal process is insufficient to ensure distribution network service providers can account for large shifts in the uptake of consumer energy resources. ECA has requested a rule change, which will require distribution network service providers to make appropriate use of the data they have, develop a roadmap towards collecting more data at greater granularity, and increase the comprehensiveness and forward-looking timeframe of their planning. Additionally, the rule change will require distribution network service providers to make public the data, methodology, calculations and outputs (such as consumer energy resources hosting capacity maps) that are central to their plans.

ECA considers the impact of the proposed changes will help achieve the National Electricity Objective and result in a host of benefits for consumers and distribution network service providers. These benefits include generating more value from the existing network infrastructure and already available data, particularly from smart meters, proactive network planning to right-size investment in consumer energy resources, improved network utilisation, improved oversight on network planning and costs, and better guiding of investment in consumer energy resources and distributed energy resources. Most importantly, better distribution system planning should reduce network costs, thereby reducing consumer electricity bills.

3.13.9 Demand management

Network service providers manage demand on their networks to reduce, delay or avoid the need to install or upgrade network assets. Managing demand can minimise network charges, improve the reliability of supply and reduce wholesale electricity costs.

The AER offers incentives for distribution network service providers to find lower cost alternatives to new investment to help cope with changing demands on the network and to manage system constraints. The demand management incentive scheme (DMIS) incentivises distribution network service providers to undertake efficient expenditure on alternatives, such as small-scale generation and demand response contracts with large network customers (or third-party electricity aggregators) to time their electricity use to reduce network constraints. The scheme gives network service providers an incentive of up to 50% of their expected demand management costs for projects that bring a net benefit across the electricity market.

225 AER, [Final decision: Distribution annual planning report template v1.0](#), Australian Energy Regulator, June 2017; AER, [Final decision: Transmission annual planning report guidelines](#), Australian Energy Regulator, December 2018.

226 An example of the available constraint data can be found in the datasheets under Ausgrid's [Distribution and transmission annual planning report](#), accessed 11 July 2024.

227 NSW Government, [NSW Transmission Planning Review 2025](#), 14 February 2025, accessed 21 February 2025.

228 AEMC, [Integrated distribution system planning](#), Australian Energy Market Commission, 22 January 2025, accessed 20 March 2025.

To receive an incentive payment, a network service provider must first submit a claim for its eligible projects²²⁹ to the AER and provide information on how it is using demand management to deliver value to its customers. The AER uses the information provided to determine if the network service provider is eligible to receive an incentive payment.

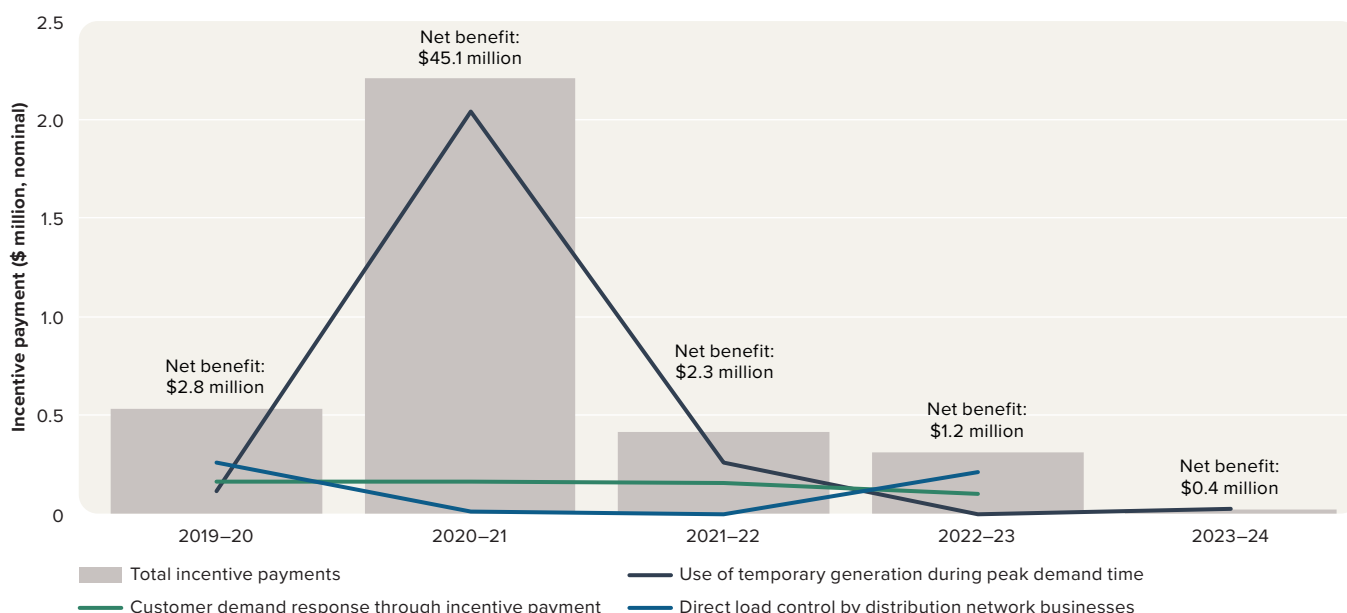
The DMIS has delivered an estimated \$52 million in benefits to consumers (at a cost of \$3.5 million) by encouraging distribution network service providers to defer replacement or augmentation capital expenditure in favour of pursuing demand management activities.

Complementing this scheme, the AER operates a demand management innovation allowance mechanism (DMIAM).^{230 231} The DMIAM provides funding for network service providers to undertake research and development works to help them develop innovative ways to deliver ongoing reductions in demand or peak demand for network services. An objective of the innovation allowance is to enhance industry knowledge of practical approaches to demand management. Network service providers publish annual activity reports setting out the details of projects they have undertaken.

The AER assesses expenditure claims to ensure distribution network service providers appropriately use their funding. Any unspent or unapproved spending is returned to customers through revenue adjustments.

To date, the DMIS has delivered an estimated \$52 million in benefits to consumers (at a cost of \$3.5 million) by encouraging distribution network service providers to defer replacement or augmentation capital expenditure in favour of pursuing demand management activities (Figure 3.25).²³²

Figure 3.25 Funding of demand management innovations – electricity distribution networks



Source: AER, Demand management incentive scheme (DMIS) assessments.

²²⁹ Eligible projects are set out in the AER's revenue determinations for each network service provider.

²³⁰ AER, [Demand management incentive scheme and innovation allowance mechanism](#), Australian Energy Regulator, 14 December 2017.

²³¹ AER, [Demand management innovation allowance mechanism \(transmission\)](#), Australian Energy Regulator, 27 May 2021.

²³² For further information on the demand management incentive scheme see the reports published by the AER. AER, [Demand management incentive scheme \(DMIS\)](#), Australian Energy Regulator.

3.14 Operating expenditure

Network service providers incur operating and maintenance costs that account for around 33% of their annual revenue (Figure 3.5). As part of its 5-year revenue determination processes, the AER sets an allowance for each network service provider to recover the efficient operating costs of supplying electricity to customers. The allowance accounts for forecasts of electricity demand, productivity improvements, changes in input prices and changes in the regulatory environment. The AER reviews the operating expenditure forecasts in each network service provider's regulatory proposal. If the AER is not satisfied the network service provider's proposal is in the long-term interests of consumers, it will request further information or a clearer business case. Subsequently, the AER may amend the proposed operating expenditure to ensure the approved cost forecasts are prudent and efficient.

Alongside this assessment, the AER's efficiency benefit sharing scheme (EBSS) encourages network service providers to explore opportunities to lower their operating costs (Box 3.4).

Box 3.4 Efficiency benefit sharing scheme

Our efficiency benefit sharing scheme (EBSS), introduced in 2007, is designed to share the benefits of efficiency gains in operating expenditure between network service providers and their customers.

The regulatory framework allows a network service provider to keep the benefit (or incur the cost) of reducing (or increasing) its ongoing level of actual operating expenditure until the end of the regulatory period. The EBSS allows a network service provider to keep the benefits (or incur the costs) for an additional period. In effect, this allows the network service provider to keep the benefit (or incur the cost) for a total of 6 years regardless of when in the regulatory period it reduces its costs (or its costs increase).

The EBSS provides network service providers with the same reward for underspending (or penalty for overspending) in each year of the regulatory period. Its incentives are designed to align with those in the capital expenditure sharing scheme (CESS) (Box 3.3). The EBSS incentives also balance against those of the service target performance incentive scheme (STPIS) (Box 3.5) to encourage network service providers to make efficient holistic choices between capital and operating expenditure in meeting reliability and other targets.

When we released our expenditure incentives guideline in 2013,²³³ we estimated around 70% of the benefits from the EBSS would go to customers. Since then, changes in rate of return parameters have increased the share of benefits going to customers. We estimate that customers are now receiving around 80% of the benefits.

Following our 2023 review of incentive schemes,²³⁴ we decided to retain the EBSS in its current format. Our analysis showed that the EBSS has contributed to improved efficiency and lower prices, and that the scheme is working as intended. The benefits to consumers are up to 4 times the benefits to network service providers.

²³³ AER, [Expenditure incentives guideline](#), Australian Energy Regulator, accessed 30 May 2024.

²³⁴ AER, [Review of incentive schemes for regulated networks](#), Australian Energy Regulator, accessed 5 May 2024.

3.14.1 Operating expenditure in 2024

Over the 12-month period to 30 June 2024, network service providers outlaid \$4.6 billion on operating expenses, \$307 million (7%) more than in the previous year and \$75 million (1.7%) more than was forecast.

Table 3.8 summarises the operating expenditure outlaid in 2024 and how this compared with previous years' expenditure and forecasts.

Table 3.8 Operating expenditure in 2024 – key outcomes

Service type	Operating expenditure (2024)	Operating expenditure (compared with 2023)	Operating expenditure (compared with peak)
Transmission	\$746 million (▼1.2% than forecast)	▲\$41 million (▲6%)	▼\$14 million (▼1.9%) (2016)
Distribution	\$3.8 billion (▲2.3% than forecast)	▲\$266 million (▲7%)	▼\$528 million (▼12%) (2012)
Total	\$4.6 billion (▲1.7% than forecast)	▲\$307 million (▲7%)	▼\$479 million (▼9%) (2012)

Note: All data are adjusted to June 2024 dollars. Excludes AER determinations on transmission interconnectors. Numbers may not sum due to rounding.
Source: AER modelling; RIN responses.

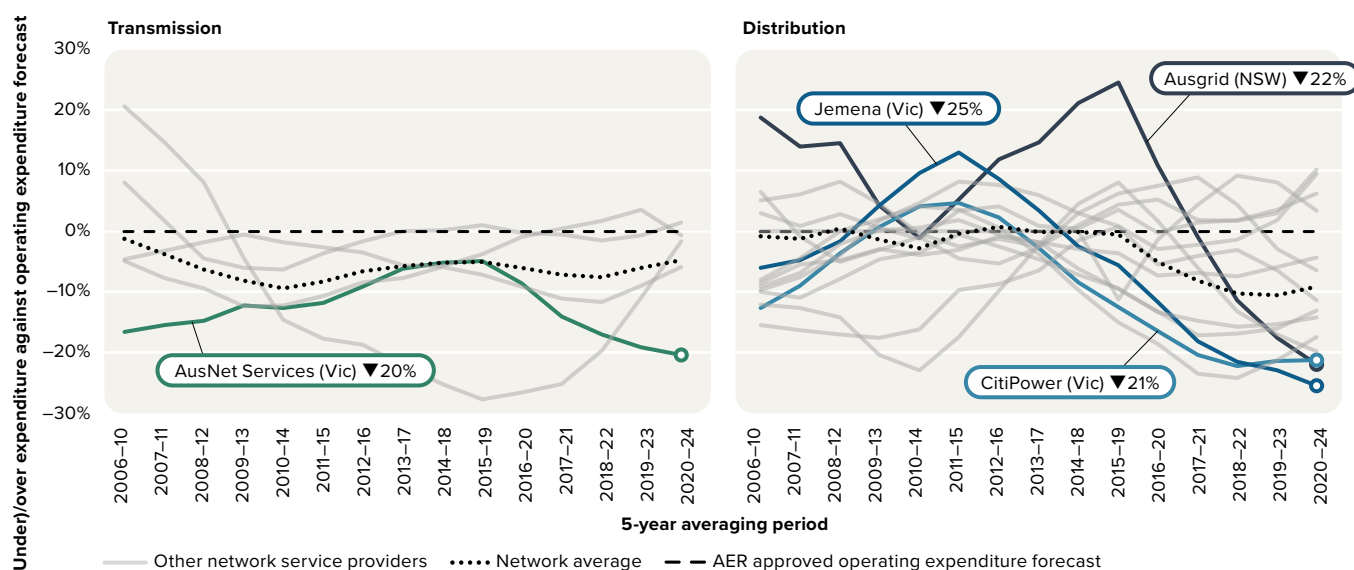
3.14.2 Trends in operating expenditure

The total aggregated operating expenditure outlaid by electricity network service providers increased by an average of 5% per year in the 6-year period from 2006, before peaking at \$5.0 billion in 2012.

Several network service providers implemented efficiencies in managing their operating expenditure from 2015, when the AER widened its use of benchmarking to identify operating inefficiencies in some networks. Other factors, such as reporting obligations, pricing reforms and greater use of non-network options (section 3.8), may have also impacted costs.

Unlike capital expenditure, a network service provider's operating expenditure – such as inspection and maintenance, vegetation management, emergency response, payroll, insurance and any funds allocated for research and development – is largely recurrent and predictable. As such, actual operating expenditure against forecast has consistently been more stable than it has been for capital expenditure (Figure 3.26).

Figure 3.26 Operating expenditure against AER approved forecast



Note: All data are adjusted to June 2024 dollars.
Source: AER modelling; annual reporting RIN responses.

3.15 Productivity

The AER benchmarks the relative efficiency of electricity network service providers to enable comparisons over time. This form of benchmarking assesses how effectively each network service provider uses its inputs (assets and operating expenditure) to produce outputs (such as meeting maximum electricity demand, electricity delivered, reliability of supply, customers served and circuit line length). Productivity will increase if the service provider's outputs rise faster than the inputs used to maintain, replace and augment its energy network.

Although benchmarking provides a useful tool for comparing network performance, some productivity drivers – for example, adhering to reliability standards set by government bodies – are beyond the control of network service providers. More generally, benchmarking may not fully account for differences in operating environment, such as legislative or regulatory obligations, climate and geography.²³⁵

The AER uses a forecast productivity growth rate when reviewing the operating expenditure forecasts of transmission and distribution network service providers. This growth rate reflects the productivity improvements that an efficient network service provider should be able to make in providing services. It is informed by the productivity growth the AER observes in its economic benchmarking results.

3.15.1 Productivity trends

Productivity for most network service providers declined from 2006 to 2015. The decline was more pronounced for distribution network service providers and was largely driven by:

- rising capital investment and capital assets (inputs) at a time when electricity demand (output) had plateaued or was declining in Australia
- rising operating costs and declining reliability (for most network service providers)
- rising expenditure on the distribution networks to meet stricter reliability standards in Queensland and NSW, and regulatory changes following bushfires in Victoria.

Over this period, the privately operated service providers in Victoria and South Australia consistently recorded higher productivity than those of government-owned or recently privatised service providers in other regions.

Transmission network productivity

Since 2006 there has been convergence in the level of productivity of all transmission network service providers, with the exception of TasNetworks (Tasmania). Since 2013, TasNetworks' productivity has improved significantly, which likely reflects efficiencies gained through the merger of Transend's electricity transmission network with Aurora's electricity distribution network in July 2014.²³⁶ In contrast, over the same period the level of productivity of Powerlink (Queensland), Transgrid (NSW) and ElectraNet (South Australia) has deteriorated, largely due to decreases in capital multilateral partial factor productivity – output per unit of capital stock – reflecting increases in capital inputs.

Productivity for the electricity transmission industry decreased by 1.0% in 2023²³⁷, primarily due to an increase in operating expenditure²³⁸ driven by higher maintenance costs across the sector. Growth in the capital inputs²³⁹ for transformers and overhead lines also had a negative impact on productivity. However, these negative impacts were partly offset by increases in circuit length and improved reliability²⁴⁰ compared with the previous year.

235 AER, [Annual benchmarking report, electricity distribution network service providers](#), Australian Energy Regulator, November 2023, pp. 66–74.

236 ENA, [TasNetworks](#), Energy Networks Australia, accessed 11 February 2025.

237 As measured by total factor productivity (TFP).

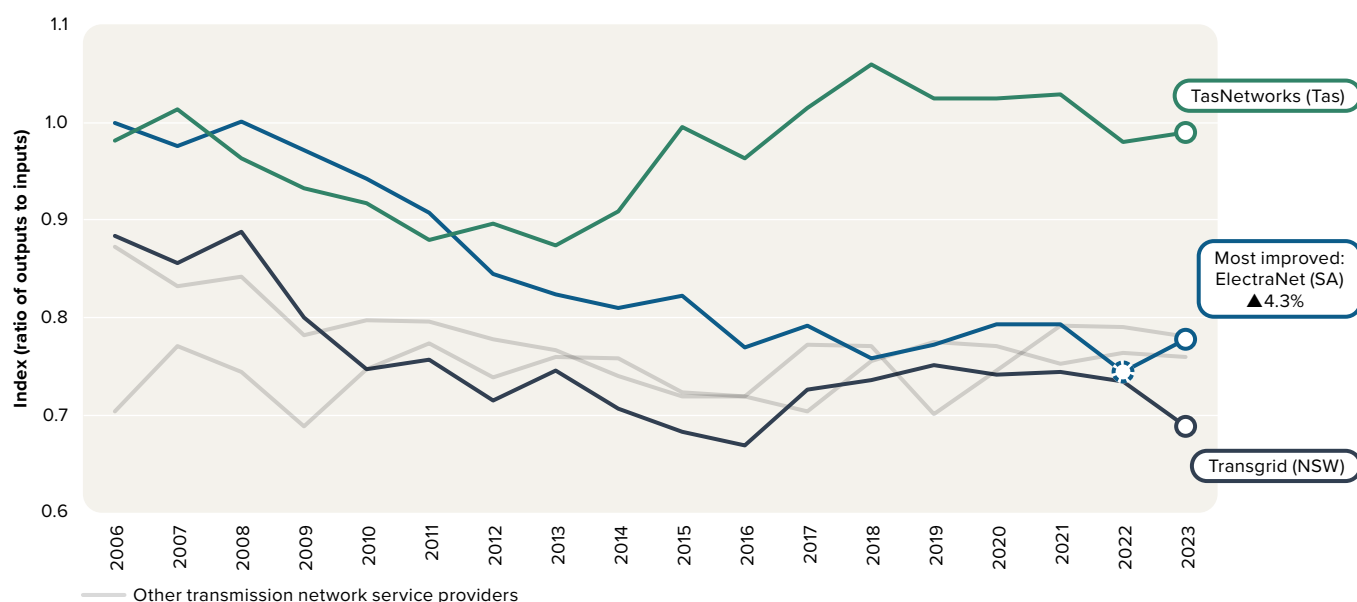
238 The operating expenditure input reflects the costs associated with the labour, materials and services that are purchased each year.

239 The capital inputs (transformers, overhead lines and underground cables) measure the physical quantity of the assets.

240 Reliability (energy not supplied) measures the extent to which network services providers can maintain a continuous supply of electricity.

ElectraNet's (South Australia) productivity increased in 2023, primarily driven by increases in circuit length and reliability. The significant positive contribution of circuit length was due to the high output weight attributed to circuit length²⁴¹ and the installation of new circuit lines as part of ElectraNet's Eyre Peninsula Link project. ElectraNet also reported 78% less 'energy not supplied' than in the previous year (Figure 3.27).

Figure 3.27 Productivity – electricity transmission networks



Note: Index of multilateral total factor productivity relative to the 2006 performance of ElectraNet (South Australia). The 'most improved' label refers to the relative change in multilateral total factor productivity over the previous year. The transmission index shown in Figure 3.27 cannot be directly compared with the distribution index shown in Figure 3.28. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: AER annual benchmarking report for electricity transmission networks, 2024.

Distribution network productivity

Productivity for the electricity distribution industry²⁴² decreased by 2.5% in 2023. This marked the largest year-on-year decrease since 2012 and was primarily due to an increase in operating expenditure²⁴³ driven by higher maintenance costs across the sector. Intensified vegetation management arising from bushfire risk related regulatory obligations, higher emergency response costs due to storm and flood events, and the clearing of maintenance backlogs after the COVID-19 pandemic were among the many drivers listed by distribution network service providers.

In 2023, 3 of the 13 distribution network service providers in the NEM improved their productivity over the previous year. Evoenergy (ACT) – the most improved network service provider – increased its productivity by 10%, driven primarily by a reduction in its operating expenditure input.²⁴⁴

Since 2006, there has been some convergence in the productivity levels of distribution network service providers. SA Power Networks (South Australia), CitiPower (Victoria) and Powercor (Victoria) have consistently been the most productive²⁴⁵ distribution network service providers in the NEM. However, both SA Power Networks and Powercor recorded large decreases in productivity in 2023 (Figure 3.28).

241 Quantonomics, [Economic Benchmarking Results for the Australian Energy Regulator's 2024 TNSP Benchmarking Report](#), 26 July 2024, p. 63.

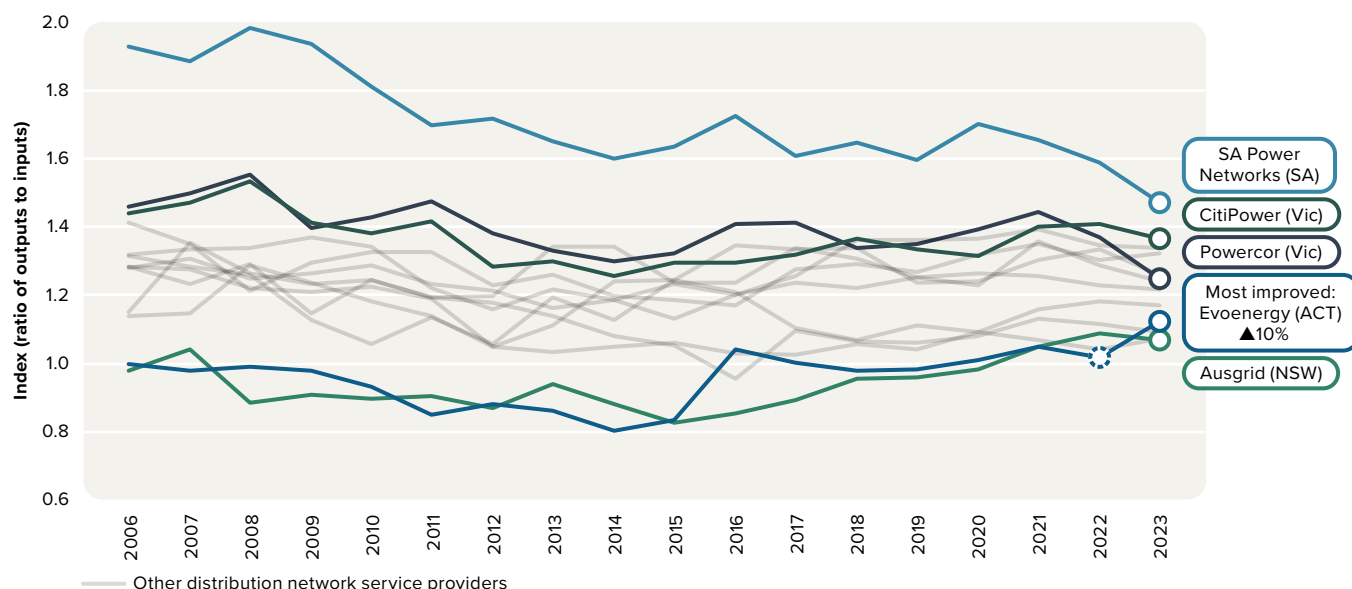
242 As measured by total factor productivity (TFP).

243 The operating expenditure input reflects the costs associated with the labour, materials and services that are purchased each year.

244 In contrast, the operating expenditure input increased by 7.0% across the distribution industry.

245 As measured by multilateral total factor productivity (MTFP).

Figure 3.28 Productivity – electricity distribution networks



Note: Index of multilateral total factor productivity relative to the 2006 performance of Evoenergy (ACT). The 'most improved' label refers to the relative change in multilateral total factor productivity over the previous year. The distribution index shown in Figure 3.28 cannot be directly compared with the transmission index shown in Figure 3.27. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: AER annual benchmarking reports for electricity distribution networks, 2024.

The time series shown in Figure 3.27 and Figure 3.28 demonstrates the variability in year-on-year productivity for individual network service providers. This variability emphasises the importance of considering single-year changes in productivity, be they negative or positive, in the context of longer-term trends.

3.15.2 Network utilisation

Our measure of network utilisation gauges how well each distribution network service provider's assets have been used to meet the needs of consumers at times of maximum demand. The proportion of network capacity being used to serve customers will fluctuate as networks' capacity and/or demand for electricity fluctuates.

Distribution networks are put under greater pressure at times of maximum demand, which generally occurs when most consumers are at home using electricity-intensive appliances, such as air conditioning, ovens and televisions.

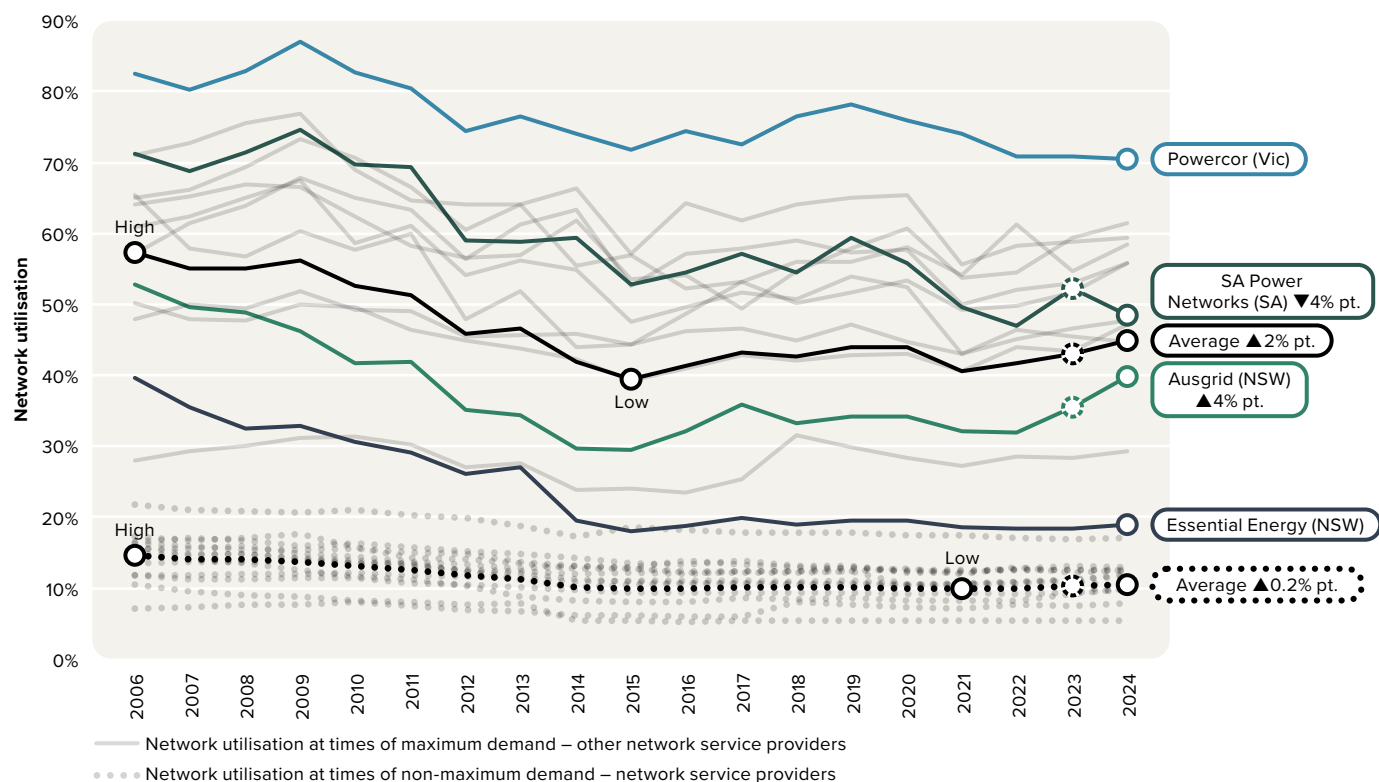
In the 12-month period to 30 June 2024:

- a 4% increase in maximum demand, coupled with a slight decrease in network capacity, saw the overall network utilisation increase to 45%, the highest since 2013 (47%)
- privately owned distribution network service providers utilised 56% of network capacity
- fully or partly government-owned networks utilised 41% of network capacity^{246 247}
- 4 of the 5 most highly utilised distribution networks are privately owned (Figure 3.29).

246 Section 3.4 provides information on network ownership.

247 TasNetworks (Tasmania) has been excluded from the network utilisation metrics/commentary. The maximum demand input (at the zone substation level) does not capture all of TasNetworks' customers as not all customers on its network are connected through a zone substation (for example, there are no zone substations in the north or north-west of Tasmania).

Figure 3.29 Network utilisation – electricity distribution networks



Note: Network utilisation at times of maximum demand is calculated using non-coincident, summated raw system annual maximum demand divided by total zone substation transformer capacity. Network utilisation at times of non-maximum demand is the average energy delivered over the year less the energy delivered during the maximum 30-minute interval divided by total zone substation transformer capacity. TasNetworks (Tasmania) has been excluded because maximum demand input (at the zone substation level) does not capture all of TasNetworks' customers. The changes identified in the labels refer to the relative change in utilisation in percentage points over the previous year.

Source: Economic benchmarking RIN responses.

The average level of network utilisation at times of maximum demand across all distribution networks decreased from a high of 57% in 2006 to a low of 39% in 2015.²⁴⁸ The decrease in network utilisation followed significant investment by many network service providers during a time of declining maximum demand.

The level of network utilisation outside of the 30-minute maximum demand window²⁴⁹ is considerably lower than it is during the peak period. This is not unexpected, given the 'non-maximum demand window' captures network demand over 99.99% of the year,²⁵⁰ including times when demand is consistently low, such as overnight or on weekends.

Network utilisation is an informative, yet incomplete, measure of a network's ability to respond to increases in maximum demand on the network. A lower utilisation rate (that is, higher spare capacity) indicates a network can service large increases in maximum demand and may also mean customers are paying for network assets they rarely use. Measuring network utilisation is further complicated by the different de-rating factors that networks may apply to their reported substation transformer capacities.

248 Data prior to 2006 is not available.

249 The 30-minute maximum demand window refers to the 30-minute period when the highest amount of electricity was consumed on any given day within the period.

250 Or the entire year less the demand reported in the highest 30-minute interval in the year (i.e. 0.01% of the year).

The method of measuring network utilisation shown in Figure 3.29 does not account for two-way network flows and may not show localised constraints from exports from solar PV systems. These constraints are increasing as more consumers continue to install solar PV systems, leading to curtailment of export capabilities.²⁵¹

Electricity pricing during periods of maximum demand operate on a 'time-of-use' tariff structure, meaning consumers are billed more for accessing electricity from the networks during peak times. Network service providers charge these higher rates to account for the greater strain placed on their networks. To change the behaviour of network customers, network service providers offer lower rates during quieter 'off-peak' periods to incentivise consumers to shift their energy use away from busier 'peak' periods.

Consumers can benefit in several ways by shifting their usage from 'peak' to 'off-peak' times. The most obvious and immediate benefit for consumers who can shift their usage is the lowering of electricity bills by taking advantage of the lower 'off-peak' rates. Further to this, spreading demand more evenly across the day reduces strain on the network, which is not only beneficial for grid stability but can also reduce or delay the need for costly network augmentation, thereby reducing future network expenditure being passed on to consumers.

If the volume of energy delivered increases at a faster rate than the total cost of delivering it, the average cost per unit of energy falls, thereby lowering distribution charges per unit for customers.

The AER continues to encourage network service providers to, where possible, increase the rates of network utilisation by utilising existing capacity before investing in new assets. Opportunities to increase electricity network utilisation at times of both 'maximum' and 'non-maximum' demand may also be found through electrification of vehicles and buildings, load shifting and generation management.

In its 2024 ISP, AEMO forecasts households to draw about as much electricity from the grid in 2050 as they do now.

'Their electric vehicles and appliances will drive up underlying consumption and be offset by their investments in rooftop solar and energy efficiency. Individual households will differ in how they rely on the grid. Many will continue to be without rooftop solar and draw electricity from the grid, while those with solar may export excess energy during the day and import from the grid overnight.'²⁵²

In August 2023, Energy Consumers Australia (ECA) wrote that numerous factors indicate that electricity demand is likely to increase over the coming years. In February 2024, the University of Technology Sydney's Institute for Sustainable Futures secured a grant from ECA to undertake a research project aimed at revolutionising network utilisation metrics. The core focus of the project is to enhance network productivity to reduce the overall cost of energy, especially as customers increasingly adopt solar and move towards electrifying their homes and vehicles.²⁵³

Given the current utilisation rates, distribution networks may be well placed to accommodate increases in demand without the need for major investment. Responding to increasing demand through actions like demand response, as opposed to additional network investment, will see distribution charges to customers decrease.²⁵⁴

251 Curtailment can take many forms, such as static limits (setting a fixed maximum limit on the amount of electricity that can be exported from a solar PV system); voltage rise (networks indirectly limiting exports by not better managing voltages on their network and the inverter trips itself off or down); or flexible export limits (networks actively managing and occasionally limiting exports).

252 AEMO, [2024 Integrated System Plan](#), Australian Energy Market Operator, June 2024, p. 26.

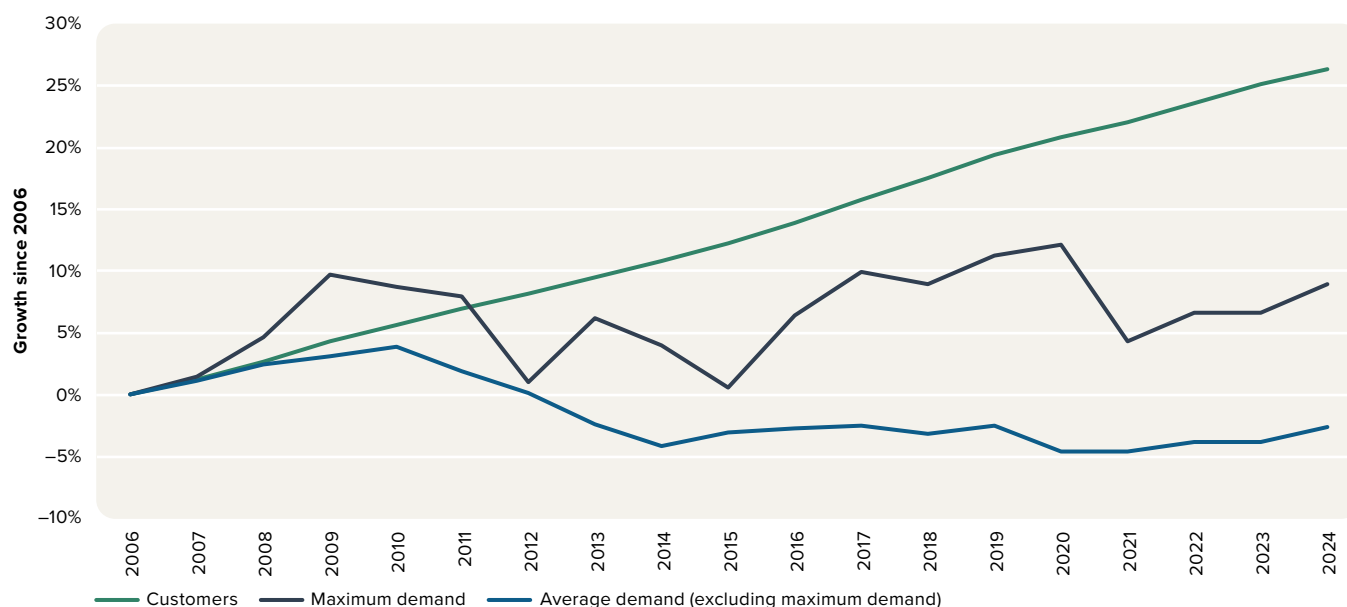
253 University of Technology Sydney, [Empowering tomorrow's energy by redefining network utilisation](#), 8 February 2024, accessed 13 July 2025.

254 Energy Consumers Australia, [The bECAuse Blog](#), 2 August 2023, accessed 13 July 2025.

Capital expenditure is largely driven by the need to meet the maximum level of demand on the network. Average demand has declined since 2006 (driven in part by improved energy efficiency and increased self-consumption of solar PV), whereas maximum demand has become more variable. While maximum demand has always varied with the weather, the increased use of air conditioners and solar PV has exacerbated this effect.

As network demand becomes ‘peakier’, assets installed to meet maximum demand – which occurs for approximately 0.01% of the year – may sit idle (or be underused) for longer periods. This outcome is reflected in poor asset usage rates, which decreases utilisation. The number of customers connected to the distribution network has steadily increased by around 1.5% per year since 2006 and has outpaced growth in both maximum and average ‘non-maximum’ demand (Figure 3.30).

Figure 3.30 Growth in customers and demand – electricity distribution networks



Note: Maximum demand is the network sum of non-coincident, summated raw system maximum demand (megawatts). Non-maximum demand is the total energy delivered (gigawatt hours) for the year, excluding the energy delivered at the time of maximum demand divided by hours in the year minus one. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

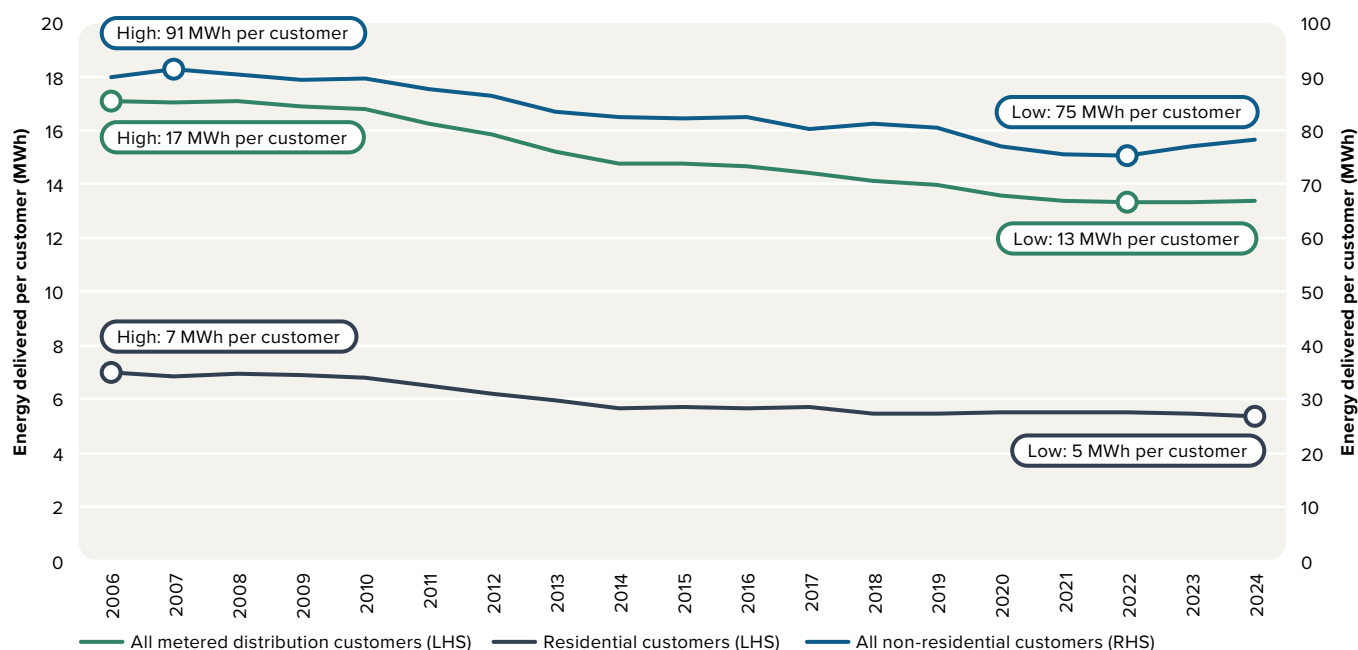
Source: Economic benchmarking RIN responses.

In 2024, the average residential customer²⁵⁵ consumed around 5 megawatt hours (MWh) of electricity from the grid, 23% less than in 2006. Over the same period the average non-residential customer – which includes low voltage, high voltage and ‘other’ customers – decreased their annual usage from the grid by around 13%.

Non-residential ‘per customer’ grid usage in 2024 increased slightly, driven by a 1.8% decrease in the number of non-residential customers not on demand tariffs, which was only partially offset by a 0.1% decrease in the amount of energy consumed by the remaining customers in that category (Figure 3.31).

²⁵⁵ A customer who purchases energy principally for personal, household or domestic use at premises.

Figure 3.31 Average grid usage per customer – electricity distribution networks



Note: MWh: megawatt hours. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: Economic benchmarking RIN responses.

3.16 Reliability and service performance

In this section, the term ‘reliability’ refers to the continuity of electricity supply to customers.²⁵⁶

Many factors can interrupt the flow of electricity on a network. Supply interruptions may be planned (for example, due to the scheduled maintenance of equipment) or unplanned (for example, due to equipment failure, bushfires, extreme weather events or the impact of high demand stretching the network’s engineering capability).

A significant network failure might require the power system operator to disconnect some customers (known as load shedding). Load shedding is the managed reduction of electricity supply to selected areas during extreme events to protect the electricity network from damage and more widespread consumer outages. Used as a last resort, load shedding assists in balancing supply and demand to maintain power system security.²⁵⁷

AEMO identifies the amount and duration of electricity shortfalls, but it does not decide which areas have their power turned off. The transmission and distribution network service providers determine how manual load shedding is done at a local level to meet the shortfall. Where load shedding is required for longer periods – such as more than 2 hours – distribution network service providers generally seek to spread the disruption across their network on a rotational basis to minimise the impact to the community, particularly health facilities, emergency services and public transport.²⁵⁸

²⁵⁶ The continuity of electricity supply from customers that export energy into the grid (for example, energy generated from rooftop solar PV) is also an element of service performance for networks. Reforms to treat export services as distribution services have been completed. See AEMC, Rule determination: [Access, pricing and incentive arrangements for distributed energy resources](#), Australian Energy Market Commission, 12 August 2021.

²⁵⁷ AEMO, [Fact sheet: Load Shedding](#), Australian Energy Market Operator, 28 November 2023, accessed 16 May 2025.

²⁵⁸ AEMO, [Fact sheet: Load Shedding](#), Australian Energy Market Operator, 28 November 2023, accessed 16 May 2025.

Most interruptions to supply originate in distribution networks. They typically relate to powerline damage caused by lightning, car accidents, debris such as falling branches, and animals (such as possums or birds). High demand during extreme weather can also overload parts of a distribution network. Transmission network issues rarely cause consumers to lose power, but the impact when they do is often widespread. For example:

- in September 2016, South Australia's catastrophic network failures caused a state-wide blackout²⁵⁹
- in February 2024, a significant thunderstorm crossed Victoria causing 6 high voltage transmission towers to collapse, resulting in 2,210 megawatts of generation to be disconnected and 90,000 customers having their supply switched off (load shedding).²⁶⁰

Electricity outages cause financial loss for consumers, such as lost productivity and business revenues. Consumers also experience less tangible losses such as reduced convenience, comfort, safety and amenity.

Residential and business consumers expect a reliable electricity supply that minimises these costs. But maintaining or improving reliability may require expensive investment in network assets, which is a cost passed on to electricity customers in their electricity bills. Therefore, there is a trade-off between electricity reliability and affordability. Reliability standards and incentive schemes need to strike the right balance by targeting levels of reliability that customers are willing to pay for.

To help achieve this, state and territory governments set reliability standards for electricity networks that seek to efficiently balance the costs and benefits of a reliable power supply. Although approaches to setting standards have varied across jurisdictions, governments have now moved to a more consistent national approach to reliability standards.²⁶¹ This approach factors in the value that consumers place on having a reliable power supply.

3.16.1 Valuing network reliability

Understanding the value that consumers place on reliability is important when conducting cost benefit analyses for proposed network expenditure, setting reliability standards or determining performance targets. This value tends to vary among customer types and across different parts of the network. Considerations include a customer's access to alternative energy sources, experience of interruptions to supply, and the duration, frequency and timing of interruptions.

In 2019, the AER developed the values of customer reliability (VCR) methodology for standard outages (up to 12 hours), following extensive consultation and quality assurance. In December 2024, the AER updated the VCR following an extensive review of the 2019 VCR methodology. Throughout the course of the review the AER engaged with market bodies, governments, network service providers, customer and industry representatives, and customers themselves.²⁶²

The AER reviews its VCR methodology and updates the values at least once every 5 years. The published VCR is adjusted on an annual basis between reviews. The values have a wide application, including as an input for:

- undertaking cost-benefit assessments, such as those applied in regulatory tests (section 3.13.5) that assess network investment proposals
- assessing bonuses and penalties in the service target performance incentive schemes (Box 3.5)
- setting transmission and distribution reliability standards and targets
- informing market settings, such as wholesale price caps.

259 AER, [Investigation report into South Australia's 2016 state-wide blackout](#), Australian Energy Regulator, accessed 13 July 2025.

260 Engage Victoria, [Final report – Network outage review 2024](#), Department of Energy, Environment and Climate Action, September 2024, accessed 13 July 2025.

261 For example, under clause 3.9.3D of the National Electricity Rules, AEMO provides a reliability framework that network service providers are required to operate within. See AEMO, [Reliability Standard Implementation Guidelines](#), Australian Energy Market Operator, 24 April 2023.

262 AER, [Values of Customer Reliability 2024 – Final report](#), Australian Energy Regulator, 30 August 2024.

3.16.2 Valuing network resilience

In September 2024, the AER published its final decision on its review of the value of network resilience (VNR) for outages lasting longer than 12 hours (i.e. ‘prolonged’ outages). The VNR will help inform network service providers and stakeholders about making appropriate investments to enhance network resilience against extreme weather events, considering both the ability to withstand and recover from such events. The AER’s VNR review was conducted simultaneously to the VCR review and provides an estimate of the value customers place on network resilience during prolonged outages.²⁶³

In May 2025, the AEMC made a rule change to help make the electricity grid more resilient to extreme weather events.²⁶⁴ The AEMC noted that storms, flooding and bushfires are becoming more frequent and intense, adding further strain to the electricity distribution network, leaving customers exposed to power outages.

Distribution network resilience will now be explicitly recognised in the National Electricity Rules, establishing a formal framework that includes:

- new resilience expenditure factors that distribution network service providers and the AER must consider when developing and assessing expenditure proposals
- a requirement for the AER to develop, publish and maintain formal network resilience guidelines
- new annual planning and reporting requirements (section 3.13.8) to improve the transparency and accountability of distribution network service providers’ performance, and outcomes for consumers, in severe weather events.

The new framework encourages distribution network service providers to plan for extreme weather and invest in measures to reduce the risk of power outages, while encouraging prioritisation of the needs of vulnerable consumers and those most at risk from power outages.

Investments could include adaptation measures such as strengthening poles and wires in high-risk communities, relocating infrastructure in flood prone areas or increasing the number of mobile generators and substations that can keep the lights on when the power supply is disrupted. Distribution network service providers can also propose resilience spending on programs to manage bushfire and flood risks.

Victorian distribution network service providers will be able to factor resilience expenditure into their revised regulatory proposals from 2 October 2025. The AER must consider these new factors in its final distribution determinations for 2026–31. Transitional rules will require:

- the AER to develop and publish formal network resilience guidelines by 1 December 2026
- distribution network service providers to comply with new annual planning and reporting requirements in their annual planning reports from 2028.

The rule is part of a broader program of work aiming to reduce the impacts of climate change on the electricity grid.

²⁶³ AER, [Value of network resilience 2024](#), Australian Energy Regulator, 30 September 2024.

²⁶⁴ AEMC, [Including distribution network resilience in the National Electricity Rules](#), Australian Energy Market Commission, 8 May 2025.

3.16.3 Transmission network reliability

Transmission networks are engineered and operated to be extremely reliable because a single interruption can lead to high impacts or widespread power outages. To minimise the risk of outages occurring, transmission networks are engineered with capacity to act as a buffer against credible unplanned interruptions.

In addition to system reliability, congestion management is another indicator of transmission network performance. All networks are constrained by capability limits and congestion arises when electricity flows on a network threaten to overload the system. As an example, a surge in electricity demand to meet air conditioning loads on a hot day may push a network service provider to the limits of its secure operating capacity.

Network congestion may require AEMO to change the generator dispatch order. A low-cost generator may be constrained from running to avoid overloading an affected transmission line and a higher cost generator may be dispatched instead, raising electricity prices. At times, congestion can cause perverse trade flows, such as a lower priced NEM region importing electricity from a region with much higher prices.

Congestion on the transmission network caused significant market disruption in 2006 when rising electricity demand placed strain on the networks. But increased network investment from 2006 to 2014 – including upgrades to congested lines – eliminated much of the problem. A decline in energy demand reinforced the trend and for several years when network congestion affected less than 10% of NEM spot prices. But ultimately, consumers have paid for the substantial costs of network investment.

Not all congestion is inefficient and augmenting transmission networks to reduce congestion is an expensive solution. Eliminating congestion is efficient only to the extent that the market benefits outweigh the costs of new investment.

Network service providers can help minimise congestion costs by scheduling planned outages and maintenance to avoid peak periods. The AER incentivises service providers to reduce the market impact of congestion under the service target performance incentive scheme (STPIS) (Box 3.5).²⁶⁵

3.16.4 Distribution network reliability

For distribution networks, the reliability of supply – that is, how effectively the network delivers power to its customers – is the focus of network performance. Around 95% of the interruptions to supply experienced by electricity customers are due to issues in the local distribution network.²⁶⁶ The capital-intensive nature of electricity networks makes it prohibitively expensive to invest in sufficient capacity to avoid all interruptions.

Planned interruptions – when a network service provider needs to disconnect supply to undertake maintenance or construction works – can be scheduled for minimal impact and the service provider must provide timely notice to customers of its intention to interrupt supply. Unplanned interruptions to supply – such as those resulting from asset overload or damage caused by extreme weather – are more disruptive and provide no warning to customers, so they cannot prepare for the impact of an interruption.

Jurisdictional reliability standards were historically set at more stringent levels to protect customers from the cost and inconvenience of supply interruptions. Following power outages in 2004, the Queensland and NSW governments tightened jurisdictional reliability standards for distribution networks. This required significant investment, driving network costs for several years. In contrast, Victoria placed more emphasis on reliability outcomes and the value that customers place on reliability.

265 AER, [Service target performance incentive scheme V6](#), Australian Energy Regulator, 17 April 2025.

266 AEMC, [Final report – 2019 annual market performance review](#), Australian Energy Market Commission, 12 March 2020, p. 51.

Concerns that reliability-driven investment was putting upwards pressure on electricity bills led to governments adopting an alternative approach to setting distribution reliability targets.²⁶⁷ The alternative approach considers both the likelihood of an interruption occurring and the value that customers place on removing or reducing the impact of an interruption (section 3.16.1). While the Queensland and NSW governments began to relax reliability standards from 2014, the assets built to meet the previously high standards remain in the RAB and customers continue to pay for them.²⁶⁸

Two widely applied measures of distribution network reliability are the system average interruption frequency index (SAIFI) and the system average interruption duration index (SAIDI). SAIFI measures the frequency – or number – of interruptions to supply the average customer experienced each year, while SAIDI measures the total time the average customer was without power.²⁶⁹

The SAIFI and SAIDI metrics have generally been used to focus on the impact of unplanned interruptions to supply. However, the impact of planned interruptions must also be considered when assessing the overall customer experience. The AER has acknowledged this and has incorporated the impact of planned outages into some of its regulatory determinations through the customer service incentive scheme (CSIS) (Box 3.6).

Maintaining or improving reliability may require expensive investment in network assets, which is a cost passed on to electricity customers in their electricity bills. Therefore, there is a trade-off between electricity reliability and affordability.

Both the frequency and duration of planned and unplanned interruptions to supply varies considerably among the distribution networks. The specific features of each distribution network can have a significant impact on the service provider's reliability performance. Customer densities, geographical characteristics and environmental conditions differ across networks, which can materially impact the number of customers affected by an outage as well as a network service provider's response time. Levels of historical investment also affect reliability outcomes.

Central business district (CBD) and urban network areas have higher load and customer connection densities. Distribution lines supplying urban areas are generally significantly shorter than those supplying rural areas. CBD and urban areas also tend to have a higher proportion of underground cables (which are protected from pollution, storms, trees, bird life, vandalism, equipment failure and vehicle collisions) and more interconnections with other urban lines. Restoration times following interruptions to supply are usually quicker for network service providers operating in urban areas than in rural areas.

Conversely, rural areas generally have lower load and lower customer connection densities and often include customers living in smaller population centres remote from supply points. Distribution lines supplying customers in rural areas tend to cover wider geographic areas. This increases exposure to external influences, such as storm damage, trees and branches and lightning. Further, rural lines are generally radial in nature, with limited ability to interconnect with nearby lines. These characteristics tend to result in more frequent and longer interruptions.

For these reasons, care must be taken when comparing the reliability outcomes of different distribution network service providers.

²⁶⁷ Ministerial Forum of Energy Ministers (formerly CoAG Energy Council), *Response to the Australian Energy Market Commission's review of the national framework for distribution reliability and review of the national framework for transmission reliability*, December 2014.

²⁶⁸ ACCC, *Retail Electricity Pricing Inquiry final report*, Australian Competition and Consumer Commission, 11 July 2018, p. 109.

²⁶⁹ Unplanned SAIDI excludes momentary interruptions (3 minutes or less).

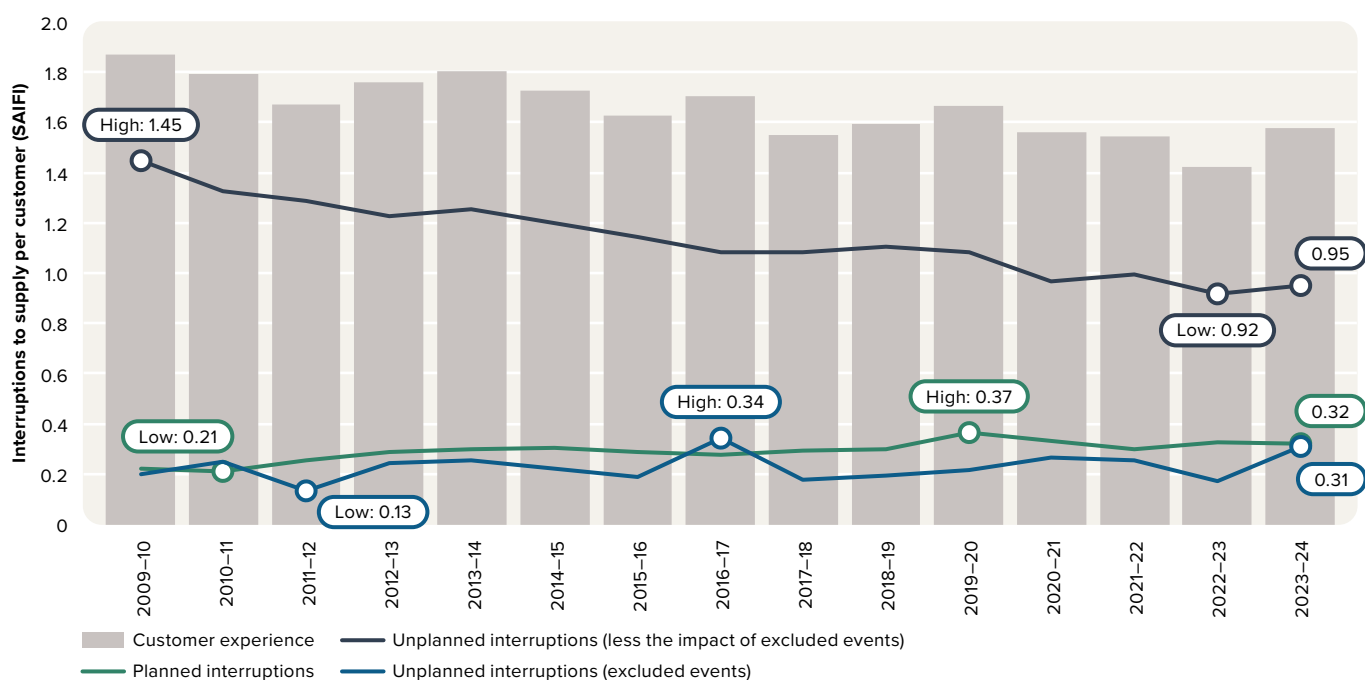
3.16.5 Distribution network reliability in 2023–24

Over the 12-month period to 30 June 2024, the average customer in the NEM experienced 1.58 interruptions to supply, 11% more than the record low set in 2022–23 (Figure 3.32).

The 1.58 interruptions to supply comprised of:

- 0.95 unplanned interruptions to supply (normalised for STPIS) – 3% more than the record low set in the previous year
- 0.31 unplanned interruptions to supply (STPIS excluded events) – 77% more than in the previous year and the most since 2016–17
- 0.32 planned interruptions to supply – 3% less than in the previous year.

Figure 3.32 Interruptions to supply (SAIFI) – electricity distribution networks



Note: SAIFI: system average interruption frequency index. Data show interruptions to supply that lasted longer than 3 minutes. This is consistent with the definition of a sustained interruption in the AER's current service target performance incentive scheme (STPIS) (version 2.0, November 2018). The previous version of the STPIS (May 2009) defined sustained interruptions as those that lasted longer than one minute. Reporting historical SAIFI using a consistent definition allows for greater comparability over time. As such, the values shown above may not reflect outcomes reported in the past. Years reflect 1 July to 30 June. The unplanned interruptions (STPIS excluded events) cannot be directly calculated at a whole of NEM level because the major event day calculation must be made at a network level. For example, 22 November 2022 was classed as a major event (STPIS excluded event) for AusNet Services (Victoria) but did not qualify as a major event day for any of the other 12 distribution network service providers in the NEM. As such, the unplanned interruptions (STPIS excluded events) and unplanned interruptions (normalised measures) are calculated based on each individual network service provider's outputs and subsequently weighted to show a 'whole of NEM' measure.

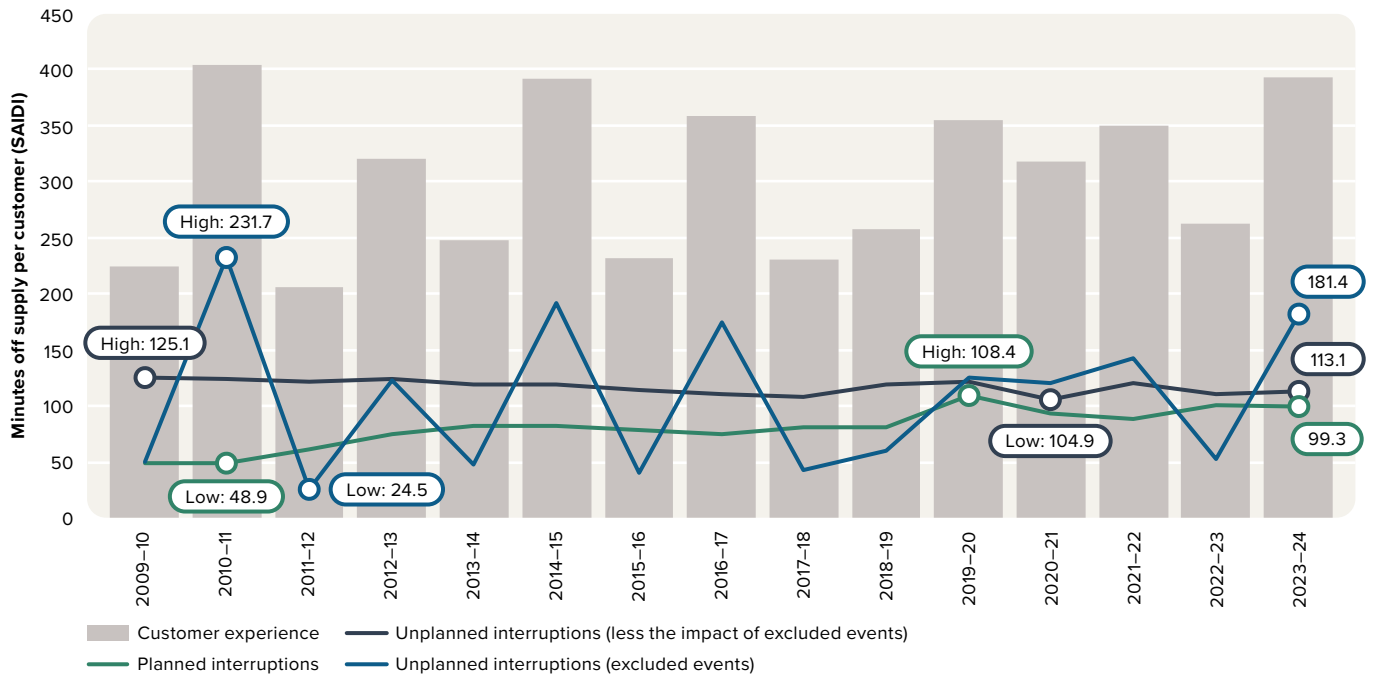
Source: AER modelling; category analysis regulatory information (RIN) responses.

Over the 12-month period to 30 June 2024, the average customer in the NEM experienced 393.8 minutes off supply – 50% more than in the previous year and the most since 2010–11 (Figure 3.33).

The 393.8 minutes off supply comprised of:

- 113.1 unplanned minutes off supply (normalised for STPIS) – 3% more than in the previous year
- 181.4 unplanned minutes off supply (STPIS excluded events) – 248% more than in the previous year and the most since 2010–11
- 99.3 planned minutes off supply – 1% less than in the previous year.

Figure 3.33 Minutes off supply (SAIDI) – electricity distribution networks



Note: SAIDI: system average interruption duration index. Data show interruptions to supply that lasted longer than 3 minutes. This is consistent with the definition of a sustained interruption in the AER's current service target performance incentive scheme (STPIS) (version 2.0, November 2018). The previous version of the STPIS (May 2009) defined sustained interruptions as those that lasted longer than one minute. Reporting historical SAIDI using a consistent definition allows for greater comparability over time. As such, the values shown above may not reflect outcomes reported in the past. Years reflect 1 July to 30 June. The unplanned interruptions (STPIS excluded events) cannot be directly calculated at a whole of NEM level because the major event day calculation must be made at a network level. For example, 22 November 2022 was classed as a major event (STPIS excluded event) for AusNet Services (Victoria) but did not qualify as a major event day for any of the other 12 distribution network service providers in the NEM. As such, the unplanned interruptions (STPIS excluded events) and unplanned interruptions (normalised measures) are calculated based on each individual network service provider's outputs and subsequently weighted to show a 'whole of NEM' measure.

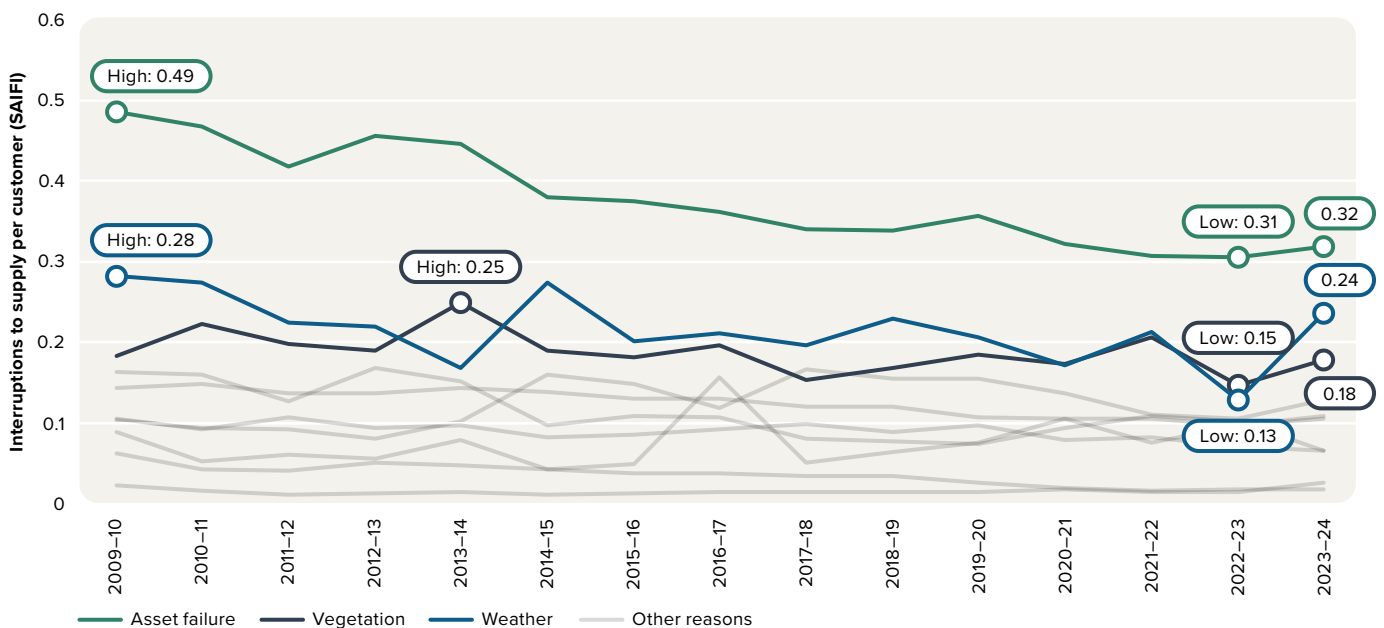
Source: AER modelling; category analysis regulatory information (RIN) responses.

Unplanned interruptions occur for many reasons, including:

- weather events
- vegetation interfering with powerlines
- bushfires
- asset failure and technical faults
- third-party accidents
- animals
- load shedding (reducing or disconnecting load from the power system) to help balance supply and demand during the peak period.

Since 2009–10, asset failure²⁷⁰ has consistently been the primary cause of interruptions to supply in the NEM (responsible for around 28% of interruptions to supply) (Figure 3.34). However, asset failure is rarely the most disruptive in terms of time off supply (Figure 3.35). Over the same 14-year period, weather events such as lightning, floods, heatwaves or high winds have generally been the secondary cause of interruptions to supply (responsible for around 15% of interruptions to supply) but are often the most disruptive in terms of duration (responsible for 16–60% of time off supply). This clearly demonstrates the destructive nature of weather events on the electricity network.

Figure 3.34 Reasons for unplanned interruptions to supply (SAIFI) – electricity distribution networks

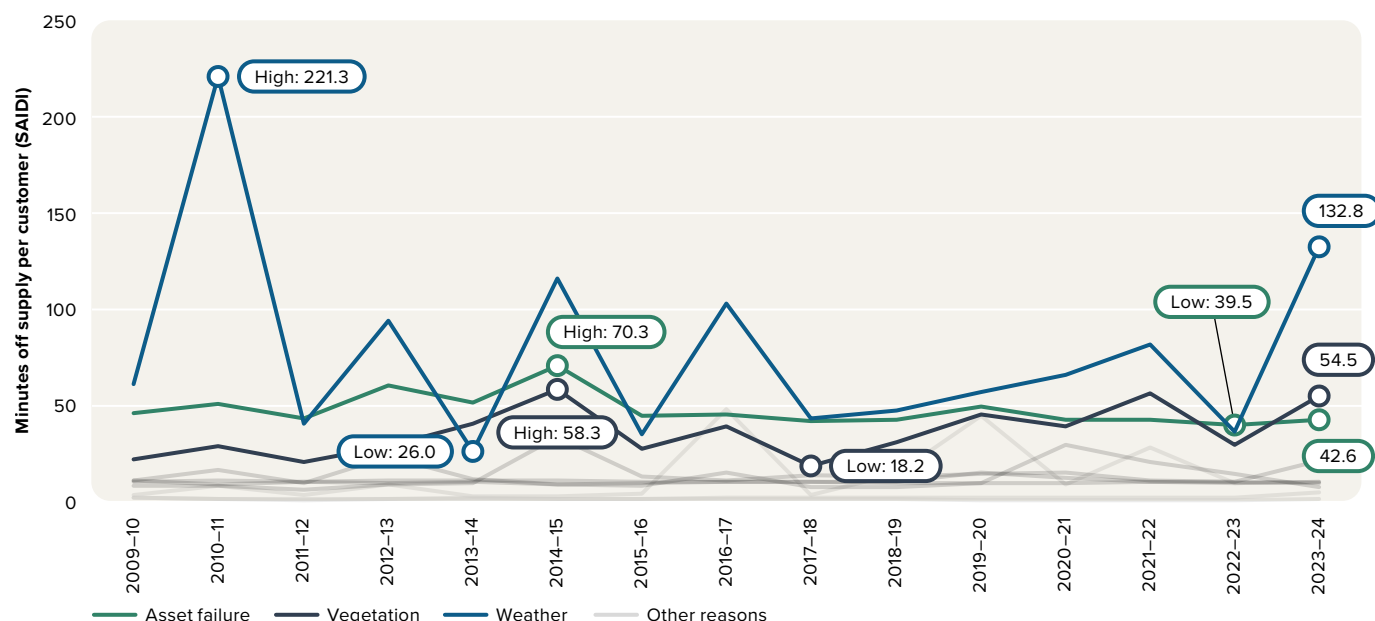


Note: SAIFI: system average interruption frequency index. Data show interruptions to supply that lasted longer than 3 minutes. This is consistent with the definition of a sustained interruption in the AER's current service target performance incentive scheme (STPIS) (version 2.0, November 2018). The previous version of the STPIS (May 2009) defined sustained interruptions as those that lasted longer than one minute. Reporting historical SAIFI using a consistent definition allows for greater comparability over time. As such, the values shown above may not reflect outcomes reported in the past. Years reflect 1 July to 30 June.

Source: AER modelling; category analysis regulatory information (RIN) responses.

²⁷⁰ The failure of an asset to perform its intended function safely and in compliance with jurisdictional regulations, not because of external impacts such as extreme or atypical weather events, third-party interference, wildlife interference or vegetation interference.

Figure 3.35 Reasons for unplanned minutes off supply (SAIDI) – electricity distribution networks



Note: SAIDI: system average interruption duration index. Data show interruptions to supply that lasted longer than 3 minutes. This is consistent with the definition of a sustained interruption in the AER's current service target performance incentive scheme (STPIS) (version 2.0, November 2018). The previous version of the STPIS (May 2009) defined sustained interruptions as those that lasted longer than one minute. Reporting historical SAIDI using a consistent definition allows for greater comparability over time. As such, the values shown above may not reflect outcomes reported in the past. Years reflect 1 July to 30 June.

Source: AER modelling; category analysis regulatory information (RIN) responses.

Due to the sheer size of the NEM, which operates on one of the world's longest interconnected power systems, the impact of a severe weather event in one region, or on a specific network within a region, can have little or no impact on neighbouring regions or networks.

