State of the energy market 2023

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Acknowledgements

This report was prepared by the Australian Energy Regulator. The AER gratefully acknowledges the following corporations and government agencies that contributed to this report:

The Australian Bureau of Statistics, the Australian Competition and Consumer Commission,
the Australian Energy Market Commission, the Australian Energy Market Operator,
the Energy Security Board, ASX Energy, the Australian Financial Markets Association,
the Clean Energy Regulator, CSIRO, the Reserve Bank of Australia, Energy Consumers Australia,
EnergyQuest, GlobalCOAL and the Victorian Essential Services Commission.

The AER also acknowledges Woodside Energy for supplying a photographic image.

Cover image sourced from iStock.

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Preface

This year's *State of the energy market* report again provides a comprehensive picture of Australia's electricity and gas markets, and how they are being experienced by consumers at a time of immense system change.

The report documents how our energy markets are performing as they continue to transition to a decarbonised future. This transition creates both opportunities for new investments and business models as well as challenges, such as reliability issues with ageing fossil fuel power plants, and coordinating wholesale market entry and exit.

While we have seen the volatility in energy markets subside since the turbulent events of June 2022, several pressures still remain in our system.

Increasing concerns about energy affordability present the backdrop to this report. Energy Consumers Australia's sentiment survey reports that 52% of households are more concerned about paying their energy bills than a year ago. Overall, we have seen numbers of customers in energy debt rise across most jurisdictions since mid-2022, while average energy debt levels have decreased in some jurisdictions but increased in others.

We have also seen the impact of significant government intervention aimed at reducing energy prices and bills. The AER has a significant role in assisting the NSW Minister administer arrangements in that state relating to capped coal prices. In addition, the Commonwealth, State and Territory Governments have funded significant bill relief packages for eligible customers.

We at the AER remain focused on protecting vulnerable consumers, while enabling consumers to participate in energy markets. Our vulnerability strategy, *Towards energy equity*, was released in late 2022 and we are continuing to work through new and tangible initiatives to protect consumers experiencing vulnerability. This includes our Better Bills Guideline to make energy bills simple, uncluttered, and easy to understand, which is mandatory from the end of September 2023. We have implemented new protections to support consumers impacted by family violence, and we are progressing additional work on billing delays and overcharging. We are also working on an energy 'game changer' to better share the costs and risks of vulnerability more equitably across the energy sector to improve outcomes and we are looking at ways this could take shape. We have made a number of enhancements to our price comparator website, Energy Made Easy, to provide consumers with a better user experience. We launched a public beta test site in June 2023 and we are on track to deliver the fully enhanced site by the end of this calendar year.

We will continue to build trust in the energy sector though diligent market surveillance and reporting, and our compliance and enforcement priorities will:

- improve outcomes for customers experiencing vulnerability
- make it easier for consumers to understand their energy plan and empower them to engage in the energy market
- support power system security and the maintenance of critical infrastructure in the National Electricity Market
- support a more efficient and transparent gas market under the new Gas Market Transparency Measures.

This report highlights a range of challenges in our energy markets that require continued monitoring, analysis and policy attention.

From an affordability perspective, it is vital that we find ways to ensure the benefits of consumer energy resources (such as rooftop solar PV, or small-scale batteries) are shared by all customers. This will require effective whole-of-system integration, which would avoid more costly alternatives of additional grid and generation investment.

In relation to system security, despite good progress, we highlight the potential for localised high costs of Frequency Control Ancillary Services, and we have seen an increased reliance on AEMO directions to manage system strength in South Australia. A lack of visibility of consumer energy resources, plus apparent high rates of technical non-compliance with certain standards, may also raise system security risks.

This report highlights the coordination challenges required to ensure new generation is built before existing coal-fired power plants retire. While the pipeline for new investment appears healthy, not enough of that pipeline is committed. The need for new investment is pressing and widespread across the NEM. In addition, it is vital that coal exits in an orderly way. This report highlights the need for greater certainty about an orderly timetable for coal exits, as well as appropriate incentives to maintain generation units until they exit on this timeline.

The greatest challenge identified through this transition relates to the timely and least-cost delivery of major transmission projects. These projects are important enablers of the transition. They are also large and complex, particularly impacting on local communities. These investments have been progressing more slowly than planned, and their costs have been escalating significantly, intensified by international and domestic supply chain issues.

Finally, we have raised concerns in relation to open and competitive markets. Our concerns are around reduced liquidity of exchange-traded hedging products, the declining number of clearing service providers for electricity derivatives, and the levels of concentration of ownership of flexible generation capacity, particularly in NSW and Victoria. The AER's anticipated new powers in relation to contract market monitoring will allow us to better monitor participant behaviour and gain sharper insights on issues of competition and market power.

I recommend the *State of the energy market 2023* report to all stakeholders as a source of key industry data as we work collaboratively to respond to the challenges and opportunities the transition presents and help make energy consumers better off now and in the future.

Clare Savage
AER Chair
October 2023

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Image source: iStock

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The energy system in transition

State of the energy market is the AER's annual summary of 'the year that has been' across electricity and gas supply chains, including wholesale markets, transportation and retail. Chapter 2, the market overview, sets out a short summary of key outcomes. Chapters 3 through 7 set out analysis of each supply chain component. In combination, they give a broad and relatively comprehensive picture of market outcomes since publication of the last *State of the energy market*.

Australia's energy systems are undergoing rapid technological and economic transition alongside national efforts to decarbonise the economy. To put annual analysis in context of the fundamental transformation taking place, this first chapter summarises major developments and challenges in progress towards the energy transition. It does so using the Strategic Energy Plan's vision for a future energy market as a reference point. The Strategic Energy Plan was developed in 2020 by the COAG Energy Council in consultation with the Energy Security Board (ESB). The Strategic Energy Plan has 5 objectives which, taken together, point to a transition through which the future energy market is able to provide:

- affordable energy and satisfied consumers
- a secure gas and electricity system
- reliable and low-emissions energy
- effective development of open and competitive markets
- efficient and timely network investment.

This chapter is structured around these objectives as a way to summarise the status of the transition today, to point to the future and to summarise some of the key challenges and work underway to address them.

1.1 2023 in summary

The energy system in 2023 has so far experienced fewer shocks and better outcomes than in 2022. Electricity and gas wholesale market prices declined from record highs in 2022, supported by more favourable market conditions alongside government interventions in coal and gas markets. Governments across Australia provided substantial short-term support to ease pressure on consumers, and worked with market bodies to progress vital policy reform to support transition.

Nonetheless, despite these improvements over 2023, many of the vulnerabilities observed in 2022 remain. Supply-demand balances in both electricity and gas markets are tight and continue to interact. Heightened wholesale electricity prices exerted major upward pressure on retail prices for 2023–24. This has occurred in economic conditions where consumers are not well placed to absorb bill increases due to broader increases in costs of living.

There are also major and urgent pressures for investments to keep pace with the energy transition and retirement of coal generation. 2023 has seen the exit of a major power station from the NEM with the closure of Liddell Power Station in April. New entrant generation and favourable market conditions meant this went smoothly. There are 4 further coal-fired power stations scheduled to close in the next decade and urgent investment in generation, storage and transmission is needed to prepare for this.

Planning for these requirements is being informed to a growing extent by the interconnectedness of electricity and gas markets. As more states and territories seek to shift drivers of gas demand into electricity demand, for example replacing gas heating with reverse cycle air-conditioning, demand pressure will ease in gas markets and grow in electricity markets. Other variables, such as the rate of take-up of electric vehicles, will also have material impacts on electricity demand and as a result the required scope and timing of new generation and network investment.

New generation and transmission investment to support the transition has faced numerous challenges, including:

- the scale and coordination of investments required
- rapidly accelerating costs across the infrastructure supply chain and higher costs of capital
- the importance of properly engaging and reflecting the views of communities that will host these assets in planning and developing projects.

Both the investments themselves and reforms to facilitate them are being supported by significant involvement from governments of all levels. This includes numerous joint initiatives between the Australian Government and state and territory governments. The scale of required investment is significant and timing is pressing. As a result, it requires comprehensive coordination and planning.

This planning will be guided in part by the expansion of the national electricity, gas and retail objectives to include emissions reduction as part of the long-term interests of energy consumers alongside price, quality, reliability, safety and security of supply.

1.2 Affordable energy and satisfied customers

Energy should be affordable and accessible for all consumers. This means that as a community we are concerned not only about the cost of energy, but also about the ability of consumers to manage their energy usage, access consumer energy resources such as solar and batteries and navigate the market. Consumers should feel confident in the choices they make in energy markets, get help and support when they need it and be protected from harm. All consumers, including those of different income and preferences and those experiencing vulnerabilities, should have equitable access to these abilities, benefits, supports and protections.

1.2.1 Affordability and consumer satisfaction in 2023

Energy affordability had been improving in recent years but has been impacted in 2022–23 by energy market shocks intersecting with wider increases in costs of living. In SEC Newgate's Mood of the Nation report for August 2023, the number one issue among the Australian public is reducing cost increases for household bills and other additional expenses. According to the report, 82% of Australians are extremely or quite concerned about electricity bills and 57% extremely or quite concerned about gas bills.[1]

In the immediate term, the Australian Government in partnership with state and territory governments has established the Energy Bill Relief Fund, ranging from $175 to $700 for eligible consumers in different regions. This recognises that the components of energy costs vary between jurisdictions. State and territory governments have also introduced targeted measures for low-income households to reduce their energy bills, such as the Victorian Household Energy Savings Package, the ACT's Home Energy Efficiency Program and the Queensland Cost of Living Rebate.[2]

Surges in wholesale electricity and gas prices over 2022 are putting immediate upward pressure on retail prices available to consumers. Wholesale prices have eased over 2023 in response to more favourable market conditions and significant interventions to stabilise markets. Nonetheless, they remain above levels seen before 2022.

In coming years, multiple factors risk putting upward pressure on costs: inflation outcomes (e.g. affecting annual network tariffs), global supply chain disruptions, labour shortages, and potential uplifts for the cost of capital (related to higher interest rates) and for other adjustments (related to maintaining social licence). These issues are discussed more extensively in chapters 4 and 6. In combination, they will pose pressures for affordability.

1.2.2 Action on key challenges

Managing energy costs remains the main concern for consumers

Upward pressure on energy costs has been challenging for consumers. In the recent sentiment survey by Energy Consumers Australia (ECA), 52% of households are more concerned about paying their energy bills than they were a year ago, up 15% from the same measure in 2022.[3]

Energy debt levels have varied between jurisdictions, but we have generally seen growing numbers of customers in energy debt across most jurisdictions since mid-2022. Over the same period, average energy debts have increased in some jurisdictions and decreased in others.

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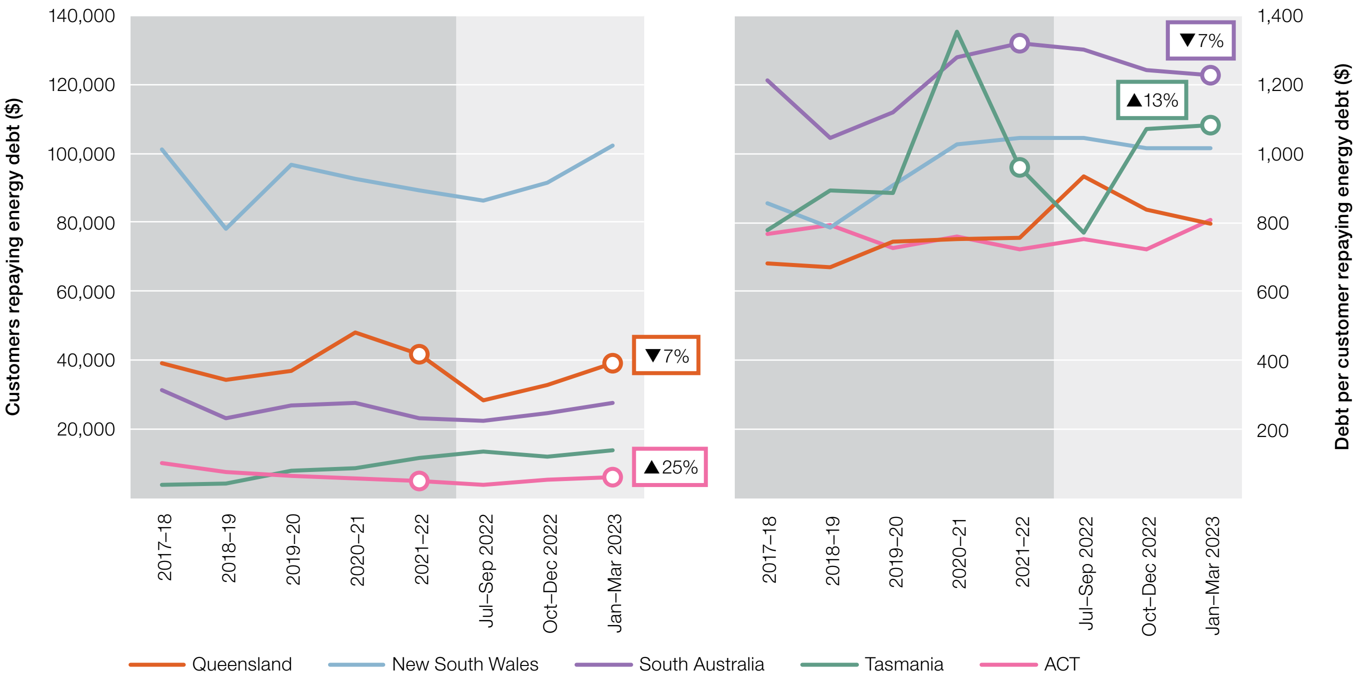
1 SEC Newgate Australia, Mood of the nation, August 2023.

2 South Australia's Retailer Energy Productivity Scheme offers free or discounted energy efficiency and energy productivity activities, but it is not specifically targeted at low-income households.

3 Energy Consumers Australia, Consumer Sentiment Survey, June 2023.

Figure 1.1 Residential 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 2022–23, June 2023.

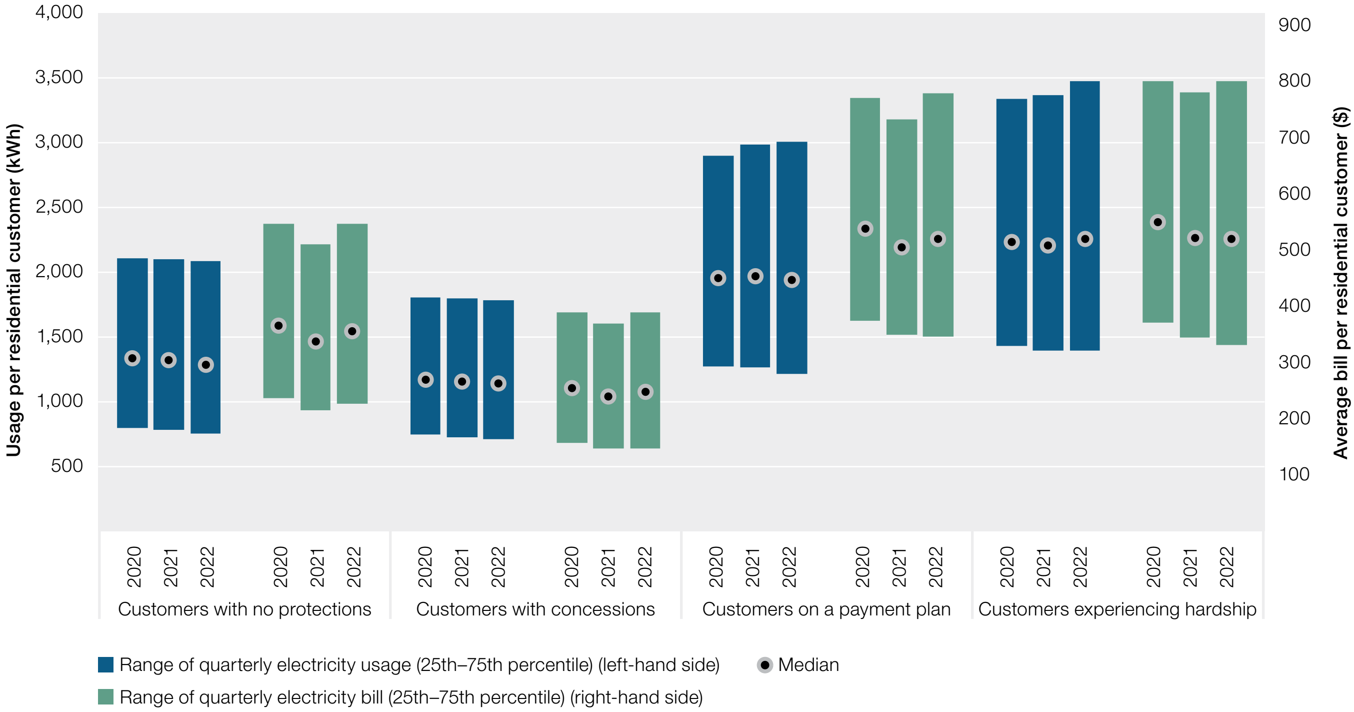
In the short term, bill relief provided by governments should mitigate the immediate effects of price increases for many customers, but there will likely remain pressure since costs of living are increasingly rapidly. Customers will also need to adjust to new prices as this temporary relief ends.

Higher bills will create additional debt pressure on customers, particularly those facing financial hardship or who face other limitations on their ability to manage costs.

Energy costs and savings are not shared evenly across consumers

Low-income consumers bear a higher cost burden for energy than other consumers. Firstly, they have less income available to pay for energy costs. For low-income earners, electricity bills as a proportion of income are at least double that of average income earners.

Figure 1.2 Electricity use and average bill by residential customer type



Note: kWH: Kilowatt hour.

Source: ACCC, Inquiry into the National Electricity Market, June 2023.

Secondly, their energy costs and/or use can be higher than average due to challenges investing in consumer energy resources or energy efficient home improvements, due to up front costs or renting. In most states, energy bills are also higher for customers in regional and remote areas, where network costs tend to be higher and can be recovered from fewer customers than in urban networks.

Irrespective of financial constraints, consumers may still struggle to engage in the energy market given its complexity. One example of growing complexity is in respect of smart meters. Smart meters allow for more flexible and sophisticated tariff structures, which for many consumers may offer opportunities to manage electricity costs. However, navigating the advantages of smart meters is complex and there is evidence that many consumers are not receiving the benefits. ECA's most recent consumer behaviour survey found that over a third of respondents in Victoria– where smart meters have been installed in up to 99% of homes – indicated they were either unsure or stated they did not own a smart meter. Another third indicated they do not use their meter to help control energy costs.

To maximise and widen the benefits of consumer energy resources, immediate work is required on data capabilities and integration of technologies

To best share the benefits of consumer energy resources across all consumers, they should be optimised at a system-wide level so that:

- demand reductions, especially at peak periods, are maximised – taking pressure off generation requirements and local network constraints
- any network investments required to integrate consumer energy resource are efficient and cost-effective.

By effectively integrating these resources, it is possible to avoid the need for more costly grid and generation investment. Increasingly, energy service providers are entering the market offering energy services that enable consumers to sell their electricity back into the grid at times when it is needed. However, the success of these services will require consumers to have trust and confidence that these new services will work for them and that they are protected from harm.

In 2021, the ESB released the Consumer Energy Resource Implementation Plan, which outlines reforms that are required to unlock the benefits of the rapid uptake of consumer energy resources, while also reducing the risks created by the speed and scale of the change. Key objectives of the plan include:

- rewarding consumers for their flexible demand and generation

- supporting energy market innovation
- ensuring effective consumer protections are in place
- allowing networks to accommodate consumer energy resources and manage security
- providing visibility and tools to the system operator to operate a safe, secure, reliable system.

In addition, the AER has been undertaking a review to understand potential gaps that may emerge in the consumer protections framework as a result of the evolving energy market. In October 2022 the AER published an options paper in its Review of consumer protections for future energy services.[4] Through its review, the AER has concluded there is a strong case for reforming the National Energy Customer Framework (NECF). The AER concluded that energy consumers need additional protection as the market evolves and that this won't be provided by the scope and regulatory approach in the existing framework.

Following the October 2022 release of the options paper setting out various options for regulatory reform, the AER has undertaken extensive stakeholder consultation and a thorough risk analysis. This has guided development of the AER's final advice on the need to reform the NECF, which will be provided to Energy Ministers before the end of 2023.

As the ESB's term draws to a close in 2023, it remains important that market and regulatory arrangements support integration of consumer energy resources, demand-side participation and new technologies, and do so in a way that empowers and protects consumers. Harnessing consumer energy resources and the new energy services that they enable is critical for an orderly, equitable and cost-effective energy transition.

1.3 Secure gas and electricity system

A key element of effective energy markets is their ability to remain in a secure operating state. That is, they must be able to respond quickly and remain stable in response to unexpected changes. System security is critical to ensuring energy reaches consumers.

In electricity supply, the energy transition will reshape how the power system achieves this capability. In a coal, gas or hydro generator, the rotation of turbines contribute to the ability of the power system to remain in a secure operating state. Many system security services are provided as a by-product of synchronous generation sources with large spinning turbines, such as coal and gas generators. However, much new renewable generation connects to the system in a different way, via power electronics, and is not currently capable of providing these services. As the spinning plants age and reach retirement, these services will need to be provided through new mechanisms and technologies.

A more detailed discussion of these essential system services can be found in AEMO and the AEMC's joint paper – *Essential system services and inertia in the NEM* and AEMO's *Engineering Framework*.[5] [6]

1.3.1 Security of gas and electricity system in 2023

Maintaining system security continues to be challenging and costly as the pace of the energy transition accelerates. However, there is some evidence of positive progress.

The AEMC is leading consideration of how to improve security frameworks for the energy transition as one of a series of rule changes at a system level to improve management of electrical characteristics such as frequency, voltage, system strength and inertia.[7] Following feedback from stakeholders in 2022, the AEMC is focusing on simple and flexible mechanisms to maximise benefits and reduce costs.

In gas markets, system security was relatively stable over 2023 but remains vulnerable to shocks demonstrated in 2022. In 2022 markets were challenged to the extent that AEMO issued 7 'threat to system security' notifications for the Victorian gas market. This included directing that gas generators in the NEM sourcing gas from the Victorian market not generate in order to preserve sufficient capacity in the Iona gas storage facility. Markets did not experience comparable threats over 2023. Lower gas-powered generation in the NEM and milder weather resulted in lower gas demand generally over winter, easing pressure on gas markets. Nonetheless, the risks will remain and

4 AER, Review of consumer protections for future energy services: Options for reform of the National Energy Customer Framework, Australian Energy Regulator, October 2022.

5 AEMC and AEMO, Essential system services and inertia in the NEM, Australian Energy Market Commission and Australian Energy Market Operator, June 2022.

6 AEMO, Engineering Framework, Australian Energy Market Operator.

7 AEMC, Operational security mechanism, Australian Energy Market Commission, accessed 15 August 2023.

intensify if exit of coal generation in the NEM outpaces investment in renewable generation and enabling transmission investment. Besides the specific risks to security in east coast gas markets, this highlights the interacting challenges of closely interconnected electricity and gas markets.

The integration of consumer energy resources presents additional system security risks and opportunities. Increasing uptake of consumer energy resources reduces reliance on the grid when it is available. If well-coordinated, this has the potential to support system security. However, at present, AEMO has relatively little visibility of the real-time contribution of consumer energy resources to the NEM. Without improved coordination, this has the potential to make system forecasting and operation more difficult, increasing the challenges of maintaining system security.

1.3.2 Action on key challenges

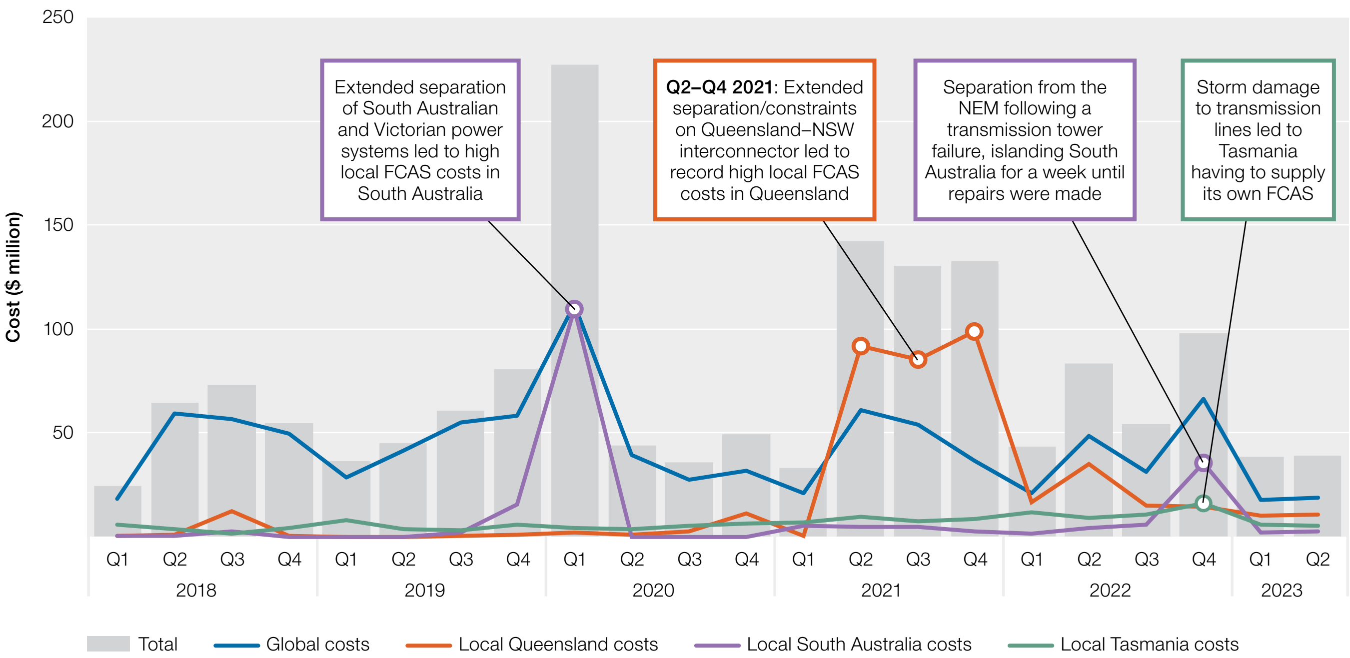
As the transition proceeds, there are longer-term risks of localised high FCAS costs

AEMO can procure frequency control ancillary services (FCAS) through the NEM to maintain grid frequency within technical operating limits.

Over the past few years, FCAS markets have attracted investments in grid-scale batteries, virtual power plants (VPPs) and demand response aggregators. This new entry has been successful in increasing competition in FCAS markets and providing new sources of FCAS as thermal plant exits.[8] Mandatory primary frequency response requirements introduced in 2020 have increased the security of the power system by increasing its resilience to frequency excursions and have reduced the need for AEMO to procure additional frequency control services. The introduction of a very fast FCAS market will further support least-cost procurement of FCAS services.[9]

Despite these positive developments, there is an ongoing risk of FCAS shortages driving costs in the event of planned and unplanned network outages preventing access to FCAS services across regional boundaries. In the last quarter of 2022, South Australia experienced high local FCAS costs ($34 million) and Tasmania experienced record local FCAS costs ($14 million) in response to network outages resulting from weather events.[10] These events, as well as the significant FCAS costs seen in Queensland in 2021 resulting from the Qld-NSW interconnector upgrade, highlight the vulnerabilities of local markets to transitory network and plant outages. In particular, local markets are highly concentrated and remain vulnerable to individual participants' commercial strategies.[11]

Figure 1.3 Frequency control and ancillary service (FCAS) costs since 2018



Note: Global and local FCAS costs, by quarter.
Source: AER analysis using NEM data.

8 AER, *Wholesale electricity market performance report 2022*, Australian Energy Regulator, ch. 9.
9 AEMC, Final determination: Fast frequency response market ancillary service rule, Australian Energy Market Commission, July 2021.
10 AER, Wholesale market quarterly report – Q4 2022, Australian Energy Regulator, February 2023.
11 AER, *Wholesale electricity market performance report 2022*, Australian Energy Regulator, pp. 121–2.

Further augmentation of the network, including upgrades to interconnectors, may help improve system security in the longer term but in the meantime will likely continue to create long outages and extended periods of reliance on local FCAS services. Costs imposed on consumers should be factored early into planning network outages, so that local FCAS can be sourced relatively cheaply and efficiently.

Directions to support system security can be expensive

AEMO uses directions when commercial generation capacity is not available or able to address problems. The frequency with which AEMO has used directions to manage system security has increased markedly since 2016. Since Q2 2022, these directions have been used exclusively to manage system strength in South Australia.[12]

Despite the installation of synchronous condensers in 2021, South Australian security direction costs have risen sharply in both cost and the proportion of time they are required since Q4 2022.[13] AEMO reports that this increase in costs has followed gas-fired generators opting to offer less into the NEM in response to higher renewable generation output.

Figure 1.4 Costs of directions since 2018 excluding RERT

Source: AEMO data; AER analysis.

Recent reforms will contribute to providing essential system services at least-cost to consumers

Essential system services reforms are focused on establishing new markets or other methods to procure system services in the long-term interests of consumers.

Implemented changes and ongoing rule proposals include:

- Creating fast frequency response markets and the introduction of a mandatory primary frequency response requirement. The implementation of mandatory primary frequency response has resulted in significantly improved and stable frequency performance. Since the commencement of this reform, the number of excursions outside of the normal operating frequency band has significantly dropped and the frequency has remained closer to the 50 hertz requirement.
- Requiring transmission businesses to proactively forecast and procure services (known as system strength), which facilitate the stable operation of the power system electronics that govern the operation of renewable generation. This reform is being implemented at a time when technological advances in the design of power system electronics may soon allow them to contribute to the provision of essential system services. It will be important to navigate this transition carefully to ensure investments are in the long-term interests of consumers.

12 RERT directions relating to reliability increased significantly in June 2022 before the suspension of the NEM.

13 AEMO, Quarterly energy dynamics: Q2 2023, Australian Energy Market Operator, July 2023, pp. 40–41.

- Recommended improvements to existing inertia, network support and control ancillary services and non-market ancillary services frameworks to create proactive, forward-looking and enduring arrangements to help ensure system security and reduce the use of directions.[14]
- A rule change proposal for an ancillary service spot market for inertia in the NEM to ensure the secure and efficient operation of the power system through the energy transition. A draft determination is expected to be published in February 2024.[15]
- Clarifying mandatory primary frequency response obligations for batteries with capacity of 5 MW or greater.[16]

Work also continues to embed the rule changes into NEM systems, as well as exploring further reform mechanisms for other system services:

- AEMO published the primary frequency response requirements in May 2023,[17] and the Frequency Contribution Factors Procedure in June 2023.[18]
- The AEMC published a revised frequency operating standard in April 2023, which will come into effect on 9 October 2023 to align with the commencement of the new market ancillary service arrangements.[19]

Low visibility to the market of consumer energy resources creates some risks

The growth of consumer energy resources provides significant opportunities for potential new sources of system services (for example, through flexible use of residential batteries). However, it may also pose some longer-term challenges to system security.

This is because of ‘minimum demand’ periods during the day and the lack of visibility and control over consumer energy resources by AEMO compared with centralised generation, all of which makes the system more difficult to operate. Figure 1.5 sets out AEMO’s projections of minimum operational demand.

14 AEMC, Improving security frameworks for the energy transition, Australian Energy Market Commission, August 2023.

15 AEMC, Rule Changes, Efficient provision of inertia, Australian Energy Market Commission, March 2023.

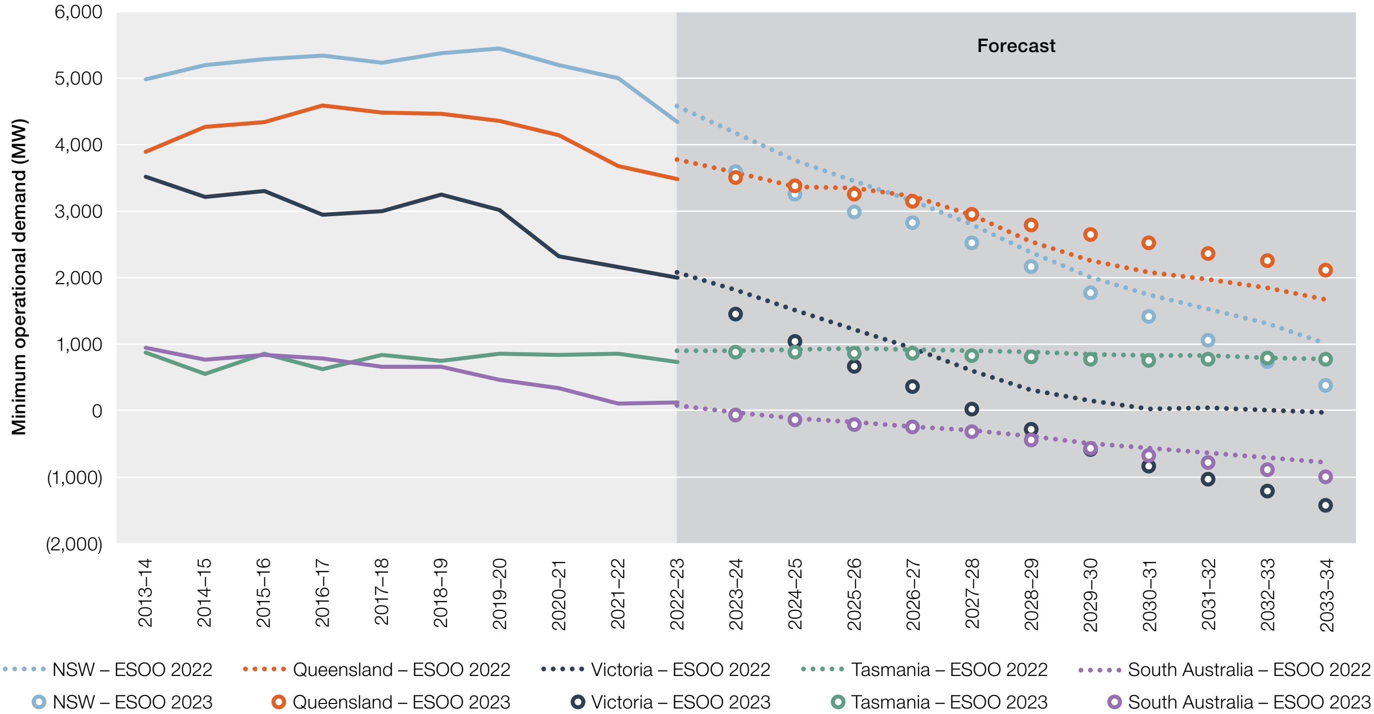
16 AEMC, Clarifying mandatory primary frequency response obligations for bi-directional plant, Australian Energy Market Commission, August 2023.