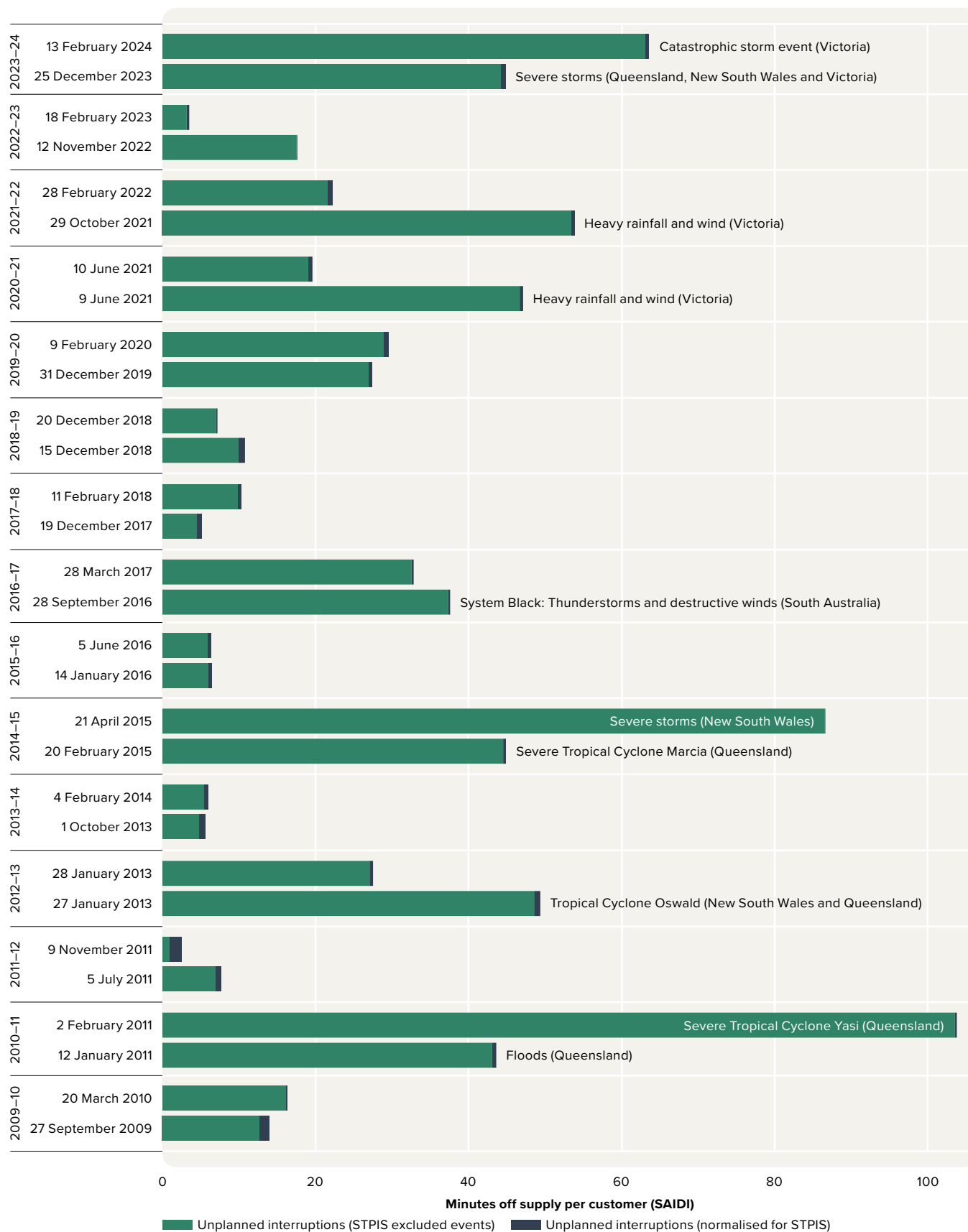
This is best illustrated by the impact of Severe Tropical Cyclone Yasi on Ergon Energy's distribution network. On 2 February 2011, the average customer on the Ergon Energy network – which operates in regional Queensland – experienced an extraordinary 1,391 minutes off supply. On that same date, the average customer on the neighbouring Energex network experienced only 0.2 minutes off supply.

The relatively high number of minutes off supply experienced by the average NEM customer in 2023–24 was in large part driven by severe storms in Queensland on Christmas Day 2023,²⁷¹ and across central and eastern Victoria in mid-February 2024.²⁷² These disruptive weather events occurred one year after the average NEM customer experienced a relatively low number of minutes off supply 2022–23, partly due to the lack of catastrophic weather events throughout the year (Figure 3.36). This again demonstrates the potentially destructive and unpredictable nature of weather events on the electricity network.

271 ABC News, [Woman killed by fallen tree as wild Christmas storm lashes south-east Queensland](#), 26 December 2023, accessed 29 April 2025.

272 Victorian Government, [February 2024 Victorian storms](#), accessed 29 April 2025.

Figure 3.36 Unplanned minutes off supply – most disruptive days each year



Note: SAIDI: system average interruption duration index. Data show interruptions to supply that lasted longer than 3 minutes. This is consistent with the definition of a sustained interruption in the AER's current STPIS (version 2.0, November 2018). The previous version of the STPIS (May 2009) defined sustained interruptions as those that lasted longer than one minute. Reporting historical SAIDI using a consistent definition allows for greater comparability over time. As such, the values shown above may not reflect outcomes reported in the past. Years reflect 1 July to 30 June.

Source: AER modelling; category analysis regulatory information (RIN) responses.

Reliability and weather events

A significant storm event hit Victoria on 13 February 2024, causing heavy rainfall and damaging winds. The event caused significant damage to Victoria's electricity distribution network, affecting around 12,000 kilometres of distribution lines and more than one million customers.²⁷³ Following this event, the Victorian Government commissioned an independent review into the operational response of electricity network service providers to the February 2024 storms. In September 2024, the Network Outage Review Expert Panel (the Panel) published its final report, which consisted of 19 recommendations and 12 observations focused on delivering a clear pathway of improvements, necessitating a step change in the operational response by transmission and distribution network service providers during prolonged power outage events.

The Panel's recommendations provided a strong focus on achieving change quickly, with certainty and using mechanisms that are within Victoria's control. The final report detailed the importance of better preparedness, coordination and collaboration as well as actions to improve the reliability of the electricity system and support the community by placing people, their needs and safety at the forefront.

In April 2024, independent advisory body Infrastructure Victoria published a report stating that most of Victoria's infrastructure – such as roads, electricity networks and buildings – are not built to perform in an environment with more severe weather and intense rainfall events, and more hot days and bushfires.²⁷⁴

Since 1 July 2022, Energy Safe Victoria (ESV) has had the power to issue fines to Victorian network service providers that do not keep trees safely clear of powerlines. Before this, ESV's powers to take enforcement action for line clearance breaches were limited to issuing warnings or notices to take corrective action or prosecution through the court system.

In May 2024, Powercor (Victoria) was fined \$2.1 million for breaching the Electricity Safety Act and contravening electric line clearance regulations. ESV prosecuted Powercor for 105 offences, including failing to inspect almost 5,000 powerlines and failing to clear vegetation from more than 100 other lines, including one span at Glenmore where a destructive fire broke out.²⁷⁵

3.16.6 Incentivising good performance

Inconsistencies in the measurement of reliability across NEM jurisdictions led the AEMC to develop a more consistent approach. In November 2018, the AER adopted the AEMC's recommended definitions for distribution reliability measures for purposes such as setting reliability targets in the STPIS.²⁷⁶

More generally, the AER reviewed the STPIS to align with the AEMC's recommendations – for example, it amended the scheme to encourage network service providers to reduce the impact of long interruptions to supply experienced by customers at the end of rural feeders.

273 Engage Victoria, [Final report – February 2024 storm and power outage event – Independent review of transmission and distribution businesses operational response](#), Department of Energy, Environment and Climate Action, September 2024, accessed 15 October 2024.

274 Infrastructure Victoria, [Weathering the storm – Adapting Victoria's infrastructure to climate change](#), April 2024, accessed 16 July 2024.

275 ESV, [Powercor convicted on record number of charges, fined \\$2.1 million](#), media release, Energy Safe Victoria, 8 May 2024, accessed 13 July 2025.

276 AER, [Amendment to the service target performance incentive scheme \(STPIS\) / Establishing a new Distribution Reliability Measures Guideline \(DRMG\)](#), Australian Energy Regulator, November 2018.

Box 3.5 Service target performance incentive scheme

We apply a service target performance incentive scheme (STPIS) to most regulated network service providers. The STPIS offers incentives for network service providers to improve their service performance to levels valued by their customers. It provides a counterbalance to the capital expenditure sharing scheme (CESS) (Box 3.3) and efficiency benefit sharing scheme (EBSS) (Box 3.4) by ensuring network service providers do not reduce expenditure at the expense of service quality. A separate STPIS applies to distribution and transmission networks.

Transmission

The transmission STPIS covers 3 service components:

- the frequency of supply interruptions, duration of interruptions to supply and the number of unplanned faults on the network
- rewards for operating practices that reduce network congestion
- funding for one-off projects that improve a network's capability, availability or reliability at times when users most value reliability or when wholesale electricity prices are likely to be affected.

Financial bonuses of up to +4% of revenue, or penalties of up to -1% of revenue, are available for exceeding (or failing) to meet performance targets under the scheme. In April 2025 we published our final decision (version 6) on our review of all components (market impact component, network capability component and the service component) of the transmission STPIS.²⁷⁷

Our final positions were to:

- suspend the market impact component, and explore developing an effective alternative with AEMO and key stakeholders
- amend the network capability component to make it a more streamlined process
- amend the loss of supply event frequency parameter of the service component.

Version 6 of the STPIS was applied to transmission interconnector Directlink for its 2025–30 regulatory period and will apply to other transmission network service providers at the commencement of their next respective regulatory period²⁷⁸.

Distribution

A distribution network service provider's allowed revenue is increased (or decreased) based on its relative service performance. The bonus for exceeding (or penalty for failing to meet) performance targets can range to ±5% of a distribution network service provider's allowed revenue.

Currently, the AER applies the distribution STPIS to 2 service elements:

- reliability of supply – unplanned (normalised) system average interruption duration index (SAIDI), unplanned (normalised) system average interruption frequency index (SAIFI) and momentary interruptions to supply (MAIFI)
- customer service – response times for phone calls, streetlight repair, new connections and written enquiries.²⁷⁹

The reliability component sets targets based on a network service provider's average performance over the previous 5 years. Performance measures are 'normalised' to remove the impact of supply interruptions deemed to be beyond the network service provider's reasonable control. While the reliability performance of each network fluctuates from year to year, network service providers have generally performed better than their STPIS targets.

²⁷⁷ AER, [Service target performance incentive scheme V6 – Final Decision](#), Australian Energy Regulator, 17 April 2025.

²⁷⁸ unless a Rule change is introduced to allow the commencement of version 6 before those dates.

²⁷⁹ Since April 2021, the AER has applied the CSIS instead of the STPIS telephone answering parameter to distribution network service providers whose customers support the change in customer service measurement.

3.16.7 Incentives to avoid fire starts

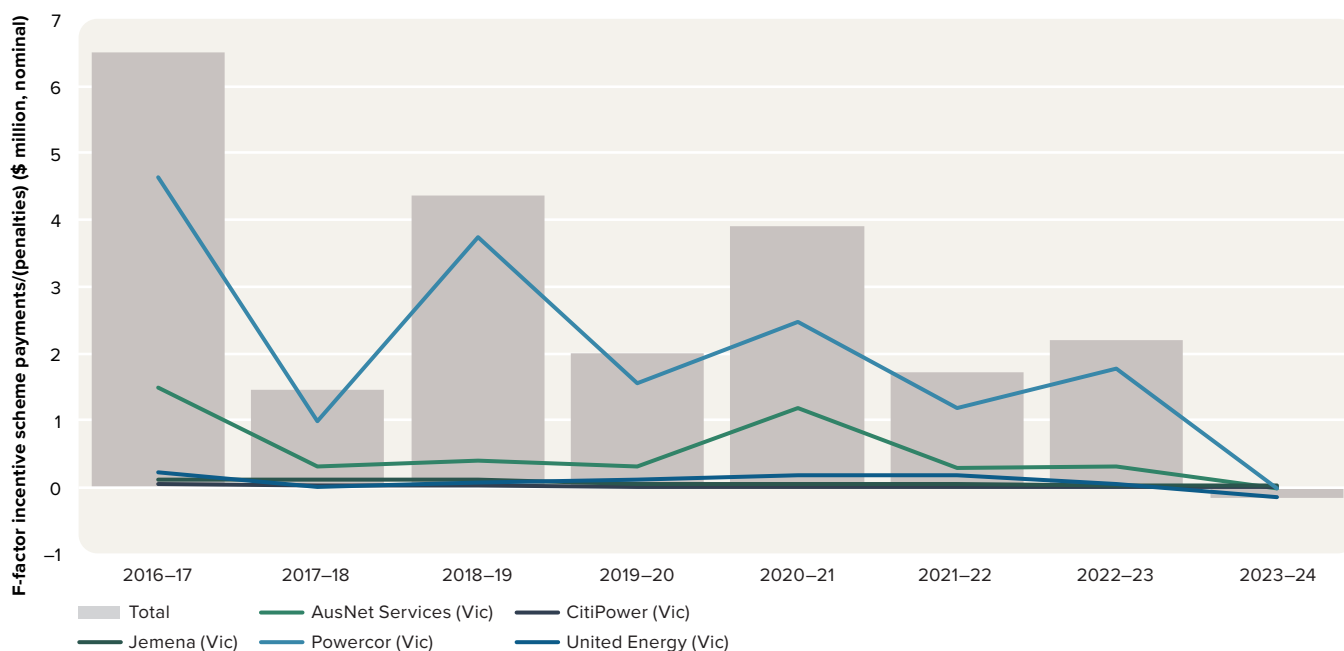
The AER administers the Victorian Government's f-factor scheme, an initiative that provides financial incentives to Victorian distribution network service providers to minimise the number of fire starts within their networks in high fire danger zones and times.

If the number of fire starts increases, the distribution network service provider is required to pay a penalty. Likewise, if the number of fire starts decreases, the service provider may receive an incentive payment. Payments and penalties are incorporated into network service providers' allowable revenue each year.

The penalty or reward rates under this scheme range from around \$1.48 million per fire start in high-risk areas on code-red days to \$300 in low-risk areas on a low fire danger day.

For the 2023–24 reporting period, incentive payments varied from a \$21,432 reward for Jemena to a \$153,816 penalty for United Energy. Both networks serve predominately urban customers with smaller components of rural customers. The impact of the incentive payments from 2023–24 will take the form of adjustments to the network service providers' regulated revenues in 2025–26 (Figure 3.37).

Figure 3.37 F-factor incentive payments – Victorian distribution networks



Source: AER, [Victorian electricity distributors' fire start reports for the July 2023–June 2024 reporting period](#).

3.16.8 Customer service

While reliability is the key service consideration for most energy customers, a distribution network service provider's performance also relates to the network business:

- providing timely notice of planned interruptions
- ensuring the quality of supply, including voltage variations
- avoiding wrongful disconnection (including for life support customers) and ensuring quick timeframes for reconnection
- being on time for appointments
- having a fast response to fault calls
- providing transparent information on network faults.

Each jurisdiction sets its own standards for these performance indicators. Some jurisdictions apply a guaranteed service level scheme that requires network service providers to compensate customers for inadequate performance. Because reporting criteria vary by jurisdiction, performance outcomes are not directly comparable. The AER provides an annual summary of outcomes against some of these measures for networks in Queensland, NSW, South Australia, Tasmania and the ACT.²⁸⁰ Victoria reports separately on network performance.²⁸¹

In July 2020 the AER released its customer service incentive scheme (CSIS), which provides incentives for distribution network service providers to provide measurable levels of customer service that align with their customers' preferences (Box 3.6).²⁸²

Box 3.6 Customer service incentive scheme

Our customer service incentive scheme (CSIS) is designed to encourage distribution network service providers to engage with their customers and provide a level of service that reflects their customers' preferences. We approve customer service performance targets as part of the 5-year revenue determination process. Under the CSIS, distribution network service providers may be financially rewarded or penalised depending on how well they perform against the designated customer service targets. The revenue at risk under the scheme is capped at $\pm 0.5\%$. The CSIS can only be applied if the telephone answering parameter of the STPIS is not applied.

The CSIS is a flexible 'principles-based' scheme that can be tailored to the specific preferences and priorities of a network service provider's customers. This flexibility allows for the evolution of customer engagement and the introduction of new technologies. The CSIS incentives are intended to target areas of service that customers want to see improved.

In subsequent regulatory periods, the targets under the scheme will be adjusted and set in accordance with any improved level of customer service.

Currently, the CSIS is applied to Victorian distribution network service providers AusNet Services, CitiPower, Powercor and United Energy for their current period (1 July 2021 to 30 June 2026) and to Essential Energy (NSW) and TasNetworks (Tasmania) (1 July 2024 to 30 June 2029).

In 2023–24 the outcomes of the CSIS were:

- \$291,423 penalty for AusNet Services
- \$1.7 million reward for CitiPower
- \$4.0 million reward for Powercor
- \$2.2 million reward United Energy.

280 AER, [Annual retail markets report 2023–24](#), Australian Energy Regulator, 2 December 2024.

281 The Essential Services Commission (Victoria) publishes all of its energy reports in one central [Victorian Energy Market Reporting Hub](#).

282 AER, [Final – Customer Service Incentive Scheme](#), Australian Energy Regulator, 21 July 2020.



4 Gas markets in eastern Australia

This chapter covers upstream gas markets in eastern Australia, encompassing gas production, wholesale markets for gas and the transport of gas along transmission pipelines for export or domestic use.²⁸³ Much of the chapter is focused on markets facilitated by the Australian Energy Market Operator (AEMO), but also includes information on bilateral commodity gas trades up to a year in duration.²⁸⁴

The main production basin in eastern Australia is the Surat–Bowen Basin in Queensland, which accounts for 65% of east coast production but less than 30% of Australia's total production. There are smaller basins in South Australia, New South Wales (NSW), off coastal Victoria and in the Northern Territory. Most of Australia's gas resources are conventional, including a large proportion off the north-west coast of Western Australia. Unconventional (coal seam gas) production is primarily supplied from the Surat–Bowen Basin.

The eastern gas market is interconnected through transmission pipelines, which source gas from these basins and deliver it to liquefied natural gas (LNG) facilities for export and to large industrial customers and major population centres for domestic use (Figure 4.1).

Due to the rapid expansion of the Australian LNG industry on both the east and west coasts, Australia has become one of the world's largest LNG exporters. Since the launch of the LNG export industry in 2015, gas producers have had the choice to export gas or sell it domestically. Consequently, prices in the domestic market are influenced by international gas prices.

Australian exports accounted for 20% of global exports in 2023, alongside Qatar (20%) and the United States (21%).²⁸⁵ On the east coast, exports accounted for 75% of gas demand in 2024, significantly exceeding domestic consumption levels.²⁸⁶

283 The Australian Energy Regulator (AER) has regulatory responsibilities in the eastern Australian gas market in Queensland, NSW, Victoria, South Australia, Tasmania and the ACT.

284 AEMO-facilitated markets include the Short Term Trading Market hubs and the Gas Supply Hub. Bilateral commodity reporting under the Gas Rules commenced in 2023, adding to secondary bilateral transaction reporting since 2019.

285 Department of Industry, Science, Energy and Resources, [Resources and energy quarterly](#), March 2025, p. 55.

286 Compared with residential and commercial, industrial and gas-powered generation demand, LNG demand accounted for 75% of gas consumption on the east coast in 2024. AEMO, [2025 Gas Statement of Opportunities](#), March 2025, p. 100.

Figure 4.1 Eastern gas basins, markets, major pipelines and storage



Source: AER; Gas Bulletin Board.

Box 4.1 The AER's role in wholesale gas markets

The Australian Energy Regulator (AER) has regulatory responsibilities across the entire gas supply chain in eastern Australia. At the wholesale level, we monitor and report on gas spot markets in Sydney, Brisbane, Adelaide and Victoria; gas supply hubs at Wallumbilla (Queensland) and Moomba (South Australia); short-term secondary capacity markets for gas transportation; and activity on the Gas Bulletin Board, which is an open access information platform covering the eastern gas market.

We monitor the markets and bulletin board to ensure participants comply with the National Gas Law and National Gas Rules, and we take enforcement action when necessary. Our compliance and enforcement work aims to promote confidence in the gas market to encourage participation. We also monitor the markets for particular irregularities and wider inefficiencies. For example, our monitoring role at the Wallumbilla and Moomba hubs explicitly looks to detect price manipulation. We are also the compliance and enforcement body for AEMO-facilitated auctions for secondary capacity in transmission pipelines.

We publish various reports, including gas industry statistics and our Wholesale markets quarterly reports, which cover gas spot market activity, prices and liquidity. The quarterly reports also include analysis of eastern Australia's liquefied natural gas (LNG) export sector and its impact on the domestic market. From July 2023, the AER began reporting more information on the export, reserve, storage, and domestic sale and swaps of gas. In May 2024, new wholesale market monitoring powers were legislated to facilitate a review of gas contract markets. Additional reporting from 2025 onwards will consider this new information alongside associated spot market impacts and implications on final costs faced by consumers.

The AER also has regulatory responsibilities for transmission and distribution pipelines (chapter 5) and retail markets (chapter 6).

We continue to engage with energy ministers' gas reform agenda and, when appropriate, we propose or participate in reforms to improve the market's operation. We also draw on our regulatory and monitoring work to advise policy bodies and other stakeholders on market trends, policy issues and irregularities.

Outside the eastern gas market, the AER is the gas pipeline regulator for the Northern Territory but plays no role in the territory's wholesale market. Facility operators in the Northern Territory must report gas flow activity to the Gas Bulletin Board.

We have no regulatory function in Western Australia, where separate laws apply. In Western Australia, the Economic Regulation Authority is the economic regulator for gas markets and pipelines and AEMO operates a gas spot market.

4.1 Snapshot

- 2024 price outcomes in gas spot markets were similar on average to 2023. In the first half of the year, spot prices were generally lower than the same time in 2023. This pattern reversed in the second half of the year and spot prices were generally higher than 2023 equivalents (section 4.3).
- In the second half of 2024, short-term (up to a year in length) bilateral gas contracting was at its highest levels since reporting of those contracts began in March 2023. This may suggest a trend towards shorter-term contracting (sections 4.3.1 and 4.3.2).
- Transportation capacity upgrades on the north–south pipeline corridor to increase the flow of gas south were completed in May and June 2024, delivering more supply from Queensland to southern markets (sections 4.6 and 4.8.3). Northern flows along the same pipeline also increased later in the year, contributing supply to record-high exports.
- The second quarter of 2024 saw spikes in gas-powered generation (GPG) output to offset periods of low wind and solar generation (section 4.4.1). This highlights strong interdependencies between electricity and gas markets in the National Electricity Market (NEM).
- Gas markets remain vulnerable to weather-driven peak demand days, when existing supplies to southern states must be supplemented with drawdowns from storage. Southern gas storage inventory at Iona depleted rapidly over June and July 2024 before easing market conditions allowed storage levels to replenish in August, averting the potential threat of a supply shortfall (section 4.5.4).

- Depleting offshore legacy gas fields in Victoria continue to limit southern production and increase supply shortfall risks. Production from Longford was higher over 2024 than 2023, breaking a recent trend of year-on-year declines. However, projected reductions in coming years are expected to drive a 47% decline in total southern production capacity by 2029. Over 30% of the projected decline is driven by reduced output from the Gippsland region, with one of Longford's 3 production trains taken offline in October 2024 (section 4.5.3).

4.2 Structure of the east coast gas market

The east coast gas market is made up of several separate underlying markets and supply hubs, as well as a supporting bulletin board that provides up-to-date information about gas flow. Around 10% to 30% of gas is traded in these spot markets, varying by location. All other gas trade is made under confidential bilateral contracts separate to these markets.

4.2.1 Contract markets

Most gas in Australia is traded through confidential bilateral contracts, which secure future supply and transportation capacity and limit participants' exposure to price fluctuations present in downstream markets. Contract prices generally reflect expectations of future market conditions, but shorter-term transactions in spot markets can reflect short-term shifts in market conditions due to factors such as immediate gas supply and gas storage levels, the timing of LNG shipments and conditions in the electricity market. As a result, their price levels are not always aligned, but they often move in similar directions.

For many domestic users, contract prices are likely to be more indicative of the costs they face than spot prices in the AEMO-facilitated gas markets.

The 2 main types of gas contracts (also known as gas supply agreements) are:

- contracts by gas producers to very large customers, such as major energy retailers and gas-powered generators
- contracts by retailers and aggregators that buy gas from producers and onsell it to commercial and industrial (C&I) customers.²⁸⁷

Long-term gas contracts historically locked in prices and other terms and conditions for several years. More recent analysis has continued to indicate an increasing shift towards shorter-term contracts (one to 2 years) since 2021.²⁸⁸ While an increase had previously been observed in the number of longer-term contracts executed at higher volumes, the overall volumes contracted for 2024 were lower than for 2023.²⁸⁹

4.2.2 Facilitated gas markets

Facilitated markets allow wholesale customers to trade gas without entering long-term contracts. Facilitated market trading can be a useful mechanism for participants to manage imbalances in their contract positions if their demand for gas changes close to the delivery date.

Several separate facilitated gas markets operate in eastern Australia – Victoria's Declared Wholesale Gas Market, the Short Term Trading Market, the Gas Supply Hub and the Day Ahead Auction, a separate east coast market for transportation and compression services.

287 Public information about contract prices was unclear. Much of the pricing was private and negotiated contract outcomes are often bespoke. There was also a disparity between the type of information available to large participants that are frequently active in the market and that available to smaller players. This imbalance favoured large incumbents in price negotiations. In response, in 2018 the ACCC began publishing gas price data as part of its 2017–2030 gas inquiry. Further reforms following the gas market transparency review require participants to report information to AEMO (from 15 March 2023) for publication on the Bulletin Board, including reserves resources reporting, facility developments, LNG spot transactions and bilateral short-term supply and swap transactions.

288 ACCC, [Gas inquiry 2017–2030, interim report, December 2024](#), Australian Competition and Consumer Commission, December 2024, pp. 40, 44–45.

289 In 2023, producers executed 12 gas supply agreements (GSAs), contracting 43.55 PJ, while retailers executed 18 GSAs, contracting 17.99 PJ. In 2024, producers executed 10 GSAs, contracting 27.85 PJ, while retailers executed 14 GSAs, contracting 12.52 PJ. These volumes relate to gas traded between suppliers and C&I users. ACCC, [Gas inquiry 2017–2030, interim report, December 2024](#), Australian Competition and Consumer Commission, December 2024, p. 77.

Victoria's Declared Wholesale Gas Market (DWGM)

Victoria's DWGM manages gas flows across the Victorian Transmission System and is the largest downstream spot market in eastern Australia.²⁹⁰ Participants submit daily supply and demand bids ranging from \$0 per gigajoule (GJ) (the floor price) to \$800 per GJ (the price cap).²⁹¹ Daily scheduling in Victoria occurs across 5 scheduling intervals over the gas day starting at 6 am, with subsequent adjustments over 4-hour intervals to account for physical or contractual constraints on gas supply and changes to forecast demand levels. Prices in the Victorian market cover gas as well as transmission pipeline delivery. AEMO selects the least-cost bids needed to match demand to establish a clearing price.

AEMO operates the financial market and manages physical balancing, including by scheduling gas injections at above market price to alleviate short-term transmission constraints if any arise.

Short Term Trading Market (STTM)

The STTM is a short-term trading market for gas, with hubs in Sydney, Brisbane and Adelaide, that allows gas trading on a day-ahead basis. AEMO sets a clearing price at each hub based on daily scheduled supply and demand by shippers to deliver gas, with a price floor of \$0 per GJ and a cap of \$400 per GJ.²⁹² Pipeline operators schedule flows to supply the necessary quantities of gas to each hub.

AEMO operates a balancing service – called market operator services (MOS) – to meet any variations in gas deliveries or withdrawals from the schedule. These services are mainly paid for by the parties causing the imbalance.

Gas Supply Hub (GSH)

Gas supply hubs at Wallumbilla in Queensland and Moomba in South Australia are a voluntary platform for gas trading. In contrast, the DWGM and STTM are mandatory for supplying the connected distribution systems. Gas can be transported through the 2 hubs and across other smaller locations on the east coast. Transactions can occur via an on-screen trading platform to automatically match supply and demand based on order price differences or through separate bilateral contracts (known as off-screen trades). Participants can use 5 standard product lengths when trading at the gas supply hubs – balance of day, daily, day-ahead, weekly and monthly. Participants can trade gas through the hubs up to a year in advance of physical supply.

Wallumbilla is a major pipeline junction linking gas basins and markets in eastern Australia, making it a natural point of trade. A single trading location makes it easier for participants to organise their gas trade across multiple pipelines, thus pooling potential buyers and sellers into a single market.

The east coast gas market is made up of several separate underlying markets and supply hubs, as well as a supporting bulletin board that provides up-to-date information about gas flow. Around 10% to 30% of gas is traded in these spot markets, varying by location. All other gas trade is made under confidential bilateral contracts separate to these markets.

²⁹⁰ Over 2024, supply to the Victorian gas market (totalling almost 200 PJ) exceeded the combined supply to the other 3 downstream spot markets in Adelaide (19.7 PJ), Brisbane (22.3 PJ) and Sydney (96.8 PJ) – totalling just under 140 PJ. On peak days, Victorian demand can exceed 1 PJ, more than double that of the next largest hub in Sydney, which peaked at a record high above 420 TJ on 20 June 2024.

²⁹¹ Supply offered in the DWGM is scheduled using 'injection bids', while demand for controllable (priced) and uncontrollable (forecast) demand are referred to as 'withdrawal bids'.

²⁹² In the STTM, supply 'offers' are scheduled alongside demand 'bids', with priced bids (only scheduled at or above the price of offered supply) determined after clearance of uncontrollable (forecast) demand bids (referred to as 'price taker' bids).

Like Wallumbilla, the Moomba hub is located at a major junction in the gas supply chain serving eastern Australia. Three critical pipelines – the South West Queensland, Moomba to Sydney and Moomba to Adelaide pipelines – connect to the hub. On 28 January 2021, trade points at Culcairn and Wilton were also introduced to facilitate trades at the Victorian and Sydney gas market locations. On 6 March 2025, AEMO introduced the Eastern Gas Pipeline (EGP) and Iona underground storage trade points alongside swap products for the notional transfer of gas between different locations. These can be traded to achieve similar physical outcomes to trading spread products.²⁹³

A significant proportion of trade on the Gas Supply Hub occurs ‘off-screen’, which allows participants to use brokers to match trades on their behalf or leverage their existing bilateral arrangements to facilitate the trading of gas supply. This can include shorter-term spot trades, and commodity trades over longer timeframes ahead of gas delivery, depending on the product traded.²⁹⁴

Day Ahead Auction (transportation-related services)

Gas produced in one region can help address a supply shortfall elsewhere, provided transmission pipeline capacity is available to transport the gas. However, several key pipelines experience contractual congestion, which arises when most or all of a pipeline’s capacity is contracted, making the pipeline unavailable to third parties. Contractual congestion may occur even if a pipeline has spare physical capacity. Reforms introduced in March 2019 enable participants to access unutilised pipeline capacity across the east coast.

Unutilised (contracted but not nominated) pipeline transport and gas compression capacity for the next day is sold the day before through an auction facilitated by AEMO. Since its inception, the auction has been widely used to move gas between the east coast gas markets. Since late 2022, participation in the auction has increased significantly and consecutive records for capacity won have been set, with amounts procured more than double the highest levels observed across previous years (section 4.6.2).

4.2.3 Gas Bulletin Board

The Gas Bulletin Board is an open access website providing current information on gas production, storage and transmission pipelines in eastern Australia. It plays an important role in making the gas market more transparent, especially for smaller players that may not otherwise be able to access day-to-day information on demand and supply conditions. It supplies information such as:

- pipeline capabilities (maximum daily flow quantities, including bidirectional flows), pipeline and storage capacity outlooks, and nominated and actual gas flow quantities
- daily production capabilities and capacity outlooks for production facilities
- gas stored, gas storage capacity (maximum daily withdrawal and holding capacities) and actual injections/withdrawals
- gas field information – reserves and resources, movement, development status, commercial recovery, including information on the basis of estimate preparation, and prices underpinning reserve and resource estimates
- LNG export and import information – shipment dates and volumes as well as detailed reporting of spot LNG transactions
- short-term gas supply and swap transactions with a contract length up to a year
- 36-month outlooks for uncontracted primary firm capacity (compression, storage, production and LNG import facilities) and short/medium-term outlooks for smaller users.

The bulletin board includes an interactive map showing gas plant capacity and production data, and gas pipeline capacity and flow at any point in a network.

Reforms were implemented in March 2023 that expanded the scope of information reported, with some participants required for the first time to report to the Gas Bulletin Board (section 4.11.2).

293 Location swaps are now available on the Gas Supply Hub at the following locations: Wallumbilla and Moomba, Moomba and Wallumbilla, Wallumbilla and Culcairn, Culcairn and Wallumbilla, Wallumbilla and Wilton, Wilton and Wallumbilla, EGP and Wallumbilla, and Wallumbilla and EGP. Spread products allow for the matching of supply and demand submitted at different locations in the Wallumbilla hub (WAL and SEQ location products) and between the Wallumbilla and Moomba hubs (WAL and MOO location products).

294 Most gas trading occurs ‘off-screen’ (not traded through the gas markets), but some of these trades are reported to the market operator and settled through the Gas Supply Hub trading platform.

4.3 Gas prices

Gas market prices are typically elevated during winter periods, when colder weather in southern markets increases demand for residential gas heating. This is particularly significant in the larger Victorian market, where daily demand can exceed 1 petajoule (PJ) on cold days. Gas prices can also increase during summer periods, influenced by higher demand for gas-powered generation in the electricity market, which coincides with warmer temperatures and increased demand for air conditioning.

4.3.1 Gas contract prices

Gas contracts can take many different forms, with variations in the time between traded and delivery dates and the timespan in which the gas is delivered over. For example, gas can be contracted to be delivered in daily quantities for weeks or months at a time and can range from 1 to 10 years in length domestically. LNG export contracts are set over longer periods of around 20 years.²⁹⁵

Market participants are required to report their gas contract information to the ACCC. The ACCC then reports on these prices through its gas inquiry responsibilities. The inquiry's interim updates consider numerous factors that affect contract prices, including the impact of domestic market supply and market price trends, LNG export activity and links to international prices (section 4.3.4).

Mandatory Gas Code of Conduct (\$12 reasonable price provision)

Following the introduction of the Competition and Consumer (Gas Market Emergency Price) Order in late 2022, the Australian Government implemented a Mandatory Gas Code of Conduct to replace the order on its expiry in 2023. The Code came into effect with a 2-month transitional period from 11 July 2023, with the aim to ensure domestic users' ability to contract for gas at reasonable prices and on reasonable terms.

The Code adopted a \$12 per GJ reasonable price provision and provides an exemptions framework to incentivise short-term supply commitments and investment to meet ongoing domestic medium-term demand. It also includes transparency obligations on uncontracted gas production and expected domestic availability, as well as conduct provisions and process standards for commercial negotiations. A review of the Code is being undertaken in the second half of 2025.

Contracting activity significantly increased in the second half of 2024

The ACCC reports on gas supply agreements (GSAs) in its inquiry reports.²⁹⁶ The number of GSAs executed by producers and retailers for supply in 2025 and 2026 more than doubled in the second half of 2024 compared with the first half of the year. The volume of gas sold under GSAs for 2025 supply also increased – producers sold 58 PJ in the second half of 2024 compared with 28 PJ in the first half of 2024, and retailers sold 31 PJ compared with 2 PJ.

Most GSAs agreed to in the second half of 2024 for 2025 and 2026 supply have a term length of 1 year. This is despite many gas buyers, including C&I users, preferring longer, multi-year contracts.

For GSAs covering 2025 supply:

- Average prices agreed under producer GSAs in the second half of 2024 were \$13.58 per GJ, a 10% decrease from prices in the first half of the year.
- Prices agreed under producer GSAs for delivery in southern states was higher than prices for delivery in Queensland. This may reflect tighter supply in southern states and the cost of transporting gas south from Queensland.
- Prices agreed under retailer GSAs in the second half of 2024 averaged \$14.51 per GJ, a 1% decrease from the preceding 6 months.
- Retailers offered more flexible terms than producers, which may reflect their ability to manage changes in demand on a portfolio basis.

²⁹⁵ RBA, [Understanding the East Coast Gas Market](#), Reserve Bank of Australia, March 2021.

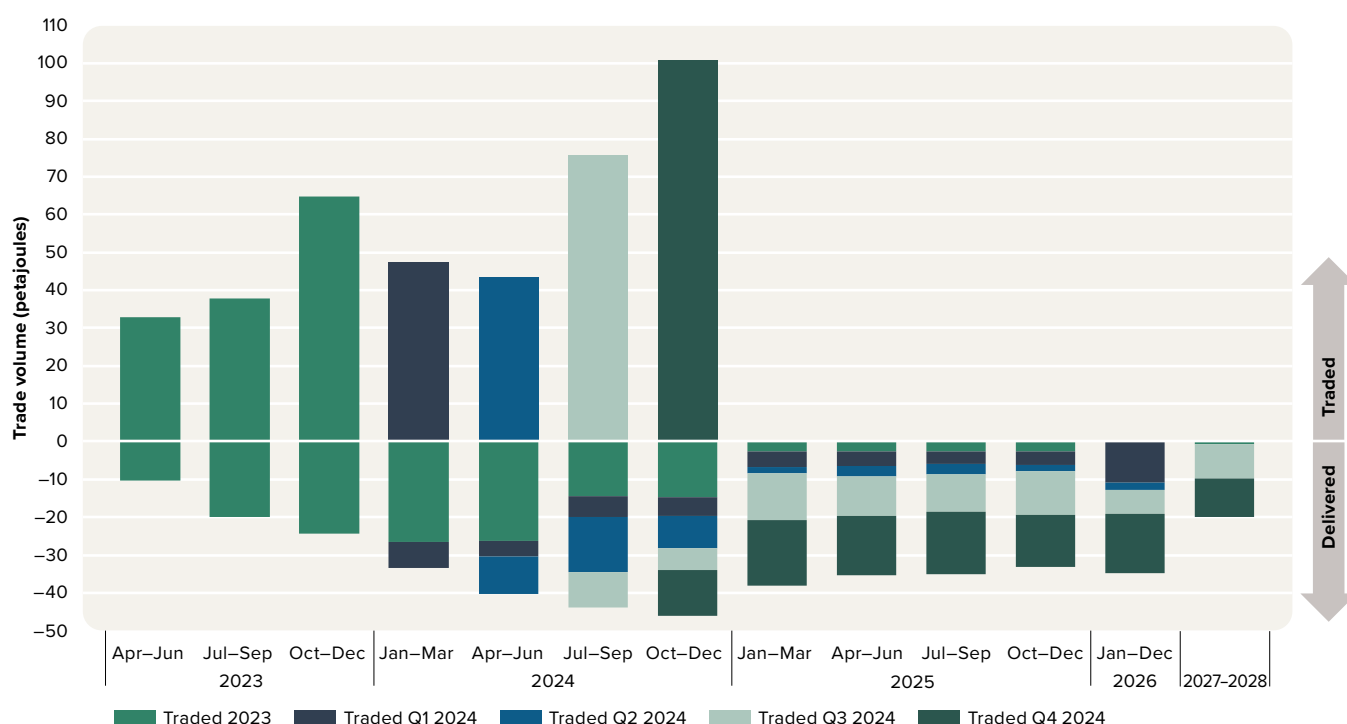
²⁹⁶ ACCC, Gas inquiry 2017–2030, [Interim update on long-term contract prices for July–December 2024](#), Australian Competition and Consumer Commission, March 2025.

For GSAs covering 2026 supply, average prices agreed under producer contracts in the second half of 2024 fell 2% compared with the first half of the year, to \$13.94 per GJ. Prices under producer contracts were higher in southern states than in Queensland. Prices agreed under retailer GSAs over 2024 averaged \$13.55 per GJ.

4.3.2 Short-term transaction reporting

With a significant proportion of gas trade being contracted directly between participants outside of AEMO-facilitated markets, increased reporting of bilateral gas supply contracts was introduced in March 2023.²⁹⁷ The Gas Market Transparency reforms require parties to report details of bilateral transactions up to a year in duration to the Gas Bulletin Board.²⁹⁸ Figure 4.2 shows a breakdown by quarter of the reported transactions by trading date and delivery date since April 2023.

Figure 4.2 Traded versus delivered quantities



Note: 'Traded' refers to the trade date of the short-term supply transaction, while 'delivered' refers to the month the gas volume will be supplied. Where there is not enough trades or participants reporting in a period, the data is aggregated to a longer timeframe.²⁹⁹

Source: AER analysis using Natural Gas Services Bulletin Board data, accessed 8 April 2025.

For supply in 2024, 267 PJ of gas sales were reported. Most of that occurred over the July to September (75.5 PJ) and October to December (100.9 PJ) quarters. The combined volume of 176.4 PJ over these quarters is an increase of 72% compared with the same period in 2023. Most of the gas traded over October to December was for delivery over 2025 and 2026, with 61.4 PJ of these sales for delivery in 2025, 15.7 PJ for delivery in 2026 and 10.2 PJ for delivery over 2027 to 2028. Two years of short-term bilateral transactions have now been reported – these show that trade significantly increases in the last quarter of the year, when participants secure and finalise supply for the following year and beyond.

²⁹⁷ DCCEEW, [Regulatory amendments to increase transparency in the gas market](#), Department of Climate Change, Energy, the Environment and Water, 19 November 2020.

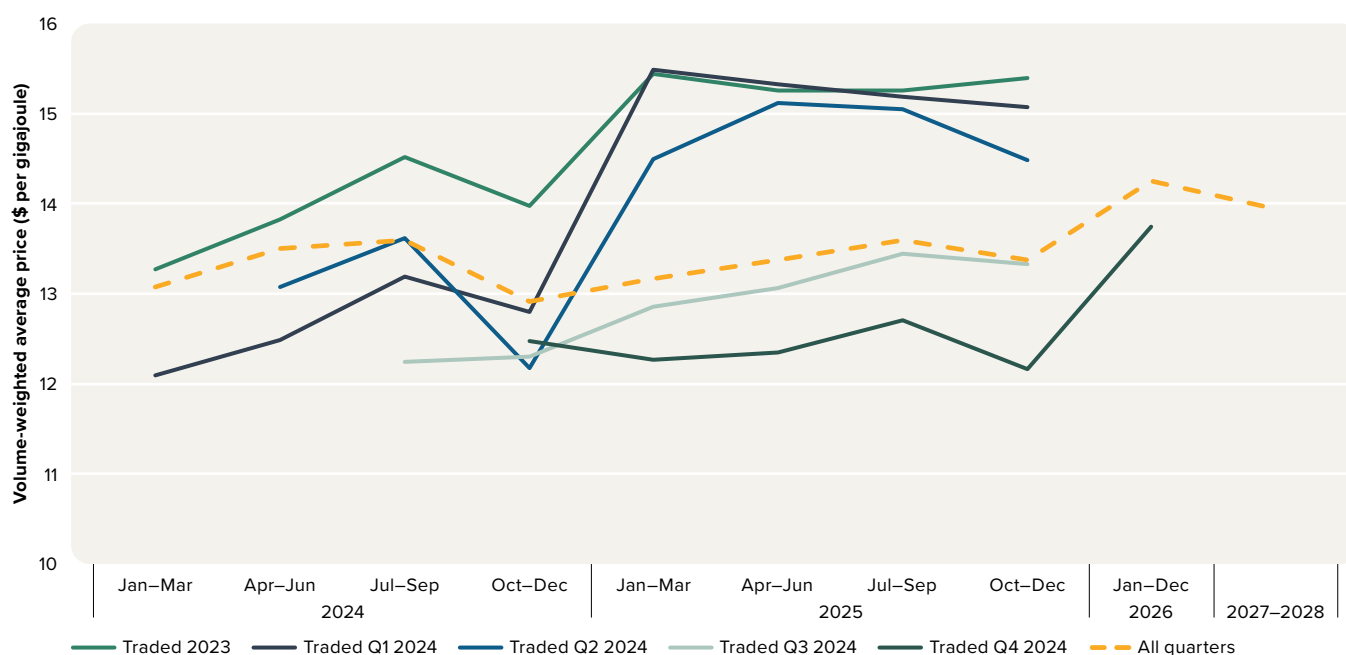
²⁹⁸ The AER published a special report in December 2023 providing analysis and insights into all short-term transactions reported up to 31 October 2023 to the Gas Bulletin Board. The report also included feedback from industry stakeholders on the effectiveness of current reporting practices and recommendations to enhance this in future reporting. AER, [Special report: Wholesale gas short term transactions reporting](#), Australian Energy Regulator, 6 December 2023.

²⁹⁹ Differences in volumes reported previously reflects a feature of the reporting framework, where contracts can be amended or volumes updated before delivery. It is also reflective of late or inaccurate reporting, which the AER monitors.

Overall, the volumes of trade reported in the last 2 quarters of 2024 were the highest volumes of trade reported since reporting commenced in March 2023, with prices trending lower over 2024. Rather than indicating a higher volume of total gas supplied, higher volumes of trade may indicate a reallocation of gas supply contracts to shorter-term contracts (up to a year in length) and away from transactions longer in length (greater than a year). These longer-term transactions are not currently reported to the Gas Bulletin Board but are reported on by the ACCC (section 4.3.1).³⁰⁰

Over 2024 the forward volume-weighted average (VWA) price continued to trend lower every quarter – the VWA price for gas traded across October to December 2024 for delivery over 2025 was \$12.38 per GJ, the lowest compared with all previous quarters (Figure 4.3). Volume-weighted average prices were \$13.37 per GJ for gas deliveries over 2025 and \$14.25 per GJ for deliveries over 2026.

Figure 4.3 Volume-weighted average forward price curve based on the traded quarter



Note: The volume-weighted average prices are based on the supply dates of the reported transactions in the quarter the transactions occurred for 2024, while all transactions for 2023 have been grouped together. These prices exclude pricing structures linked to the STTM or DWGM or where the transaction was between related parties. Where there are not enough trades or participants reporting in a period, the data has been aggregated.

Source: AER analysis using Natural Gas Services Bulletin Board data, accessed 8 April 2025.

ASX Wallumbilla Natural Gas Futures product

The new ASX Wallumbilla Natural Gas Futures product commenced trading on 19 August 2024 for first delivery in October 2024.³⁰¹ It is a monthly product that can be traded up to 3 years in the future, with each futures contract of gas representing a delivery obligation of 100 GJ per day of the calendar month being traded. 5 business days before the beginning of the month traded, any open interest positions³⁰² are converted to physical obligations on the GSH in a Monthly Netted Product deliverable at the Wallumbilla High Pressure Trade Point, referred to as delivery exchange for physical (Delivery EFP). This product aims to provide a transparent forward price curve out to 3 years, improve liquidity at the GSH and provide an additional hedging tool for participants to manage their risk.

Over the October to December quarter 2024, trading of the product increased but volumes remained low overall – 26 futures contracts were traded for the quarter, equating to 80 terajoules (TJ) when delivered. Prices for these products also increased over the quarter in line with movements observed in other domestic gas markets, with Delivery EFP prices ranging from \$13.00 per GJ to \$13.50 per GJ.

³⁰⁰ The ACCC in its [December 2024 interim report](#) also noted that gas is increasingly being sold by producers under shorter-term Gas Supply Agreements, with most new agreements having a term of less than 2 years.

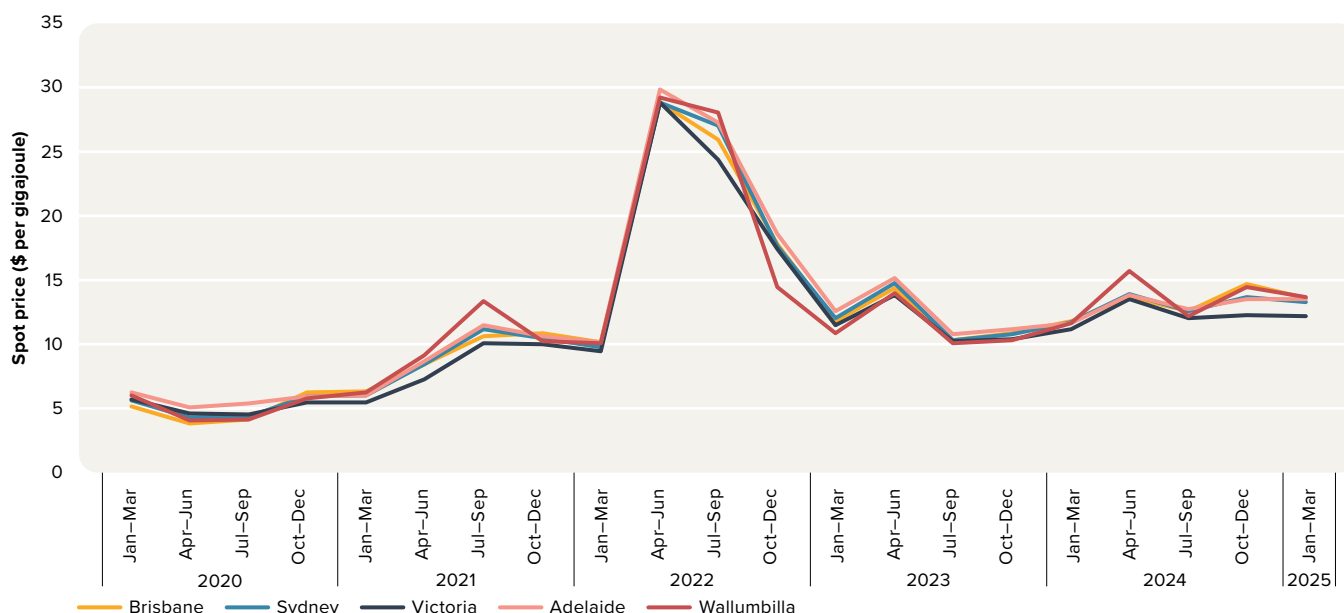
³⁰¹ ASX, [Trade our derivatives market](#), Australian Stock Exchange, accessed 27 June 2025.

³⁰² Open interest refers to outstanding contracts that have not been closed or settled, representing open positions held in the contracts, which can be used to assess market sentiment and the strength of price trends.

4.3.3 Spot market prices

Gas spot market prices over the second half of 2024 averaged just over \$13 per GJ, up 23% compared with prices across the second half of 2023 (Figure 4.4).³⁰³ This was influenced by higher LNG exports and GPG gas usage driving increased demand.

Figure 4.4 Eastern Australian gas market prices



Note: The Wallumbilla price is the volume-weighted average price for day-ahead, on-screen trades at the Wallumbilla Gas Supply Hub. Brisbane, Sydney and Adelaide prices are ex-ante. The Victorian price is the average daily weighted imbalance price.

Source: AER analysis of Gas Supply Hub, Short Term Trading Market and Victorian Declared Wholesale Gas Market data.

Gas spot market prices in 2024 and 2025

Following a period of stable prices across the start of 2024, increased prices over the April to June quarter coincided with high demand days and constrained supply and put pressure on gas storage levels in Victoria. Despite increased gas flows south from Queensland and pipeline capacity expansions on the north–south pipeline corridor, limited flows further south into Victoria contributed to a greater reliance on Iona’s storage supply, driving a rapid depletion of storage inventory. From late May, rapid drawdowns on Iona pushed up prices and resulted in numerous high-priced gas days from mid-June.³⁰⁴ These price impacts in Victoria flowed through to other markets in southern regions, with limited increases also observed in Brisbane.³⁰⁵

303 Cold weather and constraints limiting production and transportation capacity drove up prices just before winter 2023, resulting in higher prices over the April to June quarter.

304 Additional information on prices, supply and demand over winter 2024 are outlined in the [State of the energy market 2024](#) report.

305 Cold weather driving higher residential heating demand and higher gas generation requirements across mainland regions of the NEM, alongside reduced capacity at Longford (Victoria’s largest supply source) due to offshore maintenance, increased participants’ reliance on southern storage.

Box 4.2 AEMO East Coast Gas System Risk or Threat Notice³⁰⁶

On 19 June 2024 AEMO issued a system risk or threat notice, identifying that the supply of gas in all or part of the east coast gas system may be inadequate to meet demand. The notice was implemented to remain in place until 30 September, with AEMO outlining an expectation of an industry response to mitigate the system threat and prevent the requirement for market intervention.³⁰⁷ AEMO revoked the threat notice ahead of schedule on 23 August as supply and demand trends improved across all southern regions and Iona underground storage inventories recovered over August (Figure 4.20).³⁰⁸

After settling somewhat over the July to September quarter, increased prices for the following quarter were influenced by record exports coinciding with periods of elevated gas generation in Queensland. While gas flows north over the October to December quarter mirrored similar highs observed across in the corresponding fourth quarter in 2016, they were significantly elevated compared with flows over the October to December period in recent years.³⁰⁹ These high flows were supported by record gas flows north from Victoria, supplementing high Roma production levels to supply record export demand. This offset relatively low downstream market demand levels for the quarter.

Periods of higher gas prices from mid-November to mid-December primarily influenced the Brisbane market, with flow through effects on other downstream markets. This was largely driven by elevated gas-powered generation (GPG) demand in Queensland that prompted GPG gentailers to adjust gas market offer profiles across their east coast portfolios. The impact of these adjustments was less evident in Victoria, resulting in a larger average price gap emerging of around \$3.50 per GJ when Brisbane prices reached their highest levels.³¹⁰

Average annual domestic gas prices increased over 2024, rising by 7% from the previous year. Price increases occurred alongside several cold spells during winter and higher GPG demand towards the end of the year.

East coast gas price spikes occurred on several occasions over the period and tended to coincide with spikes in Queensland's GPG output and Queensland's NEM spot prices; the latter exceeded \$300 per MWh on more than 50 occasions during Brisbane's high gas prices.

From mid-December, GPG demand fell and lessened the incentive to transport Victorian gas north, easing gas price pressures. This saw refilling of gas storage at Iona recommence following a temporary pause over the high-priced period, with the facility reaching full capacity before winter 2025.

306 AEMO, [East Coast Gas System Risk or Threat Notice](#), Australian Energy Market Operator, June 2019.

307 AEMO expectations included:

- participants taking reasonable measures to maximise production and supply from Queensland for delivery to southern jurisdiction end users to reduce the rate of storage depletion
- consideration of specific gas demand requirements (including GPG) and the supply sources required to meet that demand.

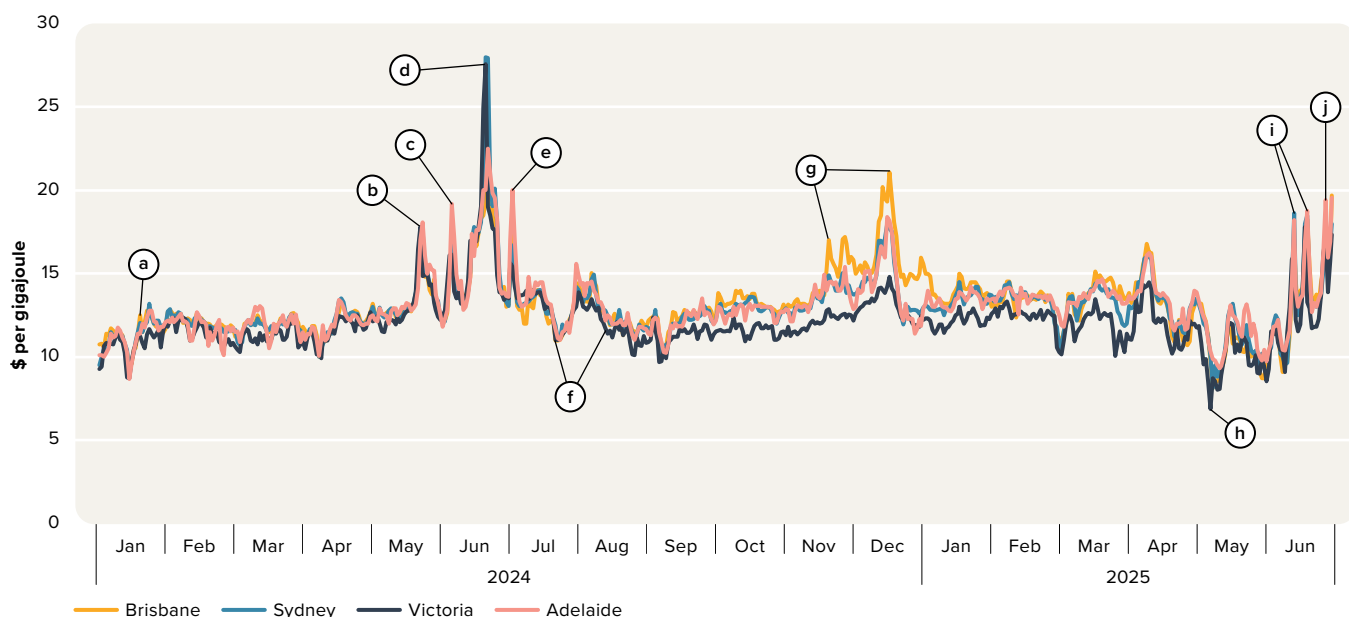
308 Replenishment of Iona's gas storage levels were assisted by warmer weather easing pressure on demand, alongside reduced gas-powered generation output.

309 High flows in 2016 coincided with the commencement of east coast LNG exports following completion of construction.

310 Daily prices in Victoria did not exceed \$14.80 per GJ in the quarter, whereas daily prices in Brisbane remained above that level and peaked at just over \$21 per GJ on 16 December. Prices in Brisbane exceeded \$15 per GJ on 35 occasions. Adelaide also recorded 12 days above that level and Sydney recorded 9 instances.

Figure 4.5 sets out an annotated timeline of key pricing events in 2024 and 2025 to date.

Figure 4.5 Daily gas spot prices



- Note:
- a From mid-January 2024: Increased price stability in downstream markets, with historically low market demand offsetting elevated LNG export flows.
 - b 21 to 23 May 2024: Cold weather driving increased heating demand, offshore maintenance constraining Longford supply and elevated mainland GPG demand.
 - c 4 to 6 June 2024: Cold weather demand and elevated GPG and delayed Longford ramp-up following maintenance.
 - d 18 to 22 June 2024: Continuing constrained output from Longford with high demand and high GPG, continued reliance on Iona storage supply and elevated Tasmanian GPG demand due to drought conditions reducing hydro-electric generation. A pipeline constraint in Victoria also resulted in significant ancillary payments to compensate for the scheduling of higher priced gas.
 - e 1 to 2 July 2024: High market demand and elevated GPG.
 - f 21 to 26 July and 11 August 2024 onwards: Reduced market demand and GPG eases price pressures, with an unseasonably warm end to winter in August.
 - g 18 November to 20 December: Higher gas generation demand in Queensland driving up prices in Brisbane, with price impacts flowing through to STTM hubs in Adelaide and Sydney. Record Queensland export demand places further upwards pressure prices, with a significant price gap emerging between Victoria and Brisbane.
 - h 4 to 13 May 2025: Full Iona storage inventory and low demand in Victoria put downward pressure on prices.
 - i 11 to 14 June 2025: Unplanned compressor outage at one of Longford's 2 remaining gas plants significantly reduced production capacity during a period of high GPG demand. Cold weather impacting southern regions also drove high gas market demand, with Victoria exceeding 1 PJ per day and Sydney peaking above 400 TJ on 13 June.
 - j 26 to 30 June 2025: High coincident GPG demand coinciding with a number of baseload generator outages across the NEM and continued high coincident gas market demand.

Source: AER; AEMO (raw data).

Significant price variations in late 2024

The significant price event reporting threshold for market operator services (MOS) was triggered in the Sydney STTM on 3 occasions in November and December 2024.

MOS, also known as balancing gas, is required to manage everyday pipeline deviations. A pipeline deviation occurs when there is a difference between the total quantity of gas nominated by the pipeline's shippers and the quantity of gas physically delivered. There are 2 kinds of pipeline deviations – positive (when more gas is delivered) and negative (when less gas is delivered, resulting in gas being 'parked' upstream of the hub on a pipeline). When actual gas deliveries are higher than final nominations, the difference is allocated as increase MOS; when actual gas flows are lower than final nominations, the difference is allocated as decrease MOS. Increase MOS is provided to the hub from gas stored on the pipeline. Participants that loan this gas are compensated for this service through service payments. Decrease MOS requires the use of capacity on the pipeline to store gas that could not be delivered to the hub. Similarly, participants that park this gas are compensated for this service through service payments.

Market operator services involve allocating costs to market participants due to gas delivered deviating from schedules. AEMO is responsible for overseeing and allocating payments between market participants. Daily total MOS payments above \$250,000 are rare and the AER is required to report on any high-priced MOS events above that threshold within 60 business days after the final settlement run for the month in which the event occurred.³¹¹ MOS payments mainly occur when there are deviations between demand and supply compared with scheduled amounts, but it can also be driven by physical pipeline dynamics, where differences in pressure between transmission pipelines and the lower-pressured distribution system impact contracted gas deliveries.³¹² This can result in counteracting MOS (CMOS) requirements, where additional supply from one pipeline offsets under-delivered supply from the other (in excess of differences between forecast and actual supply/demand). The AER did not identify any compliance issues as part of the report.

The 3 events were driven by different factors but all related to the requirement to temporarily store (park) gas that could not be physically delivered to the hub on the Eastern Gas Pipeline (EGP).

While CMOS requirements impacted costs on 28 November and 14 December, outcomes for 20 December were primarily driven by over-forecast demand.

Table 4.1 Drivers of high MOS service payments in the Sydney STTM

Date	Unplanned reduced network pressure ^a	Pipeline flow and pressure dynamics	Supply (over or under supply)	Demand (over or under forecasting)	Low pipeline flows	Pipeline renominations
28 November ³¹³	Yes	Yes	No	No	No	No
14 December ³¹⁴	No	No	Yes	Yes	Yes ^b	Yes ^b
20 December ³¹⁵	No	No	Yes	Yes	No ^c	No ^c

Note:
a The AER has a [compliance bulletin](#) designed to avoid MOS when there are pressure reductions. However, this relies on prior knowledge (before the gas day) that network pressures need to be reduced.
b Indicates that the driver did contribute to high MOS service costs on a certain day, but only in combination with other drivers.
c Indicates that the driver was not a main contributor to high MOS service costs on a certain day, but it may have some influence over MOS outcomes.

Source: AER analysis using STTM data. Pressure data provided by Jemena Gas Networks (network operator of the Sydney distribution network). EGP flow data provided by Jemena (pipeline operator of EGP).

For more detailed information on these events and the use of MOS on the affected days, see the Significant price variation report Sydney STTM – November and December 2024.³¹⁶

311 Market operator service (MOS) 'service costs' have rarely exceeded this threshold, happening on 15 prior occasions since the start of the STTMs, with high-priced MOS events occurring only 5 times in the Sydney market since 2016 and on one occasion in each of the Adelaide and Brisbane hubs.

312 The Moomba to Sydney Pipeline (MSP) operates on a pressure-controlled delivery system into Sydney, where low pressure in the hub (distribution network) is closely met by additional supply to compensate for shortterm supply shortfalls. The Eastern Gas Pipeline operates in a similar way for deliveries into the Wollongong sub-network but uses flow-controlled deliveries into the main distribution system that provide gas supply to the main trunkline. Both pipelines deliver gas into the Wilton distribution point.

313 On 28 November, an unforeseen reduction in the Sydney distribution network's pressure resulted in additional (unnominated) supply flowing from the Moomba to Sydney Pipeline (MSP), impacting scheduled deliveries on the EGP (requiring gas to be parked on the pipeline). This resulted in MOS service payments accruing to \$1,029,768.

314 On 14 December, participants renominated scheduled MSP supply over to the EGP on a day with lower than forecast hub demand. This resulted in low net flows physically supplying gas to the Sydney hub from the MSP. To meet backhaul demand upstream of the hub on the MSP, increase MOS was allocated on the pipeline to make up for the shortfall in nominated supply. As a result, MOS service payments accrued to \$305,683.

315 On 20 December, over-forecast demand resulted in MOS being allocated due to the scheduled oversupply of gas being parked on both pipelines (primarily on the EGP), with MOS service payments accruing to \$322,998.

316 AER, [Significant price variation report Sydney STTM](#), Australian Energy Regulator, March 2025.

4.3.4 Domestic spot prices and international price trends

Average annual domestic gas prices increased over 2024, rising by 7% from the previous year. Price increases occurred alongside several cold spells during winter and higher GPG demand towards the end of the year. While prices did not reach the unprecedented levels of 2022, they remained elevated – sitting around 44% higher than average downstream market prices in 2021.

Linkages between domestic and international prices

Since 2021, competition between Asian, European and South American buyers increased demand for LNG during the Northern Hemisphere winter periods. Late 2022 saw a peak in international price levels, with supply concerns in Europe due to geopolitical conflicts and infrastructure outages (Figure 4.6). Global demand surged across Europe and Asia to secure gas stocks and increase storage levels. After peaking in late 2022, international price levels reduced significantly into 2023 but remained elevated compared with historical levels.

From mid-2023, domestic prices were on par with international price levels and remained relatively stable as international prices gradually increased to the end of the year.³¹⁷ At the end of 2023, European storage inventories entered the October to December quarter at a record high of 97% full alongside record floating storage supply.³¹⁸

Seasonal factors are also strong drivers of international demand and prices for gas, typically increasing during the Northern Hemisphere winter. A mild Northern Hemisphere winter at the end of 2023 also suppressed demand,³¹⁹ reducing pressure on international prices into 2024 alongside increases in other sources of LNG supply.³²⁰

In 2024, international LNG spot prices gradually decreased across January and February before starting to rebound slightly from March, with prices in February reaching some of the lowest levels observed over the past 2 years. Ahead of the Australian winter, local prices had risen above international price levels due to numerous supply and demand factors, particularly in the southern markets that experienced a prolonged stretch of cold weather (Figure 4.7). This trend reversed across the remainder of the year, with international prices increasing above domestic levels due to the seasonal shift from summer to winter in the Northern Hemisphere.

Seasonal factors are also strong drivers of international demand and prices for gas, typically increasing during the Northern Hemisphere winter.

From mid-2024 until November 2024, European reservoir levels were significantly higher than their 5-year average and reached a 90% capacity level approximately 3 months earlier than is typical. However, drawdowns on European stock levels occurred earlier and at a higher rate than the 5-year average, putting upwards pressure on LNG prices to Europe. To avoid being stranded for gas supply and having to pay higher prices, as seen in 2022, Asian inventories were also stocked in advance. This led to a premium in LNG prices for deliveries to Asia compared with Europe, which steadily eased.

In the Northern Hemisphere, unpredictable weather variations over the Asian summer contributed to demand for spot cargoes and high LNG prices. Japan and Korea experienced intense and unpredictable heat waves while China experienced wet and cooler temperatures in the south but hot and dry in the north. These factors put upward pressure on gas-powered generation for cooling demand. Although some parts of Europe faced heatwaves, adequate supply and lower-than-expected LNG prices combined with increased availability of piped gas, ensuring that Europe was adequately stocked for winter.

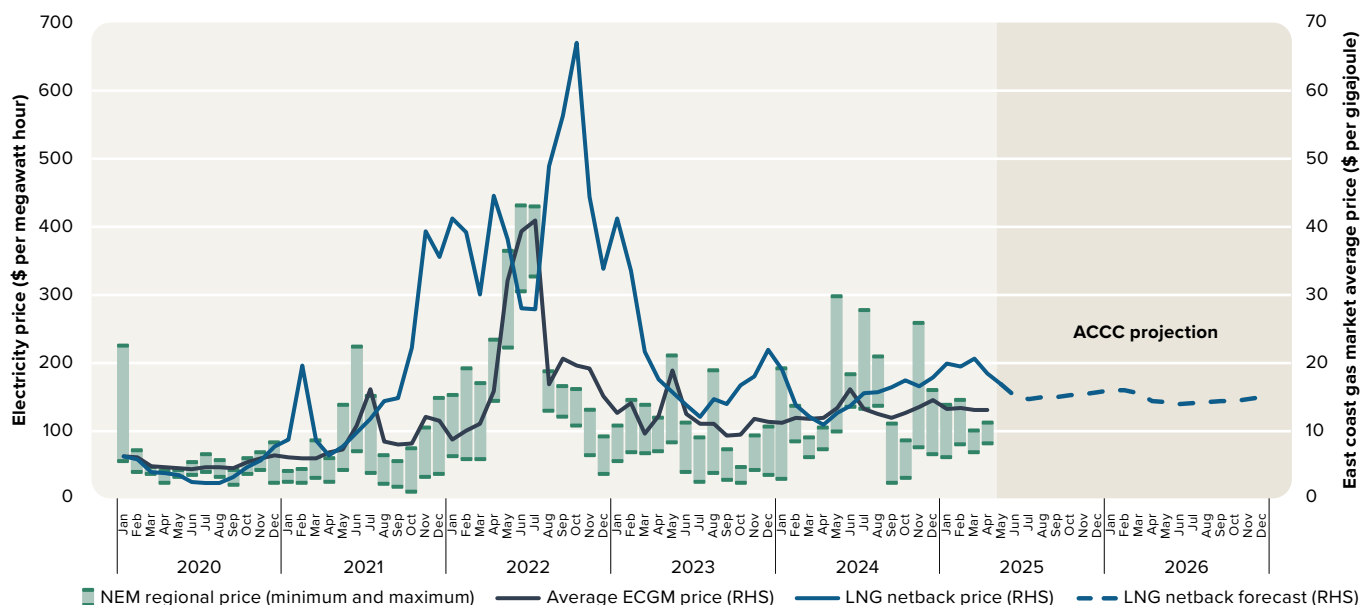
317 While international price levels had decreased significantly from record highs in the years prior, they remained above the historical trend in mid-2023.

318 AER, [Wholesale markets quarterly – Q4 2023](#), Australian Energy Regulator, January 2024.

319 Storage levels rounded out the quarter at 87% of capacity. Argus direct, *Europe LNG: Des prices tick down*, 29 December 2023.

320 LNG availability from the United States increased by 6% and Norway's availability was also up 1.5% following the resolution of unplanned outages from 2022.

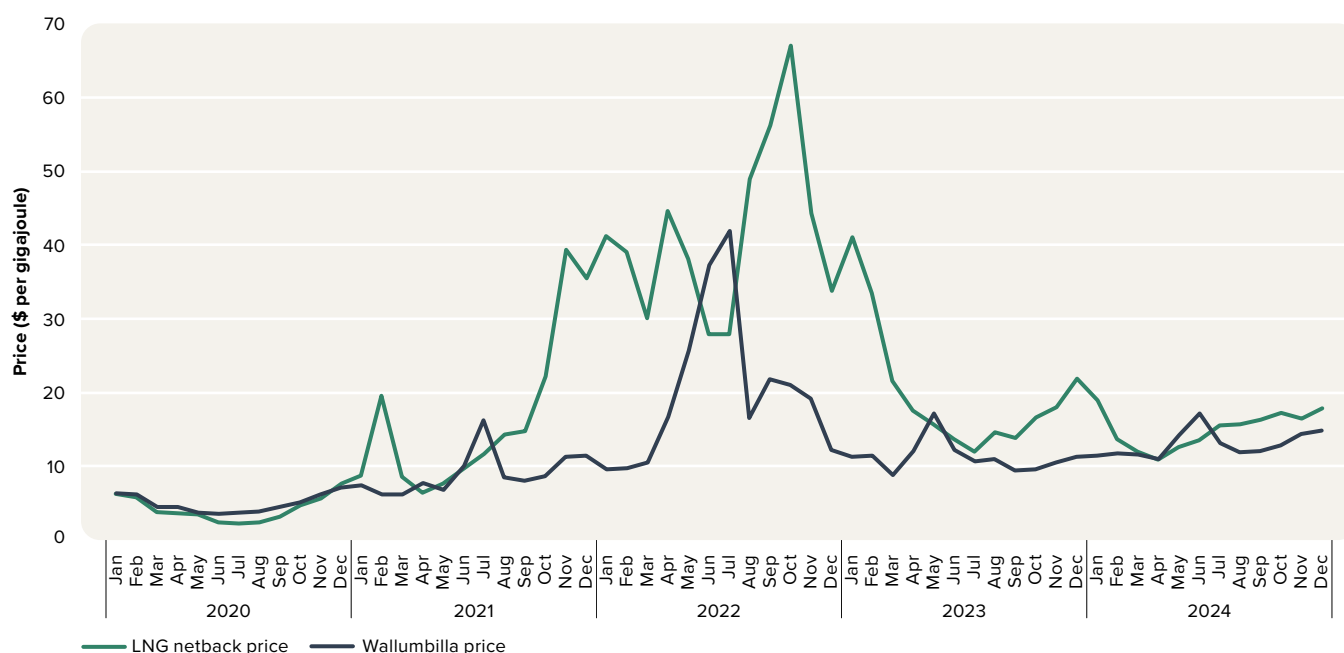
Figure 4.6 Comparison of east coast gas market, NEM and LNG netback prices



Note: ECGM is east coast gas market. NEM is National Electricity Market. The LNG netback price calculates the export parity price and subtracts the cost of liquefaction and transport required to produce and deliver LNG to international customers. LNG netback forecast 28 June 2024.