17 AEMO, Primary Frequency Response Requirements, Australian Energy Market Operator, May 2023.

18 AEMO, Frequency Contribution Factors Procedure, Australian Energy Market Operator, June 2023.

19 AEMC, Frequency Operating Standard, Australian Energy Market Commission, April 2023.

Figure 1.5 Regional annual actual and forecast 50% probability of exceedance (POE) minimum operational demand (sent-out), 2022 ESOO central and 2023 ESOO central scenarios, 2022–23 to 2033–34



Note: The actuals displayed are not weather-corrected or adjusted for system events and exclude DSP. Also, the 2023 ESOO uses the step-change scenario as its central outlook.

Source: AEMO, Electricity Statement of Opportunities 2023.

Residential solar PV capacity has increased year on year, which is likely to accelerate declining minimum demand. By 2025, AEMO forecasts that there will be periods where distributed solar PV supplies up to 70–80% of underlying customer demand in mainland NEM regions. At present, there is no ability to actively manage these resources except in South Australia, where it is only an emergency measure and not one for general support of consumer energy resource utilisation.[20] If no action is taken, with the present operational tools it has available, AEMO will struggle to deliver minimum requirements for essential system requirements including system strength, inertia, voltage management and frequency control.

Some forms of consumer energy resources have also been found to disconnect simultaneously from the power system during power system disturbances, exacerbating system instability. Technical standards for consumer energy resources have been updated to address this, but AEMO has identified that only approximately 35% of new installations are being installed correctly in compliance with the new standard.[21] The AEMC will be reviewing compliance with inverter standards as part of assessing the NEM's progress adopting standards already introduced in the NER. This is part of its broader work on governance of technical standards for consumer energy resources.[22]

1.4 Reliable and low-emissions energy

A reliable power system has enough generation, demand response and network capacity to supply customers with the energy that they demand with a very high degree of confidence.

The energy transition is changing the requirements and challenges necessary to support system reliability. To reduce emissions from electricity supply, traditional sources of electricity generation which use fossil fuels must be replaced with new, low-emissions sources. Solar and wind generation already account for a material proportion of generation in the NEM. This will continue to grow, and need to be supported with flexible capacity, such as batteries and hydro generation, that can be dispatched on demand to meet peaks. To maintain reliability while the transition takes place, the timing of this replacement expenditure will need to be coordinated in particular with the exit of coal generators.

20 AEMO, 2021 Electricity Statement of Opportunities, Australian Energy Market Operator, August 2021, Section 6.1.

21 AEMO, Power System Frequency Risk Review, Australian Energy Market Operator, July 2022, Section 3.3.1.

22 AEMC, Rule Determination National Electricity Amendment (Governance of Distributed Energy Resources Technical Standards) Rule 2022; National Energy Retail Amendment (Governance of Distributed Energy Resources Technical Standards) Rule 2022, Australian Energy Market Commission, March 2022.

Gas generation will remain an important source of flexible capacity during the transition because, unlike coal generation, it is relatively well suited to shorter periods of operation in which it ramps up and down to meet peaks in demand. In the short term, this creates demand pressure impacting both domestic and industrial uses of gas, which in turn has implications for reliability in electricity markets. However, the longer-term domestic and industrial requirements for gas as a fuel are changing. Governments across Australia are establishing and implementing visions for the future role of gas in a low-emissions energy supply chain, and in some cases are actively progressing electrification of gas usage.

1.4.1 Reliability and progress towards low-emissions energy in 2023

The energy crisis in June 2022 highlighted significant challenges to reliability and system security. The same conditions have not arisen over 2023, following significant improved market conditions and temporary interventions in electricity and gas markets. However, the experience of 2022 showed that there are a range of vulnerabilities to the reliability of energy supply as coal generation ages and exits the market. In particular, it highlighted the sensitivity of the market to outages among those ageing plants, challenges accessing fuel, exposure to international fuel prices and interconnections between electricity and gas markets in which there are related reliability challenges.

An emissions objective will shortly be implemented within the national electricity, gas and retail objectives. When the objective is implemented, emission reductions will no longer be part of the external context for decision-making by the AER and other market bodies. They will become one of the central considerations in determining if decisions are in the long-term interest of consumers. The Australian Government will in close consultation with market bodies, states and territories lead work on developing a value for emissions, or method for determining one. A value, or method for determining one, is expected to be available by November 2023. Such a value will inform system planning, expenditure assessments for network investment, cost-benefit analyses and how consumer energy resources should be factored into investment business cases.

In September 2022, Australia updated its 2030 national target to 43% emissions reduction below 2005 levels. AEMO has now incorporated this target across all of its modelling scenarios.[23] The most recent emissions projects suggest that, with currently announced policies and 'with additional measures', Australia is projected to be 40% below 2005 levels by 2030 and 1% above the 2021–2030 emissions budget.[24] From 2020 to 2030 most of the decline in emissions in the baseline scenario is projected to come from the electricity sector due to strong uptake of renewables supported by policies of the Australian, state and territory governments.

Separate to this national target, individual states and territories have also implemented:[25]

- further emissions reductions commitments, targeting earlier reductions of emissions
- specific renewable energy targets
- storage targets to support sufficient dispatchable capacity.

The pipeline of investment to support this transformation is positive. As at July 2023, AEMO forecast that the committed and announced proposed new generation pipeline is roughly 30% of the NEM's total current generation capacity.[26] Including proposed projects, the pipeline is roughly 4 times the existing capacity of the NEM. This is an over 60% increase on the proposed pipeline from July 2022. The majority of this pipeline comprises low-emissions solar, wind and hydro generation.

Nonetheless, most of the change to the extended generation pipeline is not yet committed. The NEM faces accelerated coal retirements and gas shortfalls affecting the most important current sources of flexible generation. With the NEM expected to experience 4 announced coal-fired generator retirements in the next decade, and needing resilience for potential future closures as well, the investment need is pressing and widespread across the NEM.

Illustrating this urgency, AEMO has forecast shortfalls in all NEM mainland regions as we approach 2030 (based on committed generation and transmission investment).[27] These forecast shortfalls have accelerated from the 2022 equivalent forecasts, reflecting factors including higher unplanned outage rates among generators, widespread delays in project delivery compared with forecasts, and fast growth in demand caused by electrification.

23 AEMO, Inputs, assumptions and scenarios report, Australian Energy Market Operator, August 2023, p. 28.

24 DCCEEW, Australia's emissions projections 2022, Department of Climate Change, Energy, the Environment and Water, December 2022.

25 AEMO includes in its 2023 Inputs, Assumptions and Scenarios report a detailed summary of Australian, state and territory government policies included in its modelling across all scenarios. AEMO, Inputs, assumptions and scenarios report, Australian Energy Market Operator, August 2023, pp. 7–8.

26 AEMO, Generation information: July 2023, Australian Energy Market Operator, accessed 15 August 2023.

27 AEMO, 2023 Electricity statement of opportunities, Australian Energy Market Operator, August 2023.

1.4.2 Action on key challenges

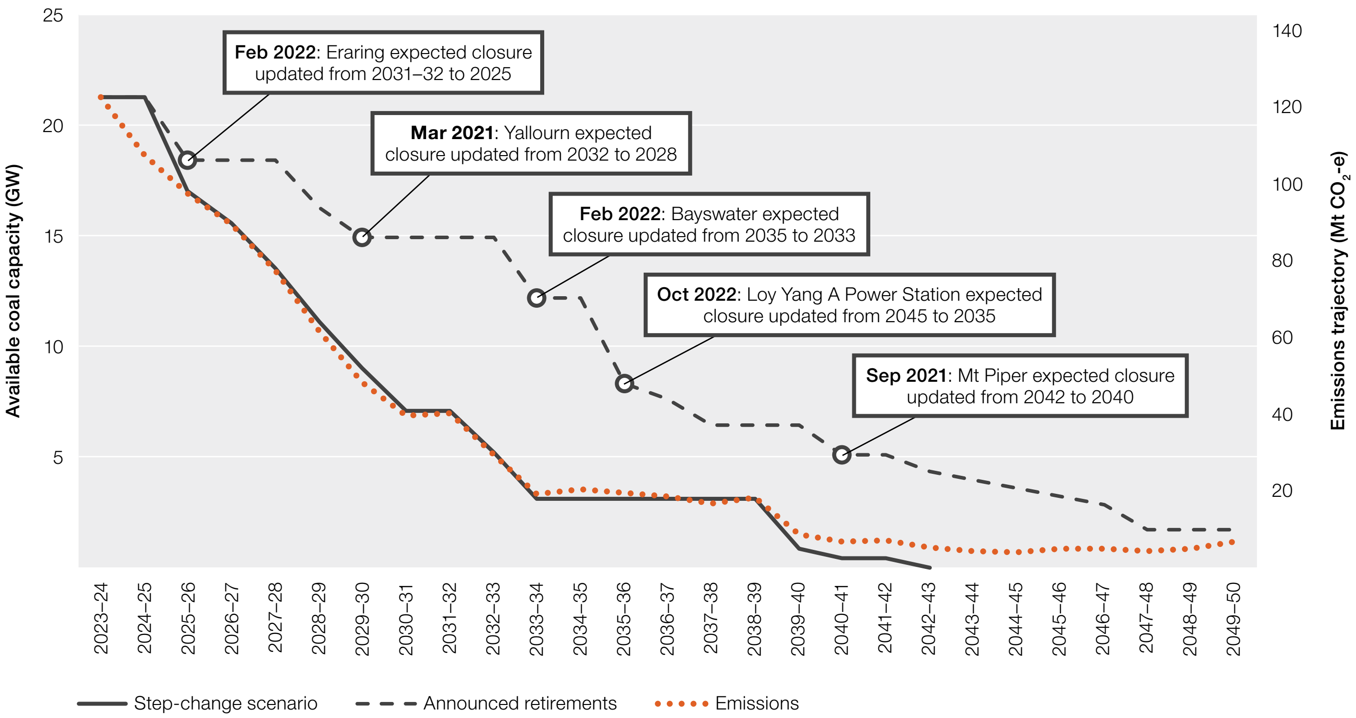
It is vital that coal exits the market in an orderly way

The remaining units of Liddell Power Station exited the NEM in April 2023, on schedule and in an orderly manner. Market impacts to date have been mitigated by the entry of new renewable generation alongside otherwise favourable market circumstances since closure (chapter 3).

The NEM now expects 4 coal-fired generator retirements in the next decade, including the remaining units of Eraring Power Station (NSW – August 2025), Callide B Power Station (Queensland – 2028), Yallourn W Power Station (Victoria – 2028) and Vales Point B (NSW – 2033).

Coal generation is the most impactful driver of the emissions from the NEM. To meet emissions reductions targets, coal generation must exit the NEM in a timely way.

Figure 1.6 Forecast coal retirements and links with emissions



Note: The ‘emissions’ line shows the forecast emissions trajectory from the ‘step change’ scenario.
Source: AER analysis, AEMO data.

The ‘step-change’ scenario, used as the central scenario in AEMO’s planning, projects coal exiting the NEM more rapidly than has been currently announced (Figure 1.6). To maintain reliability as coal exits accelerate, new generation will need to enter the NEM at a faster rate than is currently taking place. However, there are barriers to this occurring. In its *Wholesale electricity market performance report*, the AER discussed these barriers in more detail.[28] Some key barriers include that:

- Investment in long-lived generation relies on revenue certainty, and this is difficult to achieve in a complex and rapidly changing market
- Transmission investments required to connect new sources of generation are progressing more slowly than planned.

Further, as coal generation approaches its anticipated exit, units are becoming less reliable without considerable maintenance expenditure. Aging thermal generators must have the appropriate incentives to maintain generation units until they can exit on an orderly timeline.

28 AER, Wholesale electricity market performance report 2022, Australian Energy Regulator, December 2022, pp. 100–109.

Certainty around timing of coal exit and fuel supply would help coal to withdraw at a rate consistent with the entry of new generation, smoothing the transition. Policymakers have a range of options to achieve this, including contracts between governments and coal generation or some form of economic regulation framework. Any response will have benefit if it enables revenue confidence, offers clearer time frames in which to plan maintenance, contract fuel, and facilitate future investment in lower emission technologies, while also meeting the broader reliability needs of the system and ensuring an orderly and timely exit to support the transition to net zero emissions.

As a further tool to mitigate the risks of coal generation exiting the market abruptly, the NSW Government is progressing the development of an opt-in orderly exit management framework.[29]

Governments are prioritising support for dispatchable generation and storage

The Department of Climate Change, Energy, the Environment and Water has recently released a consultation paper seeking public feedback on the design of a capacity investment scheme to support investment in dispatchable renewable generation and storage, which will begin receiving public tenders in 2023. The first phase will include:[30]

- partnership with the NSW Electricity Infrastructure Roadmap – with the Australian Government to provide support for up to 550 MW of firmed capacity, in addition to 380 MW already committed by NSW
- a tender for investments in South Australia and Victoria, with tender arrangements to be announced by October 2023.

Projects selected through open tenders will be offered long-term Australian Government underwriting agreements for an agreed revenue 'floor' and 'ceiling'.

If it attracts the desired level of investment, the scheme may mitigate some risks to reliability in the NEM. In its 2022 *Wholesale electricity market performance report*, the AER found that revenue uncertainty is an important barrier to entry in a rapidly changing and complex energy market. In consultation, participants told that the AER that investors are increasingly refraining from investment unless directly tied to government policy or funding.

As such, government interventions may be essential to support reliability alongside other environmental, economic and social objectives. Where possible it is important that, along with the models in which it operates, government interventions to support investment are made in a way that maximises diversity and competition of ownership wherever possible, especially among flexible generation.

Complementary measures to support reliability are also underway, including:

- improvements to the quality and transparency of information that is collected and published about the future availability of generators as part of the medium-term projected assessment of system adequacy (MT PASA) process (published August 2022)
- an AEMC review of the retailer reliability obligation, to be completed in 2024.[31]

Domestic gas shortfalls could affect reliability

New sources of flexible generation must replace coal to meet demand in daily peak periods and when renewable output is low. Without significant increases in non-thermal storage and demand response, gas will likely power flexible generation in the medium term. The step-change scenario forecasts a continued role for gas in the longer term, with up to 10 GW gas-powered generation capacity by 2050.

Over 2023 so far, gas supply has been sufficient and prices have been far lower than in 2022. At the end of winter, Iona storage is high. In total, the risk of supply shortfalls over 2023 appears to be decreasing. This suggests improvements in the balance of supply and demand in gas markets, supported by lower gas-powered generation requirements. To some extent it may have been supported by low international LNG prices and reduced incentives to export. Nonetheless, even in these circumstances there have been material spikes in price caused by transport or supply outages. The supply-demand balance in gas markets remains vulnerable to fluctuations in supply conditions or demand.

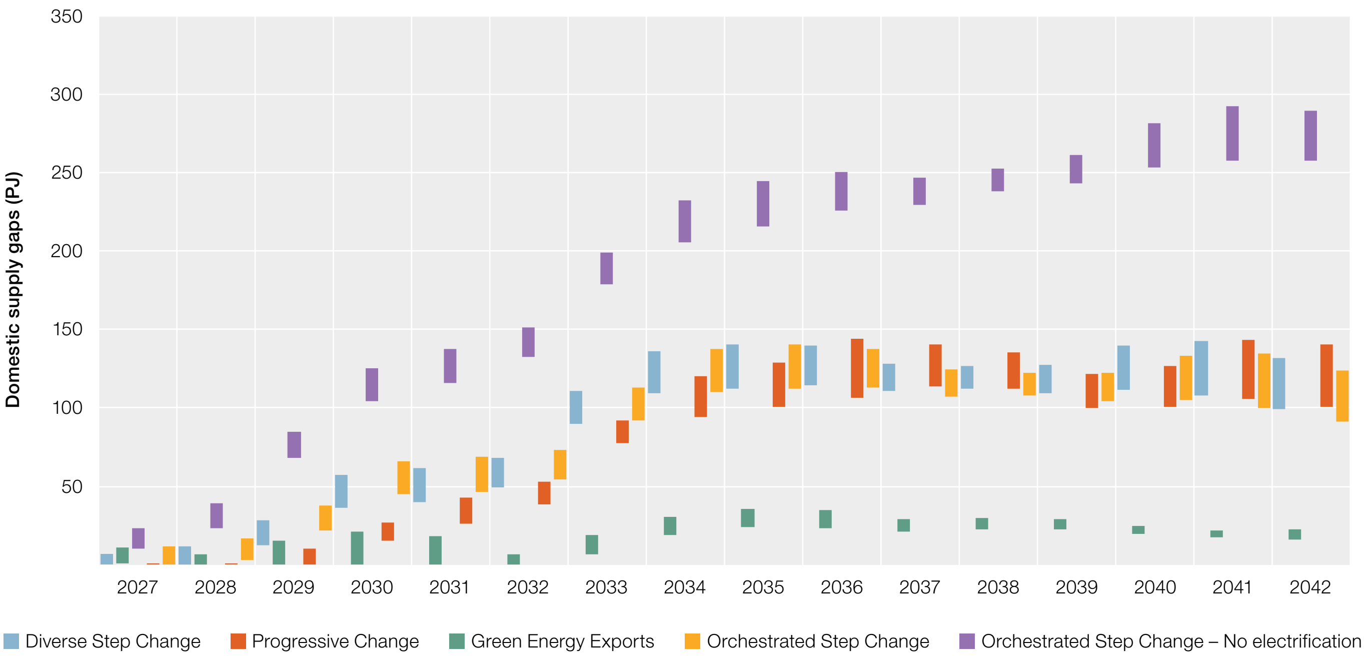
29 Energy and Climate Change Ministerial Council, Meeting Communique, 7 July 2023.

30 DCCEEW, Capacity investment scheme: Public consultation paper, Department of Climate Change, Energy, the Environment and Water, 4 August 2023.

31 AEMC, Review of the retailer reliability obligation: Consultation paper, Australian Energy Market Commission, 23 March 2023.

Despite the more positive short-term outlook, AEMO anticipates medium-term gas shortfalls as southern gas reserves deplete. In its 2023 gas statement of opportunities, AEMO forecast annual southern supply shortfalls commencing from 2027 as capacity on north–south pipelines becomes constrained.[32] The forecast timing and magnitude of these shortfalls, and therefore the optimal investments or interventions to address those shortfalls, depend to a large extent on rates of electrification.

Figure 1.7 Range of domestic annual supply gaps forecast under different scenarios, with existing, committed and anticipated developments, all scenarios, 2027–42 (PJ)



Source: AEMO, Gas statement of opportunities 2023.

Shortfalls could constrain the availability of gas generators and/or lead to higher prices. Reduced availability from gas generators would then restrict flexible generation available in the NEM, highlighting the challenges associated with closely interconnected markets.

Energy Ministers have committed to a further series of measures to support gas availability. These include:

- Extensions to AEMO's powers, providing it with tools to manage supply shortfalls in the east coast market in winter 2023. This included a rule change that requires AEMO to act as a buyer and seller of last resort at the Dandenong gas storage facility. This is to reduce the likelihood of curtailment in Victoria, reduce the risks to the safety, security and reliability of gas supply in Victoria and support the efficient operation of the Declared Wholesale Gas Market over 2023 to 2025. Since implementation of this reform, storage at Dandenong has increased markedly.
- Instructions for AEMO to develop an annual winter readiness management plan for east coast energy markets and incorporate gas supply and system adequacy risks into its annual summer readiness plan.

1.5 Effective development of open and competitive markets

Open and competitive markets, and the competitive pressure they enable, are a vital part of managing these pressures and keeping costs at levels that are no more expensive than necessary or efficient. Competitive fuel and wholesale markets are essential to support the efficient dispatch of the lowest-cost sources of energy at any point in time. In retail markets, open and competitive markets are an important tool consumers can use to find retail offers best suited to their circumstances and usage. Competitive markets for financial hedge products are also critical to enabling retailers to manage the risks and volatility of the wholesale market on behalf of their customers. With major changes to the generation fleet, including the growing prevalence of consumer energy resources, the sources of and challenges to competition are also changing.

32 AEMO, Gas statement of opportunities, Australian Energy Market Operator, March 2023, p. 82.

1.5.1 Market openness and competition in 2023

After several years of progress towards improved competition in energy markets, recent market shocks, most acute in winter 2022, posed some new challenges for retail and wholesale market participants.

In its December 2022 *Wholesale electricity market performance report*, the AER investigated the competitive structure of the NEM in more detail, finding risks to competitive pressure from factors including:

- high concentration of generation ownership, particularly with respect to flexible generation
- behaviour suggestive of the exercise of market power through economic withholding
- structural and artificial barriers to entry and impediments to efficient price signalling
- declining liquidity in contract markets and access to those contracts
- lack of investment confidence arising from revenue uncertainty in a rapidly transforming market alongside uncertainty in the macroeconomic and policy environment.
- In retail markets, consumers continue to move gradually from larger to smaller retailers, suggesting some improvement in retail competition. However, the spread of market offer prices has declined, indicating that consumers have at present lower scope to make material savings through changing offers.

Specific interventions have helped to stabilise the markets at critical junctures, mitigate price pressures and avoid load shedding. Nonetheless, they highlight continuing challenges. The energy system will likely face other market shocks as we transform our generation fleet and interact with global fuel pressures. A properly calibrated and predictable framework of interventions will play an important role in market resilience going forward.

1.5.2 Action on key challenges

Record high international fuel prices put pressure on domestic fuel availability and prices

Fuel costs are an important factor in generator behaviour. Where generators are exposed to high or volatile fuel costs, or limited fuel availability, this can impact the openness and competitiveness of wholesale markets.

Over 2022, international coal and gas prices reached record high levels, reflecting an overlapping set of domestic and international drivers. High international prices exert pressure on domestic fuel availability and price. Where international prices are high, domestic suppliers of coal or LNG face stronger incentives to sell into the export market. This increases price pressure on any fuel required through spot markets.

Many of these drivers reduced over the first half of 2023 and prices have stabilised. However, this outlook is sensitive to change. In the second half of 2023, a forecast El Niño weather event is expected to coincide with the Northern Hemisphere winter. This could contribute to increased demand from higher-than-expected summer temperatures in the Southern Hemisphere, translating to pressure on gas-powered generation to meet higher peak demand. If combined with the ordinary seasonal increase in demand as the Northern Hemisphere enters winter and increases exports, this could put significant pressure on domestic fuel availability.

Several temporary interventions have been implemented to shield domestic electricity and gas markets from international prices.

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

As a result of directions given, the price of black coal sold to generators has been capped at $125 per tonne in NSW. Although the directions to Queensland coal generators are not made public, the AER understands Queensland has a mechanism in place to achieve a similar effect. Additionally, coal generators in NSW are required to plan to maintain a stockpile that is sufficient to meet 30 days of projected demand. Coal mines in NSW are required to reserve a proportion of future coal production to supply NSW coal generators and are to prioritise delivery to generators with low stockpiles. The NSW Government has announced that this intervention will end in June 2024.

From December 2022 to July 2023, some trade in gas markets was covered by a $12 per GJ price cap. In July 2023, this was replaced with a Gas Market Code of Conduct. The Code includes 4 key elements:

- a price cap (initially set at $12 per GJ)
- an exemptions framework to incentivise the commitment of more gas to the east coast gas market and facilitate new investment
- transparency obligations
- conduct provisions to reduce bargaining power imbalances between suppliers and buyers.

High and volatile prices may reduce incentives for generators to offer hedging contracts

Spot markets and contract markets are important complements to support competition. Liquid contract markets allow generators and retailers to manage cost exposure and insulate consumers from transient high prices.

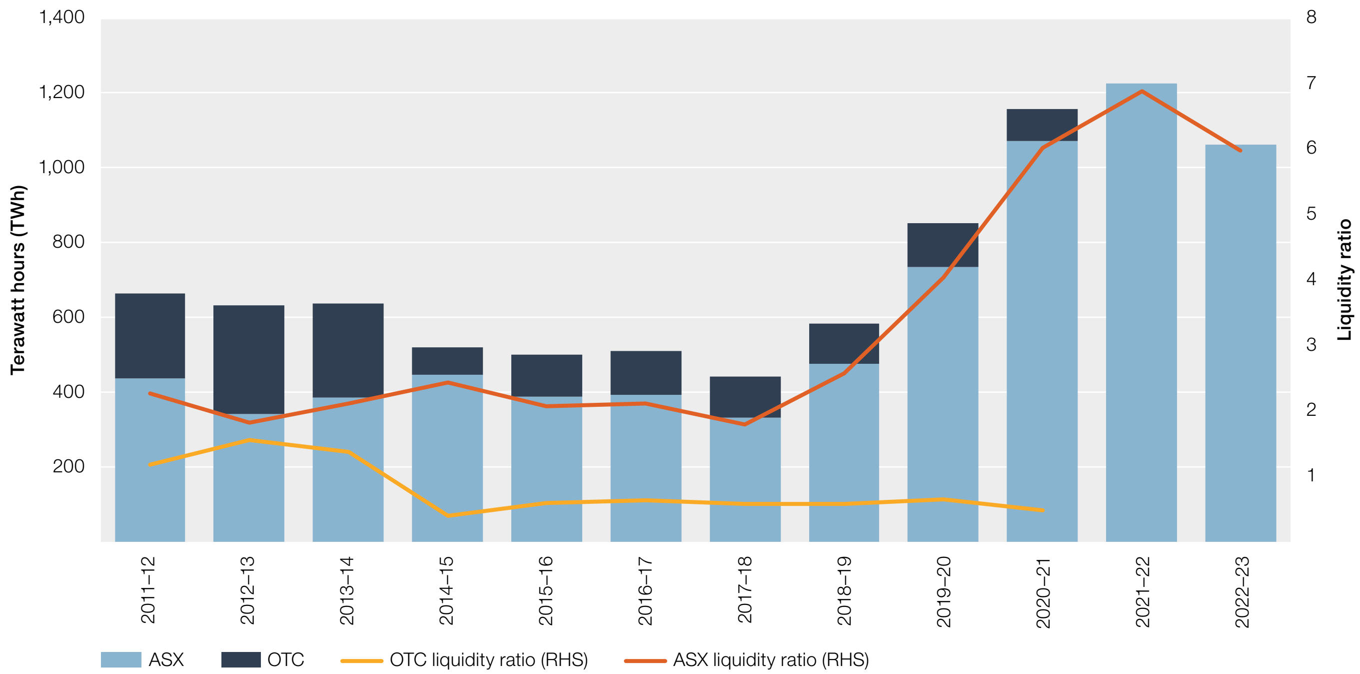
A lack of liquidity in the contract markets is a significant source of risk because it can impact the sustainability of existing participants and create barriers to entry and expansion.

During 2022–23, ASX traded volumes fell after 4 consecutive years of growth, declining 13% from the record set in 2021–22 (Figure 1.8). During the July to September quarter 2022 there was a marked decline in ASX traded volumes, down 40% compared with the previous quarter. The fall in traded volumes was likely a reaction to the significant spot and contract market volatility seen during the April to June and July to September quarters and the resulting cash-flow impacts on contract market participants. Several participants reported to the AER that, prompted by the increased volatility, they were reassessing their internal risk limits.

Traded volumes rebounded in the October to December quarter 2022, reaching the level seen in the October to December quarter the previous year. While cash flow and margining were likely still a concern, falling contract prices and less volatility in the spot market were reducing these risks.

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

Figure 1.8 Traded volumes in electricity futures contracts



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

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

If hedging contracts are not available at profitable levels, retailers without generation assets may be unable to sustainably compete. Retailers integrated with generators can manage risk internally by balancing higher retail costs against higher generation earnings. Smaller retailers that do not own generation assets are particularly exposed.

If this contributes to retailer failure, it is vital that failure be as orderly as possible to minimise disruption for consumers, and to support the resilience of the retailers of last resort (ROLRs) that those consumers are transferred to. In support of this, the AEMC recently revisited the ROLR scheme in the context of supporting market resilience. It made a series of recommendations, which Energy Ministers have adopted and agreed to progress in legislation. In May 2023, the AEMC published a directions paper in its review into the arrangements for failed retailers' electricity and gas contracts.[33] This included a series of options for managing the costs of failed electricity and gas retailers, recognising the differences in how retailers access energy in the 2 markets.

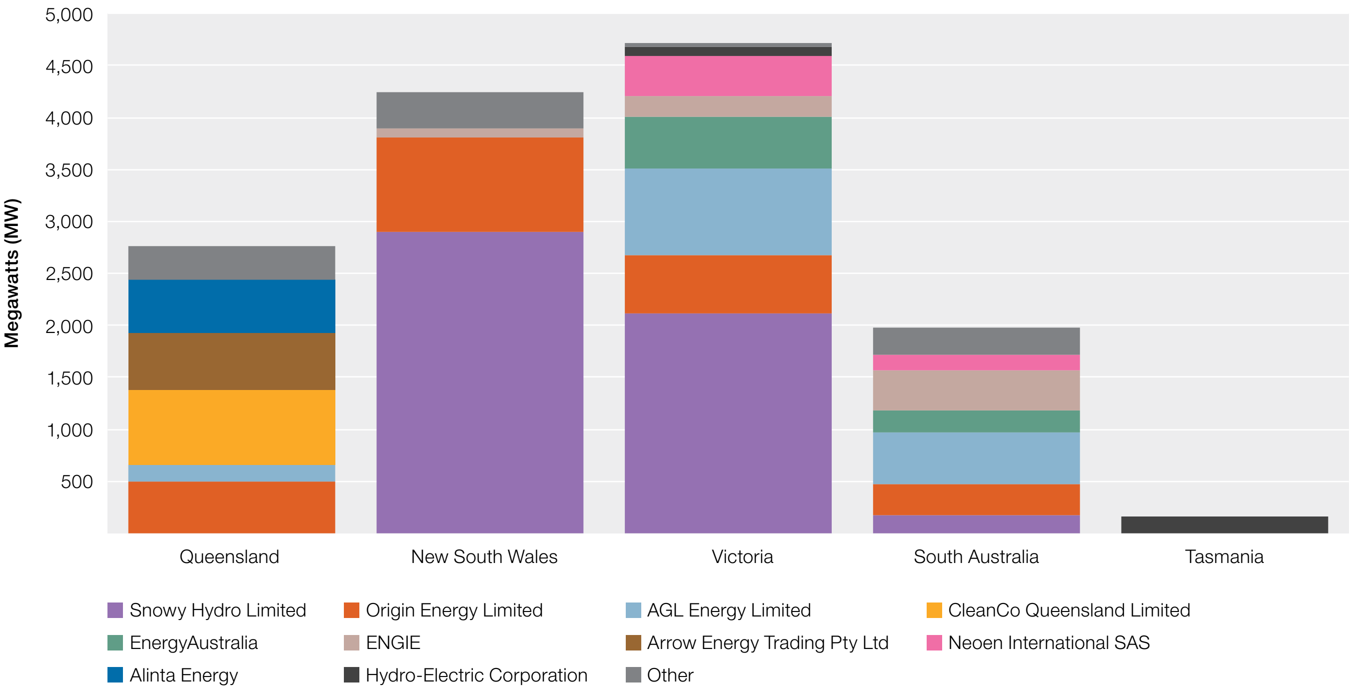
As spot prices decline and short-term pressures ease, it is possible that contract market liquidity returns to its medium-term path of improvement. This will be critical for the prospects of efficient and competitive retail markets.