Source: AER analysis of NEM, Short Term Trading Market, Victorian Declared Wholesale Gas Market and ACCC LNG netback price data.

Figure 4.7 LNG netback and Wallumbilla prices



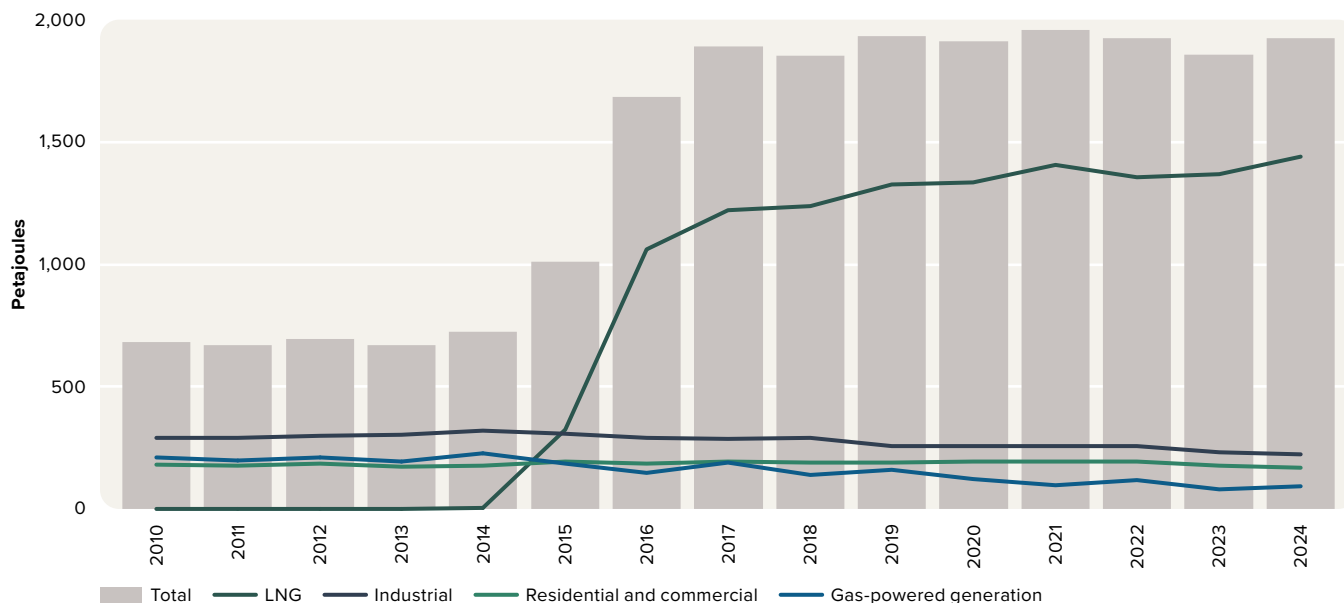
Note: The LNG netback price calculates the export parity price and subtracts the cost of liquefaction and transport required to produce and deliver LNG to international customers.

Source: AER analysis of gas supply hub data; ACCC (LNG netback prices).

4.4 Gas demand in eastern Australia

Around 75% of domestic gas production in eastern gas markets (excluding the Northern Territory) is exported and the balance is sold into the domestic market (Figure 4.8).

Figure 4.8 Eastern Australian gas demand



Source: AEMO, 2025 Gas Statement of Opportunities, March 2025.

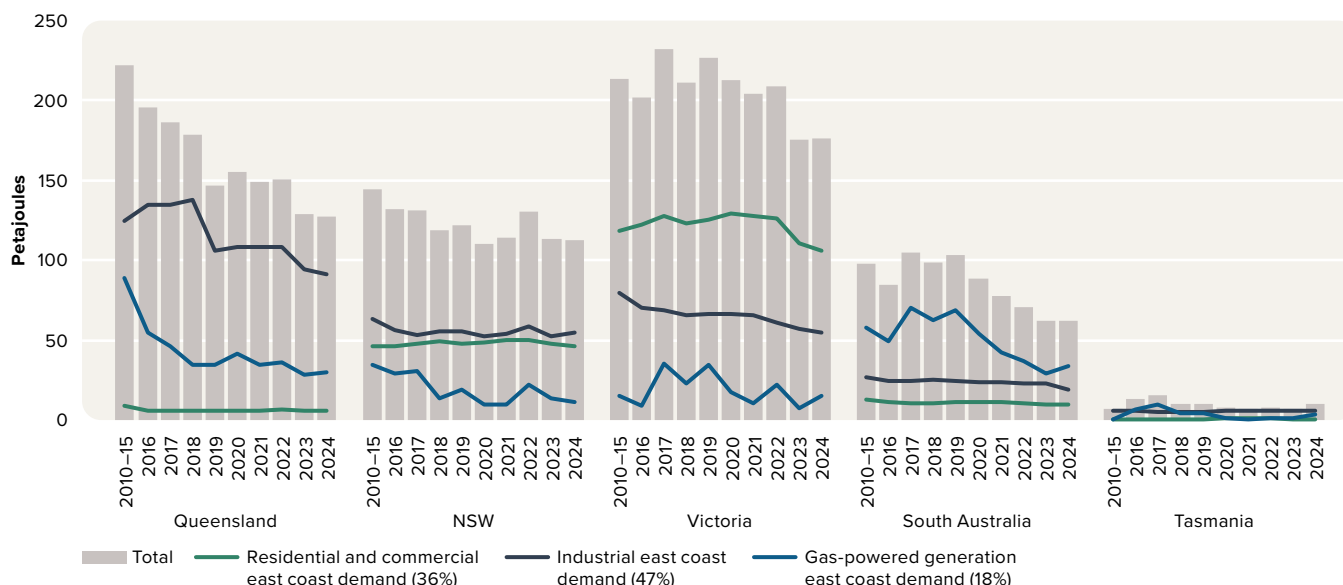
4.4.1 Domestic demand

Domestic customers in eastern Australia used around 488 PJ of gas in 2024 (Figure 4.9).

These customers included industrial businesses, electricity generators, commercial businesses and households.

Industrial customers consumed 46% of gas sold to the domestic market in 2024. Gas is used as an input to manufacture pulp and paper, metals, chemicals, stone, clay, glass and processed foods. Gas is also a major feedstock in ammonia production for fertilisers and explosives.

Figure 4.9 Eastern Australian gas demand, by state



Note: Data for 2010–15 is average annual consumption over that period.

Source: AEMO, 2025 Gas Statement of Opportunities, March 2025.

Residential and commercial customer demand levels vary from state to state. In Victoria, 60% of gas is consumed by small residential and commercial customers, who use gas mostly for heating and cooking. In Queensland, where fewer households are connected to a gas network, the share of gas consumed by residential and commercial customers is much lower, at around 5%.

Electricity generation is another major source of gas demand, accounting for 19% of domestic gas use in 2024, down from peak levels of around 30% before 2020. South Australia and Queensland used the most gas-powered generation (GPG) in 2024 (each using 36% and 32% of GPG in the NEM, respectively). The rapid responsiveness of gas-powered generators makes them suitable for meeting peak electricity demand and managing variable wind and solar generation. Consequently, the volume of gas used for electricity generation fluctuates with electricity market conditions. Long-term forecasting of expected usage for GPG in the NEM is difficult due to the unpredictability of relevant drivers such as weather, availability of other fuel types and unforeseen events.³²¹

Gas-powered generation use in 2023 and 2024

In 2024, GPG gas usage remained low across mainland regions, albeit slightly above 2023 levels (Figure 4.10).³²² At the start of 2024 average quarterly GPG demand fell to the lowest quarterly level observed over the past decade, before lower wind and solar generation output over the April to June quarter led to increased need for higher priced GPG, pushing up electricity prices in southern regions.

GPG output further increased over the July to September quarter, contributing to a quarterly gas demand record alongside increased LNG export demand, despite historically low downstream market demand. This maintained upwards pressure on gas prices for the rest of 2024. Increased GPG requirements in Queensland from mid-November to mid-December had a significant impact on downstream gas prices in the Brisbane STTM. This price pressure in turn flowed through to southern markets.

These events illustrate the ongoing complexity of gas-powered generation acting as a firming capacity in the NEM. Demand for GPG to fill in at times of low renewable generation output and high demand can be unpredictable. This is particularly evident when low renewable generation coincides with elevated gas demand driven by colder weather or electricity system constraints, potentially leading to price

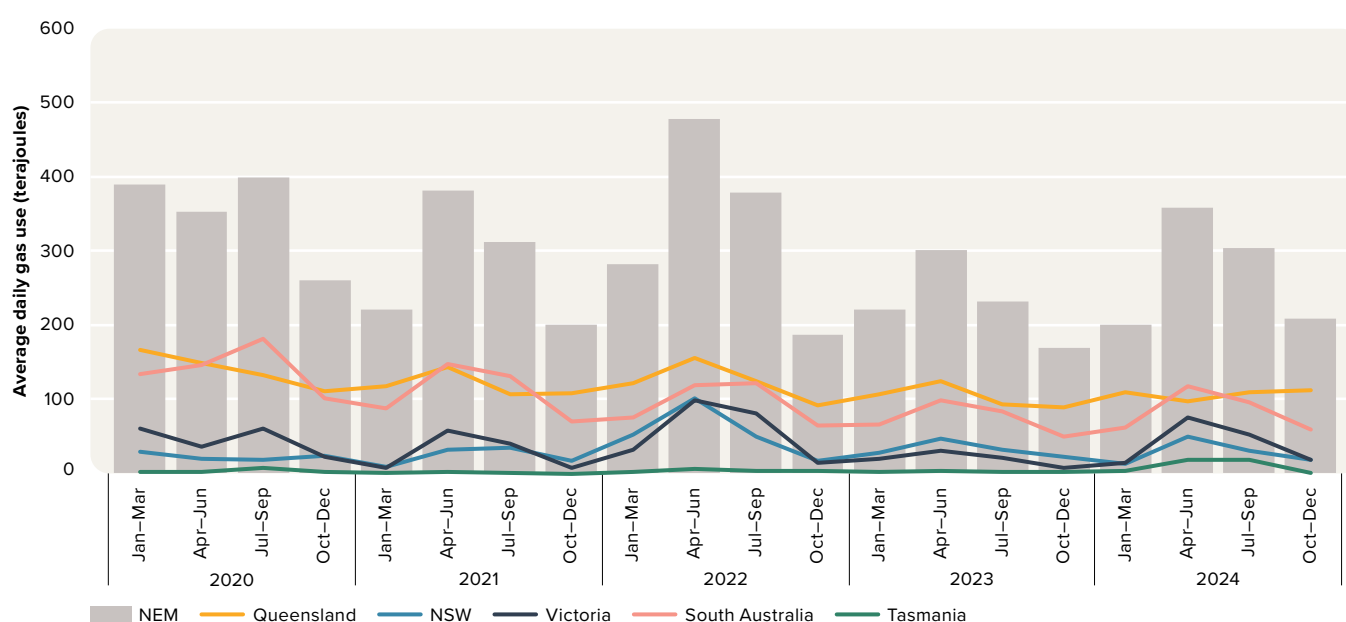
³²¹ Multiple events, including baseload generation retirement, coal shortages during hot weather, bushfires and flooding, transmission outages, and prolonged coal generation maintenance outages and plant failures, have affected the NEM in previous years.

³²² Increases in GPG gas usage were primarily driven by more generation in Victoria and South Australia last year, with NEM regions having fallen record low levels of GPG output in 2023.

spikes or gas shortfalls. Despite generally declining demand for gas across the east coast, GPG demand is projected to increase in the coming years unless new sources of firming capacity can be found to replace it. AEMO's Integrated System Plan (ISP) forecasts flexible gas capacity of 8.8 GW will be needed by 2030–31, climbing to 15.4 GW by 2051–52.

Projections indicate 7.8 GW of the existing GPG fleet will still be in service by 2030. A total of 750 MW of committed generation and 200 MW of anticipated GPG will be needed to avoid generation shortfalls between now and 2030. New generation capacity of 12.8 GW is needed by 2051–52.³²³ At the same time, governments are taking actions to reduce consumption of natural gas in order to meet net zero commitments. These include encouraging electrification where possible and investing in alternative fuels where electrification is not suitable, such as for industrial processes involving high temperatures or where methane is a feedstock rather than a source of energy. This poses challenges to the market in identifying least-cost options for avoiding shortfalls while also minimising the creation of redundant investment. The various actions being taken to stabilise supply-demand balances are discussed further in section 4.10.

Figure 4.10 Quarterly gas demand for gas-powered generation



Source: AEMO; National Electricity Market (NEM) generation data and heat rates (gigajoules per megawatt hour).

4.4.2 Liquefied natural gas exports

Most of the gas produced in eastern Australia is exported as liquefied natural gas (LNG).

In eastern Australia, export gas is liquefied in processing facilities in Queensland to make it economic to store and ship in large quantities. There are also 5 LNG export projects in Western Australia and 2 in the Northern Territory (Figure 4.11).

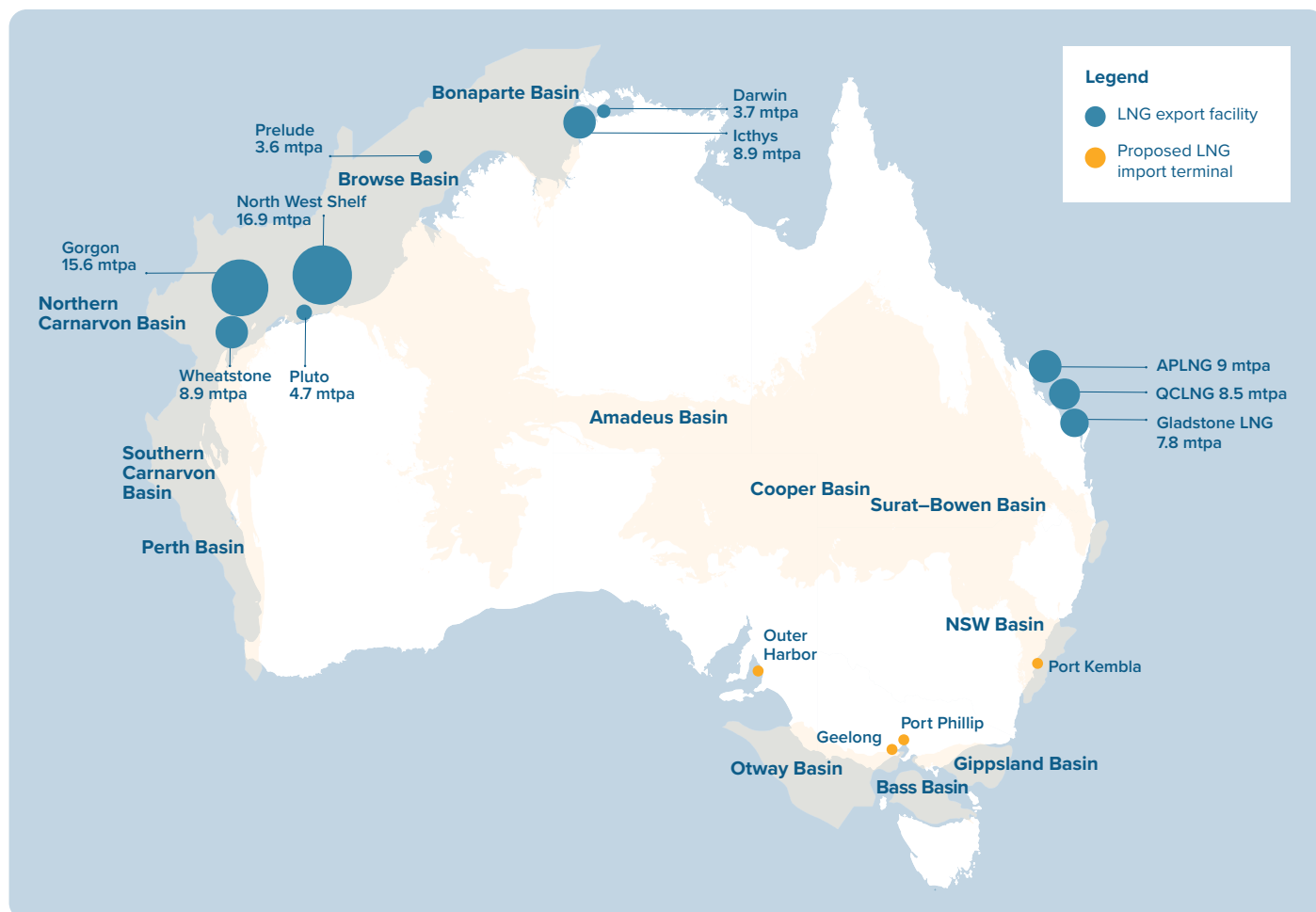
Forecast export revenue totalled \$72 billion for 2024–25, up from \$68.5 billion for 2023–24.³²⁴ The Department of Industry, Science and Resources forecast revenue to decline to \$45 billion by 2029–30, largely due to an expected easing in LNG prices. Gas remains one of Australia's largest resources and energy exports behind coal and iron ore. Australia was the second highest exporter of gas in 2023 behind the United States, following the restart of Freeport LNG in Texas.³²⁵

³²³ AEMO, [2024 Integrated System Plan \(ISP\)](#), Australian Energy Market Operator, June 2024.

³²⁴ Department of Industry, Science and Resources, [Resources and energy quarterly](#), March 2025.

³²⁵ Department of Industry, Science and Resources, [Resources and energy quarterly](#), March 2024.

Figure 4.11 Australia's LNG export projects



Note: Capacity in million tonnes per annum (mtpa). EPIK ceased development of a Newcastle import terminal due to the project being economically unfeasible.

Source: AER; Department of Industry, Science and Resources, Resources and energy quarterly, March 2025.

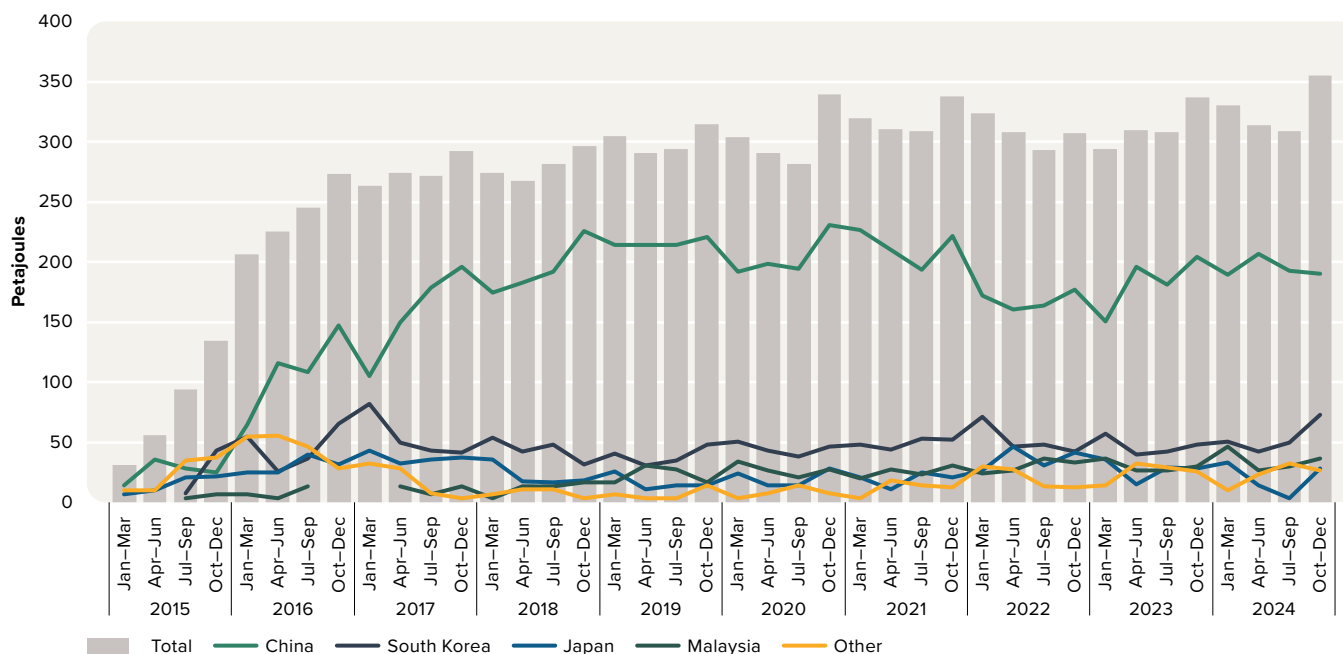
Queensland's LNG industry comprises 3 major projects, which source gas mainly from the Surat-Bowen Basin. Gas production volumes are measured in millions of tonnes of LNG per annum (mtpa).

- Queensland Curtis LNG (QCLNG) project has capacity to produce 8.5 mtpa. Shell (73.75%), CNOOC (50% equity in Train 1) and Tokyo Gas (2.5% equity in Train 2) collectively own the project.
- Gladstone LNG (GLNG) project has capacity to produce 7.8 mtpa. Santos (30%), Petronas (27.5%), Total (27.5%) and Kogas (15%) collectively own the project.
- Australia Pacific LNG (APLNG) project has capacity to produce 9 mtpa. Origin Energy (37.5%), ConocoPhillips (37.5%) and Sinopec (25%) collectively own the project.

These LNG projects control around 84% of 'proven and probable' (2P) reserves in eastern Australia.³²⁶ They also source gas from other producers through long-term production contracts and use spot markets to manage volatility and ensure they can meet their long-term exports supply obligations. East coast gas exports are typically lower mid-year, when the gas produced supplements increased domestic demand over winter, and higher over the rest of the year as Northern Hemisphere winter conditions drive up international demand.

326 ACCC, [Gas inquiry 2017–2030, interim report](#), Australian Competition and Consumer Commission, December 2024, p. 115. 2P reserves represent proven and probable reserves (probable reserves are deemed 50% likely to be commercially recoverable).

Figure 4.12 Eastern Australian gas exports



Source: AER analysis using Gladstone Port Corporation data.

East coast LNG exports have risen consistently since they began in 2015. They remained at lower levels across 2022 and 2023 compared with the record high volumes exported in late 2020 and 2021 but began to climb again from late 2023. East coast exports increased above 1,300 PJ for the first time in 2024. Exports reached quarterly record levels across each quarter of the year, peaking at 355 PJ in October to December 2024 (Figure 4.12). Total export pipeline deliveries to Curtis Island reached record daily flow rates above 4,300 TJ per day on numerous occasions in 2024, primarily in December.³²⁷

China remained the primary market for eastern Australian LNG in 2024, accounting for 60% of exports (779.5 PJ), up slightly from the previous year (733 PJ, 59%).

International gas markets have been relatively stable over the past year following supply shocks during 2022 and then forced readjustments in 2023.³²⁸ Record gas flows south occurred across winter 2024 alongside record exports (Figure 4.21).

Northern Territory and Western Australia exports

The Northern Territory's LNG projects are Darwin LNG (3.7 mtpa capacity) and Ichthys LNG (8.9 mtpa capacity). Both projects connect to the territory's domestic gas market as emergency supply sources but otherwise produce gas for export.

Western Australia has 5 LNG projects with a combined capacity of around 50 mtpa – including the North West Shelf, which is Australia's largest LNG project by capacity (16.9 mtpa). The other projects are Gorgon (15.6 mtpa), Wheatstone (8.9 mtpa), Pluto (4.7 mtpa) and Prelude (3.6 mtpa).

³²⁷ Daily flows exceeded 4,300 TJ per day on 6 occasions in December, reaching a record of 4,389 TJ on 25 December 2024.

³²⁸ Department of Industry, Science and Resources, [Resources and energy quarterly](#), March 2025.

4.5 Gas supply in eastern Australia

Gas supply to the northern regions of eastern Australia is largely supplied from Queensland's Surat–Bowen Basin. Gas is also sourced from the Cooper Basin in South Australia and was supplemented by supply from the Northern Territory from 2019 to 2024. Gas from Queensland is required to supplement Victorian gas production to meet domestic gas demand in southern Australia over winter. At other times of the year, southern gas is also transported north to meet LNG export demand. Ensuring sufficient gas remains in Australia to service the domestic market is a key priority for governments. Both AEMO and the ACCC regularly assess and publish analysis on future supply conditions and the likelihood of future shortfalls so that these can be addressed ahead of time.³²⁹

4.5.1 Background

Southern states rely on local gas production to supply most of their gas demand. However, as production in southern states has declined, sourcing gas from Queensland has become increasingly important, particularly during the Australian winter.

Output from Victoria's Gippsland Basin has been falling due to the depletion of legacy fields supplying the Longford gas plant.³³⁰ From 2023, east coast gas users have become more reliant on northern production. Gippsland's projected peak day production capability has been falling since 2022 and remains significantly lower than prior levels. AEMO's latest *Gas Statement of Opportunities* report projects an improved outlook over the next few years, with southern peak day shortfalls from 2025 now delayed until 2028 due to demand forecast reductions and the delayed retirement of the Eraring Power Station.³³¹

4.5.2 Current conditions

Despite historically low average gas demand levels, colder weather from late May 2024 drove up southern demand compared with the mild Australian winter in 2023. Due to the significant changes in demand driven by cold weather, southern gas markets are persistently vulnerable to cold weather events. Last year, tight supply and demand conditions were exacerbated by reduced production capability at Longford, Victoria's largest source of supply. This increased participants' reliance on obtaining gas from southern storage and Queensland gas fields to meet demand in southern markets. Other events in the Northern Territory and Tasmania also put upward pressure on the tight supply-demand conditions in southern markets.

Northern Gas Pipeline (NGP) gas shortfall

Although southern demand for gas from northern regions has increased, supply previously provided to the east coast from the Northern Territory ceased between Q2 2024 and Q1 2025, resuming in April 2025. Production issues at the Blacktip offshore gas fields led to the pipeline connection between Queensland and the Northern Territory being restricted, with industrial demand on the Carpentaria Pipeline now reliant on gas supplies from South East Queensland. The pipeline has now been reconfigured to flow gas into the Northern Territory, with the NGP reverse capability project completed in August 2024 (section 4.8.5).

329 AEMO, [Gas Statement of Opportunities](#), Australian Energy Market Operator; ACCC, [Gas inquiry 2017–2030](#), Australian Competition and Consumer Commission.

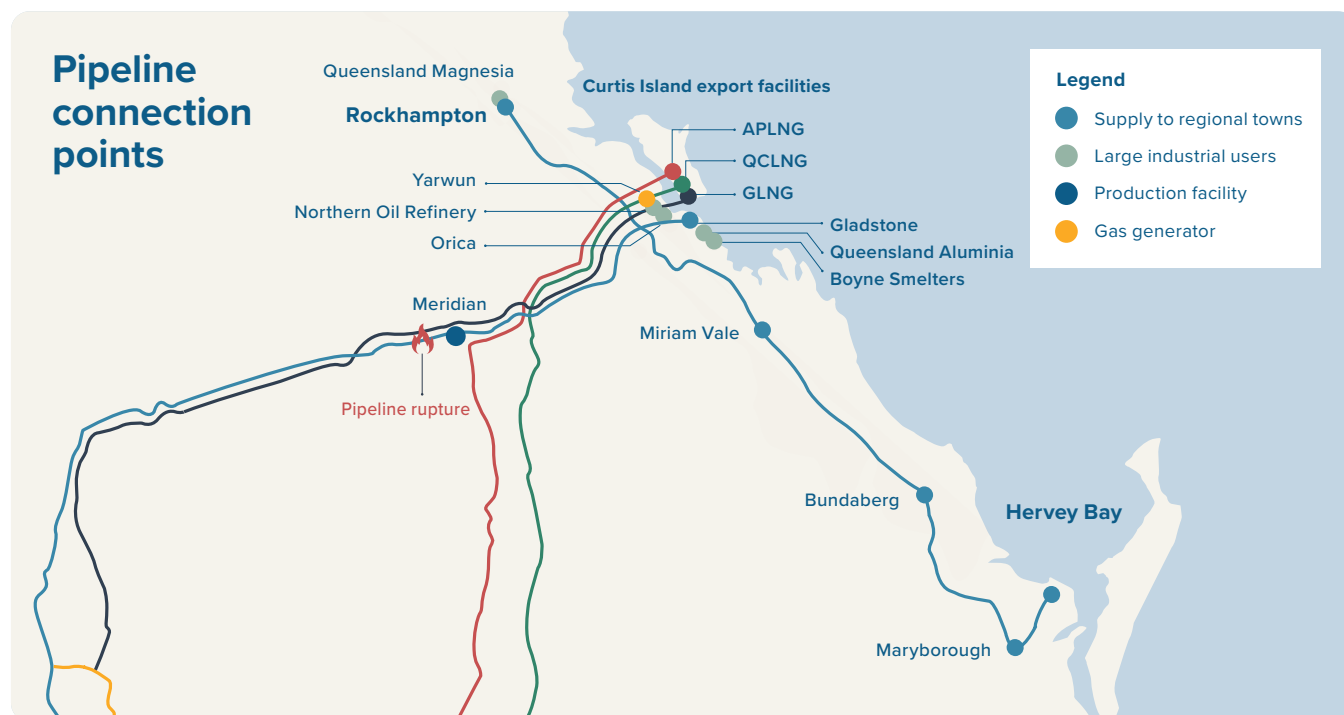
330 Longford is the largest and most flexible source of southern gas supply.

331 This is due to lower forecasts for residential, commercial and industrial users and the temporary reduction in expected peak day GPG requirements and the extended availability of the Eraring Power Station. AEMO, [2025 Gas Statement of Opportunities](#), Australian Energy Market Operator, March 2025, p. 68.

Loss of containment event on the Queensland Gas Pipeline

On Tuesday 5 March 2024 a loss of containment on the Queensland Gas Pipeline (QGP) resulted in a large fire south-west of Rockhampton (Figure 4.13).³³² From 17 March, the QGP was recommissioned at a reduced operating pressure, with Meridian supply directions being revoked as gas flows resumed on the affected pipeline segment.³³³ Pipeline flow and customer offtakes began ramping up the following day at a reduced operating pressure of 105 TJ, ramping up to 118 TJ per day from mid-May and to 130 TJ per day from early September. The pipeline was returned to normal operating pressure of 145 TJ per day from 10 December following the completion of pipeline repairs on the isolated pipeline segment.³³⁴

Figure 4.13 Queensland Gas Pipeline and surrounding downstream infrastructure



Source: AER analysis using Gas Bulletin Board facility information and AEMO's detailed gas pipeline map.

³³² AEMO directed Westside to divert gas supply from their Meridian gas production facility, the only main production source downstream of the fire, and issued curtailment directions to downstream consumers. A backflow process was also initiated on the adjacent GLNG export pipeline to support Meridian supply, with APLNG, GLNG, Meridian and Jemena coordinating the response to increase gas supply. Large industrial users impacted by the incident were taken offline or run at minimum standby load for safety reasons, with some smaller regional towns also affected downstream of the QGP's Wide Bay offtake.

³³³ Large industrial customer curtailments remained in place, but most large users had transitioned to contractual pro-rata allocations agreed with Jemena, the pipeline operator.

³³⁴ AER, *Wholesale markets quarterly – Q4 2024*, Australian Energy Regulator, January 2025, p. 22.

4.5.3 Gas reserves and production

Eastern Australia had 31,968 PJ of ‘proven and probable’ (2P) gas reserves reported by AEMO in the *2025 Gas Statement of Opportunities*.³³⁵ Of these 2P reserves, 29,728 PJ (93%) is concentrated in the north including the Surat, Bowen and Cooper basins in Queensland and the Amadeus Basin in the Northern Territory.

Ownership is highly concentrated in some gas basins, but more diverse across the east coast. APLNG owns the majority of reserves in eastern Australia through an incorporated joint venture with Origin Energy, ConocoPhillips and Sinopec.

Queensland’s Surat–Bowen Basin holds almost 90% of the 2P gas reserves in eastern Australia and supplied close to 80% of gas produced in 2024.

In Victoria, the Gippsland Basin is the largest basin, while the Bass and Otway basins are smaller. These 3 basins account for 6% of eastern Australian 2P reserves, but production has continued to decline due to anticipated decreases from Gippsland legacy fields. This is important because Victoria is the highest domestic consumer of gas. AEMO forecasts a steep decline in southern field production in the coming years.

The Cooper Eromanga Basin in central Australia has just over 900 PJ of eastern Australia’s 2P reserves, with reserves in the basin declining over the past decade. The Cooper Eromanga Basin plays an important role as a ‘swing’ producer in managing seasonal and short-term supply imbalances in the domestic gas market.

NSW has significant contingent resources³³⁶ (around 1,500 PJ) but only 6 PJ of 2P reserves and no current production since AGL’s Camden facility ceased production in late August 2023. Santos received approval to develop reserves near Narrabri in the Gunnedah Basin, but final investment decisions depend on project approvals being cleared (section 4.8.1).

The AER is required to report annually on price assumptions used by field owners to prepare their annual gas field reserve estimates as part of the Gas Market Transparency reforms.³³⁷ The median contracted reserve price for 2025 was \$10.44 per GJ, ranging from \$10.43 per GJ to \$10.86 per GJ for the 5-year period from 2025 to 2029. For the same period the median uncontracted reserve price assumptions were higher, at approximately \$12 per GJ. Both contracted and uncontracted reserve prices showed year-on-year increases of approximately 4%. This largely reflects the consumer price index (CPI) but for contracted prices it was also influenced by large field-level price variations – some fields reported year-on-year price changes exceeding 25%.³³⁸

Location-based analysis of uncontracted prices indicated the average price for southern basins is higher than northern basins. The price differential increases across the 5-year period from approximately \$1 per GJ in 2025 to over \$3 per GJ in 2029. Noting the increased reliance on northern gas to meet southern demand, the higher southern price expectations possibly reflect a competitive pricing once the transportation cost for moving gas from the north is considered.

335 AEMO, *2025 Gas Statement of Opportunities*, Australian Energy Market Operator, accessed 20 March 2025.

336 2C contingent resources are reserves that are estimated to be potentially recoverable from known deposits but are not currently considered to be commercially recoverable.

337 AER, *Wholesale gas reserves price assumption report: Insights into the gas reserves prices assumptions reported to the AER covering calendar year 2024*, 15 April 2025, Australian Energy Regulator, April 2025, accessed 9 May 2025.

338 Uncontracted reserve prices refer to forecast price assumptions made on the value of 2P gas reserves that have not been locked into existing contractual arrangements. The assumptions made on the value of these reserves are required to be verified by independent qualified gas industry professionals.

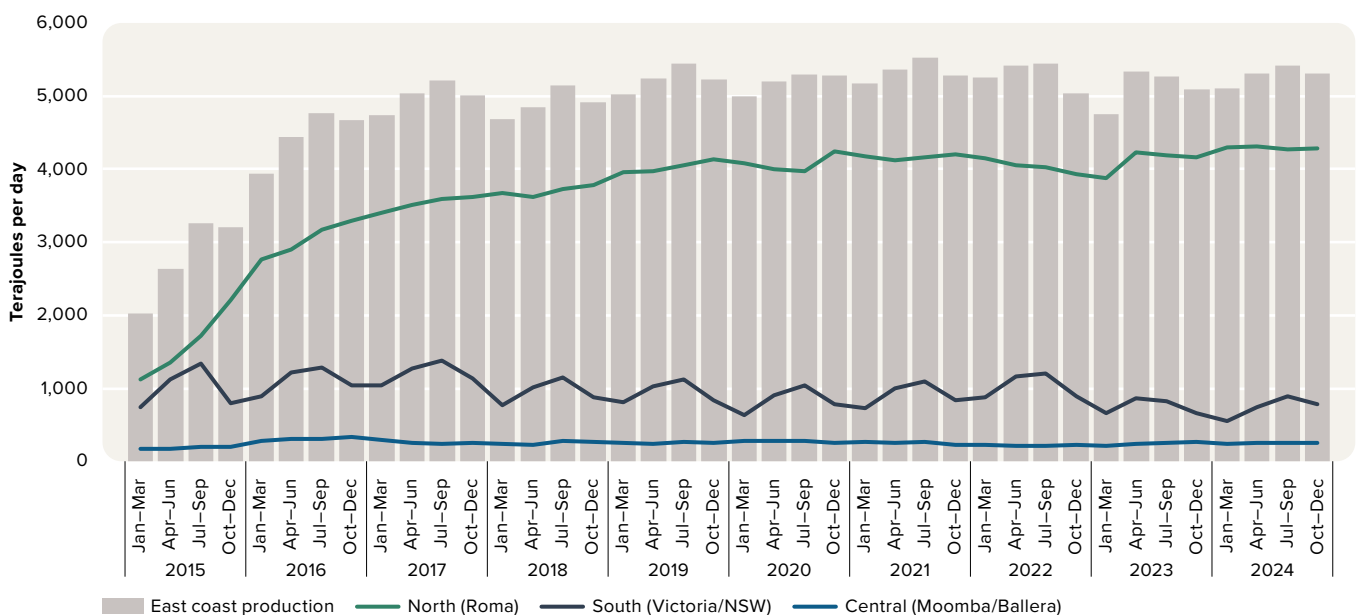
Table 4.2 Gas basins serving eastern Australia

Gas basin	Gas production – 12 months to December 2024			2P gas reserves (December 2024)	
	Petajoules	Share of eastern Australian supply (%)	Change from previous year (%)	Petajoules	Share of eastern Australian reserves (%)
Bowen and Surat (Qld)	1,571	81%	4%	25,763	90%
Galilee (Qld)	0	0%	0%	0	0%
North Bowen (Qld)	0	0%	0%	79	0.3%
Cooper Eromanga (SA–Qld)	92	5%	2%	923	3%
Gunnedah (NSW)	0	0%	–100%	7	0.02%
Gippsland (Vic)	212	11%	–8%	1,354	5%
Bass Otway (Vic)	61	3%	44%	390	1.4%
Beetaloo (NT)	0	0%	0%	0	0%
McArthur (NT)	0	0%	0%	0	0%
Amadeus (NT)	11	1%	–18%	221	0.8%
Total	1,947	100%	–	28,735	100%

Note: 2P: proven and probable reserves estimated to be at least 50% sure of successful commercial recovery. Most production and reserves in the Surat–Bowen and NSW basins are coal seam gas. Production and reserves in other basins are mainly conventional gas. Totals may not add to 100% due to rounding.

Source: AER analysis of Gas Bulletin Board data (production). ACCC, [Gas inquiry 2017–2030, interim report, December 2024](#), Australian Competition and Consumer Commission, December 2024, p. 76.

Figure 4.14 Eastern Australian gas production



Source: AER analysis of Gas Bulletin Board data.

Roma production reached record quarterly levels across 2024, peaking at an average daily output above 4,300 TJ per day over the April to June quarter (Figure 4.14). This coincided with record quarterly export levels across 2024. Export cargo levels over the October to December quarter reached 355 PJ, exceeding the previous record of 340 PJ set over the same period in 2020.

From mid-June, new gas supply from the Otway Gas Plant in Victoria increased to more than 150 TJ per day on average, reaching daily output levels close to 200 TJ over winter.³³⁹ Moomba production also continued to increase over late 2023, with average daily output close to 250 TJ across 2023 and 2024.³⁴⁰

Looking forward, southern production is forecast to decrease by more than 30% over the next 5 years, driven by depleting legacy fields in the Gippsland region.

Longford production decline

Victoria's largest supply source at Longford has been running down reserves from its depleting legacy fields in the Gippsland Basin in recent years. Since 2023, supply levels from Longford have declined markedly compared with previous years (Figure 4.15). While production output over 2024 remained comparable to 2023, this was influenced by low gas consumption and increased winter supply from Queensland last year, rather than reflecting available production capacity at that time.³⁴¹

In 2024, continued production declines saw Longford's supply over the January to March quarter drop to approximately 35PJ. This was the lowest level recorded since the commencement of Bulletin Board reporting in mid-2008.³⁴² In 2024, Longford production over the January to March quarter was well below available capacity.³⁴³ Reduced output continued in the April to June quarter with a delayed ramp-up following planned maintenance, which was scheduled to conclude in late May but instead prevented supply levels reaching expected higher rates until late June.

Since 2023, supply levels from Longford have declined markedly compared with previous years

Over the July to September quarter 2024, southern gas production saw increased supply from the Otway and Orbost gas plants offset the decline in production from Longford³⁴⁴, with new production from the Enterprise gas field commencing in June.³⁴⁵ Increased output from the Otway gas plant continued to drive higher southern production levels in Victoria over the October to December quarter, assisted by Longford increasing supply by 3.7 PJ to 50 PJ.

Higher available production capacity over 2024 was the result of fewer maintenance outages compared with 2023.³⁴⁶ While production levels at Longford have been aided by the Kipper Compression Project³⁴⁷ being commissioned from October, the facility's production capability remains limited to around 700 TJ per day, with higher output levels observed during winter 2024 no longer achievable.³⁴⁸

339 Production from Port Campbell (including the Otway and Athena gas plants) increased from 38 PJ in 2023 to 56 PJ in 2024, with the connection of new gas supply to the Otway Gas Plant including the Enterprise field in mid-2024 and the Thylacine West wells later in 2024. AEMO, [2024 Victorian gas planning report](#), Australian Energy Market Operator, March 2024, p. 9.

340 Average production in 2022 was just over 220 TJ per day. Increased production coincides with an increase in the number of wells drilled in the Cooper Basin throughout 2023. AEMO, [Quarterly Energy Dynamics](#) Q4 2023, Australian Energy Market Operator, January 2024, p. 57.

341 AEMO, [2024 Victorian gas planning report](#), Australian Energy Market Operator, March 2024, p. 9.

342 Available production capacity of 45 PJ was also at the lowest level recorded. AEMO, [Quarterly Energy Dynamics](#) Q1 2024, Australian Energy Market Operator, April 2024, p. 56.

343 Offshore maintenance at Longford from mid-January to mid-February saw participants draw down on Iona's underground storage inventories, which were at record high levels heading into 2024 following a mild 2023 winter.

344 AEMO, [Quarterly Energy Dynamics](#) Q3 2024, Australian Energy Market Operator, October 2024, p. 58. Longford's production capacity also reduced in October 2024 following the retirement of the Gas Plant 1 processing facility, with the upcoming retirement of Gas Plant 3 expected later this decade.

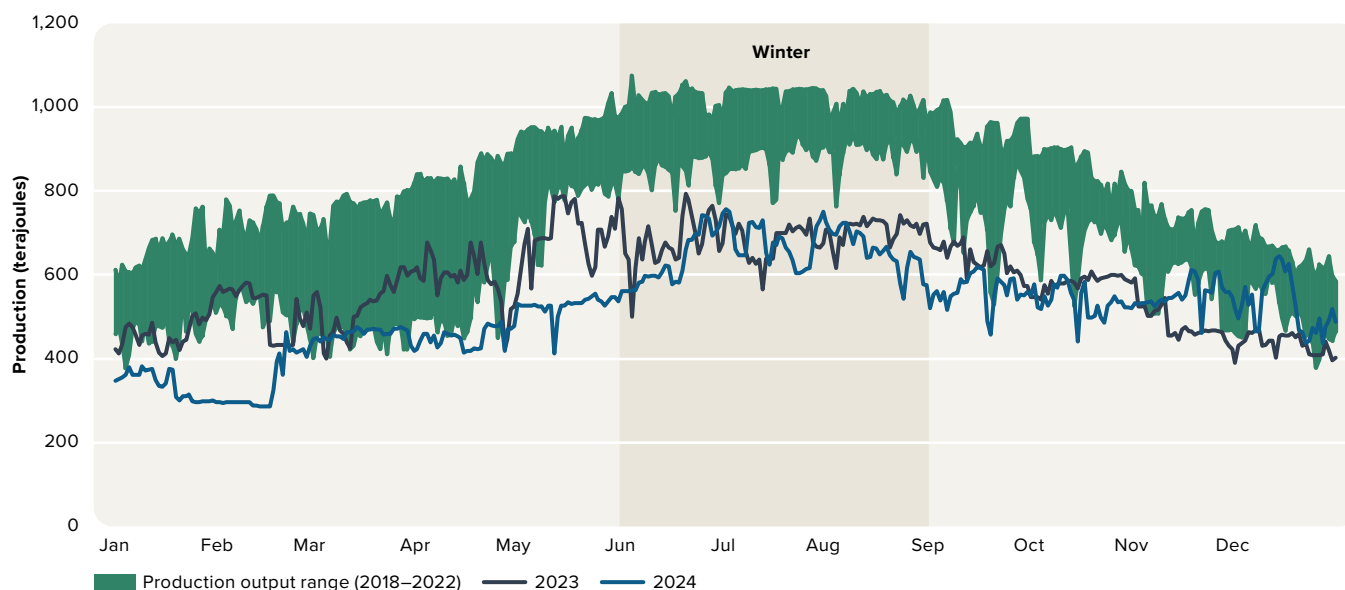
345 Beach Energy, [Enterprise project](#), Otway Gas Plant, accessed June 2025, accessed June 2025.

346 AEMO, [Quarterly Energy Dynamics](#) Q4 2024 Australian Energy Market Operator, January 2025, p. 57.

347 ExxonMobil, [Esso Australia delivers crucial project for Australian natural gas supplies](#), 18 October 2024.

348 Longford Gas Plant 3 operation is expected to extend to December 2028 (from December 2027), thereby improving the forecast maximum daily production in winter 2028.

Figure 4.15 Longford production levels since 2018



Source: AER analysis of Gas Bulletin Board data.

Gippsland's peak day production capacity is forecast to be 680 TJ until mid-2025, representing a 198 TJ reduction from the previous year's forecast.³⁴⁹ Forecast 2025 Victorian production has fallen from 296 PJ to 257 PJ, a 39 PJ (13%) reduction from the previous year's forecast.³⁵⁰ Total southern production is also projected to decrease by 47% from 1,165 TJ per day in 2025 to 618 TJ per day in 2029. Production from the Longford plant has been falling and the plant is becoming less reliable, with plant constraints and maintenance outages increasingly disrupting production.³⁵¹

Changing basin profiles

Activity in all gas basins across eastern Australia has evolved to meet the needs of the LNG industry. Production from the Surat–Bowen Basin is mainly earmarked for export. But supply from other eastern Australian basins rose between 2015 and 2017 to help LNG projects meet their export contracts (Figure 4.21). This shift accelerated a depletion of gas reserves in southern basins. AEMO and the ACCC have identified the ongoing depletion of southern gas fields as a significant risk to supply in the coming years.

Following government intervention in 2017, LNG producers diverted more gas to the domestic market (section 4.10.1). Over 2019 and 2020, Surat–Bowen Basin production increased (9%), largely matching LNG export growth (10%), while production from southern basins decreased by a similar proportion (10%). Over 2021, strong southern supply and gas flows north to support high exports coincided with export levels growing more than Queensland production increases. Gas shortfalls are expected to emerge from 2027 unless new sources of supply are made available.³⁵² Potential gas supply has been identified by producers to reduce the risk of near-term shortfalls, but this is mostly conditional on the ability to obtain regulatory approvals and make final investment decisions (section 4.5.5). Import terminals may also help address supply gaps, but their viability is subject to international price movements and the ability to secure foundation customers to contract gas supplies.³⁵³ These would be a supplement to other supply solutions, including pipeline, production and storage developments (section 4.8).

349 AEMO, [2025 Gas Statement of Opportunities](#), Australian Energy Market Operator, March 2025, p. 53.

350 AEMO, [2025 Victorian gas planning report](#), Australian Energy Market Operator, March 2025, p. 3.

351 Capacity is decreased to around 700 TJ per day following the retirement of Gas Plant 1 from October 2024. This makes production capability reliant on the remaining 2 production trains, elevating the likelihood of production capacity halving in the event of an issue with either of the remaining plants.

352 ACCC, [Gas inquiry 2017–2025, interim report, December 2024](#), Australian Competition and Consumer Commission, January 2025, p. 92.

353 Import terminals will not replace the requirement to develop more domestic supply sources.

4.5.4 Gas storage

Storage facilities can store surplus gas produced in summer for use during higher demand winter periods, providing supply flexibility and quick delivery capability to meet peak demand requirements. Refill and drawdown rates for these facilities can be impacted by connected pipeline capacity and low storage levels, limiting the amount of gas in storage that can be replenished or delivered. Eastern Australia's gas storage capacity includes 3 different ways of storing gas.

- Large facilities use depleted gas fields in Queensland, Victoria and South Australia.
 - Iona underground storage (Victoria) has a nameplate storage capacity of 24.4 PJ, with a delivery capability of 570 TJ per day³⁵⁴ – this is the second largest supply source in the south and can deplete and refill at a much higher rate than other east coast storage facilities. The facility typically refills with large quantities of gas, which are drawn down over the higher demand winter period (Figure 4.18).
 - Moomba Lower Daralingie Beds storage (South Australia) has a nameplate storage capacity of 70 PJ, with a delivery capability of less than 5 TJ per day (Figure 4.17).³⁵⁵
 - Silver Springs storage (Queensland) has a nameplate storage capacity of 45 PJ, with a delivery capability of 8 TJ per day (Figure 4.18).³⁵⁶
 - Roma Underground Gas Storage (Queensland) has a nameplate storage capacity of 54 PJ, with a delivery capability of up to 60 TJ per day (Figure 4.17).³⁵⁷
- LNG storage is in smaller seasonal or peaking facilities located near demand centres – for example, the Newcastle LNG facility in NSW and the Dandenong LNG facility in Victoria (Figure 4.19).³⁵⁸ These facilities have relatively high supply rates, but depletion cannot be sustained for many days due to slow refill rates. The primary use for the Dandenong LNG facility is to store small volumes of gas to be injected quickly into the Victorian Transmission System to cater for short-term peak requirements and manage threats to system security.
- There are short-term peak storage services on gas pipelines, which are mostly contracted by energy retailers – for example, the Tasmanian Gas Pipeline stores gas that can be sold into the Victorian market at times of peak demand.

The Dandenong LNG and Iona underground storage facilities are the only ones that currently provide storage services to third parties in the east coast gas market.³⁵⁹ The importance of storage in managing supply and demand has risen since the LNG industry began operating, with some storage facilities drawn down to meet LNG export demand and replenished when prices were low. Large gas customers (particularly retailers) have secured their own storage capacity to manage supply risks and seasonal demand. Average storage levels have decreased since 2021 and in the July to September quarter 2022 reached their lowest levels since reporting commenced in late 2016. This brought average storage levels down to one-third of capacity (Figure 4.16).³⁶⁰ Iona entered 2024 above the record high storage level reached the previous year. However, high utilisation this winter has resulted in rapid depletion of inventories despite high levels of gas flowing south from Queensland. The drawdown of supply from

354 The maximum supply rate achieved in 2021 with a nameplate capacity of 530 TJ per day was 455 TJ.

355 Progressive depletion of storage levels has reduced delivery capacity to 10 TJ per day from late 2021, with current delivery capabilities now sitting around 5 TJ per day since April 2022.

356 Silver Springs delivery outlooks reduced to around 10 TJ per day from mid-October 2021 and have been sitting around 8 TJ per day or lower since 2022.

357 Short-term capacity outlooks for the Roma Underground Gas Storage facility generally range from 25 TJ per day to 60 TJ per day, occasionally reaching up to 80 TJ per day.

358 The Dandenong LNG storage facility reached record low levels in 2021 (since the commencement of the Declared Wholesale Gas Market in 1999), driven by a reduction in contracted capacity for winter. Following a rule change by the AEMC, AEMO now acquires uncontracted gas storage supply at the facility and acts as a buyer and supplier of last resort to mitigate potential supply shortfalls, ensuring the facility is at or near full capacity heading into winter. The rule change was initially due to end on 31 December 2025, with a [consultation](#) proposing a 3 year extension to the interim arrangements initiated on 1 May 2025.

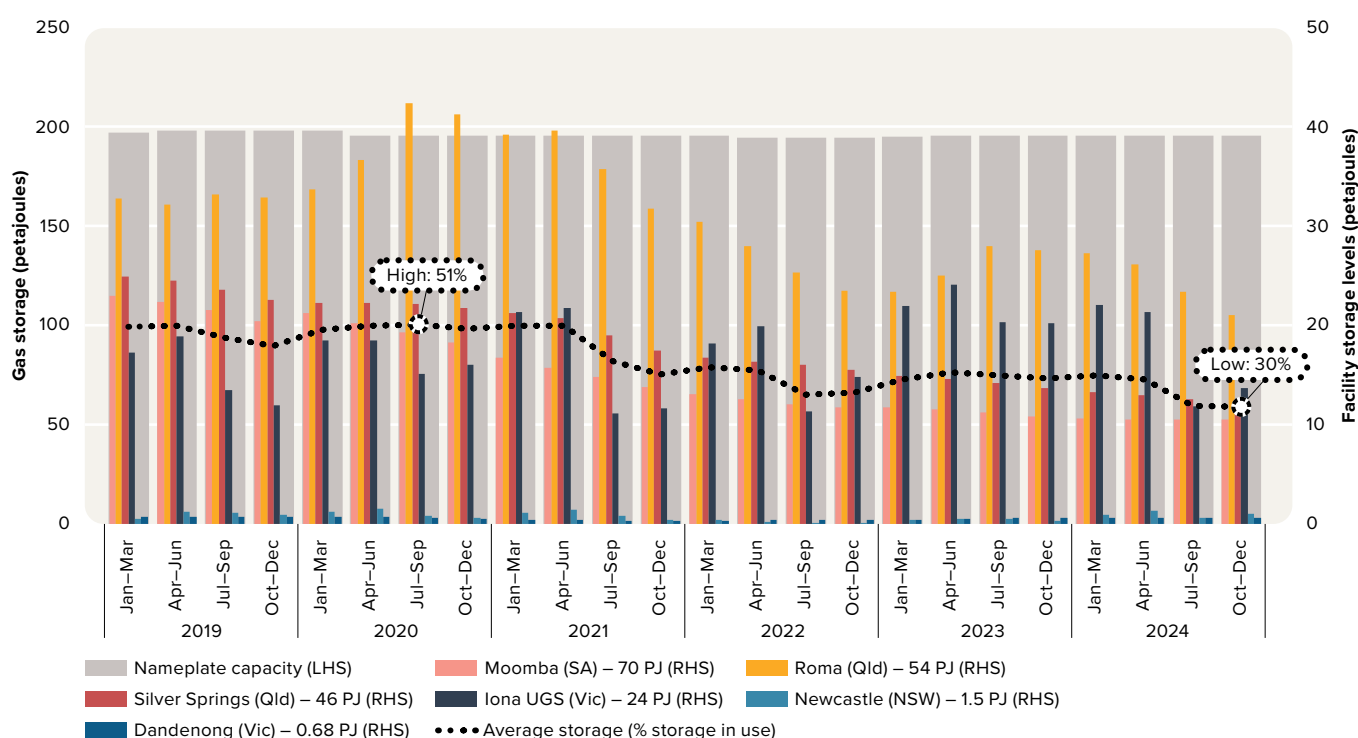
359 ACCC, [Gas inquiry 2017–2030, interim report, December 2023](#), Australian Competition and Consumer Commission, December 2023, p. 127.

360 Storage levels fell to record lows across all east coast facilities in 2022, with this trend continuing at most facilities in the following years. Utilisation of storage at the larger and more flexible Roma and Iona storage facilities over 2024 contributed to total east coast storage levels falling to a new low for the last quarter of the year.

other large facilities has also continued, with declining pressure in the storage wells slowing the rate at which gas can be withdrawn from storage to supply the markets (Figure 4.17 and Figure 4.18).³⁶¹ This demonstrates the dominant impact of weather-driven demand levels on supply adequacy for the southern states.

In contrast, some refilling at the Roma facility in Queensland over 2023 saw supply rates³⁶² return to higher levels, while refilling of the smaller Newcastle gas storage facility commenced in December 2022 and storage levels were at close to full capacity by late April 2024 after some utilisation across late 2023.³⁶³ After 2024 winter utilisation, Newcastle storage levels had decreased to around one-third of full capacity by late August but have since refilled towards full capacity from late 2024 and into 2025. Low daily supply capabilities at the Moomba and Silver Springs storage facilities mean they do not make a significant contribution to gas supply.

Figure 4.16 Gas storage in eastern Australia



Note: Petajoule (PJ) value next to each facility reflects nameplate capacity.

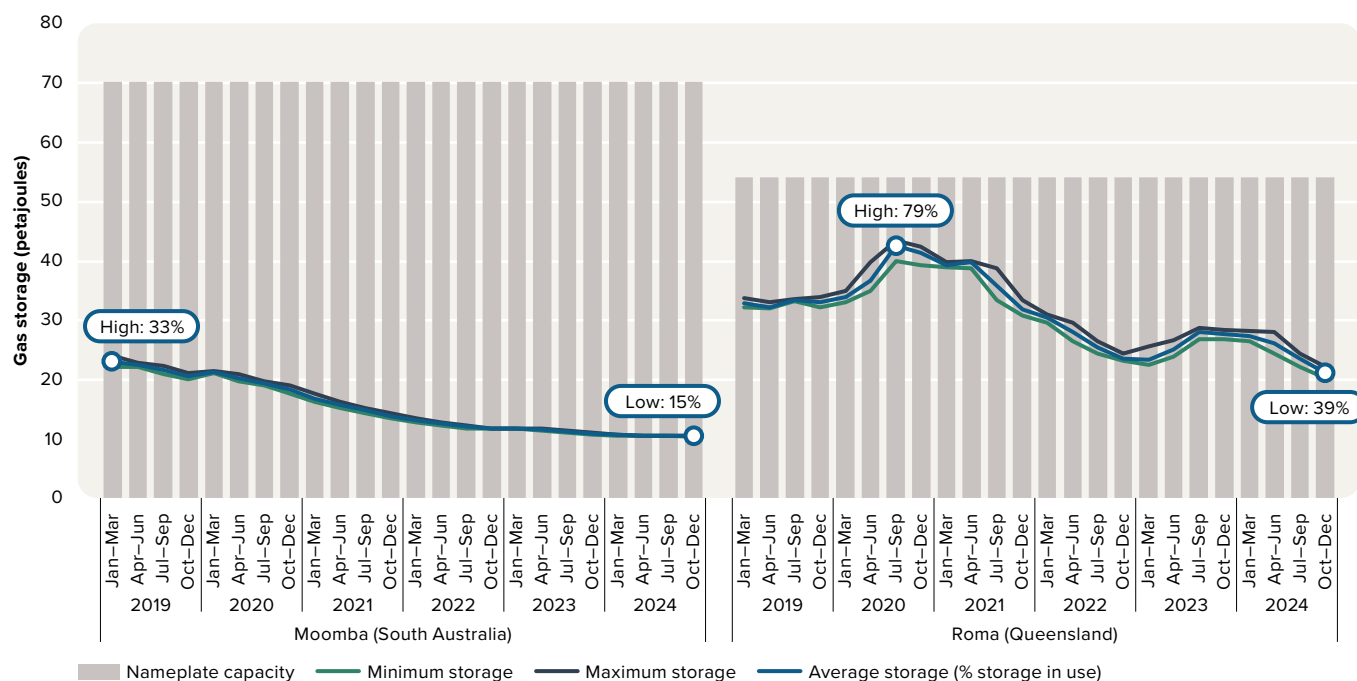
Source: AER analysis of Gas Bulletin Board data.

³⁶¹ For example, Moomba has reduced its nameplate supply capability from 100 TJ per day when it commenced reporting in late 2016, with current storage levels below 11 PJ limiting its physical injection capacity as low as 2 TJ per day since June 2022.

³⁶² Different levels of storage can impact the daily supply capability of storage facilities.

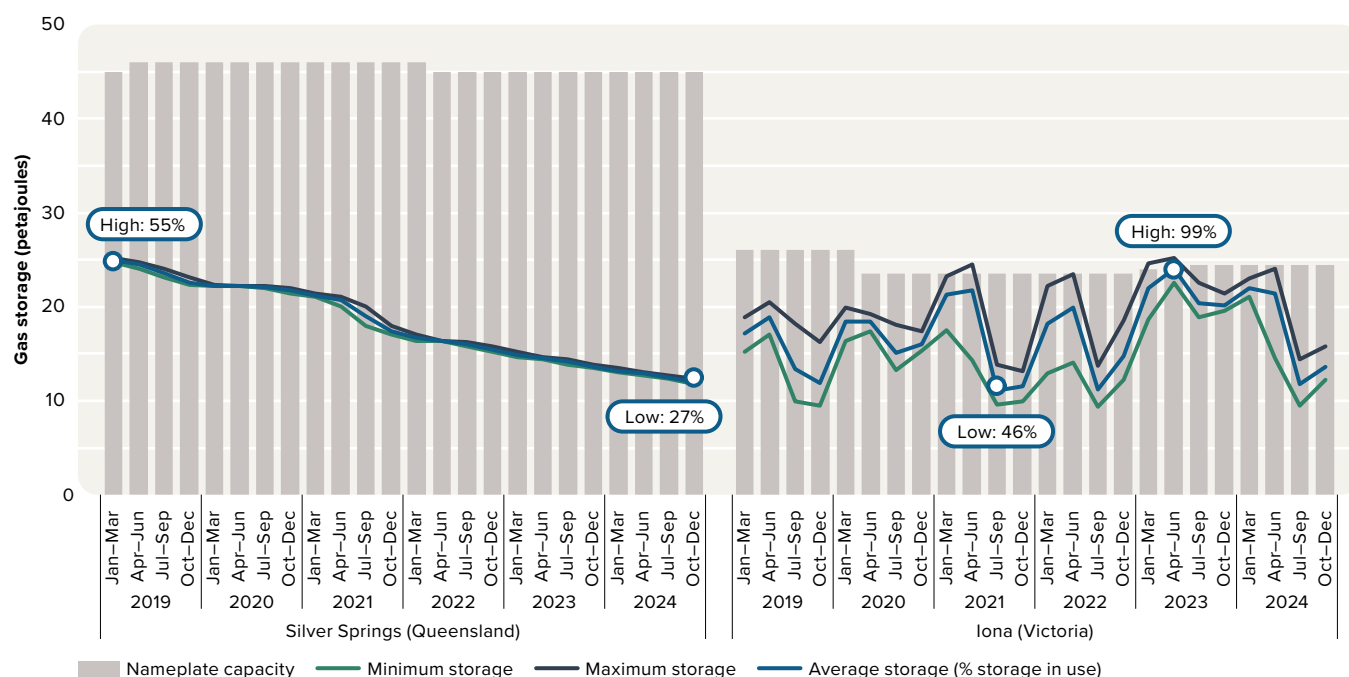
³⁶³ In June 2022, Newcastle gas storage reduced all the inventory in its LNG storage tank for the first time since the facility started operating. The facility filled to around one-third of capacity over winter 2023, with lower utilisation during a period of lower than usual demand.

Figure 4.17 Large gas storage facilities – Moomba (South Australia) and Roma (Queensland)



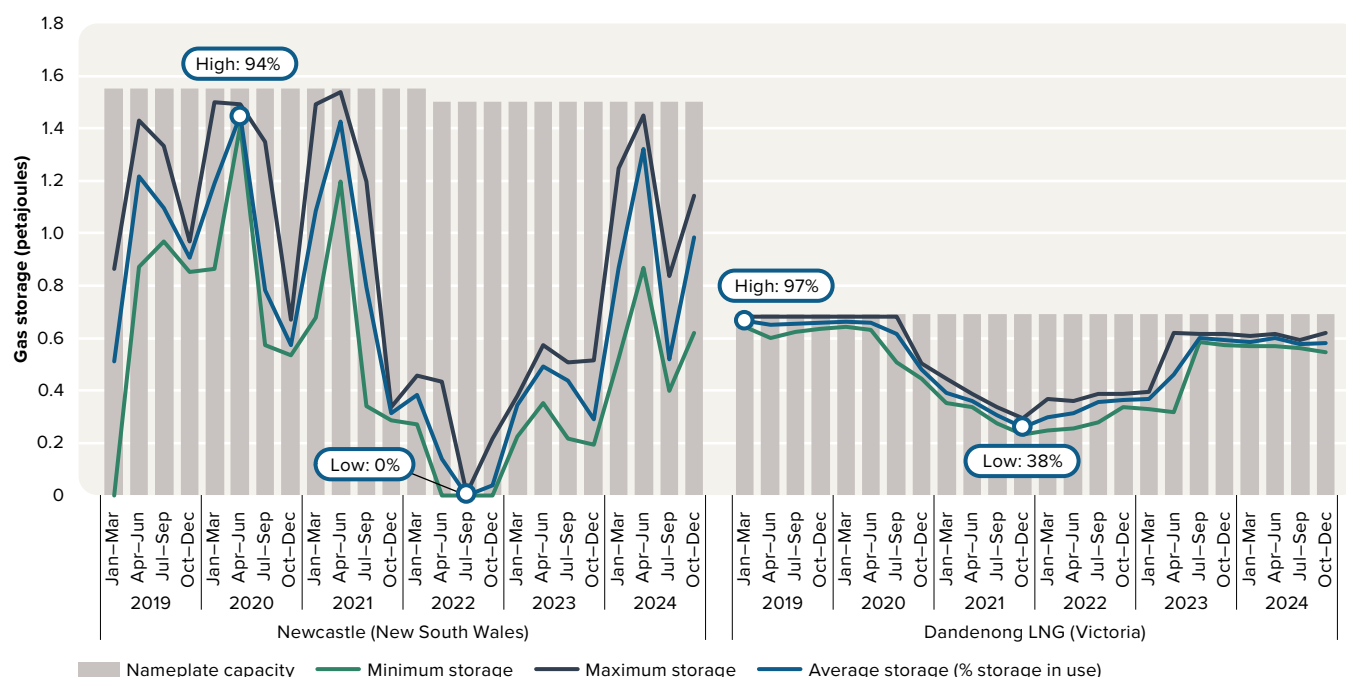
Source: AER analysis of Gas Bulletin Board data.

Figure 4.18 Large gas storage facilities – Silver Springs (Queensland) and Iona (Victoria)



Source: AER analysis of Gas Bulletin Board data.

Figure 4.19 Small LNG gas storage facilities – Newcastle (NSW) and Dandenong (Victoria)



Source: AER analysis of Gas Bulletin Board data.

Unlike other storage facilities, Lochard Energy's Iona underground gas storage facility (Iona) operates more dynamically, with higher supply and refill rates, and is an integral southern supply source during winter. Since 2018, upgrades to Iona have expanded storage capacity and supply capability in the Victorian gas market.³⁶⁴

Victoria has become increasingly reliant on gas storage inventory from Iona. Recent upgrades have effectively increased Iona's peak day supply capability to 530 TJ per day. However, supply into the Victorian market is still limited by available pipeline capacity in the transmission system (section 4.8.3).³⁶⁵ Both the facility and transmission system upgrades have resulted in the facility being better able to respond to daily supply requirements. However, much faster depletion of storage levels in recent years has demonstrated an increased risk of reducing storage inventories to critically low levels before the end of the peak winter demand period.

In 2021 and 2022, storage levels fell to their lowest point since reporting commenced (Figure 4.20). The significant drawdown on gas inventories reduced available supply capacity to very low levels by mid-winter in both years. The fast depletion in 2022 led AEMO to issue a notice of a threat to system security, which remained in place until 30 September.³⁶⁶ In contrast to the mild winter conditions that resulted in record high winter storage levels in 2023, similar storage drawdown in 2024 mirrored the high rates recorded over the preceding 2 years. The 2024 notice was revoked on 23 August due to improvement in gas supply and demand trends.³⁶⁷

Preparatory works have commenced on the Heytesbury Underground Gas Storage (HUGS) Project to expand storage capacity through the development of existing depleted gas fields.³⁶⁸ This could potentially increase Iona's storage capacity by 3.3 PJ by 2026. HUGS and Golden Beach are 2 proposed projects under consideration for development near southern load centres in Victoria (section 4.8.4).

364 Following Lochard's takeover from EnergyAustralia in 2015, the storage facility's supply capacity has expanded significantly from 390 TJ per day to 530 TJ per day (17 March 2021), 545 TJ per day (28 January 2022) and 558 TJ per day (1 January 2023). The most recent upgrade increased the facility's supply capability to 570 TJ per day in early 2024.

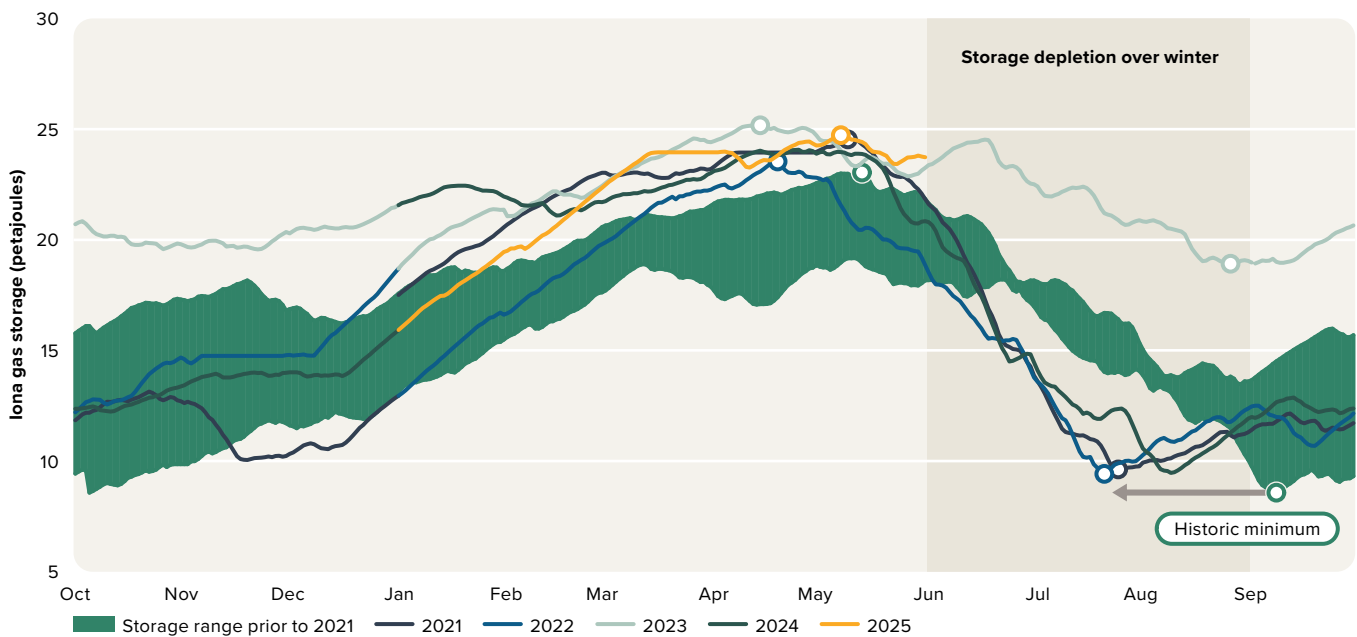
365 A new pipeline segment added to Victoria's transmission system's Western Outer Ring Main (WORM) and a second compressor at Winchelsea have been commissioned and are now operational. These upgrades have increased peak supply capacity to Melbourne by 83 TJ per day. AEMO, [2024 Gas Statement of Opportunities](#), March 2024, pp. 44, 55.

366 The AEMO notice highlighted the possibility of reduced injection capability at Iona due to low pressure, increasing the risk of curtailment on peak demand days.

367 AEMO, [Revocation of East Coast Gas System Risk or Threat Notice](#), Australian Energy Market Operator, 23 August 2024.

368 Lochard Energy, [Heytesbury Underground Gas Storage \(HUGS\) Project](#). Pipeline construction initially scheduled to begin in early 2025 has been rescheduled to commence in late 2025 but is not expected to impact the target operation date for the project.