Flexible generation capacity is concentrated among small number of owners

Material investment has been made in new renewable generation. However, when renewable generation is reduced due to weather constraints, the market must rely on dispatchable generation including flexible technologies such as hydro, battery and some gas generators. While transient high prices reflective of scarcity are features of an efficient and competitive market, recent experience highlights the risk of inefficiencies arising from market concentration in flexible capacity.

The AER highlighted the concentration of flexible capacity in its 2022 *Wholesale electricity market performance report*. This concentration has intensified further with the closure of Liddell Power Station in April 2023. As shown in Figure 1.9, this concentration is most acute in NSW and Victoria.

Figure 1.9 Market share by registered flexible capacity



Note: Flexible capacity in this chart captures all generation defined as 'fast' by start type.
Source: AER analysis.

Approximately 5 GW of new entry flexible generation has been committed over the next 10 years, including 1.6 GW of battery storage capacity, 2.3 GW of pumped hydro and 1.1 GW of gas capacity.[34] These committed projects are expected to increase the concentration of flexible generation ownership even further.

33 AEMC, Review into the arrangements for failed retailers' electricity and gas contracts: Directions paper, Australian Energy Market Commission, May 2023.

34 Based on projects identified by AEMO as committed. See AEMO, NEM Generation Information July 2023, Australian Energy Market Operator, accessed 7 August 2023.

Greater concentration increases the potential for inefficient market outcomes, either through potential exercise of sustained market power or exposure to the supply, planning or strategies of individual participants. These inefficiencies can cause major market impacts if intermittent generation output is low over an extended period. The 2022 *Wholesale electricity market performance report* highlighted that competitive pressure is vital to spreading risk and encouraging innovation, and recommended that facilitating competition during and beyond the transition would enable the NEM to function efficiently.[35]

Clearing services will play an important role in contract market effectiveness

The relatively small number of companies providing market clearing services has been limited further by restraints on clearing new contracts. As of March 2023, there were only 5 clearing service providers for electricity derivatives approved by the ASX.[36] It was reported on 14 October 2022 that Bell Potter had withdrawn its clearing services for ASX electricity derivatives and Macquarie had moved to restrict clearing services for electricity futures for would-be clients.[37]

Clearing services play a vital role in facilitating ASX trading. They are also important for the viability of other trading platforms, such as FEX Global, which promote competition and greater diversity of standard contracting products. Participants without access to the ASX or FEX Global will be forced to hedge using OTC contracts, either through a broker or negotiated directly with a counterparty. An OTC trade negotiation can be time-consuming and small retailers may find the credit requirement imposed on them by counterparties to be onerous.

The exit of Bell Potter and restriction of Macquarie's services illustrates the risks of having such a small pool of clearing service providers. This is especially true at times of high electricity prices, when clearers are forced to take on more risk due to the volatile daily price fluctuations and risk that the client is unable to make the daily margin payment. The limited clearing pool is also a risk for new exchanges. FEX Global has confirmed to the AER that it considers the scarcity of available clearers as currently the most significant barrier that new customers face when seeking access to FEX Global products and services.

While the market appears to be functioning with the limited number of clearing services, they play an important role and this will remain a topic of interest.

Enhanced visibility of contract markets will improve risk analysis and response

Better insight into contract positions is a vital element of monitoring market dynamics. In March 2023 enhanced gas market transparency measures were introduced. These measures facilitate greater insights into east coast bilateral trades and materially improve the comprehensiveness of available gas trade data. Further, Energy Ministers are progressing reforms to expand the AER's wholesale market monitoring and reporting functions, including broader access to contract information. This will:

- enable better monitoring of participant behaviour to support the AER's compliance and enforcement activities
- equip the AER to form a more developed view about whether the capacity for market power exists and whether participant conduct suggests that participants are exercising market power
- enable the AER to identify impediments to competition and efficiency and make recommendations about any further structural change that may be required.

The Department of Climate Change, Energy, the Environment and Water held 2 rounds of consultation with government and industry stakeholders on the proposed amendment to the National Energy Laws in August 2022 and April 2023. If the draft amendment is passed in the SA parliament, the AER will develop relevant guidelines.

35 AER, Wholesale electricity market performance report 2022, Australian Energy Regulator, December 2022, pp. 3, 125–6.

36 ABN Amro, BNP Paribas, JP Morgan, Macquarie Bank and Societe Generale.

37 Australian Financial Review, Energy retailers struggle for hedges as Bell Potter withdraws, 14 October 2022.

1.6 Efficient and timely investment in networks

Networks transport energy from large generators or gas fields, which are typically remote, to demand centres like major cities or gas hubs. As major new sources of electricity generation are developed in new locations, significant new investment in transmission investment is required to support it. The costs of this infrastructure will be shared widely, but the infrastructure itself will have direct impacts on the communities that host it, which is increasingly being reflected in planning and delivery of major projects.

As legacy gas fields deplete close to southern demand centres and the long-term role of gas is changing, it is likely the future role of gas pipelines will be materially different to what has traditionally been the case. The potential development of domestic LNG import terminals emphasises this changing dynamic.

In addition, as the energy transition progresses, the role and requirements of electricity networks is also evolving. With a higher proportion of energy generation now taking place through consumer energy resources, distribution networks increasingly play a role as providers of export services supporting the contribution of surplus domestic generation into the market. Over time, their roles will likely grow further as a platform to support new technologies, storage and trading. The potential implications of widespread electrification or uptake of electric vehicles may have major implications for the size and timing of network peaks, and require new and more sophisticated network price signals to encourage the most efficient use of the networks. This in turn must be shaped by consumers' ability to understand and respond to these more complex price signals.

1.6.1 Network investment in 2023

Network investment has continued at a relatively steady pace over recent years. Electricity networks and fully regulated gas networks are subject to a well-established incentive framework to minimise costs.

Networks have continued to generate profits under the regulatory framework, while costs to consumers have declined. There are likely to be some upward cost pressures over coming years as higher inflation and, if recent capital market trends continue, higher costs of capital feed into network revenue requirements.

The greatest challenge in relation to networks is the timely and least-cost delivery of major transmission projects that will support the changing generation mix. The projects are large and complex. They are important enablers of the energy transition but have specific impacts for communities that host the assets. Reflecting these complexities, they are and have been prone to delays and cost increases through planning and approval stages. These projects are taking place in an environment of emerging upward pressures on network costs – including domestic and global inflationary pressures and signs that the costs of raising capital are rising. Nonetheless, as the exit of coal generation accelerates, it is increasingly urgent that these projects progress.

This expenditure must also be supported by access reform to ensure generators get clear signals to connect into the right parts of the network. Reforming access has proven complex and contentious over several years, but it is vital to make the most efficient use of these transformative network investments.

In May 2023, the AEMC completed its transmission planning and investment review and made a series of recommendations to support timely and efficient investment in and delivery of Integrated System Plan projects.[38] It considers these can be implemented prior to more substantial change under consideration in its review of the Integrated System Plan.

1.6.2 Action on key challenges

Essential transmission investment has been slower and more costly than planned

Under the optimal development path in the 2022 Integrated System Plan (ISP), AEMO forecast approximately $30 billion of transmission expenditure to 2050, of which:

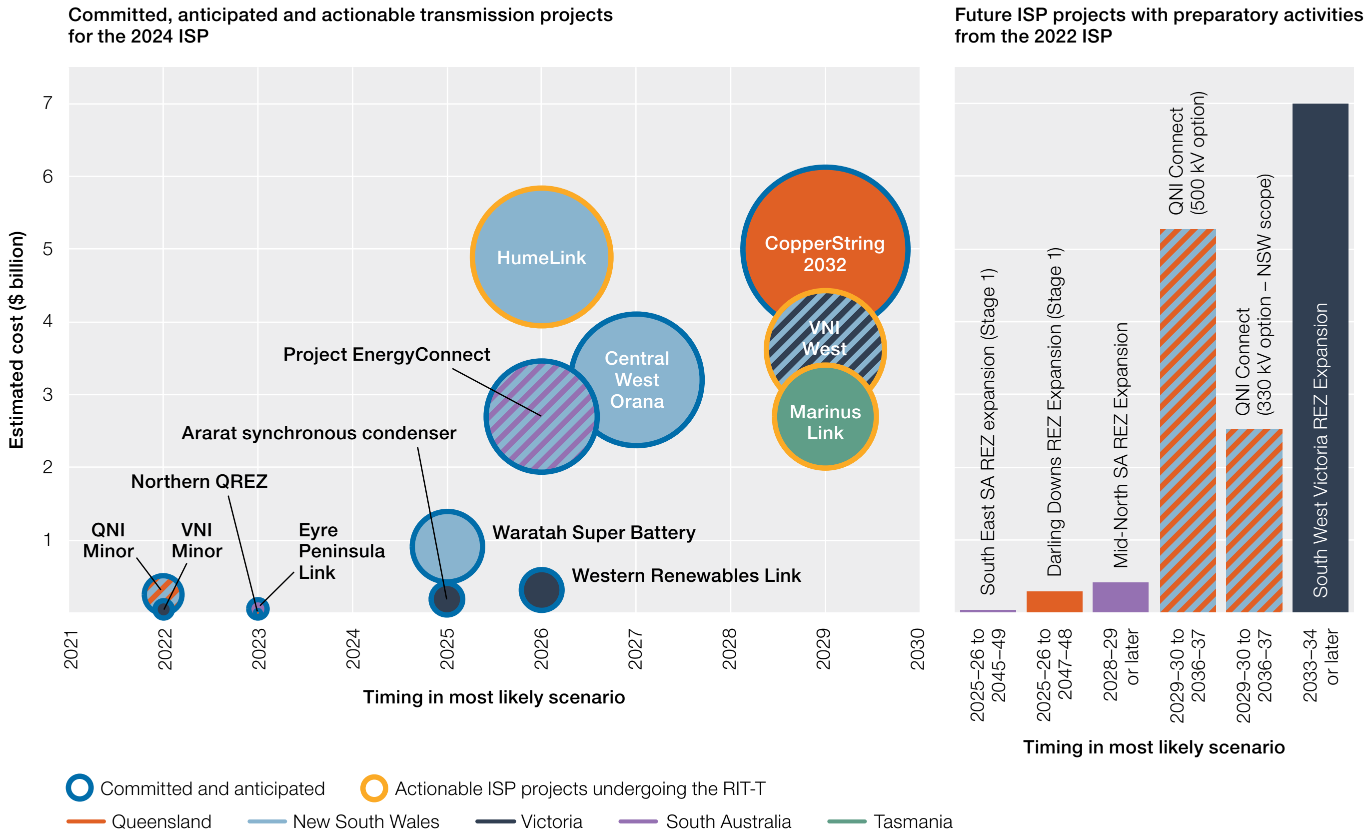
- $14 billion is already actionable – meaning the project should be delivered to its earliest schedule and triggering a regulatory investment test for transmission (RIT-T)
- $3.2 billion is committed and anticipated
- $13 billion has been identified for future ISP projects.

38 AEMC, Transmission planning and investment review: Stage 3 final report, Australian Energy Market Commission, May 2023.

These estimates will be updated again in development of the 2024 ISP and it is likely they will be materially higher. After accounting for inflation, cost estimates provided to AEMO for development of its recent *Transmission expansion options report* generally show increases of approximately 30% increase in real costs compared to equivalent cost estimates prepared for the 2022 ISP.[39] Further, AEMO expects project costs will continue to increase beyond the rate of inflation while the sector adapts to global market pressures.

The scope of required network investment could increase materially if Australia pursues significant development of hydrogen as a domestic fuel source or export commodity.

Figure 1.10 AEMO's integrated systems plan



Note: Committed projects meet 5 criteria relating to planning consents, construction commencement, land acquisition, contracts for supply and construction of equipment and necessary financing arrangements. Anticipated projects are in the process of meeting at least 3 of the criteria. Data used to show the estimate costs of future ISP projects with preparatory activities was provided to AEMO by the transmission network service providers. Preparatory activities are intended to improve the conceptual design, lead time, location and cost estimates for transmission projects. The ISP may require preparatory activities for some future ISP projects. Future ISP projects are projects which address an identified need, form part of the optimal development path, and may be actionable ISP projects in the future.

Source: AER analysis, AEMO integrated system plan, June 2022, AEMO Transmission Expansion Options Report, September 2023.

Since then, some of these projects have been completed at close to forecast costs, including:

- QNI minor interconnection upgrade
- VNI minor interconnection
- Eyre peninsula link.

Nonetheless, larger projects have been more difficult to progress for several reasons, including:

- Cost pressures – These are major projects sensitive to a range of cost inputs and are taking place in an environment of rapidly escalating costs. AEMO identified in its *Transmission expansion options report* that cost estimates provided in this report generally show up to an approximately 30% increase in real costs compared with equivalent cost estimates prepared for the 2022 ISP.[40] These costs are all borne by consumers over the lives of the assets. Ongoing inflationary pressures and higher costs of capital may further exacerbate these impacts.

39 AEMO, 2023 Transmission Expansion Options Report, Australian Energy Market Operator, September 2023, pp. 3–4.

40 AEMO, 2023 Transmission Expansion Options Report, Australian Energy Market Operator, September 2023, pp. 3–4.

- Complex decision processes – The process for developing the ISP and subsequent regulatory investment tests is rigorous so that only efficient investments will progress to delivery. However, they are also lengthy. Combined with other delays that projects of this scale are subject to, such as delays in engaging affected communities and achieving community support, this increases the risk that projects do not proceed on schedule.
- Supply chain risks – Projects of this scale are sensitive to domestic and global supply chain risks. Due to the overlapping timelines for these projects, they will compete for plant, skills and resources. Challenges in accessing or coordinating these necessary inputs could increase both the costs and time required to complete projects.

Perhaps the greatest challenge in progressing these projects has been building and maintaining social licence. Hosting major transmission assets has social and environmental impacts on landholders and communities. It is vital that those key stakeholders can trust development processes and be involved in decisions affecting them. Failure to do so will impede the timeliness and cost-effectiveness of investments.

A wide-reaching work program is underway to encourage better engagement of communities and better implementation of those views in the transmission planning progress:

- In April 2023, the Minister of Industry and Science submitted a rule change proposal to the AEMC to support focus on social costs and benefits within the transmission planning process.[41]
- In response, the AEMC published its draft determination in August 2023 designed to improve clarity and consistency of how local communities are included in the development and consideration of transmission planning.
- The Australian Energy Infrastructure Commissioner is engaging with state governments to produce a best practice framework for community engagement and is due to produce a report by December 2023.
- AEMO has established a Community Advisory Council with 11 members appointed to represent a diverse range of perspectives, including those of landholders, agriculture, rural and regional communities. This group has and will support development of inputs, scenarios and assumptions underlying the 2024 Integrated System Plan.[42]

State governments in Queensland, NSW and Victoria also operate payment schemes to compensate landholders for hosting transmission infrastructure. This is in addition to the compensation provided through conventional land acquisition frameworks.

Key policy and reform work has been initiated

Ministers recognise the national significance of these projects and have engaged with the risks. The National Energy Transformation Partnership commits to:

- identify and declare transmission of national significance (including the actionable projects in the Integrated System Plan – Marinus, VNI West (via Kerang) and Humelink) to accelerate the timely delivery of these critical projects and ensure better community consultation
- start work on a co-designed First Nations Clean Energy Strategy with First Nations people to help drive the energy transformation
- develop detailed integrated energy infrastructure and regional planning scenarios
- assess the workforce, supply chain and community needs associated with the pipeline of transmission, renewable energy, storage and industry development opportunities, which will inform work on risks and opportunities and identify community engagement needs to support a national action plan on these issues
- recognise the role electricity networks and demand-side participation will play in delivering the energy transformation.

To support this work, the AEMC completed stages 2 and 3 of its Transmission Planning and Investment Review in October 2022 and May 2023. Through this process, it has identified recommendations to assist the timely and efficient delivery of transmission investments. Regulatory changes are in the process of design and development to ensure the framework is fit for purpose to support the efficient and timely delivery of major projects.

A separate work program is underway to consider whether current mechanisms to build and support social licence remain fit for purpose.

41 The Hon. Chris Bowen MP, Minister for Climate Change and Energy, Rule change request: Ensuring consistent stakeholder engagement for ISP projects, March 2023.

42 AEMO, Community voice speaks volumes at inaugural advisory council meeting, Australian Energy Market Operator, accessed 29 August 2023.

The materiality of the anticipated transmission work presents challenges for the existing incentive framework due to the greater challenges in forecasting capital costs for specific, large and complex projects. The AER has recently commenced a review on expenditure incentive schemes to ensure they are fit for purpose in this context.

Access reform can support efficient transmission investment

Efficient transmission investment relies on efficient decisions for the location of generation, storage and demand-side resources connecting to the networks. Some congestion is a normal feature of an efficient network. The ISP is not designed to remove all congestion where the benefits exceed the costs. Nonetheless, excessive congestion creates needless costs and risks, specifically:

- generation investment is riskier than is necessary
- storage and demand-side resources are not paid to alleviate congestion
- consumers face high costs for inefficient or avoidable investment in transmission infrastructure.

It is important that generators, storage and demand-side resources face appropriate signals regarding the costs and impacts of congestion.

Energy Ministers tasked the Energy Security Board, now the Energy Advisory Committee, to investigate potential access reform models. This complements the work underway by jurisdictions to establish Renewable Energy Zones (REZs) and coordinate transmission and generation investments. A hybrid model, comprising a congestion relief market alongside priority access, is being designed and tested with stakeholders including through public consultation and technical working groups. The Energy Advisory Committee's recommendations on this model are expected to be presented to Energy Ministers in November 2023. Access reform for the NEM has been under consideration for many years but proven complex to implement.

Smart meters are important to support efficient investment in and use of networks

Traditionally, most households and small businesses have been charged the same network tariff component for using the distribution network regardless of how and when they use energy (that is, flat/single rate or non-cost-reflective network tariffs). Because flat tariffs are independent of when and how electricity is used, they don't reflect the relatively higher costs of a network built to supply electricity during peak periods.

Tariff reform can encourage more efficient use of networks, delay the need for network augmentation and investment, and spread network costs more equitably. Initially, reform focused on signalling costs during peak demand periods (which historically drove network investment). Recent reform has involved sending price signals to efficiently integrate consumer energy resources – such as rooftop solar, batteries and electric vehicles – into distribution networks. This includes sending price signals to encourage the use of solar energy in the middle of the day to avoid excess solar (minimum demand) on the network.

The availability of smart meters fundamentally shapes networks' ability to increase the cost-reflectiveness of network cost structures, which are passed to retailers and in turn retailers can reflect in their offers to consumers. They can also support faster identification of network outages, both improving the consumer experience and improving the efficiency of networks' operational expenditure. For this tariff reform to reach a critical mass, when it shapes the options retailers offer to consumers, legacy meters will need to be replaced with smart meters at scale.

In August 2023, the AEMC published its final report setting out several recommendations and options to accelerate the deployment of smart meters in the National Electricity Market (NEM).[43]

The AEMC's proposed reforms target all consumers having access to smart meters by 2030.

As one of a broader suite of innovations in network and communication technology – including interactive household devices and energy management and trading platforms – smart meters support change in energy markets. These innovations allow consumers to access real-time information about, and make informed decisions in managing, their energy use. If consumers choose to voluntarily reduce their energy use from the grid in peak periods (by shifting energy use or relying on battery storage), it can delay the need for costly network investment. Moreover, since demand for energy imports is increasingly at its minimum when solar generation is high, shifting consumption from peak periods can help reduce the costs of supply, manage minimum demand constraints (such as voltage issues) and draw more energy from a low-emissions fuel source.

43 AEMC, Final report – Review of the regulatory framework for metering services, Australian Energy Market Commission, 30 August 2023.

Work is underway to clarify the long-term use of gas pipelines

Decarbonisation and electrification will impact gas distribution and transmission pipelines in different ways. In many cases, those same pipelines are undergoing material programs of replacing aging assets. There is a potential risk of incurring significant investment costs with a falling customer and demand base.

In 2021, the AER released a paper on 'Regulating gas pipelines under uncertainty' to canvas some of these issues as it relates to the fully regulated pipelines, which are predominantly distribution pipelines serving significantly residential and small business customer bases. Many of the same uncertainties are relevant to the use of gas as an input for industrial users, though the scope for industrial users to substitute other fuels varies from user to user. The implications for network investment also depend on whether industrial substitution takes place through electrification, which would reduce pipeline requirements, or by replacement of natural gas with hydrogen, hydrogen blends or biomethane which might make use of existing pipelines.

As well as impacting investment decisions, uncertainty about the future use of gas pipelines has implications for how costs of the transition are shared. For example, in its recent review of Victorian gas access arrangements, the AER's final decisions included changes to the pricing structures of permanent disconnections from gas pipelines.[44] Some consumers choosing to move away from gas have been opting for temporary disconnection to avoid higher direct costs associated with permanent disconnection from the pipeline, but this has safety implications. The model adopted in the decisions retains for permanent disconnections some direct costs to the disconnecting customer, but shares some of the costs amongst the customer base at large. This is a short-term measure to address current incentives. Energy Safe Victoria has committed to working with pipelines to understand whether other methods may be more appropriate than permanent abolishment in the context of the large number of disconnections that have been forecast as a result of the Victorian Government's policy to support electrification, or whether there are any new technologies that may reduce the safety risk.

The Australian Government has recently commenced developing a future gas strategy.[45] When complete, this should help to guide decision-making on investment in long-lived gas assets. In parallel, states and territories such as the ACT and Victoria have set out pathways towards electrification, which will shape the long-term role of gas in those jurisdictions.

Many of the same complex investment and pricing questions also apply to other vital pipelines not currently covered within the full regulatory framework and where pipeline owners have relatively more scope to exercise market power.

In March 2023, a package of changes to the National Gas Law and Rules commenced that, when fully implemented, are likely to simplify the framework of pipeline regulation, improve transparency for users of those pipelines and provide a more effective constraint to the exercise of market power. In combination, these changes should contribute to more efficient regulation of the pipelines and ultimately more efficient investment outcomes.

As part of this initiative, the AEMC recommended changes to rules that will support the development of a decarbonised gas sector by allowing hydrogen blends and renewable gases to be safely supplied through the existing distribution systems.[46] Energy Ministers agreed to these amendments in October 2022 and they are expected to become law by the end of 2023.[47] AEMO is leading work to amend the instruments required for settlement and metering in the facilitated and regulated retail gas markets.[48]

The reforms aim to provide regulatory certainty to support investment in innovative projects that will reduce emissions in gas networks. The reforms will also ensure existing regulatory provisions and consumer protections will work as intended when hydrogen and renewable gases are incorporated into the gas network.

44 See for example: AER, Final decision overview: Multinet gas networks gas distribution access arrangements 1 July 2023 to 30 June 2028, June 2023, p. 7.

45 Department of Industry, Science and Resources, Planning for gas to 2050, accessed 15 August 2023.

46 AEMC, Final rules report: Review into extending the regulatory framework into hydrogen and renewable gases, Australian Energy Market Commission, November 2022.

47 DCCEEW, Extending the national gas regulatory framework to hydrogen and renewable gases, Department of Climate Change, the Environment, Energy and Water, 14 July 2023.

48 AEMO, Final report: Hydrogen blends and renewable gases procedures review, Australian Energy Market Operator, September 2022.

Image source: iStock

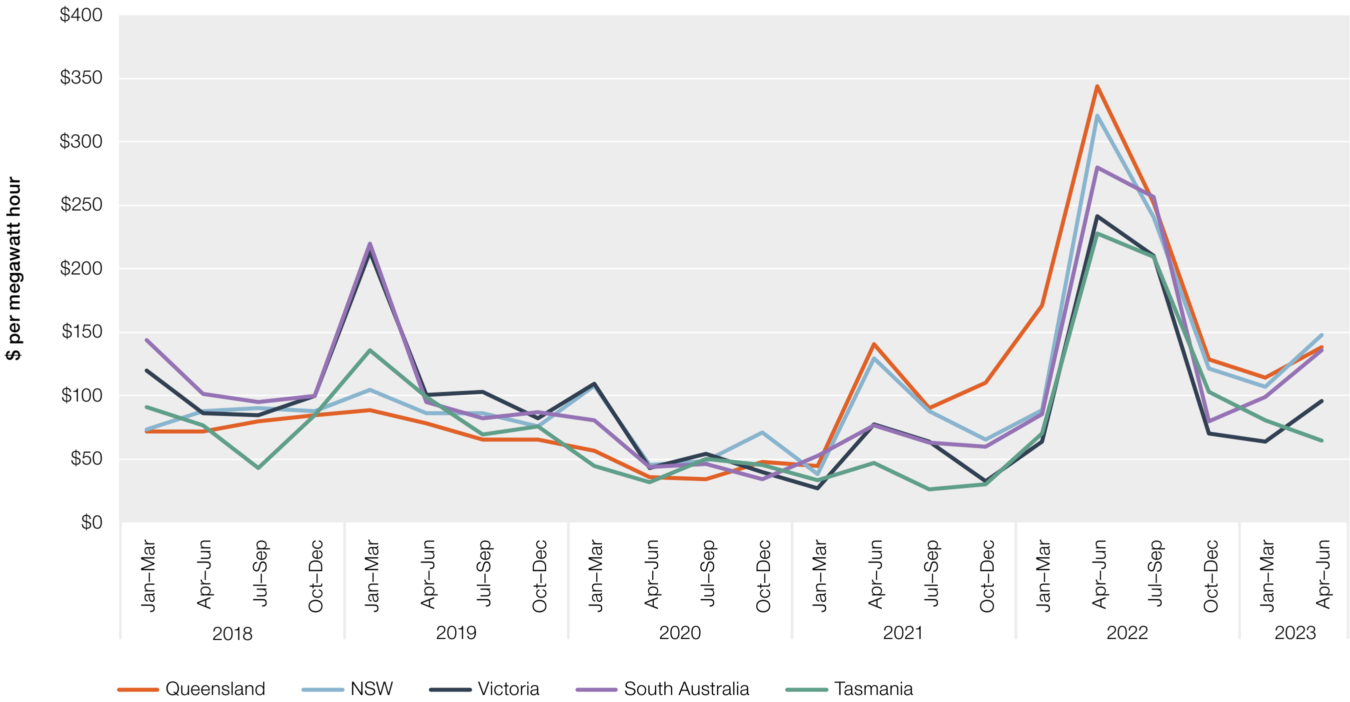
2 Market overview

This chapter is a brief overall summary of key market outcomes set out in more detail in chapters 3 through 7.

2.1 National Electricity Market (chapter 3)

Recently NEM prices have declined substantially from record highs in 2022. Nonetheless, they remain high by historical standards.

Figure 2.1 Quarterly wholesale electricity prices



Note: Volume weighted average quarterly prices.

Source: AER; AEMO (data).

In 2022 overlapping factors combined to put extreme upward pressure on prices in the NEM. These included multiple supply-side problems experienced by generators – coal plant outages, coal supply issues, domestic gas supply shortfalls and hydro generating constraints. These supply-side constraints increased the NEM's reliance on gas and hydroelectric generation at a time of record high gas prices and when hydroelectric generators were also facing environmental constraints.

The severity of these supply constraints diminished as spring arrived. Increased wind and solar generation, fewer baseload outages, improved fuel supply and lower gas prices contributed to lower prices in the electricity markets. Prices continued to decline into summer as demand fell due to mild weather conditions and renewable generation producing record output. Prices increased into winter 2023 but remained far lower than in winter 2022.

The unprecedented high wholesale energy prices in 2022 prompted governments to intervene in coal and gas markets in December. Sale of coal to generators in NSW has been capped at $125 per tonne, and although directions in Queensland are not public, a similar mechanism is understood to be in place there. Governments also implemented an emergency price order, including a $12 per GJ price cap in gas markets.

Announced on 9 December 2022, the interventions appeared to have had immediate effect on the price of electricity base futures contracts, which fell sharply following the announcement. Prices of futures contracts have since risen, but they remain well below the levels observed in mid-2022. Contract prices for future years have improved significantly, indicating that the market expects lower priced outcomes in future years than was the case in 2022. Though prices have fallen, traded volumes also fell and liquidity of contract markets remains an ongoing concern in South Australia.

The interventions have resulted in some coal generators offering cheaper electricity into the wholesale market. This was supported by other favourable market conditions and mild weather, jointly contributing to lower prices.

April saw the Liddell coal-fired power station exit the NEM, taking with it 1.5 GW of dispatchable generation. Liddell's closure marks the first of 5 coal station exits in the next 10 years, which will result in the loss of 8.3 GW of dispatchable generation. Remaining coal generation may be more likely to break down as it reaches the end of its life.

The impact of Liddell's retirement was mitigated by nearly 2.5 GW of renewable generation. This included 1.2 GW of solar and 0.6 GW each of wind and batteries. Increased renewable capacity saw wind and solar output records set in the October to December quarter 2022 and the January to March quarter 2023, as well as a record number of negative prices in the October to December quarter.

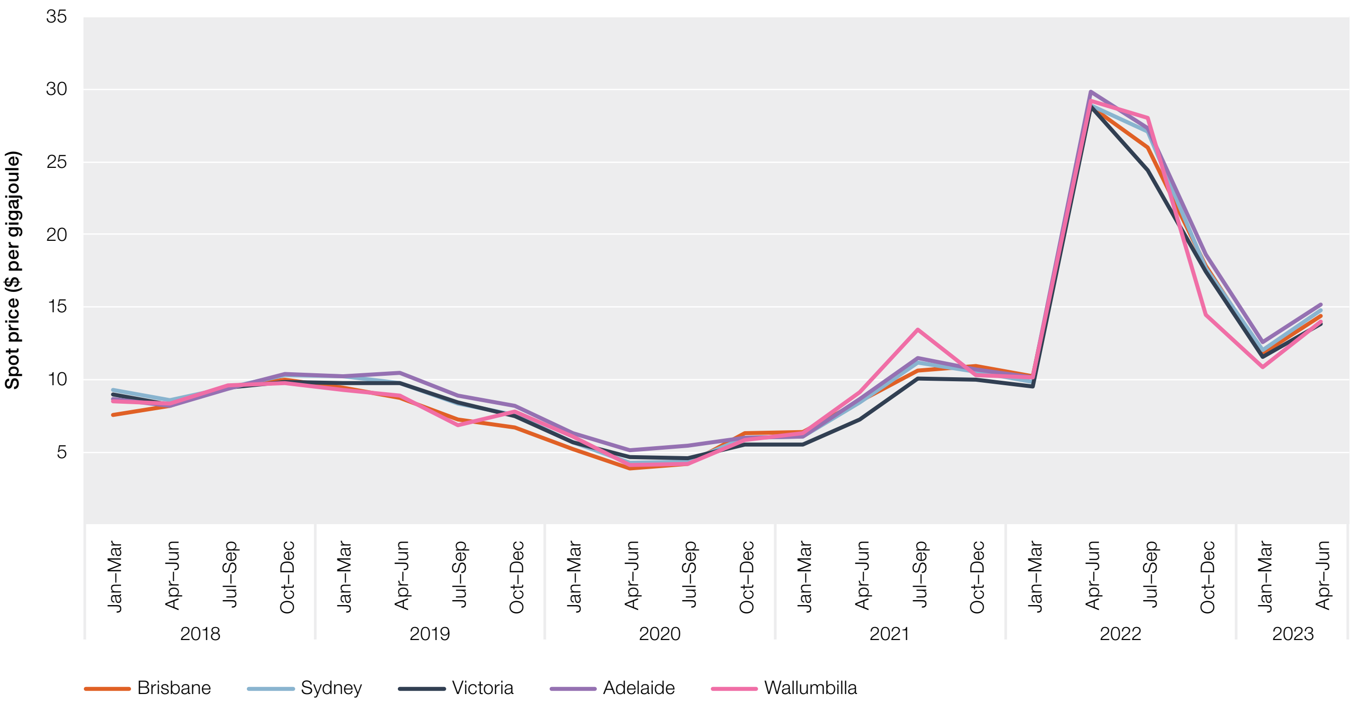
The imminent exit of much of the NEM's coal-fired generation, which accounted for just less than 60% of the NEM's generation output in 2022, has prompted AEMO to forecast reliability gaps (risk of unserved electricity demand) as early as 2024 in some regions. AEMO's forecasts of these shortfalls are accelerating in response to growing demand via electrification and generation investment proceeding slower than hoped. Wind and solar provide emission-free, low-cost electricity when weather conditions allow them, but their supply will need to be supplemented with adequate electricity storage technology to avoid reliability gaps as coal stations continue to retire.

Despite these approaching risks, maintaining system reliability was less costly over 2022–23. The total cost of the Reliability Emergency Reserve Trader fell in 2022–23, with fewer supply constraints resulting in reserves needing to be activated less often. Other costs associated with managing power system reliability and security also fell, including the costs of Frequency Control Ancillary Services and the cost of directions to maintain power system security.

2.2 Gas markets in eastern Australia (chapter 5)

As in the NEM, wholesale gas prices declined steeply from record highs in 2022. This occurred alongside steadily declining international gas prices, putting export parity prices roughly on par with domestic east coast price levels. With the exception of a price spike in May prompted by supply and transport constraints, prices across 2023 have been subdued compared with recent years. This has been aided by planned export maintenance outages providing surplus gas supply to local markets. However, average prices across the east coast remain high by historical standards.

Figure 2.2 Eastern Australia 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.