Figure 4.20 Iona underground storage, rapid winter depletion rates since 2021



Source: AER analysis of Gas Bulletin Board data.

In 2022, the much smaller Dandenong LNG storage facility fell to particularly low levels in June following a reduction in participants contracting supply. While much smaller than Iona, the facility plays an important role in mitigating curtailment during potential supply shortfalls, as well as providing critical system security to avoid pressure drops at the Dandenong city gate. Due to the high potential for the facility to be needed from winter 2023, energy ministers submitted an urgent rule change giving AEMO power to contract underutilised LNG storage capacity in Victoria before winter 2023. The facility entered winter 2024 at close to full capacity and has since refilled to full capacity ahead of winter 2025.³⁶⁹ As the buyer and supplier of last resort, AEMO is required to publish a report setting out a range of information on its activities.³⁷⁰

4.5.5 Outlook

Despite improved short-run supply forecasts, the longer-term outlook remains uncertain. While decreases in projected demand for gas generation, residential and commercial demand and industrial gas usage had improved previously reported forecast shortfalls, further improvements now project a surplus in supply for 2025 and 2026 due to higher Queensland production.³⁷¹ However, production is still expected to become increasingly reliant on uncertain and undeveloped sources of supply, with Victoria's primary supply source having already declined due to legacy gas fields in the Gippsland Basin coming to the end of their productive lives. Potential supply shortfalls have been forecast to occur in southern states in the coming years and across the east coast from 2027.³⁷² Recent projections indicate the potential for a small shortfall in southern states over winter 2025.³⁷³ High levels of demand over the peak winter period in 2024 displayed an increased risk of peak day shortfalls, with heavy reliance on Iona gas storage inventories despite significantly higher volumes of gas flowing south.³⁷⁴

³⁶⁹ The facility ended winter 2024 with 11.9 PJ (49% of nameplate capacity) after refilling from 10 August, with an unseasonably warm end to winter putting downwards pressure on market demand, which eased prices.

³⁷⁰ AEMO, [LNG Summary Report](#), Australian Energy Market Operator.

³⁷¹ ACCC, [Gas inquiry 2017–2030, interim report](#), December 2024, Australian Competition and Consumer Commission, 10 January 2025, p. 18.

³⁷² ACCC, [Gas inquiry 2017–2030, interim report](#), June 2024, Australian Competition and Consumer Commission, July 2024, p. 33.

³⁷³ Forecast supply and demand levels do not consider the extended operation of the Eraring coal-fired power station in NSW, which is expected to reduce gas-powered generation requirements from August 2025. ACCC, [Gas inquiry 2017–2030, interim report](#), December 2024, Australian Competition and Consumer Commission, July 2024, p. 22.

³⁷⁴ Storage depletion in 2024 mirrored the rapid rates of drawdown that occurred in 2021 and 2022, yet higher supply output from Longford in previous years reduced the requirement for gas to flow south from Queensland.

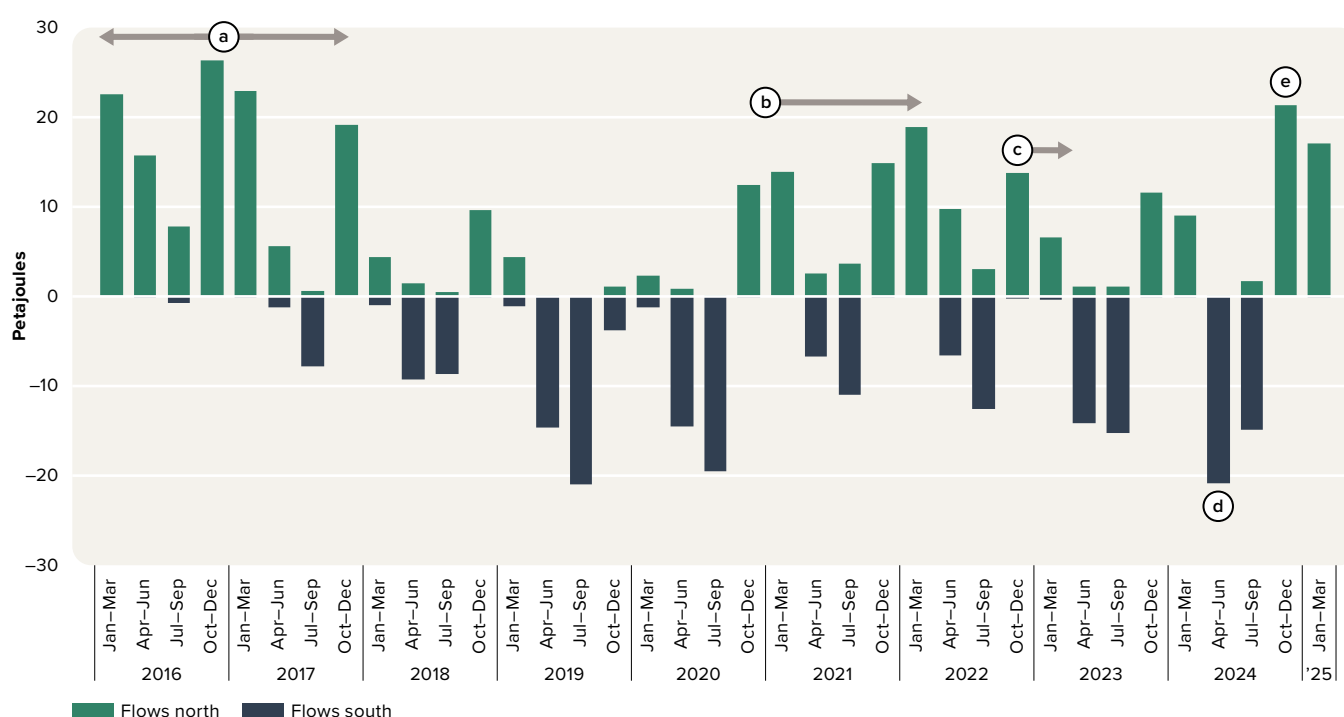
More supply and associated infrastructure is clearly needed, but projects proposed to increase production between 2026 and 2029 have been delayed, reportedly due to long regulatory approval processes and planned maintenance.³⁷⁵ The speculative nature of unsanctioned new domestic supply sources, with a range of barriers including significant investment in infrastructure to bring gas to market, have led to producers finding it increasingly difficult to obtain finance to invest in fossil fuel projects.³⁷⁶

Further factors also contribute to uncertainty surrounding long-term supply conditions, including underperformance of developed resources and the potential for southern production to decline faster than expected. Forecasts also make assumptions about undeveloped resources – uncertain reserves, which are increasingly unreliable, depend on more speculative sources of supply. While some development proposals in eastern Australia have shown promising signs, others face significant regulatory hurdles linked to environmental concerns. Uncertainties also exist around projected demand levels due to factors such as electrification policies across different regions of the east coast.

4.6 Inter-regional gas trade

Domestic gas typically flows south in the Australian winter (to meet heating demand) and north in the Australian summer (the Northern Hemisphere winter) when Asia's LNG demand peaks (Figure 4.21).

Figure 4.21 North–south gas flows in eastern Australia



Note: Flows on the QSN (Queensland / South Australia / New South Wales) Link segment of the South West Queensland Pipeline (flowing through the Moomba location).

- a 2016 to 2017: increased southern production to meet LNG demand.
- b Late 2020 onwards: record LNG exports continue to rise.
- c Late 2022 onwards: LNG exports reduce closer to 2019 levels.
- d Winter 2024: additional compressors commissioned on the Moomba to Sydney Pipeline and South West Queensland Pipeline in May and June. Expanded capacity facilitates record monthly gas flows south in June (close to 11 PJ).
- e Late 2024: record quarterly LNG export level.

Source: AER analysis of Gas Bulletin Board data.

375 ACCC, [Gas inquiry 2017–2030, interim report](#), June 2024, Australian Competition and Consumer Commission, July 2024, p. 36.

376 ACCC, [Gas inquiry 2017–2030, interim report](#), January 2023, Australian Competition and Consumer Commission, January 2023, p. 125.

Northerly gas flows increased from late 2020 in line with record exports (Figure 4.12) and reduced flows south over winter periods (Figure 4.21, note b). Over the January to March quarter 2024, flows remained predominantly northerly despite reduced production from Longford, with exports for the quarter at the highest quarterly level observed over the previous years. While northern export flows for the April to June quarter continued at high levels, southerly flows increased significantly from May 2024. Demand to bring gas south over the April to June period exceeded capacity to do so, resulting in drawdown from southern storage facilities.³⁷⁷

From June 2024, stage 2 capacity expansions increased shippers' ability to bring gas south on the South West Queensland Pipeline (SWQP) and Moomba to Sydney Pipeline (MSP) (section 4.8.3). As a result of this and elevated southern market demand over winter, a record volume of gas flowed south from Queensland over June 2024. Southerly flows reached close to 11 PJ and increased the quarterly quantity shipped south to a level equal to the record reached in 2019 (Figure 4.21, note d).

Over the last quarter of 2024 and into the January to March quarter 2025, high export levels led to the highest level of gas flows north observed since early 2017 (Figure 4.21, note e). In contrast, following the stage 2 expansion of the north to south transmission corridor (section 4.8.3), increases in Day Ahead Auction activity in June on the Moomba to Sydney Pipeline and South West Queensland Pipeline occurred primarily on routes bringing gas south through Moomba.³⁷⁸

Data on trade flows may understate the extent of north–south gas trading. Some gas producers enter swap agreements to deliver gas to southern gas customers without physically shipping it along pipelines. To improve transparency, from 2023 participants' reporting requirements were expanded to encompass a range of bilateral arrangements, including physical swaps (section 4.11.2).

4.6.1 Gas transmission pipelines

Supply conditions depend on the availability of transmission pipeline capacity to transport gas to customers. Improving this availability, pipeline operators are considering a range of upgrades to extend or expand existing infrastructure. For example, APA has announced projects to expand east coast pipeline transportation and storage capabilities following completion of its South West Queensland Pipeline and Moomba to Sydney Pipeline upgrades in 2024 (section 4.8.3).

Wholesale customers buy capacity on transmission pipelines to transport their gas purchases to destination markets. Around 20 major transmission pipelines transport gas to the eastern gas market (key pipeline routes are shown in Figure 4.1). Dozens of smaller pipelines fill out the transmission grid.

The eastern gas market's transmission system has evolved from a series of point-to-point pipelines, each transporting gas from a producing basin to a demand centre, into an integrated network. Many gas pipelines became bidirectional and gas increasingly flows across multiple pipelines to reach its destination. While the Northern Territory was connected to the east coast transmission pipelines in 2019, steadily declining output from the offshore Blacktip gas field led to the interim closure of the Northern Gas Pipeline (section 4.8.5). Access to capacity on key pipelines is important because it provides participants with more options to purchase and move gas between different regions. This ability to move gas gives participants a wider range of options to manage their portfolios across different regions, making it easier to arbitrage the purchase and sale of gas supply without the need to negotiate swap agreements.

Gas production and transmission pipeline assets are owned by separate companies. A gas customer must negotiate with a gas producer to buy gas and separately contract with one or more pipeline businesses to get the gas delivered. This separation adds a layer of complexity to sourcing gas, especially for smaller customers (section 4.6.2).

377 Significant auction capacity was won on auction routes south on the Moomba to Sydney Pipeline reaching almost 2.5 PJ for May 2024.

378 Capacity won on auction on routes bringing gas south accounted for 98% of the record 3.5 PJ of capacity won in June on the MSP, while increases on the SWQP saw over 90% of capacity won on southern routes (1.3 PJ).

The range of services provided by transmission pipelines is expanding to meet the needs of industry as the market evolves. Pipeline operators no longer simply transport gas from a supply source to a demand centre. Gas customers now seek more flexible arrangements, such as bidirectional and backhaul shipping, and park and loan services.³⁷⁹

Pipeline ownership

Australia's gas transmission sector is privately owned (chapter 5). The publicly listed APA Group is the largest owner of pipeline assets, with equity in 13 major pipelines, including key routes into Melbourne, Sydney, Brisbane and Darwin. Another major pipeline owner with equity in numerous pipelines is Jemena. The pipelines fall under different regulatory arrangements, now classified as either scheme or non-scheme pipelines under recent pipeline reforms (section 5.3 and Table 5.1).³⁸⁰

4.6.2 Transport services and pipeline access

Wholesale gas customers buy capacity on transmission pipelines to transport their gas purchases from gas basins. Gas production companies and gas pipelines are separately owned, so a gas customer must negotiate separately with producers to buy gas and with pipeline businesses to have the gas delivered. To reach its destination, gas may need to flow across multiple pipelines with different owners and use compression to facilitate the movement of gas.

Capacity on some pipelines is fully contracted to gas shippers that may not fully use it. Access to transmission pipelines on key north–south transport routes is critical for gas customers. But if many critical pipelines have little or no spare, uncontracted capacity, it makes it difficult to negotiate access. In addition, many pipelines face little competition and may charge monopolistic prices.

Reforms introduced in March 2019 made it easier to access this capacity to pipelines and compression facilities, giving other parties an opportunity to procure capacity through trading platforms or win auctioned quantities.

Capacity can be acquired in 2 ways through AEMO-facilitated markets. First, the capacity trading platform allows shippers to sell any capacity they do not expect to use. Second, any unused capacity not sold must be offered at a mandatory Day Ahead Auction. Any shipper can bid at the auction, which is finalised shortly after the cut-off time for nominations one day in advance of the relevant gas day.

Auction revenues go to the pipeline, or facility operator, rather than the shippers that own the capacity rights. The auctions have a reserve price of zero and most settlements have occurred at no cost.³⁸¹ Shippers may also be able to enter into bilateral contracts with third parties and onsell their pipeline capacity outside of the AEMO-facilitated markets.³⁸²

379 Pipelines with bidirectional flows can ship gas in both directions. Backhaul shipping is the 'virtual transport' of gas in a direction opposite to the main flow of gas. Parking gas is a way of temporarily storing gas in the pipeline by injecting more than is to be withdrawn. Loaning gas allows users to inject less gas into the pipeline than is to be withdrawn.

380 Full regulation pipelines have their prices assessed by the AER. Light regulation pipelines do not have their prices assessed by the AER, but parties can seek arbitration to address a dispute. Part 23 pipelines are subject to information disclosure and arbitration provisions. Exempt pipelines are subject to no economic regulation. Chapter 5 outlines the various tiers of regulation.

381 Although participants can win capacity for \$0 per GJ, additional charges and registration fees make the real cost slightly higher.

382 Bilateral trades are submitted to the Gas Bulletin Board and reported on the AEMO website.

Pipeline capacity trading (Day Ahead Auction)

Since the commencement of the Day Ahead Auction in March 2019, over 330 PJ of contracted but unominated pipeline capacity has been won across 16 of the 22 auction facilities (Figure 4.22).³⁸³

In late 2024 the AER released a focus report on the Day Ahead Auction, assessing the extent it has supported efficiency and competition in the east coast gas wholesale market.³⁸⁴ Analysis found the Day Ahead Auction has improved market dynamics by enhancing competition, especially in southern markets. Access to low or zero cost pipeline capacity is allowing shippers to move relatively low-priced northern gas into southern spot markets, easing price pressure in those markets.³⁸⁵

However, auction activity on some pipelines remains relatively low. Underutilisation may result from higher auction fees, which can discourage smaller players in particular. While most capacity is won at the reserve price of \$0 per GJ, the total cost is higher, because participants need to pay pipeline and storage operators for facility use (which can include both fixed and variable fees). Smaller participants also may be required to provide credit support or collateral to use auction services – in some cases, these costs can be significant. The ability to sell off pipeline capacity through bilateral contracts may also reduce the need for the auctions, especially if a shipper can predict its changes in demand well in advance.

Close to 80% of all capacity procured through the Day Ahead Auction has been won at the reserve price of \$0 per GJ and almost two-thirds of this capacity has been won on 4 key pipelines: the South West Queensland Pipeline (SWQP) and Moomba to Sydney Pipeline (MSP), which facilitate gas flows south and north between spot markets; and the Eastern Gas Pipeline (EGP) and the Roma Brisbane Pipeline (RBP), which facilitate flows to several gas-powered generators. Around 20% of total capacity won has been won on the Wallumbilla B compressor (WCFB).³⁸⁶

Trade over the January to March quarter 2024 (39.4 PJ) exceeded the record set over the same period in 2023.³⁸⁷ Of this capacity, around one-third or 13.4 PJ was traded on gas routes that transport gas between northern and southern markets (SWQP/MSP). The quantity won for the period on the SWQP set a record at close to 5.5 PJ and the WCFB also set a record of 10.8 PJ.

APA has announced projects to expand east coast pipeline transportation and storage capabilities following completion of its South West Queensland Pipeline and Moomba to Sydney Pipeline upgrades in 2024.

While quantities won on the auction decreased markedly from the first quarter's record levels, quantities won across the April to June quarter 2024 continued to exceed previous record levels for April to June quarters. This trend continued with consecutive quarter on quarter increases, despite a slight reduction in trading over the October to December quarter. Trade over the April to June quarter saw participants using the auction to send gas south, particularly in June when volumes on southern routes reached a record 3.1 PJ on the MSP.

383 There has been no significant activity on the voluntary capacity trading platform since its introduction.

384 AER, [Wholesale gas market focus report: Day Ahead Auction](#), Australian Energy Regulator, 3 October 2024.

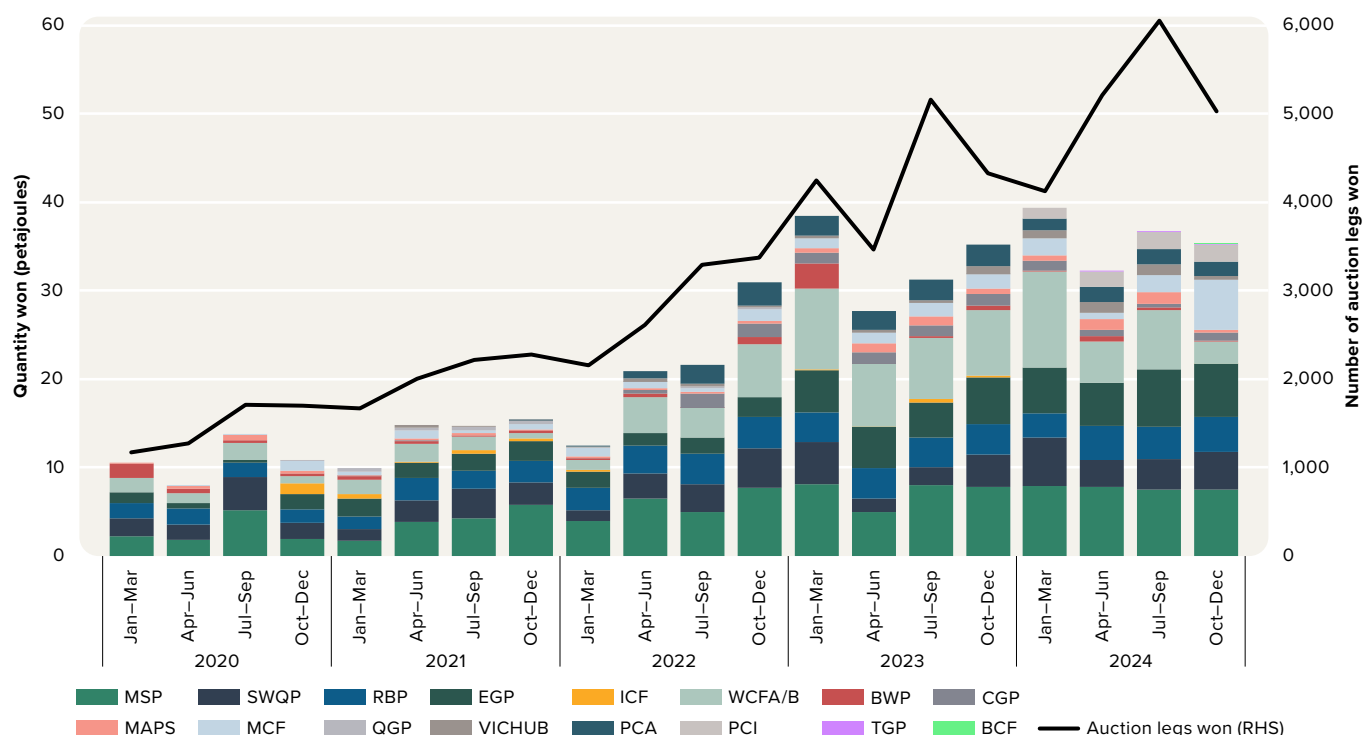
385 The AER's *Pipeline capacity trading – two-year review* found Day Ahead Auction capacity increased liquidity in both upstream and downstream markets. It also reported on how the auction can indirectly ease supply costs for some gas-powered generators in the NEM. AER, [Pipeline capacity trading – two-year review](#), March 2021, Australian Energy Regulator, p. 23.

386 The Wallumbilla B facility can compress gas to a restricted specification, rather than the Australian Standard gas specification of the Wallumbilla A facility, allowing participants with the ability to provide gas at the restricted specification the opportunity to win capacity on the auction.

387 The January to March quarter record set in 2023 was 24% higher than all prior quarters since the auction commenced, and around 3 to 4 times higher than previous January to March quarters.

The July to September 2024 quarter saw a significant change in behaviour compared with the previous quarter – from August, capacity won on the MSP and SWQP increasingly shifted onto routes taking gas north. This trend continued into the following quarter alongside high northerly gas flows.

Figure 4.22 Day Ahead Auction quantities won, by facility



Note: BCF: Ballera Compression Facility; BWP: Berwyndale to Wallumbilla Pipeline; CGP: Carpentaria Gas Pipeline; EGP: Eastern Gas Pipeline; ICF: Iona Compression Facility; MAPS: Moomba to Adelaide Pipeline; MCF: Moomba Compression Facility; MSP: Moomba to Sydney Pipeline; PCA: Port Campbell to Adelaide Pipeline; PCI: Port Campbell to Iona Pipeline; QGP: Queensland Gas Pipeline; RBP: Roma to Brisbane Pipeline; SWQP: South West Queensland Pipeline; TGP: Tasmania Gas Pipeline; VICHUB: VicHub (eastern Victoria); WCFA/B: Wallumbilla compression facilities.

Source: AER analysis of Day Ahead Auction data.

4.7 Trade in east coast gas markets

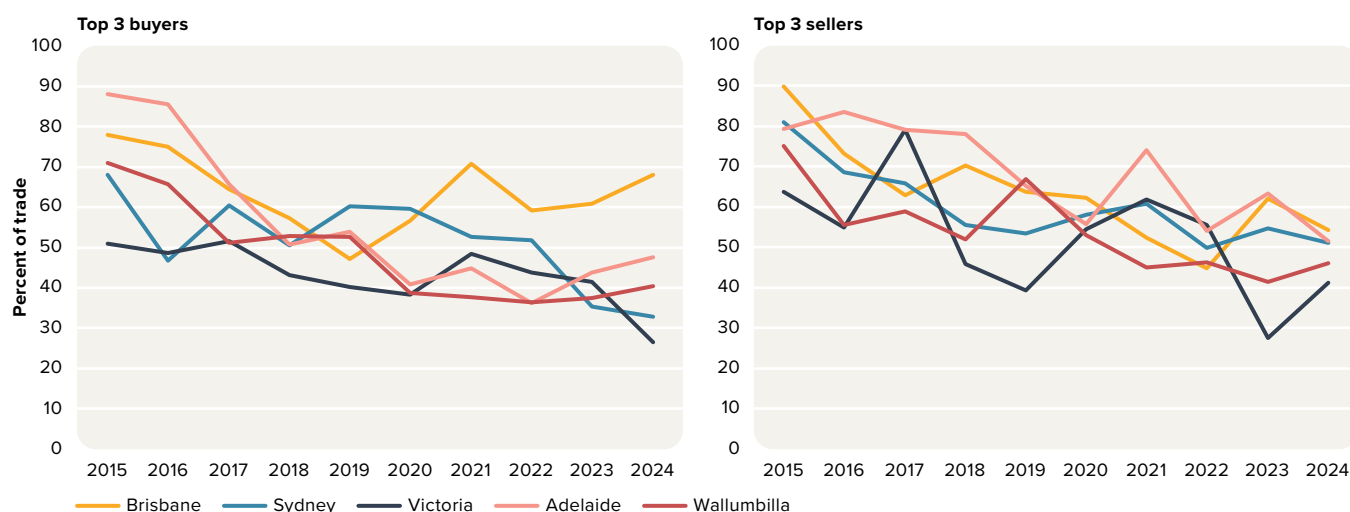
In 2024, gas markets remained liquid with continued high trade levels in the Gas Supply Hub, supported by increasing levels of transportation capacity won through the Day Ahead Auction.

In downstream Short Term Trading Market (STTM) hubs and the Declared Wholesale Gas Market (DWGM), net trade in 2024 reached levels higher than 2023 but lower than in 2022 and 2021, peaking over the winter months when severe cold weather in southern states in May and June led to several high demand days. This aligned with an increase in Day Ahead Auction capacity won on the Moomba to Sydney pipeline and South West Queensland Pipeline to bring gas south (section 4.6.2). The last quarter of 2024 saw record net trade volumes over the October to December quarter, largely driven by increased participation in the Brisbane hub of the STTM with the entry of new participants.

In the Gas Supply Hub, strong trade from the July to September quarter of 2024 set a new quarterly record for traded commodities, reaching 14.4 PJ. At the Day Ahead Auction, the capacity won remained high, with the first quarter of 2024 setting a quarterly record high of 39.4 PJ. Overall, more than 143.6 PJ of auction capacity was won in 2024 across all the auction facilities, 8% higher than in 2023.

The top 3 buyers and sellers at a given point in time generally account for a significant proportion of gas trades across all east coast regions. Trading profiles varied across the markets. The concentration of trades among the top 3 sellers increased in the Victorian DWGM and the Wallumbilla Gas Supply Hub, with decreases recorded in other regions – with Sydney remaining relatively stable (Figure 4.23). In Victoria, the proportion increased by 50%, following 2 years of declines in the level of trade attributed to the top 3 sellers. Among the top 3 buyers, the proportion of gas purchased in 2024 increased in Brisbane by 12%, with marginal increases also observed in Adelaide and the Wallumbilla Gas Supply Hub. In Sydney, the concentration of buyers remained relatively stable while in the Victorian DWGM, the proportion dropped from 42% in 2023 to 27% in 2024.

Figure 4.23 Top 3 buyers and sellers in eastern Australian gas markets



Source: AER analysis of data from the Gas Supply Hub, Short Term Trading Market and Victorian Declared Wholesale Gas Market.

4.7.1 Victoria's Declared Wholesale Gas Market (DWGM)

In 2024, 40 participants traded in the Victorian market. The market's participants include energy retailers, power generators and other large gas users, and traders. Net traded volumes reached above 30 PJ, increasing by 9% from 2023, with higher levels of mid-year and end-of-year trade. Despite this increase, total trade in Victoria did not reach 2021 and 2022 levels.

The volume of trade in the Victorian gas futures market, which is designed to support the trading and hedging needs of Victorian gas market participants, was down 32% in 2024 compared with the previous year. Ultimately, this quantity still accounts for only a small proportion (less than 5%) of the total volume traded in the spot market.

4.7.2 Gas Supply Hub (GSH)

In 2024, 25 participants traded at the gas supply hubs, 24 of which were active in trading both on-screen and off-screen products. Numerous off-market trades were facilitated by a broker participant. On average, participants executed around 515 trades per month in 2024 – an increase of 22% from 2023. LNG export businesses and gas producers remained the most active participants in 2024, accounting over half of the total volume sold at the Gas Supply Hub. Gentailers were the second most active participant group, accounting for 30% of the volume sold.³⁸⁸

LNG producers are large suppliers of gas into the hubs, although operational issues can limit their participation. In addition, the physical interconnection of LNG facilities allows them to trade easily among themselves. Some market participants have suggested the scale of the LNG producers' operations may involve greater volumes than the hubs can currently absorb. Other participants trading were large industrial users.

³⁸⁸ Gentailers are participants that own electricity generation assets and retail market portfolios.

In 2024, an increase in shorter-term trades at the Gas Supply Hub persisted, with most deliveries occurring closer to the date of trade (Figure 4.24). This is different to the trend seen in 2021 and 2022, where larger forward trade volumes indicated participants locking in gas supply prior to winter. The lower volumes of forward trade suggest a greater reliance on spot market trade to meet participants' demand levels over winter. Overall trade volumes in 2024 were up 8% compared with 2023, with the proportion of gas traded within 3 days of the delivery date increasing from 48% in 2023 to 57% in 2024.

Wallumbilla hub activity

Wallumbilla is the larger of the 2 primary hubs that make up the Gas Supply Hub. Users of the Wallumbilla hub include the LNG projects, gas-powered generators and trader participants taking advantage of the Day Ahead Auction to arbitrage prices between Wallumbilla and the downstream markets. Trade at the Wallumbilla hub represents the bulk of gas traded through the Gas Supply Hub.

In 2021, off-screen trade at Wallumbilla began to increase with the trend continuing into 2023. However, in 2024 the volume of off-screen trades was marginally lower (3%) than in 2023. Despite this, overall trade volumes at Wallumbilla in 2024 remained higher compared with 2023, due to an uptick in on-screen trades (which increased by 66%), and were particularly high in the January to March quarter 2024.

Gas traded through the Wallumbilla hub represents only a small share of total gas traded, because many participants continue to favour bilateral, off-market arrangements. In 2024, gas traded through the Wallumbilla hub accounted for around 18% of total gas flows through pipelines in the Wallumbilla bulletin board zone, slightly higher than in the previous year. In total, close to 43 PJ of gas was traded for delivery in 2024.

Moomba hub activity

Trade at Moomba has been slow to develop. The first trade was executed in September 2017 and 141 trades were executed in 2019. Like Wallumbilla, trades at the Moomba location decreased significantly in 2020, declining further in 2021 before a very slight upturn in 2022. However, an upturn in 2023 saw traded quantities reach 3.8 PJ – this was partially driven by an upturn in trade levels on the Moomba to Sydney Pipeline.

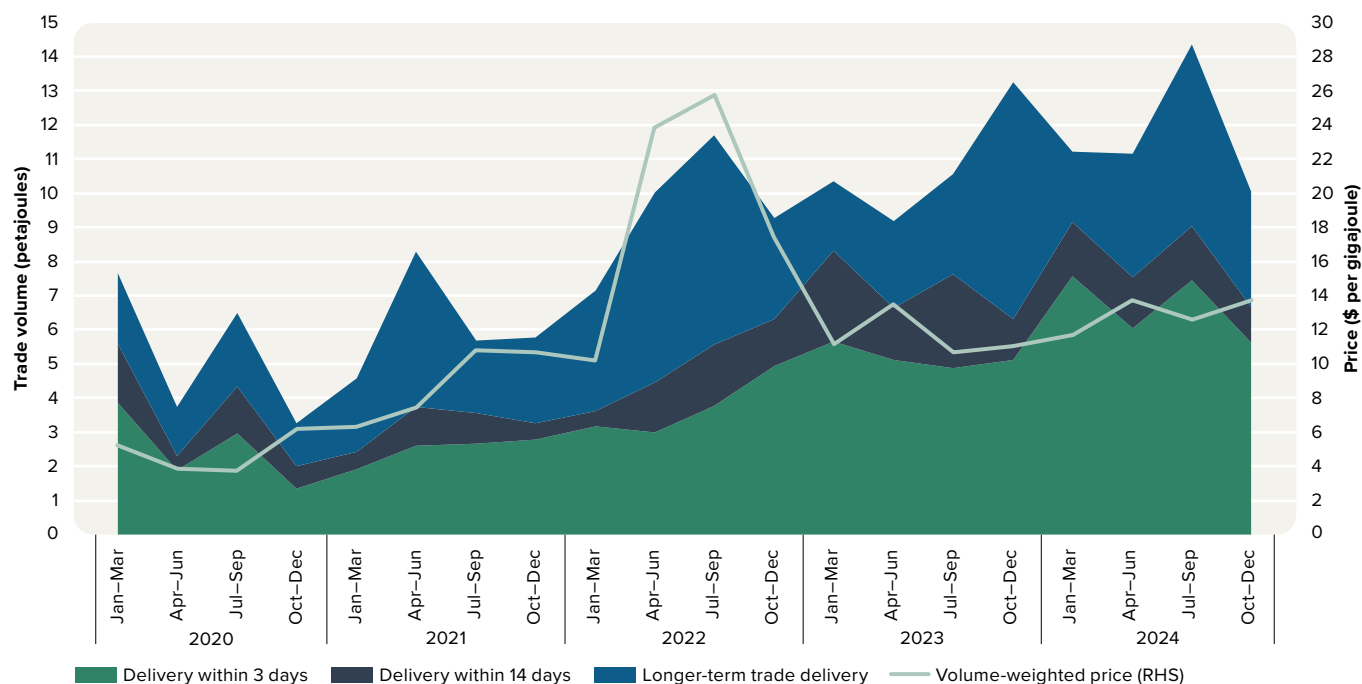
In 2024, 5.8 PJ of gas was traded at Moomba, a 53% increase from 2023 volumes. This was partially due to a drastic increase in trades on the Moomba to Adelaide pipeline, with traded volumes increasing by almost 300%. While still significantly lower trade levels than at Wallumbilla, trades at Moomba represented around 11% to 12% of the total volume of gas traded through the Gas Supply Hub in 2024.

Activity at other locations

Trade levels at the Culcairn (Victoria) and Wilton (Sydney) trading locations have occurred in small volumes since becoming available in 2021, reaching a total of 315 TJ and 3,250 TJ respectively by the end of 2024.³⁸⁹

389 Quantities traded from 2021 up to 31 December 2024.

Figure 4.24 Gas supply hub – increase in shorter-term trade



Note: Volume-weighted average price includes all Gas Supply Hub products (excluding capacity trading platform) at all locations, excluding brokered sales.
Source: AER analysis of Gas Supply Hub data.

4.7.3 Short Term Trading Market (STTM)

In 2024, 40 participants traded in the Sydney STTM, 30 participants traded in the Adelaide market and 22 in the Brisbane market. The participants included energy retailers, power generators, large industrial gas users, gas producers and exporters, and traders. The markets are particularly useful for gas-powered generators because they can source gas at short notice when electricity demand is high (and offload surplus gas if electricity demand is low).

Shippers deliver gas for sale into the market and users buy the gas for delivery to energy customers. Many participants operate both as shippers and users but in effect trade only their net positions – that is, the difference between their scheduled gas deliveries into and out of the market.

In 2024, quarterly net trade levels accounted for 19.1% to 24.4% of the total scheduled demand in the Sydney market and 16.5% to 29.9% in Brisbane. Brisbane has historically traded below 10% of market demand but has seen an uptick since 2023 as more participants are trading in the spot market. In Adelaide, the proportion of trade reached to near record high levels above 30% in the January to March quarter 2024. In Sydney, which has the highest volume of traded quantities across the STTM hubs, net trade levels across 2024 were up 22% from the previous year (19.7 PJ), with scheduled demand 4% higher (91.7 PJ).

4.8 Market responses to supply risk

Concerns about potential gas shortfalls have prompted a range of potential market responses. These include further gas development, LNG imports, transmission pipeline solutions and demand response. AEMO's *Gas Statement of Opportunities* reports have repeatedly highlighted the risk of both short-term and long-term shortfalls in the east coast gas markets, particularly due to the depletion of legacy gas fields in Victoria's offshore Gippsland Basin. However, several projects that could help fill the supply gap have either stalled, been postponed or abandoned.

4.8.1 Gas field development

Numerous projects have been progressing to bring additional supply to the domestic market:

- In Queensland, Senex expanded the Atlas gas fields to increase production from February 2025, with plans for the expansion of the Roma North gas fields having progressed from anticipated to committed status.³⁹⁰ The Roma North Expansion project is currently under construction, with both projects to provide an additional daily processing capacity of 57 TJ and 28.5 TJ, respectively.³⁹¹
- In Victoria, Cooper Energy announced plans to expand its Otway gas hub. After commencing production at the Athena gas plant (formerly Minerva) from mid-December 2021.³⁹² However, a downgrade of reserves at the Thylacine North and Enterprise fields in the Otway Basin has reduced levels of forecast production from these gas fields.³⁹³ The proposed 3-well drilling program targets backfilling declining Otway fields to supply into the existing Athena gas plant with a potential to supply 90 TJ per day of production by 2028.
- Exxon Mobil announced funding of the Kipper Compression Project in the January to March quarter 2022, committing supply from 2024 and additional investment to develop and produce gas from the Kipper and Turrum fields over the following 5 years.³⁹⁴ While additional gas is expected to be processed at Longford from 2026, supply is not expected to increase winter capacity to levels previously supplied by their depleting legacy field production.³⁹⁵ In addition to the Turrum phase 3 project, the Gippsland Basin Joint Venture is considering the Longford Late Life Optimisation project to maximise production from depleting reserves later in the decade.³⁹⁶
- Beach Energy committed to the development of Geographe and Thylacine North and West fields to increase Port Campbell supply, including the drilling of 6 new production wells commencing in February 2021. From mid-May 2023, Otway's actual daily production output increased above 170 TJ, reaching close to 200 TJ across the April to June quarter 2024. Total production output from Otway over the second half of 2024 reached almost 30 PJ, compared with just over 20 PJ across the first half of the year. Beach Energy has also prioritised the ongoing development of its Yolla West field and deferred final investment decision for Trefoil, which is now considered as potential supply.³⁹⁷ The same strategic decision was also made for White Ibis, Bass and Yolla West due to the developments not meeting minimum investment requirements.³⁹⁸
- A proposed plant to process gas from the Golden Beach field in the Gippsland Basin could provide additional supply before providing storage capability (section 4.8.4). In late November 2024, offshore geotechnical investigations commenced to assess the seabed's suitability for supporting a drilling rig and the offshore pipeline route.³⁹⁹
- Beach Energy discovered Artisan 1 as part of the Otway drilling campaign completed in 2022, which has the potential to be developed pending final investment decision.

390 AEMO, [Gas Statement of Opportunities](#), Australian Energy Market Operator, March 2025, p. 48.

391 The Roma North project was originally scheduled to be operational before winter 2025.

392 Athena sources gas from the Otway Basin's Casino, Henry and Netherby fields, some of which was formerly processed at Iona (Casino). The East Coast Supply Project, formerly known as the Otway Phase-3 Development (OP3D) project, was originally targeted to bring additional gas to the market before winter 2025. Wells at the Annie, Juliet and Isabella fields are currently undergoing exploration well drilling.

393 AEMO, [Gas Statement of Opportunities](#), Australian Energy Market Operator, March 2025, pp. 48, 67.

394 ExxonMobil, [Opportunities for the Gippsland Basin and Australia's energy transition](#), 22 March 2022.

395 AEMO, [2023 Victorian gas planning report](#), Australian Energy Market Operator, March 2023, p. 63.

396 The project depends on the progression of the Turrum phase 3 project. AEMO, [2023 Victorian gas planning report](#), Australian Energy Market Operator, March 2023, p. 63.

397 AEMO, [2023 Victorian gas planning report](#), Australian Energy Market Operator, March 2023, p. 63.

398 AEMO, [2023 Victorian gas planning report](#), Australian Energy Market Operator, March 2025, p. 68.

399 AEMO, [2023 Victorian gas planning report](#), Australian Energy Market Operator, March 2025, p. 67.

- Gas supply from Amplitude Energy's Manta field could be processed at the Orbost Gas Plant as a backfill after Sole field production declines. The project requires an appraisal well to be drilled prior to a development decision.
- Other potential projects include redevelopment of Gippsland's Longtom field previously processed at the Orbost Gas Plant (Seven Group Holdings Energy) and the Wombat field (Lakes Blue Energy) with an estimated supply capacity of 10 TJ per day.
- In NSW, Santos proposed to develop 850 wells across its 95,000-hectare Narrabri gas project, with the potential to supply up to 200 TJ per day. The staged development was expected to provide up to 55 PJ per year in 2026, all of which had been voluntarily committed to the domestic market and has now been fully committed following a recent ruling. Appeals against the project's approval have delayed any final investment decision, which now depends on project approvals being cleared.⁴⁰⁰ The recent Native Title Tribunal ruling has cleared the project, allowing the lease of land for the development of gas extraction to assist with southern gas shortfalls. The project is contingent on the planning approval and construction of a 450 km gas pipeline connecting the project to the Moomba to Sydney Pipeline.

Barriers to gas development

In some states and territories, community concerns about environmental risks associated with fracking led to legislative moratoria and regulatory restrictions on onshore gas exploration and development.⁴⁰¹ Victoria, South Australia, Tasmania, Western Australia and the Northern Territory have onshore fracking bans in place, with varying degrees of coverage:

- The Victorian Government banned onshore hydraulic fracturing and exploration for and mining of coal seam gas or any onshore petroleum until 30 June 2020.⁴⁰² In March 2021 the government committed the ban on fracking and coal seam gas exploration to the Victorian Constitution.⁴⁰³ Onshore conventional gas exploration recommenced from July 2021. Other projects, such as the development of new or existing storage solutions, also face regulatory hurdles such as environmental assessments being approved by government.
- In 2018 South Australia introduced a 10-year moratorium on fracking in the state's south-east. It introduced the moratorium by direction and announced its intention to legislate it. However, unconventional gas extraction is allowed in the Cooper and Eromanga basins. South Australia has no restrictions on onshore conventional gas.
- The Tasmanian Government banned fracking for the purpose of extracting hydrocarbon resources (including shale gas and petroleum) until March 2020. This has since been extended to 2025.⁴⁰⁴
- The Northern Territory has made 51% of the territory eligible for hydraulic fracturing. The decision covers much of the Beetaloo Basin, which holds most of the territory's shale gas resources.
- NSW has no outright ban on onshore exploration, but significant regulatory hurdles have stalled development proposals. Regulatory restrictions include exclusion zones, a gateway process to protect 'biophysical strategic agricultural land', an extensive aquifer interference policy, and a ban on certain chemicals and evaporation ponds.⁴⁰⁵ The state's regulations also require community consultation on environmental impact statements and a detailed review process for major projects, as highlighted by the protracted process for Santos's Narrabri gas project.⁴⁰⁶ Under an agreement reached in early 2020, the NSW and Australian governments set a target of increasing supply to the NSW market by 70 PJ per year.⁴⁰⁷

400 The Australian Government approved the project in November 2020, with the conditions of approval consistent with those set by the NSW Independent Planning Commission. In December 2022, the Native Title Tribunal conditionally decided to allow land leases for the project's development, which was subsequently delayed by a good faith appeal being lodged. The appeal was overturned in 2024 with an order for the reassessment of environmental concerns.

401 Hydraulic fracturing, also known as fracking, involves injecting a mixture of water, sand and chemicals at high pressure into underground rocks to release trapped pockets of oil or gas. A well is drilled to the depth of the gas or oil-bearing formation, then horizontally through the rock. The fracturing fluid is then injected into the well at extremely high pressure, forcing open existing cracks in the rocks, causing them to fracture and breaking open small pockets that contain oil or gas. The sand carried by the fluid keeps the fractures open once the fluid is depressurised, allowing oil or gas to seep out.

402 Victorian Department of Economic Development, Jobs, Transport and Resources, Onshore gas community information, August 2017.

403 Victorian Government, [Enshrining Victoria's ban on fracking forever](#), media release, March 2021, accessed 17 July 2025.

404 Tasmanian Department of State Growth, Tasmanian Government policy on hydraulic fracturing (fracking) 2018, accessed 17 July 2025.

405 NSW Department of Planning and Environment, Initiatives overview, July 2018.

406 NSW Department of Planning and Environment, 'Community views on Narrabri Gas Project to be addressed', media release, 7 June 2017.

407 Prime Minister of Australia and Premier of New South Wales, 'NSW energy deal to reduce power prices and emissions', media release, January 2020.

4.8.2 Liquefied natural gas import terminals

To address future supply concerns, market participants have proposed numerous gas projects to develop LNG import facilities on the east coast. Each project would involve importing LNG through floating storage and regasification units.

- Due to uncertainty around the contracting of gas supply, AIE's terminal at Port Kembla (NSW) was reclassified by AEMO and removed from the list of anticipated projects feeding into forecast supply outlooks. In 2021 AIE and Jemena signed a project development agreement to connect to the Eastern Gas Pipeline (EGP), with modifications set to allow bidirectional flows to deliver gas to Sydney and Victoria (section 4.8.3). Jemena completed construction of the 12 km buried gas pipeline to connect the LNG Terminal to Jemena's EGP in December 2023, while physical construction at the LNG Terminal has been completed and commissioning work is underway.⁴⁰⁸
- Venice Energy's Outer Harbour LNG project at Port Adelaide (South Australia) is projected to potentially supply gas by 2027.⁴⁰⁹ However, gas deliveries to Victoria are currently constrained due to the SEAGas Pipeline, which is currently only able to flow gas out of Victoria, and the limited available capacity on the South West Pipeline.
- Prior to the completion of the Venice Outer Harbour project, the Adelaide Energy Bridge has been reported to act as an interim supply source, making gas supply of up to 150 TJ per day (50 PJ per year) available to South Australia before the end of 2025 until the end of 2028.
- Viva Energy's Geelong (Victoria) Gas Terminal project is forecast to supply up to 140 PJ per year, have a capacity of 620 TJ per day and potentially be operational from 2028.⁴¹⁰
- Vopak's import terminal in Port Phillip Bay (Victoria) is planned to have a supply capacity of up to 778 TJ per day, supply around 270 PJ per year and be operational from 2028.
- EPIK ceased development of a Newcastle import terminal in early 2023 due to the project being economically unfeasible.⁴¹¹

4.8.3 Transportation capacity expansion

To assist with reducing existing gas supply transportation constraints, pipeline expansions have been progressing to bring more gas south from Queensland, bring more gas from western Victoria into Melbourne, and provide upcoming import supply with the ability to provide gas to NSW and Victoria.

APA pipeline expansions

South West Queensland and Moomba to Sydney pipelines project

APA has been expanding the pipeline corridor through Queensland into NSW by adding additional compression on the South West Queensland Pipeline (SWQP)⁴¹² and the Moomba to Sydney Pipeline (MSP).⁴¹³ The expansion enables more gas flow on pipelines where capacity has been fully or close to fully contracted.⁴¹⁴

408 Squadron Energy, [Port Kembla Energy Terminal](#), accessed 13 May 2025. The forecast supply capacity of 500 TJ per day is projected to be available from 2026 following physical mechanical completion. AEMO, 2024 [Victorian gas planning report](#), Australian Energy Market Operator, March 2024, p. 64.

409 AEMO, [Gas Statement of Opportunities](#), Australian Energy Market Operator, March 2025, p. 65.

410 AEMO, [Gas Statement of Opportunities](#), Australian Energy Market Operator, March 2025, p. 65.

411 AEMO, [Gas Statement of Opportunities](#), Australian Energy Market Operator, March 2023, p. 65; Mandurah Mail, [Gas market volatility kills off \\$590m gas terminal](#), 3 February 2023.

412 The SWQP connects to the Northern Territory through the Carpentaria Gas Pipeline and is a gateway between large northern gas fields in Queensland (including the 3 Gladstone LNG projects) and southern regions with highly seasonal demand.

413 The MSP connects the Moomba hub in South Australia to southern markets in Sydney/ACT and Victoria (through Young and the Victoria/New South Wales Interconnector). Seasonal (non-peak) capacity on the MSP can be limited by up to 50% due to annual maintenance, while southern haul capacity on the VNI lateral can be limited by dynamic interactions between Young, Sydney and GPG requirements at Uranquinty.

414 ACCC, [Gas inquiry 2017–2025, interim report](#), Australian Competition and Consumer Commission, February 2022, p. 15.

Stage 1 of the expansion was completed by June 2023, increasing transportation capacity by 49 TJ on the SWQP (to 453 TJ per day) and by 30 TJ on the MSP (to 475 TJ per day).⁴¹⁵ Further stage 2 expansions on the pipelines added 2 more additional compressors, with commissioning completed by June 2024, increasing transportation capacity by 59 TJ on the SWQP (to 512 TJ per day) and by 90 TJ on the MSP (to 565 TJ per day). These were the first 2 of 4 initially proposed stages, with a recently announced fifth stage to add flexibility to stages 3 and 4 and upgrade capacity in the Victorian Transmission System (VTS).

Further APA pipeline expansions

In addition to the Kurri Kurri Lateral Pipeline (KKLP) project, other projects announced by APA in a 5-year East Coast Gas Grid expansion plan are projected to deliver a 24% increase in north-to-south gas transportation capacity for delivery from Young (NSW) to southern market demand centres in NSW and Victoria.⁴¹⁶ These would supplement existing expansions of the north–south pipeline corridor, which took place in 2023 and 2024, and added around 25% of additional transportation capacity into southern regions.⁴¹⁷

Committed projects to increase north-to-south transportation capacity in 2025 and 2026 have reached final investment decision, including the Moomba to Sydney Ethane Pipeline (MSEP) conversion project and the Moomba to Sydney Pipeline (MSP) off-peak expansion project.

- The MSEP conversion project is targeted for completion in 2025 and is projected to provide an additional 20 TJ per day of supply capacity from Moomba to Victoria, or 25 TJ per day to Sydney, through conversion of the existing pipeline to natural gas.⁴¹⁸
- The MSP off-peak capacity expansion project will deliver 2 pressure regulation skids to increase capacity in summer months during pipeline maintenance periods, with new capacity expected to come online in summer 2025 and 2026. This would raise summer capacity to 80 to 120 TJ per day to support gas storage refill at Iona.

Other medium-term projects being progressed include the Bulloo Interlink (stage 3) and Riverina storage pipeline (stage 4).

- The stage 3 expansion is expected to increase transportation capacity from northern basins to southern markets by 24%, including the proposed delivery of a new 380 km pipeline (the Bulloo Interlink) connecting the South West Queensland Pipeline (SWQP) to the MSP, and 2 new compressors between Moomba and Young, and Young and Culcairn.⁴¹⁹ Stage 3 compression upgrades have been split into 2 phases:
 - Stage 3a consists of an additional compressor on the MSP between Moomba and Young and will increase the nominal capacity of the MSP by 34 TJ per day to 599 TJ per day.
 - Stage 3b consists of an additional compressor between Young and Culcairn to provide a capacity increase of 41 TJ per day to Culcairn and a further 5 TJ per day for the mainline MSP.
- The stage 4 expansion aims to deliver additional storage and delivery capacity to support projected requirements for peak gas-powered generation (Riverina storage pipeline) with new compression and pipeline infrastructure. If progressed, stage 4 would add new storage capacity in winter 2028 and 2029 (section 4.8.4).
- The stage 5 expansion has the potential to expand the MSP and VTS systems to 350 TJ per day from Young (NSW) to Wollert (Victoria) through the addition of new compressors, reconfiguration works and new metering and pressure regulation infrastructure.

⁴¹⁵ Stage 1 of the expansion includes an additional compressor on the SWQP and an additional compressor between Moomba and Young on the MSP.

⁴¹⁶ APA Group, [APA's East Coast Gas Expansion Plan](#), 24 February 2025.

⁴¹⁷ South West Queensland and Moomba to Sydney pipelines project stage 1 and stage 2 expansions.

⁴¹⁸ The incremental capacity increase would raise the total southbound capacity on the MSP from 565 TJ per day to 590 TJ per day.

⁴¹⁹ The project would progressively increase MSP capacity from 590 TJ per day to 700 TJ per day. SWQP capacity would increase from 512 TJ per day to 605 TJ per day and capacity between Young and Melbourne would increase from 190 TJ per day to 229 TJ per day.

South West Pipeline, Western Outer Ring Main (WORM) project

The South West Pipeline (SWP) is a bidirectional facility that primarily transports gas from Port Campbell supply (gas from the Otway Basin and Iona underground storage) into Melbourne. The pipeline also supports refilling the Iona reservoir and transports gas west, fuelling the Mortlake power station and South Australia (through the SEAGas pipeline) during periods of lower Victorian demand.⁴²⁰

In 2024, APA upgraded the Victorian Transmission System by building a 51 km high-pressure transmission pipeline to address a key capacity constraint previously limiting the connection of existing gas supply from the west of the state to demand in the north and east. The WORM pipeline was commissioned in February 2024, increasing capacity on the South West Pipeline from 447 TJ per day to 506 TJ per day, facilitated by the addition of a second compressor station at Winchelsea.⁴²¹ The transportation of gas was also assisted by the upgrade of the existing compressor station at Wollert.

While capacity on the SWP has increased, supply from the Iona underground storage facility remains constrained below the facility's maximum supply capacity.

Further proposed expansions are not yet committed because they are subject to approval under APA's Access Arrangement. However, they have been projected to increase supply capacity from Port Campbell to between 528 TJ and 570 TJ per day through pipeline augmentation (compression or looping) and up to 670 TJ per day with additional looping and/or compression.⁴²²

Eastern Gas Pipeline expansion project

The Eastern Gas Pipeline (EGP) is a unidirectional pipeline that transports gas from the Gippsland Basin (Victoria) into Sydney. In 2021 Jemena and AIE signed a project development agreement to connect the PKET import terminal (section 4.8.2) at Kembla Grange. If the project is developed, Jemena plans to modify the pipeline to allow for bidirectional flows, with an initial ability to supply 200 TJ into Victoria and up to 440 TJ towards Sydney per day.⁴²³

4.8.4 Storage expansion

AEMO has highlighted that new storage developments are required to address southern gas supply risks after 2034.⁴²⁴ These developments will be required in conjunction with other supply solutions such as pipeline and production expansions to provide more gas to southern markets over winter. Storage solutions provide increased supply flexibility during peak times, having the capability to rapidly ramp up and down, and the potential to relieve existing bottlenecks in network capacity.

Toward the end of the 2030s, all options assessed in AEMO's *Gas Statement of Opportunities* report will require about 500 to 550 TJ per day of additional injection capacity from southern storages. To put this in perspective, 2 current uncertain projects, Golden Beach and the HUGS Phase 2 project, can provide up to 525 TJ per day in total.

Iona underground gas storage – HUGS

Lochard Energy upgraded its underground storage facility to increase supply capabilities to 570 TJ per day, with a recently commissioned South West Pipeline (SWP) expansion – the WORM pipeline upgrade – increasing transportation capacity into Melbourne to 530 TJ per day (section 4.8.3).

Further upgrades after the development of the Heytesbury Underground Gas Storage (HUGS) project have been proposed to add additional pipeline assets and additional storage capacity of 1.8 PJ to 3.5 PJ, increasing supply capacity by up to 45 TJ per day from 2027.⁴²⁵

420 Limited capacity on the SWP restricts supply being provided from Port Campbell in Victoria's west.

421 The capacity for flow from Melbourne to Port Campbell is maximised on days of low demand, with the current maximum at 350 TJ per day, having risen by 154 TJ per day following the completion of WORM. AEMO, [2025 Gas Statement of Opportunities](#), Australian Energy Market Operator, March 2025, p. 60.

422 AEMO, [2022 Victorian gas planning report](#), Australian Energy Market Operator, March 2022, p. 14.

423 Jemena completed construction of the 12 km buried gas pipeline to connect the LNG Terminal to Jemena's EGP in December 2023. The EGP could also be upgraded to flow 325 TJ per day to Victoria.

424 AEMO, [2025 Gas Statement of Opportunities](#), March 2025, p. 90.

425 Construction of a new wellsite at Mylor, Fenton Creek and Tregony (MFCT) gas fields Lochard Energy, [Our HUGS Project](#), April 2022, accessed May 2025.

An increasing reliance on Iona following recent capacity expansions has enabled a more rapid drawdown rate of storage inventory levels. Due to low pressure levels, when Iona's storage inventory falls below 6 PJ withdrawal capability also decreases, potentially reducing to half of the facility's usual supply capacity. The Iona gas storage facility will continue to play a critical role in meeting southern gas demand requirements in winter due to declining output from Longford's legacy gas fields diminishing the supply capabilities at Victoria's largest supply source.

Golden Beach project

A proposed plant to process gas from the Golden Beach field in the Gippsland Basin could provide additional supply to assist with peak day demand in Victoria before operating as an underground storage facility.

The facility is forecast to supply up to 35 PJ over 2 years from mid-2026 (delayed from 2025), with an initial delivery capacity of up to 125 TJ per day for winter 2026.⁴²⁶

Kurri Kurri Lateral Pipeline (KKLP) project

APA Group's KKLP project is a gas transmission and shallow storage facility under construction near Newcastle. It is designed to provide 62 TJ of daily supply capacity and 72 TJ of storage capacity for the new Hunter Power Station in NSW.⁴²⁷ The facility will also connect into the Sydney Short Term Trading Market and is scheduled for completion in early 2025.

Riverina storage pipeline

A recently announced plan to build a new pipeline in NSW could add around 200 TJ of storage capacity by 2028, with a potential expansion projected to increase storage to around 500 TJ by 2029. The storage expansion is part of a 5-stage project to increase supply capacity from Queensland to southern regions (section 4.8.3).

4.8.5 Northern Territory gas

From 2019, Jemena's Northern Gas Pipeline connected the east coast gas pipeline transmission system to supply in the Northern Territory. However, production issues at the offshore Blacktip gas field have led to the closure of the Northern Gas Pipeline.

Since the pipeline commenced operation, it has delivered more than 80 PJ of gas to the east coast. Initial supply across 2020 and 2021 saw pipeline deliveries average around 55 TJ per day before a decline from 2022.⁴²⁸ Reduced flows on the pipeline from 2022 have mirrored production declines at the Yelcherr gas plant, the largest supply source in the Northern Territory sourcing gas from the offshore Blacktip gas field (Figure 4.25). Short-term production output at the Yelcherr gas plant increased above 40 TJ from late March 2025 following a ramp down close to zero from mid-December. However, this remains below initial daily production levels above 80 TJ reported from mid-2019.

Reduced supply from Blacktip led to average flows decreasing to just over 30 TJ per day over the first half of 2022 before production issues resulted in flows ceasing from October to mid-December 2022.⁴²⁹ Subsequent flows averaged below 20 TJ per day, fluctuating up to a high of just over 50 TJ before the pipeline's closure from late February 2024. As a result, this has contributed to reduced supply and increased demand in the east coast markets, with supply on the Carpentaria Pipeline now requiring gas to be sourced from east coast production sources.

426 AEMO, [2022 Gas Statement of Opportunities](#), Australian Energy Market Operator, March 2024, p. 63.

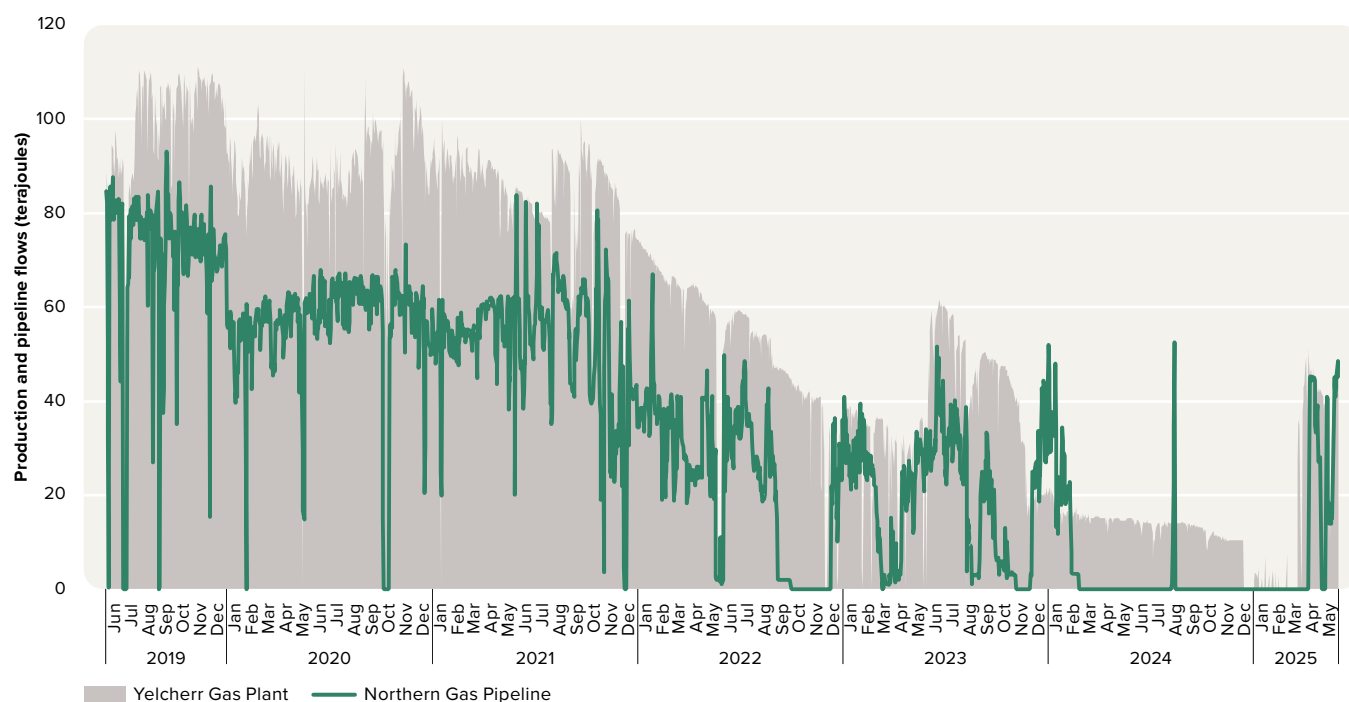
427 Construction of the KKLP project commenced in October 2023. APA, [Kurri Kurri Lateral Pipeline project](#), accessed 12 May 2025.

428 With the prospect of other potential gas sources being brought online in the Northern Territory, Jemena had planned to connect Beetaloo Basin supply to the Queensland's Wallumbilla gas supply hub and increase capacity on the pipeline from its nameplate 90 TJ per day up to 200 TJ per day by 2025.

429 The low pressure in the pipeline forced Jemena to temporarily shut down the pipeline due to safety concerns, requiring Mount Isa to be supplied from east coast production sources.

The Northern Territory presently relies on alternative and interim gas arrangements, including with Darwin LNG exporters.⁴³⁰ While the Carpentaria gas field has progressed from uncertain to anticipated, projected production levels would not provide sufficient supply to meet increasing industrial demand and the Northern Territory's ongoing reliance on gas-powered generation.⁴³¹ These factors contribute to a heightened risk of supply shortfalls in the event of production outages and high gas-powered generation requirements, particularly if they coincide with peak winter demand in the southern markets that are increasingly reliant on Queensland gas supply. With inadequate local supply and uncertainty around production levels from the Yelcherr gas plant, the Northern Gas Pipeline was reconfigured to flow gas into the Northern Territory.⁴³² While this provides a backup solution to address forecast supply gaps in the Northern Territory, it also raises the risk of providing Queensland supply to southern markets when supply and demand conditions tighten over winter.

Figure 4.25 Northern Gas Pipeline flows and Yelcherr production decline



Source: AER analysis of Gas Bulletin Board data.

430 AEMC, [NT Emergency Gas Supply Arrangements](#), Australian Energy Market Commission, 15 August 2019.

431 The Carpentaria gas field is expected to produce 10 TJ per day from 2026, increasing to 25 TJ per day (9 PJ per year) from 2027. AEMO, [2025 Gas Statement of Opportunities](#), Australian Energy Market Operator, March 2025, p. 12.

432 The Northern Gas Pipeline reverse capability project was completed in August 2024.

4.8.6 Demand response

Volatile markets and the expiry of legacy gas supply agreements are prompting commercial and industrial (C&I) customers to take a more active role in gas procurement. Some customers have become direct market participants by engaging in collective bargaining agreements.

Some C&I users are exploring or implementing options such as purchasing gas directly from producers rather than retailers, using brokers to secure supply agreements, participating in gas markets and investing in new LNG import facilities.⁴³³ Some users have lowered their gas use by changing fuels or increasing efficiencies. Others have also deferred large investments.

In addition, some C&I users are considering alternatives to gas, such as renewable energy, as longer-term options.⁴³⁴ The suitability of options such as electrification or switching to green hydrogen, biomethane or other biofuels is set out in more detail in the *Future Gas Strategy Analytical Report*.⁴³⁵

Concerns about potential gas shortfalls have prompted a range of potential market responses. These include further gas development, LNG imports, transmission pipeline solutions and demand response.

In the more immediate term, demand response has a key role in managing peak day shortfalls. Although a formal demand response mechanism is not yet in place in wholesale gas markets, the Energy and Climate Change Ministerial Council has requested the Australian Energy Market Commission (AEMC) introduce an administered demand response mechanism as part of a broader supplier of last resort mechanism (section 4.10.4). A study by ACIL Allen of suitability of C&I users to supply demand response indicates that up to 22 TJ per day could potentially be used to absorb shortfalls with 6 hours or less notice.⁴³⁶

Governments have also started enacting policies to reduce residential gas demand. The ACT Government initially removed mandatory gas connection requirements for new homes, before legislating a stop to new gas connections from 2023.⁴³⁷

Victoria's Gas Substitution Roadmap and Energy Upgrades program identified electrification as the best solution to achieve a short-term reduction to gas consumption levels for residential consumers.⁴³⁸ The roadmap offers options and support for Victorian residential and small commercial consumers who are interested in switching from gas to solar or electricity.

Since 1 January 2024, all new homes in Victoria requiring a planning permit are required to be all-electric, with new homes and residential subdivisions no longer able to connect to the gas network.

433 ACCC, [Gas inquiry 2017–2025, interim report](#), January 2021, Australian Competition and Consumer Commission, February 2021, pp. 73–74.

434 ACCC, [Gas inquiry 2017–2025, interim report](#), January 2020, Australian Competition and Consumer Commission, February 2020, p. 74.

435 DISR, [Future Gas Strategy Analytical Report](#), Department of Industry, Science and Resources, 9 May 2024.

436 AEMC, [ECGS Supplier of Last Resort Mechanism](#), Australian Energy Market Commission, July 2024, p. 82. 22 TJ per day is calculated as 28% of 82 TJ per day, based on data obtained as part of the demand response study.

437 ACT Government, [ACT reaches milestone preventing new fossil fuel gas connections](#), media release, 8 June 2023.

438 AEMO, [2025 Gas Statement of Opportunities](#), Australian Energy Market Operator, March 2025, p. 5.

4.9 Compliance and enforcement activities

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

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

Each year, the AER identifies and publishes a set of compliance and enforcement priorities, some of which relate to participants in east coast gas markets.

For 2023–24, the AER's compliance and enforcement priority relating to gas markets was to clarify obligations and monitor compliance with reporting requirements under the new Gas Market Transparency Measures.

4.9.1 Compliance with Gas Market Transparency Measures

New gas market transparency reforms were legislated in late 2022, following the passage into law of the National Gas Amendment (Market Transparency) Rule 2022. These reforms promote transparency in east coast gas markets through enhanced and expanded reporting of traded gas volumes and prices and the provision of information on overall gas supply adequacy to the Gas Bulletin Board and to AEMO's *Gas Statement of Opportunities*.

New participant reporting to the Gas Bulletin Board commenced on 15 March 2023. The AER has focused on the following activities:

- Continued to work with AEMO and market participants recognising the enhanced compliance risks associated with entities that are reporting for the first time, engaging with individual participants and communicating our compliance expectations more broadly through industry forums and AER publications.⁴³⁹
- Monitored the behaviour of service providers, viewing them as a critical tool to inform our power to initiate form of regulation reviews to ensure that the appropriate level of regulation is applied to pipelines to promote access. Our findings are published on the AER website in our first *Gas pipeline monitoring and transparency: report on the behaviour and compliance of gas pipeline service providers*.⁴⁴⁰
- Analysed the contracted and uncontracted reserve price assumptions of gas field operators submitted yearly to the AER. These price assumptions coincide with the requirement to provide reserve volume information to AEMO. The findings are published on the AER website in our second wholesale gas reserves price assumptions report for contracted prices and uncontracted gas reserve price assumptions reported to the AER for the 2024 calendar year.⁴⁴¹ Alongside this report, we also released an updated reserve price assumption submission template.⁴⁴²
- Reviewed compliance with requirements under Part 27 of the National Gas Rules pertaining to East Coast system reliability and supply adequacy. This was supported by consultations with AEMO, our analysis of the data reported under Part 27, compliance self-reports and our compliance assessments.
- Published our final *Day Ahead Auction Record Keeping Guideline*, which sets out how facility operators and transportation facility users must record and maintain nomination and renomination data relevant to the AER's monitoring functions.⁴⁴³

439 Previous activities included working with AEMO and participants on short-term transaction reporting and reserves and resources reporting.

440 AER, [Gas pipeline monitoring and transparency report 2025](#), Australian Energy Regulator, 26 March 2025.

441 AER, [Wholesale Gas Reserves Price Assumption Report 2025](#), Australian Energy Regulator, 15 April 2025.

442 AER, [AER Reserves Reporting Template – Gas Transparency Measures](#), Australian Energy Regulator, 2025.

443 AER, [Day Ahead Auction Record Keeping Guideline](#), Australian Energy Regulator, 2 August 2024.

4.9.2 Other compliance and enforcement activities

The AER also carried out the following activities, some of which relate to the AER's 2024–25 Compliance & Enforcement Priority 5 – Monitor and enforce compliance with reporting requirements under the new Gas Market Transparency Measures:

- The AER has undertaken a number of compliance and enforcement activities in relation to the Auction Quantity Limit (AQL) obligations for the Day Ahead Auction (section 4.2.2) which determines how much capacity is available to be won at auction.
 - In April 2025 the Federal Court ordered 4 Jemena subsidiaries (collectively, Jemena) to pay penalties totalling \$5.5 million for breaches of the Gas Rules related to the DAA. During court proceedings, Jemena admitted that between 1 March 2019 and 22 February 2022 it breached rules 649(1) and 653(1)(a) of the Gas Rules by failing to determine AQLs in accordance with the procedures developed by AEMO and the Part 24 information standard. The contravening conduct resulted in incorrect AQLs being provided to AEMO and had the potential to result, in some instances, in auction participants paying above what they otherwise would have paid.⁴⁴⁴
 - In July 2024 a market participant submitted a self-report to the AER, advising that it had underreported AQLs by 4 TJ for 27 days between May and June 2024 and by 9 TJ for one day in July 2024. We conducted an assessment and found that the underreporting of these AQLs contributed to DAA constraints on 3 gas days – 4 June, 5 June, and 14 June – resulting in a total loss of 7,178 GJ of auction capacity and collectively \$27,235.22 in overpayments by 5 shippers. After the review, we met with the participant to communicate the review outcome. The participant reimbursed the affected shippers for their overpayments.
 - Following Shell's failure to submit daily forecasts as required by the Gas Rules, Shell Energy Retail and Powershop, both subsidiaries of Shell Energy Australia (Shell), completed an administrative undertaking that required Shell to submit quarterly demand data comparing forecast and actual demand in the Adelaide, Brisbane and Sydney Short Term Trading Markets between 1 January 2023 and 31 December 2024. This undertaking by Shell further prompted enquiries into the accuracy of daily demand forecasts on the STTM by other market participants due to the revelation that there are trends and patterns in unpredictability and inaccuracies of demand forecasting. As part of the undertaking, Shell entities also volunteered information on its monitoring of demand forecasting accuracy; we are continuing to monitor the accuracy of Shell and other STTM participant forecasts due to their potential impact on market price outcomes.

More detail on the AER's compliance and enforcement work is outlined in the *Annual compliance and enforcement report 2024–25*.

4.10 Government intervention in gas markets

In response to concerns around the adequacy of gas supplies to meet domestic demand and prolonged price volatility seen in 2022, the Australian Government and some state and territory governments have intervened in the market. This has included measures to increase supply stability, reduce demand and limit price volatility, and provide additional monitoring powers to market bodies.

In 2017, the Australian Government directed the ACCC to use its compulsory information gathering powers to inquire into wholesale gas markets in eastern Australia. The inquiry was initially tasked to run until 30 April 2020, with successive governments extending the inquiry to 2025 (in July 2019) and then out to 2030 (in October 2022).⁴⁴⁵

4.10.1 Australian Domestic Gas Security Mechanism

The Australian Domestic Gas Security Mechanism (ADGSM) empowers the Australian Minister for Resources to require LNG projects to limit exports, or find offsetting sources of new gas, if a supply shortfall is likely.⁴⁴⁶ Since 2017, the minister has been able to determine if a shortfall is likely in the following year and may revoke export licences if necessary to preserve domestic supply.