From late 2022, the Competition and Consumer (Gas Market Emergency Price) Order 2022 came into effect for 12 months, with nearly all producer contracts from this period decreasing to levels at or below the $12 per GJ price cap. Since the introduction of the price cap, the AER has observed a shift towards shorter-term gas products, with less long-term gas available in the markets the AER monitors. Similarly, the ACCC observed a reduction in long-term gas contracting levels. From mid-July, the Australian Government replaced the price order through implementing a mandatory Gas Code of Conduct. The Code of Conduct maintains a $12 per GJ price cap, supporting it with a longer-term exemptions framework and other transparency requirements and extending to gas supply from 2024.

The depletion of gas legacy fields in the Gippsland Basin has continued to impact southern markets' supply capabilities, yet strong deliveries from Queensland suppliers into southern markets from May also assisted in putting downward pressure on prices alongside reduced demand for gas-fired generation in the National Electricity Market. In coming years, southern markets are expected to continue to rely more heavily on northern gas supplies to meet local demand.

East coast exports eased from late 2022 to levels comparable with those of 2019, before rebounding in the April to June quarter. China's move towards offsetting lower Australian supply with higher imports from Russia saw an increase in east coast exports going to Japanese and Korean markets.

Activity on the Day Ahead Auction has continued to remain strong since mid-2022, with record quarterly levels of capacity won to transport gas across the east coast. This also supported access to continued higher levels of gas commodities being traded at the Gas Supply Hub, which has transitioned towards more gas being sold over shorter-term delivery windows across 2023.

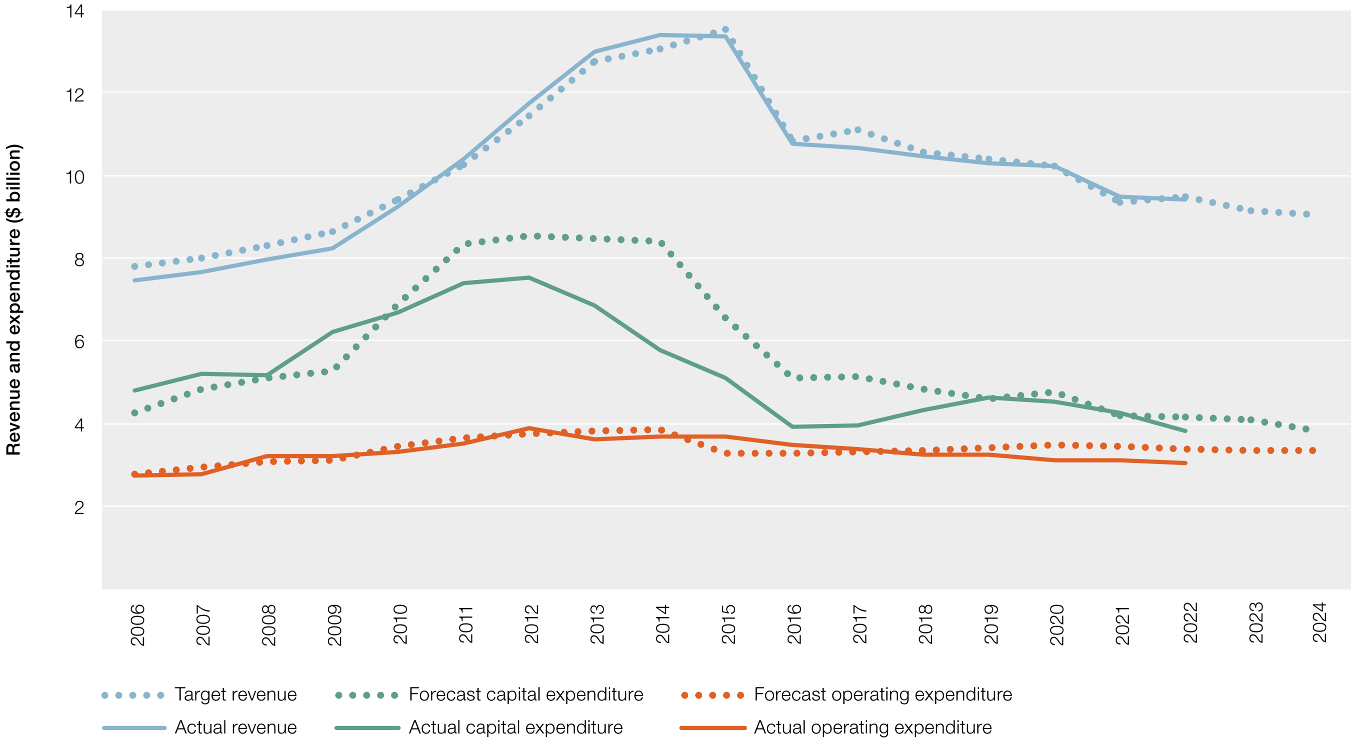
From mid-2023, pipeline expansions on the supply corridor from Queensland to Sydney and Victoria have increased deliverable capacity into southern markets. Further expansions in Victoria over spring 2023 are set to provide higher flexibility to move gas in and out of storage at Iona's underground facility. The Iona storage facility has also completed upgrades to increase storage and supply capacity, with the construction of further upgrades to increase storage capacity proposed to commence from late 2023. In 2021 and 2022 unprecedented drawdown of storage stocks by mid-winter reduced inventories near to critical low levels. Unlike these previous years, when the drawdown put pressure on Victoria's gas supply, inventories in 2023 remained at sufficient levels to comfortably supply the market in winter.

2.3 Electricity networks and regulated gas pipelines (chapters 4 and 6)

Consumers in 2023 faced similar costs to network services on the year prior:

- Combined electricity network revenue, including both distribution and transmission network components, was down 0.1%, marking the eighth consecutive year of aggregate decreases in revenue
- Similarly, total regulated gas pipeline revenue was slightly down (2.4%), noting that this captures many of the key pipelines serving retail customers but not the pipelines subject to lighter forms of regulation.

Figure 2.3 Revenue and key drivers – electricity distribution networks (aggregate)



Note: All data are adjusted to June 2022 dollars. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Target revenue is derived from regulatory determinations but adjusted to present it on a comparable basis to actual revenues. 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. 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.

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

Electricity networks and gas pipelines are capital-intensive assets. The costs networks incur to raise capital and finance investment are higher after several years of historically low rates putting downward pressure on network revenue. If higher costs of capital persist as network revenue determinations are completed, this will put upward pressure on the revenue requirements of both electricity networks and gas pipelines. In addition, high consumer price index (CPI) outcomes in recent years will feed into higher network costs through annual tariff increase processes from 2023 and onwards.

Reliability of supply is the key network output consumers should receive for their expenditure on network services. Electricity network consumers faced longer and more frequent unplanned interruptions to supply than over 2020–21, although that year marked a record low frequency of interruptions. Major weather events continued to have significant impact on the overall consumer experience. Consumers on gas pipelines continued to experience very few outages.

Other key revenue drivers also remained moderate. Capital investment in electricity networks was less this year than in the previous year (down 11%) but remains significantly above the long-term average. Amongst distribution networks, most investment is in replacement of existing assets. For transmission networks, growth-related expenditure is increasingly the most significant driver of investment and will become more so as networks progress the projects specified through the integrated system plan.

Capital expenditure on regulated gas pipelines was, in aggregate, slightly higher (1.7%) than in the previous year. However, this was the outcome of divergent underlying results between transmission and distribution pipelines:

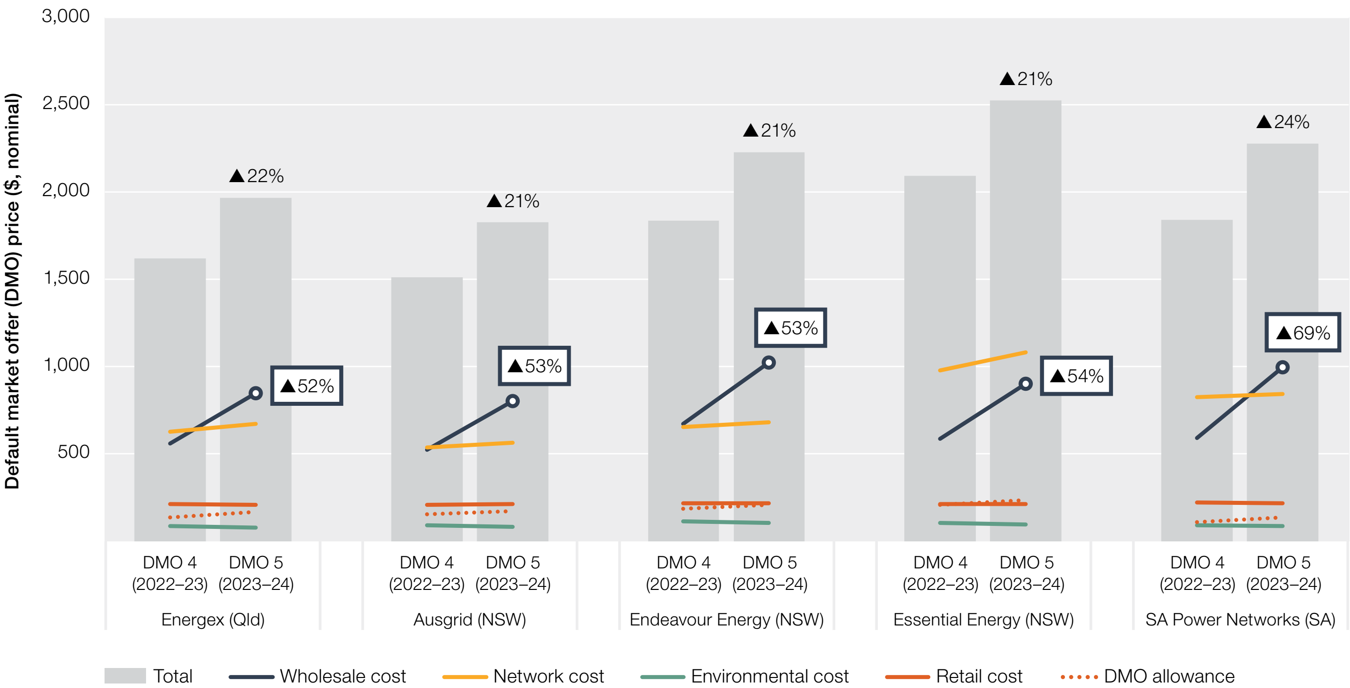
- Investment in gas transmission was significantly higher (144%) than in the previous year, due to APA Victorian Transmission System's (Vic) expansion of the South West Pipeline and its construction of the Western Outer Ring Main project
- In contrast, there was a significant fall in investment in gas distribution pipelines compared with the previous year (17%). Distribution pipeline assets make up the majority of the combined capital bases amongst the regulated pipelines.

2.4 Retail energy markets (chapter 7)

From June 2022 to June 2023, estimated energy bills increased in all NEM jurisdictions. Estimated electricity bills increased by 9% to 20% in 2022–23 from the previous year and estimated annual gas bills in 2022–23 ranged from $703 in Queensland to $1,647 in the ACT.[1] The increases were driven by material increases in wholesale energy costs of both gas and electricity.

Increased wholesale costs are incorporated in the higher default market offers for 2023–24, which came into effect on 1 July 2023. The DMO is the maximum price (or price cap) that a retailer can charge a customer on a standing offer in New South Wales (NSW), South Australia and south-east Queensland each year. It protects consumers from unjustifiably high prices, while allowing retailers to recover their costs.

Figure 2.4 Components of the default market offer



Note: Comparison of cost components calculated for the 2022–23 (DMO 4) and 2023–24 (DMO 5) prices, for residential customers without controlled load. Prices include GST. Values are nominal.

Source: AER, Default market offer prices 2023–24, May 2023.

Market offers, which are typically adjusted in July, increased to accommodate higher wholesale costs. Bills are likely to increase, commencing from August (for customers with monthly billing cycles) to October 2023 (for customers with quarterly billing cycles). Some customers are not well-placed to absorb these higher prices, with slow wage growth and increasing costs of living continuing to impact consumers' capacity to pay. This is a major concern – electricity affordability remains a top cost-of-living issue for households.

1 We base estimated bill costs on available offers displayed over time on government price comparison websites Energy Made Easy and Victorian Energy Compare. Pricing data is aggregated across multiple pricing areas within some electricity and gas distribution networks. Bill estimates across areas are not directly comparable because each is based on average consumption in the relevant area.

In the short term, rebate assistance should mitigate some of these impacts. In December 2022, the Australian Government announced in partnership with state and territory governments that it would provide up to $3 billion in electricity bill relief for eligible households and small businesses through the Energy Bill Relief Fund. This fund also includes other measures to mitigate price pressures through temporary price caps and support for investment in clean energy generation and storage.

Origin Energy, AGL Energy and EnergyAustralia (the 'big 3') are the largest energy providers in Australia. The big 3 retailers have a significant share in the residential electricity and gas markets of NSW and South Australia and a lesser but still substantial portion of the Queensland and Victorian markets. Although their market share continues to decline, as at March 2023 the big 3 still served at least 60% of residential and small business electricity customers, 79% of residential gas customers and 90% of small business gas customers.

Growth in the number of alternative retailers (Tier 2 retailers) supports effective retail competition.[2] Following strong growth of alternative market providers from 2016, the number of retailers remained relatively stable throughout 2022. Sharp increases in wholesale energy costs have caused some strain for retailers and will likely subdue interest from new market entrants until wholesale prices stabilise.

2 Tier 2 retailers include any retailer that is not Origin Energy, AGL Energy, EnergyAustralia or one of the primary regional government-owned retailers – Ergon Energy (Queensland), ActewAGL (ACT) and Aurora Energy (Tasmania).

Image source: iStock

3 National Electricity Market

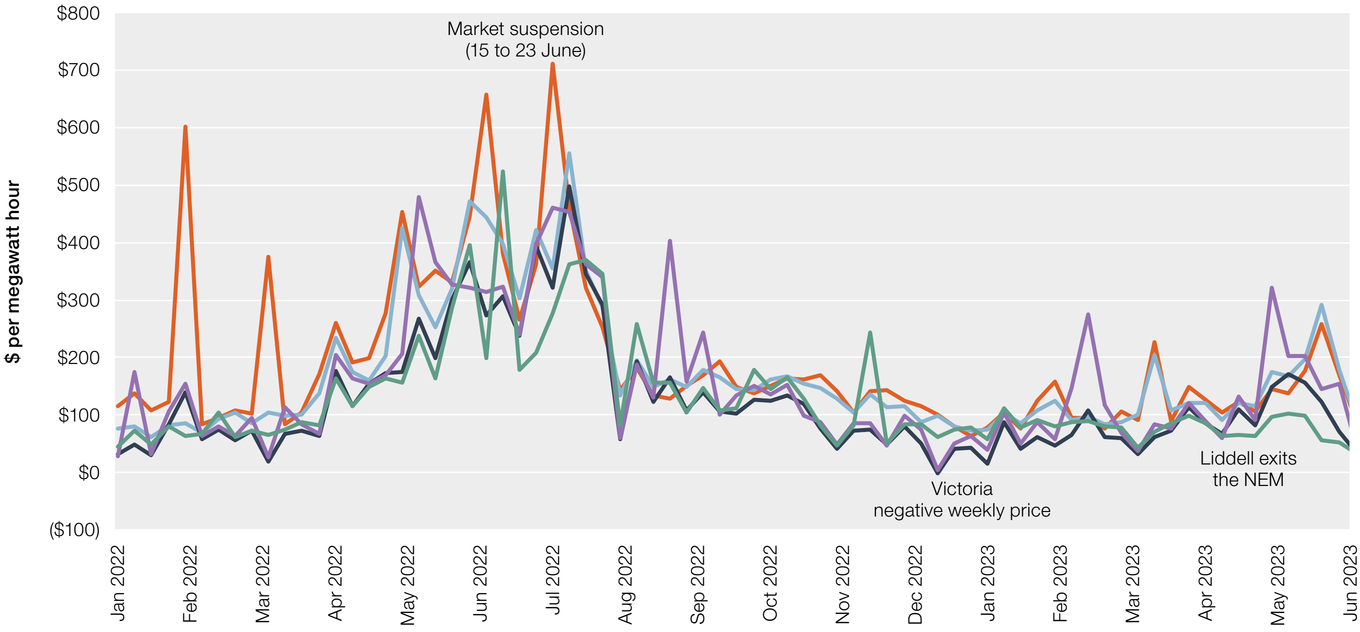
Electricity generated in eastern and southern Australia is traded through the National Electricity Market (NEM). Generators make offers to sell electricity into the market and the Australian Energy Market Operator (AEMO) schedules the lowest priced generation available to meet demand. The amount of electricity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

3.1 Snapshot

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

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

Figure 3.1 Weekly wholesale electricity prices

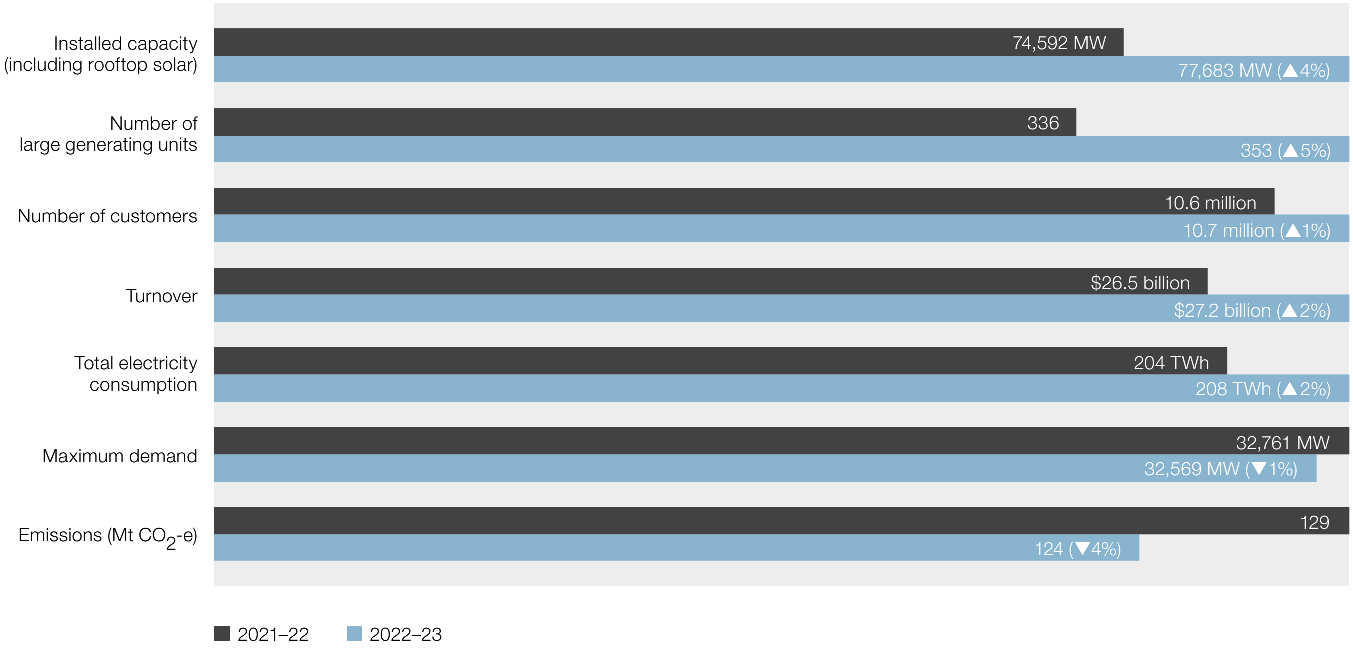


Note: Volume weighted weekly average prices.
Source: AER; AEMO (data).

3.2 NEM overview

353 generating units produce electricity for sale into the NEM (Figure 3.2). A transmission grid carries this electricity along high voltage power lines to industrial energy users and local distribution networks (chapter 4). Energy retailers complete the supply chain by purchasing electricity from the NEM and packaging it with transmission and distribution network services for sale to residential, commercial and industrial energy users.

Figure 3.2 NEM key statistics



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

Box 3.1 How the NEM works

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

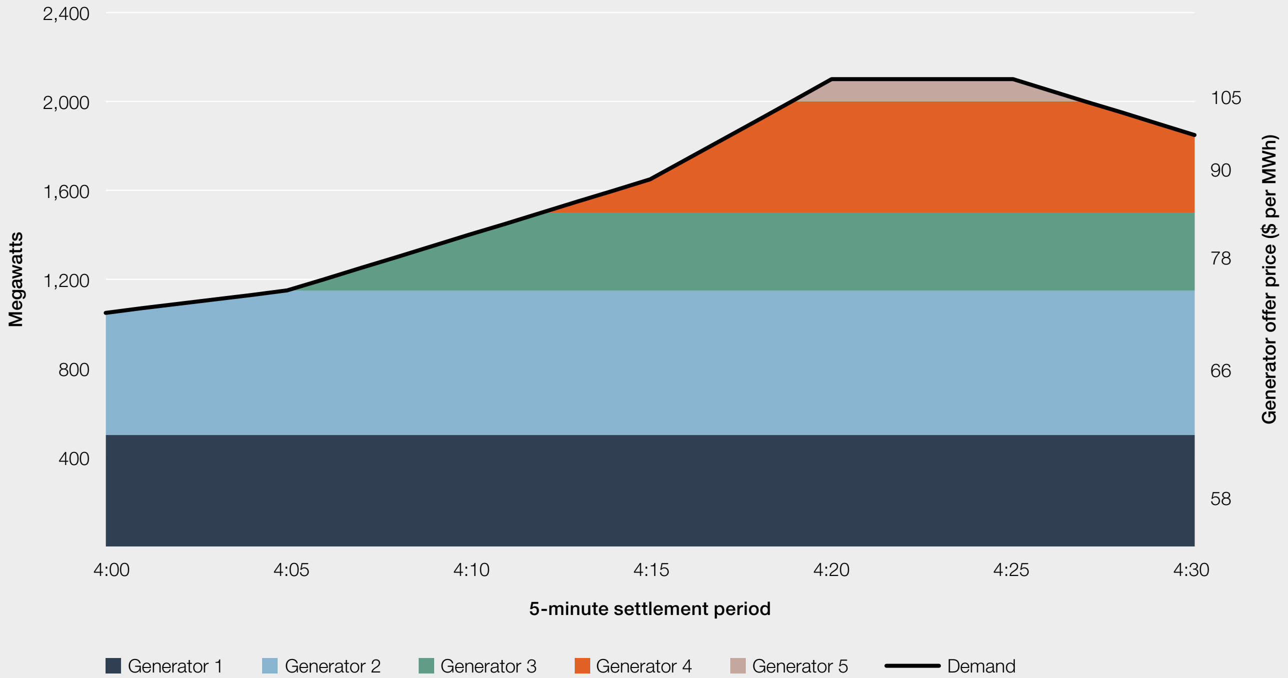
Power stations make offers to supply quantities of electricity in different price bands for each 5-minute dispatch interval. Scheduled loads, or consumers of electricity such as pumped hydro and batteries, also offer into the market. From 2021, consumers (either directly or through aggregators) are also able to bid demand response directly into the wholesale market as a substitute for generation (section 3.8). Electricity generated by rooftop solar systems is not traded through the NEM, but it does lower the demand that market generators need to meet.

A separate price is determined for each of the 5 NEM regions. Prices are capped at a maximum of $16,600 per megawatt hour (MWh) in 2023–24. A price floor of –$1,000 per MWh also applies. The market cap has increased in line with the consumer price index (CPI) each year, but the market floor price remains unchanged.

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

The Box Figure 3.1 illustrates how prices are set. In this example, 5 generators offer capacity in different price bands between 4:00 pm and 4:30 pm. At 4:15 pm the demand for electricity is 1,650 MW. To meet this demand, generators 1, 2 and 3 must be fully dispatched and generator 4 is partly dispatched. The dispatch price is $90 per MWh. By 4:20 pm demand has risen to the point where a fifth generator is needed. This generator has a higher offer price of $105 per MWh, which becomes the dispatch price for that 5-minute interval. That price is paid to all dispatched generators, regardless of their offers. This process is repeated for all 5-minute intervals.

Box Figure 3.1 Setting the price



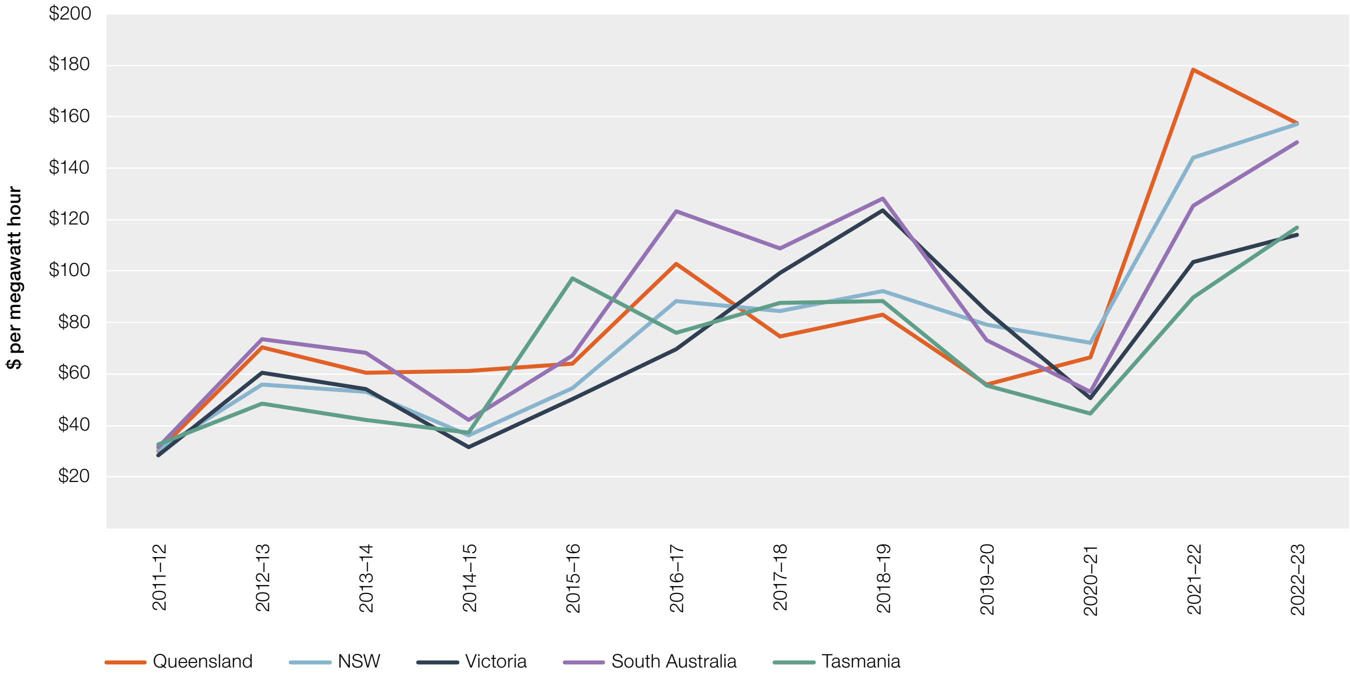
While the market is designed to meet electricity demand in a cost-efficient way, other factors can intervene. At times, dispatching the lowest cost generator may overload the network or risk system security, so AEMO dispatches more expensive (out of merit order) generators instead.

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

3.3 Wholesale prices and activity

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

Figure 3.3 Annual wholesale prices, financial year



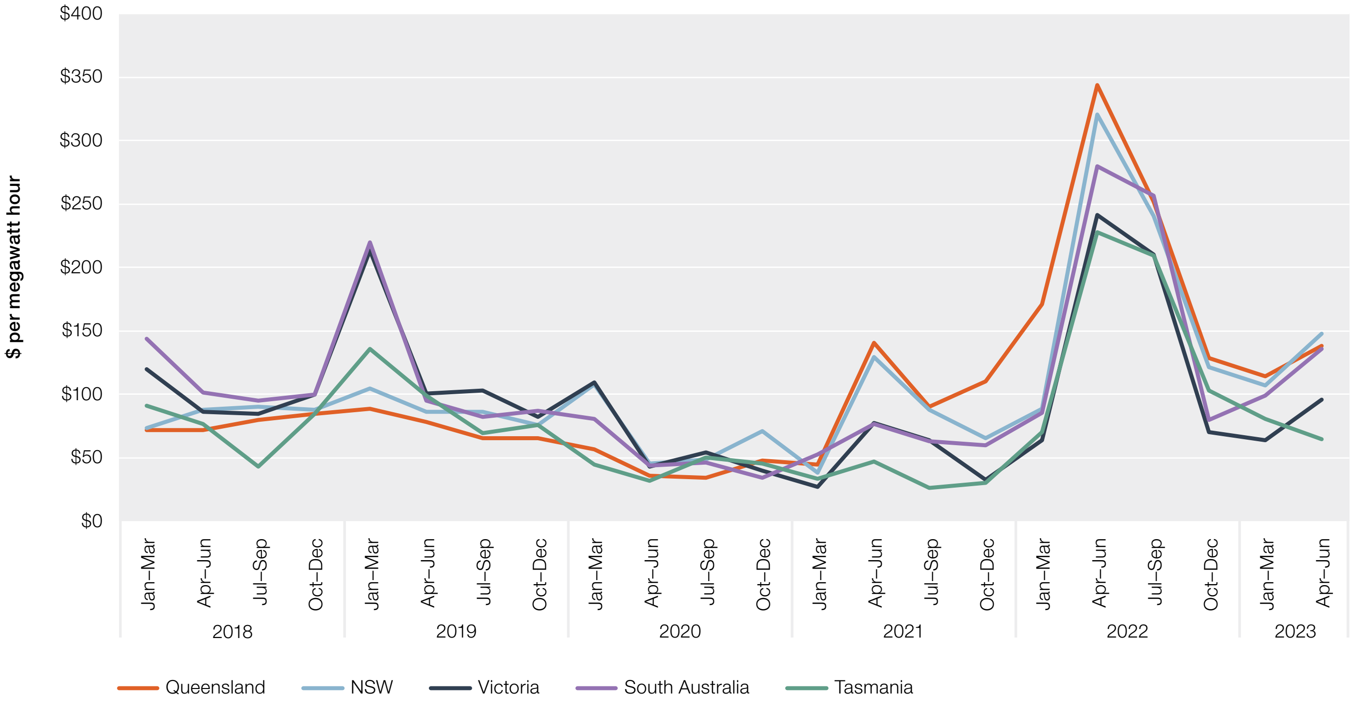
Note: Volume weighted average financial year prices.
Source: AER; AEMO (data).

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

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

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

Figure 3.4 Quarterly wholesale electricity prices



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

3.3.1 July to September 2022

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

3.3.2 October to December 2022

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

3.3.3 January to March 2023

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

3.3.4 March to June 2023

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

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

3.4 Generator fuel costs, fuel availability and market interventions

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

3.4.1 Market interventions

Coal price cap

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

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

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

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

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

Gas price cap

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

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

3.4.2 Generator fuel availability

Coal

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

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

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

Gas

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

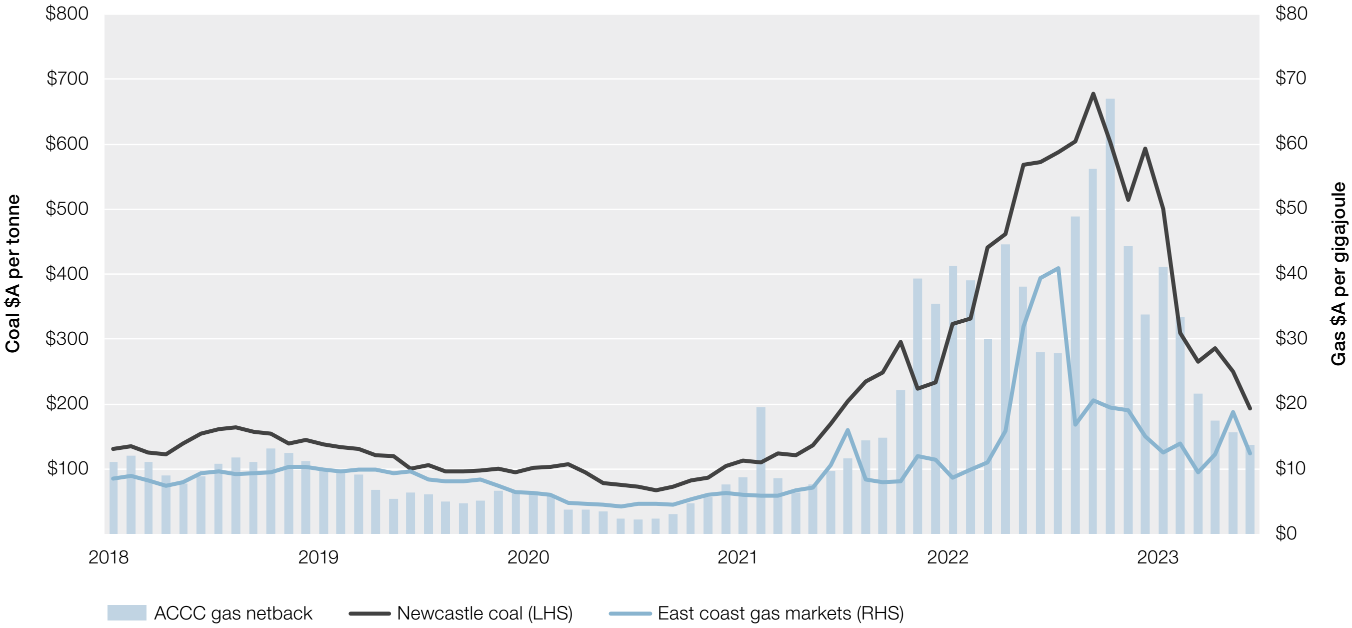
In winter 2022, an abnormally high number of unplanned coal generator outages, among other exacerbating factors, saw the NEM become significantly more reliant on GPGs (gas-powered generators) to meet demand. As a result, contracted deliveries of gas to GPGs were insufficient, resulting in an unprecedented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

3.4.3 International fuel prices

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

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

Figure 3.5 Coal and gas prices



Note: The black coal price is derived from the Newcastle coal index (US$ per tonne), converted to Australian dollars with the Reserve Bank of Australia exchange rate. The east coast gas market (ECGM) average gas price is the average of gas prices in Queensland, NSW, Victoria and South Australia. The ACCC gas netback is the Asian gas price benchmark plus additional costs associated with export.