⁴⁴⁴ AER, [Jemena penalised \\$5.5 million for breaching National Gas Rules](#), 11 April 2025.

⁴⁴⁵ ACCC, [Gas inquiry 2017–2030](#), Australian Competition and Consumer Commission, accessed 10 May 2025.

⁴⁴⁶ Department of Industry, Science and Resources, Australian Domestic Gas Security Mechanism, July 2018.

Following the introduction of this mechanism, Queensland's LNG producers entered agreements with the Australian Government, committing to offer uncontracted gas on reasonable terms to meet expected supply shortfalls.⁴⁴⁷ They also committed to offer gas to the Australian market on competitive market terms before offering any uncontracted gas to the international market.⁴⁴⁸ In 2023, following a review by the Australian Government Department of Industry, Science and Resources, the scheme was extended until 2030. The changes made to the ADGSM introduced more flexibility to activate the mechanism to secure domestic supply on a quarterly basis, rather than the yearly timeframe in the previous regulations.⁴⁴⁹

The new reforms came into place on 30 March 2023 with a newly negotiated Heads of Agreement with east coast LNG exporters in place until 1 January 2026. To prevent a gas supply shortfall, an additional 157 PJ of gas was committed to the east coast market in 2023. The Australian Government has not yet activated the ADGSM.

On 30 June 2025, the Department of Climate Change, Energy, the Environment and Water opened a consultation to carry out a combined review of the Australian Domestic Gas Security Mechanism (ADGSM), Gas Market Code (section 4.10.5) and the Heads of Agreement with east coast liquified natural gas exporters. The review is being carried out to examine the effectiveness of the existing mechanisms and identify possible improvements, while also considering long-term policy settings and reforms for Australia's gas markets to support investment and energy security.

4.10.2 Gas Supply Guarantee

The gas industry developed the Gas Supply Guarantee as a mechanism to meet commitments to the Australian Government to ensure enough gas is available to meet peak demand periods in the NEM. The mechanism was originally scheduled to finish in March 2020, but the Australian Government extended the guarantee to March 2023, with a review recommending a further extension to March 2026.⁴⁵⁰ The Gas Supply Guarantee has since been replaced by AEMO's new reliability and supply adequacy functions and powers under the National Gas Law and National Gas Rules (NGR), which came into effect in May 2023.⁴⁵¹

AEMO triggered the Gas Supply Guarantee for the first time on 1 June 2022.⁴⁵² Following activation of the mechanism, gas producers in Queensland diverted gas into the domestic market and AEMO subsequently deactivated the mechanism the next day. AEMO reactivated the mechanism from 19 July 2022 following notification of a threat to system security in Victoria due to insufficient storage, after directing 2 generators to cease taking gas from the Victorian market until 30 September 2022. The Gas Supply Guarantee and threat to system security remained in effect until sufficient supply was available.⁴⁵³

In March 2024, AEMO issued a threat to system security notice in response to the Queensland Gas Pipeline (QGP) fire, and the resulting isolation of a section of the QGP between the Rolleston Compressor Station and Oombabeer due to a rupture of the pipeline. Prior to revocation of the notice in December 2024, AEMO made directions to:⁴⁵⁴

- facilitate gas supply into the QGP
- curtail supply to relevant entities
- maintain supply to end users, necessary to mitigate the consequence of inadequate supply to as low as reasonably practicable.

447 Department of Industry, Science and Resources, Securing Australian domestic gas supply, accessed 10 May 2025.

448 The agreement specifically notes that LNG netback prices, as referenced by the ACCC, play a role in influencing domestic gas prices.

449 The Hon Madeline King MP, [Reforms ensure domestic gas supply, protect long-term contracts](#), Minister for Resources and Minister for Northern Australia, media release, 30 March 2023.

450 AEMO, [Gas supply guarantee guidelines consultation final determination](#), Australian Energy Market Operator, 25 March 2020.

451 ACCC, [Gas inquiry 2017–2030, December 2023](#), Australian Competition and Consumer Commission, December 2023, p. 105, footnote 128.

452 AEMO, Gas Supply Guarantee, Australian Energy Market Operator, accessed 28 May 2021.

453 AEMO, [AEMO takes further steps to manage tight gas supplies](#), Australian Energy Market Operator, 19 July 2022.

454 AEMO, [East Coast Gas System – Queensland Gas Pipeline event, Final Post-Intervention Report](#), Australian Energy Market Operator, December 2024.

Similarly, in June 2024, AEMO issued a threat to system security notice (section 4.3.3) anticipating that the supply of gas to the east coast market would be inadequate to reach demand.⁴⁵⁵ This notice was ultimately revoked in August 2024 without exercise of directions, following market responses to the notice.⁴⁵⁶

4.10.3 Better integration of gas into the Integrated System Plan

In recognition of the uncertainty surrounding future demand for gas, governments have taken actions to better integrate gas assumptions into the Integrated System Plan (ISP). On 19 December 2024, the AEMC released its final determination on *Better integration of gas and consumer sentiment into the ISP*.⁴⁵⁷

The rule change sets out several areas of specific gas analysis that significantly influence development of the electricity system. These include costs associated with gas infrastructure investments and the likelihood or commercial feasibility of GPG in the ISP, and availability of gas to service GPG in the quantity or price anticipated. The rule change:

- requires the AEMO to include gas development projections in the ISP to provide rigour and clarity around the gas analysis that informs the ISP
- allows AEMO to access gas information it collects under the NGR and use it as an input for analysis in the ISP
- amends the NGR to ensure confidentiality protections for the gas information is maintained
- requires AEMO to develop projections about the future utilisation of gas infrastructure and collated pipeline closures or conversion dates.

4.10.4 Additional powers for AEMO to support reliability and supply adequacy

In March and April 2025, the AEMC initiated consultation on a further set of significant rule change proposals outlining longer-term solutions to manage threats to the east coast gas market. These include:

- a reliability standard to apply to east coast gas supply, which would be used to assess the sufficiency of the supply of covered gas and the capacity of relevant infrastructure, and would be based on a value of gas customer reliability to be determined by the AER and similar to the AER's role in setting the value of customer reliability for electricity⁴⁵⁸
- a 'notice of closure for gas infrastructure' rule change request to extend the medium-term capacity reporting requirements in Part 18 of the NGR to require the reporting of planned closure of supply and delivery infrastructure at least 36 months before closure – it would apply to operators of production, pipeline, compression and storage facility infrastructure that meet the Bulletin Board reporting threshold⁴⁵⁹
- an east coast gas supply projected assessment of system adequacy mechanism, specifically over short-term (7-day) and medium-term (12-month) horizons.⁴⁶⁰

The AEMC has also received an 'ECGS supplier of last resort mechanism' rule change request. This would give AEMO power to establish a storage reserve and/or reserve of any other gas service, such as demand response or gas supply, and to use that reserve in the absence of a response from market participants, as a last resort.⁴⁶¹

455 AEMO, [East Coast Gas System Risk or Threat Notice](#), Australian Energy Market Operator, 19 June 2024.

456 AEMO, [Revocation of East Coast Gas System Risk or Threat Notice](#), Australian Energy Market Operator, 23 August 2024.

457 AEMC, [Better integration of gas and community sentiment into the ISP](#), Australian Energy Market Commission, December 2024.

458 AEMC, [ECGS Reliability standard and associated settings](#), Australian Energy Market Commission, March 2025.

459 AEMC, [ECGS Notice of closure for gas infrastructure](#), Australian Energy Market Commission, 26 June 2025.

460 AEMC, [ECGS Projected assessment of system adequacy](#), Australian Energy Market Commission, April 2025.

461 AEMC, [ECGS Supplier of last resort mechanism](#), Australian Energy Market Commission, July 2024.

4.10.5 Competition and Consumer (Gas Market Emergency Price) Order

On 23 December 2022, the Competition and Consumer (Gas Market Emergency Price) Order 2022 came into effect for 12 months, effectively introducing a price cap of \$12 per GJ on gas producers and affiliates of gas producers (regulated producers) on the east coast.⁴⁶² Several exemptions to the cap included LNG exports, downstream market trade in the Short Term Trading Market (STTM) and Declared Wholesale Gas Market (DWGM), and retailers that met certain criteria.⁴⁶³

From 11 July 2023, as part of the Energy Price Relief Plan announced in December 2022, the Australian Government implemented a Mandatory Gas Code of Conduct.⁴⁶⁴ The Code aims to ensure that east coast gas users can contract for gas at reasonable prices and on reasonable terms. It also includes a 2-month transitional period to allow companies to adapt to the conduct provisions, record keeping and process standards for commercial negotiations. The key elements of this code include:

- the price cap, initially set at \$12 per GJ, with the first mandated review of the Code by 1 July 2025
- an exemptions framework to incentivise short-term supply commitments and investment to meet ongoing medium-term demand
- transparency obligations to increase visibility of uncontracted gas production and its expected availability to the domestic market
- conduct provisions aimed at reducing bargaining power imbalances between producers and gas buyers and establishing minimum conduct and process standards for commercial negotiations.

4.10.6 National hydrogen strategy

The Australian Government has identified hydrogen as a potential alternative fuel to natural gas to facilitate emission reductions across energy and industrial sectors. It released its *National Hydrogen Strategy 2024* setting out 4 objectives for the development of a hydrogen industry that benefits Australia's communities and economy, enables Australia's net zero transition and positions Australia as a global hydrogen leader.⁴⁶⁵

AEMO's ISP models a green energy export scenario to examine potential requirements of expanding the existing transmission system and to present different options to replace retiring coal-fired generation assets.

Recently, the Future Gas Strategy has noted low-emission gases – such as biomethane, hydrogen, ammonia and e-methane – have the potential to substantially decarbonise gas supply chains.

4.10.7 State government schemes

State governments are responsible for different elements of gas infrastructure and exploration in Australia – for example, approving new gas exploration licences in their respective jurisdictions.

To encourage stability in the domestic supply of gas, the Queensland Government grants exploration authorities for 'domestic only' exploration tenements. As part of this grants program, it released almost 70,000 km² of land for exploration between 2015 and 2019, of which around 25% was reserved for domestic supply. The Queensland Government released a further 3,000 km² of land in September 2020, with over 15% tagged for domestic supply.⁴⁶⁶ In 2021, the Queensland Government announced it would make 14,100 km² available for oil and gas exploration.⁴⁶⁷ In June and July 2022, the Queensland Exploration Program released prospect tenders for petroleum and gas exploration (8 areas, 14,420 km²) and greenhouse gas storage (14,500 km²).⁴⁶⁸ In May 2024, the Queensland Government announced \$21 million in funding to support exploration in the Bowen Basin.⁴⁶⁹

462 Australian Government, [Competition and Consumer \(Gas Market Emergency Price\) Order 2022](#), December 2022.

463 The cap also exempted near-term trades on the upstream Gas Supply Hub exchange that occurred within a 3-day window of the delivery date and provided the minister powers to grant additional exemptions outside of the standard exceptions that were delegated to the ACCC. A list of exempted entities is available on the ACCC's [Gas price exemptions register](#). The delegation commenced on 23 December 2022.

464 DCCEE, [Mandatory Gas Code of Conduct](#), Department of Climate Change, Energy, the Environment and Water, 11 July 2023.

465 Australian Government, [National Hydrogen Strategy 2024](#), September 2024.

466 Queensland Government, 'Queensland gas exploration ramping up', media release, September 2020.

467 Queensland Government, [2021 Queensland Exploration program](#), November 2021, accessed 28 June 2022.

468 Queensland Government, [Queensland Exploration Program](#), Business Queensland, accessed 25 May 2023.

469 Queensland Government, '[\\$21 million in grants to accelerate energy supply](#)', media release, accessed 9 May 2025.

In January 2020, through a memorandum of understanding with the Australian Government, the NSW Government committed to bringing new gas supplies to the domestic market. It set a target of injecting an additional 70 PJ of gas per year into the NSW market.⁴⁷⁰

In April 2021 the Australian and South Australian governments announced an agreement to invest in energy infrastructure and reduce emissions in South Australia. As part of this, the state set a target to unlock an additional 50 PJ per year by 2023.⁴⁷¹

In April 2022 the Australian and Northern Territory governments signed an energy and emissions reduction agreement to deliver affordable and reliable power and unlock gas supplies to help prevent shortfalls in the market.

4.11 Gas market monitoring reforms

The Energy and Climate Change Ministerial Council (ECMC) agreed to an expedited package of carefully designed measures expanding the AER's gas and electricity market monitoring powers.⁴⁷² This follows the introduction of new laws providing the AER with greater powers to monitor wholesale gas and electricity markets, which was passed into legislation on 23 June 2022.⁴⁷³

The reforms stem from findings by bodies such as the AEMC, the ACCC and the Gas Market Reform Group on shortcomings in the current regulatory framework. The reforms aim to increase transparency in the gas market, improve the Gas Bulletin Board and improve the availability of information on market liquidity, prices and gas reserves.

4.11.1 Enhanced wholesale market monitoring

The National Energy Laws Amendment (Wholesale Market Monitoring) Bill 2023 (Amendment Bill) was proclaimed on 8 May 2024, enhancing the AER's wholesale market monitoring and reporting functions to include wholesale gas markets and electricity and gas contract markets. Access to contracts and related information will provide the AER with visibility of the underlying drivers influencing participant behaviour in gas and electricity markets, allowing for the examination of effective competition and whether wholesale markets are operating efficiently. Improved understanding and insights will allow for the AER's existing suite of reports to be enhanced to provide timely and transparent information to relevant stakeholders throughout the energy transition.

In November 2024, the AER released its final guideline on wholesale market monitoring and reporting, setting out how the AER will approach its wholesale market roles including use of these new market monitoring powers.⁴⁷⁴ Following this, the AER consulted on a set of market monitoring information collection instruments (Orders and Notices).

In response to stakeholder feedback, the AER decided to engage further with stakeholders before finalising these instruments.⁴⁷⁵

In the interim, in June 2025, the AER commenced further consultation on a more targeted gas Notice to collect over the counter contract and risk information in advance of the first gas wholesale market monitoring report to be delivered under this new power in 2026.

470 Department of Climate Change, Energy, the Environment and Water, [Memorandum of understanding – NSW energy package](#), 31 January 2020.

471 Australian Government, [‘Energy and emissions reduction agreement with South Australia’](#), media release, 18 April 2021, accessed 2 July 2025.

472 Department of Climate Change, Energy, the Environment and Water, [Amending the Australian Energy Regulator Wholesale Market Monitoring and Reporting Framework](#), 15 February 2024, accessed 17 July 2025.

473 AER, [AER welcomes new powers to keep watch on wholesale gas markets](#), news release, Australian Energy Regulator, 1 July 2022.

474 AER, [Wholesale market monitoring and reporting guideline – Version 1](#), Australian Energy Regulator, November 2024.

475 AER, [Update on Market Monitoring Information Orders](#), Australian Energy Regulator, 28 May 2025, accessed 2 July 2025.

4.11.2 Gas Bulletin Board reforms

The Gas Bulletin Board is a publicly accessible source of information. Data was published to the Bulletin Board commencing 1 July 2008 and aims to make the gas market more transparent by providing up-to-date information on gas production, pipelines and storage options in eastern Australia.

Market participants can access detailed information from production and compression facilities on their daily nominations, forecast nominations, intra-day changes to nominations and capacity outlooks. This adds transparency to production outages, which informs market responses and helps maintain security of supply.

In the pipeline sector, operators must submit daily disaggregated receipt and delivery point data to the Bulletin Board. The data includes information on flows at key supply and demand locations along pipelines.

The AER assesses the quality and accuracy of the data submitted by market participants against an 'information standard' to ensure the information presented on the Bulletin Board has integrity.

In June 2022 states adopted the National Gas Amendment (Market Transparency) Rule 2022, which extended reporting to large gas users and LNG processing facilities. These laws give the AER new powers to monitor information on price and volume in the shorter-term bilateral gas contract market, including how gas is exported overseas and how it is traded in Australia. In particular, the AER now monitors subsets of information on the export, reserve, storage and domestic sale and swaps of gas to report more comprehensively on competition.

In March 2025, AEMO released its biennial review of the Gas Bulletin Board,⁴⁷⁶ in which it reviewed the effectiveness of the Bulletin Board. AEMO found it largely effective and made recommendations on measures to improve the usefulness and effectiveness of reporting on the Gas Bulletin Board.

Price and reserves transparency

Transparency of price and other market information is critical for effective market functioning. The ACCC publishes data on LNG netback prices to help gas users negotiate more effectively with gas producers and retailers when entering new gas supply contracts (section 4.3.1).⁴⁷⁷

Reporting of new information commenced on 15 March 2023, requiring participants to provide information to AEMO through the Gas Bulletin Board. New information published on the Bulletin Board includes reserves and resources reporting, facility developments, LNG Transactions and Short Term Transactions (section 4.3.2).⁴⁷⁸

These reforms were designed to enhance transparency in the eastern and northern Australian gas markets, to address information gaps and asymmetries relating to:

- gas and infrastructure prices
- supply and availability of gas
- gas demand
- infrastructure used to supply gas to end markets.

More information on the introduction of regulatory amendments can be found on energy.gov.au.⁴⁷⁹

⁴⁷⁶ AEMO, *Gas Bulletin Board biennial report – Biennial review of the Gas Bulletin Board*, Australian Energy Market Operator, March 2025.

⁴⁷⁷ ACCC, *Gas inquiry 2017–2030 – LNG netback price series*, Australian Competition and Consumer Commission, accessed 16 July 2025.

⁴⁷⁸ AEMO, *Reserves Resources Reporting and Facility Developments* and *LNG and Short Term Transactions*, Australian Energy Market Operator, accessed 16 July 2025.

⁴⁷⁹ Department of Industry, Science, Energy and Resources, *Regulatory amendments to increase transparency in the gas market*, 19 November 2020.

4.11.3 Future of gas strategy and transition to net zero

With Australia's commitment to net zero by 2050, governments have been consulting on how to shift from natural gas to renewable energy sources throughout the economy. The Australian Government released its Future Gas Strategy in May 2024, which explains the principles the Australian Government will use to guide policymaking about gas to support the transition to net zero. The guiding principles note the importance of gas remaining affordable for Australian users throughout the transition to net zero, and that gas and electricity markets must adapt to remain fit for purpose throughout the energy transformation. The strategy reiterates Australia's commitment to supporting global emissions reductions to reduce the impacts of climate change and reaching net zero emissions by 2050.⁴⁸⁰

480 DISR, [Future Gas Strategy](#), Department of Industry, Science and Resources, May 2024.



5 Gas pipelines in eastern Australia

Australia's gas pipeline infrastructure consists of transmission and distribution pipelines. The role of the transmission pipelines is to transport gas from upstream producing basins to major population centres, power stations, and large industrial and commercial plants. Smaller urban and regional distribution pipelines transport gas to customers in local communities.

The focus of this chapter is the 9 scheme pipelines regulated by the Australian Energy Regulator (AER), which is the regulator in all states and territories except Tasmania and Western Australia.⁴⁸¹ Scheme pipelines are subject to more intensive regulation than other pipelines, including access arrangements that set reference prices and other terms and conditions of access to certain services on the pipeline. The rest of the gas pipeline infrastructure in eastern Australia are non-scheme pipelines, which are subject to access negotiation and dispute resolution frameworks and ring-fencing requirements, as well as specified monitoring and reporting obligations (section 5.4).

5.1 Snapshot

In May 2025, the AER finalised its access arrangement determination for distribution pipeline service provider Jemena Gas Networks (NSW). This determination sets the maximum amount of revenue Jemena Gas Networks can earn from customers through to 30 June 2030. The AER also released a final decision to not accept the 2023–28 gas access arrangement variation proposal from AusNet Services (Victoria).⁴⁸²

Across the 3 transmission scheme pipeline service providers for which the AER determines access prices, over the 12-month period to 30 June 2024:

- \$103 million was invested in capital projects, \$113 million (52%) less than in the previous year but \$49 million (90%) more than was forecast (section 5.10)
- \$87 million was spent on operating costs, \$10 million (10%) less than in the previous year but \$13 million (17%) more than was forecast (section 5.11).

481 The [Economic Regulation Authority \(ERA\)](#) administers separate regulatory arrangements in Western Australia. The [Office of the Tasmanian Economic Regulator \(OTTER\)](#) administers separate regulatory arrangements in Tasmania.

482 AER, [AusNet Gas Services 2023–28 Access arrangement variation proposal – Final decision](#), Australian Energy Regulator, 14 May 2025.

Across the 6 distribution scheme pipeline service providers for which the AER determines access prices, over the 12-month period to 30 June 2024:

- \$1.6 billion in revenue was collected for providing access (selling capacity) to parties needing to transport gas, \$90 million (6%) more than in the previous year (section 5.6)
- \$555 million was invested in capital projects, \$59 million (10%) less than in the previous year (the least in any year since we started collecting this data in 2011), and \$121 million (18%) less than was forecast (section 5.10)
- \$588 million was spent on operating costs, \$40 million (7%) more than in the previous year and the most in any year since we started collecting this data in 2011 (section 5.11).

The AER decided not to make a scheme pipeline determination for the South West Queensland pipeline, noting that the benefits of scheme regulation do not currently outweigh the potential costs. This means that the South West Queensland pipeline will remain subject to non-scheme regulation.

The AER's inaugural *Gas pipeline monitoring and transparency report* indicated that non-scheme service providers are still adapting to the requirements under the new gas pipeline reforms.

5.2 Gas pipeline characteristics

Pipeline service providers earn revenue by providing access (selling capacity) to parties needing to transport gas. These parties include:

- energy retailers seeking to buy natural gas in large volumes, then sell it to consumers
- commercial and industrial users
- liquefied natural gas (LNG) exporters that buy gas directly from producers and contract with a pipeline service provider to transport it to export terminals.

The most common service provided by transmission pipelines is haulage – that is, transporting (or 'shipping') gas from an injection point on the pipeline to an offtake point further along. Haulage may be offered on a firm (guaranteed) or interruptible (only if spare capacity is available) basis. Some customers seek backhaul too, which is transporting gas in the opposite direction to the main flow of the pipeline, or pay for gas to be stored (parked) in a pipeline or stored in a connected storage facility, also on a firm or interruptible basis.

As the gas market evolves, more innovative services are being offered, including compression (adjusting pressure for delivery), loans (loaning gas to a third party), redirection and in-pipe trades with other customers.

The combined value of the capital bases for scheme pipelines for which the AER sets access prices is around \$14 billion. This comprises 3 transmission pipelines valued at \$2.2 billion and 6 distribution pipelines valued at \$11.8 billion.

Transmission pipelines typically have wide diameters and operate under high pressure to optimise shipping capacity. An interconnected transmission grid links gas basins and retail markets in all states and territories other than Western Australia (Figure 5.1).

Distribution pipelines are installed underground and operate under high, medium or low pressure. The high and medium-pressure pipes provide a 'backbone' that services high demand zones, while the low-pressure pipes lead off high-pressure mains to commercial and industrial customers and residential homes.

Distribution pipeline service providers transport gas to consumers, but they do not sell gas. Energy retailers purchase gas from sellers and pipeline services (which includes transportation) from pipeline service providers.⁴⁸³ This combination of gas and pipeline services is sold as a packaged retail product to customers. Many retailers offer both gas and electricity products.

The services provided by transmission pipelines continue to evolve to meet changing market needs, but distribution pipelines tend to offer fairly standard transport services – namely, allowing gas injections into a pipeline, conveying gas to supply points and allowing gas to be withdrawn.

Gas is distributed to most Australian capital cities, major regional areas and towns. Queensland and Victoria each have multiple distribution pipeline service providers, while New South Wales (NSW), South Australia, Tasmania and the Australian Capital Territory (ACT) are each served by a single regulated service provider.⁴⁸⁴ Gas is also distributed to export terminals in Queensland, where it is converted to LNG before being transported overseas via cargo ship.

In 2024, residential customers accounted for more than 97% of the total number of distribution customers, but only consumed around 46% of the total gas delivered within Australia. The other 3% of customers were either industrial or commercial customers and consumed the balance (54%) of the total gas delivered.

The combined value of the capital bases for scheme pipelines for which the AER sets access prices is around \$14 billion.⁴⁸⁵ This comprises 3 transmission pipelines valued at \$2.2 billion and 6 distribution pipelines valued at \$11.8 billion. In total, the networks consist of around 80,000 kilometres of pipe and supply natural gas to more than 4.3 million residential customers and around 110,000 commercial and industrial customers (Figure 5.2 and Figure 5.3).⁴⁸⁶

Box 5.1 How the AER regulates scheme and non-scheme pipelines

Gas pipeline service providers are regulated under the National Gas Law and National Gas Rules. In March 2023, several significant changes were made to improve and simplify the regulatory framework to support the safe, reliable and efficient use of and investment in gas pipelines. Transitional arrangements implementing the new framework are ongoing (section 5.4).

Prior to the reforms, the National Gas Law provided for the following forms of regulation:

- full regulation for some scheme pipelines
- light regulation for other scheme pipelines
- Part 23 (National Gas Rules) regulation for non-scheme pipelines that provided third party access to pipeline services.

Under the reforms, gas pipelines are now only classified as either:

- scheme pipelines, or
- non-scheme pipelines (section 5.4).

In March 2025, the AER published its first *Gas pipeline monitoring and transparency report*,⁴⁸⁷ in line with the AER's new monitoring and reporting powers covering the behaviour and compliance of non-scheme gas pipeline service providers. A summary of our findings from this report are set out in Box 5.2.

483 For some transmission routes, retailers may also purchase gas through contracts that include transport costs, if not buying gas directly from a gas producer.

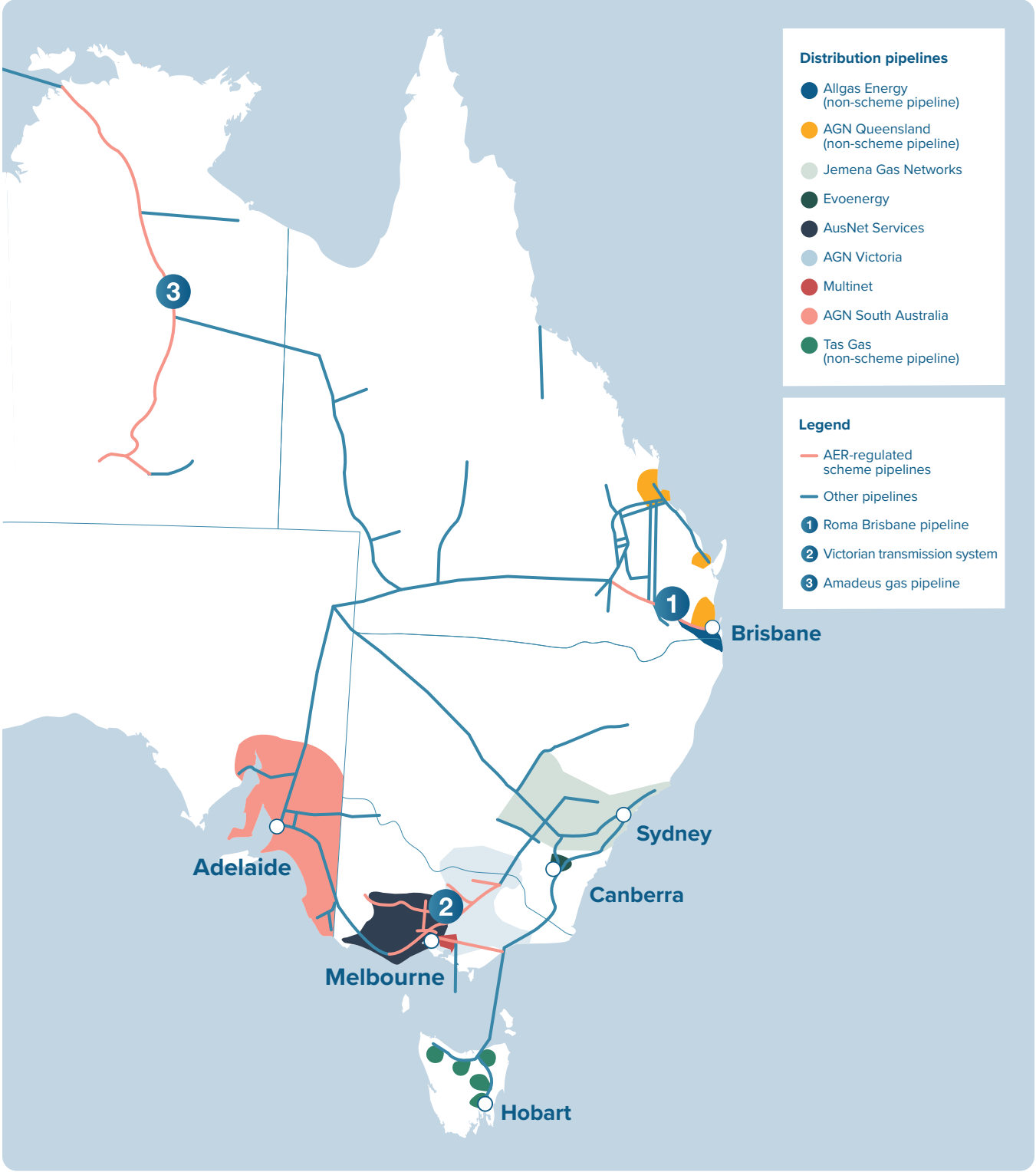
484 Some pipelines cross state or territory boundaries. For example, Australian Gas Network's Victorian pipeline and Evoenergy's ACT pipeline both extend into NSW. Some jurisdictions also have smaller unregulated regional pipelines, such as the Wagga Wagga pipeline in NSW.

485 Capital bases capture the total economic value of assets that are providing pipeline services to customers. These assets have been accumulated over time and are at various stages of their economic lives.

486 The AER does not set access prices for the 3 non-scheme pipelines (GLNG, APLNG, QCLNG) that deliver gas from the Roma region, including from the Roma Brisbane scheme pipeline directly to Queensland's LNG export terminals.

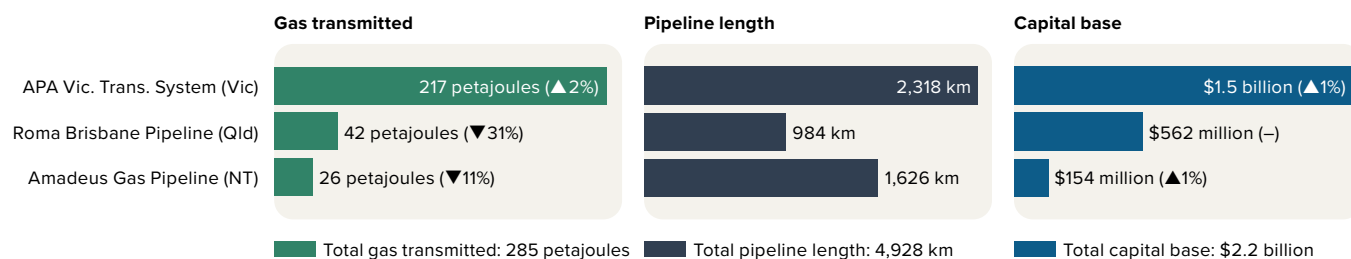
487 AER, [Gas pipeline monitoring and transparency report](#), Australian Energy Regulator, 26 March 2025, accessed 9 April 2025.

Figure 5.1 Major gas transmission and distribution pipelines



Source: AER.

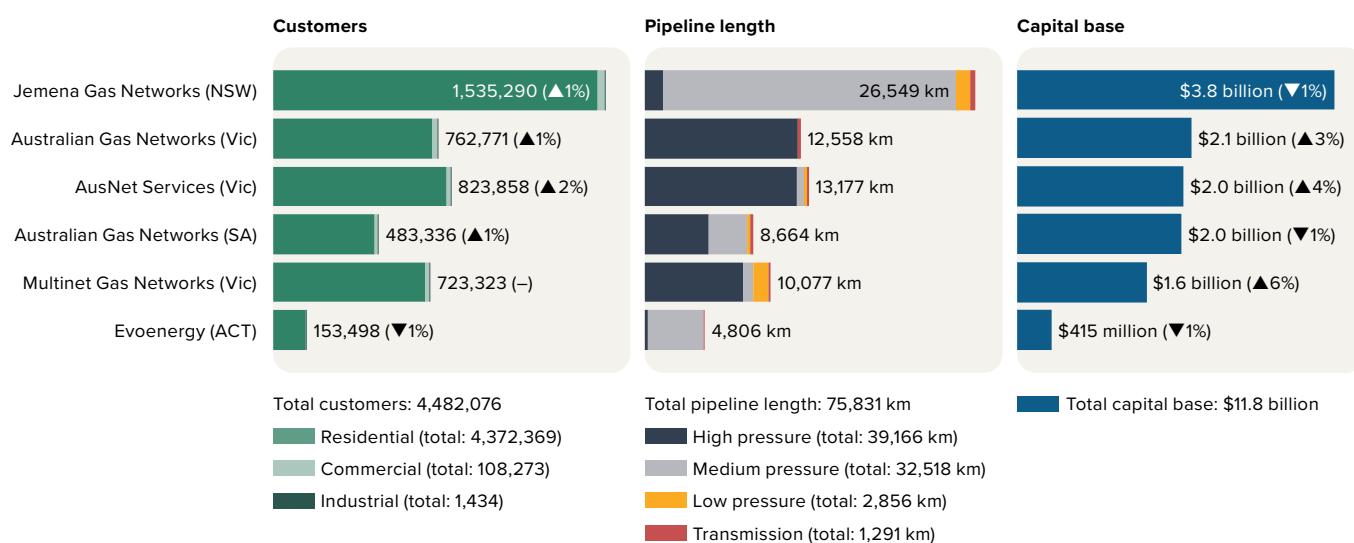
Figure 5.2 Gas transmission pipelines regulated by the AER



Note: Capital base is adjusted to June 2024 dollars. The capital base is the forecast value of pipeline assets based on the closing capital base at 30 June 2024, except for APA Victorian Transmission System (31 March 2024). Pipeline length includes looping where applicable. Looping refers to 2 or more lengths of pipeline along a route – for example, where the existing pipeline has been duplicated.

Source: AER access arrangement decisions and annual regulatory information notices (RINs).

Figure 5.3 Gas distribution pipelines regulated by the AER



Note: Capital base is adjusted to June 2024 dollars. The capital base is the forecast value of pipeline assets based on the closing capital base at 30 June 2024, except for the Victorian distribution pipelines (31 December 2024).

Source: AER access arrangement decisions and annual regulatory information notices (RINs).

5.3 Gas pipeline ownership

Australia's gas pipelines are generally privately owned. The ASX-listed APA Group is Australia's largest pipeline service provider, with a portfolio mainly in gas transmission. Other sector participants include Jemena Gas Networks (Jemena, owned by State Grid Corporation of China and Singapore Power International), AusNet Services (Victoria) owned by Australian Energy Holdings No 4 Pty Limited (a company controlled by Brookfield Asset Management) and Australian Gas Networks (owned by Cheung Kong Infrastructure Holdings Limited).

Table 5.1 summarises the ownership structure and characteristics of key gas transmission pipelines.

Table 5.1 Ownership structure and characteristics of key gas transmission pipelines

Pipeline service provider	Location	Capacity (TJ/day)	Regulatory status	Owner
Roma Brisbane Pipeline	Qld	167 (125)	Scheme pipeline	APA Group
Victorian Transmission System (GasNet)	Vic	1,160	Scheme pipeline	APA Group
Amadeus Gas Pipeline	NT	165	Scheme pipeline	APA Group
South West Queensland Pipeline (Wallumbilla to Moomba)	Qld-SA	512 (340)	Non-scheme pipeline	APA Group
Queensland Gas Pipeline (Wallumbilla to Gladstone)	Qld	148 (37)	Non-scheme pipeline	Jemena (State Grid Corporation of China 60%, Singapore Power 40%)
Carpentaria Pipeline (South West Qld to Mount Isa)	Qld	119 (65)	Scheme pipeline	APA Group
GLNG Pipeline (Surat-Bowen Basin to Gladstone)	Qld	1,497	Non-scheme pipeline/ 15-year no coverage	Santos 30%, PETRONAS 27.5%, Total 27.5%, KOGAS 15%
Wallumbilla Gladstone Pipeline	Qld	1,598	Non-scheme pipeline/ 15-year no coverage	APA Group
APLNG Pipeline (Surat-Bowen Basin to Gladstone)	Qld	1,760	Non-scheme pipeline/ 15-year no coverage	Origin Energy 37.5%, ConocoPhillips 37.5%, Sinopec 25%
Moomba to Sydney Pipeline	SA-NSW	565 (193)	Non-scheme pipeline	APA Group
Moomba to Adelaide Pipeline	SA	249 (85)	Non-scheme pipeline	QIC Global Infrastructure
Eastern Gas Pipeline (Longford to Sydney)	Vic-NSW	349	Non-scheme pipeline	Jemena (State Grid Corporation of China 60%, Singapore Power 40%)
Vic-NSW Interconnect	Vic-NSW	224 (218)	Non-scheme pipeline	Jemena (State Grid Corporation of China 60%, Singapore Power 40%)
SEA Gas Pipeline (Port Campbell to Adelaide)	Vic-SA	254	Non-scheme pipeline	APA Group 50%, Retail Employees Superannuation Trust 50%
Tasmanian Gas Pipeline (Longford to Hobart)	Vic-Tas	129	Non-scheme pipeline	Palisade Investment Partners
Northern Gas Pipeline (Tennant Creek to Mount Isa)	NT-Qld	90 (60)	Non-scheme pipeline	Jemena (State Grid Corporation of China 60%, Singapore Power 40%)
Bonaparte Pipeline	NT	108	Non-scheme pipeline	Energy Infrastructure Investments (Marubeni 49.9%, Osaka Gas 30.2%, APA Group 19.9%)

Note: TJ/day: terajoules per day. For bidirectional pipelines, reverse capacity is shown in brackets. The Victoria Northern Interconnect is part of the Victorian Transmission System.

Source: AER; ACCC, interim reports of gas inquiry 2017-2025; corporate websites; [Gas Bulletin Board](#).

Table 5.2 summarises the ownership structure of key gas distribution pipelines.

Table 5.2 Ownership of key gas distribution pipelines

Pipeline service provider	Location	Owner
Jemena Gas Networks	NSW	Jemena (State Grid Corporation of China 60%, Singapore Power 40%)
AusNet Services	Vic	Australian Energy Holdings No 4 Pty Limited
Multinet Gas Networks	Vic	CK Infrastructure Holdings
Australian Gas Networks	Vic	CK Infrastructure Holdings
Australian Gas Networks	SA	CK Infrastructure Holdings
Evoenergy	ACT	ICONWater (ACT Government), 50%; Jemena, 50%
Allgas Energy	Qld	Marubeni, 40%, SAS Trustee Corp, 40%; APA Group, 20%
Australian Gas Networks	Qld	CK Infrastructure Holdings

Source: Corporate websites.

5.4 Regulatory objective and approach

For gas pipelines, the AER's key objective is to deliver efficient regulation of monopoly electricity and gas infrastructure while incentivising networks to become platforms for energy services.⁴⁸⁸ The National Gas Law and National Gas Rules set out the regulatory framework for gas pipelines to support the achievement of the National Gas Objective.

In May 2023, Energy Ministers agreed to amend the national energy laws to incorporate an emissions reduction objective into the National Gas Objective.⁴⁸⁹ The amended Objective seeks to promote efficient investment in, and efficient operation and use of, covered gas services for the long-term interests of consumers of covered gas with respect to:

- price, quality, safety, reliability and security of supply of covered gas
- the achievement of targets set by a participating jurisdiction
 - for reducing Australia's greenhouse gas emissions, or
 - that are likely to contribute to reducing Australia's greenhouse gas emissions.

In February 2024, the National Gas Rules were amended to enable pipeline service providers to include expenditure that contributes to achieving emissions reduction targets in their access arrangement proposals. This amendment to the National Gas Rules provides greater clarity to Australia's energy market bodies⁴⁹⁰ for transitioning Australia's energy system to net zero by 2050.

The regulation of gas infrastructure in eastern Australia allows for the AER (and previously, the National Competition Council) to determine if a gas pipeline should be economically regulated as a scheme pipeline or subject to market-based regulation (non-scheme pipelines). Following an extensive stakeholder consultation process, reforms were introduced to the National Gas Law and National Gas Rules in March 2023. The reforms have significantly changed the way non-scheme gas pipelines are regulated, aiming to:

- implement stronger constraints on how non-scheme pipeline service providers can exercise their market power
- facilitate better access to pipeline services
- enhance support for commercial negotiations between service providers and parties needing to transport gas (generally referred to as shippers or gas users)
- streamline governance arrangements.

488 AER, *Strategic plan 2020–25*, Australian Energy Regulator, 14 December 2020, accessed 21 May 2025.

489 The National Electricity Objective (NEO), National Energy Retail Objective (NERO) and the National Gas Objective (NGO) govern and guide the Australian Energy Market Commission (AEMC) in all its activities under the relevant national energy legislation.

490 The Australian Energy Market Commission (AEMC), the Australian Energy Market Operator (AEMO), the Australian Energy Regulator (AER) and Western Australia's Economic Regulation Authority (ERA).

The AER is now responsible for determining the form of regulation that applies to a gas pipeline, as well as monitoring and reporting on the compliance of gas pipelines with the regulatory framework (section 5.4.1).

Other recent reforms to gas pipeline regulation

In May 2024, the Essential Services Commission (Victoria) released its final decision on the Gas Distribution Code of Practice, which sets out the minimum standards for the operation and use of the Victorian gas distribution system.⁴⁹¹ The new code, which took effect on 1 October 2024:

- enables the Essential Services Commission to use its enforcement powers to effectively monitor and enforce the rules on distribution pipeline service providers, including through civil penalty provisions
- requires distribution pipeline service providers to provide clear information to customers on their websites, including how customers can disconnect or permanently abolish their gas connections
- removes duplication with other regulations to streamline the regulatory framework.

The new code also removes inefficient incentives for new gas connections. Since 1 January 2025, customers in Victoria who seek to establish a new gas connection must pay up-front installation costs, consistent with the current practice for new electricity and water connections.

In February 2025, the Essential Services Commission of South Australia (ESCOSA) made its final decision on the protections that Australian Gas Networks (South Australia) must deliver for consumers during its forthcoming (1 July 2026 to 30 June 2031) access arrangement period.⁴⁹² The final decision was to:

- extend the application of the Australian Gas Networks (South Australia) distribution licence so it also applies to distribution of hydrogen and other renewable gases
- continue monitoring network reliability and create service standards if required
- require that Australian Gas Networks (South Australia) reports directly to the public on new aspects of its operational performance
- begin monitoring the timely provision of disconnection and permanent abolishment services
- ensure that consumers receive information about how to disconnect from the gas network
- ensure that customers are notified when customer-requested disconnection services will be provided and when they have been delivered
- require Australian Gas Networks (South Australia) to seek ESCOSA's approval if it proposes to disable any part of the gas distribution network in the future
- create specific timeframes for reconnecting customers after de-energisation where Australian Gas Networks (South Australia) is obliged to do so by the National Energy Retail Rules
- ensure that customers are provided with notice before a different meter (like a digital smart meter) is installed and are provided with information about the impact of that change
- make a series of changes to the Gas Metering Code to improve consistency with other regulatory instruments, provide for changes in the composition of gas and accommodate possible expanded use of digital meters.

⁴⁹¹ Essential Services Commission, [New code of practice for gas distributors to apply from 1 October 2024](#), media release, Essential Services Commission, 9 May 2024.

⁴⁹² ESCOSA, [Australian Gas Networks regulatory framework review 2026–2031](#), Essential Services Commission of South Australia, 2 February 2025, accessed 9 March 2025.

5.4.1 Forms of regulation

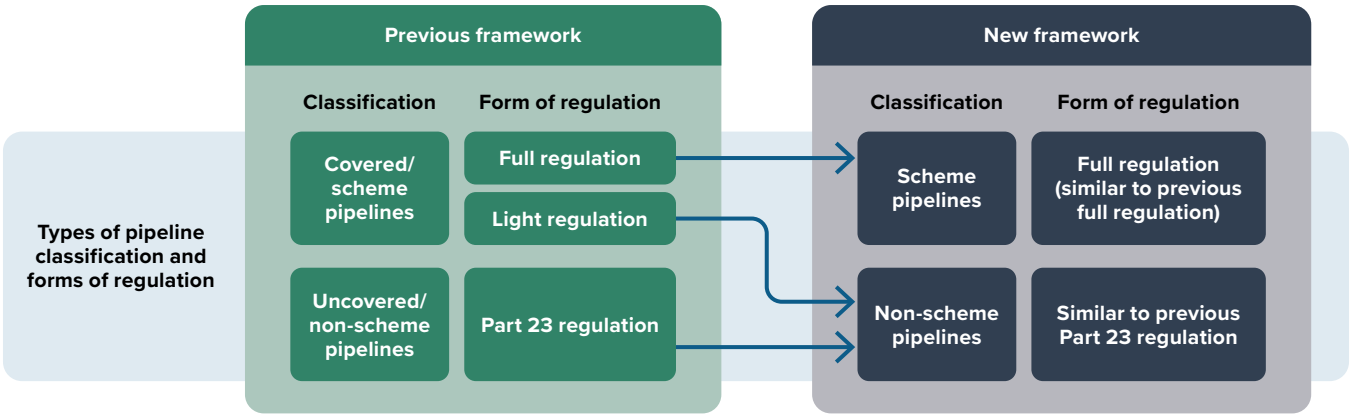
The March 2023 reforms (Box 5.1) updated how different forms of regulation could be applied to different gas pipeline infrastructure to deliver a simpler regulatory framework, increased market transparency and improved access to pipelines on fair terms. The reforms:

- require all transmission and distribution pipeline service providers to provide third party access where it is sought, subject to available exemptions
- ensure all pipelines are subject to the same access negotiation and dispute resolution frameworks and ring-fencing requirements
- make the AER responsible for overseeing a new dispute resolution mechanism that includes mediation as an option for small gas shippers to use in pipeline access disputes
- require all pipeline service providers to publish prescribed transparency information under a unified information disclosure framework unless they hold an exemption
- require standalone compression and storage facilities to publish standing terms and price information.

The AER is now responsible for determining the form of regulation for a pipeline by applying a regulatory determination test. Under the current regulatory framework, the form of regulation of a scheme or non-scheme pipeline can change if:

- the AER makes a determination that a scheme pipeline should become a non-scheme pipeline (a scheme pipeline revocation determination) or a non-scheme pipeline should become a scheme pipeline (a scheme pipeline determination) – the determination can follow a review initiated by the AER or after the AER receives an application from any person
- a non-scheme pipeline service provider elects for a pipeline to become a scheme pipeline (a scheme pipeline election).⁴⁹³

Figure 5.4 Summary of changes to pipeline regulatory framework



The AER is also responsible for determining the level of regulation for new pipelines after they are commissioned, unless greenfield determinations apply (all new pipelines will be non-scheme pipelines when they are commissioned), as well as the classification and reclassification of pipelines. This role was previously fulfilled by the National Competition Council and the jurisdictional minister.

493 AER, [Pipeline regulatory determinations and elections guide](#), Australian Energy Regulator, 30 July 2024, accessed 20 May 2025.

While all pipelines are now subject to a range of uniform access, transparency and ring-fencing requirements, service providers operating scheme pipelines are subject to more comprehensive regulatory obligations, including:

- a regulatory-oriented access dispute process
- periodically submitting an access arrangement revisions proposal to the AER for approval⁴⁹⁴
- submitting a reference service proposal to the AER 12-months before submitting the relevant access arrangement revisions proposal, with reference services being subject to price regulation by the AER.⁴⁹⁵

Determining a service to be a reference service or non-reference service makes a significant difference to how the service is regulated. For reference services, the AER sets maximum prices, or price caps, that gas network pipeline service providers may charge network users for reference services. Gas network pipeline service providers may choose to charge network users less than the price caps we determine but they may not charge more. Services the AER determines to be non-reference services are not subject to price regulation. This means gas pipeline service providers set their own charges for non-reference services.

South West Queensland Pipeline form of regulation decision

In December 2024, the AER published its final decision for the South West Queensland Pipeline (SWQP)⁴⁹⁶ form of regulation review.⁴⁹⁷ The AER's final decision was that the SWQP, owned and operated by APA Group, should remain a non-scheme pipeline, subject to non-scheme regulation.

The AER considered the benefits of scheme regulation did not appear to outweigh the potential costs for SWQP. For example, the direct costs associated with scheme regulation, such as regulatory, transaction and administrative costs, would be higher than those incurred under non-scheme regulation. The indirect costs associated with delayed or foregone efficient investment could also be higher due to the processes associated with the implementation of scheme regulation. In particular, there would be uncertainty around how the initial capital base would be determined and how the AER would treat any major new investment until the first access arrangement was approved.

The AER's final decision was that the South West Queensland Pipeline should remain a non-scheme pipeline, subject to non-scheme regulation. The AER considered that the benefits of scheme regulation did not appear to outweigh the potential costs.

⁴⁹⁴ A pipeline is a scheme pipeline if it was a covered pipeline (other than a light regulation pipeline) immediately before 2 March 2023.

⁴⁹⁵ In deciding whether a pipeline service should be specified as a reference service, the AER must have regard to the reference service factors specified in the National Gas Rules. Services that the AER determines meet the reference service factors will be determined to be reference services. Services that the AER determines do not meet the reference service factors will be treated as non-reference services.

⁴⁹⁶ The South West Queensland Pipeline is a bidirectional transmission pipeline consisting of 2 parallel pipelines, linking Wallumbilla in South East Queensland to Moomba in South Australia.

⁴⁹⁷ AER, [South West Queensland Pipeline form of regulation review](#), Australian Energy Regulator, 2 December 2024, accessed 9 March 2025.

While this is a transitory and relatively short-term effect, it could have broader implications for the east coast gas market. The Australian Competition and Consumer Commission (ACCC) and the Australian Energy Market Operator (AEMO) predict possible supply shortfalls in southern states could occur as early as 2027 or 2028 unless additional sources of supply are developed.⁴⁹⁸ One potential source is additional capacity being made available on pipelines used to transport gas from Queensland.

The AER found APA Group likely has market power in the supply of services on the SWQP and is able to exercise that market power to some extent. However, the AER also considered there are currently some constraints on APA Group's ability to do so in negotiations with larger shippers – gas customers that purchase capacity on a pipeline to deliver gas – and that the emergence of substitutes could constrain APA Group further in the future.

At the same time, the AER considered the largest pipeline users have a degree of countervailing market power that likely constrains APA Group to some extent. The majority of pipeline capacity on the SWQP is used by a small number of large shippers. These shippers rely on the SWQP because it is essential to transport gas from Queensland to the southern states, and from the southern states into Queensland and onto LNG export terminals. However, the volume of capacity these shippers purchase likely means that APA Group is also reliant, to some extent, on these shippers to maintain its revenue on the SWQP.

Further, recently introduced improvements to the non-scheme regulatory regime may improve shippers' ability to negotiate access to the SWQP. Very few stakeholders that participated in the AER's consultation process, including shippers on the SWQP, were in favour of scheme regulation. The AER's final decision foreshadowed its intention to closely monitor prices, terms and conditions on the SWQP as capacity becomes available for contracting.

The review of the SWQP was the first AER-initiated form of regulation review and the pipeline was chosen due to its importance to the east coast gas system. Outcomes of the AER's monitoring and compliance activities will be used to identify future pipelines for review, with a particular emphasis on indicators of market power and access concerns.⁴⁹⁹

5.4.2 Pipeline classification and reclassification

In July 2024, the AER published a new version of the *Pipeline regulatory determinations and elections guide* outlining its functions and powers under Chapter 3 of the National Gas Law and Part 4 of the National Gas Rules. The guide outlines how the AER approaches regulatory determinations and how stakeholders can make applications about the regulatory treatment of a pipeline.⁵⁰⁰

Under the reforms, the default position is that a pipeline is a distribution pipeline if it is classified as a distribution pipeline under its jurisdictional licence or authorisation. Similarly, a pipeline is a transmission pipeline if it is classified as a transmission pipeline under its licence or authorisation. For new pipelines, if the jurisdictional licence contains no classification, the pipeline service provider must apply to the AER for a classification decision.⁵⁰¹ A service provider may apply to the AER for reclassification if it considers it has been wrongly classified. The AER may also, on its own initiative, decide that a pipeline should be reclassified.

Transmission and distribution pipelines have similar regulatory obligations under the National Gas Law and National Gas Rules. However, a transmission pipeline classification means that the pipeline must also report information on AEMO's Gas Bulletin Board and the Short Term Trading Market, a wholesale gas market operated by AEMO. Distribution pipelines are not required to report this information.

498 ACCC, *Gas Inquiry 2017–2030 Interim update on east coast gas market*, Australian Competition and Consumer Commission, June 2024, pp 34–39; AEMO, *2024 Gas Statement of Opportunities*, Australian Energy Market Operator, 21 March 2024.

499 AER, *Gas pipeline monitoring and transparency report*, Australian Energy Regulator, 26 March 2025, accessed 9 April 2025.

500 AER, *Pipeline regulatory determinations and elections guide*, Australian Energy Regulator, 30 July 2024, accessed 9 March 2025.

501 AGS, *Legal briefing – Gas pipeline reforms*, 17 March 2023, accessed 9 March 2025.

The AER's decision to classify the Kurri Kurri Lateral Pipeline as a transmission pipeline in May 2025 was the AER's first pipeline classification decision since the 2023 reforms. The decision reflects consideration of the pipeline's characteristics, stakeholder feedback, the National Gas Objective and the pipeline classification criteria set out in section 13 of the National Gas Law.

On 27 June 2025, the AER published its draft decision to classify the Atlas to Reedy Creek Pipeline (ARCP) – a new pipeline in the Surat Basin in Queensland – as a transmission pipeline.⁵⁰² The AER considered the ARCP's characteristics were consistent with that of a transmission pipeline and that its primary function is to convey gas to a market.

5.4.3 Greenfields pipeline projects

Greenfields determinations are intended to ensure that the threat of regulation does not disincentivise new pipeline development. A pipeline that has a greenfields incentives determination is effectively protected from being regulated as a scheme pipeline for the duration of the determination (up to a maximum of 15 years).

Under the reforms, a service provider for a greenfields pipeline project – being a new pipeline or a major extension to an existing pipeline – may apply to the AER for a greenfields incentive determination before the pipeline is commissioned.⁵⁰³ They may also apply for a greenfields price protection determination,⁵⁰⁴ either as part of the greenfields incentive determination application process or later if they obtain a greenfields incentive determination.⁵⁰⁵

In assessing whether to make a greenfields determination, the AER must:

- apply the regulatory determination test under section 112 of the National Gas Law, including the costs to be incurred by the service provider, users of the pipeline services and end users
- consider the extent to which the form of regulation factors or competition to develop the pipeline between 2 or more unrelated prospective service providers will, or is likely to, pose an effective constraint on the exercise of market power.⁵⁰⁶

In May 2025, the AER received its first greenfields determination application from APA Group for the Bulloo Interlink (chapter 4, section 4.8.3), which forms part of its stage 3 east coast grid expansion. The Bulloo Interlink is designed to transport new gas from northern basins such as the Surat in Queensland and the Beetaloo in the Northern Territory, among others. Engineering design and planning, along with long lead item procurement, is progressing as part of committed early works funding.⁵⁰⁷

5.4.4 Part 10 Prescribed transparency information for pipelines

Part 10 of the National Gas Rules prescribes the information that all scheme and non-scheme pipeline service providers must make publicly available on their websites, including pricing, pipeline and financial information. This assists pipeline users in negotiations with pipeline service providers.⁵⁰⁸

Exemptions from certain information disclosure requirements are available for pipeline service providers that have no third-party access in place or only provide services to a single shipper.⁵⁰⁹

502 AER, [Draft decision – Atlas to Reedy Creek Pipeline classification](#), Australian Energy Regulator, 27 June 2025.

503 Prior to March 2023, '15-year no coverage' determinations were made by the relevant minister on the recommendation of the National Competition Council. The minister was required to make the determination if the coverage criteria was satisfied. The former coverage criteria included increased competition and public interest criteria.

504 A greenfields price protection determination is only available to greenfields pipeline projects that have a greenfields incentive determination. This price protection determination 'protects' certain terms and conditions in the case that there is an access dispute in relation to the pipeline.

505 AGS, [Legal briefing – Gas pipeline reforms](#), 17 March 2023, accessed 9 March 2025.

506 National Gas Law, section 112(3).

507 APA, [East Coast Gas Grid Expansion Plan](#), accessed 2 July 2025.

508 Previously, service providers of light regulation pipelines and non-scheme pipelines were required to prepare similar prescribed transparency information under Parts 7 and 23 of the National Gas Rules, respectively. These Parts are repealed and have been replaced by Part 10.

509 The requirements to prepare, publish and maintain the information set out in the National Gas Rules and the pipeline information disclosure guidelines are classified as 'tier 1' civil penalty provisions under the National Gas (South Australia) Regulations.

The prescribed information must be published on the service provider's website, and in some cases, copies must also be provided to the AER. The information to be provided is set out in the AER's Pipeline information disclosure guidelines and Price reporting guidelines, and includes:

- financial and historical demand information
- standing prices and the methodology used to calculate them
- information on actual prices paid by contracted users of the pipeline (under the previous requirements in Part 23, only weighted-average prices were required to be disclosed).⁵¹⁰

The AER is required to systematically monitor and report on the above transparency information (section 5.4.6).

5.4.5 Ring-fencing requirements

Under the reforms, all pipelines are subject to a set of requirements that previously only applied to some pipelines.⁵¹¹ Pipeline service providers must comply with ring-fencing provisions regarding related businesses and provisions regarding associate contracts. The requirement is classified as a conduct provision and tier 2 civil penalty provision under the National Gas (South Australia) Regulations.⁵¹²

The National Gas Rules provide for a service provider to apply to the AER for an exemption from the ring-fencing requirements. As at 23 May 2025, the following 4 exemptions were in place:

- APT Pipelines (Northern Territory)⁵¹³
- Meridian SeamGas Joint Venture and WestSide Corporation Limited⁵¹⁴
- Power and Water (McArthur River Mining Pipeline)⁵¹⁵
- Jemena (Northern Gas Pipeline/ Phillip Creek Compressor Station).⁵¹⁶

In all 4 of these cases, the AER considered that the costs of complying with the ring-fencing obligations outweigh any associated public benefit.

5.4.6 Monitoring and surveillance

Under the reforms, the AER is required to monitor the behaviour of pipeline service providers, including the prices charged for pipeline services, the information published by pipeline service providers, outcomes of access negotiations, dealings with associates and compliance with ring-fencing requirements (Box 5.2).

In addition to these recently assigned monitoring and surveillance responsibilities, the AER already publishes an annual electricity and gas networks performance report.⁵¹⁷ The report provides an in-depth analysis of key outcomes and trends in the operational and financial performance of the transmission and distribution pipelines that, under the new framework, are classified as scheme pipelines.

510 AER, [Pipeline information disclosure guidelines and Price reporting guidelines for Part 18A facilities Explanatory note](#), Australian Energy Regulator, October 2023, accessed 21 May 2025.

511 AGS, [Legal briefing – Gas pipeline reforms](#), 17 March 2023, accessed 9 March 2025.

512 Government of South Australia, [National Gas \(South Australia\) Regulations](#), accessed 9 March 2025.

513 AER, [Final decision on APTNT's ring fencing exemption application](#), Australian Energy Regulator, 17 August 2011. Note: APT Pipelines (Northern Territory) has applied for a revocation of its exemption. The AER is due to make its final decision in mid-June 2025.

514 AER, [Final decision on ring fencing exemption application for Meridian SeamGas Joint Venture and WestSide Corporation](#), Australian Energy Regulator, 25 July 2012.

515 AER, [Power and Water Corporation – Ring Fencing Decision – McArthur River Mining Pipeline](#), Australian Energy Regulator, 29 November 2024.

516 AER, [Jemena – Ring Fencing Decision – Phillip Creek Compressor Station](#), Australian Energy Regulator, 5 March 2025.

517 AER, [Electricity and gas networks performance report](#), Australian Energy Regulator, 20 September 2024.

Box 5.2 Insights from our report on the behaviour and compliance of selected gas pipeline service providers

Gas is a critical source of energy on Australia's east coast and will remain a key input in some industrial sectors for the foreseeable future (section 5.5.7). Gas pipeline regulations were reformed in March 2023⁵¹⁸ to address broad concerns of under-regulation and more effectively restrict the market power of service providers by building greater support for shippers – gas customers that purchase capacity on a pipeline to deliver gas – negotiating access to pipelines.

The reforms require us to monitor and report on the behaviour of service providers to:

- promote transparency that helps shippers in their negotiations with service providers
- keep policymakers and the public informed about gas pipelines and the extent and impact of market power on the wholesale gas market
- support our role in determining which form of regulation should apply to a gas pipeline.

The 2023 regulations are still being implemented and new financial reporting requirements will be published by 31 December 2025. This additional information is expected to deliver improved transparency by providing pipeline users with cost-based pricing benchmarks.

In March 2025, we published our *Gas pipeline monitoring and transparency report*⁵¹⁹ – our first report as part of our new reporting responsibilities. Our next gas pipeline monitoring and transparency report will be published in 2026 after the transitional arrangements have concluded and will draw on all information provided under the reforms.

Financial information currently available indicates:

- Pipelines are capital-intensive assets with large initial capital bases (section 5.8). These capital bases depreciate over the life span of the pipeline. A pipeline service provider's primary capital cost is the pipeline itself, as opposed to other assets, such as compressors or easements. The incorporation of 'other non-depreciable pipeline assets', which may include intangible assets such as goodwill and which do not reflect the pipeline service provider's debt and equity costs, have likely inflated capital bases and reduce the transparency of the Part 23 information.
- Pipeline service providers tend to make most of their revenue from firm forward transportation services. As such, a pipeline service provider's revenue is highly dependent on the demand for the pipeline services (how much capacity it can contract out) and the price set for those services.
- As pipelines are capital intensive (section 5.10), operational expenses (section 5.11) tend to be relatively low. The largest expense a pipeline incurs is generally the depreciation of its capital base.
- Pipelines typically generate more revenue than is required to cover costs. A pipeline's profitability is measured via a calculation of return on assets, which is influenced by the pipeline's capital base, revenue and expenses.

Prices paid by shippers

Different shippers reported different experiences and bargaining power to negotiate terms and conditions for pipeline services. This was supported by our own analysis, which indicated that some users may have limited ability to negotiate across pipelines.

While compliance with the publishing of the actual prices payable information needs improvement, there were only a few instances among service providers of non-compliance with their other obligations. These instances of non-compliance were self-reported and were primarily due to a lack of understanding of the new regulatory obligations.

⁵¹⁸ National Gas Rules (Gas Pipelines) Amendment Rules 2023 was made on 10 March 2023 and the making of the rule was published in the South Australian Government Gazette on 16 March 2023. It was consolidated into version 66 of the National Gas Rules.

⁵¹⁹ AER, [Gas pipeline monitoring and transparency report](#), Australian Energy Regulator, 26 March 2025, accessed 9 April 2025.

5.5 How gas access prices are set

Pipeline service providers earn revenue by selling capacity to customers needing to transport gas. A customer purchases access to capacity under terms and conditions that include an access price. The AER sets access prices for gas pipelines in eastern Australia and the Northern Territory under broadly similar rules to those applied to electricity networks (chapter 4). There are currently 9 gas pipelines that have their access prices set by the AER.

As with electricity, the AER uses a building block approach to assess a gas pipeline service provider's revenue needs (section 5.5.1). The AER draws on a range of inputs to assess efficient costs, including cost and demand forecasts and revealed costs from previous experience. Unlike electricity, the approach is not formalised in published guidelines; it is described in the AER's final decisions on access arrangements. An exception is the allowed rate of return assessment, for which a common AER guideline applies to both electricity and gas.

Gas pipelines are capital intensive and require significant investment to install, operate and maintain the necessary infrastructure. This gives rise to a natural monopoly industry structure, where it is more efficient to have a single pipeline service provider than to have multiple providers offering the same service.

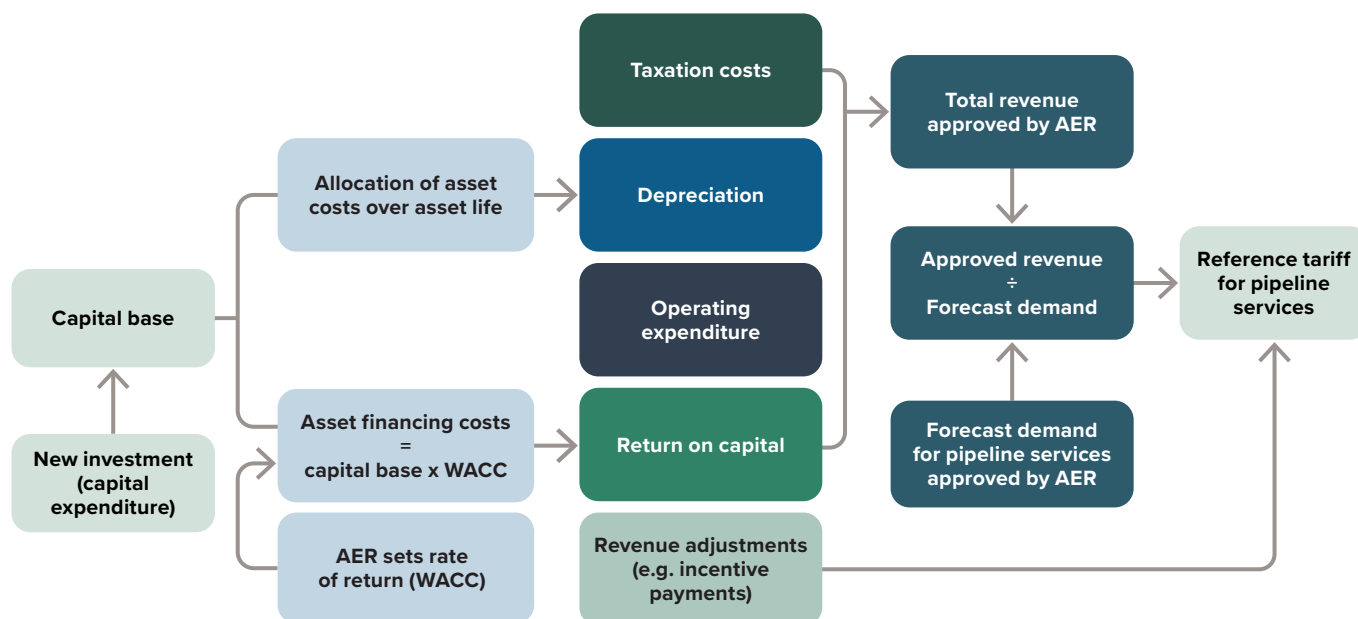
Because monopolies face little competitive pressure, they have opportunities and incentives to charge higher prices than they could charge in a competitive market. This monopolistic environment poses risks to consumers because pipeline charges make up around 40% of a residential customer's gas bill (Figure 6.3 in chapter 6). To counter these risks, the AER's role as the economic regulator of scheme pipelines is to administer the regulatory framework effectively by replicating the incentives that pipeline service providers would face in a competitive market (that is, to control costs, invest efficiently and not overcharge consumers).

5.5.1 Building blocks of gas pipeline revenue

The AER's building block approach forecasts how much revenue the service provider will need to cover:

- a return to investors that funds the pipeline service provider's assets and operations
- efficient operating and maintenance costs
- asset depreciation costs
- taxation costs.

Figure 5.5 How gas pipeline revenue and charges are set



Note: WACC: weighted average cost of capital. Revenue adjustments from incentive schemes encourage pipeline businesses to manage their operating and capital expenditure efficiently and to innovate.

Source: AER.

Operating and maintenance costs are forecast to account for around 38% of revenue requirements in the current access periods.

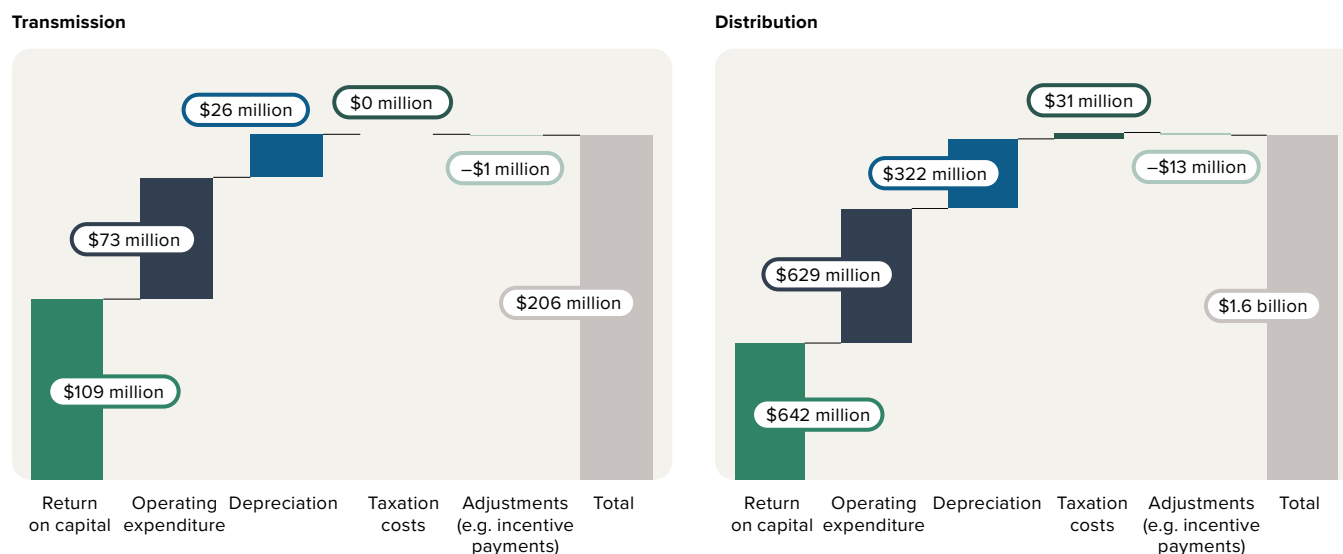
Pipeline assets generally have long lives, and investment costs are recovered over the economic life of the assets. The amount recovered each year is called depreciation and reflects the lost value of pipeline assets each year through wear and tear and technical obsolescence.

Additionally, the shareholders and lenders that fund these assets must be paid a commercial return on their investment. Those returns are forecast to absorb around 41% of revenues (52% for transmission and 39% for distribution) in the current access arrangements. The returns are calculated by multiplying the value of the pipeline service provider's capital base by the rate of return that the AER allows based on the forecast cost of funding those assets through equity and debt.⁵²⁰

Overheads, taxation and other costs account for the remainder of a pipeline service provider's revenue.

520 The return on equity is the return that shareholders of the business will require for them to continue to invest. The return on debt is the interest rate that the pipeline service provider business pays when it borrows money to invest.

Figure 5.6 Composition of average annual gas pipeline revenue



Note: Composition of average annual gas pipeline revenue – current periods as at 1 July 2025. All data are adjusted to June 2024 dollars.
Source: Post tax revenue modelling used in AER determination process.

5.5.2 Incentive schemes

The National Gas Rules provide scope for pipeline service providers to earn financial rewards by outperforming efficiency targets (and incur financial penalties for underperformance). An efficiency carryover mechanism allows service providers to retain, for up to 6 years, efficiency savings in managing their operating expenditure. In the longer term, service providers must share efficiency gains with their customers by passing on around 70% of the gains through lower access prices. The mechanism is similar to the efficiency benefit sharing scheme (EBSS) in electricity (chapter 3, Box 3.4). The difference is that if the proposed application of the scheme is accepted by the AER, it is written into the service provider's access arrangement rather than being set out in a general guideline.

Several pipeline service providers proposed the application of a capital expenditure sharing scheme (CESS) in their most recent access arrangement. The National Gas Rules do not mandate such schemes, but they do allow the AER to approve their use to incentivise service providers to efficiently maintain and operate their pipelines.