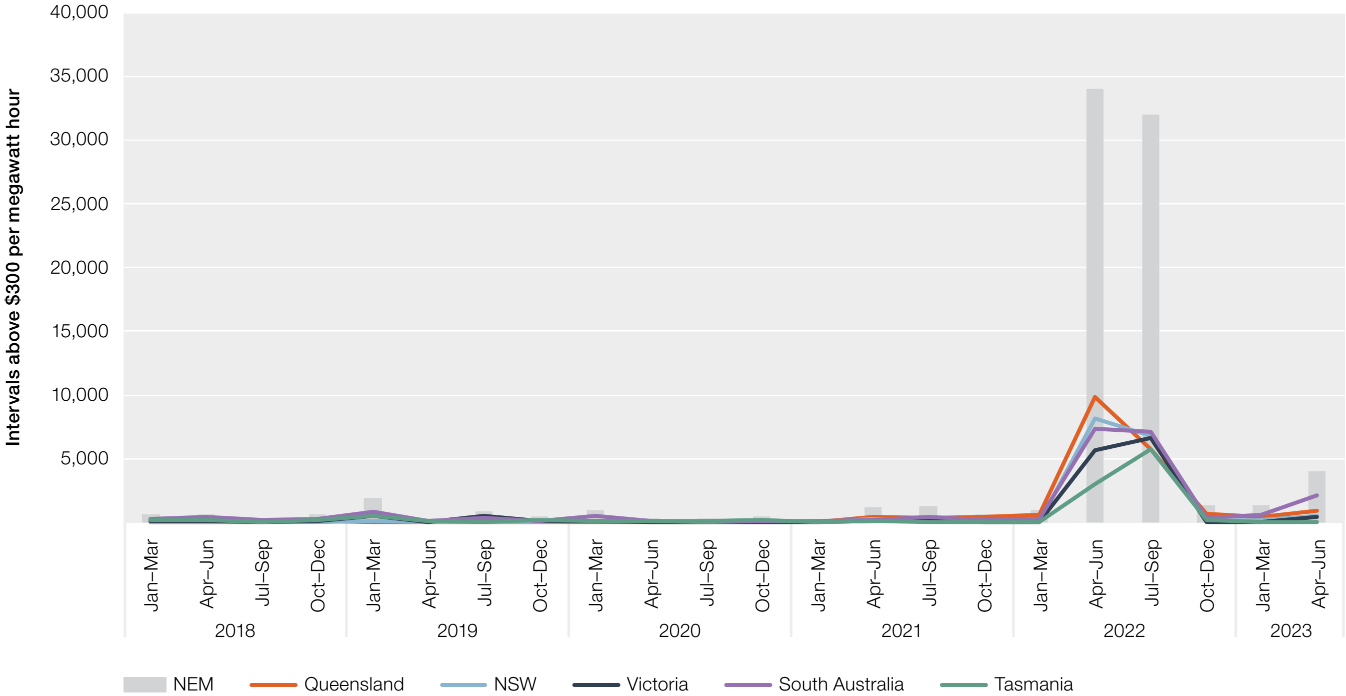
Source: AER analysis using globalCOAL data; ACCC data.

3.4.4 Price volatility

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

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

Figure 3.6 Count of prices above $300 per MWh



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

Source: AER; AEMO (data).

3.4.5 Negative prices

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

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

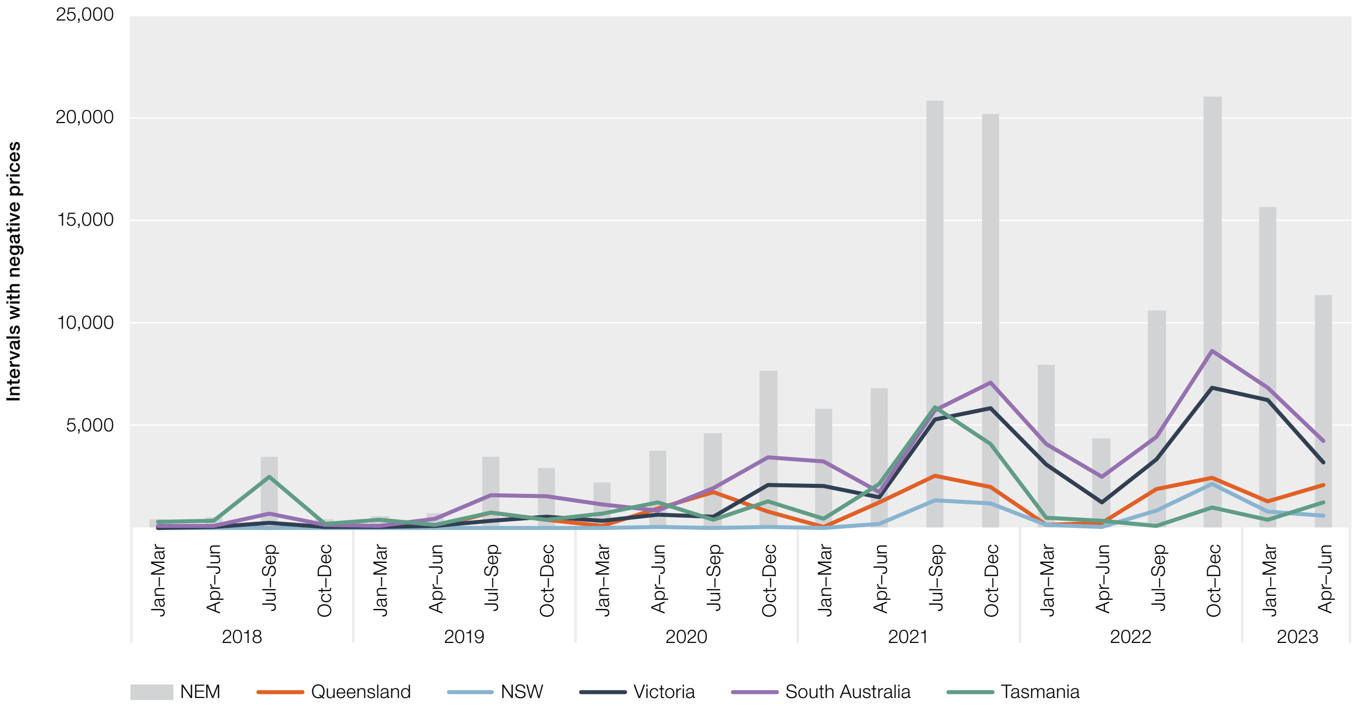
Negative prices have been more frequent since renewables entered the market

The ability of wind and solar generators to operate varies with prevailing weather conditions. These generators do not incur high startup or shutdown costs and have marginal costs close to zero. If generating conditions are optimal, they may bid capacity at negative prices to guarantee dispatch. Some wind and solar generators also source revenue from the sale of renewable energy certificates[1] or power purchase agreements, so they may operate profitably even when wholesale prices are negative.

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

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

Figure 3.7 Count of negative prices



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

Source: AER; AEMO (data).

If electricity demand is low, the market has surplus capacity and the chances of the market settling at a negative price are higher. The geographic grouping of renewable generators can intensify the effect because when conditions are favourable for one generator in the area, conditions tend to be favourable for others too. With multiple low-cost generators all competing for dispatch, the likelihood of negative prices increases.

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

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

3.5 Electricity contract markets

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

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

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

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

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

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

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

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

- Futures contracts allow a party to lock in a fixed price (strike price) to buy or sell a given quantity of electricity at a specified time in the future. Available products include quarterly base contracts (covering all trading intervals) and peak contracts (covering specified times of generally high energy demand). Futures can also be traded as calendar or financial year strips covering all 4 quarters of a year. Futures contracts are settled against the spot market price in the relevant region – that is, when the spot price exceeds the strike price, the seller of the contract pays the purchaser the difference; when the spot price is lower than the strike price, the purchaser pays the seller the difference. In OTC markets, futures are known as swaps or contracts for difference.
- Caps are contracts setting an upper limit on the price that a holder will pay for electricity. Cap contracts on the ASX have a strike price of $300 per MWh and the FEX caps have a strike price of $300 or $500 per MWh. When the spot price exceeds the strike price, the seller of the cap (typically a generator) must pay the buyer (typically a retailer) the difference between the strike price and the spot price. Alternative (higher or lower) strike prices are available in the OTC market.
- Options are contracts that give the holder the right – without obligation – to enter a contract at an agreed price, volume and term in the future. The buyer pays a premium for this added flexibility. An option can be either a call option (giving the holder the right to buy the underlying financial product) or a put option (giving the holder the right to sell the underlying financial product). Options are available on base load futures contracts.

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

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

3.5.1 Contract market activity

Until recently, the ASX was the sole futures exchange operating in the NEM. FEX Global launched a separate futures exchange in March 2021 offering a similar range of products, but the volume of trade on the exchange has been minimal.

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

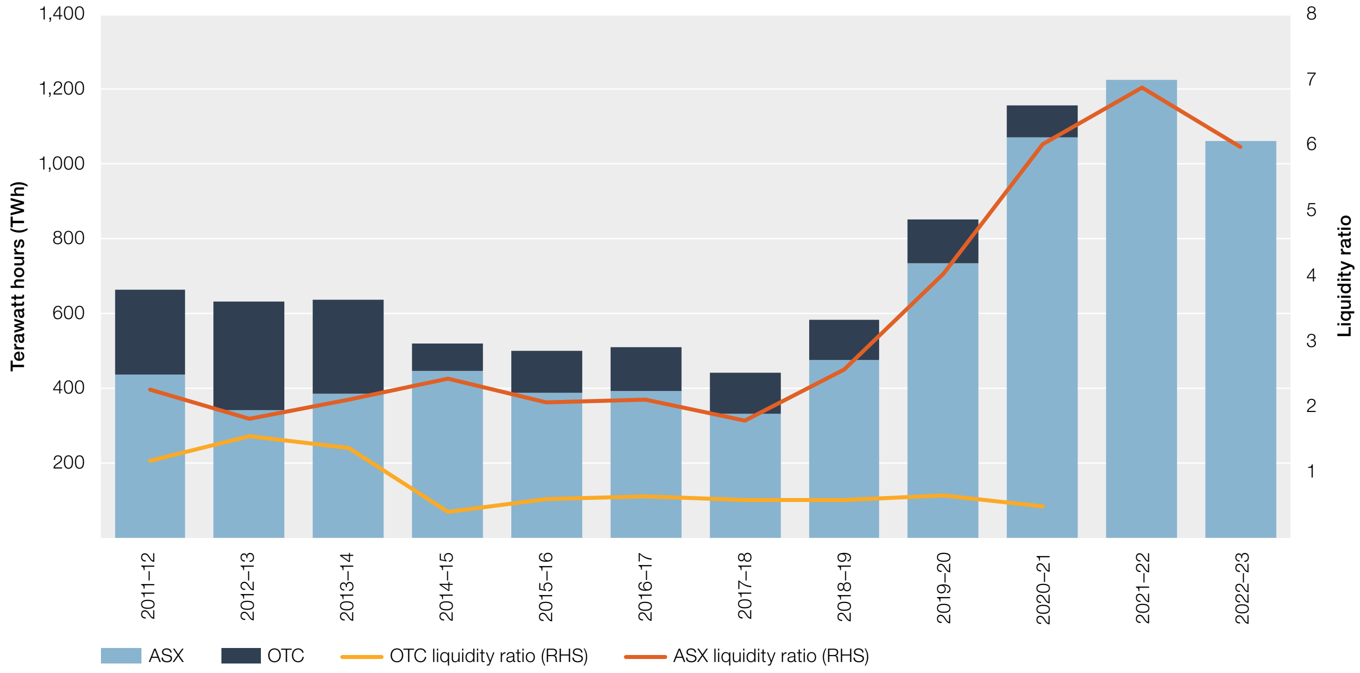
During 2022–23, ASX traded volumes fell after 4 consecutive years of growth, declining 13% from the record set in 2021–22 (Figure 3.8). During the July to September quarter 2022 there was a marked decline in ASX traded volumes, down 40% on the previous quarter. The fall in traded volumes was likely a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

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

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

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

Figure 3.8 Traded volumes in electricity futures contracts

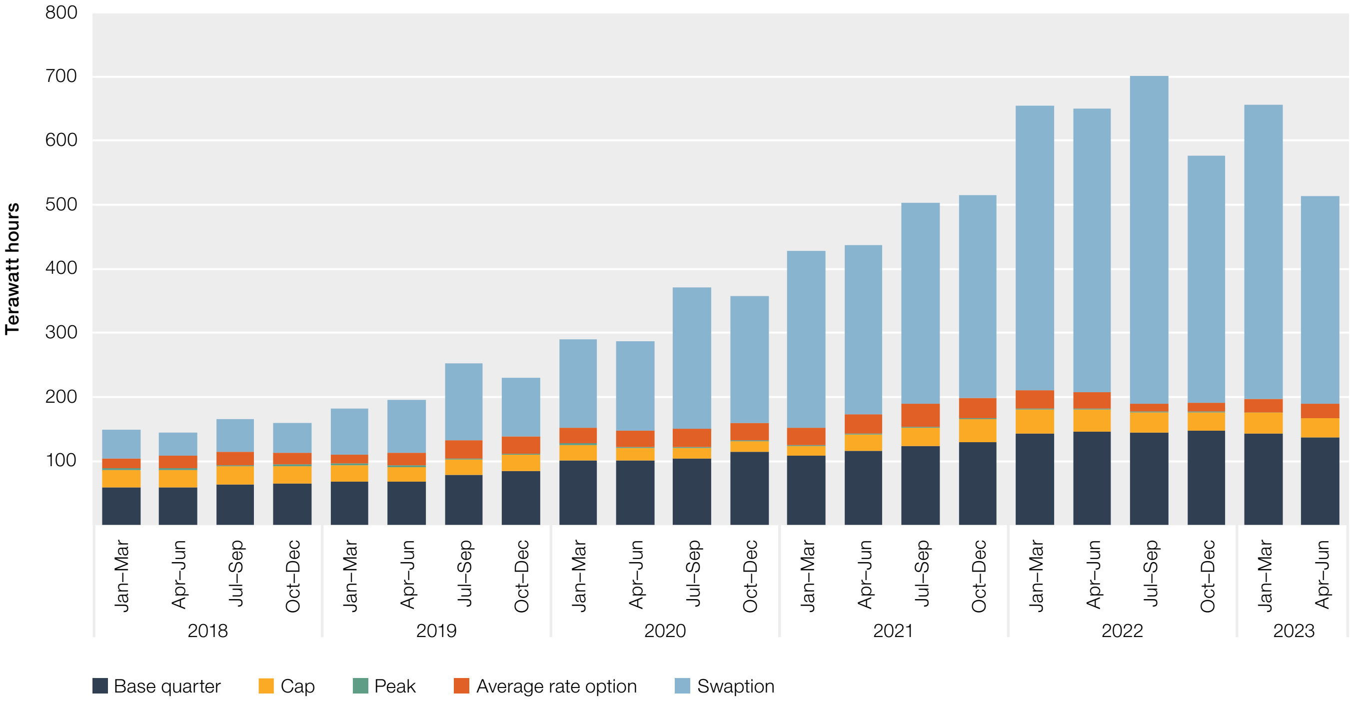


Note: Exchange trades are publicly reported, while activity in over-the-counter (OTC) markets is confidential and disclosed publicly only via voluntary participant surveys in aggregated form. The OTC data are published on a financial year basis. To allow some comparability across OTC and exchange traded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

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

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

Figure 3.9 ASX open interest volumes



Source: AER; ASX Energy (data).

The decline in trading of ASX contracts in the 2022–23 financial year may also be due to falling capacity of baseload coal generation and rising share of wind and solar generation in the market. Intermittent renewables generation is not as well suited to the sale of standard contracts as coal generation. This is because its output is uncertain and weather dependent. 'Firming' this generation with energy storage or gas-powered plant could help support contract market participation. Several market participants with flexible generation capacity offer firming products targeted at renewable generation.

ARENA provided funding support to Renewable Energy Hub, a specialist advisory and technology solutions provider, to establish a firming market platform that offers new hedge products designed for clean energy technologies.[2] The platform aims to fill a gap in risk management products and overcome a market barrier for clean energy technologies. New hedging products introduced by Renewable Energy Hub include:

- 'solar shape' and 'inverse solar shape' contracts to provide a level of flexibility to manage the intermittency of renewable generation; they are tailored to specific periods of the day and provide an alternative to flat contracts – trades in the contract have thus far been subdued
- a 'super peak' electricity contract for electricity supply during the high demand hours of the morning, afternoon and evening periods
- a 'virtual storage' electricity swap for buying and selling stored energy – the price of the product is set at the spread of the agreed charge and discharge prices. The first ever trade deal for stored energy was brokered for the 2021–22 financial year.

3.5.2 Contract market liquidity

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

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

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

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

Liquidity is poorer in South Australia, where trading volumes are less than underlying electricity demand. For just ASX trades, South Australia's liquidity ratio has fallen in the past 5 financial years consecutively, reaching just 17% of underlying demand in 2022–23. The region's high proportion of renewable generation and relatively concentrated ownership of dispatchable generation has likely contributed to this weaker liquidity.

3.5.3 Composition of trade

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

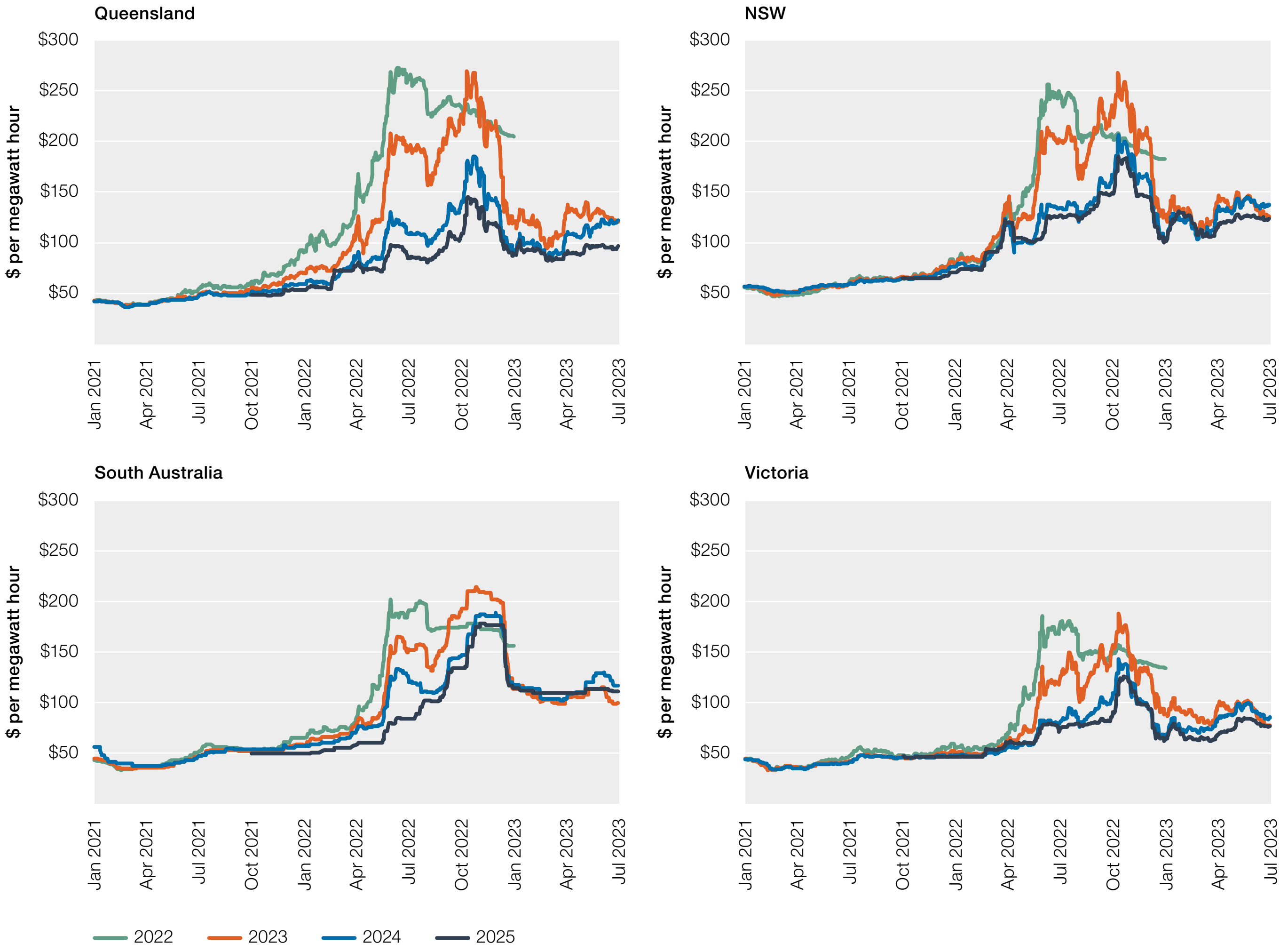
For 2022–23, swaptions (48%) were the most traded products on the ASX. The next most traded products were quarterly base futures, accounting for 39% of the traded volume. Average rate options (3%) and caps (4%) are traded at lower rates. Peak products continue to decline in popularity, accounting for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

3.5.4 Contract prices

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

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

Figure 3.10 Prices for calendar year base futures

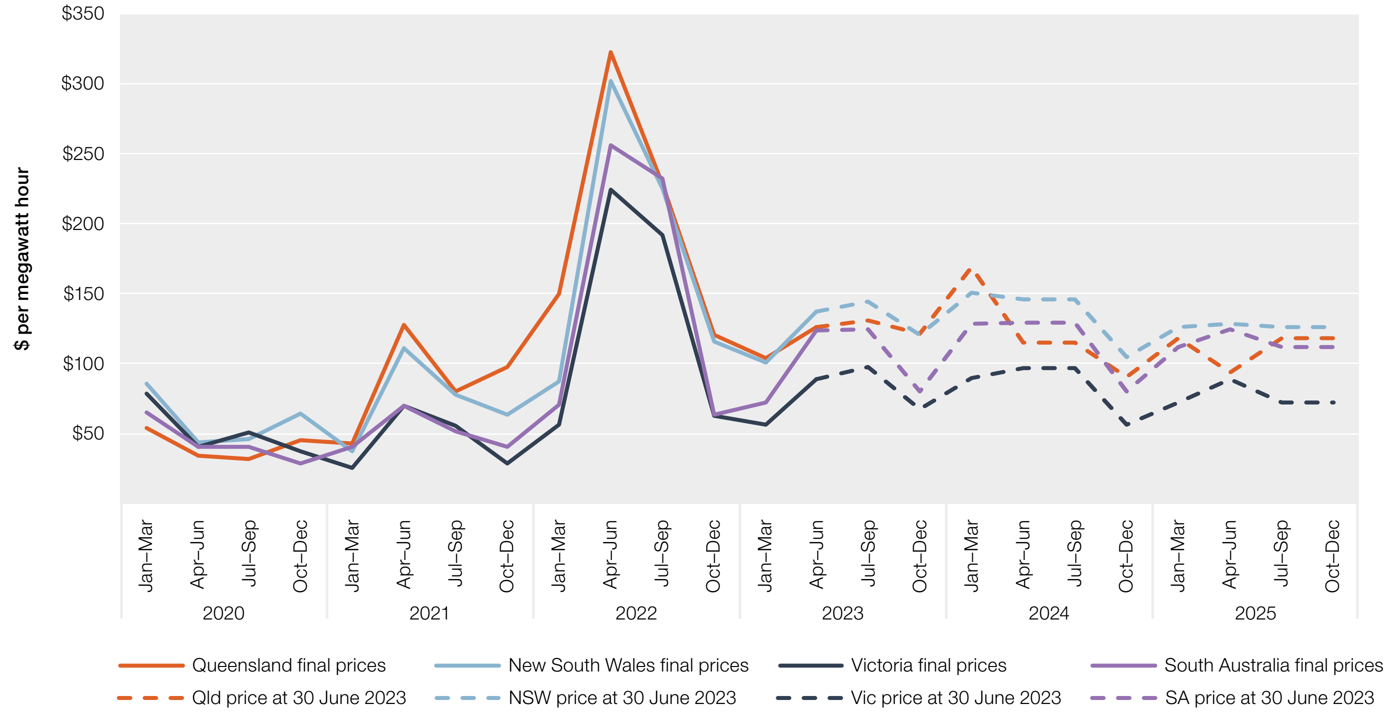


Source: AER; ASX Energy (data).

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

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

Figure 3.11 Prices for quarterly base futures



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

Source: AER; ASX Energy.

3.5.5 Access to contract markets

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

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

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

The Retailer Reliability Obligation (RRO) scheme introduced in July 2019 includes features aimed at improving access to contracts through an exchange. It includes a market liquidity obligation (MLO) on specified generators to post bids and offers in contract markets in the period leading up to a forecast reliability gap, to help smaller retailers meet their requirements. The AEMC will publish a review of operational aspects of the RRO in early 2024.[3]

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

3.6 Electricity demand and consumption

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

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

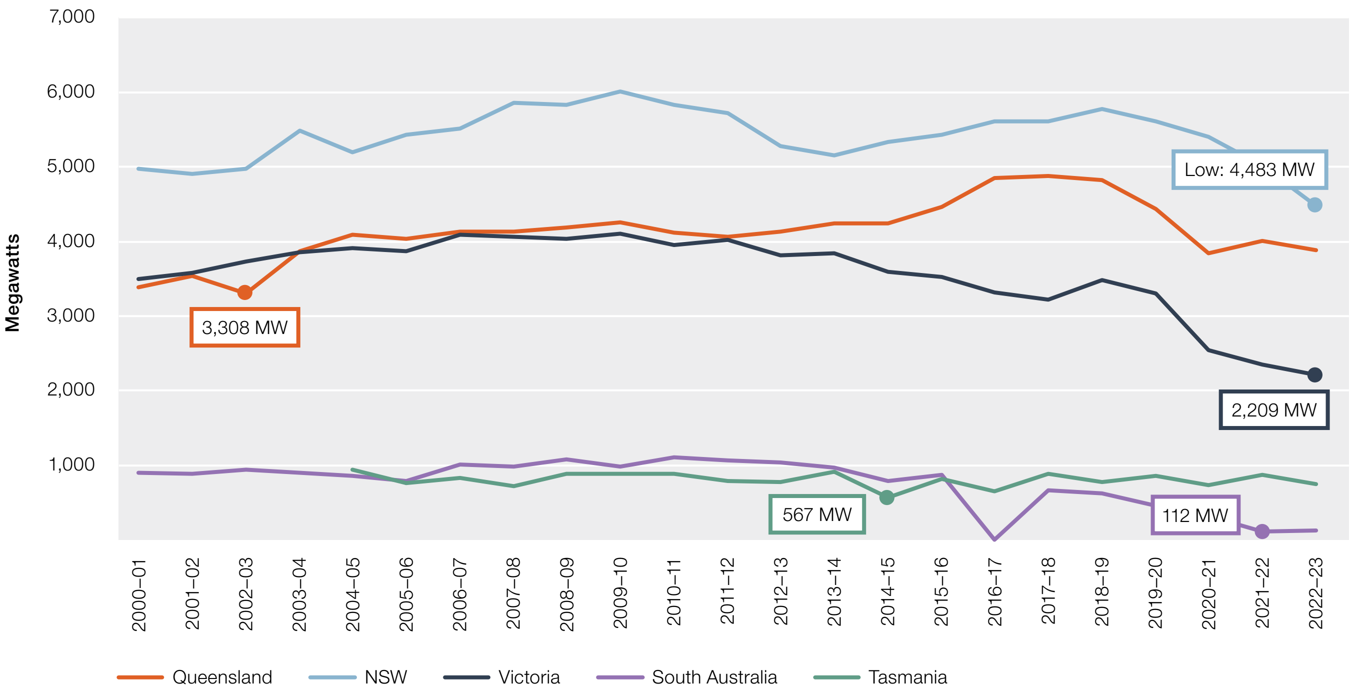
Grid demand has been falling for the past 6 years due to the increasing number of electricity customers generating their own electricity using rooftop solar (section 3.8.1). However, consumption has fallen only slightly in the past 3 years, after rising steadily for 5 years. The increase in consumption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

3.6.1 Minimum grid demand

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

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

Figure 3.12 Minimum grid demand



Note: Minimum 30-minute grid demand (including scheduled and semi-scheduled generation, and intermittent wind and large-scale solar generation) is for any time during the year. Data excludes consumption from rooftop solar systems. The low value for South Australia in 2016–17 is due to the Black System Event in October of that year.

Source: AER; AEMO (data).

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

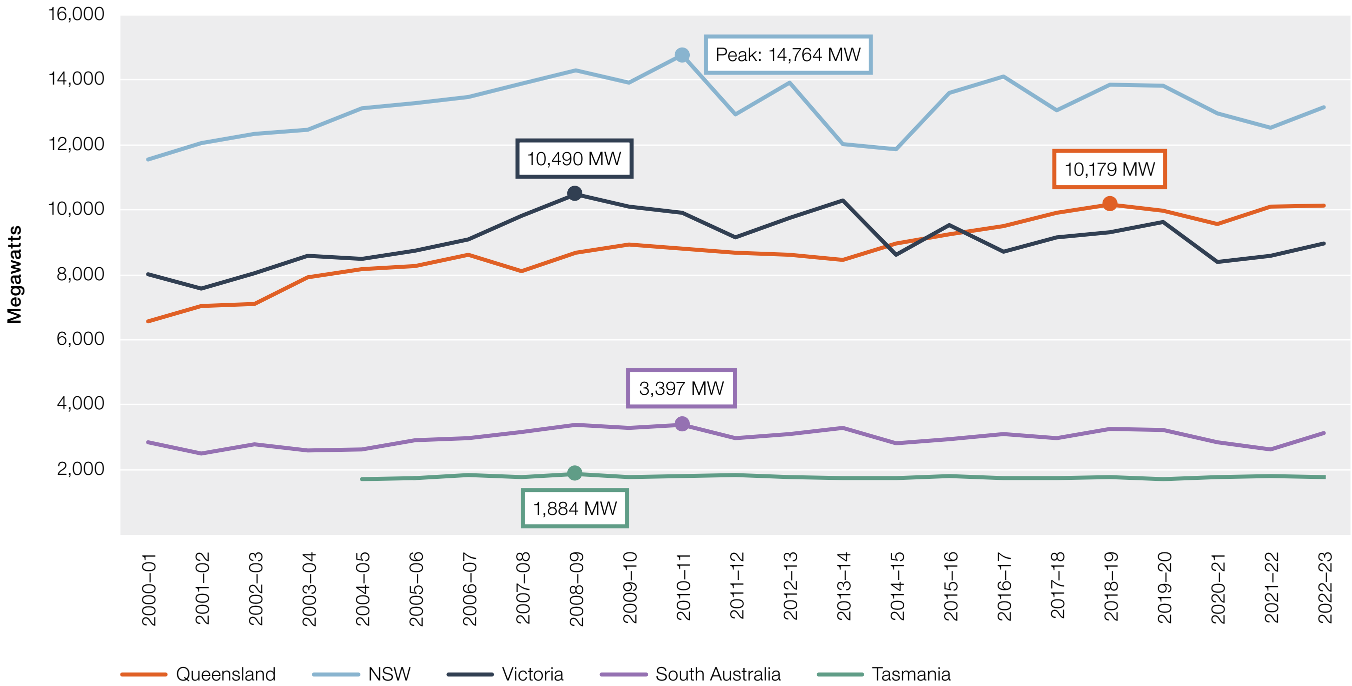
Several mechanisms have been developed to respond to demand low enough to threaten system security. AEMO has announced that, in such events, it will intervene to maintain system security through directing generators and loads, and directing network service providers to return lines to service.[5] The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

3.6.2 Maximum grid demand

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

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

Figure 3.13 Maximum grid demand



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

Source: AER; AEMO (data).

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

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

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

3.7 Generation in the NEM

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

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

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

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

Figure 3.14 Generation capacity, by fuel source

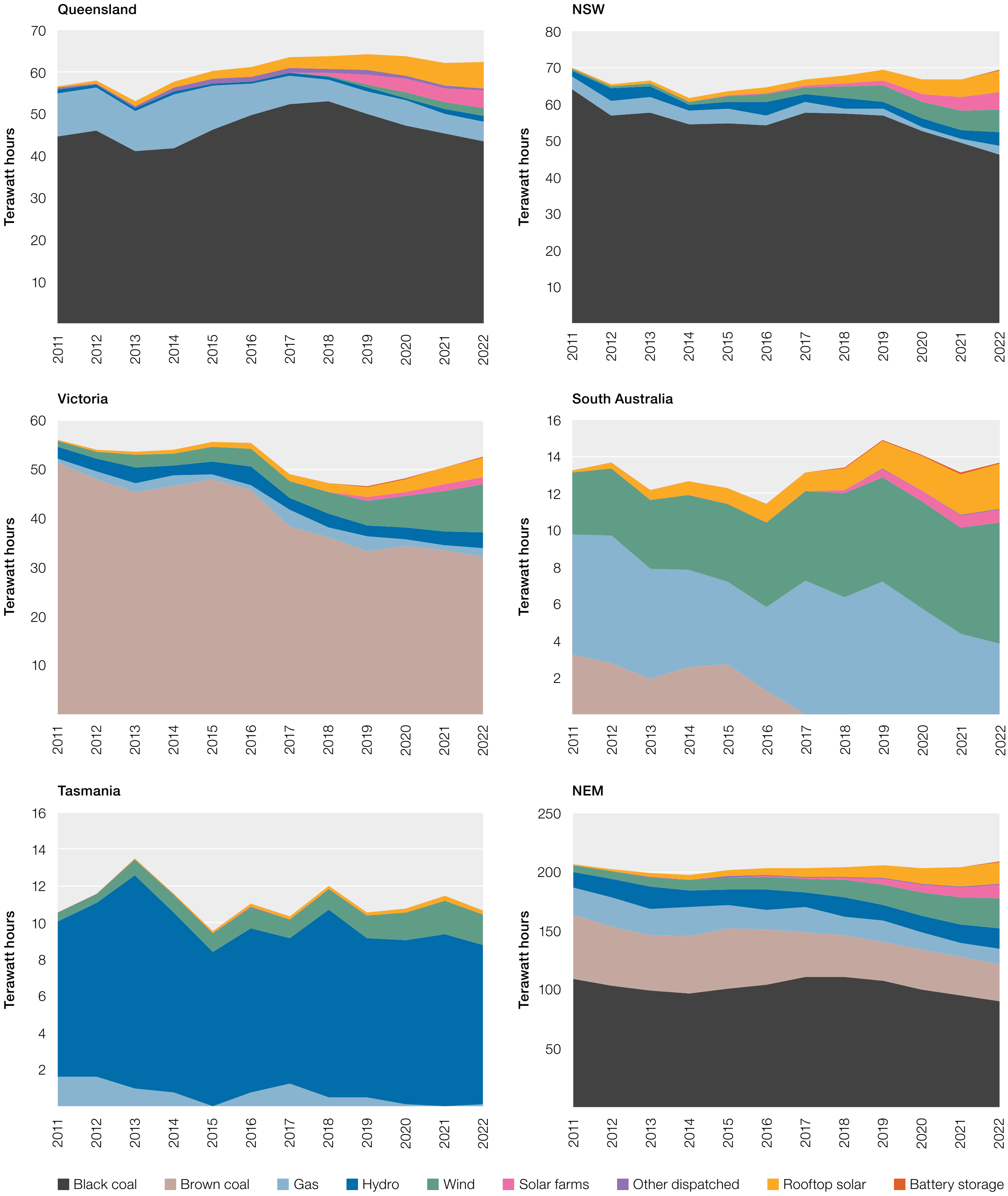
Note: Generation capacity at 30 June 2023. Other dispatch includes biomass, waste gas, diesel and liquid fuels. Loads and non-scheduled generation have been excluded. Solar capacity is maximum capacity, rather than registered capacity.

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

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

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

Figure 3.15 Generation output, by fuel source



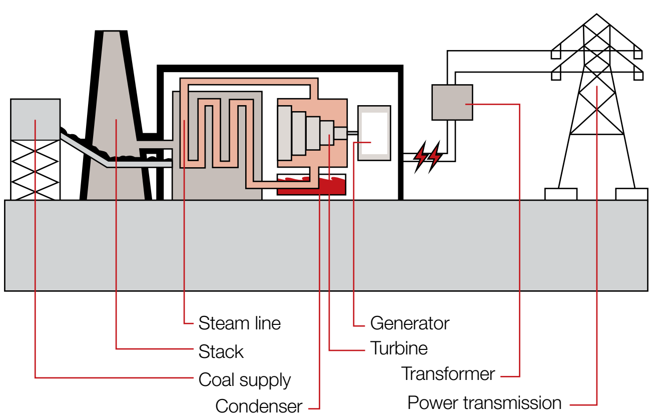
Note: Other dispatch includes biomass, waste gas, diesel and liquid fuels.

Source: AER; AEMO (data).

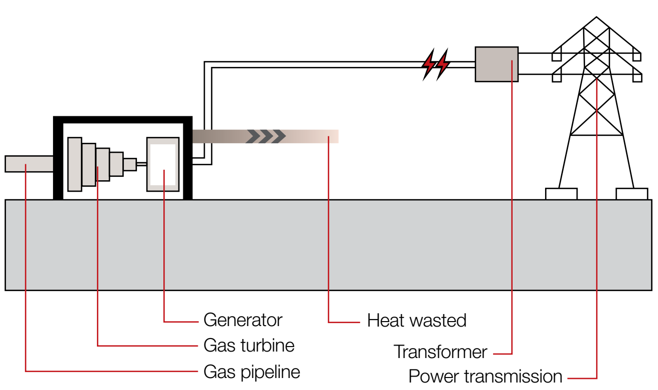
The various generation technologies have differing characteristics (Figure 3.16). Differences in startup, shutdown and operating costs influence each fuel type's bidding and generation strategies. Technology types also have different implications for power system security, including system strength and frequency.

Figure 3.16 NEM generation technologies

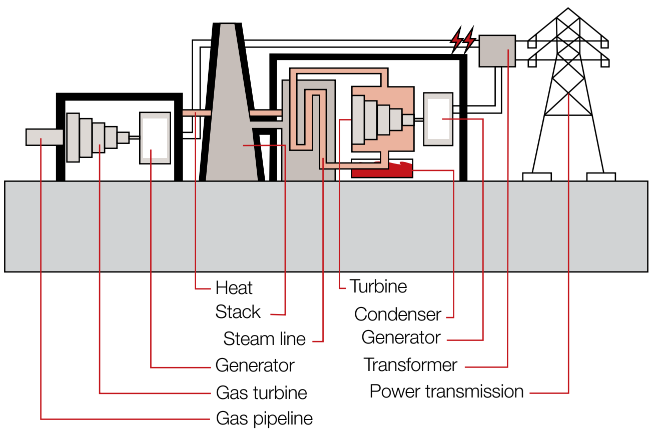
Coal-fired generation



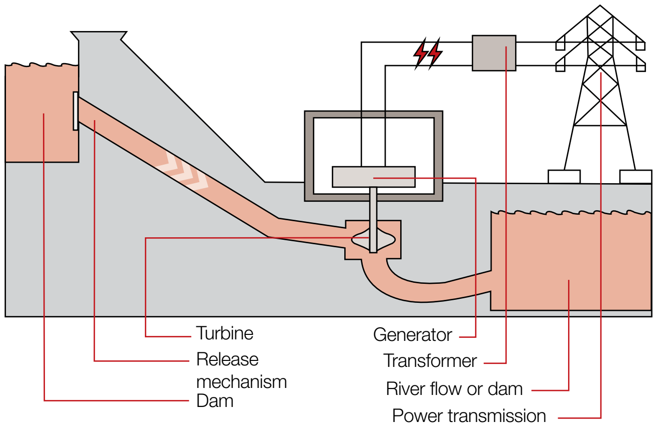
Open cycle gas-powered generation



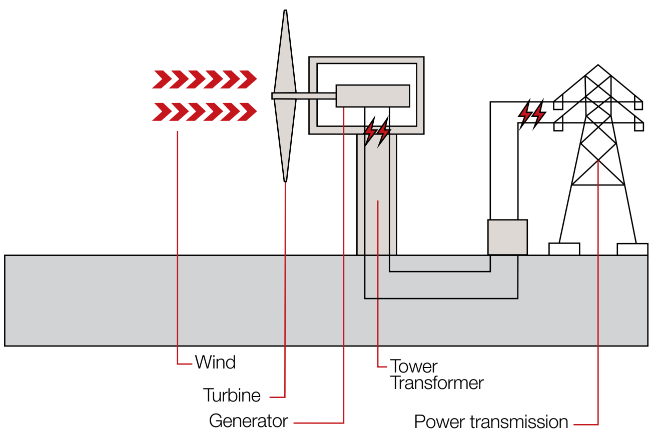
Combined cycle gas-powered generation



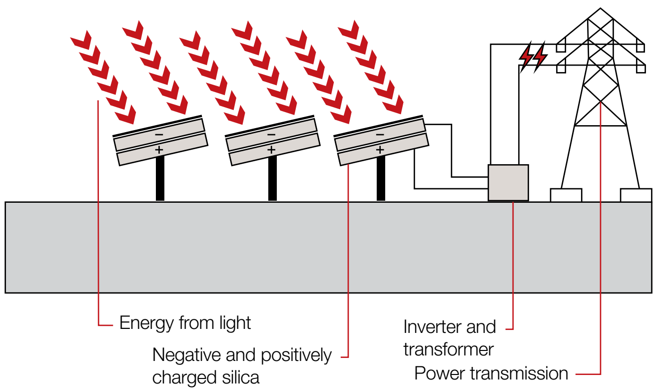
Hydroelectric generation



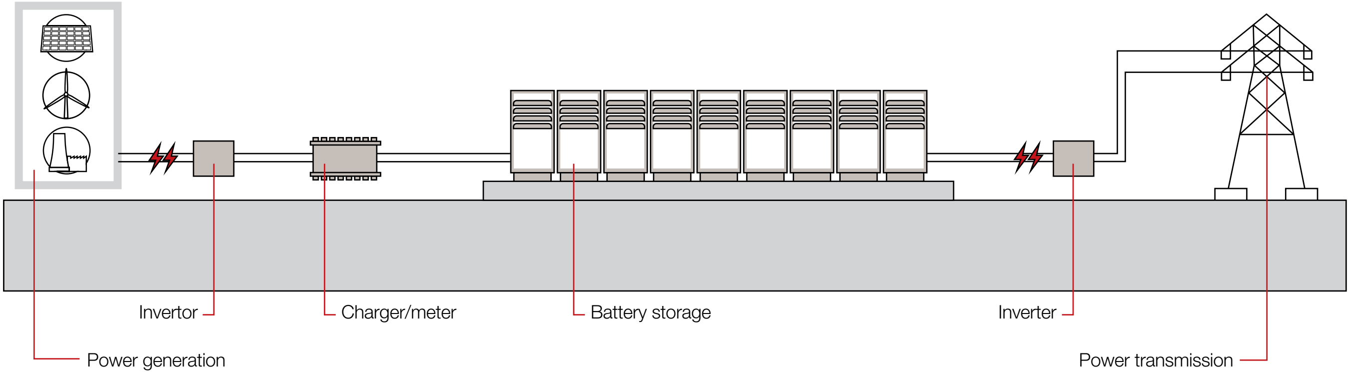
Wind-powered generation



Solar PV generation



Battery energy storage system



3.7.1 Coal-fired generation

Coal-fired generators burn coal to create pressurised steam, which is then forced through a turbine at high pressure to drive a generator (Figure 3.16). Coal is the only fuel type in the NEM that tends to generate at all hours of the day. Coal-fired generation remains the dominant supply technology in the NEM, producing just under 60% of all electricity traded through the market in 2022.

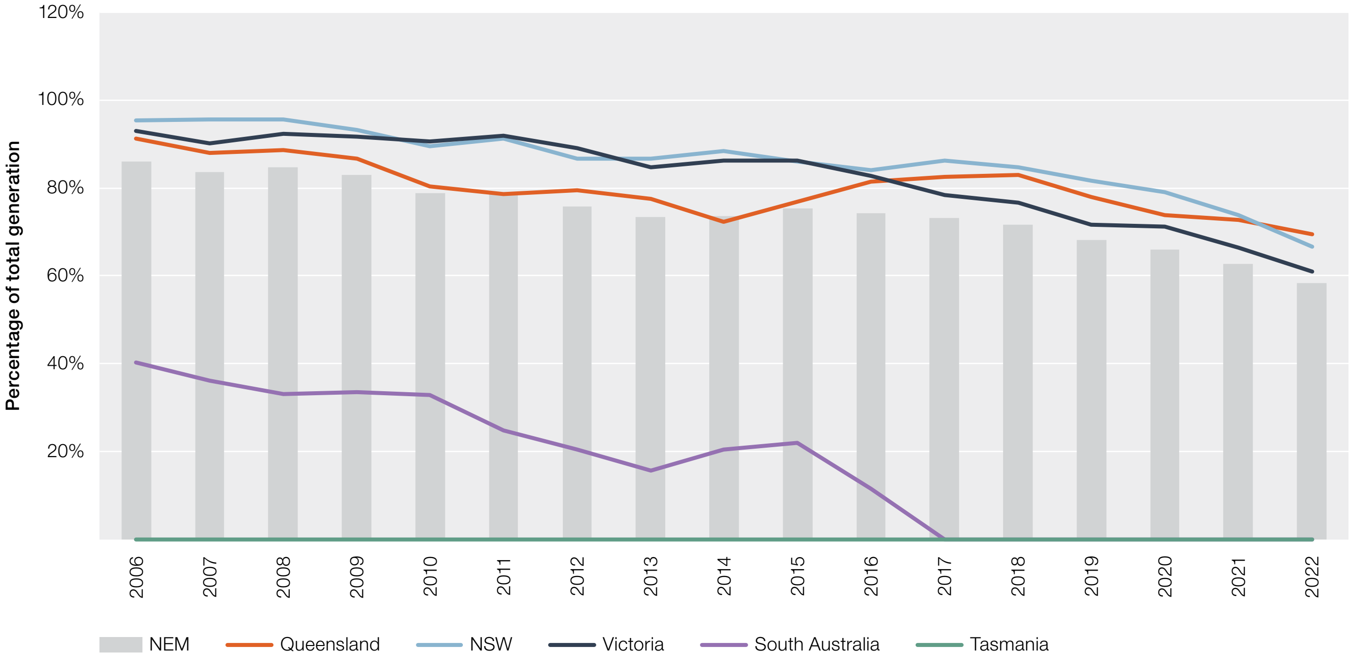
Coal plants operate in Queensland, NSW and Victoria. Generators in Queensland and NSW burn black coal and generators in Victoria depend on brown coal. Black coal produces more energy than brown coal because it has lower water content and produces 30–40% lower greenhouse gas emissions when used to generate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

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

Impact of solar on coal-fired generation

The rapid influx of grid and rooftop solar over the past 3 years has changed the shape of wholesale electricity prices and demand for baseload (coal) generation during the day. As a result, coal-fired generation makes up a declining but still large proportion of total NEM generation (Figure 3.17).

Figure 3.17 Proportion of total generation by region, coal



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

Source: AER; AEMO (data).

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

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

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

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

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

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

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

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

Coal outages fell in 2022–23 but remain a risk

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

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

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

3.7.2 Gas-powered generation

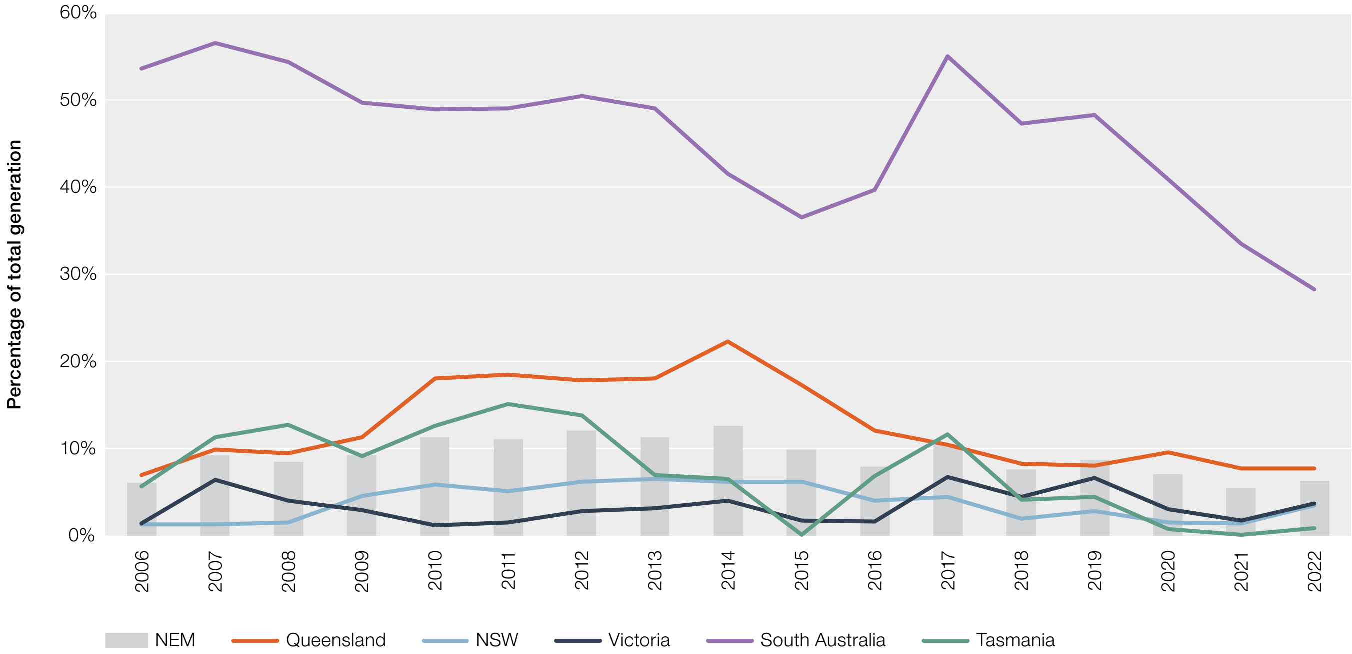
Two dominant types of gas generation technologies operate in the NEM (Figure 3.16). Open cycle gas turbine (OCGT) plants burn gas to heat compressed air that is then released into a turbine to drive a generator. In combined cycle gas turbine (CCGT) plants, waste heat from the exhaust of the first turbine is used to boil water and create steam to drive a second turbine. The capture of waste heat improves the plant's thermal efficiency, making it more suitable for longer operation than an open cycle plant. Reciprocating engine gas plants use gas to drive a piston that spins a turbine. These plants operate similarly to OCGTs but are more flexible. Some legacy 'steam turbines' – which operate similarly to coal plants – also remain in the market.

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

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

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

Figure 3.18 Proportion of total generation by region, gas



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

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

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

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

3.7.3 Hydroelectric generation

Hydropower uses the force of moving water to generate power. The technology involves channelling falling water through turbines. The pressure of flowing water on the blades rotates a shaft and drives an electrical generator, converting the motion into electrical energy (Figure 3.16). Like coal and gas plants, hydroelectric generators are synchronous, meaning they provide inertia and other services that support power system security. Because their fuel source is usually available (except in drought conditions), they are 'dispatchable' plants that can switch on as required.

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

Hydroelectric plants have low fuel costs (that is, they do not explicitly pay for the water they use), but they are constrained by storage capacity and rainfall levels to replenish storage, unless pumping is used to recycle the water. For this reason, the opportunity cost of fuel is comparatively high. Therefore, hydroelectric generators typically operate as 'flexible' or 'peaking' plant, similar to gas-powered generation.

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

While some pumped hydroelectric generation already operates in NSW and Queensland, the construction of Snowy 2.0 will add a further 2,000 MW of pumped hydroelectric capacity in the Snowy Mountains. When it was announced in 2017, Snowy 2.0's estimated completion date was 2021. Since the last report, Snowy Hydro has pushed back the completion date from 2026 to 2029.[11]

Conditions in the electricity market affect incentives for hydroelectric generation. Subject to environmental water release obligations, hydroelectric generators tend to reduce their output when electricity prices are low and run more heavily when prices are high. Incentives under the Renewable Energy Target (RET)[12] scheme also affect incentives to produce.

Hydroelectric generation can also be constrained by environmental factors. In NSW in 2022, despite pressure to run harder to compensate for the high level of coal outages, generation at Snowy Hydro's biggest power station, Tumut 3, was constrained due to concerns resulting from heavy rains. These included high water levels in the release reservoir, Blowering Dam, and the limited release capacity of the Tumut River.[13]

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

3.7.4 Wind generation

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

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

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

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

3.7.5 Grid-scale solar farms

Australia has the highest solar radiation per square metre of any continent, receiving an average 58 million petajoules of solar radiation per year. All solar investment to date has been in photovoltaic systems, which use layers of semi-conducting material to convert sunlight into electricity (Figure 3.16).

Investment in large-scale solar farms in Australia did not occur at a significant scale until 2018, supported by government incentives under the RET scheme and funding support from the Australian Renewable Energy Agency (ARENA) and Clean Energy Finance Corporation (CEFC). In 2017, commercial solar farms accounted for only 0.5% of total NEM generation capacity and met only 0.3% of the NEM's electricity requirements. By 2022, solar farms made up 11% of capacity and 5% of output. In 2022–23, 9 solar farms, over 1 GW, entered the market. All but one of these new entrants are located in Queensland or NSW.

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

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

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

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

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

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

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

3.7.6 Grid-scale storage

Stored energy can be used to support system reliability by being injected into the grid at times of high demand and can provide stability services to the grid by balancing variability in renewable generation. Storage technologies in the NEM include batteries and pumped hydroelectricity. As the firm capacity of coal generators exits the market and is replaced by intermittent wind and solar generation, increased storage will be essential to manage daily and seasonal variations in output.

Battery storage

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

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

Batteries take advantage of variations in the spot price. They typically charge when prices are low, which is often in the middle of the day, and discharge when prices are high during morning and evening demand peaks. The difference between the charge price and the dispatch price determines the battery's profit ratio per megawatt. With increasing instances of negative spot prices during the day being followed by high evening prices, batteries can often profit from both charging and dispatching.

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

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

Pumped hydroelectricity

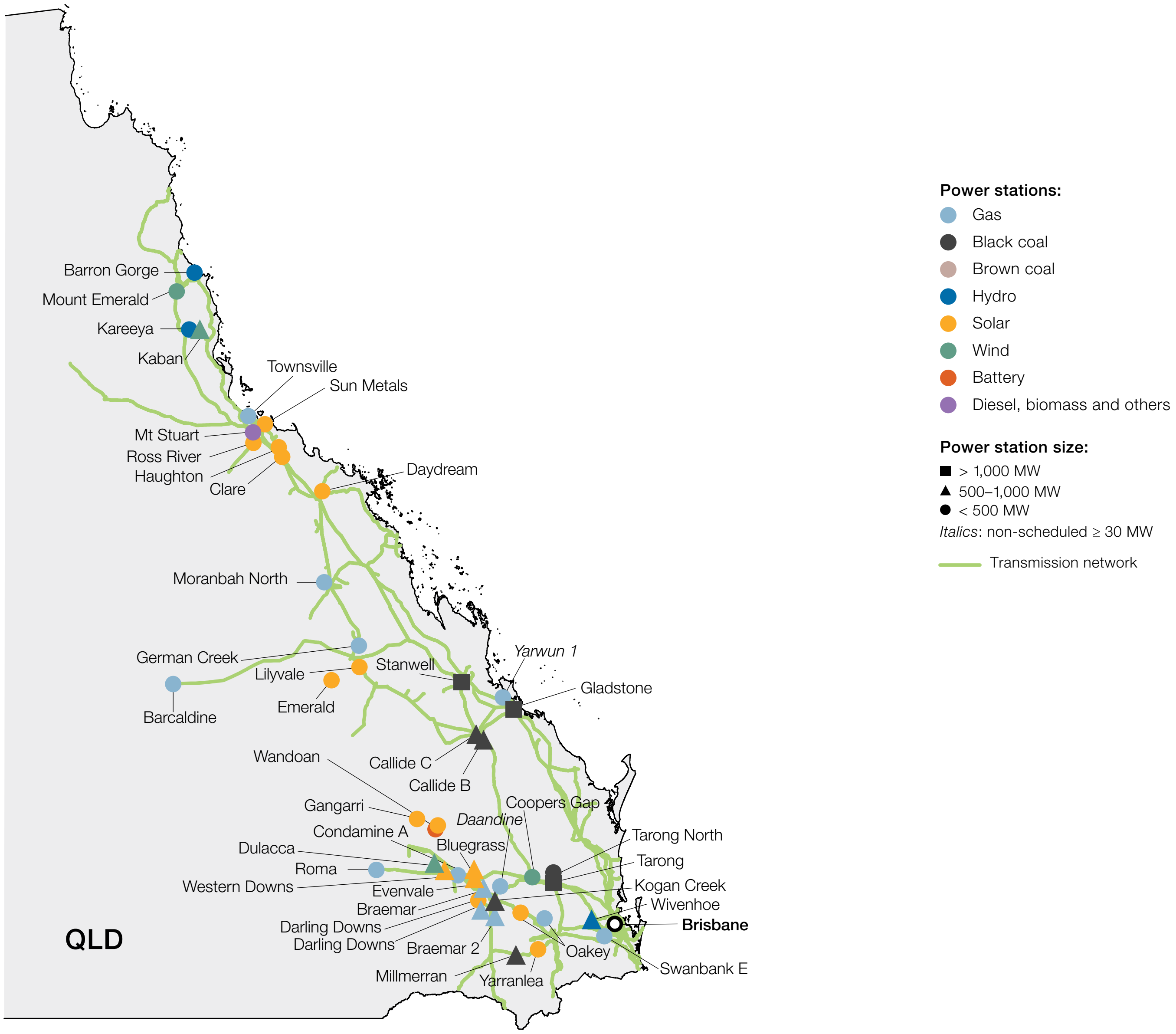
Large-scale storage can be provided through pumped hydroelectric projects, which allow hydroelectric plants to reuse their limited water reserves. The technology involves pumping water into a raised reservoir while electricity is cheap and releasing it to generate electricity when prices are high. Like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

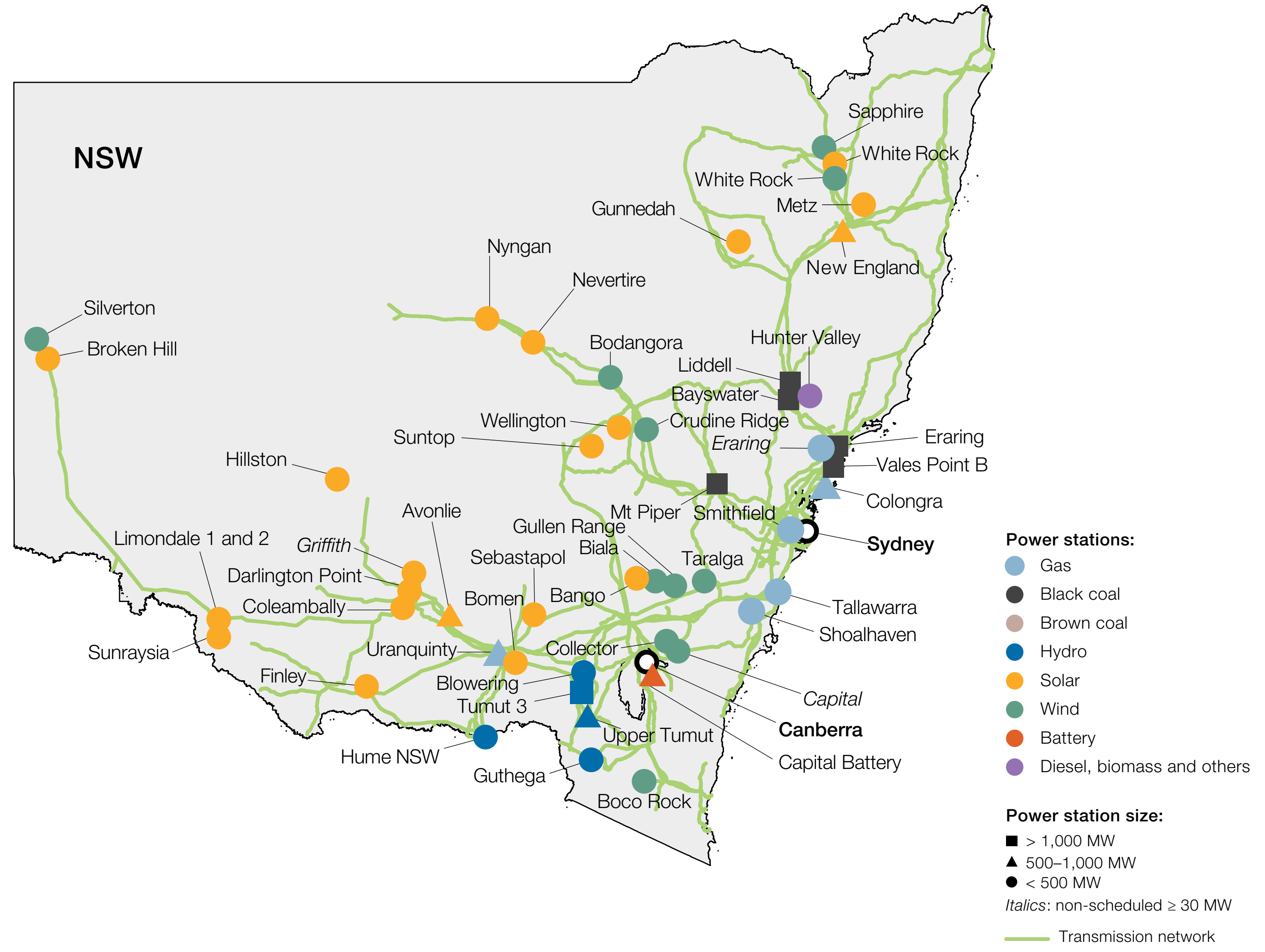
Pumped hydroelectric technology has been available in the NEM for some time, with generation in Queensland (570 MW at Wivenhoe) and NSW (240 MW at Shoalhaven and 1,500 MW at Tumut 3). Use of this technology is limited by the availability of appropriate geography. However, advances in technology and the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

3.7.7 Generator information

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

Figure 3.19 Generators in the NEM




NSW
Sapphire
White Rock
White Rock
Metz
Gunnedah
New England
Nyngan
Nevertire
Silverton
Broken Hill
Bodangora
Hunter Valley
Liddell
Bayswater
Wellington
Crudine Ridge
Suntop
Eraring
Eraring
Vales Point B
Hillston
Colongra
Mt Piper
Smithfield
Avonlie
Gullen Range
Limondale 1 and 2
Griffith
Sydney
Biala
Sebastapol
Taralga
Darlington Point
Bomen
Bango
Tallawarra
Coleambally
Shoalhaven
Uranquinty
Collector
Sunraysia
Finley
Blowering
Capital
Tumut 3
Canberra
Upper Tumut
Hume NSW
Capital Battery
Guthega
Boco Rock
Power stations:
Gas
Black coal
Brown coal
Hydro
Solar
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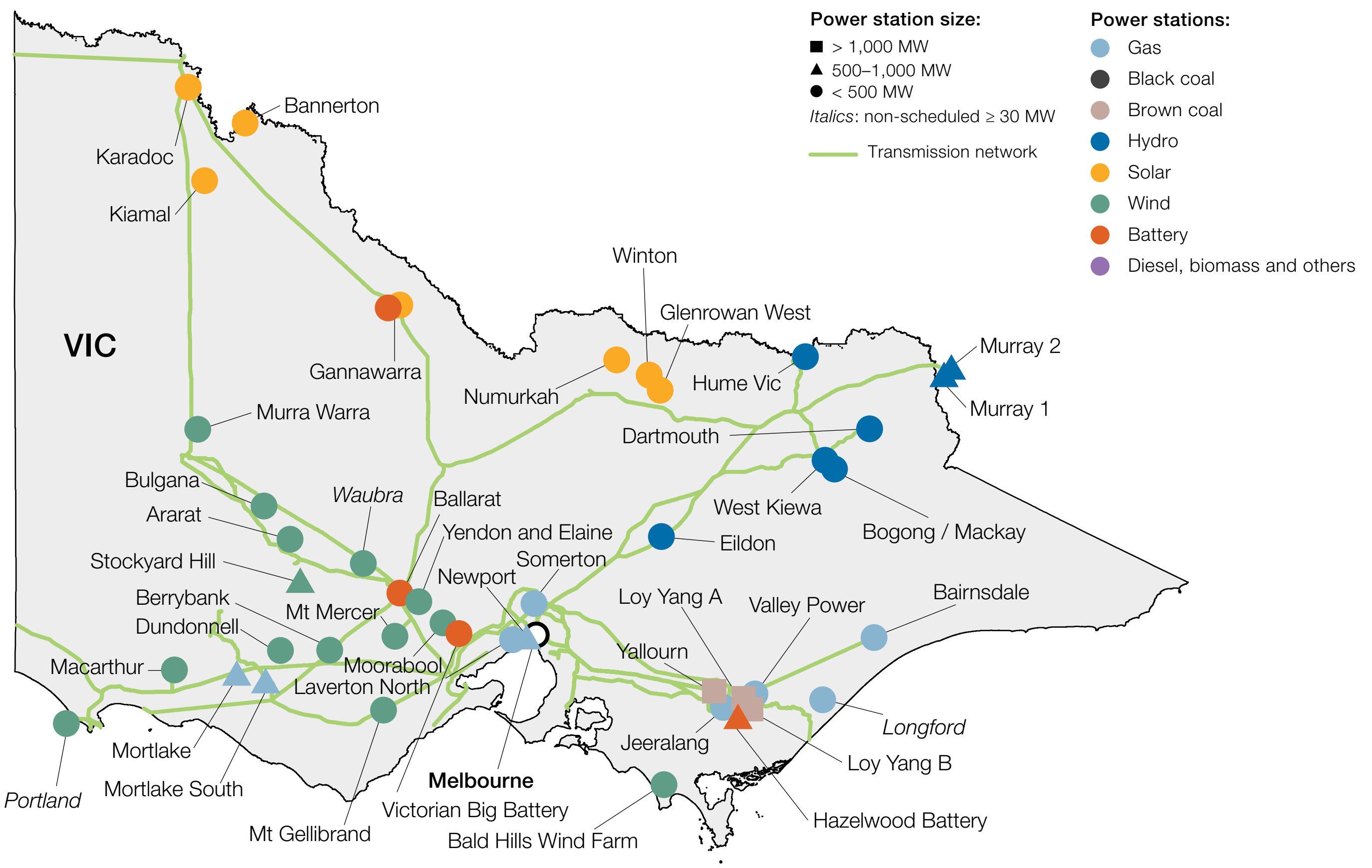
Transmission network