The Victorian distribution pipeline service providers were the first to propose and implement a CESS approved by the AER as part of their 2018–22 access arrangements. The AER subsequently approved Jemena Gas Networks' (NSW) request for a CESS for its 2020–25 access arrangement and requests by Australian Gas Networks (South Australia) and Evoenergy (ACT) for their 2021–26 access arrangements. To date, no transmission service providers have sought to participate in a CESS.

The CESS for gas pipeline service providers operates in a similar way to the CESS for electricity networks (chapter 3, Box 3.3). It allows a service provider to earn financial rewards by keeping new investment spending below forecast levels (and incur financial penalties for investing above forecast). In later access arrangements, the service providers must pass on 70% of savings to customers through lower charges.

The CESS carries a risk of encouraging service providers to inflate their investment forecasts. To mitigate this risk, the AER scrutinises whether proposed investments are efficient. The design of the CESS ensures deferred expenditure does not attract rewards so that service providers are not incentivised to defer critical investment needed for safe and reliable pipeline operation. A network health index ensures that rewards depend on the service provider maintaining current service standards.

Other incentive schemes applied to electricity networks – such as those relating to service performance and demand management – are not available to gas pipeline service providers.

5.5.3 Timelines and processes

Once a pipeline service provider submits an access arrangement proposal, the AER has 6 months (plus optional stop-the-clock time at certain stages) to make a final decision on the access arrangement. The assessment period can be extended by up to 2 months, with a maximum of 13 months to render a decision.

The AER consults with pipeline customers and other stakeholders during the assessment process. As part of this consultation, the AER publishes a draft decision on which it seeks stakeholder input to inform its final decision. At the completion of a review, the AER publishes a final access arrangement decision that sets the reference tariff that a pipeline service provider can charge its customers. The AER annually reviews pipeline tariff variations to ensure they are consistent with its decision.

The AER assesses access arrangements on a rolling cycle. The (typically) 5-year review cycle helps create a stable investment environment but also risks locking in inaccurate forecasts. Countering this risk, the National Gas Rules include ways of managing uncertainties. The AER can approve cost pass-throughs if a specified event (such as a regulatory change or natural disaster) imposes significant costs on the pipeline service provider that were not forecast. A pipeline service provider may also approach the AER to pre-approve a contingent investment project if the need to do so was uncertain at the time of the access arrangement decision. A pre-approval allows a service provider to roll the project into the capital base in the forthcoming access arrangement if pre-determined conditions are met.

In October 2020, the Victorian Government changed the timing of the Victorian distribution pipeline service providers' access arrangements from calendar to financial regulatory years.⁵²¹ To implement the change, the 1 January 2018 to 31 December 2022 access arrangement period was extended to include a 6-month transition period. The current access arrangement periods began on 1 July 2023.

5.5.4 Consumer engagement

An important focus of gas pipeline regulation is how constructively a pipeline service provider engages with its consumers in developing an access arrangement proposal. Although not mandated in the National Gas Rules, evidence of constructive engagement can give the AER confidence that the service provider is genuinely committed to meeting its consumers' needs and preferences. Robust consumer engagement can lay the foundation for the AER to accept elements of an access arrangement proposal, including capital and operating expenditure forecasts.

The AER's framework for considering consumer engagement in pipeline access arrangement determinations is set out in the *Better Resets Handbook*.⁵²²

The AER acknowledged that Jemena Gas Networks (NSW) undertook and delivered a well-planned, comprehensive and high-quality consumer engagement program, which delivered transparent and sincere engagement with its customers and stakeholders as part of its 2025–30 access arrangement proposal.⁵²³

521 Victorian legislation, [National Energy Legislation Amendment Act 2020](#), 20 October 2020, accessed 12 October 2024.

522 AER, [Better Resets Handbook – Towards consumer-centric network proposals](#), Australian Energy Regulator, 18 November 2022, accessed 12 March 2025.

523 AER, [Final decision – Jemena Gas Networks \(NSW\) access arrangement 2025 to 2030 – Overview](#), Australian Energy Regulator, 14 May 2025.

5.5.5 Road to net zero by 2050

Australia now has a legislated carbon emissions target of net zero greenhouse gas emissions by 2050 and a National Gas Objective that includes achievement of emissions reductions targets. The Future Gas Strategy maps the Australian Government's plan for how gas will support our economy's transition to net zero in partnership with the world.⁵²⁴

The objectives of the strategy are to:

- support decarbonisation of the Australian economy
- safeguard energy security and affordability
- entrench Australia's reputation as an attractive trade and investment destination
- help our trade partners on their own paths to net zero.

State and territory governments are already taking measures to reduce residential and small commercial consumers' reliance on gas.

The NSW Government has committed to deliver a NSW gas decarbonisation roadmap by late 2026. This roadmap is intended to provide clarity to communities and industry on fossil gas decarbonisation and the role of gas in the future of the energy system. It follows the November 2020 release of the NSW Government's Electricity Infrastructure Roadmap – a 20-year plan to transform the state's electricity system into one that is affordable, clean and reliable for everyone.⁵²⁵

In June 2025, the City of Sydney made the decision to ban gas appliances in new homes. Coming into effect from 1 January 2026, under the proposed reforms developers will be required to equip new homes with electric cooktops, ovens, and indoor heating and cooling systems while phasing out gas appliances to reduce the city's greenhouse gas emissions.⁵²⁶

In October 2022 the Victorian Government released its Gas Substitution Roadmap – a plan to help Victoria reduce the cost of energy bills and cut carbon emissions.⁵²⁷ Victoria is taking steps to speed up the transition to renewable energy with the goal of achieving a 45–50% reduction in emissions by 2030, 75–80% reduction by 2035 and net zero by 2045. To achieve its targets, Victoria must cut emissions across the entire economy, including the gas sector, which contributes around 17% of the state's net greenhouse gas emissions.

The Gas Substitution Roadmap offers options and support for Victorian residential and small commercial consumers who are interested in switching from gas to solar or electricity. Switching from gas to efficient electric appliances will help households to save money on their energy bills. The Gas Substitution Roadmap indicates that converting an existing home with solar panels from dual-fuel to all-electric can save around \$1,700 per year on energy bills, in addition to the approximately \$1,000 of savings per year generated by the solar PV system.⁵²⁸

The pace of change in Victoria has continued to accelerate with the introduction of rule changes to reduce new and existing gas connections. Since 1 January 2024, new gas connections have been phased out for new dwellings, apartment buildings and residential subdivisions requiring planning permits. This rule does not apply to new dwellings that do not require a planning permit, existing homes with existing gas connections, or renovations and extensions to existing houses.

On 24 June 2025, the Victorian Government announced reforms to:

- secure Victoria's gas supply
- drive down energy bills
- make rental homes more comfortable and affordable
- back local manufacturing.⁵²⁹

524 Australian Government, [Future gas strategy](#), Department of Industry, Science and Resources, 25 June 2024, accessed 12 March 2025.

525 NSW Government, [Electricity infrastructure roadmap](#), 20 November 2020, accessed 12 March 2025.

526 City of Sydney, [All electric buildings in city's future](#), 24 June 2025, accessed 2 July 2025.

527 Victorian Government, [Victoria's Gas Substitution Roadmap](#), Department of Energy, Environment and Climate Action, accessed 12 March 2025.

528 Assuming a 6.6 kilowatt solar PV system.

529 Victorian Government, [Securing Victoria's gas supply while slashing energy bills](#), media release, 24 June 2025.

The Victorian Government's *Gas Security Statement*⁵³⁰ outlines the steps it is taking to avoid the gas shortfalls forecast by AEMO for south-eastern states by 2029. The Statement confirms that the government's reforms will deliver major gas savings, supported by more Victorians switching to efficient electric appliances thereby reducing household demand and reserve gas for industry. From 1 January 2027, all new homes and new commercial buildings (other than industrial, manufacturing and agricultural buildings) will be built all electric. This will save homeowners around \$880 per year or \$1,820 if they have solar.

The Victorian Government estimates by 2029 the reforms will unlock just under 12 petajoules (PJ) of gas every year and by 2035 they will deliver 44 PJ annually – enough to meet 85% of Victoria's forecast industrial demand.

From 1 March 2027, when a gas hot water system in Victoria reaches the end of its life, it must be replaced with an efficient electric alternative like a heat pump. Electric hot water systems will save households around \$330 a year or \$520 with solar.⁵³¹ Electric hot water systems are also often cheaper up-front than gas systems, with rebates available from the government's Victorian Energy Upgrades⁵³² and Solar Victoria programs⁵³³ of up to \$1,400. Also from 1 March 2027, new minimum energy efficiency standards will apply to rental properties and public housing, saving renters potentially thousands of dollars a year.⁵³⁴

The Victorian Government has also committed to investing \$9.5 million towards an Industry Diversification Program to making sure Victoria's appliance manufacturing industry is ready to meet the demand for energy efficient hot water appliances.⁵³⁵

The ACT Government's Climate Change and Greenhouse Gas Reduction (Natural Gas Transition) Amendment Bill 2022 established the legal framework to end new fossil fuel gas connections in the ACT.⁵³⁶ In June 2024, the ACT Government announced its intention to invest in an all-electric, zero emissions future for Canberra with the release of a new Integrated Energy Plan (IEP). The IEP sets out the next stage of work for the ACT's transition over the next 20 years, including a range of government commitments to support consumers through the transition.⁵³⁷

The future role of Australia's existing pipeline infrastructure will depend on the broader role of gas, both domestically and abroad. Gas underpins a wide range of economic activity in Australia and globally, with secure gas supplies being a core component of energy security for many economies. Australia's domestic climate action is progressing against a backdrop of growing global momentum to deliver the goals of the Paris Agreement. Therefore, emissions from gas must reduce significantly.⁵³⁸

Australian contracts for LNG exports will begin to expire around the mid-2030s and these will likely be replaced with a combination of new contracts for fixed LNG volumes over fixed periods and LNG sales through the international spot market. Within the Asian region to which Australia currently exports LNG, demand for LNG is expected to continue to 2050 and beyond and consultation indicates continued demand for secure exports from Australia.⁵³⁹

530 Victorian Government, [Gas Security Statement](#), Department of Energy, Environment and Climate Action, 24 June 2025, accessed 2 July 2025.

531 Victorian Government, [Securing Victoria's gas supply while slashing energy bills](#), media release, 24 June 2025.

532 Victorian Government, [Victorian Energy Upgrades for homes](#), Department of Energy, Environment and Climate Action, 19 August 2024, accessed 2 July 2025.

533 Victorian Government, [Solar Victoria programs](#), Solar Victoria, 9 April 2025, accessed 2 July 2025.

534 Victorian Government, [Securing Victoria's gas supply while slashing energy bills](#), media release, 24 June 2025.

535 Victorian Government, [Securing Victoria's gas supply while slashing energy bills](#), media release, 24 June 2025.

536 ACT Government, [ACT reaches milestone preventing new fossil fuel gas connections](#), media release, 8 June 2023.

537 ACT Government, [Electrifying Canberra](#), media release, 19 June 2024.

538 Australian Government, [Future Gas Strategy Analytical Report](#), Department of Industry, Science and Resources, 9 May 2024, accessed 12 March 2025, p. 3.

539 ACCC, [Gas Inquiry](#) 2017–2030, Interim update on east coast gas market, Australian Competition and Consumer Commission, June 2024,

5.5.6 Regulating gas pipelines under uncertainty

In November 2021, the AER published an information paper, *Regulating gas pipelines under uncertainty*, which discussed the potential implications of a decarbonised future energy mix on the long-term gas demand forecast and the expected economic lives of gas pipeline assets.⁵⁴⁰

The paper explained how these potential implications may affect the AER's regulatory approaches when undertaking access arrangement reviews for service providers operating scheme pipelines now and in the future. It canvassed a range of potential options, including their costs and benefits, for managing the pricing risk and stranded asset risk that may arise from a potential material decline in gas demand in the future. These options included:

- accelerating asset depreciation (section 5.8.1)
- providing ex-ante risk compensation
- removing redundant assets from capital base
- removing capital base indexation
- revaluating capital base
- introducing exit fees
- increasing fixed charges.

The paper also discussed how the uncertainty in future gas demand (section 5.5.7) can affect specific aspects of the AER's regulatory decisions, such as:

- the assumed payback period of pipeline investment in expenditure assessments
- the incentives that regulated service providers may have in substituting capital and operating expenditure
- whether it is in the long-term interests of gas consumers to preserve optionality when evaluating capital investments that are for repurposing gas networks⁵⁴¹
- the increased demand risk that regulated service providers may face under price cap regulation if gas demand falls persistently.

In its 2023–28 access arrangements for the Victorian gas transmission and distribution pipelines and its 2025–30 access arrangement for distribution pipeline Jemena Gas Networks (NSW), the AER:

- changed the way costs are recovered for gas disconnections to encourage consumers to disconnect safely through permanent abolishment of their gas connection instead of the cheaper temporary disconnection option
- allowed for some accelerated depreciation of assets, noting that bringing forward the recovery of assets while pipeline use remains relatively high spreads the increased costs among a larger pool of customers.

The AER noted that these were interim measures and may not be suitable for greater rates of declining demand for gas. Addressing the broader issues in the gas sector requires a holistic policy response. While accelerated depreciation can be used as a tool for reducing asset stranding risk, it has limitations and on its own cannot resolve the issues faced by the gas networks and customers from anticipated declining demand. Declining demand is ultimately the key driver of rising future network prices. As long as demand continues to decline, no affordable amount of accelerated depreciation will achieve long-term price stability. The AER continues to encourage an open discussion between consumers, pipeline service providers and governments about who should pay for the costs of stranded assets associated with past and future capital investments, and when and how these costs should be shared. Abolition of gas connections and accelerated depreciation are discussed in section 5.8.1 and Box 5.4.

⁵⁴⁰ AER, [AER tackles gas pipeline regulation in an uncertain future](#), Australian Energy Regulator, November 2021.

⁵⁴¹ Future hydrogen users are not currently considered as gas consumers under the National Gas Law or National Gas Rules.

5.5.7 Gas consumption and demand forecasts

AEMO, through its *Gas Statement of Opportunities*,⁵⁴² forecasts the adequacy of gas supplies to meet the needs of consumers in central and eastern Australia using different scenarios. The ‘step change’ scenario is now considered the most likely scenario, forecasting a scale of energy transformation that supports Australia’s contribution to limiting global temperature rise and sees consumer investment in the energy transition remain strong, with households valuing the benefits of consumer energy resources.

AEMO’s forecasts reflect assumptions about connections and population growth and the impacts of energy efficiency investments, gas fuel-switching such as electrification, gas prices and climate change. In the most recent *Gas Statement of Opportunities*, residential and commercial consumption is forecast to decline over the forecast period, while industrial consumption is expected to remain relatively stable after some initial plant closures.

Electrification remains the most significant driver of forecast declining residential/commercial consumption, with a total anticipated demand reduction of around 25 PJ by 2030 and a total anticipated demand reduction of 120 PJ by the end of the outlook period (2044). As new homes in all jurisdictions are increasingly likely to be built without a gas connection, demand may fall even further (Figure 5.7).

Figure 5.7 AEMO’s forecast gas consumption – residential/commercial customers



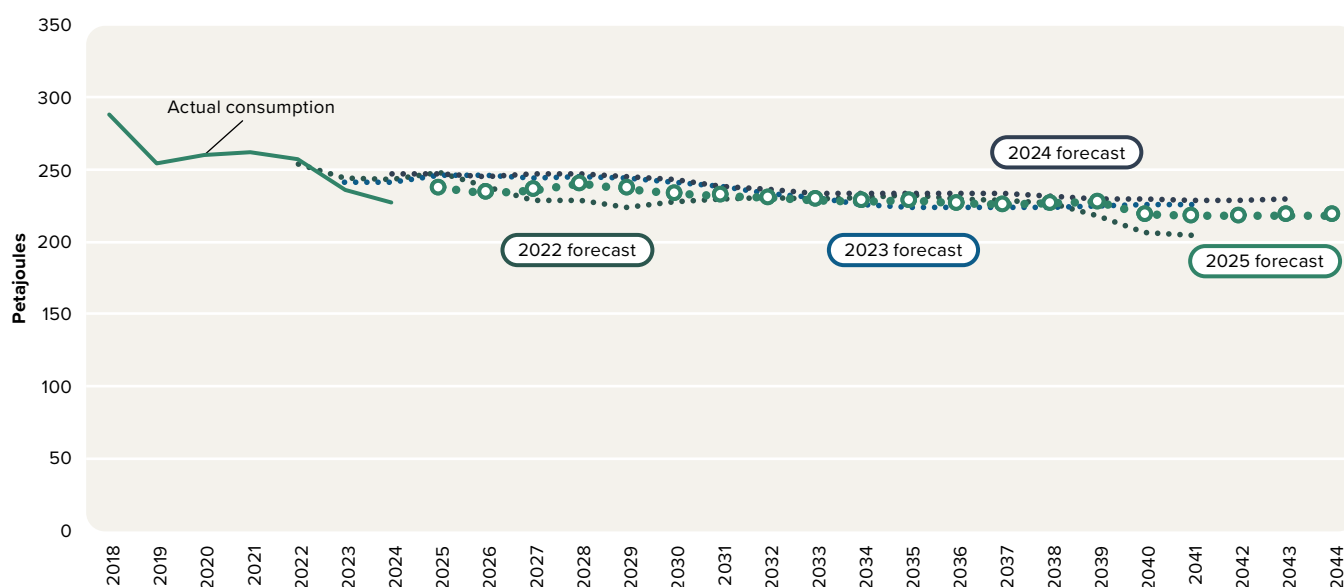
Note: Residential and commercial customers include consumers on volume-based tariffs. Forecasts represent the most likely scenario in AEMO’s Gas Statement of Opportunities: 2022 step change scenario, 2023 orchestrated step change (1.8°C) scenario, 2024 step change scenario and 2025 step change scenario.

Source: AEMO, *Gas Statement of Opportunities*, March 2025.

542 AEMO, *Gas Statement of Opportunities*, Australian Energy Market Operator, 20 March 2025, accessed 24 March 2025.

Industrial consumption has declined in recent years, with plant disruptions affecting gas consumption – several facilities have closed or are expecting to close in the near future. Reductions of gas consumption due to electrification investments in the industrial sector are more modest than those in the residential/commercial sectors, given the technical and operating challenges of replacing high temperature and process-specific production steps in operating facilities with alternative energy sources. The Australian Government’s Safeguard Mechanism,⁵⁴³ which requires certain industrial facilities⁵⁴⁴ to limit their emissions below a declining baseline, may encourage some fuel substitution, particularly in low-temperature process alternatives. However, many processes have limited electric alternatives that are currently technically or commercially available. Apart from retrofitting site equipment, the increased power requirements could also call for electricity network upgrades to support increased local demand for electricity. Additionally, a significant share of natural gas usage in industry is for chemical feedstock, for which electricity is not a substitute without additional changes in technology and processes (Figure 5.8).

Figure 5.8 AEMO’s forecast gas consumption – industrial customers



Note: Industrial customers include large customers such as fertiliser producers, mineral processing, primary metal, paper and chemical producers, oil refineries, large food processors and mining. Any onsite electricity generation that consumes gas is also included. Forecasts represent the most likely scenario in AEMO’s Gas Statement of Opportunities: 2022 step change scenario, 2023 orchestrated step change (1.8°C) scenario, 2024 step change scenario and 2025 step change scenario.

Source: AEMO, [Gas Statement of Opportunities](#), March 2025.

Transformation in the energy system and the explicit policy goal of reaching net zero emissions by 2050 create considerable uncertainties in forecasting gas demand. While the decline in the demand for gas is expected to accelerate, there is considerable uncertainty as to how quickly the acceleration will happen, what the path to small customer ‘electrification’ will look like and whether existing gas pipelines will have an ongoing role in transporting hydrogen or biogas.

Declining use of pipeline infrastructure will put upwards pressure on the price of gas haulage. If this eventuates, it will likely encourage further decline in demand and an increase in customers leaving the network, causing self-reinforcing upwards pressure on tariffs for remaining customers. In a report for Energy Consumers Australia, CSIRO and Dynamic Analysis undertook modelling of how this scenario may arise under AEMO’s ‘step change’ scenario.⁵⁴⁵

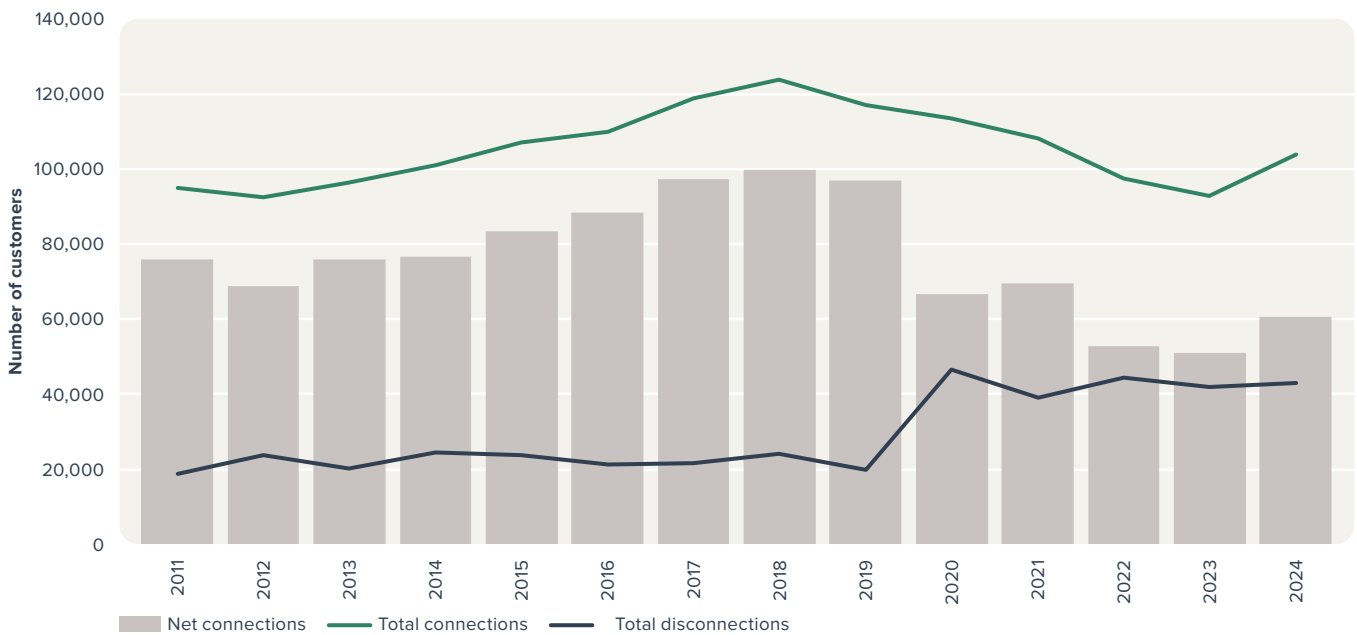
⁵⁴³ Australian Government, [Safeguard Mechanism](#), Department of Climate Change, Energy, the Environment and Water, accessed 24 March 2025.

⁵⁴⁴ The Safeguard Mechanism applies to industrial facilities emitting more than 100,000 tonnes of carbon dioxide equivalent (CO₂-e) per year.

⁵⁴⁵ CSIRO and Dynamic Analysis, [Consumer impacts of the energy transition: Modelling report](#), Energy Consumers Australia, July 2023, pp. 21–22, accessed 14 July 2025.

Although residential/commercial customer connections continue to outnumber disconnections, the contrast between the 2 has shifted over the past 5 years (Figure 5.9). While declining demand is already having an impact on growth-driven elements of forecast expenditure, its impact on other drivers of expenditure is expected to happen more slowly. The AER closely scrutinises proposed capital and operating expenditure to ensure that customers who are still reliant on gas are paying no more than necessary for a safe, reliable and secure supply. The obligation on pipeline service providers to continue to offer the same services while meeting the same regulated standards means many costs will not necessarily fall as demand falls. This makes it difficult to avoid increases in costs per customer due to falling demand under the current regulatory framework.

Figure 5.9 Growth in residential and commercial customers



Source: Annual reporting RIN responses.

Box 5.3 Temporary disconnection versus permanent abolishment of gas connections

Through our assessments of Victorian distribution pipeline service providers AusNet Services', Australian Gas Networks' and Multinet Gas Networks' 2023–28 access arrangements, we became aware that some customers seeking to move away from gas have sought temporary disconnection measures over the safer, permanent removal of connection assets.

Energy Safe Victoria, the regulator responsible for electricity, gas and pipelines safety, considers that when a customer chooses to stop using gas at their premises, permanent abolishment of the connection is required. Failure to do so impedes the pipeline service providers from meeting their safety obligations.

However, permanent abolishment of a gas connection (by removing the pipeline assets and closing off the connection or premises to the mains) is more costly than temporarily stopping the withdrawal of gas through the meter. This makes the cost of permanent abolishment a deterrent for customers wanting to move away from gas.

To narrow the price difference between temporary disconnection and permanent gas abolishment services, and the associated safety risks it appears to be creating, we determined an up-front cost of \$220 for permanent abolishment. The remaining cost was socialised and added to the regulated revenue we use to set haulage tariffs and shared between all customers.⁵⁴⁶

We acknowledge this is not a long-term solution.

Energy Safe Victoria is committed to working with the distribution pipeline service providers to understand whether other methods may be more appropriate than permanent abolishment.

In our most recent access arrangement review for Jemena Gas Networks (NSW) we again sought to strike a balance between cost and safety. Our final decision was to partially socialise the cost of permanently abolishing a residential connection point across the remaining network customers, setting an up-front tariff of \$250 for customers permanently leaving Jemena's gas network.

However, for customers requesting permanent abolishment with the intention of reconnecting due to renovating, rebuilding or reconstructing, a fully priced abolishment tariff of \$1,200 will apply. A variable price will be available for customers in multi-tenancy properties, reflecting the more limited works required in most of those contexts.

Reducing the price gap between temporary disconnection and permanent abolishment services is aimed at addressing safety concerns consistent with the view of the NSW safety regulator.⁵⁴⁷ Noting that Jemena Gas Networks requires time to work with retailers to establish appropriate systems and protocols to deliver these changes, we required these pricing changes to commence on 1 July 2026.

⁵⁴⁶ AER, [AER decision supports Victorian gas consumers in energy transition](#), Australian Energy Regulator, 2 June 2023, accessed 14 July 2025.

⁵⁴⁷ NSW Government, Letter: Costings for the disconnection and abolishment to the natural gas asset for households in NSW, Department of Climate Change, Energy, the Environment and Water, 2 July 2024, pp. 1–2.

5.6 Recent AER access arrangement decisions

In May 2025, the AER finalised its access arrangement determination for distribution pipeline service provider Jemena Gas Networks (NSW). This determination sets the expected amount of revenue Jemena Gas Networks can earn from customers for the 5-year period through to 30 June 2030.

The AER did not approve Jemena Gas Networks' revised access arrangement proposal.⁵⁴⁸ The AER instead allowed Jemena Gas Networks to set gas network charges to recover around \$2.8 billion⁵⁴⁹ in revenue over the 2025–30 access arrangement period (4.3% less than was proposed).⁵⁵⁰

The AER's final decision allowed for an increase of \$385 million⁵⁵¹ (16%) in revenue compared with the previous access arrangement period (2020–25). There were several drivers of this outcome, such as increases in:

- the return on capital, primarily due to changes in market variables outside of Jemena Gas Networks' control, including a higher rate of return and higher inflation compared with the 2020–25 period
- the corporate income tax allowance, primarily due to a higher return on equity and lower tax depreciation
- revenue adjustments, primarily due to the expiry of a one-off large negative revenue adjustment for the 2015–20 remittal decision included in the 2020–25 access arrangement.

With the energy transition underway and given the Australian Government's goal of reaching net zero emissions by 2050, there are complex questions being asked about the future of gas pipelines. Uncertainty in the external environment was taken into account in the AER's consideration of several elements of its final decision. The AER did not accept Jemena Gas Networks' capital expenditure forecast for the 2025–30 period, and instead substituted an alternative estimate that was 14% lower than Jemena Gas Networks' revised proposal.

Table 5.3 and Figure 5.10 provide comparisons between the AER's revenue and expenditure allowances for Jemena Gas Networks for the current (2025–30) and previous access arrangement periods.

Table 5.3 Recent AER gas pipeline access arrangement determination

Pipeline service provider	Revenue (forecast)	Capital expenditure (forecast)	Operating expenditure (forecast)
Jemena Gas Networks (NSW)	\$2.8 billion (▲16%)	\$698 million (▼31%)	\$1.1 billion (see note)

Note: All revenue and expenditure data are adjusted to June 2024 dollars. Changes in revenue and capital expenditure are in relation to forecasts from the previous access arrangement. Forecast operating expenditure in Jemena Gas Networks 2025–30 access arrangement cannot be directly compared with the previous access arrangement because the 2025–30 forecast relates only to gas transportation whereas the forecast for the previous access arrangement also included ancillary reference services.

Source: AER estimates.

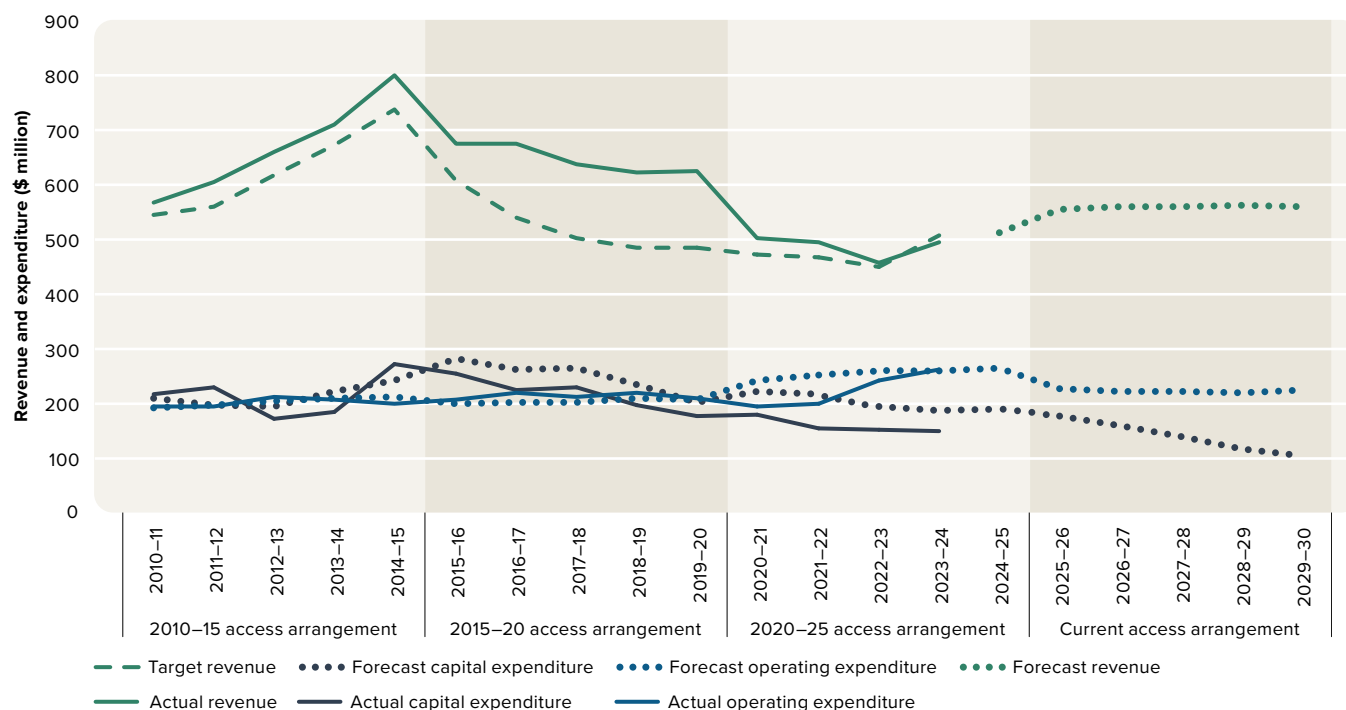
548 AER, [Jemena Gas Networks \(NSW\) – Access arrangement 2025–30 – Revised proposal](#), Australian Energy Regulator, 15 January 2025.

549 Adjusted to June 2024 dollars.

550 AER, [Final decision – Jemena Gas Networks \(NSW\) access arrangement 2025 to 2030 – Overview](#), Australian Energy Regulator, 14 May 2025.

551 Adjusted to June 2024 dollars.

Figure 5.10 Revenue and key drivers – Jemena Gas Networks (NSW)



Note: All data are adjusted to June 2024 dollars.
Source: AER modelling; annual reporting RIN responses.

The AER did not accept Jemena Gas Networks' proposed meter replacement expenditure or its proposed expenditure for renewable connections to connect biomethane production facilities to its network. These decisions were partially offset by the AER's decision to increase Jemena Gas Networks' customer connections capital expenditure, reflecting a higher forecast of residential customer connection growth.

For Jemena Gas Networks' renewable connection projects, the AER accepted that, if completed and supplied as specified, these projects are likely to provide a net benefit. However, the AER remains concerned there is significant commencement and completion risk for these projects. The AER's decision reflected the significant uncertainty relating to the investments, as well as the uncertainty around who bears the risk of funding these investments.

The AER's decision does not prevent Jemena Gas Networks from undertaking the capital expenditure during the current access arrangement period (2025–30) and seeking funding once these supply arrangements are more certain.⁵⁵²

The AER approved Jemena Gas Networks' hybrid tariff variation mechanism for its gas transportation reference service, incorporating elements of both weighted average price cap and revenue cap regulation. This hybrid mechanism reduces Jemena Gas Networks' incentive to grow the volume of gas carried by its network while mitigating year-on-year tariff volatility associated with revenue caps.

552 AER, [AER releases final decision for Jemena Gas Networks' gas access arrangement](#), Australian Energy Regulator, media release, 14 May 2025.

Table 5.4 provides a comparison between the AER's final decisions on the access arrangements in place for the current access period and those in place in the previous access period.⁵⁵³

Table 5.4 AER gas revenue determinations – current access arrangements

Service type	Revenue (forecast)	Capital expenditure (forecast)	Operating expenditure (forecast)
Transmission	\$1.0 billion (–%)	\$306 million (▼23%)	\$363 million (▲10%)
Distribution	\$8.0 billion (▲7%)	\$2.9 billion (▼17%)	\$3.2 billion (see note)
Total	\$9.1 billion (▲6%)	\$3.3 billion (▼18%)	\$3.5 billion (see note)

Note: The current access arrangements are the arrangements in place at 1 July 2025. All revenue and expenditure data are adjusted to June 2024 dollars. Changes in revenue and expenditure are in relation to forecasts from the previous regulatory periods. Forecast operating expenditure in Jemena Gas Networks' current access arrangement cannot be directly compared with the previous access arrangement because the 2025–30 forecast relates only to gas transportation whereas the forecast for the previous access arrangement also included ancillary reference services.

Source: AER estimates.

The AER also released a final decision to not accept the 2023–28 gas access arrangement variation proposal from AusNet Services (Victoria). In its final decision, the AER maintained its draft decision position that AusNet Services did not justify its proposal to vary its access arrangement to recover more accelerated depreciation from customers due to the impacts of Victorian Government policy and regulatory changes. As such, the AER's original final decision (June 2023) for the 2023–28 access arrangement period has been maintained.⁵⁵⁴

In March 2025, AusNet Services responded to the AER's draft decision, accepting the draft decision to not accept its variation proposal. AusNet Services acknowledged the AER's draft decision reasoning that the issues raised by its proposal could be better assessed in the context of its 2028–33 access arrangement proposal. AusNet Services did not submit a revised proposal.⁵⁵⁵

5.7 Revenue

All gas transmission and distribution service providers operating scheme pipelines are regulated under a weighted average price cap. Pipeline service providers can earn above or below forecast revenue over time due to changes in demand. If actual demand exceeds forecast demand, the service provider benefits from additional revenue. Conversely, if actual demand is less than forecast revenue, the service provider is exposed to the shortfall.

5.7.1 Revenue in 2024

Over the 12-month period to 30 June 2024, \$1.6 billion in revenue was collected by distribution scheme pipeline service providers for providing access (selling capacity) to parties needing to transport gas, \$90 million (6%) more than in the previous year.⁵⁵⁶

Table 5.5 provides a summary of the revenue that distribution service providers' scheme pipelines earned in 2024 and how it compared with previous years.

Table 5.5 Revenue in 2024 – key outcomes

Service type	Revenue (actual) (2024)	Revenue (actual) (compared with 2023)	Revenue (actual) (compared with peak)
Distribution	\$1.6 billion	▲\$90 million (▲6%)	▼\$395 million (▼20%) (2015)

Note: All data are adjusted to June 2024 dollars. Actual revenue collected by transmission scheme pipelines is not shown because the data contains commercially sensitive information.

Source: AER estimates.

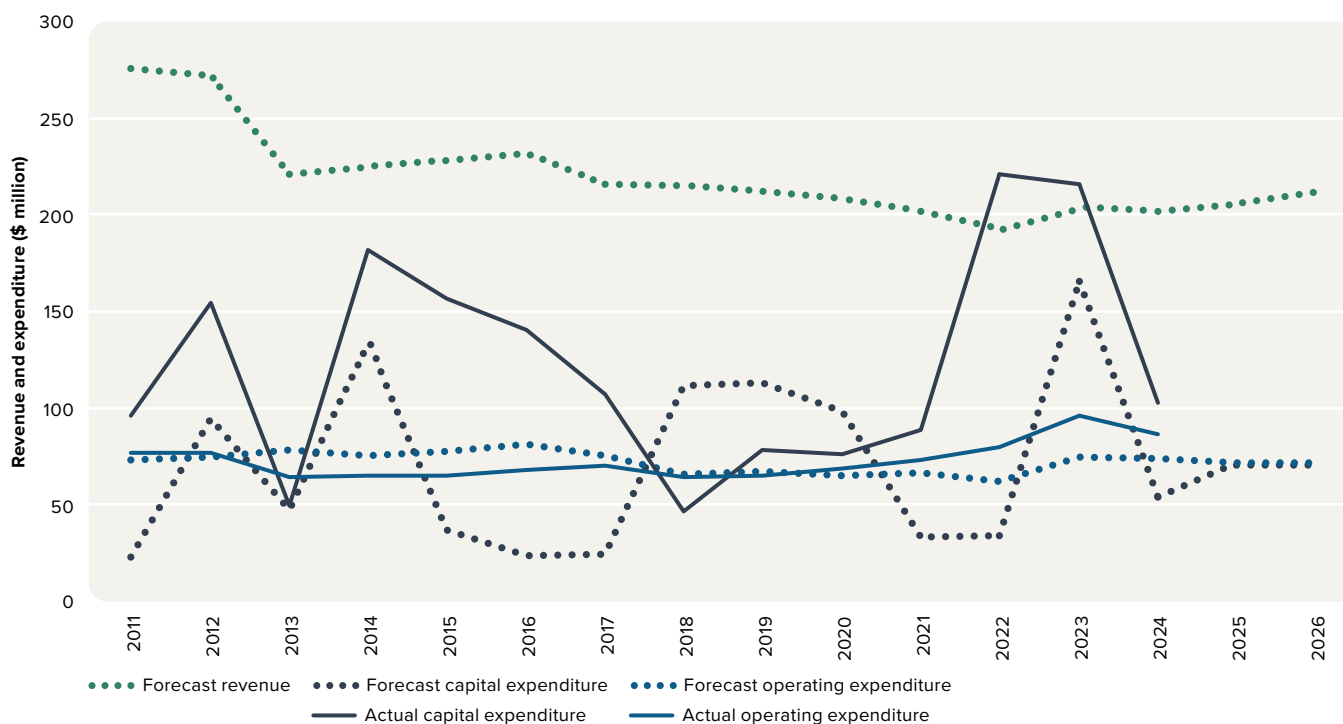
553 The current access arrangement period is the arrangement in place at 1 July 2025.

554 AER, [AusNet Gas Services 2023–28 Access arrangement variation proposal – Final decision](#), Australian Energy Regulator, 14 May 2025.

555 AusNet Services, [Response to the AER Draft decision – GAAR 2024-2028 Variation proposal](#), 14 March 2025.

556 Actual revenue collected by transmission scheme pipelines is not shown because the data contains commercially sensitive information.

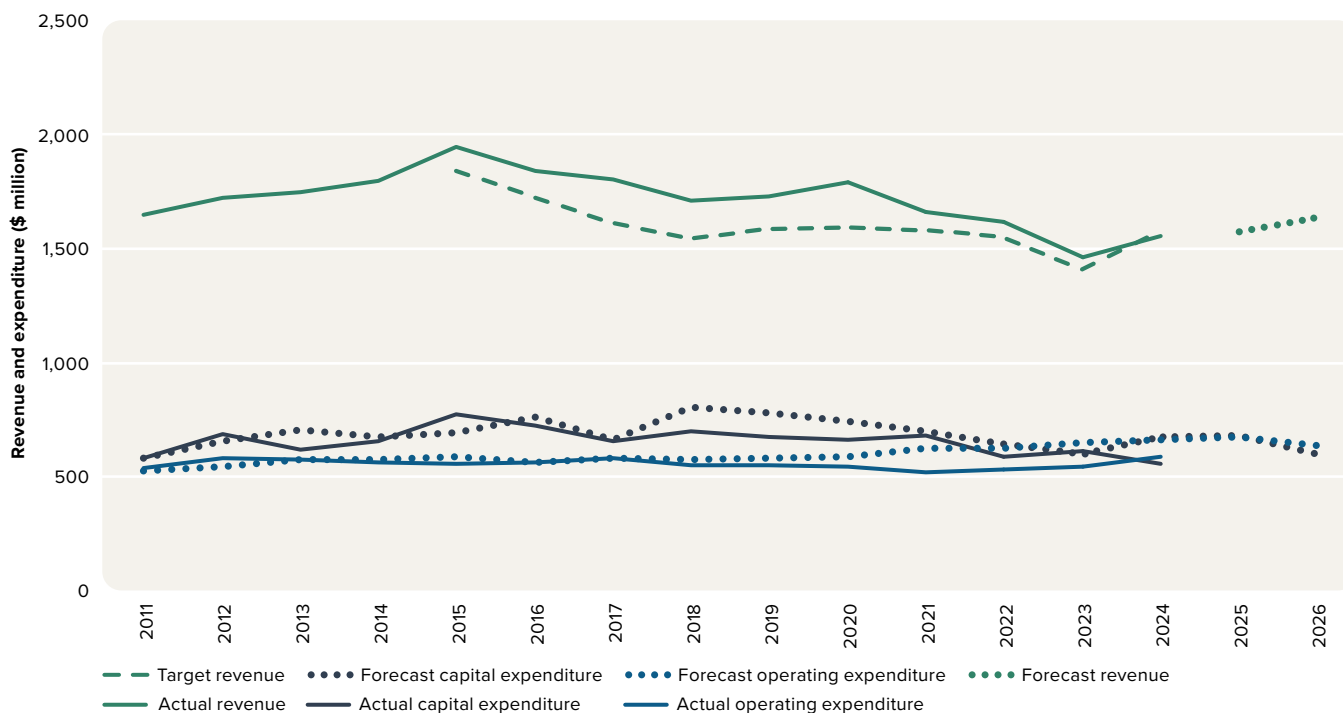
Figure 5.11 Revenue and key drivers – gas (scheme) transmission pipelines (aggregate)



Note: All data are adjusted to June 2024 dollars. APA Victorian Transmission System (Vic) reports on a calendar year basis (year ending 31 December). All other transmission scheme pipeline service providers report on a financial year basis (year ending 30 June). The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Actual revenue is not shown for transmission scheme pipeline service providers as the data contains commercially sensitive information.

Source: AER modelling; annual reporting RIN responses.

Figure 5.12 Revenue and key drivers – gas (scheme) distribution pipelines (aggregate)



Note: All data are adjusted to June 2024 dollars. Up until 31 December 2022, Victorian gas pipeline service providers reported on a calendar year basis (year ending 31 December). Since 1 July 2023, Victorian distribution scheme pipeline service providers have reported on a financial year basis. No revenue forecasts were developed for the Victorian distribution scheme pipeline service providers for the 6-month transition period (1 January 2023 to 30 June 2023). All other distribution scheme pipeline service providers report on a financial year basis (year ending 30 June). The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: AER modelling; annual reporting RIN responses.

Costs of capital and inflation have increased in recent years, both of which put upward pressure on gas pipeline revenue (section 5.9), similar to what has occurred for electricity networks. Any increases in a pipeline service provider's allowed rate of return will be reflected in forecast revenue through the return on capital building block (section 5.5.1).

Specific investment requirements will also increase pipeline costs, so additional revenue is still needed to cover some new projects. For example, APA Victorian Transmission System justified the need for capital expenditure to finance its South West Pipeline and Western Outer Ring main projects. These projects were deemed necessary to avert shortfalls and increase capacity between existing sources of natural gas supply.⁵⁵⁷

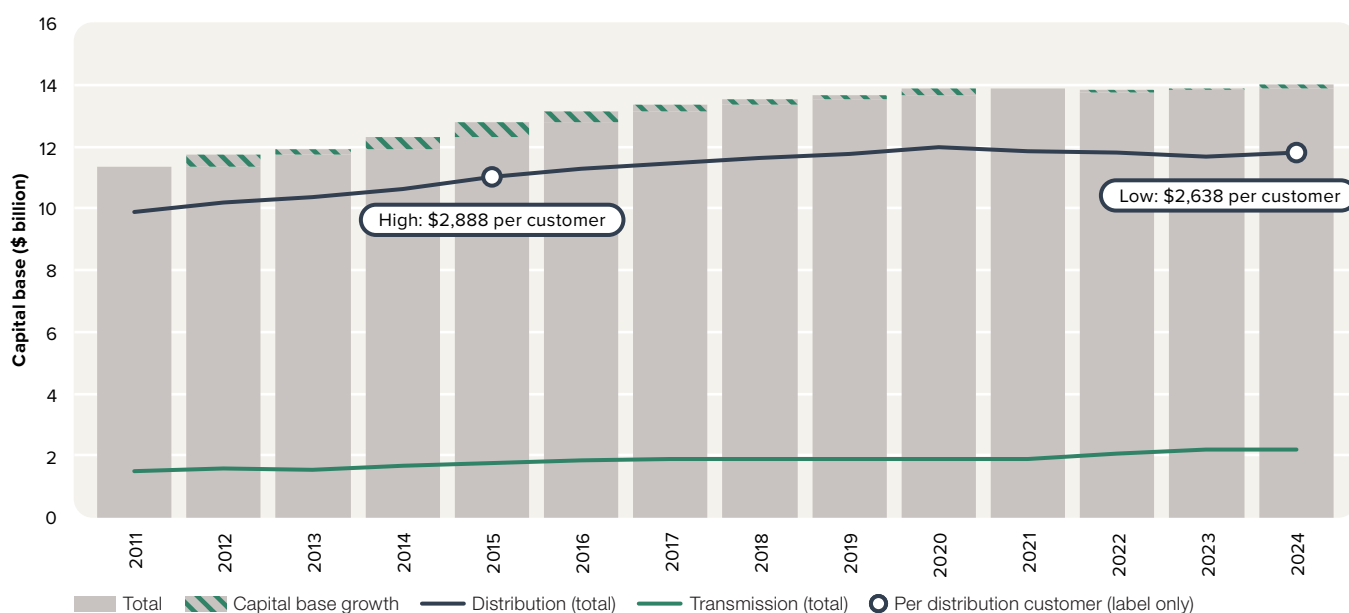
5.8 Capital base

The capital base for a gas pipeline service provider represents the total economic value of assets that provide services to customers. The value of the capital base substantially impacts a service provider's revenue requirement. Capital investment approved by the AER is added to a service provider's capital base, on which future returns are earned.

5.8.1 Capital base in 2024

As at 30 June 2024, the combined value of the capital bases for scheme pipeline service providers was \$14 billion, an increase of \$156 million (1.1%) from the previous year. This comprises 3 transmission pipelines valued at \$2.2 billion and 6 distribution pipelines valued at \$11.8 billion (Figure 5.13).

Figure 5.13 Value of gas pipelines assets (capital base)



Note: All data are adjusted to June 2024 dollars. Victorian pipeline service providers report on a calendar year basis (year ending 31 December). All other pipeline service providers report on a financial year basis (year ending 30 June). The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: AER modelling.

557 AER, [APA Victorian Transmission System – Access arrangement 2023–27](#), Australian Energy Regulator, 9 December 2022, accessed 12 March 2025.

5.8.2 Accelerated depreciation of gas network assets

The national gas regime is not well equipped to deal with a network in decline and was developed at a time when the gas market was growing and was expected to continue to expand. Since then, the market has begun to evolve in ways unforeseen when the National Gas Rules were developed.

The forecast decline in demand for natural gas (section 5.5.7) will lead to higher gas network prices due to fewer customers to share the fixed costs.

This poses a number of challenges, including the cost of past investments being disproportionately borne by future gas customers along with the risk that assets may become economically stranded.

Depreciation is a method used in the AER's determination to allocate the cost of an asset over its useful life and provide an incentive for networks to invest efficiently. It is the amount provided so capital investors recover their investment over the economic life of an asset.

While accelerated depreciation can be used for reducing asset stranding risk while there is a wide customer base, it does have limitations. On its own, accelerated depreciation cannot resolve the issues faced by the gas networks and customers from the anticipated declining demand.

Declining demand is ultimately the key driver of rising future network prices. As long as demand continues to decline, no affordable amount of accelerated depreciation will achieve long-term price stability. The AER considers the appropriateness of applying accelerated depreciation on a case-by-case basis, taking into account relevant regional factors, such as state government decarbonisation policies.

Addressing the broader issues in the gas sector requires a holistic policy response. The AER continues to encourage an open discussion between consumers, pipeline service providers and governments about who should pay for the costs of stranded assets associated with past and future capital investments, and when and how these costs are shared.

In its final decision on the 2025–30 access arrangement for Jemena Gas Networks (NSW) the AER allowed for some accelerated depreciation of its assets. However, the AER did not accept Jemena Gas Networks' proposed accelerated depreciation amount of \$230 million in full and instead provided a reduced amount of \$115 million for the 2025–30 period.⁵⁵⁸ The AER acknowledged Jemena Gas Networks' genuine commitment to listening to its customers and its willingness to engage on accelerated depreciation and other complex issues.

The AER's final decision for Jemena Gas Networks allowed a measured start to accelerated depreciation, rather than none, in recognition of the potential stranded asset risk. The AER considered this to be necessary to ensure that Jemena Gas Networks is not deterred from making efficient investments required to maintain safe and reliable services for an aging network, in the long-term interest of consumers.

The reduced amount of accelerated depreciation the AER approved is consistent with its forecast of declining demand, and lower alternative forecast capital expenditure, which does not contain any significant growth in capital expenditure. It considered that accelerated depreciation and minimising capital expenditure are both necessary to reduce stranded asset risk.

The AER considered the reduced amount also reflects the outlook and strength of policy signals surrounding the future role of Jemena Gas Networks at the time of its decision. Unlike Victoria and the ACT, there is no statewide ban on new gas connections or a gas substitution roadmap in NSW at the time of the AER's decision. Even after the publication of a roadmap, there may still be a period of uncertainty regarding the speed of electrification and the materialisation of this impact on gas demand.⁵⁵⁹

⁵⁵⁸ This amount was determined by firstly providing a base level of accelerated depreciation amount of \$77 million by shortening the economic lives of multiple long-lived asset classes, and an additional accelerated depreciation amount of \$38 million from the 'medium pressure services' asset class to achieve an overall 'base' real annual price increase of 0.5%.

⁵⁵⁹ AER, [Final decision – Jemena Gas Networks \(NSW\) access arrangement 2025 to 2030 – Overview](#), Australian Energy Regulator, 14 May 2025.

In its final decisions on the 2023–28 access arrangements for the Victorian gas transmission and distribution pipelines, the AER also allowed for some accelerated depreciation of assets. The AER considered that accepting some accelerated depreciation supported network investment while minimising bill impacts to consumers, taking into account the Victorian Government's Gas Substitution Roadmap.

The Victorian Government's Gas Substitution Roadmap (section 5.5), which sets the strategic direction to support all Victorians to move away from gas in the long term, includes several initiatives that will reduce the role for gas in Victoria. These include incentives for residential customers to switch to electric appliances, the removal of planning provisions requiring new housing developments to connect to gas and higher energy efficiency requirements for housing and making rental homes more comfortable and affordable.⁵⁶⁰

Declining demand is ultimately the key driver of rising future network prices. As long as demand continues to decline, no affordable amount of accelerated depreciation will achieve long-term price stability.

On 14 February 2025, Energy Consumers Australia (ECA) submitted a request to the AEMC to amend the National Gas Rules to ensure they remain fit-for-purpose in a transitioning energy system.⁵⁶¹ The suite of rule changes proposed by ECA will require gas distribution pipeline service providers to proactively plan for the future of their networks and make decisions to minimise any further non-critical investment. They also aim to increase the tools and information regulators, councils, governments, electricity distribution network service providers, advocates and other stakeholders have available to them to start actively planning for how to fairly transition away from gas.

ECA noted that failing to proactively address the declining reliance on gas pipelines poses significant risk to consumers. The expected decrease in the number of customers connected to the gas network will result in fewer customers left to pay the costs of maintaining and operating the network.⁵⁶²

In making its Jemena Gas Networks' 2025–30 decision, the AER conducted modelling of what declining demand could mean for gas network prices and customer bills. The AER's long-term modelling showed that network prices and customer bills are expected to increase significantly in the medium to long term, irrespective of the depreciation profiles that were modelled. Under a future scenario of declining demand, Jemena Gas Networks' network prices and customer bills are expected to almost double by 2035 and potentially increase by 500% to 600% by 2050 compared with current levels, in nominal terms. Its long-term modelling also demonstrated the potential for accelerated depreciation to reduce the unrecovered residual capital base and, therefore, stranded asset risk.⁵⁶³

560 Victorian Government, [Securing Victoria's gas supply while slashing energy bills](#), media release, 24 June 2025.

561 AEMC, [Gas distribution networks – Depreciation](#), Australian Energy Market Commission, 14 February 2025, accessed 20 March 2025.

562 ECA, [How to responsibly wind down the gas network?](#), Energy Consumers Australia, 19 March 2025, accessed 27 March 2025.

563 AER, [Draft decision, Jemena Gas Networks \(NSW\) access arrangement 2025 to 2030 – Attachment 4 – Regulatory depreciation](#), Australian Energy Regulator, 29 November 2024, pp. 14–17.

Box 5.4 Accelerated depreciation – global perspective

The declining demand for gas is not unique to Australia. In July 2024, scientific journal Cell Press published a journal highlighting the issue of regulating gas transportation infrastructure in Europe. According to Cell Press:

‘... the era of widespread fossil gas consumption across Europe will also come to an end as the world decarbonises its energy use.’ ‘At the moment, regulation in most European countries treats gas distribution broadly as if they are expected to operate in perpetuity, though there are some exceptions.’ [As is the case in Australia, the declining demand for gas] ‘poses a significant challenge for policy makers: if fewer customers use gas, how is the decline of the system managed and who pays for it...?’

‘The Netherlands is making far-reaching changes via a combination of accelerated depreciation and local authority powers. In the current regulatory period (2022–26), distribution system operators are permitted to depreciate investments in their grids on a cost-reflective basis which recognises a shrinking grid. This is intended to align the costs with the actual use of the network, with connection points expected to decrease in the medium term. Furthermore, gas distribution system operators receive compensation for the costs of dismantling the gas distribution networks and for removing connection points. ... UK regulator Ofgem has consulted on future network regulation, which includes a proposal to accelerate financial depreciation rates and smooth their impacts in line with expected disconnection rates’.⁵⁶⁴

5.9 Rates of return

The shareholders and lenders that finance a gas pipeline service provider expect a return on their investment. The rate of return estimates the financial return a pipeline service provider’s financiers require to justify investing in the business. It is a weighted average of the expected returns needed to attract both equity and debt funding. Equity funding is provided by shareholders in exchange for part ownership of a pipeline service provider, while debt funding is provided by an external lender such as a bank. Given this weighted approach, the rate of return is sometimes called the weighted average cost of capital (WACC).

The AER sets an allowed rate of return based on a benchmark efficient entity, but a service provider’s actual returns can vary from the allowed rate. The difference can be due to several factors, such as the impact of incentive schemes, efficiency improvements, forecasting errors or the pipeline service provider adopting a different debt or tax structure to the benchmark efficient entity. Some differences may be temporary if caused by revenue over-recovery or under-recovery under a revenue cap or the revenue smoothing process. The AER calculates allowed returns each year by multiplying the capital base (section 5.8) by the allowed rate of return.⁵⁶⁵

Lower financing costs and updated estimates of rate of return parameters contributed to the average allowed rate of return declining from around 10% at the beginning of the 2010s, to less than 6% from 2018 (Figure 5.14). This reduction translated to significantly lower forecast pipeline revenue requirements.

Legislation introduced in 2018 provided for the AER to make binding rate of return determinations that apply to all regulated pipeline service providers.

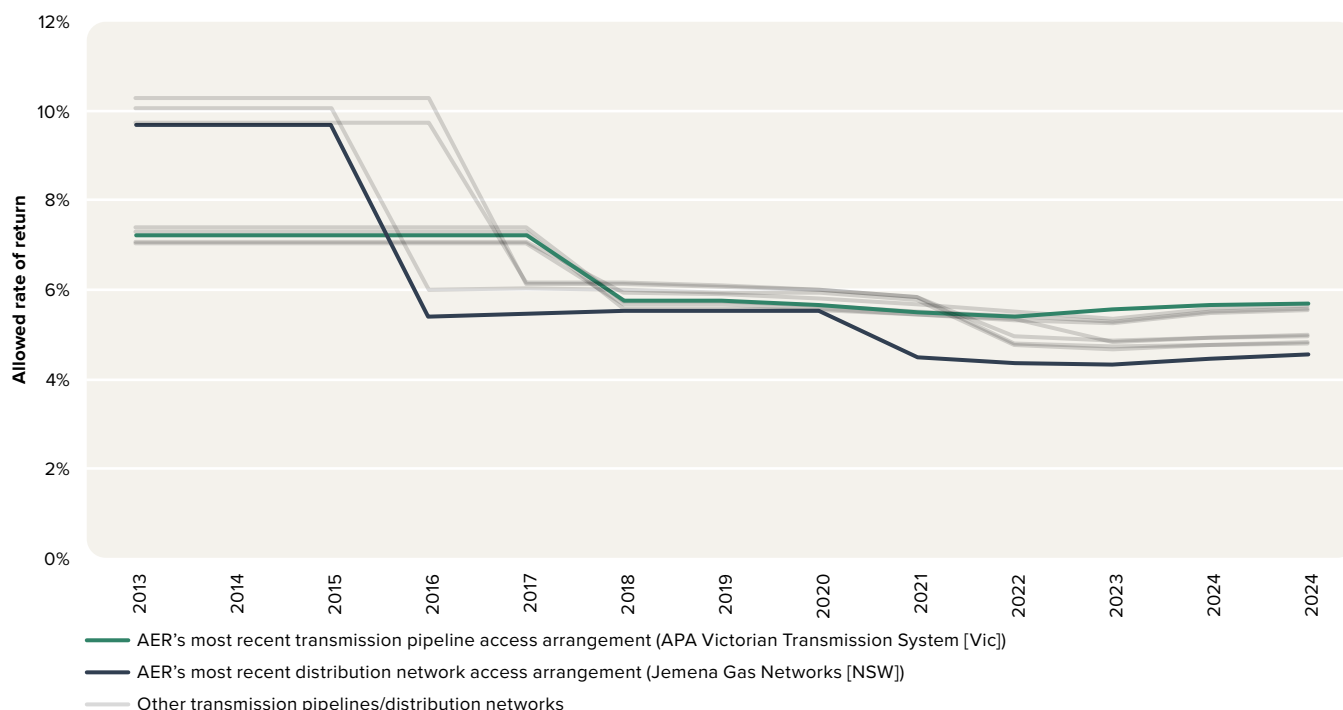
In February 2023, the AER released its latest rate of return instrument (the 2022 Instrument). The rate of return is a key component used to determine the amount of revenue network service providers can recover from customers. The AER sets the rate of return to cover the cost of capital of an efficient service provider.

⁵⁶⁴ Rosenow, et al., *The elephant in the room: How do we regulate gas transportation infrastructure as gas demand declines?*, One Earth, 19 July 2024 (purchased journal).

⁵⁶⁵ For example, if the rate of return is 5% and the capital base is \$10 billion, then the return to investors is \$500 million. This return forms part of a gas pipeline service provider’s revenue needs and must be paid for by customers.

In March 2024, the AER released an updated version of the February 2023 Instrument, which binds all access arrangements from 25 February 2023 until the next revision of the Instrument.⁵⁶⁶ In March 2025, as a first step toward making the 2026 Rate of Return Instrument, the AER published a paper setting out the high-level review process it will undertake to produce the Instrument.⁵⁶⁷

Figure 5.14 Allowed rate of return



Note: Allowed rate of return = nominal vanilla weighted average cost of capital (WACC).

Source: AER decisions on gas pipeline access arrangements; AER decision following the remittal by the Australian Competition Tribunal and Full Federal Court.

Recently, a key input into rates of return has increased. The risk-free rate is an important driver of allowed returns on equity and is estimated using required returns on Commonwealth Government Securities (CGSs), also known as Australian Government bonds. Since January 2020, annual yields on 10-year CGSs have ranged from 0.61% (March 2020) to 4.94% (November 2023). Over the 12-month period to 30 June 2025, annual yields on 10-year CGSs averaged around 4.29%.⁵⁶⁸

5.10 Capital expenditure

Capital expenditure (i.e. investment) requirements differ between the gas transmission and distribution sectors.

Investment in gas transmission typically involves large capital projects to expand existing pipelines (through compression, looping or extension) or constructing new infrastructure. Additionally, some transmission pipelines have been re-engineered for bidirectional flows to increase flexibility of transportation on those pipelines.

Investment in gas distribution mainly comprises augmentation (expansion) of existing systems to cope with new customer connections, such as for new housing estate developments. Older pipelines also require replacement programs for deteriorating infrastructure. For regulated service providers operating scheme pipelines (Table 5.1), the AER assesses whether investments are prudent and efficient based on criteria in the National Gas Rules.

⁵⁶⁶ AER, [Rate of Return Instrument 2022](#), Australian Energy Regulator, accessed 20 March 2025.

⁵⁶⁷ AER, [Rate of Return Instrument – 2026 review process paper](#), Australian Energy Regulator, 28 March 2025.

⁵⁶⁸ RBA, [Capital Market Yields – Government Bonds – Daily – F2](#), Reserve Bank of Australia, accessed 6 July 2025.

Long-term demand risk can influence the AER's regulatory decisions on pipeline investments. Demand forecasts that underpin the need for new investments are carefully scrutinised.

Regulated service providers will incur ongoing maintenance and replacement costs to maintain safe and reliable reference services for the remaining customers on the network, subject to any partial shutdowns of the network, for as long as the gas pipeline assets remain in use. The costs to maintain the gas pipeline do not decrease in proportion to the decline in gas demand, and if demand falls past a certain point, pipeline assets can become 'stranded', wherein they are prematurely written down, devalued or even reclassified as liabilities.⁵⁶⁹

5.10.1 Capital expenditure in 2024

Over the 12-month period to 30 June 2024, scheme pipeline service providers invested \$658 million in capital projects, \$172 million (21%) less than in the previous year and \$72 million (10%) less than was forecast.

Table 5.6 provides a breakdown of the amount of investment that scheme pipeline service providers undertook in 2024 and how this compared with previous years' expenditure and forecasts.

Table 5.6 Capital expenditure in 2024 – key outcomes

Service type	Capital expenditure (actual) (2024)	Capital expenditure (actual) (compared with 2023)	Capital expenditure (actual) (compared with peak)
Transmission	\$103 million (▲90% than forecast)	▼\$113 million (▼52%)	▼\$118 million (▼53%) (2022)
Distribution	\$555 million (▼18% than forecast)	▼\$59 million (▼10%)	▼\$223 million (▼29%) (2015)
Total	\$658 million (▼10% than forecast)	▼\$172 million (▼21%)	▼\$277 million (▼30%) (2015)

Note: All data are adjusted to June 2024 dollars.

Source: AER estimates.

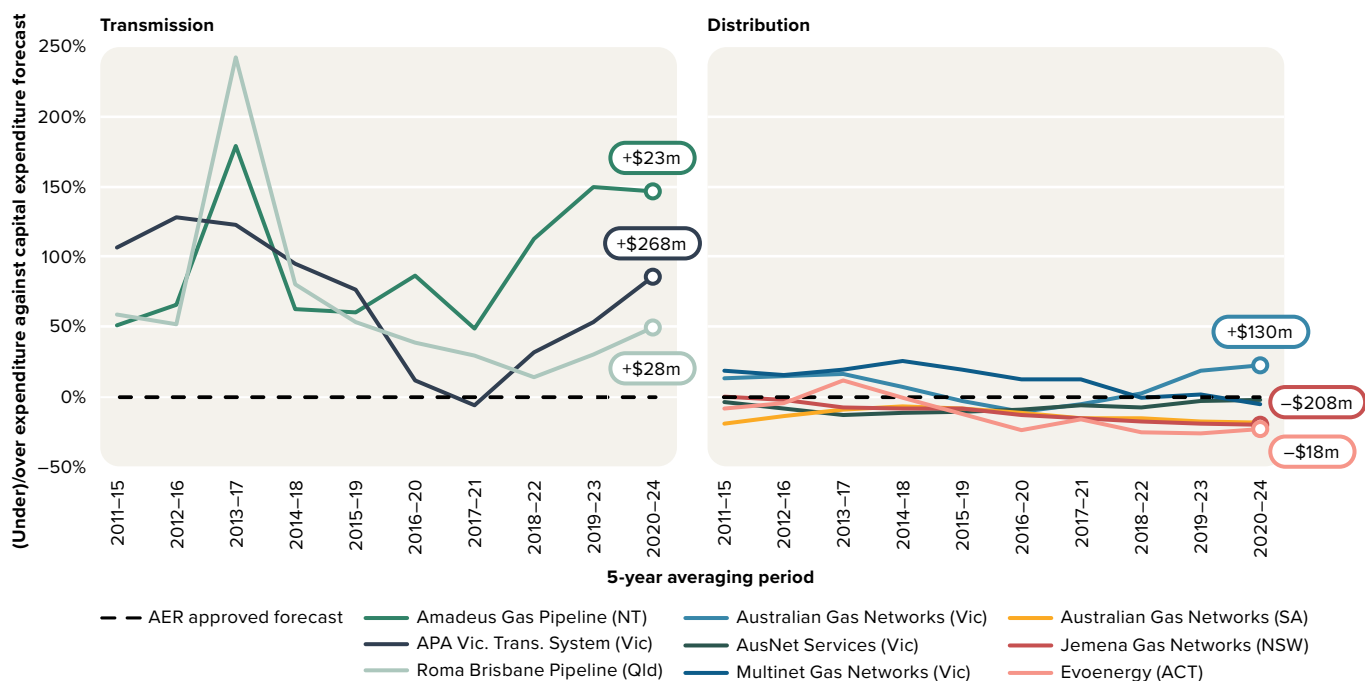
APA Victorian Transmission System (Victoria) reported a significant overspend on its Western Outer Ring Main (WORM) project in 2024. This was primarily due to construction delays resulting from several compounding factors, including delays obtaining a pipeline licence, delays awarding a construction contract, wet weather, constraints obtaining First Nations resources and a large cultural heritage discovery at one of the sites leading to a redesign. Much of the WORM project was forecast to be complete prior to 2024.⁵⁷⁰

Figure 5.15 shows the contrasting trends in actual capital expenditure against forecast for transmission and distribution pipeline service providers. While transmission scheme service providers continue to overspend against forecast, distribution scheme service providers continue to underspend. The size of both forecast and actual capital expenditure varies greatly among the different service providers. To address this, dollar values representing the size of the under/overspends have been shown in Figure 5.15 to demonstrate the scale of the under/overspend over the past 5 years for a selection of pipeline service providers.

569 Lucas Davis, Catherin Hausman, Energy Institute at Haas, [Who will pay for legacy utility costs?](#), March 2022, accessed 20 March 2025.

570 APA, Annual RIN reporting – VTS – RIN response and basis of preparation, APA VTS Australia (Operations), 29 April 2025.

Figure 5.15 Capital expenditure compared with AER approved forecasts



Note: The size and the scale of the forecast and actual capital expenditure differs for each transmission and distribution pipeline service provider.

Source: AER modelling; annual reporting RIN responses.

5.11 Operating expenditure

Pipeline service providers incur operating and maintenance costs that absorb around 38% of their annual revenue (35% for transmission and 38% for distribution) (Figure 5.6). When assessing the efficiency of a pipeline service provider's operating and maintenance costs, the AER considers cost drivers such as forecast customer growth, expected productivity improvements, changes in labour prices and changes in the regulatory environment. Pipeline service providers are also subject to an efficiency carryover mechanism, which incentivises them to reduce operating expenditures where efficient to do so.

5.11.1 Operating expenditure in 2024

Over the 12-month period to 30 June 2024, scheme pipeline service providers spent \$674 million on operating costs, \$31 million (5%) more than in the previous year, but \$61 million (8%) less than was forecast.

Table 5.7 provides a breakdown of scheme pipeline service providers' operating costs in 2024 and how this compared with previous years' expenditure and forecasts.

Table 5.7 Operating expenditure in 2024 – key outcomes

Service type	Operating expenditure (actual) (2024)	Operating expenditure (actual) (compared with 2023)	Operating expenditure (actual) (compared with peak)
Transmission	\$87 million (▲17% than forecast)	▼\$10 million (▼10%)	▼\$10 million (▼10%) (2023)
Distribution	\$588 million (▼11% than forecast)	▲\$40 million (▲7%)	2024 = peak
Total	\$674 million (▼8% than forecast)	▲\$31 million (▲5%)	2024 = peak

Note: All data are adjusted to June 2024 dollars.

Source: AER estimates.

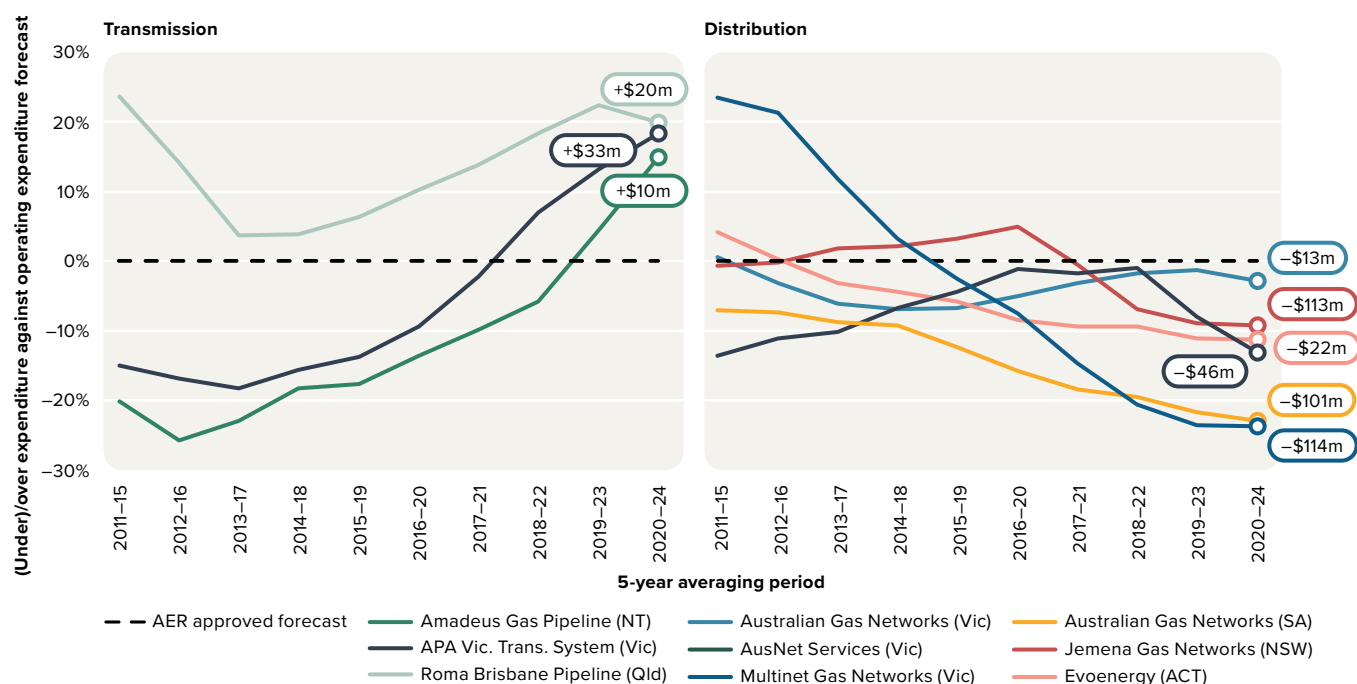
As was evident with the contrasting trends in capital expenditure against forecast, transmission and distribution pipeline service providers are also trending in different directions for their actual operating expenditure against forecast.

In each of the past 5 years, transmission service providers have collectively spent more than their approved forecasts. Conversely, distribution service providers have collectively spent less than their approved forecasts for 12 consecutive years.

In the 7 years since Multinet Gas Networks (Victoria) was purchased by CK Infrastructure Holdings, it has underspent by 23% against its operating expenditure forecast.⁵⁷¹ Likewise, in the 10 years since Australian Gas Networks (South Australia) was purchased by CK Infrastructure Holdings, it has underspent by 18% against its operating expenditure forecast.⁵⁷²

Unlike for capital expenditure, a pipeline service provider's operating expenditure is largely recurrent and predictable. As such, the scale of the under/overspends for operating expenditure is generally smaller than it is for capital expenditure. However, the size of both forecast and actual operating expenditure still varies greatly among the different service providers. To address this, dollar values representing the size of the under/overspends have been shown in Figure 5.16 to demonstrate the scale of the under/overspend over the past 5 years for each pipeline scheme service provider.

Figure 5.16 Operating expenditure compared with AER approved forecasts



Note: The size and the scale of the forecast and actual operating expenditure differs for each transmission and distribution pipeline service provider.
Source: AER modelling; annual reporting RIN responses.

571 Australian Financial Review, [FIRB approves Cheung Kong's DUET acquisition](#), 20 April 2017, accessed 20 March 2025.

572 Australian Gas Networks, [Australian Gas Networks – Our History](#), accessed 14 July 2025.



6 Retail energy markets and energy consumers

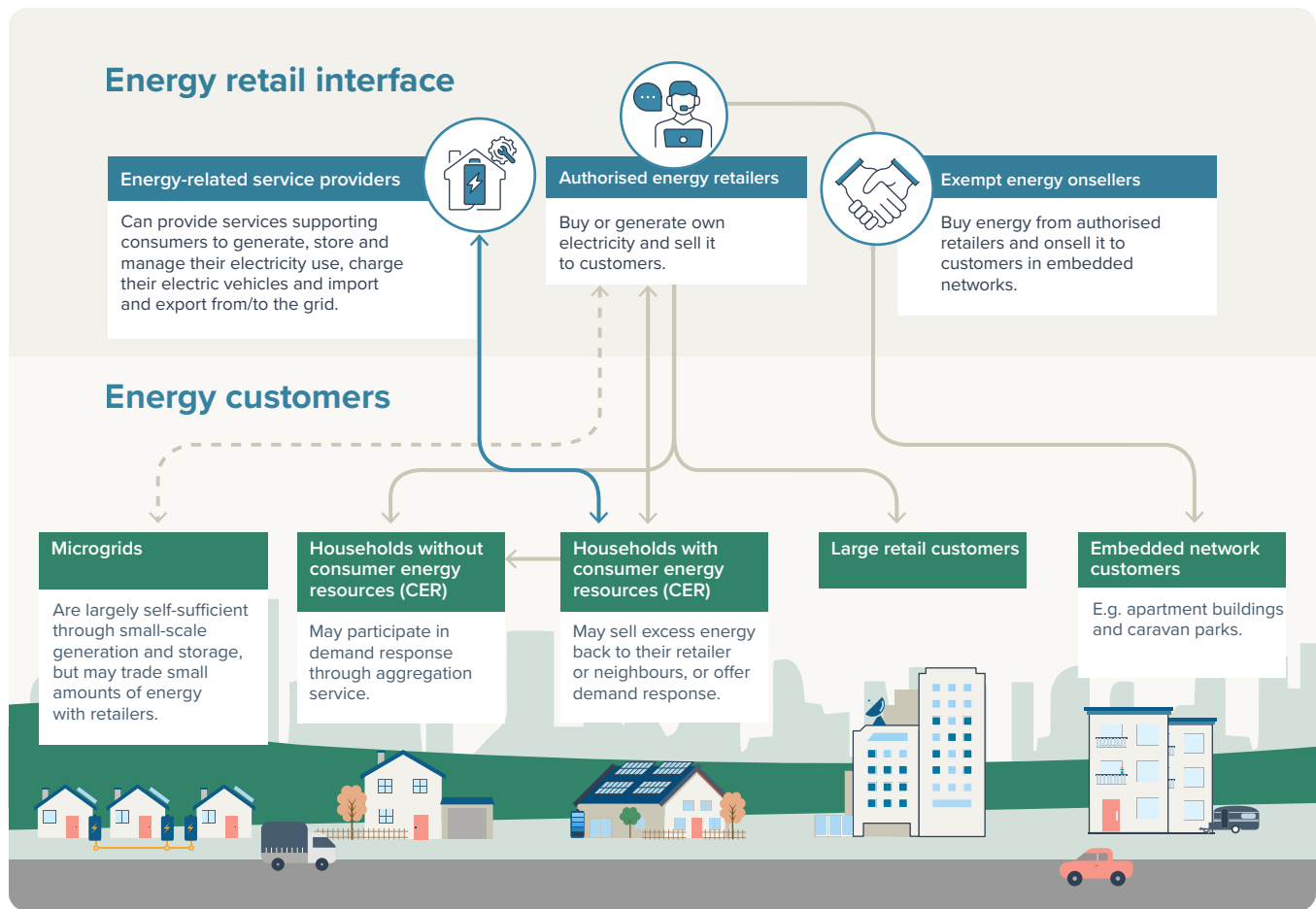
The retail markets are the final links in the energy supply chain, providing an interface for retailers and energy-related service providers to sell electricity, gas and energy services to residential and small business customers.⁵⁷³ Retailers purchase energy either through direct contracts with suppliers or from wholesale markets. The retailer then on sells the energy to its customers. In most areas of the National Electricity Market (NEM) where there is effective competition, consumers can choose their energy retailer based on the price and suitability of services offered (Figure 6.1).

The performance of the energy market is ultimately measured by the outcomes it achieves for energy consumers. This includes ensuring consumers have access to the energy they need, pay a fair amount for the energy they consume, can manage their energy consumption and make informed energy-related decisions.

Consumers have increasingly become producers of energy by installing rooftop solar. With the increase in use of home batteries and electric vehicles (EVs), they are now playing an increasing role in supplying the energy system.

⁵⁷³ Residential and small business customers (that consume energy at business premises below the upper consumption threshold) are considered 'small customers' under the National Energy Retail Law. The term 'small customers' is used throughout this report to refer to both residential and small business customers. Where required, the terms 'residential' and 'small business' are used separately.

Figure 6.1 Retail electricity market supply chain



This chapter focuses on the 5 jurisdictions where the AER has regulatory responsibilities – Queensland, New South Wales (NSW), South Australia, Tasmania and the Australian Capital Territory (ACT). Victoria, Western Australia and the Northern Territory apply separate regulatory arrangements and are not covered in this chapter except when data from these jurisdictions are included to provide insights into broader energy consumer issues or where it assists in comparative analysis between the NEM and other energy systems.

6.1 Snapshot

As at 31 March 2025:

- median electricity market offers for residential customers under a default market offer (DMO)⁵⁷⁴ price ranged from a 5% decrease (SA Power Networks [South Australia]) to a 4% increase (Energex [Queensland]) compared with 31 March 2024 (section 6.4.2)
- median electricity market offers for residential customers under a Victorian default offer (VDO)⁵⁷⁵ price ranged from a 5% decrease (Powercor) to a 0.3% increase (Jemena) compared with 31 March 2024 (section 6.4.2)
- median gas market offers for residential customers ranged from an 18% decrease (Australian Gas Networks [Queensland]) to a 3% increase (Australian Gas Networks [Victoria]) compared with 31 March 2024 (section 6.4.2).

Over the 12-month period to 31 March 2025:

- the number of residential energy customers on a payment plan decreased from 140,190 to 129,498 (down 8%) (section 6.8.2)
- the proportion of residential customers with energy debt⁵⁷⁶ (excluding customers on a hardship program) increased from 3.0% to 3.1% (section 6.8.1)
- the average debt per residential customer with energy debt increased from \$1,106 to \$1,415 (up 28%) (section 6.8.1)
- fewer customers received assistance through hardship programs; however, both the average level of hardship program debt and the average level of debt on entry to hardship programs increased (section 6.8.2)
- disconnection rates for non-payment remained low (around 0.06% of small electricity and/or gas customers); when disconnection did occur, the average customer debt levels at the time of disconnection were higher than in the previous year (section 6.8.3)
- 140,136 customer complaints were made to retailers, 19,940 (17%) more than were made in the previous 12 months – retailers attributed higher volumes of complaints to price increases, cost-of-living and affordability challenges, and the implementation and consolidation of their new retail customer service platforms (section 6.8.4).

After 18 months of extensive stakeholder consultation, the AER concluded that current protections for customers experiencing payment difficulty are not fit for purpose. In May 2025, the AER published the findings from its review of payment difficulty protections and identified 13 opportunities to improve the National Energy Customer Framework.⁵⁷⁷

On 19 June 2025, the Australian Energy Market Commission (AEMC) made a rule change⁵⁷⁸ seeking to increase support to people experiencing payment difficulty due to hardship. The rule change will require retailers to offer hardship customers a better offer if available or provide a financial benefit equivalent to the amount the customer would have saved if they had been on the better offer. The new protection comes into effect from 30 December 2026.⁵⁷⁹

574 The default market offer (DMO) is applied in the Energex (Queensland), Ausgrid (NSW), Endeavour Energy (NSW), Essential Energy (NSW) and SA Power Networks (South Australia) distribution zones.

575 The Victorian default offer (VDO) is applied in AusNet Services, CitiPower, Jemena, Powercor and United Energy distribution zones (Victoria).

576 Energy debt is defined as electricity and gas charges that are outstanding for 90 days or more.

577 AER, [Review of payment difficulty protections in the National Energy Customer Framework](#), Australian Energy Regulator, 15 May 2025.

578 In August 2024, the Hon. Chris Bowen MP, Minister for Climate Change and Energy submitted, on behalf of the Energy and Climate Change Ministerial Council, a rule change request to the AEMC seeking to amend the National Energy Retail Rules to incorporate the [game changer reforms](#).

579 AEMC, [Assisting hardship customers](#), Australian Energy Market Commission, 19 June 2025, accessed 14 July 2025.

6.2 Retail energy market regulation

The National Energy Customer Framework and the Energy Retail Code of Practice (Victoria) regulate the sale and supply of electricity and gas to retail customers.

The National Energy Retail Law sets out protections for residential consumers,⁵⁸⁰ operating alongside the Australian Consumer Law to protect residential and small business customers in their electricity and gas supply arrangements. Victoria does not apply the national framework but applies similar regulatory provisions.⁵⁸¹

The National Energy Retail Law and equivalent arrangements in Victoria focus on consumer protections related to the traditional retailer–customer relationship in buying electricity and gas. Protections are generally stronger for consumers supplied through an authorised retailer than consumers supplied via an embedded network⁵⁸² or entering solar power purchase agreements.⁵⁸³

The AER is responsible for regulating retail energy markets in Queensland, NSW, South Australia, Tasmania (electricity customers only) and the ACT. In Victoria, the AER only regulates electricity connections for retail customers. The AER's key responsibilities include:

- maintaining an energy price comparator website⁵⁸⁴ to help residential and small business customers understand the range of offers in the market, make better choices about those offers and be aware of their rights and responsibilities when dealing with energy providers
- assessing applications from businesses looking to become energy retailers and granting exemptions from the requirement to hold a retailer authorisation
- administering a retailer of last resort scheme, which protects customers and the market if an energy retailer fails (in Victoria the Essential Services Commission (ESC) initiates the Retailer of Last Resort process in the event of retailer failure and the AER is responsible for its administration)
- developing guidance notes for energy retail markets
- monitoring and enforcing compliance (by retailers, exempt sellers and distribution network service providers) with obligations in the National Energy Retail Law, Rules and Regulations
- approving policies energy retailers must implement to assist customers who are facing financial hardship and looking for help to manage their bills
- monitoring the NEM and reporting on the performance of the retail markets and energy businesses, including information on trends in energy affordability and customers experiencing hardship.

Since 1 July 2019, the AER has also been responsible for determining the default market offer (DMO) electricity price, a 'safety net' protecting consumers from unjustifiably high prices, while also allowing retailers to recover costs. The DMO represents the maximum price an electricity retailer can charge standing offer customers in South East Queensland, NSW and South Australia.⁵⁸⁵ The DMO price also acts as a 'reference price' for all other market offers in each applicable distribution region. DMO prices are designed to aid consumers to compare energy plans across different providers. Jurisdictional regulators regulate electricity prices in regional Queensland, Victoria, Tasmania and the ACT.⁵⁸⁶

580 The thresholds for who meets the criteria of residential or small business customer vary between jurisdictions.

581 Changes to the Victorian framework, including recommendations adopted from the [Thwaites Independent review into the electricity and gas retail markets in Victoria \(August 2017\)](#), have resulted in greater divergence between the Victorian and national frameworks.

582 Embedded networks are smaller, localised private networks that distribute energy to sites such as apartment blocks, retirement villages, caravan parks and shopping centres. They operate alongside major distribution networks under a similar, but different, regulatory framework.

583 A solar power purchase agreement is a contract where a business provides, installs and maintains the solar panels in exchange for the consumer agreeing to buy the energy produced by the system at an agreed price for an agreed period.

584 [Energy Made Easy](#) is a free, independent government service that enables consumers to compare different energy retailers and choose the best plan for them.

585 Standing offers are intended to provide a level of protection to customers who have not engaged, or cannot engage, in the retail electricity market.

586 These include the Queensland Competition Authority (QCA) in regional Queensland, Essential Services Commission (ESC) in Victoria, Office of the Tasmanian Economic Regulator (OTTER) in Tasmania and the Independent Commission and Regulatory Commission (ICRC) in the ACT.

6.3 Energy bills

Energy bills are the main channel that retailers use to communicate with their customers. Energy bills show a customer's energy consumption over a period of time, tariffs, daily supply charges and other fees and discounts. Information on bills can enable consumers to compare their current offer with other offers available to them.

Independent comparator websites provided by the AER and the Essential Services Commission (Victoria)⁵⁸⁷ enable consumers to compare available plans in the market. Consumers can access their usage data – a key input for the comparator websites – directly from the Australian Energy Market Operator (AEMO) (Box 6.1).

Every retailer must have a standing offer and customers have the right to ask for one. However, for those customers with an existing electricity connection, only their existing retailer is obliged to supply them on these standing offer terms. Customers seeking a standing offer can make that request of their existing retailer, knowing it will be met and that they will be protected by the DMO price cap. Retailers must ensure they comply with this obligation. Standing offers are usually more expensive than a market offer. Customers may be on standing offers because they have never switched, have moved house without setting up an energy plan or because they wish to take advantage of the safety net contract terms and DMO prices.

In contrast, retailers set the terms and conditions for market offers. Discounts and other incentives may apply and market offers are typically more competitive. Market offers are priced in comparison to a reference price in DMO and VDO regions and it is not uncommon for a retailer to offer large discounts off the regulated reference price to attract customers onto market contracts. On 1 July 2025, the AEMC announced a rule change that restricts retailers from increasing prices in market retail contracts more than once every 12 months.⁵⁸⁸

The AER's retail guidelines provide instructions for how energy retailers are expected to communicate with their customers about their current offer:

- The Better Bills Guideline sets out how energy retailers must prepare and issue bills to make it easy for small customers to understand and use their bills, including to compare their plan with others on the market.
- The Benefit Change Notice Guidelines provide retailers with requirements for when they are notifying customers that a benefit under their market retail contract is ending or changing.
- The Retail Pricing Information Guidelines provide guidance to retailers on how standing and market offer prices are presented to customers and are intended to assist customers to consider and compare standing and market offers.

⁵⁸⁷ Victorian Government, [Victorian Energy Compare](#), Department of Energy, Environment and Climate Action, 18 July 2025.

⁵⁸⁸ The rule does not restrict price changes that are a direct result of a tariff reassignment by the distributor, changes to tariffs, charges or energy payments that continually vary in relation to the prevailing spot price of energy. The rule applies to any tariffs, charges or payments within the same contract that are not linked to the prevailing spot price of energy. Customers on standard retail contracts will continue to have a maximum of 2 price increases permitted per year under the Retail Law.

6.3.1 Components of an electricity bill

Retail electricity bills largely reflect the cost of producing and supplying electricity. Table 6.1 provides an overview of the key components that contribute to a typical residential electricity retail bill.

Table 6.1 Key components of a residential electricity bill

Cost component	Cost description
Wholesale	Retailers generally charge their customers fixed prices for electricity despite purchasing the electricity at variable prices in the wholesale market. Retailers are exposed to price risk, where they may need to purchase electricity at higher prices than they have agreed to charge their customers. Retailers manage price risk by considering price volatility when setting retail contract prices and by entering into hedge contracts that lock in future wholesale prices for the future.⁵⁸⁹ Some retailers also own generation assets or enter into demand response contracts to manage risk. Wholesale costs contribute between 33% and 41% of DMO 7 prices that apply in 2025–26.
Network	The AER regulates network charges, which cover the efficient costs of building and operating electricity networks and provide a return to the network service provider's equity holders (chapter 3). Network costs comprise around 33% to 48% of DMO 7 prices for 2025–26.
Environmental	These are costs associated with environmental schemes at both national and state levels, such as: • Large-scale Renewable Energy Target (LRET), which provides a financial incentive to encourage investment in large-scale renewable energy generation projects • Small-scale Renewable Energy Scheme (SRES), which provides incentives to households and businesses to invest in small-scale renewable energy systems • jurisdictional green schemes, such as state and territory-based energy efficiency improvements for households and businesses, rebates for customer energy resources and feed-in tariffs for rooftop solar. Most environmental costs relate to complying with the LRET and SRES. These costs are incurred by retailers and passed on to customers. Environmental costs account for 3% to 4% of DMO 7 prices.
Retail	Retail costs include costs of servicing customers, such as: • managing billing systems and bad and doubtful debt⁵⁹⁰ • handling customer enquiries • complying with regulatory obligations • replacing infrastructure such as upgrading meters (smart meters). They also include customer acquisition and retention costs, such as marketing and other activities to gain or retain customers. Retail costs account for around 11% to 16% of DMO prices for residential customers and 6% to 9% for small business customers.

⁵⁸⁹ Retailers are exposed to financial risk through spot price volatility in wholesale electricity and gas markets. Most retailers manage this financial risk by purchasing hedging contracts that limit part, or all, of the wholesale price they pay. Hedging contracts enable retailers to offer stable prices to consumers, allowing for more predictable energy bills and protecting customers from bearing the risk of potentially volatile wholesale energy prices.

⁵⁹⁰ Bad and doubtful debt are instances where customers are not expected to pay their electricity debt.

6.3.2 Components of a gas bill

The composition of a retail gas bill is less transparent than it is for electricity due to the relative fragmentation of gas markets, the different regulatory arrangements applying to gas pipelines and the absence of a regulatory responsibility to periodically analyse the different cost components.

Table 6.2 provides an overview of the key elements that contribute to the cost of a typical residential gas retail bill.

Table 6.2 Key components of a residential gas bill

Cost component	Cost description
Wholesale	Retailers purchase wholesale gas to sell to residential customers. The bulk of this is purchased through contracts, generally with terms of around 1 to 2 years, while approximately 10% to 15% is purchased through Short Term Trading Markets (Chapter 4, section 4.2). Purchasing gas through contracts minimises the need to settle gas prices through volatile wholesale gas markets. Wholesale costs can account for approximately 20% to 40% of a customer's bill depending on region and network expenditure.
Network	Network costs include the costs to operate, upgrade and maintain gas distribution networks that supply homes. Networks, or gas pipelines, are regulated as 'scheme' or 'non-scheme pipelines' (Chapter 5, Box 5.2). The AER is responsible for determining the form of regulation that applies to a gas pipeline, with a key objective to promote investment in and efficient operation of gas services in the long-term interests of consumers (Chapter 5, section 5.4). Distribution network costs are usually the largest component of a customer's gas bill, ranging between 23% and 54%.⁵⁹¹ However, this can vary significantly over time depending on factors such as the level of peak demand, which is a key driver of investment, and operating and maintenance costs.⁵⁹²
Retail	Retail costs include costs of servicing customers, such as: • managing billing systems and debt • handling customer enquiries • complying with regulatory obligations. They also include customer acquisition and retention costs, such as marketing and other activities to gain or retain customers. Retail costs make up the remainder of residential customers' bills, at around 20%, on average, depending on the quantum of wholesale and network costs and other factors.⁵⁹³

6.4 How retail energy prices are set

Energy retailers in the NEM offer a range of market offers. Market offers are energy contracts advertised by retailers that are entered into by customers. Alongside market pricing, government agencies regulate prices for electricity standing offers. Standing offers are contracts that customers are placed on by default if they do not enter into a market offer. A customer might be on a standing offer when their market offer expires or if they have never switched to a retailer's market offer.

Governments have implemented electricity price control mechanisms for customers on standing offers. Table 6.3 provides an overview of these mechanisms and the responsible administrator.

Gas prices are deregulated and set by the market in each region.

⁵⁹¹ This information has been calculated from the indicative bill impact information submitted by gas DNSPs in their most recent access arrangement proposals.

⁵⁹² Australian Government, [Network service charges](#), Department of Climate Change, Energy, the Environment and Water, accessed 4 August 2025.

⁵⁹³ Oakley Greenwood, [Gas price trends review 2017](#), 29 January 2018.

Table 6.3 Standing offer electricity price control mechanisms

Region	Mechanism	Administrator	Approach
South East Queensland	Default market offer (DMO)	AER	Sets a cap on standing offer electricity prices for residential and small business customers and provides a reference price for comparing offers.
New South Wales			
South Australia			
Victoria	Victorian default offer (VDO)	Essential Services Commission (ESC)	Sets a cap on standing offer electricity prices for residential and small business customers and provides a reference price for comparing offers.
Regional Queensland	Annual pricing proposal and government subsidy	AER / Queensland Competition Authority (QCA)	Determines an annual regulated electricity price for residential and small business customers. The Queensland Government then subsidises Ergon Energy for the difference between the regulated price and the price customers are charged so that regional customers do not pay more than customers in South East Queensland.
Tasmania	Standing offer price approvals	Office of the Tasmanian Economic Regulator (OTTER)	Sets a cap on standing offer electricity prices for residential and small business customers with a regulated retailer and provides a reference point for comparing offers.
ACT	Price regulation of electricity supply	Independent Competition and Regulatory Commission (ICRC)	Sets a cap on electricity prices for residential and small business customers who buy electricity from the original monopoly energy provider, now authorised retailer, ActewAGL and provides a reference point for customers of other retailers to compare offers.

Source: AER, [Default market offer prices 2025–26 – Final determination](#), Australian Energy Regulator, 26 May 2025; ESC, [Victorian Default Offer](#), Essential Services Commission, accessed 1 May 2025; QCA, [Regulated electricity prices for regional Queensland 2025–26](#), Queensland Competition Authority, accessed 1 May 2025; OTTER, [2025 Standing Offer Investigation and Determination](#), Office of the Tasmanian Economic Regulator, accessed 1 May 2025; ICRC, [Price Regulation of Electricity Supply](#), Independent Competition and Regulatory Commission, accessed 1 May 2025.

6.4.1 Default market offer

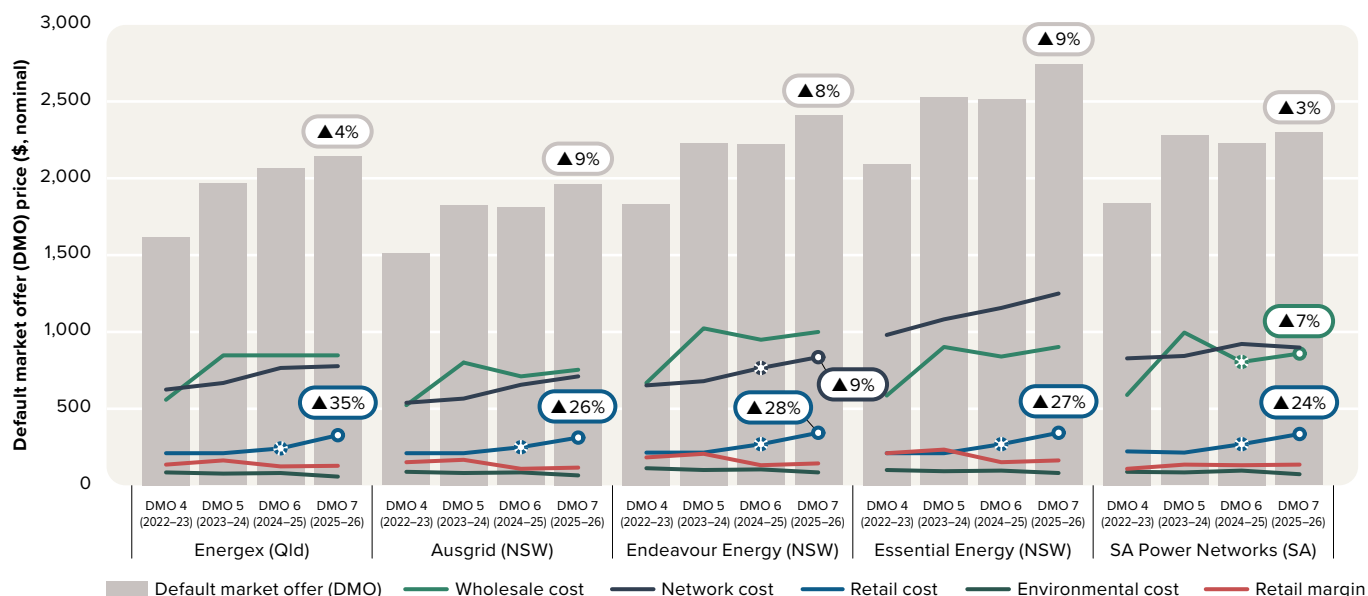
DMO prices across all regions have increased over the past 4 years. From DMO 4 (2022–23) to DMO 5 (2023–24), price increases were largely due to increases in wholesale costs. From DMO 5 (2023–24) to DMO 6 (2024–25), decreases in wholesale costs – driven by downward movements in most contract prices – were partly offset by increases in network costs.

On 26 May 2025, the AER published its DMO 7 determination, which took effect from 1 July 2025. From DMO 6 (2024–25) to DMO 7 (2025–26), prices increased across all regions – driven by:

- increases in retail costs, including bad and doubtful debts and the costs associated with the implementation of smart meters
- increases in network costs resulting from a range of factors, including higher actual inflation and interest rates causing a higher return on capital (chapter 3, section 3.5.2)
- upward movements in contract prices that retailers use to manage their exposure to wholesale spot market outcomes.

Figure 6.2 illustrates the relative contribution each cost component has had in the calculation of the DMO over the past 4 years for residential customers without controlled load.

Figure 6.2 Cost components of the default market offer for residential customers without controlled load



Note: Comparison of DMO cost components for residential customers without controlled load. Prices include GST. Values are nominal. The methodology to calculate the retail margin was adjusted in DMO 6 and is not directly comparable to prior years.

Source: AER, *Default market offer prices 2025–26*, 26 May 2025.

6.4.2 Recent activity in retail electricity prices

To analyse what customers are paying for their energy, new retailer market and standard offers are compared over time to provide insight into relative price movements. The analysis does not show what customers are paying on their existing plans.

As at 31 March 2025:

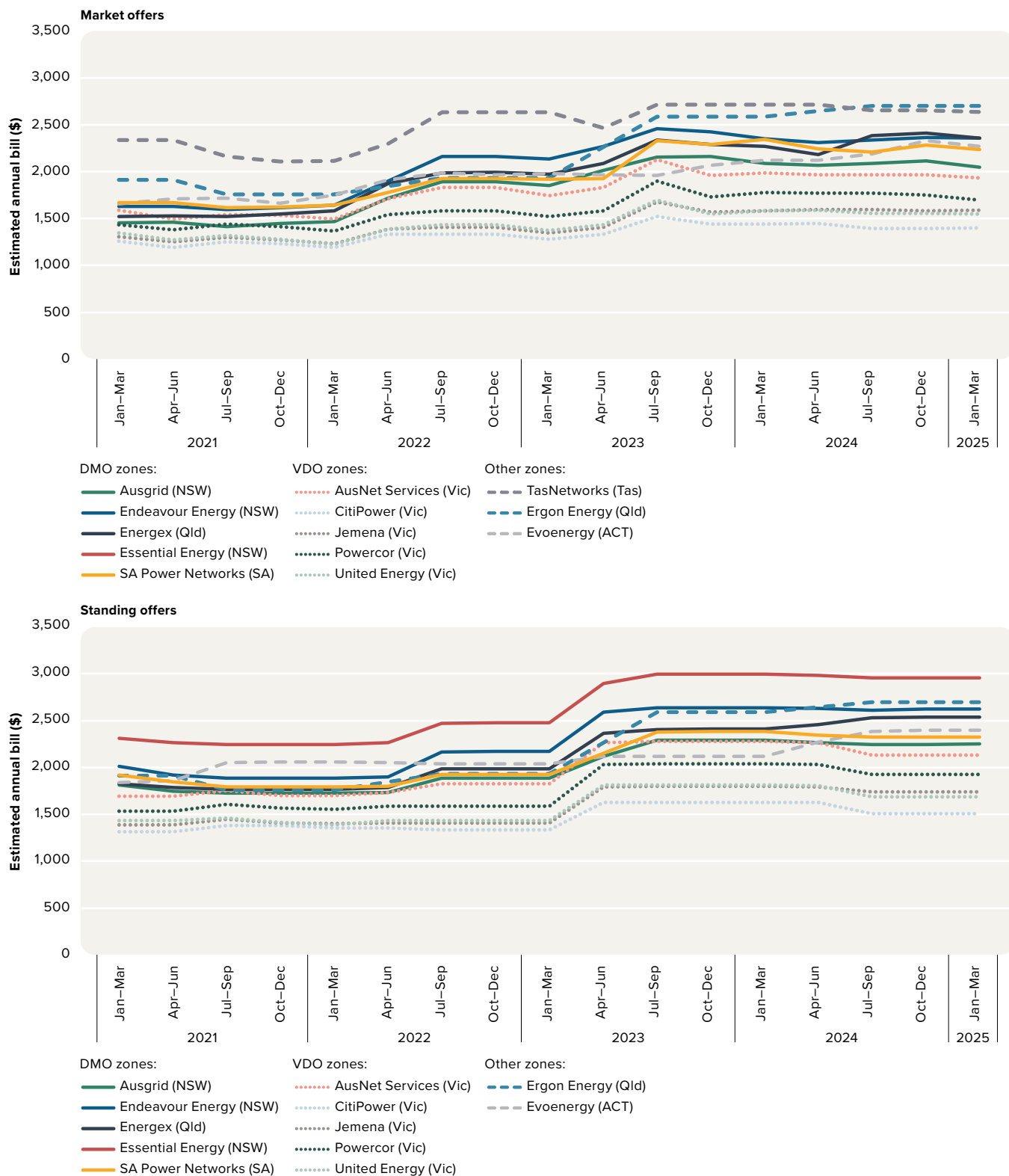
- across all regions, the estimated annual electricity bill for residential customers on median standing offers ranged between 4% and 13% higher than for those on median market offers⁵⁹⁴ (Figure 6.3)
- estimated annual electricity bills for residential customers within the Victorian default offer (VDO)⁵⁹⁵ region are historically lower compared with residential customers in default market offer (DMO)⁵⁹⁶ and other regions because electricity consumption is lower in Victoria due to a higher penetration of gas
- median market offers for residential customers under a DMO price ranged from a 5% decrease (SA Power Networks [South Australia]) to a 4% increase (Energen [Queensland]) compared with 31 March 2024 (Figure 6.3)
- median market offers for residential customers under a VDO price ranged from a 5% decrease (Powercor) to a 0.3% increase (Jemena) compared with 31 March 2024 (Figure 6.3)
- the gap between median market offers and median standing offers was narrower than at 31 March 2024.

⁵⁹⁴ There may be some customers on older market offers paying more than the standard contract. The median standard offer has not been included for the Ergon Energy distribution region as most residential customers in this region are on a regulated offer.

⁵⁹⁵ The Victorian default offer (VDO) is applied in AusNet Services, CitiPower, Jemena, Powercor and United Energy distribution zones (Victoria).

⁵⁹⁶ The default market offer (DMO) is applied in the Energen (Queensland), Ausgrid (NSW), Endeavour Energy (NSW), Essential Energy (NSW) and SA Power Networks (South Australia) distribution zones.

Figure 6.3 Estimated electricity bills for residential customers on median market and median standing offers



Note: Prices shown as at the end of the stated period – for example, Jan–Mar is price at 31 March. Default market offer (DMO) applies to electricity retailers in the Energex (Queensland), Ausgrid (NSW), Endeavour Energy (NSW), Essential Energy (NSW) and SA Power Networks (South Australia) distribution zones. Victorian default offer (VDO) applies to electricity retailers in the AusNet Services, CitiPower, Jemena, Powercor and United Energy distribution zones (Victoria). Other distribution zones includes Ergon Energy (Queensland), TasNetworks (Tasmania) and Evoenergy (ACT). Based on single rate offers for residential customers and average consumption in each distribution area. Average consumption for 2023–24 has been applied to all periods. In regions where consumption is typically higher, such as regional NSW (Essential Energy), the average estimated cost is typically higher compared to estimated costs in metropolitan networks. Some offers listed may not be available to all customers in a distribution zone. TasNetworks' standing offer is not included. Values are nominal.

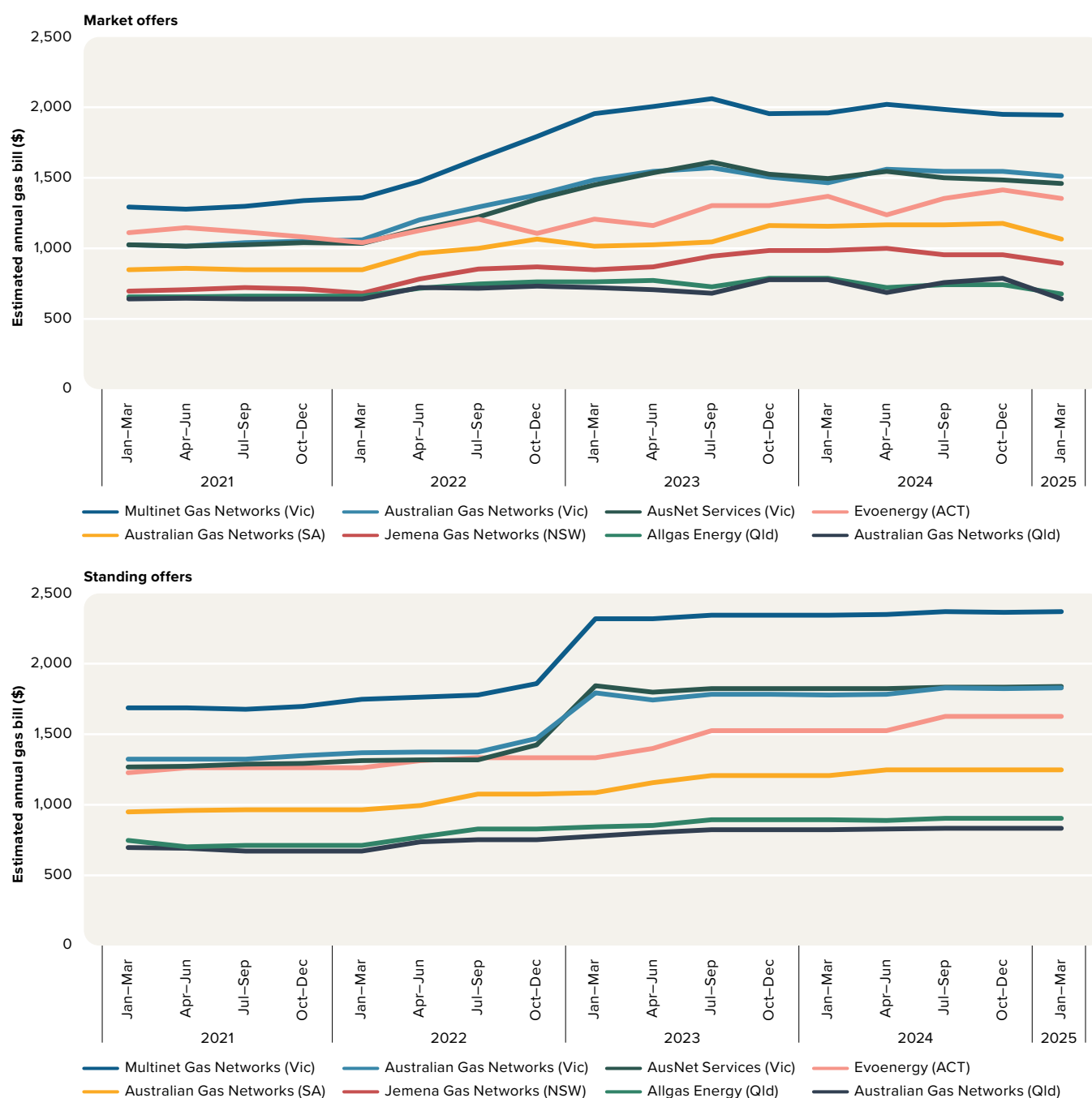
Source: AER analysis using offer data from Energy Made Easy (AER) and Victorian Energy Compare (Department of Energy, Environment and Climate Action). Consumption based on Economic benchmarking regulatory information notice (RIN) responses.

6.4.3 Recent activity in retail gas prices

At 31 March 2025:

- across all regions, the estimated annual gas bill for residential customers on median standing offers was higher than for those on median market offers, which ranged from 17% in Australian Gas Networks (South Australia) to 34% in Allgas Energy (Queensland) (Figure 6.4)
- median gas market offers for residential customers ranged from an 18% decrease (Australian Gas Networks [Queensland]) to a 3% increase (Australian Gas Networks [Victoria]) compared with 31 March 2024 (Figure 6.4)
- the gap between median market offers and median standing offers was, on average, marginally narrower compared with 31 March 2024.

Figure 6.4 Estimated gas bills for residential customers on median market and median standing offers



Note: Based on offers for residential customers and estimated consumption in each jurisdiction. Values are nominal.

Source: AER analysis using offer data from Energy Made Easy (AER) and Victorian Energy Compare (Department of Energy, Environment and Climate Action). Consumption based on Economic benchmarking regulatory information notice (RIN) responses.

6.5 Competition in retail energy markets

Competition in retail energy markets is designed to stimulate innovation and ensure better quality, lower cost products and services for consumers. The AER's role in delivering consumer protections – such as monitoring and reporting on market performance, enforcement and compliance activities, provision of price comparison services, setting the default market offer reference price and regulating monopoly infrastructure.

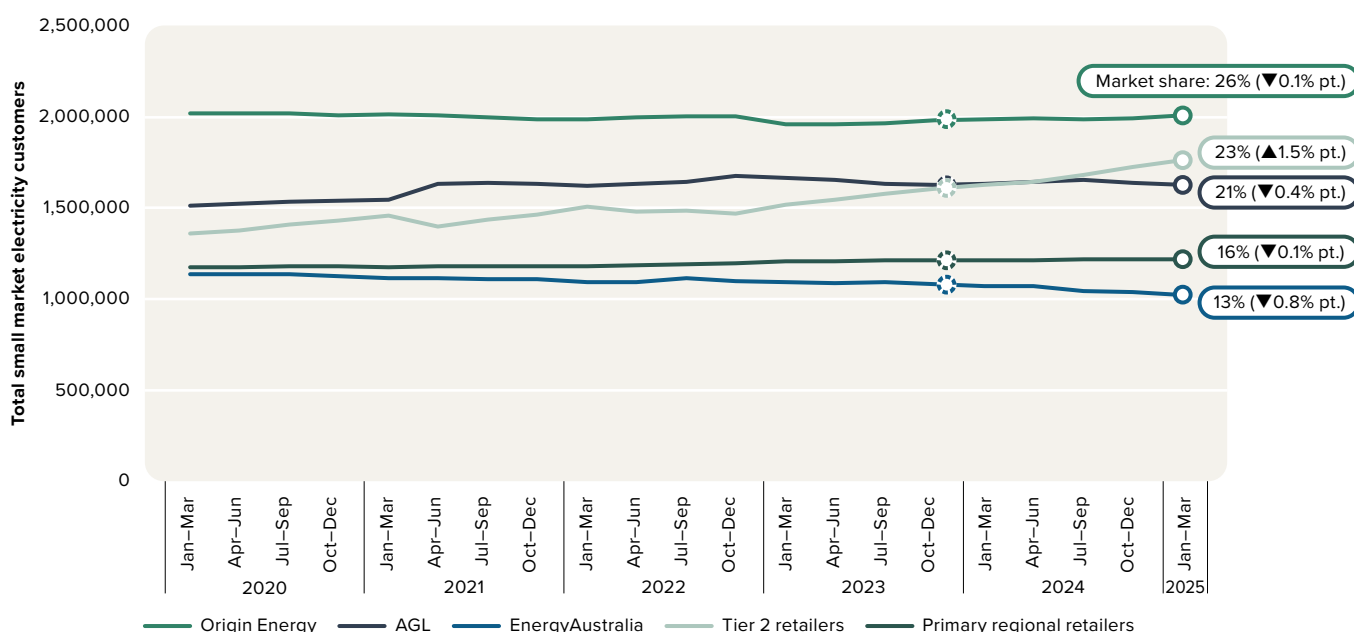
The level of market concentration and customer participation and engagement in the market provide a means of assessing the level of competition in the retail energy markets.

6.5.1 Market concentration

Origin Energy, AGL and EnergyAustralia are the largest energy retailers in the NEM. These 3 retailers collectively serve around 61% of small electricity customers (Figure 6.5) and around 77% of small gas customers (Figure 6.6).

However, the continued growth in market share of Tier 2 retailers demonstrates that Origin Energy, AGL and EnergyAustralia are subject to some competitive pressure in the retail energy market.

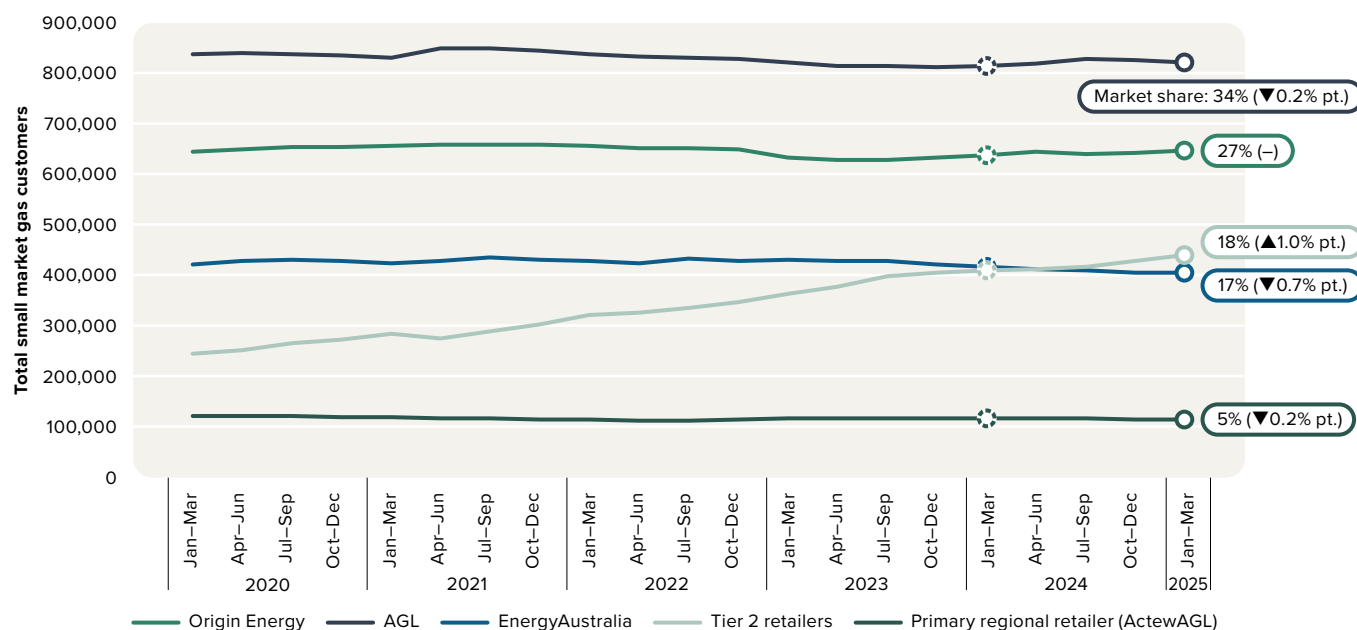
Figure 6.5 Customer numbers – small electricity customers



Note: All data as at 31 March 2025. Data includes customers in Queensland, NSW, South Australia, Tasmania and the ACT. Primary regional retailers include government-owned retailers – Ergon Energy (Queensland), Aurora Energy (Tasmania) and ActewAGL (ACT).

Source: AER, *Retail markets quarterly*, Q3 2024–25, June 2025.

Figure 6.6 Customer numbers – small gas customers



Note: All data as at 31 March 2025. Data includes customers in Queensland, NSW, South Australia and the ACT.

Source: AER, *Retail markets quarterly*, Q3 2024–25, June 2025.

Over the last few years many of the new retailers authorised to sell energy into the market have sought to differentiate themselves through innovative business practices and product offerings, including:

- leasing batteries and solar, making renewable technology accessible to customers that cannot afford upfront costs of renewables
- bundling batteries and solar with energy plans, providing convenience to customers looking to purchase consumer energy resources – these offers can subsidise or amortise the upfront cost of batteries and solar through usage charges
- virtual power plant plans, where the retailer uses batteries to arbitrage energy prices (charging when electricity is cheap or negatively priced, discharging when electricity is expensive), contributing to the stabilisation of the grid – revenue from these activities can subsidise the energy costs for the consumer
- peer-to-peer community trading, where customers with excess solar generation or battery storage can trade with other members of their community.

The AER is particularly interested in new products that deliver benefit to consumers and the wider energy market and has signalled a new approach to testing and trialling new ideas in the energy market with the introduction of policy-led sandboxing.⁵⁹⁷ This is intended to help explore new ways of accelerating access to, and deployment and orchestration of, new energy resources, such as community batteries, electric vehicles and rooftop solar.

597 AER, [Innovative trials welcomed as AER introduces policy-led sandboxing approach](#), Australian Energy Regulator, 13 February 2025, accessed 21 March 2025.

6.5.2 Market participation

Competition in the retail energy market is intended to drive customer participation by offering a wider range of products and prices to meet differing customer preferences and demands. To remain on the best possible plan, customers need to regularly review, compare, renegotiate or switch market contracts to maintain the best product offering. This requires a reasonable level of ‘energy literacy’ – that is, the ability to navigate through comparative pricing websites such as Energy Made Easy⁵⁹⁸ to identify the best possible product to suit individual consumers’ requirements (Box 6.1).

In December 2024, the ACCC reported that customers who can regularly switch between market contracts can save on energy costs by accessing the best available offer and discounts designed to attract new customers.⁵⁹⁹ The ACCC found that customers on older offers were paying more than those on newer offers across all offer types. For all regions combined, and when compared with similar types of offers, customers on older offers were paying prices that were:

- 11.7% higher on flat rate offers
- 11.8% higher on time of use offers
- 6.3% higher on flat rate offers with a demand charge
- 4.3% higher on time of use offers with a demand charge.⁶⁰⁰

Box 6.1 Price comparison websites

The variety of product structures, discounts and other inducements can make it difficult for energy customers to compare retail offers. Due to the fundamental role shopping around has in delivering savings to consumers, some customers use comparator websites to manage the complexity and range of offers in the market.

We operate an independent online price comparator [Energy Made Easy](#) to help small customers compare market offers. The website shows all generally available offers and has a benchmarking tool that allows consumers to compare their electricity use with similar-sized households in their area. It also allows consumers to enter their household-specific National Meter Identifier (NMI) to identify more personalised energy offers. The website is available to consumers in jurisdictions that have implemented the National Energy Retail Law (Queensland, NSW, South Australia, Tasmania and the ACT). The Victorian Government operates a similar online price comparator, [Victorian Energy Compare](#).

Comparison websites and brokers can provide consumers with a quick and easy way of engaging in the market, but some services may not provide customers with the best outcomes. For example, commercial comparator websites may only show offers of retailers affiliated with the site. Commercial comparators also typically require retailers to pay a commission per customer acquired or a subscription fee to have their offers shown. These arrangements are opaque to the customer. Commissions may vary across listed retailers, creating incentives for websites to promote offers that will most benefit the comparator business rather than show the cheapest offer for the customer. Government-operated comparison sites avoid this bias by listing all generally available offers in the market.

598 AER, [Energy Made Easy](#), Australian Energy Regulator, accessed 18 July 2025.

599 ACCC, [Inquiry into the National Electricity Market – December 2024 report](#), Australian Competition and Consumer Commission, 30 December 2024.

600 ‘Older offers’ include offers that were in the ACCC’s dataset at 1 August 2023 and ‘newer offers’ refer to offers in the ACCC’s dataset at 1 August 2024. See ACCC, [Inquiry into the National Electricity Market – December 2024 report](#), Australian Competition and Consumer Commission, 30 December 2024.

6.6 Energy market reforms to assist consumers

In December 2022, the Australian Government partnered with states and territories to launch the Energy Price Relief Plan to help mitigate both cost-of-living challenges and high price events.⁶⁰¹ Measures under the plan included temporary and ongoing coal and gas price caps, an investment scheme to unlock investment in clean dispatchable capacity to support reliability and moderate the risk of future price shocks, and an Energy Bill Relief Fund to provide targeted energy bill relief for residential and small business customers to improve energy affordability.

The Australian Government announced a \$1.8 billion, 6-month extension of the Energy Bill Relief Fund in its 2025–26 Budget. Australian households and eligible small businesses with electricity bills may receive up to \$150 in energy bill rebates from 1 July 2025 to the end of 2025.⁶⁰²

This builds on the government’s existing \$3.5 billion energy bill relief rolled out in the 2024–25 financial year. Under the 2024–25 program, households were eligible for up to \$300 of energy bill relief and eligible small businesses may have received up to \$325.

In addition, other concessions are available including:

- The Queensland Government offered a \$1,000 Cost-of-Living Rebate to households in 2024–25, along with other targeted concessions.⁶⁰³
- The NSW Government offers several rebates to help eligible households pay their electricity and gas bills.⁶⁰⁴
- The South Australian Government offers a range of energy payment supports, including the SA Concessions Energy Discount Offer and the Emergency Electricity Payment.⁶⁰⁵
- The Tasmanian Government provides a one-time Renewable Energy Dividend (RED) payment to residential electricity customers, including those on embedded networks, when Hydro Tasmania’s annual dividend exceeds \$90 million. For 2024–25, the dividend was \$60 per residential account, which is credited directly to electricity bills.⁶⁰⁶
- The ACT Government offers the Home Energy Support Scheme.⁶⁰⁷
- Northern Territory customers benefit from the territory’s Community Service Obligation.⁶⁰⁸

6.6.1 Improving the approach to consumers experiencing vulnerability – retailer obligations

Energy retailers play a central role in delivering support and assistance for consumers who are having difficulty meeting regular energy bill repayments, ranging from short-term, temporary late bill arrears to longer-term entrenched energy bill debt. Several reforms are underway by a range of stakeholders to improve how retailers engage with consumers experiencing vulnerability.

In October 2022, the AER launched its *Towards energy equity* strategy (section 6.6.2), focusing on reducing barriers to participation, supporting consumers experiencing payment difficulty, ensuring the consumer voice is heard in sector reforms and improving affordability by reducing the cost to serve energy consumers. The strategy also seeks to support consumers experiencing family violence, unequal protections and market complexity.

601 Australian Government, [Energy Price Relief Plan](#), Department of Climate Change, Energy, the Environment and Water, 9 December 2022, accessed 28 April 2025.

602 Australian Government, [Energy Bill Relief Fund](#), accessed 15 July 2025.

603 Queensland Government, [Cost-of-Living Action](#), accessed 15 July 2025.

604 NSW Government, [Find an energy rebate](#), NSW Climate and Energy Action, accessed 15 July 2025.

605 South Australian Government, [Energy bill concessions](#), accessed 15 July 2025.

606 Aurora Energy, [Delivering Tasmania’s Energy Savings](#), accessed 15 July 2025.

607 ACT Government, [Home Energy Support: Rebates for Homeowners](#), accessed 15 July 2025.

608 Northern Territory Government, [Cost of living support](#), accessed 15 July 2025.

Throughout 2023 and 2024, actions from the strategy were progressed and implemented. For example, the AER delivered recommendations to energy ministers for modernising the consumer protections framework for new energy services as well as for sector-wide ‘game changer’ reforms to improve outcomes for consumers experiencing vulnerability. The AER also implemented the Better Bills Guideline, collaborated with the Australian Government’s Behavioural Economics Team to evaluate the guideline’s benefits for consumers, and progressed major reviews of payment difficulty protections in the National Energy Customer Framework and the exemptions framework for embedded networks.

On 14 March 2025, energy ministers reiterated their commitment to an equitable energy transition for all Australians by agreeing to the National Energy Equity Framework.⁶⁰⁹ The framework – developed by the Australian and state and territory governments and informed by independent research – will help to ensure that energy policies do not unintentionally disadvantage any type of consumer. It calls for factors such as hardship and equity to be considered when policies and programs are being developed.

6.6.2 Towards energy equity

The AER’s *Towards energy equity* strategy seeks to address some of the enduring issues that prevent people from getting what they need from Australia’s energy system.⁶¹⁰ The strategy has 15 actions relating to 5 core objectives that the AER has undertaken to:

- improve identification of vulnerability
- reduce complexity and enhance accessibility for energy consumers
- strengthen protections for consumers facing payment difficulty
- use the consumer voice and lived experience to inform regulatory design and change
- balance affordability and consumer protections by minimising the overall cost to serve.

Action 15 of the strategy is to advocate for sector-wide ‘game changer’ reforms.⁶¹¹ This action recognises the potential in the energy sector to innovate and better allocate resources to not only provide a safer, healthier experience for consumers but also potentially save money and resources throughout the system. The game changer reforms aim to better balance cost and risk within the energy sector so that consumers experiencing vulnerability are identified early and get the support they need to improve outcomes.

One of the proposed game changer reforms has already been progressed through a recent decision by the Australian Energy Market Commission (AEMC) in response to a rule change request from the Energy and Climate Change Ministerial Council. On 19 June 2025, the AEMC made a rule change⁶¹² that seeks to increase support for people experiencing payment difficulty due to hardship by requiring retailers to offer hardship customers a better offer if available or provide a financial benefit equivalent to the amount the customer would have saved if they had been on the better offer. The new protection comes into effect from 30 December 2026.⁶¹³ To monitor the change, the AER is required to report on new hardship indicators from the 2027–28 retail market performance reporting period. The Essential Services Commission (Victoria) is also considering a similar protection for Victorian customers.

Other game changer reforms are being considered as part of the Energy and Climate Change Ministerial Council’s Better Energy Customer Experiences reform program, which is being led by the Australian Government Department of Climate Change, Energy, the Environment and Water. The Better Energy Customer Experiences reform program is also considering the recommendations from the AER’s Review of payment difficulty protections in the National Energy Customer Framework, which progressed actions 8, 9 and 10 of the *Towards energy equity* strategy.

609 Australian Government, [National Energy Equity Framework](#), Department of Climate Change, Energy, the Environment and Water, 10 June 2025, accessed 15 July 2025.

610 AER, [Towards energy equity - a strategy for an inclusive energy market](#), Australian Energy Regulator, 20 October 2022.

611 AER, [Game changer reforms](#), Australian Energy Regulator, accessed 17 June 2025.

612 In August 2024 the Hon Chris Bowen MP, Minister for Climate Change and Energy, submitted, on behalf of the Energy and Climate Change Ministerial Council, a rule change request to the AEMC seeking to amend the National Energy Retail Rules to incorporate the [game changer reforms](#).

613 AEMC, [Assisting hardship customers](#), Australian Energy Market Commission, 19 June 2025, accessed 14 July 2025.

The findings from this review were published on 15 May 2025. The AER identified 13 opportunities to improve the framework and deliver better customer experiences and outcomes, such as introducing minimum standards for assistance, improving retailer engagement with customers experiencing payment difficulty and strengthening minimum disconnection protections to ensure disconnection is only used as a last resort – including by increasing the minimum amount that must be outstanding before a customer can be disconnected for non-payment of a bill.

Box 6.2 Safety and support for consumers affected by family violence

Recent work commissioned by the Essential Services Commission (Victoria) has identified significant room for improvement in protecting and supporting energy customers affected by family violence and financial abuse.⁶¹⁴ We are committed to working with energy sector participants to prevent essential services and energy debt from being weaponised.

In May 2025, we released our *Strategy to support a safer energy market for customers affected by family violence*⁶¹⁵ alongside an open letter to the energy sector⁶¹⁶ calling on the industry to make its services safer for customers affected by family violence. Our strategy established our 3 key priorities:

1. Building organisational awareness and capability within the AER.
2. Supporting a regulatory framework that enables safety by design.
3. Encouraging regulated entities to prioritise safety in their businesses.

These priorities reflect what we have learned through our work in this space so far and builds on our progress, including our guidance on expectations⁶¹⁷ in relation to family violence protections in the National Energy Retail Rules⁶¹⁸ and on better practices for identifying and engaging with customers experiencing vulnerability, including customers affected by family violence.⁶¹⁹

In addition to the above, we have proposed to introduce a condition that exempt sellers must provide relevant protections to embedded network customers affected by family violence. On 17 March 2025, we published a draft decision to introduce new protections for customers of exempt sellers, including improved pricing visibility and an obligation for exempt sellers to develop, implement and maintain family violence policies.⁶²⁰ Due to an extension to our consultation, we now anticipate the final instrument to be released on or before 29 August 2025.

6.6.3 Consumer protections for future energy services

On 23 December 2023, the AER provided advice on consumer protections for future energy services for energy ministers' consideration.⁶²¹ The advice presented the case for reviewing the National Energy Customer Framework to ensure it can continue to protect consumers in an evolving energy market, supporting the energy transition.

New energy services such as virtual power plants, aggregation services and home energy management services are being increasingly intertwined with the essential services consumers rely on. New energy services will also become increasingly important in supporting the grid through the energy transition and driving down emissions, and have the potential to reduce the costs of supplying electricity.

The AER considers that, unless there is some regulatory reform to enhance protections, there is the risk of harm to consumers. Effective consumer protections would also support the wider uptake of these new services, driving further innovation and realising the significant benefits that they bring to the transition.⁶²²

614 C Fitzpatrick, *Designed to disrupt: Safety by design for essential services*, Flequity Ventures, 19 May 2025.

615 AER, *Strategy to support a safer energy market for customers affected by family violence*, Australian Energy Regulator, 22 May 2025.

616 AER, *Open letter to the energy sector in response to Designed to Disrupt discussion paper*, Australian Energy Regulator, 22 May 2025.

617 AER, *Family Violence Rules: Guidance for Energy Retailers*, Australian Energy Regulator, 12 February 2025.

618 AEMC, *Protecting customers affected by family violence*, Australian Energy Market Commission, 15 September 2022.

619 AER, *Customer engagement toolkit*, Australian Energy Regulator, accessed 3 June 2025.

620 AER, *Review of the AER exemptions framework for embedded networks – Draft decision*, Australian Energy Regulator, 17 March 2025.

621 AER, *Final advice to Energy Ministers*, Australian Energy Regulator, Australian Energy Regulator, 23 November 2023.

622 AER, *Final advice to Energy Ministers*, Australian Energy Regulator, Australian Energy Regulator, 23 November 2023.

Among other reforms, the AER recommended introducing principles-based regulation for new energy services, with a strong focus on consumer outcomes. The AER considers that an overarching consumer duty would provide a degree of flexibility for providers to account for the uncertainty over how energy offerings will develop through the energy transition. The overarching duty would complement existing general consumer protections offered under the Australian Consumer Law.

In response to consultation on the Better Energy Customer Experiences reform program, the AER continues to advocate for progress on these and other recommendations arising from comprehensive review processes undertaken by the AER, including the Review of consumer protections for future energy services, the Review of the exemptions framework for embedded networks, the Review of payment difficulty protections in the National Energy Customer Framework and the Game changer initiative.⁶²³

6.7 Energy affordability

Energy affordability is impacted by several factors, including a customer's energy needs, available tariffs, income, living costs and the ability to participate effectively in the energy market. Energy bills can be a significant burden for households even in times of relatively low energy prices. Additional strains will be felt by consumers as the broader cost of living in Australia continues to rise.⁶²⁴

In October 2024, the AER commissioned consumer research to explore:

- which consumers are experiencing financial stress
- how consumers prioritise the payment of energy bills against other payments
- who is using non-traditional lending products
- how extensively traditional and non-traditional lending products are being used to pay energy bills – this includes credit cards, buy now pay later, wage advance loans, personal loans and payday loans
- how much consumers know about how they could reduce their energy bills.

Key findings from the research included:

- 37% of energy customers surveyed were experiencing financial stress
- financially stressed energy customers were significantly more likely to have used a non-traditional lending product to pay energy and water bills in the previous 6 months
- more than 33% of financially stressed customers were unable to pay an energy or water bill on time in the previous 12 months
- among those who had been unable to pay their energy bills on time in the previous 12 months, 45% cut essential spending, 40% cut optional spending and 32% contacted their energy retailer to ask for assistance
- almost 40% of energy customers were currently or had previously been on a retailer instalment plan to smooth their energy bills
- 44% of financially stressed energy customers were or had been on a debt repayment plan with their retailer – more than 33% of these customers had never received any extra support through their energy retailer's assistance program
- financially stressed energy customers were younger, had less education, lived more regionally and had lower income.

623 Australian Government, [Better Energy Customer Experiences](#), Department of Climate Change, Energy, the Environment and Water, 14 March 2025.

624 Over the 12 months to March 2025, the Living Cost Indexes (LCIs) – which measures the price change of goods and services and its effect on living expenses of selected household types – increased by 2.4% and 3.5%. See ABS, [Selected Living Cost Indexes, Australia](#), Australian Bureau of Statistics, March 2025, accessed 17 June 2025.

6.7.1 Energy usage

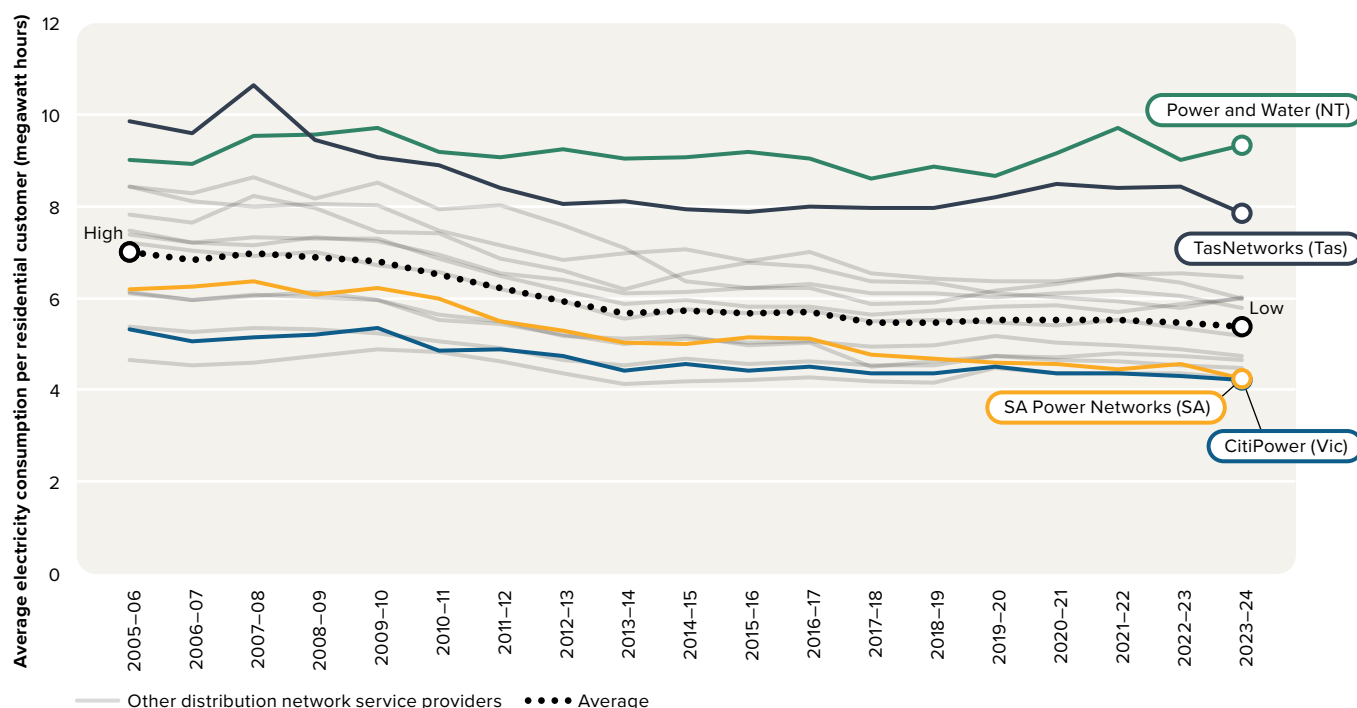
Usage charges represent the largest component of energy bills for most households.⁶²⁵ Therefore, a customer's energy usage significantly impacts energy affordability.

Several factors can impact usage costs, including household size, how energy efficient the house is, appliance quality, heating and cooling needs, and lifestyle. Some consumers use both electricity and gas, and others only use electricity.

Key drivers of greater electricity and gas use are climate (with greater heating requirements in some jurisdictions) and the penetration of gas as an alternative fuel. Residential customers in Tasmania use the most electricity (per customer) of any jurisdiction in the NEM.⁶²⁶ However, the above average electricity usage is offset by relatively few Tasmanian households using gas. Most households in Victoria have both electricity and gas connections, resulting in below average household electricity consumption (per customer) and above average household gas consumption (per customer).

Over the past 10 years, the amount of electricity the average residential consumer has sourced from the grid has decreased, reaching a new low in 2023–24. The overall decline in energy consumption from the grid can be attributed to several factors, including rooftop solar replacing electricity previously sourced from the grid and housing and appliances becoming more efficient (Figure 6.7).

Figure 6.7 Average electricity consumption per residential distribution network customer

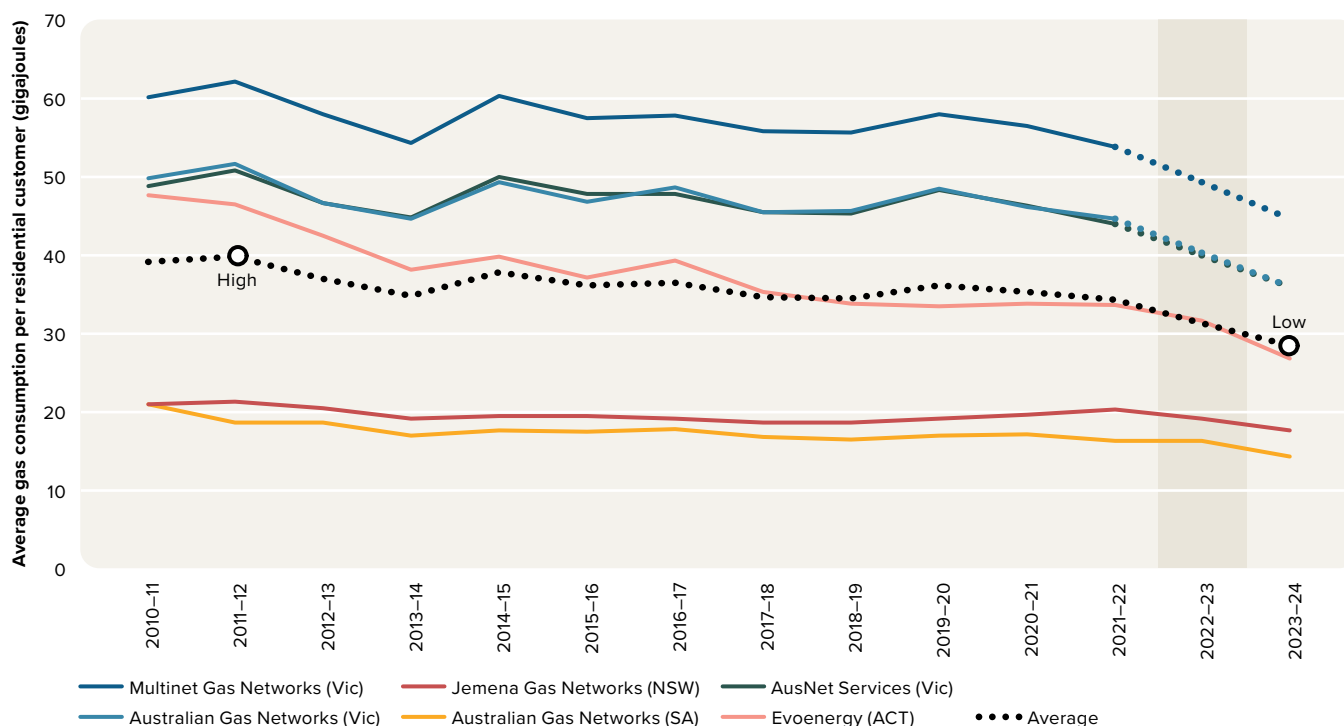


Source: Economic benchmarking regulatory information notice (RIN) responses.

625 Most energy offers include usage charges as well as a fixed supply charge. Some offers also include membership fees or additional charges for metering.

626 The Northern Territory has 3 separate distribution networks – the Darwin–Katherine, Alice Springs and Tennant Creek systems – all owned by Power and Water. The 3 networks are classified as a single distribution network for regulatory purposes but do not connect to each other or the NEM.

Figure 6.8 Average gas consumption per residential distribution pipeline customer⁶²⁷



Source: Annual regulatory information notice (RIN) responses.

6.7.2 Affordability of median market offers

Energy affordability in 2024–25 varied across customers and jurisdictions. This was largely due to differences in government support provided in different regions and changes in median market offers from retailers.

Rebates and concessions provided by governments (section 6.6) partially shielded eligible low-income households from electricity price rises. While the Australian, and state and territory governments have provided energy bill relief since 2023, the greatest impacts in 2024–25 were observed in Queensland and Tasmania, where low-income electricity customers benefited from the Queensland Government's \$1,000 Cost-of-Living Rebate and the Tasmanian Government's one-time Renewable Energy Dividend (RED) payment.

Retail energy prices paid by consumers differ according to their jurisdiction. While retail prices in the ACT, Tasmania and regional Queensland are regulated by responsible jurisdictional administrators, the level of competition can impact retail prices paid in other NECF regions. Other price factors include the customer's ability to identify an appropriate energy plan and whether the customer is eligible for a concession or rebate to help manage their energy costs.