Power station size:
> 1,000 MW
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Italics: non-scheduled ≥ 30 MW
Transmission network
Power stations:
Gas
Black coal
Brown coal
Hydro
Solar
Wind
Battery
Diesel, biomass and others
Bannerton
Karadoc
Kiamal
Winton
Glenrowan West
VIC
Murray 2
Gannawarra
Hume Vic
Numurkah
Murray 1
Murra Warra
Dartmouth
Bulgana
Waubra
Ballarat
West Kiewa
Ararat
Yendon and Elaine
Eildon
Bogong / Mackay
Stockyard Hill
Somerton
Newport
Bairnsdale
Berrybank
Loy Yang A
Mt Mercer
Valley Power
Dundonnell
Yallourn
Macarthur
Moorabool
Laverton North
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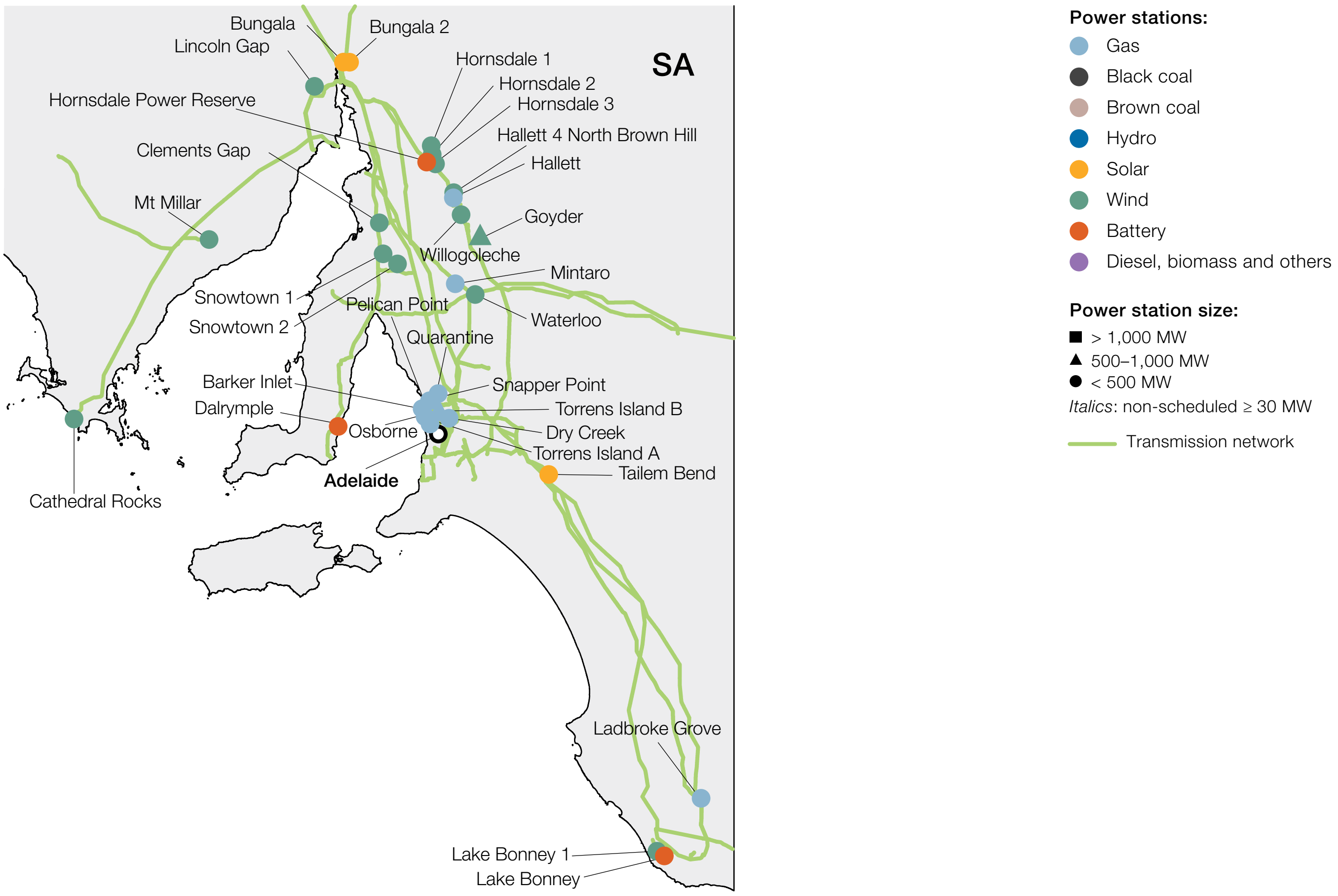
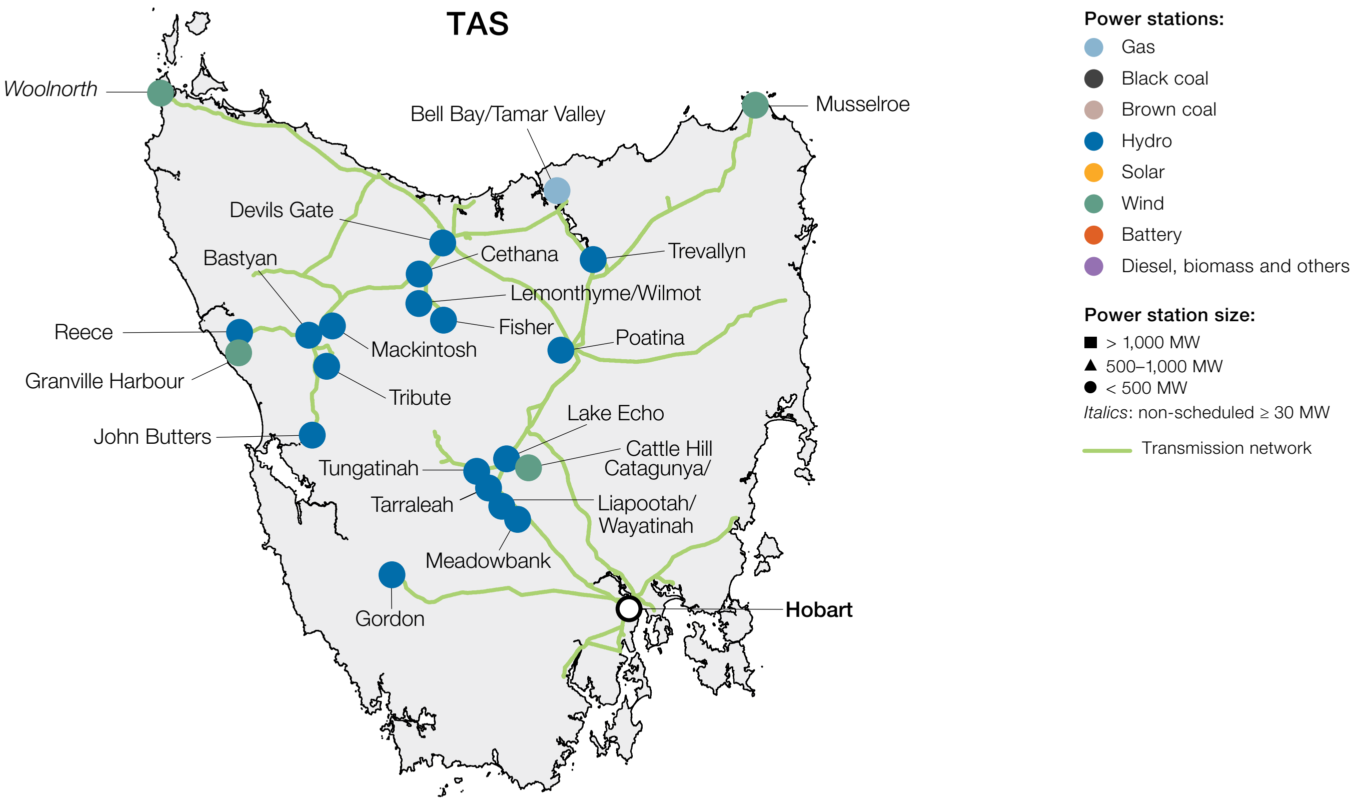
Hazelwood Battery
Mt Gellibrand
Bald Hills Wind Farm





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

3.8 Consumer energy resources

Alongside major shifts occurring in the technology mix at grid level, significant changes are occurring in small-scale electricity supply with the uptake of consumer energy resources. These resources allow individual consumers and groups to generate or store their own electricity, as well as enabling them to actively manage their consumption. They include:

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

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

3.8.1 Rooftop solar generation

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

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

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

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

3.8.2 Small-scale storage

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

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

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

3.8.3 Controlled load

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

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

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

3.8.4 Virtual power plants (VPPs)

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

3.9 Trade across regions

Transmission interconnectors (mapped and listed in chapter 4) link the NEM's 5 regions, allowing trade to take place. Trade enhances the reliability and security of the power system by allowing each region to draw on the generation plant of their neighbours. This allows for more efficient use of the generation fleet.

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

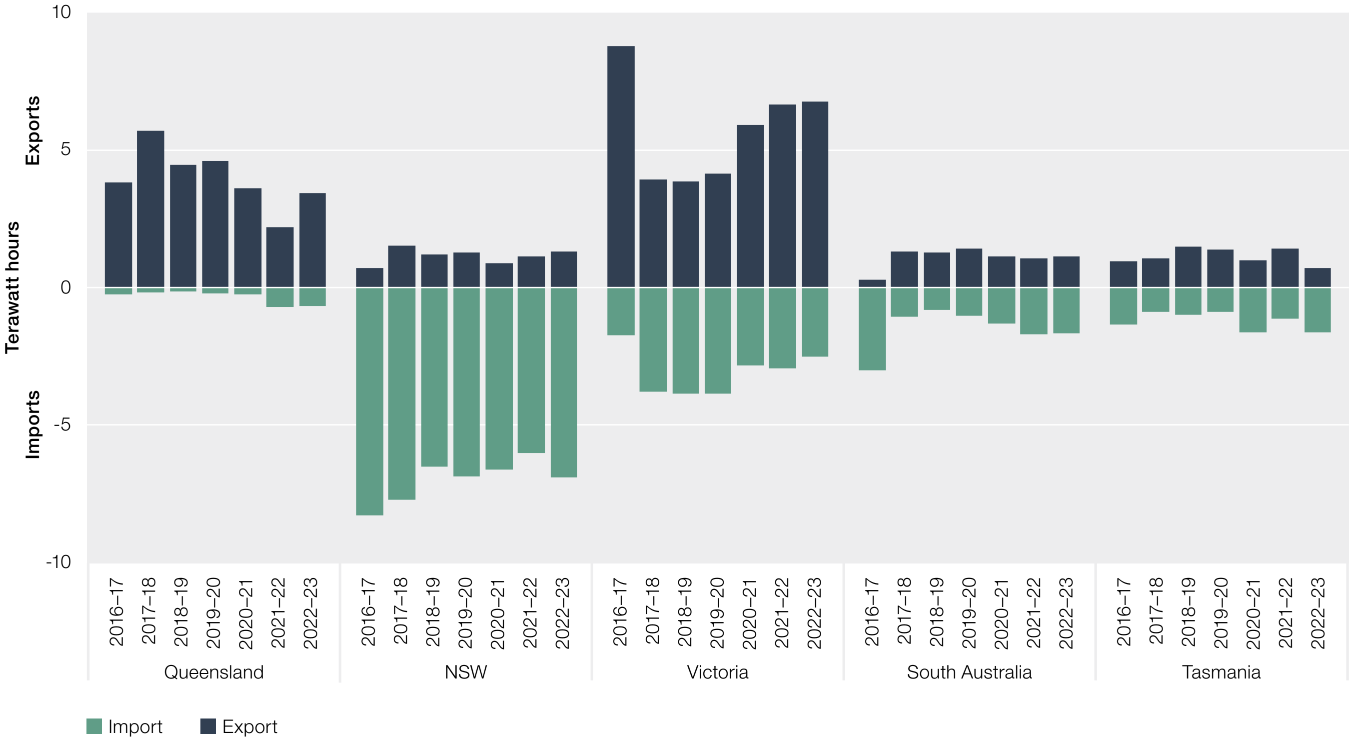
NSW has relatively high generation fuel costs, typically making it a net importer of electricity. NSW is able to import electricity from both Queensland and Victoria, so the outages during the QNI upgrade impacted NSW imports less than it did Queensland's exports. With the completion of the upgrade,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

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

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

Tasmania's trade position varies with environmental and market conditions. Key drivers include local rainfall (which affects dam levels for hydroelectric generation), Victorian spot prices and the availability of the Basslink interconnector (which has suffered multiple extended outages in recent years). Tasmania has historically switched between net importer and exporter. In 2021–22 it switched from net import to exporter but this trend was reversed in 2022–23 as exports fell and imports rose, causing the region to revert to a net importer.

Figure 3.20 Inter-regional trade

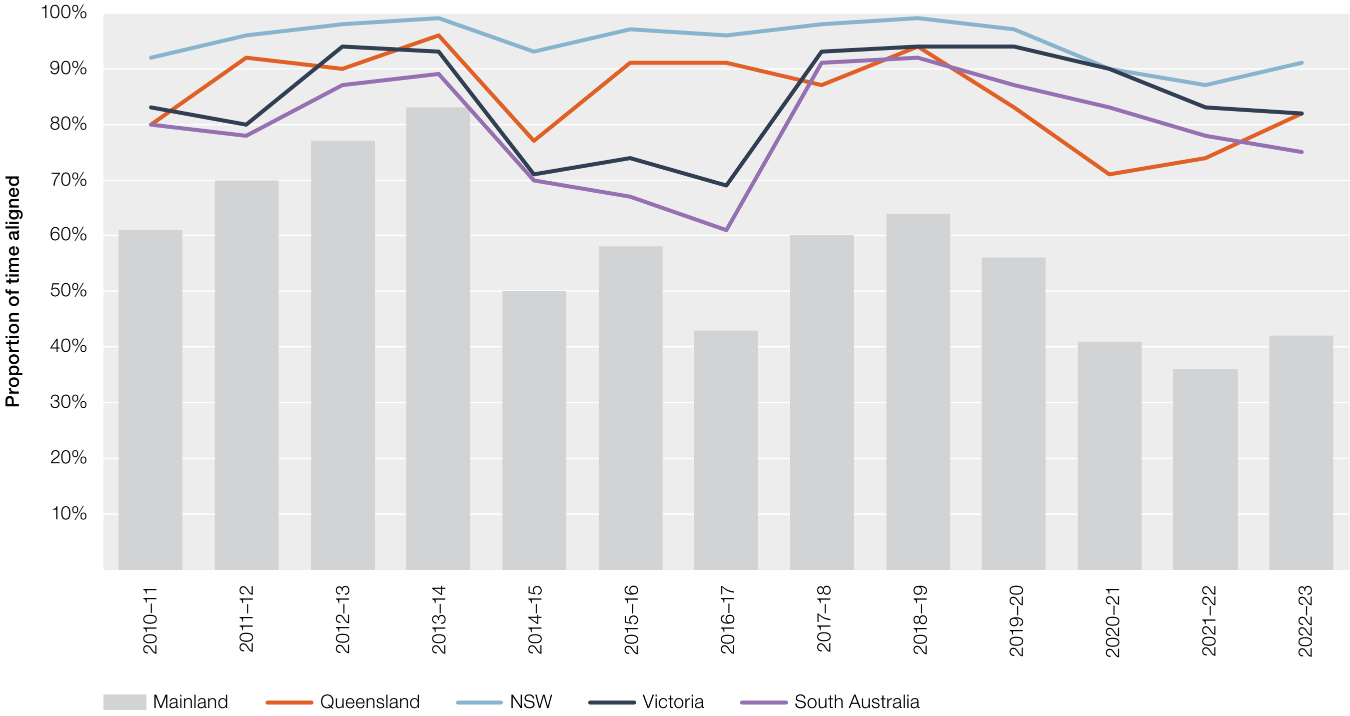


Source: AER; AEMO (data).

3.9.1 Market alignment and network constraints

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

Figure 3.21 Price alignment in mainland NEM regions



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

Source: AER; AEMO (data).

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

3.10 Market structure

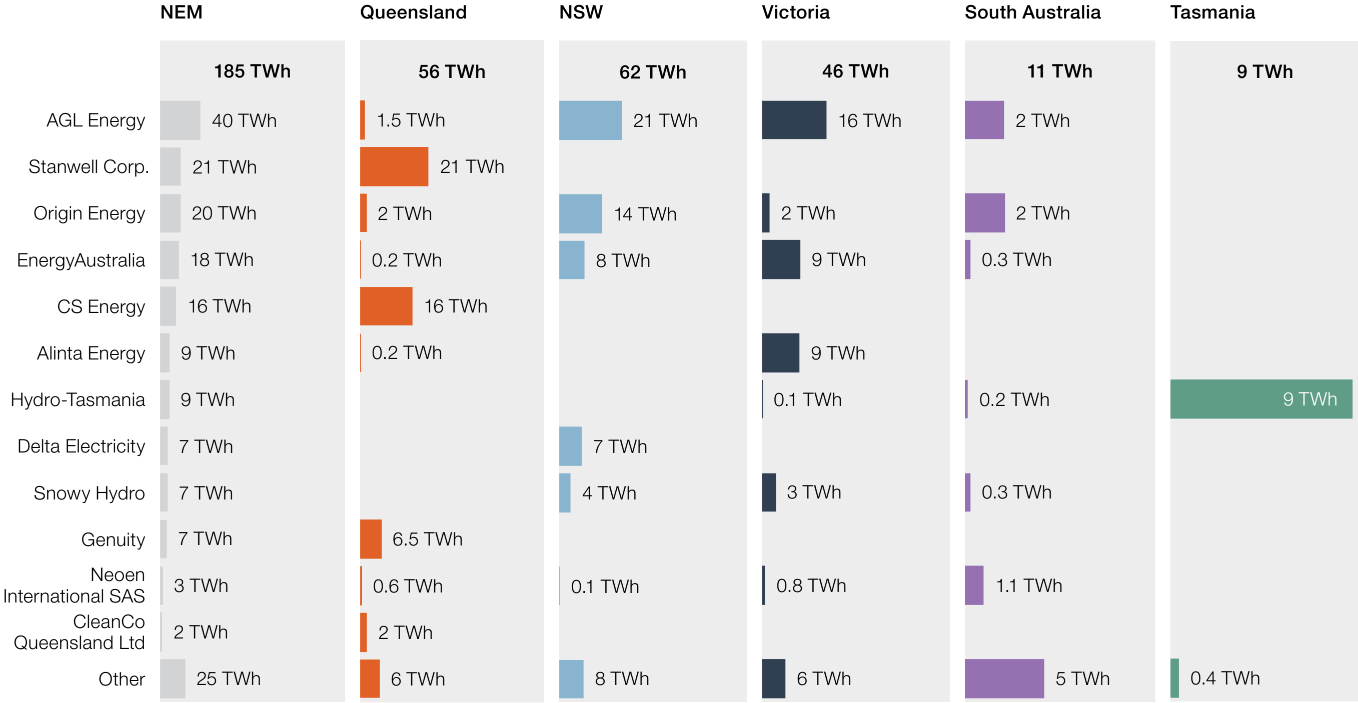
Over 200 power stations sell electricity into the NEM spot market. Despite significant new entry over recent years, a few large participants control a significant proportion of generation in each NEM region. Ownership of flexible generation is particularly concentrated. The AER released its *Wholesale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

3.10.1 Market concentration

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

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

Figure 3.22 Market shares in generation output



Note: Output in 2022–23. Market shares are attributed to the owner of the plant or the intermediary (should one be declared to AEMO). Output is split on a pro rata basis if the owner or intermediary changed in 2022–23. Data exclude output from rooftop solar systems and interconnectors. Loads and non-scheduled generation are excluded. Where multiple owners are invested in a generating unit, the output of that unit has been split proportionally between owners according to their percentage of total ownership.

Source: AER; AEMO; company announcements.

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

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

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

3.10.2 Vertical integration

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

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

Vertical integration has become the primary business structure for large electricity companies in the NEM. The 4 largest vertically integrated participants in each region account for the majority of generation output and supply more than half of retail load. Across the NEM, 3 retailers – AGL Energy, Origin Energy and EnergyAustralia – supplied 43% of electricity generation in 2021–22 and supplied 64% of residential energy customers in the January to March quarter 2022.

Second tier retailers – Red Energy and Lumo Energy (Snowy Hydro), Simply Energy (Engie) and Alinta – also own major generation assets. These vertically integrated businesses supplied 19% of electricity generation in 2021–22 and 13% of residential energy customers in the January to March quarter 2022.

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

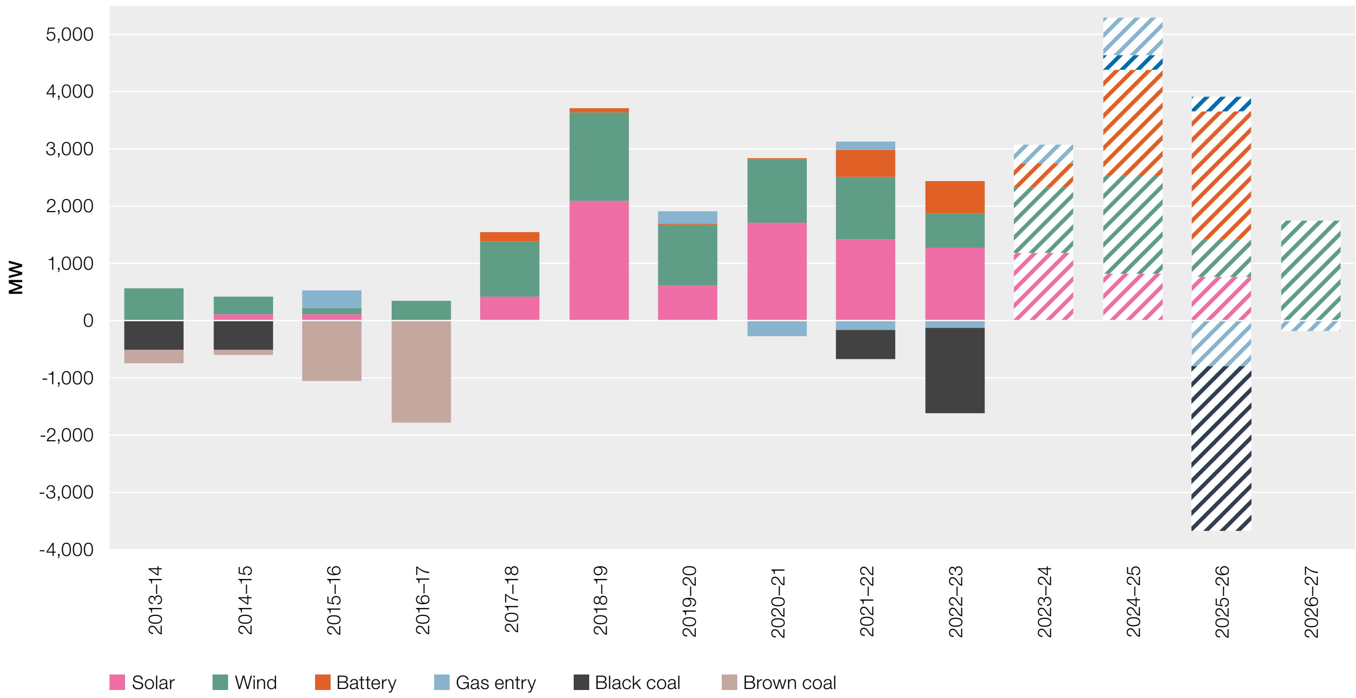
Several smaller retailers are also vertically integrated:

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

3.11 Generation investment and plant closures

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

Figure 3.23 New generation investment and plant withdrawal



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

Source: AER; AEMO (data).

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

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

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

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

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

3.12 Power system reliability

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

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

Reliability risks remain highest over summer, particularly at times when peak demand coincides with low renewable generation or transmission or plant outages. But they may also emerge over winter when solar output is low. Reliability concerns were elevated over winter 2022 due to coal plant outages, fuel constraints and high demand. While fewer outages of coal plant occurred in 2023, they are increasingly likely to break down as they age, and outages will represent a greater portion of supply as more exit.

Box 3.2 How reliability is measured

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

While the 0.002% target is used to assess market performance and the appropriateness of reliability settings such as the market price cap, a stricter interim reliability standard is used as a trigger for market mechanisms to prevent forecast supply shortages. From 2020 to 2025 a tighter standard of 0.0006% is applied to trigger the Retailer Reliability Obligation (RRO)[17]. If unserved energy is forecast to exceed the 0.0006% threshold, the AER can trigger the RRO and organise for liable entities to enter into sufficient qualifying contracts to cover their share of a once-in-two-year demand event.

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

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

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

3.12.1 Managing reliability

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

Reliability and Emergency Reserve Trader

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

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

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

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

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

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

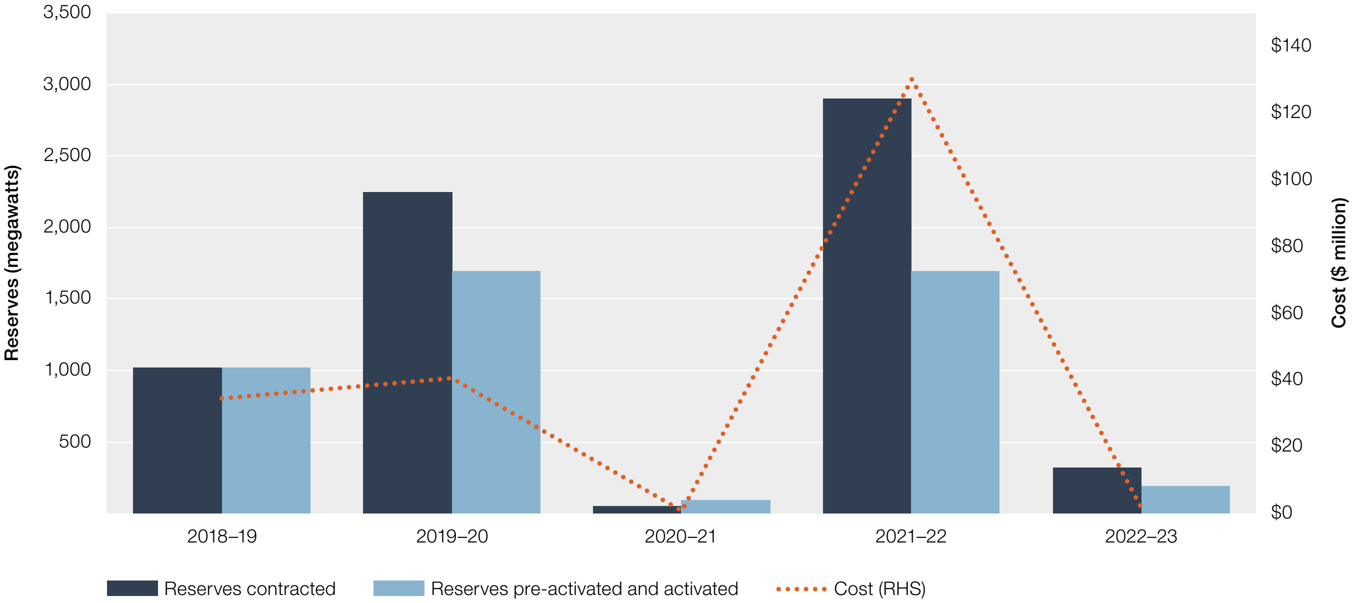
18 AER, Values of customer reliability, Australian Energy Regulator, accessed 18 August 2023.

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

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

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

Figure 3.24 RERT reserves and costs



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

Source: AER analysis of AEMO's RERT reporting.

3.12.2 Reliability outlook

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

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

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

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

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

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

3.13 Power system security

Power system security refers to the power system's technical stability in terms of frequency, voltage, inertia and similar characteristics. Historically, the NEM's coal, gas and hydroelectric generators helped maintain a stable and secure system through inertia and system strength services provided as a by-product of producing energy. Inertia is provided by the energy generated through continual rotation of turbines after a generator stops running, due to stored momentum. This can help smooth changes to frequency after a large generator exits suddenly. System strength refers to the power system's ability to maintain correct voltage waveforms. It is supported by synchronous generators, which are typically electromagnetically connected to the voltage waveform of the grid.[24] As older synchronous plants retire, or reduce operations in response to falling demand, these sources of inertia and system strength are reduced with them. Falling inertia makes it harder to keep frequency within an acceptable band and falling system strength makes it harder to keep voltages stable.

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

The energy transition is necessitating frequent directions from AEMO to maintain power system security. Directions for system security are intended as a last resort intervention when the market has not delivered the necessary requirements. In South Australia, directions to market participants to take action to maintain or restore power system security have been in place for a substantial amount of time for the past 3 years.[25]

In South Australia, 4 synchronous condensers, installed by ElectraNet, started operating in October 2021 to provide system strength and inertia. Each has a flywheel with a large amount of momentum. In the event of a disturbance on the network, these provide the electrical inertia to power through the fault. They have reduced the number of market interventions and relaxed constraints on wind and solar output. Directions in South Australia fell from being in place over 50% of the time in the 2021–22 financial year to 43% in 2022–23.

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

Three key regulatory changes have either been implemented or are in development to improve system security:

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

3.13.1 Security performance in the NEM

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

Security performance can be impacted by changing system conditions (including extreme weather), generation volatility and an increase in load. AEMO reports annually on system security needs across the NEM for the coming 5-year period. Its December 2022 report identified voltage shortfalls in NSW, Queensland and Tasmania. AEMO expects the need for additional system security services will only increase over the coming years as power stations that previously supplied these services withdraw from the system. AEMO needs to consider what technologies will be incentivised to provide these services in future and whether the new market arrangements currently being developed will provide sufficient incentives to do so.