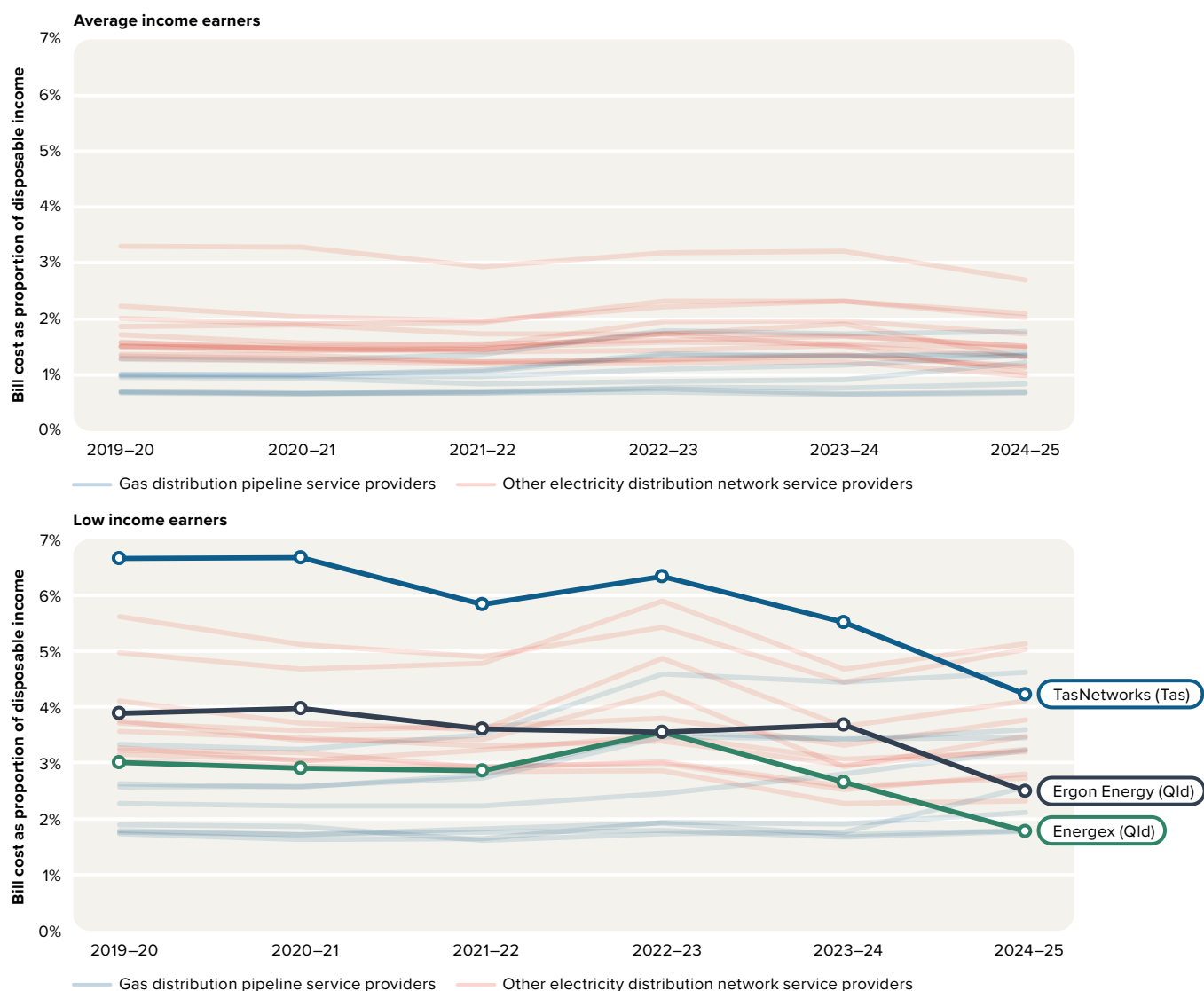
As at 31 March 2025, after eligible concessions and rebates were applied:

- average-income households were spending 1.0% to 2.7% of their income on electricity, which is a decrease across most jurisdictions since 2023–24
- expenditure for gas was stable and ranged between 0.7% and 1.8% of income
- low-income household electricity spending increased from 2023–24 and ranged between 1.8% and 5.1%
- household expenditure for gas also increased, ranging from 1.8% to 4.6% (Figure 6.9).

Gas bills as a proportion of income are higher for Victorian customers because gas consumption is higher in Victoria than elsewhere (Figure 6.8). As such, increases in gas prices (due to both local supply and international prices) have a greater impact on Victorian customers relative to their income because it makes up more of their overall energy usage.

627 2022–23 data not included for Victorian pipeline service providers.

Figure 6.9 Affordability of median market offers



Note: Based on offers for residential customers in each jurisdiction. Average household consumption for the financial year ending June of each period was used in annual bill calculations. Proportion refers to mean disposable income. Use of average incomes across jurisdictions may overstate affordability in regional areas, where average incomes are typically lower than across the jurisdiction more broadly.

Source: Offer data from Energy Made Easy (AER) and Victorian Energy Compare (Department of Energy, Environment and Climate Action). Consumption estimates based on Economic benchmarking regulatory information notice (RIN). Income data are unpublished Australian Bureau of Statistics (ABS) estimates of household disposable income.

6.7.3 Energy market evolution and the ‘equity gap’

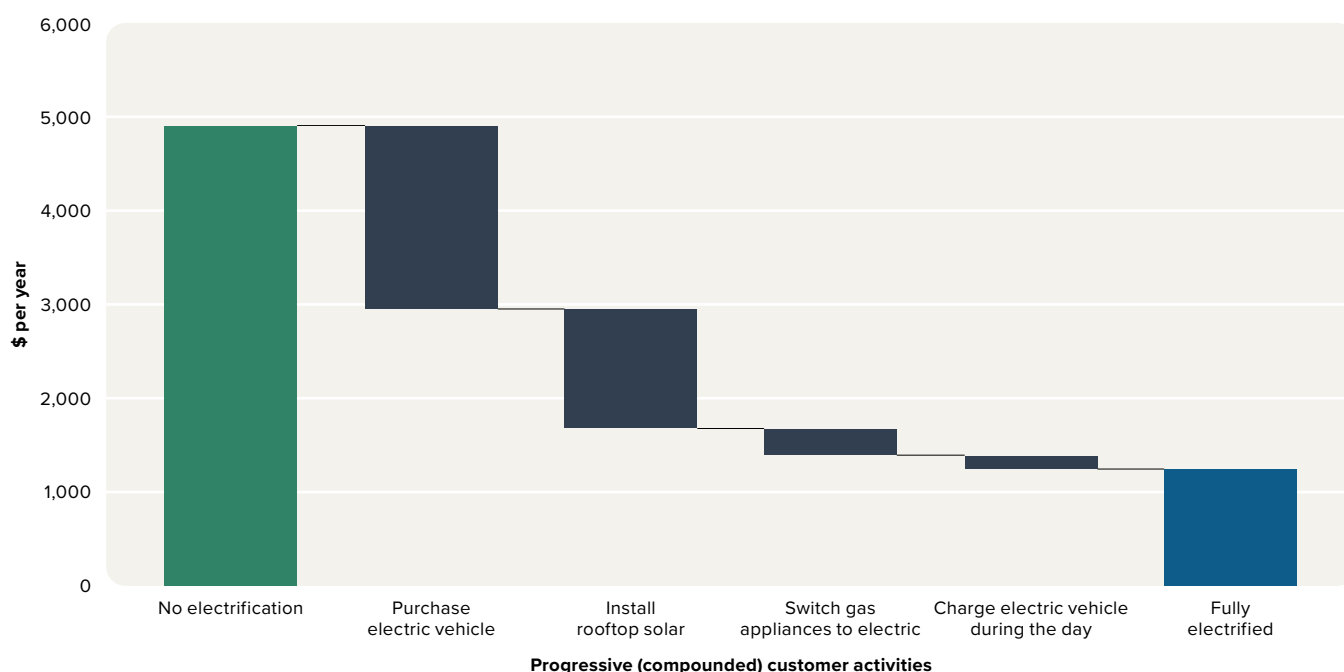
Indicators of average energy use – such as those shown in section 6.7.1 – are likely obscuring a widening gap between households that have the capacity to adopt new technology or modify energy use, and those that do not. The main drivers of the reduction in energy use – rooftop solar and energy efficient housing – are not equally accessible to all consumers. This could be due to the up-front cost or renting a property without rooftop solar or batteries.⁶²⁸

Consumers that have the capacity to adopt new technology or modify energy use have likely been experiencing a substantial reduction in electricity sourced from the grid, while for other households the amount of electricity sourced from the grid has likely remained relatively consistent over time.

628 Cong et al., [Unveiling hidden energy poverty using the energy equity gap](#), May 2022, accessed 13 August 2025.

Traditionally, energy consumption, and therefore cost, was managed at a household level by reducing the usage of appliances or by energy efficiency measures, such as installing insulation or double glazing. But as the energy market evolves, household energy consumption and costs can vary significantly based on the extent to which some households can invest in consumer energy resources. This is sometimes referred to as the energy ‘equity divide or gap’.⁶²⁹

Figure 6.10 Typical energy cost savings if a household electrified today



Note: All data shown in June 2025 dollars. Data are estimates based on the AEMC’s *Residential electricity price trend 2024* report. Reflects a household with annual electricity consumption of 3,900 kilowatt hours.

Source: AEMC, *Residential electricity price trend 2024* report, 28 November 2024, accessed 16 July 2025, p. 19.

Distribution network service providers have introduced reforms such as ‘solar soak’ periods – where consumers have access to low rates in the middle of the day.⁶³⁰ When ‘solar soak’ periods are passed on to customers in retail tariff offers, both customers with and without solar can access the benefits of plentiful rooftop solar generation during the day if they can shift energy consumption into the middle of the day (chapter 3, section 3.8.2).

6.7.4 Potential benefits of consumer energy resources

Consumer energy resources such as rooftop solar, home batteries and electric vehicles have the potential to lower energy costs and increase energy self-reliance for consumers equipped with those assets (Figure 6.10).

Modelling conducted by the AEMC for its *Residential electricity price trends (2024)* report showed a household could reduce its energy expenditure by more than 70% – from about \$5,000 to under \$1,500 a year – by taking advantage of these 4 electrification actions (Figure 6.10):

- purchasing an electric vehicle
- installing rooftop solar
- switching gas appliances to electric
- charging electric vehicles during off peak periods during the day instead of during the evening peak periods.

629 Energy Consumers Australia, [Understanding the Energy Divide](#), December 2023, accessed 13 August 2025.

630 Clean Energy Council, [Home Battery Saver Program](#), accessed 14 August 2025.

The broader system and economic benefits for all consumers will depend on the extent to which consumer energy resources can be orchestrated. Orchestration occurs when the operation of consumer energy resources is coordinated to achieve certain outcomes, such as a reliable electricity supply, enhanced grid stability and lower costs for all consumers. AEMO forecasts that if consumer energy resources are not effectively orchestrated, additional investment of around \$4.1 billion in grid-scale storage will be required by 2049–50.⁶³¹ Avoiding these costs, which would be passed on to all consumers, will help ensure those unable to install or use consumer energy resources can share in the benefit of more reliable and lower cost energy.

Rooftop solar generation

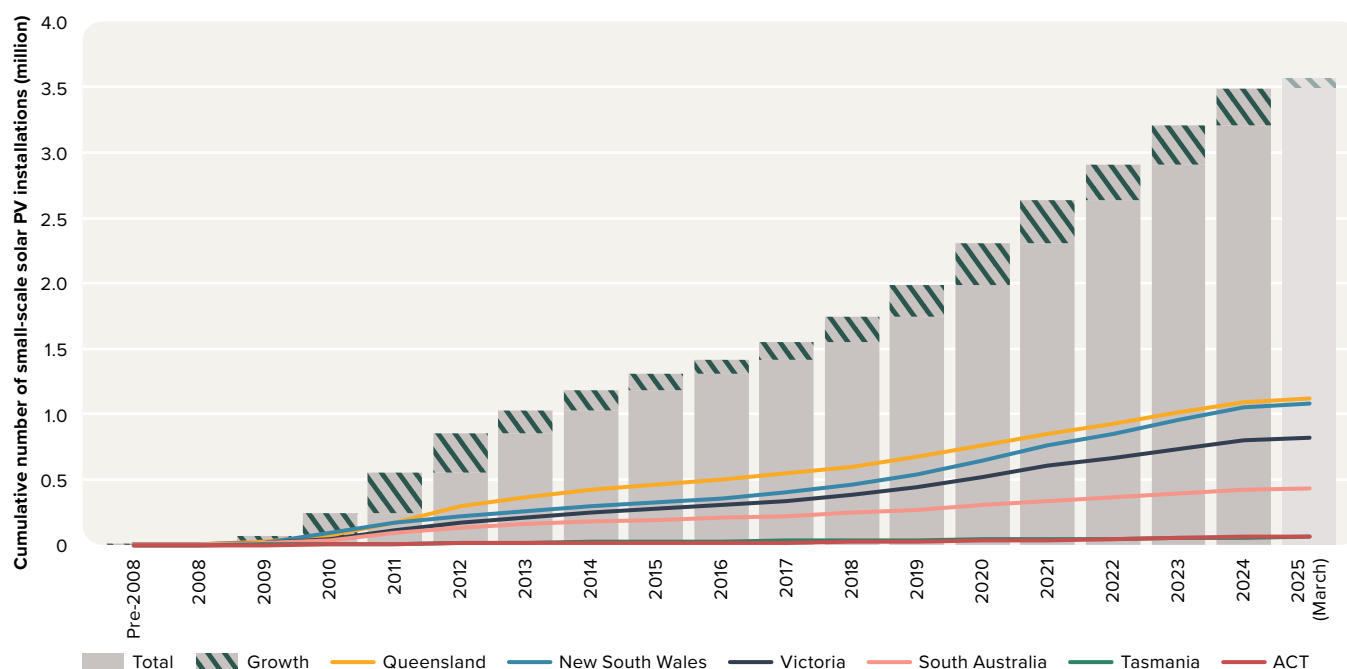
Australia is the largest per capita user of rooftop solar in the world.⁶³² Backed by Australian and state and territory government incentives, households and businesses have continued to install large volumes of rooftop solar capacity every year since 2015. Ongoing subsidies combined with falling costs of solar PV systems have helped sustain the growth in new installations.

As at 31 March 2025, more than 3.5 million small-scale solar PV systems had been installed across the NEM (Figure 6.11), 9% more than in the previous year, with a combined capacity of around 23 gigawatts (chapter 3, Figure 3.23).

Customers with solar panels may save on their electricity bills in 2 ways. First, the electricity generated by solar is free and used by the household, so they can buy less electricity from the grid. Second, customers exporting surplus electricity back into the grid receive a feed-in tariff, and other consumers have access to the surplus electricity that is exported.

Electricity generated from consumers' rooftop solar systems add more value to the customer and grid when paired with a household battery. This enables surplus electricity from the rooftop system to be stored in the battery for household use during the evening peak, when costs are generally highest. At a grid level, surplus electricity stored in home batteries can be exported when it is needed, offsetting the need for more expensive, dispatchable generation such as gas or hydro.

Figure 6.11 Small-scale solar PV installations across the NEM



Note: Small-scale generation units have a capacity of no more than 100 kilowatts and a total annual electricity output of less than 250 megawatt hours.
Source: Clean Energy Regulator, Postcode data for small-scale installations, data as at 16 June 2025.

631 Modelling for AEMO's 2024 ISP did not include the costs of distribution network investments. AEMO, [2024 Integrated System Plan](#), Australian Energy Market Operator, 26 June 2024.

632 Clean Energy Regulator, [Rooftop solar](#), 30 June 2025, accessed 21 July 2025.

Batteries

Batteries are a relatively new technology, and the high upfront costs to install home batteries has been a barrier to uptake. However, since 2013 global battery prices have fallen by 86%, and the expected payback period on the upfront cost of purchasing a battery has dropped to an average of 8.3 years in Australia (as at 2024) compared with 10 years in 2022 and 19 years in 2016.⁶³³ Falling prices and government rebates could increase the rate of home battery uptake.

The Australian Government is delivering a \$200 million grant program in recognition of the multiple benefits community-scale batteries can unlock.⁶³⁴ As part of the first round of funding, the Australian Renewable Energy Agency (ARENA) has contributed \$124.7 million to deploy 318 community batteries across all states and territories. A second funding round launched in March 2025, making a further \$46.3 million available.⁶³⁵

Community-scale batteries allow consumers to send excess electricity generated from their rooftop solar to a local large-scale battery system for storage and later use. This stored electricity can be used during peak times or as an alternative to purchasing their own home battery or electric vehicle. With typical storage capacities of around 100 kilowatts up to 5 megawatts, a single community-scale battery system could serve up to several hundred nearby homes and small businesses.

Across the NEM, the most common form of community-scale batteries are ‘in-front-of-the-meter’ systems connected to the main grid. These batteries may be owned by the local distribution network service provider, local council, community group, retailer or other third party. However, there are also ‘behind-the-meter’ systems, which are generally co-located with other consumer energy resources. These can be owned by individual customers, businesses or third-party service providers.

Several state and territory programs and trials are also underway.⁶³⁶ Retailers are increasingly participating in community-scale battery schemes as the asset owner or in partnership with a distribution network service provider, and several retailers have been conditionally approved to receive Australian Government funding to develop and install community-scale batteries across NEM regions.⁶³⁷

South Australia has the largest volume of installed DER capacity per customer, followed by Queensland, the ACT and then Victoria. Capacity is lower in Tasmania and NSW (Figure 6.12). In each state, solar is the biggest source of capacity per customer.

633 Climate Council, [Battery Boom: Supercharging Australia's Renewable Rollout](#), 10 June 2025, accessed 18 July 2025.

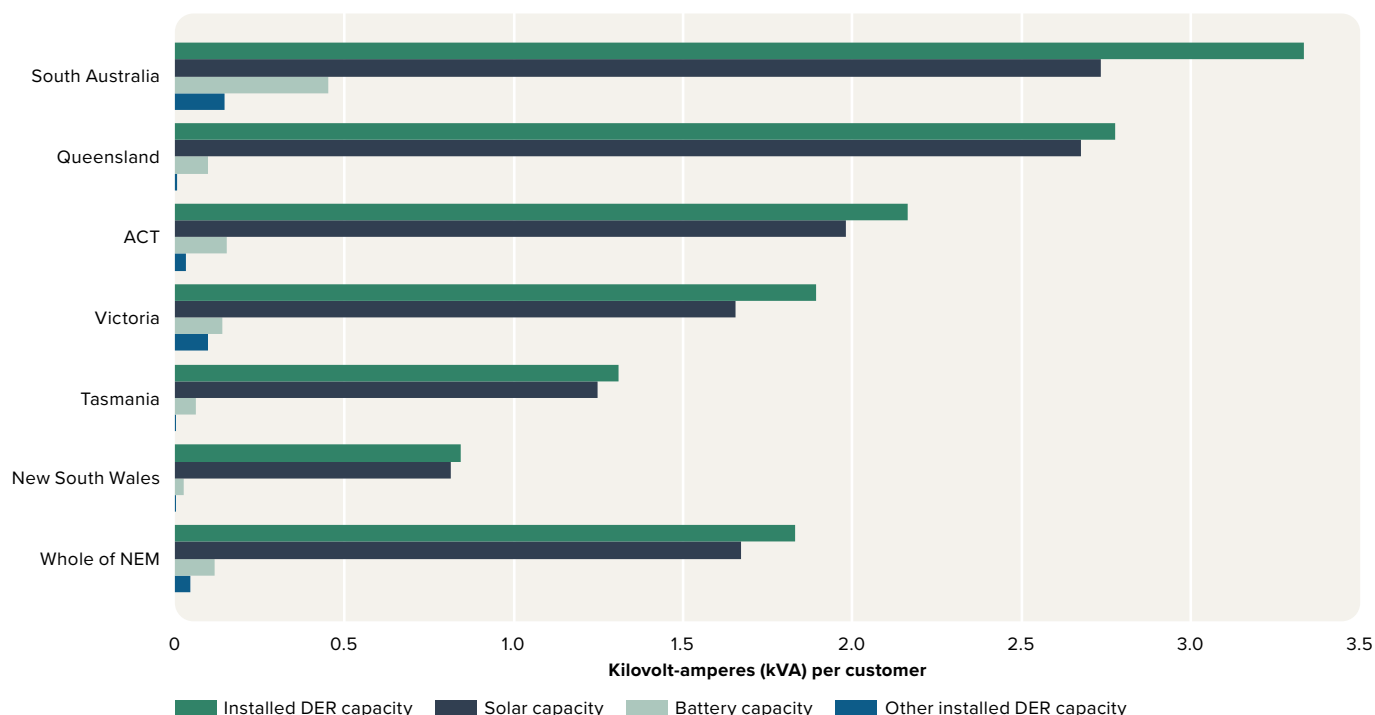
634 Australian Government, [Community Batteries for Household Solar program](#), Department of Climate Change, Energy, the Environment and Water, accessed 12 September 2024.

635 ARENA, [Community batteries, community benefits and the clean energy transition](#), Australian Renewable Energy Agency, accessed 1 July 2025.

636 For example, the Victorian Government's [100 Neighborhood batteries program](#) and the South Australian Government's [emPowering SA program](#), accessed 11 September 2024.

637 Australian Government, [Community Batteries for Household Solar program](#), Department of Climate Change, Energy, the Environment and Water, accessed 12 September 2024.

Figure 6.12 Registered distributed energy resources (DER) capacity per customer, by NEM region



Note: AEMO's distributed energy resources register includes consumer energy resources such as rooftop solar and home batteries as well as other distributed energy resources (DER) capacity. Other DER capacity can include other small-scale renewable generation systems as well as diesel/petrol generators and electric vehicles with vehicle-to-grid or vehicle-to-home technology.

Source: AEMO, Distributed energy resource register (DERR), March 2025; Economic benchmarking regulatory information notice (RIN) responses.

On 1 July 2025, the Australian Government introduced a \$2.3 billion Cheaper Home Batteries Program to increase the uptake of home batteries.⁶³⁸ The program provides an around 30% discount off the upfront cost of installing eligible small-scale battery systems for households, businesses and community facilities. The Australian Government will fully fund the discount for batteries by purchasing small-scale technology certificates. This means no costs will be passed on to householders through energy retailers.

While this is likely to accelerate uptake of home batteries, as evidenced by similar schemes in other jurisdictions,⁶³⁹ the extent of broader system and economic benefits for all consumers will depend on the degree to which home batteries and other consumer energy resources can be orchestrated.⁶⁴⁰

A single community-scale battery system could serve up to several hundred nearby homes and small businesses.

⁶³⁸ Australian Government, [Cheaper Home Batteries Program](#), Department of Climate Change, Energy, the Environment and Water, accessed 6 June 2025.

⁶³⁹ See Clean Energy Council, [Home Battery Saver Program](#), accessed 6 June 2025, p. 8.

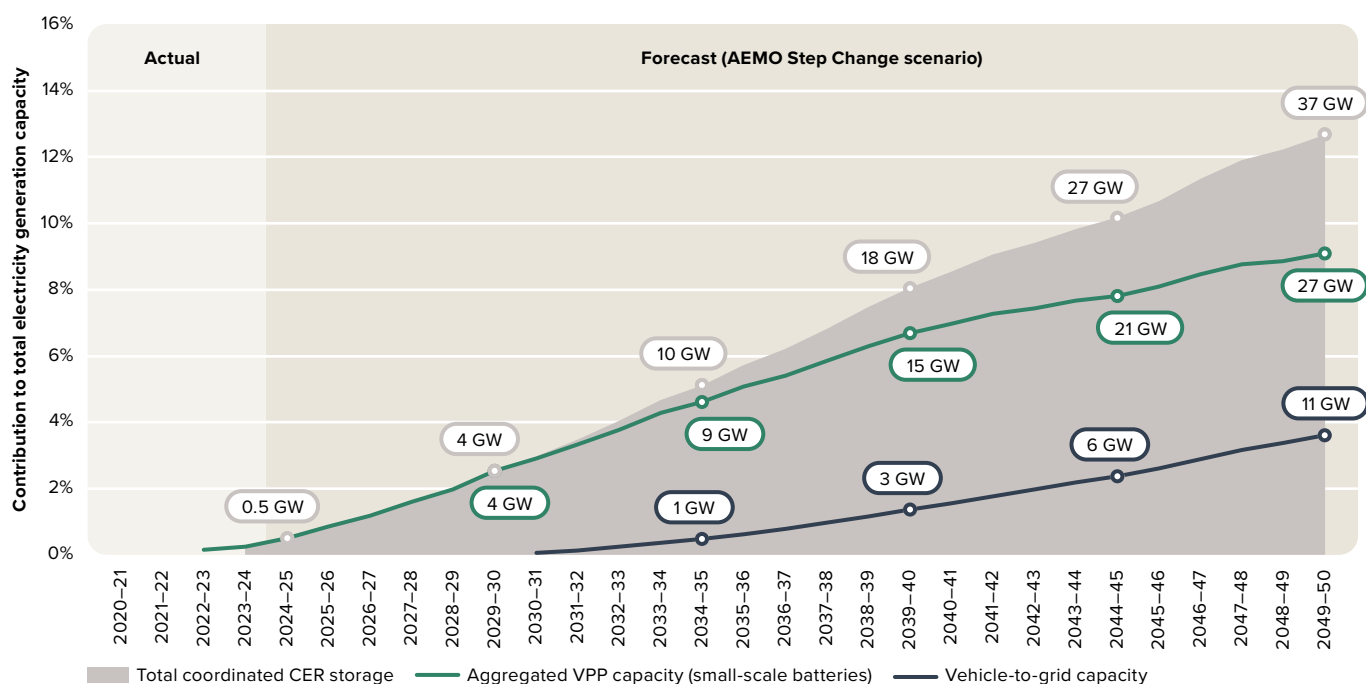
⁶⁴⁰ Orchestration is when the operation of consumer energy resources is coordinated to achieve certain outcomes, such as a reliable electricity supply, enhanced grid stability and lower costs for all consumers. The ability to effectively orchestrate consumer energy resources is contingent on multiple factors, in particular social licence, upgrades to distribution networks and operations and policy settings. See AEMO, [2024 Integrated System Plan](#), Australian Energy Market Operator, 26 June 2024.

Electric vehicles as energy storage

Electric vehicle batteries have the potential to act as small-scale storage by charging from a consumer's rooftop solar or from the grid when renewable generation output is high, then providing electricity back to the consumer's home or to other consumers via the grid when it is needed.⁶⁴¹ Referred to as 'bidirectional charging' or 'vehicle-to-grid' and 'vehicle-to-home' technology, enabling the use of electric vehicles as energy storage is a priority reform area of the National Consumer Energy Resources Roadmap⁶⁴² and work is progressing to develop technical standards and other regulatory reforms.

AEMO forecasts that by 2049–50, bidirectional charging could provide 11 gigawatts of a total 37 gigawatts of coordinated consumer energy resources storage capacity in the NEM (Figure 6.13). A well-timed and coordinated approach to electric vehicle charging and discharging has the potential to support grid stability and boost self-consumption of solar, with minimal impacts to consumers.

Figure 6.13 AEMO's modelled coordinated consumer energy resources contribution to electricity generation capacity



Note: GW: gigawatts.

Source: AEMO, 2024 Integrated System Plan, June 2024.

641 More information about progress towards vehicle-to-grid and vehicle-to-home is available in ARENA, [National Roadmap for Bidirectional EV Charging](#), Australian Renewable Energy Agency, 12 February 2025.

642 Australian Government, [National Consumer Energy Resources Roadmap - Powering Decarbonised Homes and Communities](#), Department of Climate Change, Energy, the Environment and Water, 19 July 2024, accessed 6 June 2025.

6.8 Retailer assistance to customers

The National Energy Customer Framework (NECF)⁶⁴³ is a suite of legal instruments that regulate the sale and supply of electricity and gas to retail customers, including how retailers are obligated to support customers experiencing payment difficulties.

Generally, the first stage of support is a payment plan which allows customers to repay their energy debt in affordable, regular instalments. Payment plan support should be afforded to all residential customers and are among the minimum forms of assistance that retailers must offer customers.

The NECF also contains the AER's Customer Hardship Policy Guideline to assist customers that are challenged with energy debt or are experiencing financial hardship. Key components of these guidelines include the following requirements for retailers:

- Identification of hardship – retailers must have clear processes to identify customers who may be experiencing hardship.
- Early intervention – retailers must respond promptly to customers who are experiencing hardship.
- Flexible payment arrangements – retailers must offer payment plans tailored to individual customer circumstances.
- Hardship programs – which can encompass emergency relief, financial counselling and assistance with improving energy efficiency to reduce bills.
- Disconnection protections – customers participating in hardship programs cannot be disconnected.

However, many households continue to struggle with energy debt and are not receiving payment support from their retailer via payment plans or hardship programs. Additionally, over the past few years, broader economic conditions and cost-of-living issues have challenged both energy consumers and retail energy market participants. This has resulted in more customers accumulating energy debt.

In response, governments have provided additional support with rebates and concessions, which has assisted energy affordability across most customers.

The AER monitors data on debt levels (section 6.8.1) as well as payment plans (section 6.8.2) and the number of customers identified to be in financial hardship (section 6.8.2).

6.8.1 Energy bill debt

Energy debt is defined as electricity and gas charges that are outstanding for 90 days or more.

The number of customers repaying debt excludes customers on hardship programs (see section 6.8.2) and non-active debts that retailers may still have on record.

Typically, electricity and gas customers have access to an unlimited supply of each energy type and are charged retrospectively. If energy bills are not paid in full, debt can remain on a customer's account and can accumulate over time.

The proportion of customers in energy debt and the average level of debt provide an insight into:

- the extent to which customers are experiencing difficulty paying their energy bills
- whether customers in certain jurisdictions are more susceptible to experiencing difficulty paying their energy bills
- whether retailers are effectively assisting their customers to meet their energy debt repayments.

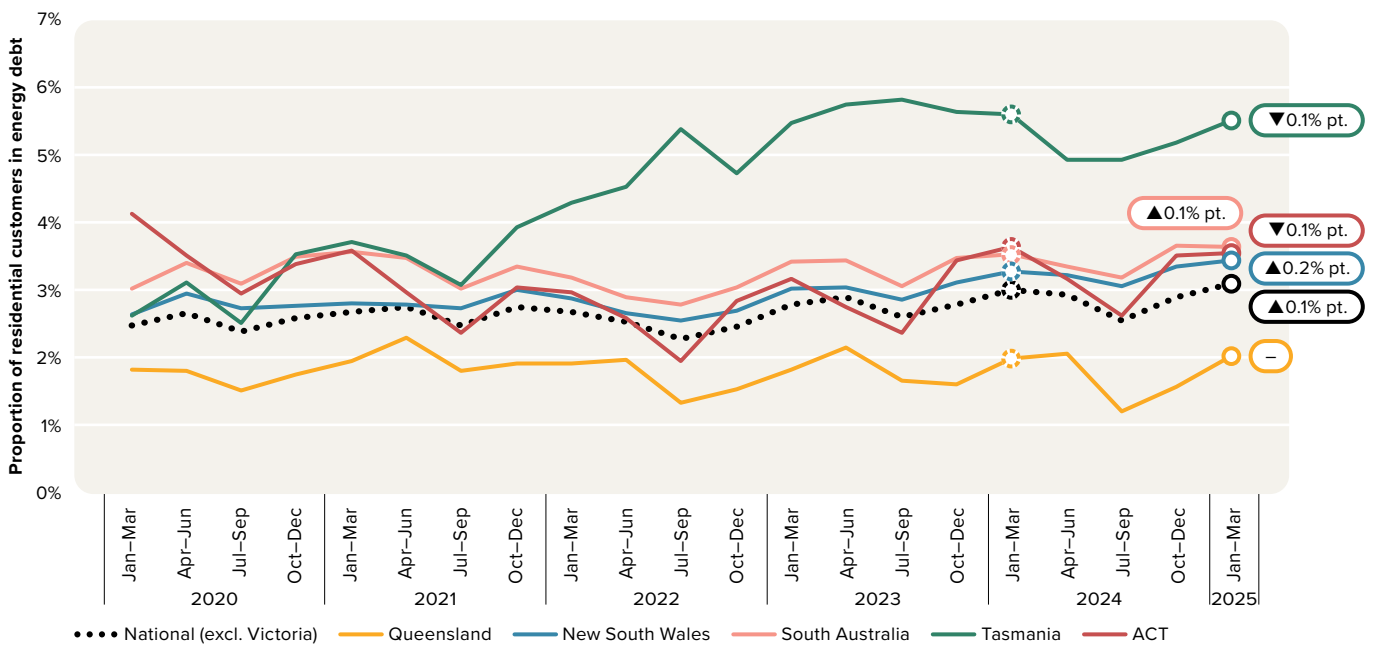
As at 31 March 2025:

- the overall number of residential customers with energy debt had increased from 205,963 to 215,637 (up 5%) over the 12 months since 31 March 2024
- the proportion of residential customers with energy debt had increased from 3.0% to 3.1% over the 12 months since 31 March 2024 (Figure 6.14)
- the average debt per residential customer with energy debt had increased from \$1,106 to \$1,415 (up 28%) over the 12 months since 31 March 2024 (Figure 6.15).

643 [National Energy Retail Law](#), Division 7, Section 50.

Further analysis and new data will be provided in the AER's Annual retail markets report 2024–25, due to be published in November 2025.

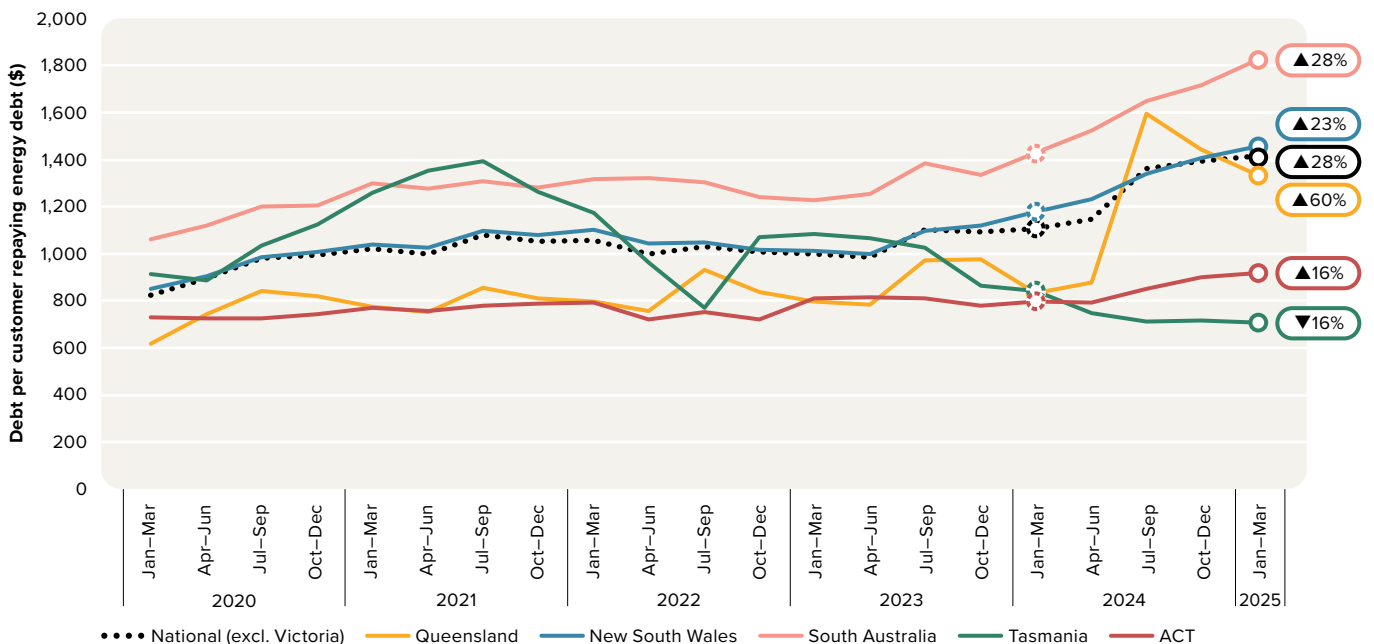
Figure 6.14 Residential electricity and gas customers in energy debt



Note: Based on electricity and gas customers with an amount owing to a retailer that has been outstanding for 90 days or more. Excludes customers that have entered into hardship programs.

Source: AER, *Quarterly retail performance report, Q3 2024–25*, June 2025.

Figure 6.15 Average debt per residential customer repaying energy debt



Note: Based on electricity and gas customers with an amount owing to a retailer that has been outstanding for 90 days or more. Excludes customers that have entered into hardship programs.

Source: AER, *Quarterly retail performance report, Q3 2024–25*, June 2025.

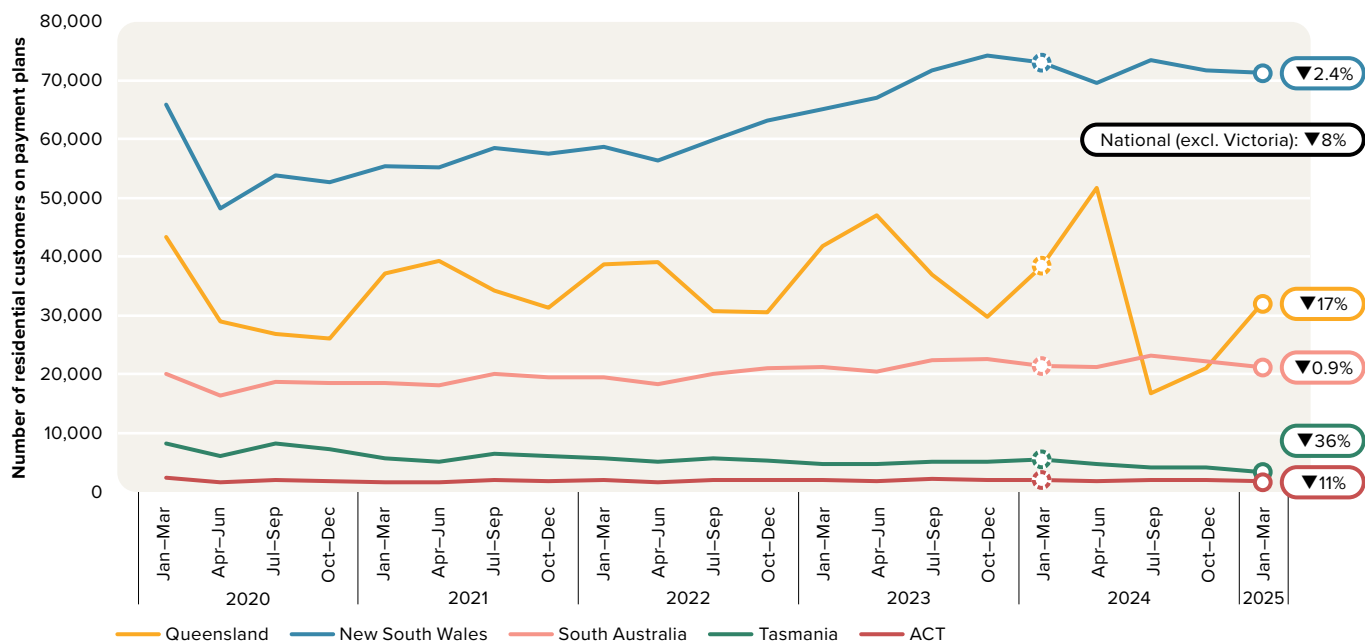
6.8.2 Customer support

Payment plans

As at 31 March 2025, the overall number of residential energy customers on a payment plan had decreased from 140,190 to 129,498 (down 8%) over the 12 months since 31 March 2024.

The significant decrease in the number of residential customers on payment plans in Queensland was believed to be attributable to the Queensland Government's Cost-of-Living Rebate (Figure 6.16).⁶⁴⁴

Figure 6.16 Residential electricity and gas customers on payment plans



Source: AER, *Quarterly retail performance report, Q3 2024–25*, June 2025.

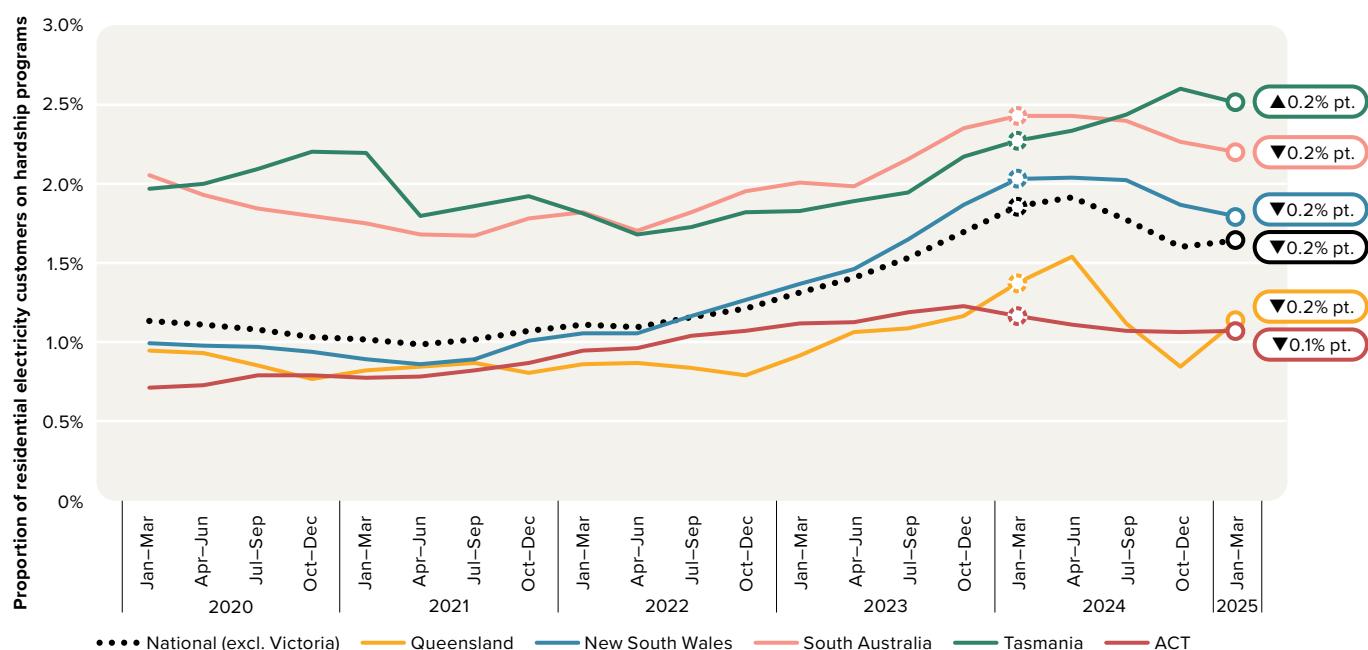
Hardship programs

As at 31 March 2025:

- around 1.6% of residential electricity customers were on hardship programs, marginally less than on 31 March 2024 (Figure 6.17)
- around 1.2% of residential gas customers were on hardship programs, marginally less than on 31 March 2024 (Figure 6.18).

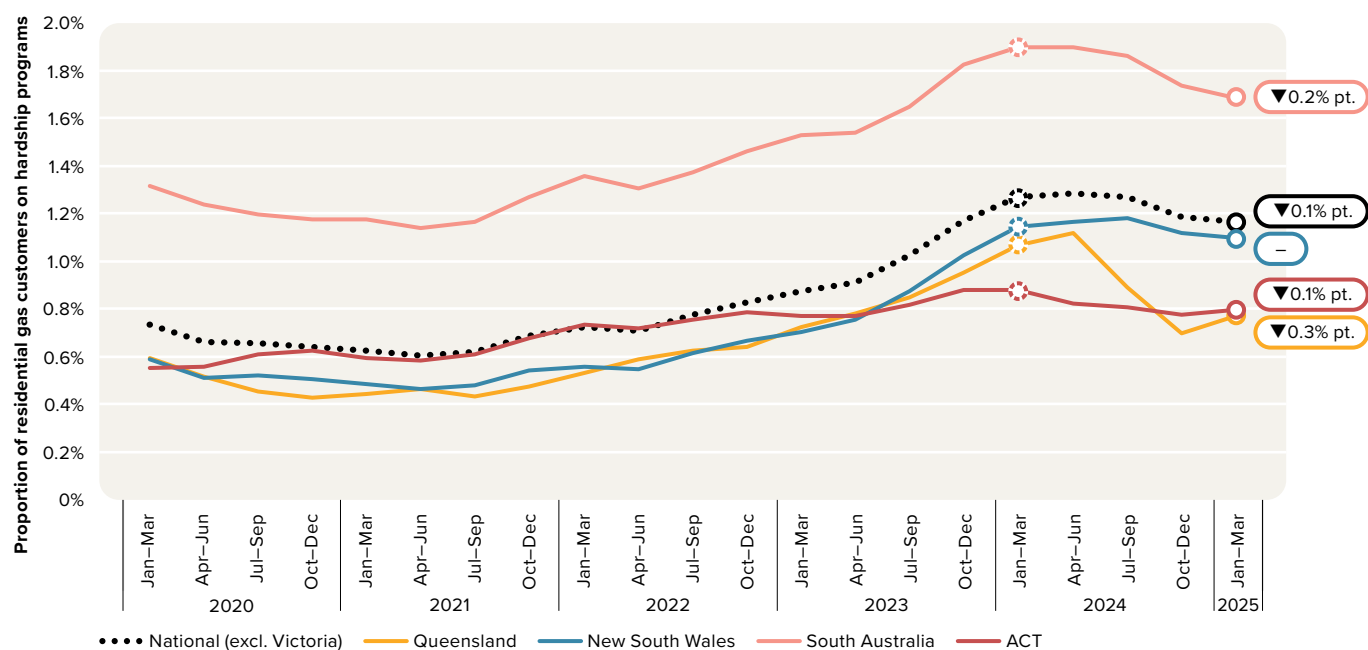
644 Queensland Government, [Cost-of-Living Action](#), accessed 15 July 2025.

Figure 6.17 Residential electricity customers on hardship programs



Source: AER, Quarterly retail performance report, Q3 2024–25, June 2025.

Figure 6.18 Residential gas customers on hardship programs

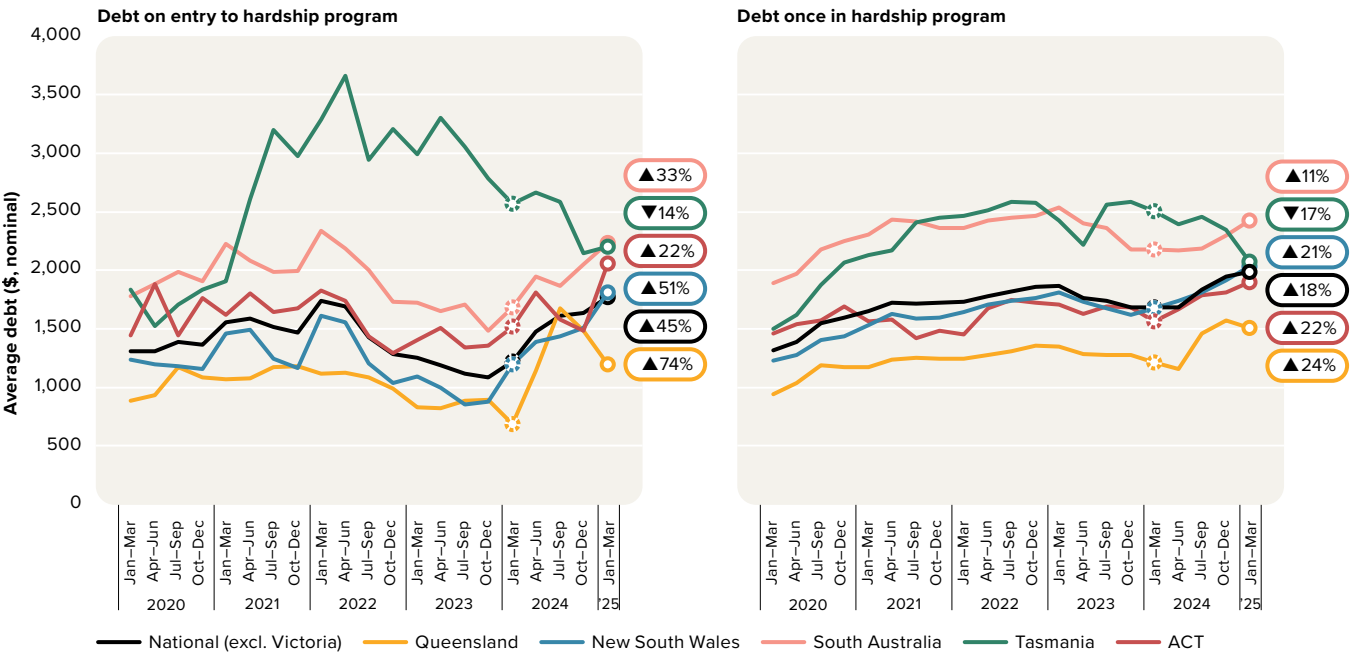


Source: AER, Quarterly retail performance report, Q3 2024–25, June 2025.

Despite the broadly decreasing number of customers on hardship programs, both the average level of debt and the average level of debt on entry to a hardship program increased in 2024–25 (Figure 6.19 and Figure 6.20).

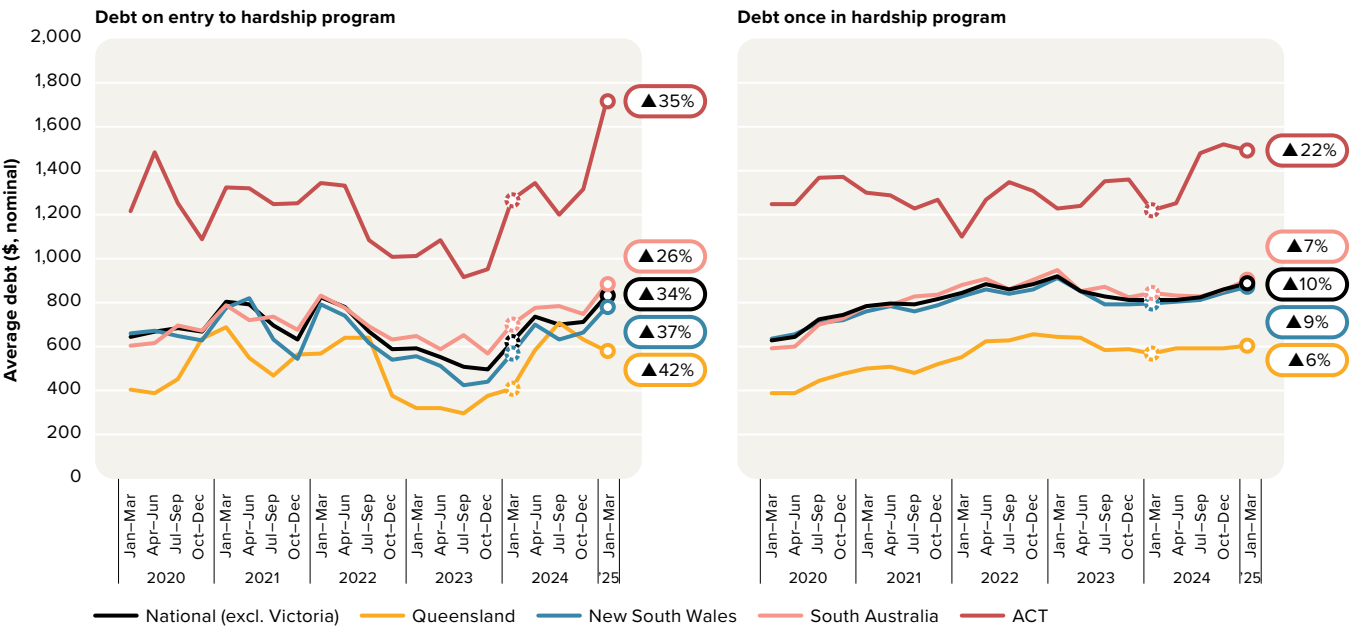
While being on a hardship program provides customers experiencing payment difficulty with added protections, the programs themselves could be more effective if they provided these customers with additional assistance, such as identifying opportunities to lower their energy usage, which would help customers reach a sustainable position for their future energy use and payments.

Figure 6.19 Average hardship debt – residential electricity customers



Source: AER, Quarterly retail performance report, Q3 2024–25, June 2025.

Figure 6.20 Average hardship debt – residential gas customers



Source: AER, Quarterly retail performance report, Q3 2024–25, June 2025.

6.8.3 Disconnecting customers for non-payment

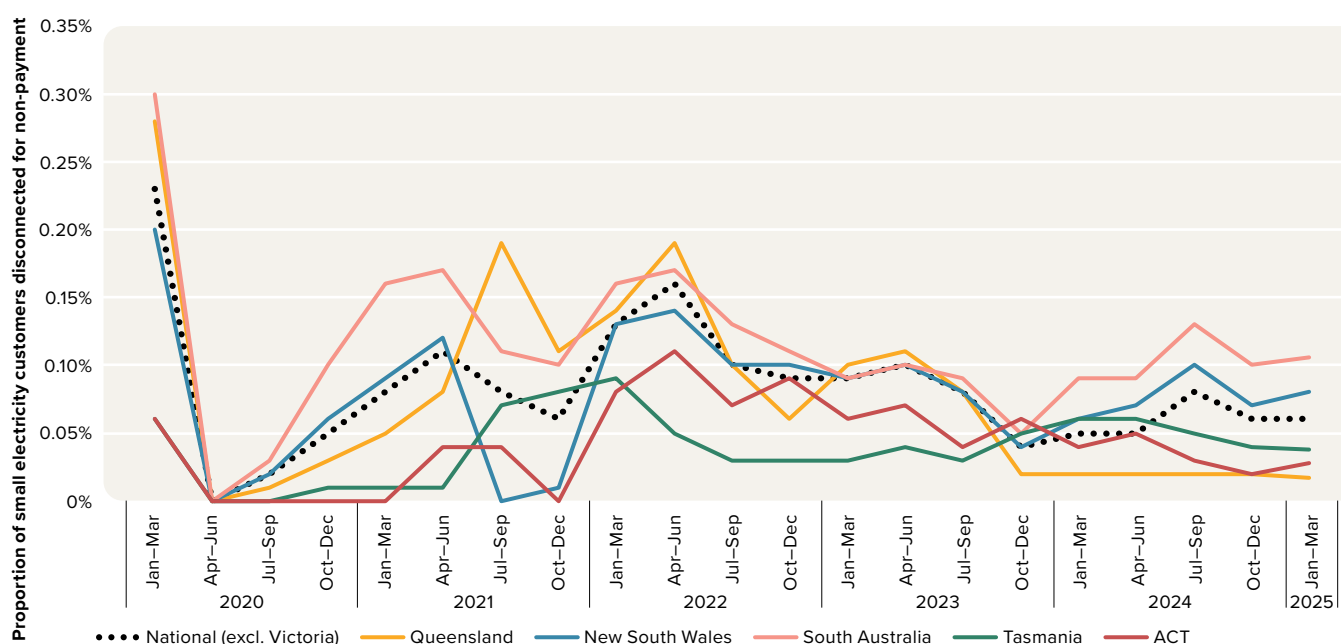
Under the Retail Law, disconnection for non-payment of bills is a last resort option. Disconnection is not permitted at all in certain circumstances – such as when a customer’s premises are registered as requiring life support equipment, when a customer on a hardship program is meeting their payment obligations or where a customer’s debt is below \$300. Action 10 of the *Towards energy equity* strategy committed to review the consumer energy debt threshold for disconnection, which was progressed as part of the AER’s Review of payment difficulty protections in the NECF. On 15 May 2025, the AER published its findings from this review, which identified an opportunity to strengthen minimum disconnection protections by increasing the minimum disconnection amount. We also published a draft decision proposing to increase the minimum disconnection amount to \$500 (including GST).⁶⁴⁵ A final decision is expected in mid-2025.

There are also specific times during which consumers are protected from disconnection. Typically, disconnections cannot occur:

- on a Friday, Saturday, Sunday, public holiday, or the day before a public holiday
- between 20 December and 31 December (inclusive)
- before 8 am or after 3 pm on any other day.

The rate of disconnections remains lower than in pre-COVID-19 years. This is encouraging because the AER’s *Statement of Expectations*, which directed retailers not to disconnect small customers during COVID-19, lapsed on 30 June 2021.⁶⁴⁶ The persistence of lower disconnection rates is apparent for both small electricity (Figure 6.21) and small gas (Figure 6.22) customers.

Figure 6.21 Disconnection for failure to pay – small electricity customers

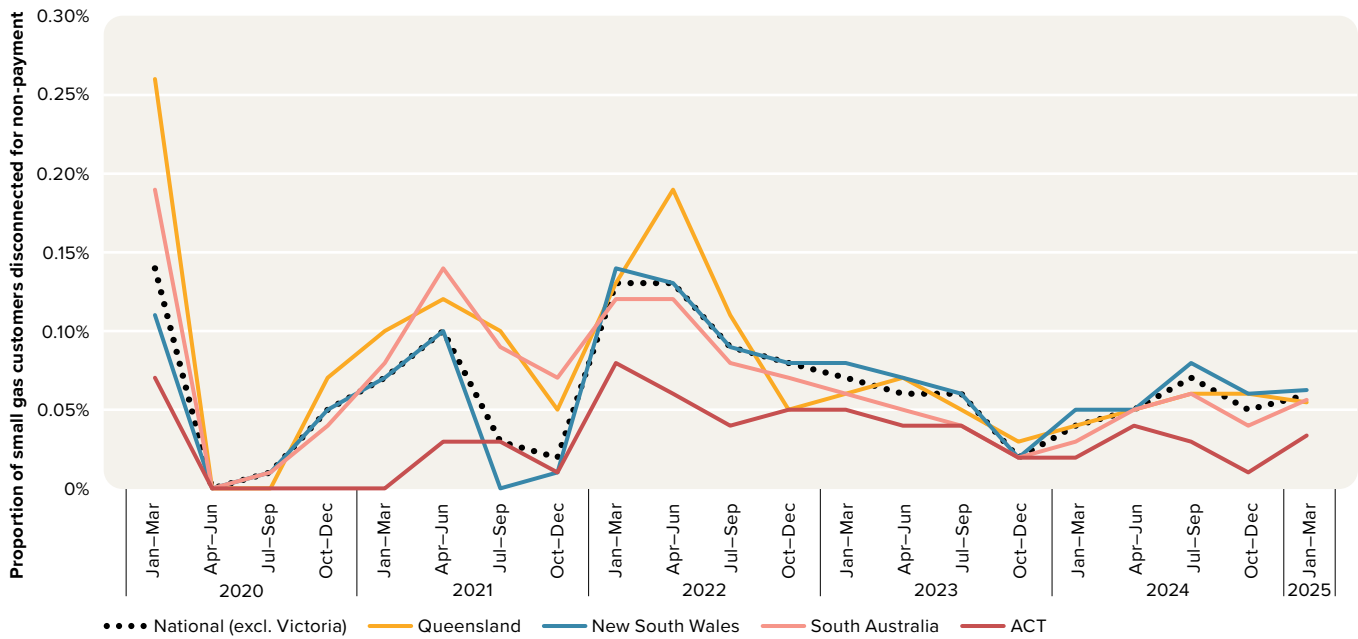


Source: AER, *Quarterly retail performance report, Q3 2024–25*, June 2025.

645 AER, [Draft decision - Minimum disconnection amount – 2025 review](#), Australian Energy Regulator, 15 May 2025.

646 AER, [Statement of Expectations of energy businesses: Protecting customers and the energy market during COVID-19](#), Australian Energy Regulator, 29 June 2021.

Figure 6.22 Disconnection for failure to pay – small gas customers



Source: AER, Quarterly retail performance report, Q3 2024–25, June 2025.

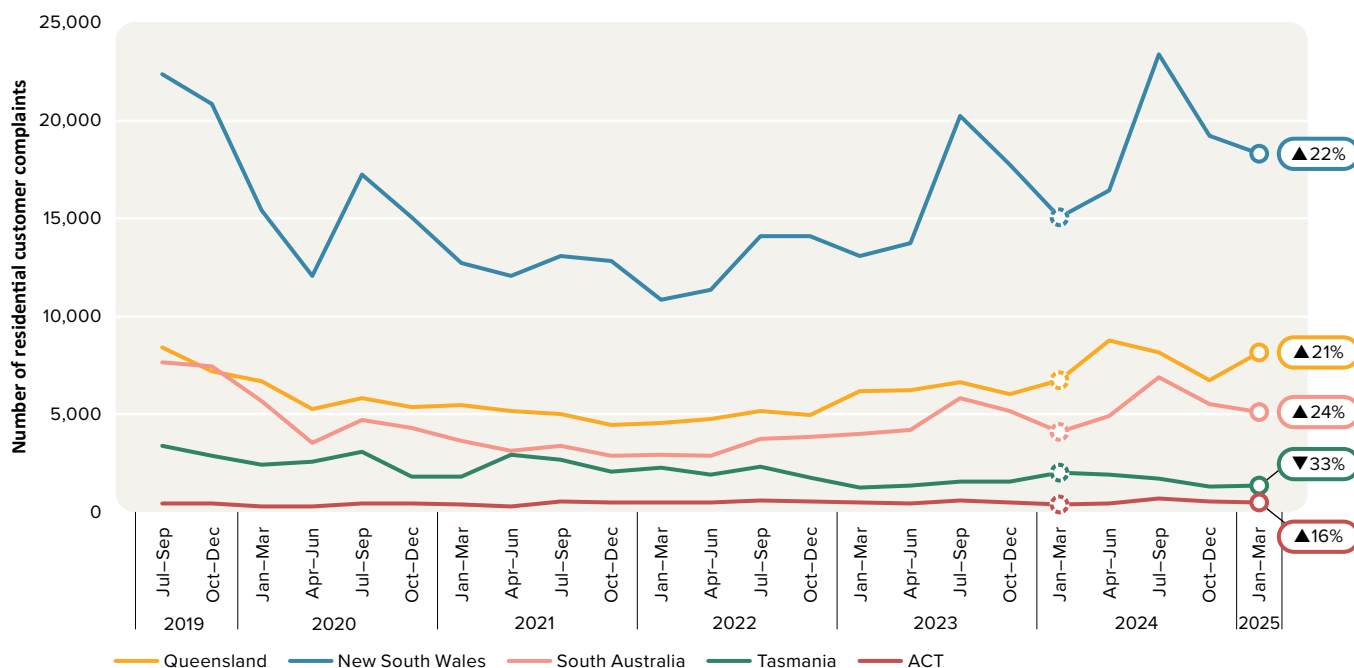
6.8.4 Customer complaints

Customers contact their retailer for various reasons, including billing enquiries, payment assistance, to seek better deals or to lodge a complaint. A high level of customer service should help give customers confidence that their needs are being considered and met where possible. It may also be a deciding factor for a customer considering which retailer to choose for their energy plan.

Over the 12-month period to 31 March 2025:

- 140,136 customer complaints were made to retailers, 19,940 (17%) more than were made in the previous 12 months. Retailers attributed higher volumes of complaints to price increases, cost-of-living and affordability challenges, and the implementation and consolidation of their new retail customer service platforms.
- The primary category of complaint was billing (including pricing, billing errors, payment arrangements and debt recovery practices).
- The number of complaints about smart meters (anything related to metering contestability) was relatively low; however, there were significantly more than were made in the previous 12 months. It will be important to continue monitoring this metric given the AEMC's rule change to accelerate smart meter deployment to achieve universal uptake by 2030 (chapter 3, section 3.8.1).

Figure 6.23 Residential customer complaints



Source: AER, *Quarterly retail performance report, Q3 2024–25*, June 2025.

6.9 Compliance and enforcement outcomes

Compliance and enforcement activity is a major part of the AER's regulatory toolkit. The AER seeks to ensure compliance with national energy laws so that consumers and energy market participants can have confidence that energy markets are working effectively and in their long-term interests.

The AER's 2024–25 compliance and enforcement priorities relating to retail markets were:

- Improve outcomes for customers experiencing vulnerability, including by improving retailer hardship policies and access to hardship and payment plan protections.
- Make it easier for consumers to understand their plan and engage in the market by focusing on compliance with billing and pricing information obligations, including the Better Bills Guideline and tariff change notification requirements.

Key compliance and enforcement activities in retail markets in the 2024–25 financial year included:

- securing a Federal Court finding that AGL had breached the National Energy Retail Rules by failing to notify and refund customers for overcharges obtained from Centrepay payments – AGL was ordered to pay penalties totalling \$25 million⁶⁴⁷
- securing a Federal Court penalty against CAM Engineering for failing to become a member of the Energy and Water Ombudsman NSW (EWON) scheme, in breach of the AER's Retail Exempt Selling Guideline⁶⁴⁸
- 5 Origin Energy subsidiaries ordered to pay penalties totalling \$12 million for more than 5,000 occasions where life support obligations under the National Energy Retail Rules (the Retail Rules) were breached – Origin also undertook to make a \$1 million community-based contribution to organisations assisting people using life support equipment⁶⁴⁹
- securing payment of \$542,400 for infringement notices issued to Powershop Australia Pty Ltd for alleged breaches of the life support obligations in the Retail Rules⁶⁵⁰

647 AER, [AGL penalised \\$25 million for breaches of overcharging rules related to Centrepay payments](#), Australian Energy Regulator, 19 December 2024.

648 AER, [CAM Engineering & Construction Pty Ltd: Breach of the National Energy Retail Law](#), Australian Energy Regulator, 4 July 2025, accessed 18 July 2024.

649 AER, [Origin subsidiaries penalised \\$12 million for breaching life support obligations](#), Australian Energy Regulator, 18 December 2024, accessed 18 July 2025.

650 AER, [Powershop fined \\$542,400 for alleged life support breaches](#), Australian Energy Regulator, 29 May 2024, accessed 18 July 2025.

- securing payment of \$135,600 for infringement notices issued to Locality Planning Energy Pty Ltd for alleged breaches of the National Electricity Law by owning embedded networks at residential sites without being registered with the AEMO or exempted by the AER⁶⁵¹
- securing payment of \$135,600 for infringement notices issued to Ergon Energy Queensland Pty Ltd for alleged failures relating to life support registration and deregistration obligations⁶⁵²
- reviewing retailers' family violence policies to ensure retailers are complying with new family violence protections that commenced in May 2023 under the Retail Rules – on 1 April 2025, the AER's Retail Compliance Procedures and Guidelines also updated to include new reporting obligations for breaches of the family violence obligations.

The AER has also undertaken and progressed numerous compliance and enforcement actions to ensure a secure and reliable energy supply and that Australia's energy markets operate efficiently and competitively. This includes activities relating to wholesale markets and networks, in addition to retail markets. The AER's compliance functions cover all NEM regions, excluding the energy retail market in Victoria, which is regulated by the Essential Services Commission (Victoria).⁶⁵³

More detail on the AER's compliance and enforcement work is available in the *Annual compliance and enforcement report 2024–25*.⁶⁵⁴

6.9.1 Compliance and enforcement priorities for 2025–26

The AER published its compliance and enforcement priorities for 2025–26 on 1 July 2025.⁶⁵⁵

The priorities align with the objectives in the AER's Strategic Plan 2020–2025.⁶⁵⁶ The compliance and enforcement priorities for 2025–26 relating to retail markets and energy consumers are:

- Improve outcomes for consumers experiencing vulnerability, including by ensuring access to hardship protections and affordable payment plans that reflect capacity to pay, and improving retailer hardship policies.
- Protect consumers during the universal transition to smart meters by focusing on compliance with smart meter rollout requirements, resultant tariff changes and ongoing metering practices.

651 AER, [LPE pays infringement notices for alleged breaches of the National Electricity Law](#), Australian Energy Regulator, 2 October 2024, accessed 18 July 2025.

652 AER, [Ergon Energy fined for alleged breaches of life support rules](#), Australian Energy Regulator, 3 May 2024, accessed 18 July 2025.

653 Other industry letters include information about [providing energy plan information on energy made easy, expectations around HelpPay and expectations on hardship obligations](#).

654 AER, [Annual compliance and enforcement report 2024–25](#), Australian Energy Regulator, 23 July 2025.

655 AER, [AER Compliance and enforcement priorities 2025–26](#), Australian Energy Regulator, July 2025.

656 AER, [Strategic Plan 2020–2025](#), Australian Energy Regulator, 14 December 2020.

Abbreviations

2P	proven and probable (gas reserves)
ACCC	Australian Competition and Consumer Commission
ACT	Australian Capital Territory
ADGSM	Australian Domestic Gas Security Mechanism
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGN	Australian Gas Networks
ARENA	Australian Renewable Energy Agency
APA	Australian Pipeline Agency
APLNG	Australian Pacific LNG
AQL	Auction Quantity Limit
ASX	Australian Securities Exchange
BECE	Better Energy Customer Experiences
C&I	commercial and industrial
CBD	central business district
CCGT	combined cycle gas turbine
CER	consumer energy resources
CESS	capital expenditure sharing scheme
CIS	Capacity Investment Scheme
CO ₂ -e	carbon dioxide equivalent
CoAG	Council of Australian Governments
CPI	consumer price index
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CSIS	customer service incentive scheme
DER	distributed energy resources
DMIAM	demand management innovation allowance mechanism
DMIS	demand management incentive scheme
DMO	default market offer
DWGM	Declared Wholesale Gas Market
EBSS	efficiency benefit sharing scheme
ECA	Energy Consumers Australia
ECGM	east coast gas market
EGP	Eastern Gas Pipeline
ERA	Economic Regulation Authority
ESC	Essential Services Commission
ESOO	Electricity Statement of Opportunities

EV	electric vehicle
EWON	Energy and Water Ombudsman NSW
FCAS	frequency control ancillary services
GJ	gigajoule
GLNG	Gladstone LNG
GPG	gas-powered generation
GSA	gas supply agreement
GSH	Gas Supply Hub
GST	goods and services tax
GW	gigawatt
GWh	gigawatt hour
HUGS	Heytesbury Underground Gas Storage
ICRC	Independent Competition and Regulatory Commission
IRR	interim reliability reserve
ISDA	International Swaps and Derivatives Association
ISP	integrated system plan
KKLP	Kurri Kurri Lateral Pipeline
km	kilometre
kW	kilowatt
kVA	kilovolt-ampere
LNG	liquefied natural gas
LRET	Large-scale Renewable Energy Target
MAIFI	momentary average interruption frequency index
MOS	market operator services
MSEP	Moomba to Sydney Ethane Pipeline
MSP	Moomba to Sydney Pipeline
Mt CO ₂ -e	million metric tonnes of carbon dioxide equivalent
mtpa	million tonnes per annum
MW	megawatt
MWh	megawatt hour
NECF	National Energy Customer Framework
NEM	National Electricity Market
NEO	National Electricity Objective
NERO	National Energy Retail Objective
NGO	National Gas Objective
NGP	Northern Gas Pipeline
NSW	New South Wales
NT	Northern Territory
OCGT	open cycle gas turbine
OTC	over-the-counter
OTTER	Office of the Tasmanian Economic Regulator
PJ	petajoule
PV	photovoltaic

QCA	Queensland Competition Authority
QCLNG	Queensland Curtis LNG
QGP	Queensland Gas Pipeline
Qld	Queensland
QNI	Queensland–NSW Interconnector
RAB	regulatory asset base
RED	Renewable Energy Dividend
RERT	Reliability and Emergency Reserve Trader
REZ	renewable energy zone
RIN	regulatory information notice
RIT	regulatory investment test
RIT-D	regulatory investment test – distribution networks
RIT-T	regulatory investment test – transmission networks
RRO	Retailer Reliability Obligation
SA	South Australia
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SRES	Small-scale Renewable Energy Scheme
STPIS	service target performance incentive scheme
STTM	Short Term Trading Market
SWP	South West Pipeline
SWQP	South West Queensland Pipeline
TJ	terajoule
TWh	terawatt hour
VDO	Victorian default offer
Vic	Victoria
VNI	Victoria to NSW Interconnector
VPP	virtual power plants
VTs	Victorian Transmission System
WACC	weighted average cost of capital
WCFB	Wallumbilla Compressor Facility B
WORM	Western Outer Ring Main
YTD	year to date



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