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

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

3.13.2 Frequency control markets

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

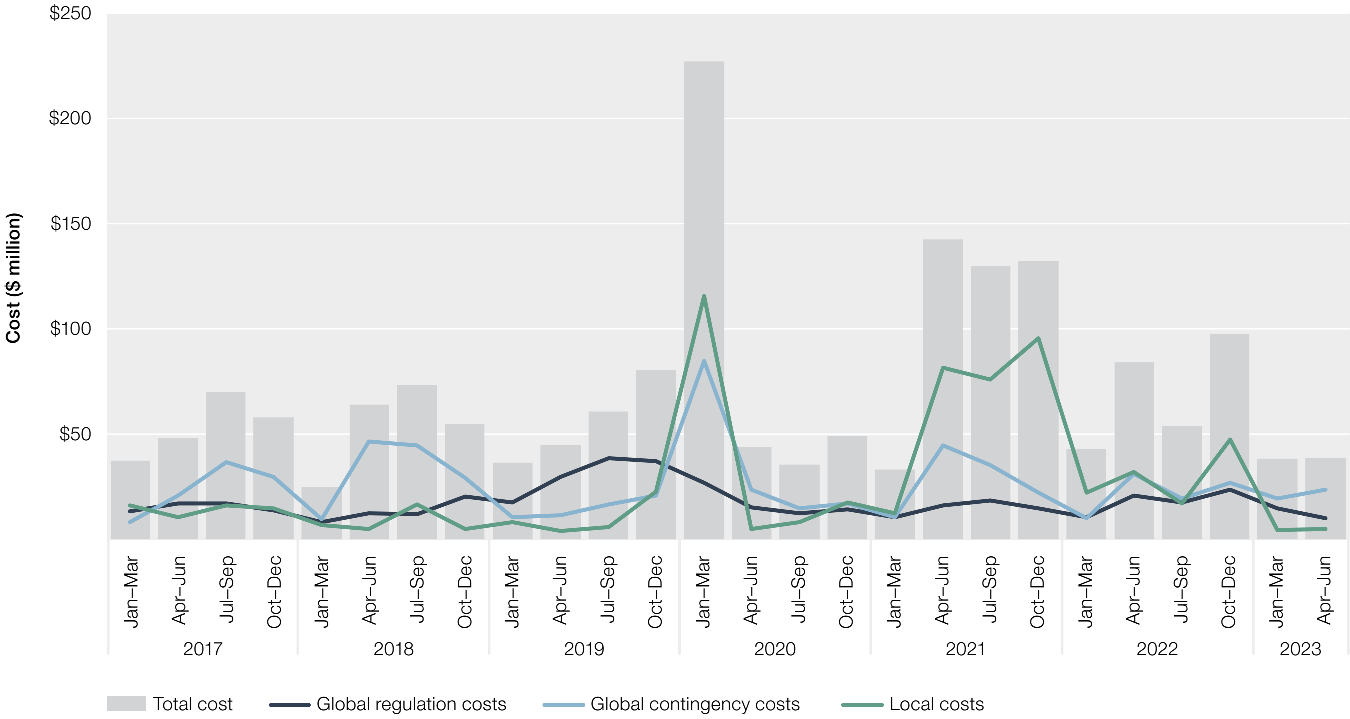
Frequency control ancillary services (FCAS) are used to maintain the frequency of the power system close to 50 hertz. With the introduction of 1 second raise and lower services in October 2023, the NEM will have 10 FCAS markets, which fall into 2 categories – regulation services and contingency services. Regulation services operate continuously to balance minor variations in frequency caused by small changes in demand or supply during normal operation of the power system. Contingency services manage large frequency changes from sudden and unexpected shifts in supply or demand, and they are used less often.

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

Fewer participants operate in FCAS markets than in the wholesale electricity market, but several new participants have emerged in recent years. In mid-2023, 13 participants were providing FCAS in Queensland, 16 in NSW, 16 in Victoria, 21 in South Australia and 3 in Tasmania. Batteries, demand response and virtual power plants offer FCAS services. Some of these new entrants account for only a small proportion of FCAS trades and others such as batteries have displaced incumbent providers. Batteries are the largest provider of FCAS in the NEM – in the April to June quarter 2023 they provided a record 40% of all FCAS (by volume). Demand response provided 13% of FCAS volumes.

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

Figure 3.25 Frequency control ancillary service costs



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

Source: AER; AEMO (data).

3.14 Market reforms and policy developments

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

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

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

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

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

3.14.1 Compliance and enforcement activities

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

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

Each year, the AER identifies and publishes a set of compliance and enforcement priorities, some of which relate to participants in the NEM. The challenge to maintain system security has increased focus on generators meeting technical standards and providing accurate information to AEMO. Providing inaccurate information undermines AEMO's ability to manage frequency deviations, creating a risk to system security and stability. In addition to these priorities, the AER was appointed as regulator for directions pertaining to the NSW coal market intervention.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Image source: iStock

4 Electricity networks

Australia's electricity infrastructure consists of transmission and distribution networks, as well as smaller standalone regional systems. Together, these networks transport electricity from generators to residential and industrial customers. This chapter covers the 21 electricity network service providers regulated by the Australian Energy Regulator (AER), which are located in all Australian states and territories except Western Australia.

4.1 Snapshot

In 2023, the AER finalised revenue determinations for transmission network service providers Transgrid (NSW) and ElectraNet (South Australia), and the Murraylink interconnector (between South Australia and Victoria). The determinations set target revenue controls for those service providers through to 30 June 2028.

Across all transmission and distribution network service providers, over the 12-month period to 30 June 2022:

- Revenue earned for delivering core regulated services[1] was 0.1% lower than in the previous year, marking the eighth consecutive year of decreases in aggregated transmission and distribution network revenue (section 4.9).
- Expenditure on capital (investment) projects was the lowest since 2017 and 11% lower than in the previous year (section 4.13).
- Despite the decline in capital expenditure asset bases continued to grow, driven by investment on ElectraNet's (South Australia) and Transgrid's (NSW) transmission networks. Asset bases are forecast to grow at an accelerated rate as several major transmission projects progress (sections 4.11 and 4.13.6).
- Operating expenditure was at its lowest since 2007; 1.2% lower than in the previous year and 5% lower than the average operating expenditure over the previous 5 years (section 4.14.1).
- Customers experienced 3% more frequent and 15% longer unplanned interruptions to supply than in the previous year[2] — noting the previous year saw a record low frequency of interruptions. Major weather events had significant impact on the overall customer experience (section 4.16.4).

4.2 Electricity network characteristics

Transmission networks provide the link between generators located away from population centres and consumers by transporting high voltage electricity to major load centres. Electricity is injected from points along the transmission grid into the distribution networks that deliver electricity to residential homes and commercial and industrial premises. When electricity enters a distribution network, it is stepped down to lower voltages for safe delivery to consumers. Distribution networks consist of poles and wires, substations, transformers, switching equipment, and monitoring and signalling equipment.

Distribution 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 7).

Electricity networks traditionally provided a one-way delivery service to consumers. However, the role of electricity networks is evolving as technology continues to change how electricity is generated and used. Many small-scale generators such as rooftop solar systems are now embedded within distribution networks, resulting in two-way electricity flows along the networks. Energy users with rooftop solar systems are able to source electricity from the distribution network when they need it and sell the surplus electricity they generate at other times. 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, its use is expected to continue to grow over the coming years.[3]

Alongside the major distribution networks, smaller localised 'embedded' networks distribute energy to sites such as apartment blocks, retirement villages, caravan parks and shopping centres. Electricity is delivered from the distribution network to a single connection point at these sites, then sold by the embedded network operator to tenants or residents. While consumers within embedded networks may still have the option to buy electricity from an authorised energy retailer, they may have difficulty doing so because of the way the network has been wired or because energy retailers may not want to sell to a consumer inside an embedded network. The revenues of embedded networks are not regulated.

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

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

3 AEMO, Current inputs, assumptions and scenarios, Australian Energy Market Operator, 28 July 2023.

4.3 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 networks are linked by cross-border interconnectors. Three interconnectors (Queensland–NSW, Heywood, and Victoria to NSW) are owned by the state governments and 3 interconnectors (Directlink, Murraylink and Basslink) are privately owned (Figure 4.2). The transmission network also directly supplies energy to large industrial customers, such as rail companies, mines and mineral processing facilities.

The transmission grid connects with 13 distribution networks.[4] Consumers in Queensland, NSW and Victoria are supplied 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 serviced by single distribution service providers operating within each jurisdiction (Figure 4.1 and Figure 4.3).

The Northern Territory has 3 separate distribution networks – the Darwin–Katherine, Alice Springs and Tennant Creek systems – all owned by Power and Water Corporation. The 3 networks are classified as a single distribution network for regulatory purposes but do not connect to each other or the NEM.[5] The AER regulates all major network service providers in the NEM, other than the Basslink interconnector linking Victoria and Tasmania.[6] It also regulates the Northern Territory's distribution network.

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

- Project EnergyConnect – a new 330 kilovolt (kV) double-circuit interconnector between South Australia and NSW
- incremental upgrades to the transfer capacities of the existing Victoria to NSW (VNI Minor) and Queensland–NSW (QNI Minor) interconnectors (section 4.13.6).

The combined value of the regulatory asset bases (RABs) for the electricity networks regulated by the AER is around $105.8 billion.[7] This comprises 7 transmission networks valued at $23.1 billion and 14 distribution networks valued at $82.7 billion. In total, the networks operate more than 800,000 kilometres of lines and deliver electricity to more than 10.8 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.[8]

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

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

6 On 19 May 2023, APA Group lodged an application to the AER seeking to convert Basslink's network services from market network services to prescribed transmission services.

7 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.

8 For further information, see the WA Department of Treasury and ERA websites.

Figure 4.1 Electricity networks regulated by the AER

Note: QNI is the Queensland–NSW Interconnector. The AER does not currently regulate the Basslink Interconnector.

Source: AER.

Figure 4.2 Electricity networks regulated by the AER – transmission

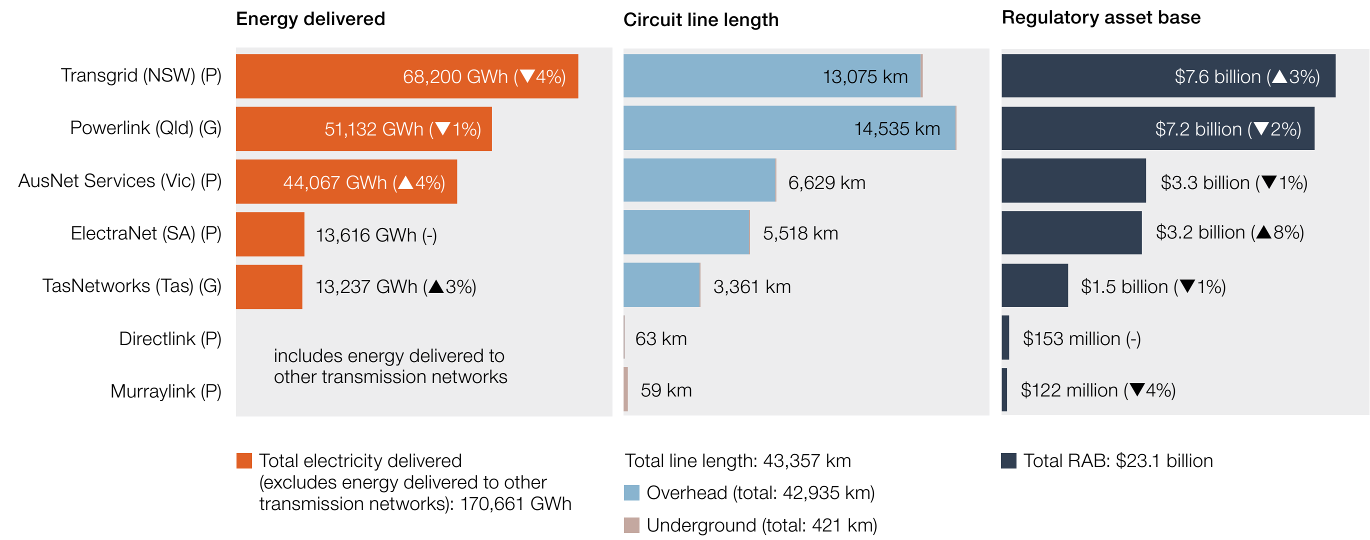
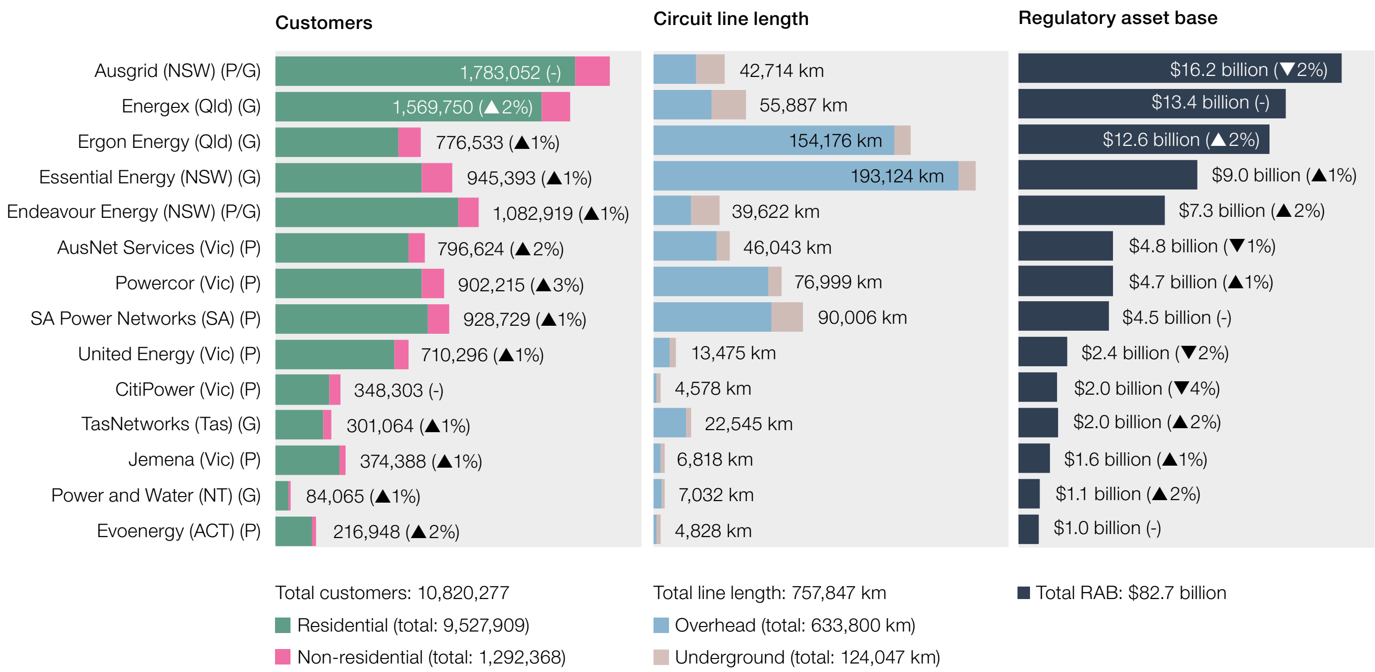


Figure 4.3 Electricity networks regulated by the AER – distribution



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 2022 dollars. Line length and regulatory asset base are as at 30 June 2022 (31 March 2022 for AusNet Services transmission). Electricity transmitted is for the year to 30 June 2022 (year to 31 March 2022 for AusNet Services). Customer numbers, line length and asset base are as at 30 June 2022 for the distribution networks. For regulatory purposes, Northern Territory transmission assets are treated as part of the distribution system. Energy delivered is a measure of total energy transported through the transmission networks. The information reported includes energy delivered to distribution networks, pumping stations and directly connected end users. Energy delivered to other transmission networks is included in the data for individual transmission network but has been excluded from the total.

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

4.4 Network ownership

Australia's electricity networks were originally government owned, but many 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 service providers Energex and Ergon Energy under a parent company, Energy Queensland.

In some jurisdictions, ownership of electricity networks overlaps with other industry segments. 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 products (section 4.8.2). For example, Queensland's state-owned Ergon Energy provides both distribution and retail services in regions outside south-east Queensland.

4.5 How network prices are set

Electricity networks are capital intensive and require significant investment in order to build and operate the required 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 environment poses risks to consumers, given network charges currently make up around 40% of a residential electricity bill (Figure 7.2 in chapter 7). To counter these risks, the role of the AER as the economic regulator is to replicate the incentives that network service providers would face in a competitive market (that is, to control costs, invest efficiently and not overcharge consumers).

4.5.1 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 4.13.4).[9]

The National Electricity Law and the National Electricity Rules set the framework that the AER administers when regulating electricity networks. The regulatory objective of the National Electricity Law is 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 AER's regulatory toolkit to pursue this objective is wide ranging (Box 4.1), but one of its fundamental roles is to set the maximum revenue that a network service provider can earn from its customers for delivering electricity. 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. Network revenues are then capped at this level for the regulatory period, which is typically 5 years.[10]

9 ACCC and AER, ACCC and AER Corporate plan 2023–24, 31 August 2023, accessed 5 September 2023.

10 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.

Box 4.1 The AER's role in electricity network regulation

Every 5 years the AER sets a cap on the revenue that a network service provider can earn from its customers. Alongside this central role, we undertake broader regulatory functions, including:

- assessing distribution network charges each year to ensure they reflect underlying costs and do not breach revenue limits
- 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
- publishing information on the performance of network service providers, including benchmarking and profitability analysis
- monitoring whether network service providers properly assess the merits of new investment proposals
- promoting and enforcing compliance with regulations, including connections policies and ring-fencing.

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 4.7)
- reviewing and refining our incentive schemes and guidelines to ensure they remain relevant and fit for purpose
- publishing information on network profitability
- reviewing how rates of return and taxation allowances are set for energy networks (section 4.12).

In November 2021, the AER was appointed as a regulator under the *Electricity Infrastructure Investment Act 2020* (NSW) (EII Act). The AER is now responsible for making revenue determinations for network operators authorised by the independent Consumer Trustee, or authorised or directed by the Minister, to undertake a network infrastructure project (including in a Renewable Energy Zone (REZ)). The AER is required to determine the prudent, efficient and reasonable capital costs for both contestably procured and non-contestable network infrastructure projects. Other key functions undertaken by the AER include:

- determining annual amounts to be recovered from each of the NSW distribution network service providers to provide for the functions under the EII Act
- approving a risk management framework developed by the Consumer Trustee to protect the interests of NSW electricity consumers in connection with the risks associated with long-term energy service agreements
- reviewing tender rules proposed by the Consumer Trustee for competitive tender processes for the procurement of long-term energy service agreements.

As part of the determination process, a network service provider submits a proposal to the AER setting out the amount of revenue it considers it will need to cover the costs of providing a safe and reliable supply of electricity. The AER assesses the proposal and forms an opinion on the reasonableness of the service provider's forecasts and the efficiency of its proposed expenditure. If the AER is not satisfied the 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 amount of revenue proposed to ensure the approved cost forecasts are efficient.

In conducting its assessment of a network service provider's revenue proposal, the AER draws on a range of inputs, including expenditure forecasts, benchmarking and revealed costs from past expenditure. It engages closely with stakeholders from an early stage of the process, including before the network service provider lodges a formal proposal (section 4.7).

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. The AER does not determine the service provider's capital programs or projects.

Unlike capital expenditure, a network service provider's operating costs are 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.[11]

4.5.2 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:

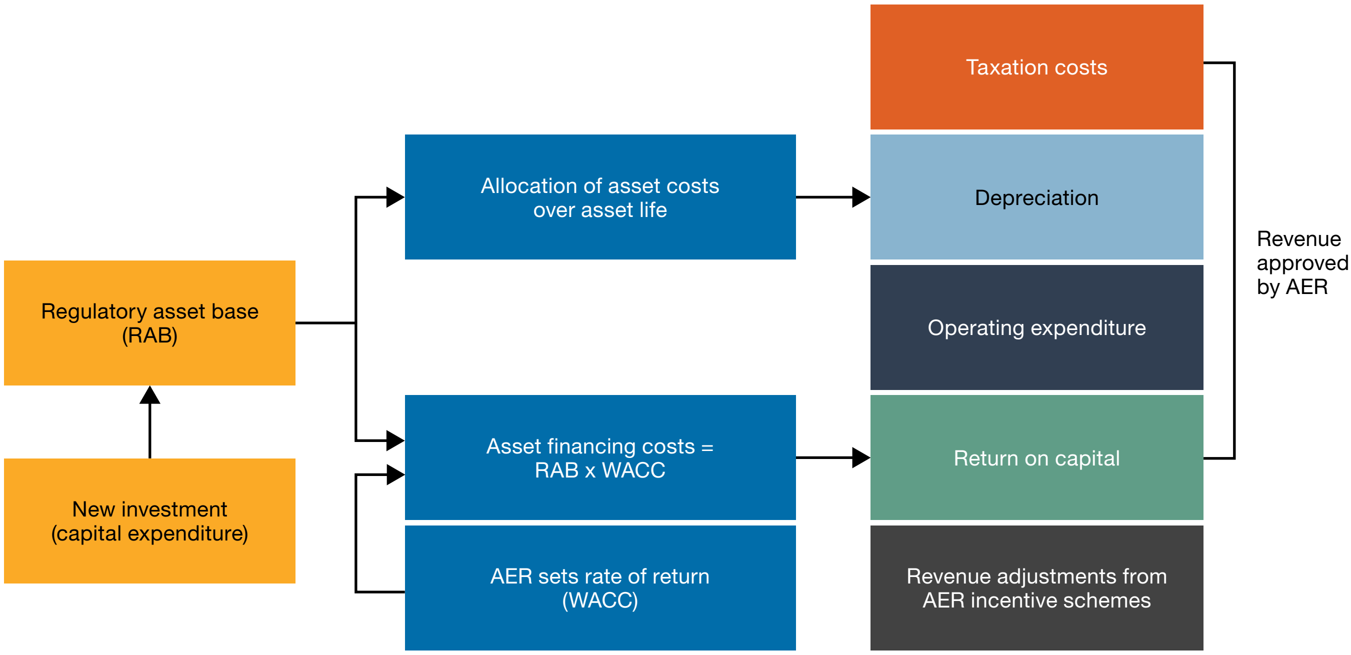
- a commercial return to investors that fund its assets and operations
- efficient operating and maintenance costs
- asset depreciation costs
- taxation costs.

The AER also makes revenue adjustments for over- or under-recovery of revenue made in the past and for rewards or penalties earned through any applicable incentive schemes.

While network service providers are entitled to earn revenue to cover their efficient costs each year, this revenue does not include the full cost of investment in new assets made throughout the year. Network assets have a long life and investment costs are recovered over the economic life of the assets, which may run to 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 4.4).

The regulatory asset base (RAB) includes the total remaining economic value of assets in a network, to be recovered through depreciation over time. 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 4.4 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.

11 AER, Guidelines, schemes, models & reviews, Australian Energy Regulator, accessed 15 December 2022.

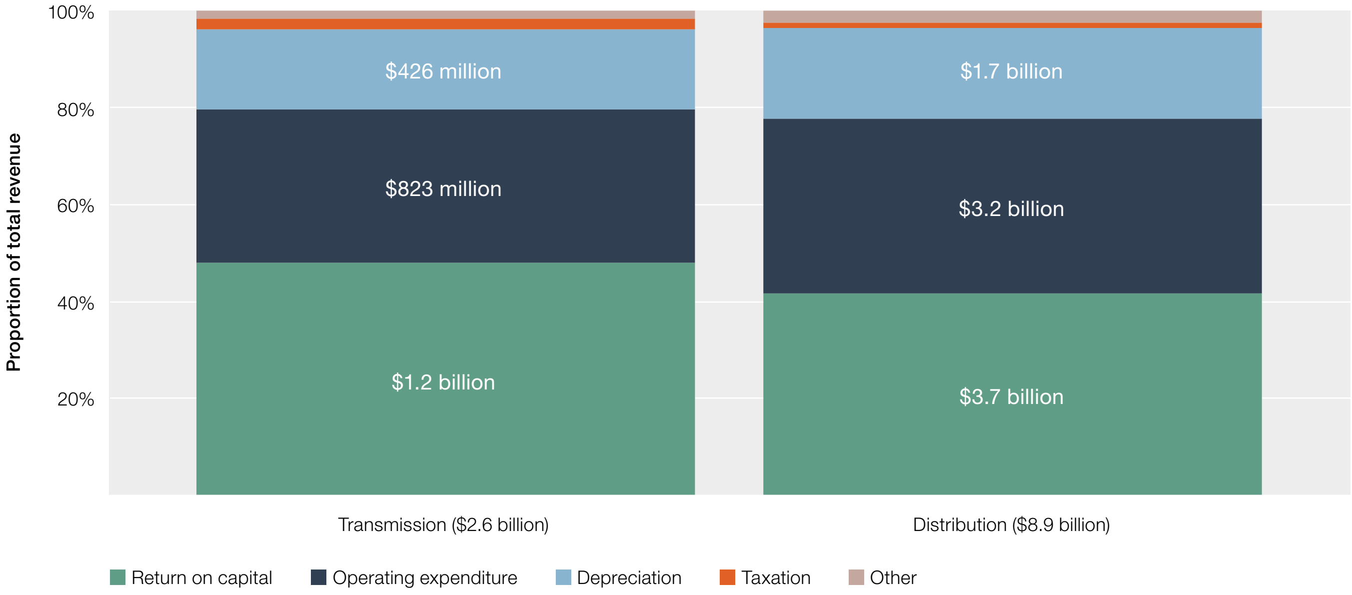
Additionally, the shareholders and lenders that fund these assets must be paid a commercial return on their investment. The AER sets the allowed rate of return (also called the weighted average cost of capital (WACC)) (section 4.12). The size of this return depends on:

- the value of the network's regulatory asset base (RAB)
- the 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.[12]

Overall, the return on capital takes up the largest share of network revenue, accounting for 43% of total revenue across all networks (Figure 4.5).

Sections 4.11 to 4.14 examine major cost components in more detail.

Figure 4.5 Composition of average annual electricity network revenue



Note: Composition of average annual electricity network revenue – current periods as at June 2023. All data are adjusted to June 2022 dollars.
Source: Post-tax revenue modelling used in AER determination process.

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

4.6 Recent AER revenue determinations

In 2023, the AER published its final revenue determinations for transmission network service providers Transgrid (NSW) and ElectraNet (South Australia), and the Murraylink interconnector (between South Australia and Victoria) for the 5-year period ending 30 June 2028 (Table 4.1).

Table 4.1 Recent AER electricity network revenue determinations

Service provider	Revenue (forecast)	Capital expenditure (forecast)	Operating expenditure (forecast)	Annual impact on residential bill
Transgrid (NSW)	$4.1b (▲3%)	$2.4b (▼35%)	$1.0b (▲3%)	▲0.2%
ElectraNet (South Australia)	$1.9b (▲15%)	$690m (▼51%)	$625m (▲25%)	▲0.3%
Murraylink (interconnector)	$77m (▼4%)	$12m (▼62%)	$23m (▼3%)	-

Note: Changes in revenue and expenditure are in relation to forecasts from the previous regulatory periods. Bill impact is the change in the average annual customer bill compared with the customer bill in the final year of the previous period, adjusted for inflation, assuming retailers pass through outcomes of the determination.

Source: AER estimates.

The key driver of the higher forecast revenues for Transgrid and ElectraNet is the allowed rate of return, which is higher than the rate applied in the previous period.[13] This reflects an increase in interest rates compared with those in the previous period, meaning the cost for network service providers to obtain the capital needed to run their businesses has increased. Forecast revenues were also affected by an increase in operating expenditure – driven by insurance costs, new investment to improve cyber security and (for ElectraNet) the forecast increases in circuit line length associated with the Eyre Peninsula Link and Project EnergyConnect.

4.7 Refining the regulatory approach

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

In December 2021, the AER published the *Better Resets Handbook – Towards consumer-centric network proposals* (the Handbook). The Handbook seeks to encourage network service providers to better engage with consumers and have consumer preferences drive the development of network proposals.[14] If a network proposal is developed in line with the expectations set out in the Handbook, the AER will be better placed to undertake a more targeted review of the proposal rather than the standard, more detailed review.

The Handbook outlines what the AER expects should be included in a high-quality, consumer-centric regulatory proposal. 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 is expected to provide many other benefits, including improved relationships and understanding between network service providers and consumers, greater trust between all parties in regulatory processes, and the creation of new ideas and regulatory approaches that benefit both consumers and service providers.

In March 2023, the AER expressed that it was encouraged to see several network service providers had used the Handbook when formulating regulatory proposals, particularly regarding the scope and quality of consumer engagement.[15]

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

14 AER, Better Resets Handbook – Towards consumer centric network proposals, Australian Energy Regulator, 9 December 2021.

15 AER, AER releases issues papers on 2024–29 revenue proposals, Australian Energy Regulator, 28 March 2023.

Before publishing the Handbook, the AER had trialled the 'New Reg' process with Victorian distribution service provider AusNet Services. The New Reg process offered an enhanced, more open approach to how network service providers incorporate consumer perspectives in developing their regulatory proposals.

Additionally, the AER's Consumer Challenge 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.[16]

4.7.1 Aligning business and consumer interests

The regulatory process is complex and often adversarial. In this environment, consumers may find it challenging to have their perspectives heard and to assess whether a network service provider's proposal reflects their preferences. The AER and network service providers continue to trial new approaches to improve consumer engagement.

To help consumers engage in the regulatory process, the AER publishes informative documents – including fact sheets that simplify technical language – and holds public forums. The AER's Consumer Challenge Panel also provides a mechanism for consumer perspectives to be voiced and considered.

Several network service providers are experimenting with early engagement models to better reflect consumer preferences and perspectives in framing their regulatory proposals – for example, running 'deep dive' workshops.

Early engagement offers the potential to expedite the regulatory process, reducing costs for both service providers and consumers. Effective consumer engagement can contribute to the AER accepting significant components of a network service providers' revenue proposal.

Service providers are increasingly looking to maintain open and ongoing dialogue with stakeholders throughout the regulatory period, rather than engaging intensively once every 5 years when a proposal is being considered.

In its 2022 draft decision, the AER recognised that ElectraNet (South Australia) had demonstrated sincerity and a desire to engage collaboratively with consumers in the development of its initial revenue proposal for the current regulatory period.[17]

Conversely, the AER considered Transgrid's consumer engagement to be a missed opportunity to demonstrate that a strong engagement culture has been embedded into its business-as-usual operations since its previous determination.[18]

We note the AER is not the only industry body focusing on consumer engagement. Each year Energy Networks Australia[19] and Energy Consumers Australia[20] recognises Australian energy networks that demonstrate best practice consumer engagement. In September 2022, 2 electricity distribution network service providers were shortlisted for the Consumer Engagement Award – Endeavour Energy (NSW) for its engagement with the community by planting 1,000 trees in response to the devastating 2019–2020 bushfires, and Essential Energy (NSW), for its 'Customer Journey Mapping' initiative to gain better insight on customer experiences.[21]

The award was ultimately won by 3 gas distribution networks that collaborated to design and deliver a single, integrated consumer and stakeholder engagement program as part of their regulatory reset engagement plans (section 6.5.3 in chapter 6).

In August 2023, distribution network service providers Ausgrid (NSW), Endeavour Energy (NSW) and SA Power Networks (South Australia) were shortlisted for the 2023 Consumer Engagement Award. The judging panel also commended Power and Water (Northern Territory) for its recent consumer engagement strategy.[22]

16 AER, Consumer Challenge Panel, Australian Energy Regulator, accessed 30 May 2023.

17 AER, ElectraNet 2023-28 - Final decision - Overview, Australian Energy Regulator, 28 April 2023, accessed 10 May 2023.

18 AER, Transgrid 2023-28 - Final decision - Overview, Australian Energy Regulator, 28 April 2023, accessed 10 May 2023.

19 The national industry body representing Australia's electricity transmission and distribution and gas distribution networks.

20 The independent, national voice for residential and small business energy consumers.

21 ENA, Consumer engagement report, Energy Networks Australia , 15 December 2022.

22 ENA, Consumer engagement awards shortlist announced, media release, Energy Networks Australia, 18 August 2023. The winner of the 2023 Consumer Engagement Award had not been announced when this report was published.

4.7.2 Changes to revenue setting approaches

The AER frequently reviews and updates key aspects of its revenue setting approaches.

In February 2023, the AER released its latest rate of return instrument (the 2022 Instrument).[23] 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.

The 2022 Instrument is largely consistent with the 2018 Instrument but has been updated to reflect the latest data and market conditions. 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. The 2022 Instrument binds all regulatory determinations from 25 February 2023 (section 4.12).

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 we publish and use in our network revenue determinations.

4.7.3 Review of incentive schemes

In April 2023, the AER published its final decision on its review of incentive schemes for network service providers.[24] The review forms part of the AER's strategic objectives for 2020–2025 to improve its approach to regulation by being more efficient and focusing on outcomes that matter most to consumers.

Incentive regulation rewards regulated network service providers for improving consumer outcomes by realising efficiency gains, reducing costs and improving service outcomes. Insights gained through the application of the AER's incentive schemes are used as inputs into determining future revenue forecasts.

A key reason the AER conducted its review of incentive schemes was in response to consumer concerns about the lack of transparency of the benefits to consumers compared with the observed costs. In aggregate, the efficiency benefit sharing scheme (EBSS), capital expenditure sharing scheme (CESS) and the service target performance incentive scheme (STPIS) payments have added up to $1.2 billion (2%) of revenues over the past 5 years. Consumers had also questioned the extent to which network service providers are being rewarded for expenditure overforecasting rather than efficient spending, particularly in the context of capital expenditure.

The AER concluded that the incentive schemes have driven significant improvements in performance through efficiency gains, which reduces prices and interruptions to supply over time. While network service providers have been rewarded for achieving the efficiency gains, the majority of benefits have gone to consumers. As such, the AER will continue to apply the incentive schemes, but with several modifications to the CESS. These modifications will require amendments to the AER's *Capital Expenditure Incentive Guideline*.[25]

Sections 4.10, 4.14 and 4.16 examine the incentive schemes in more detail. Further information can be found in the AER's annual electricity network performance reports, which provide analyses of the impact incentive schemes have had on network service providers' revenue and performance.[26]

23 AER, Rate of Return Instrument 2022, Australian Energy Regulator, accessed 22 March 2023.

24 AER, Review of incentive schemes for regulated networks, Australian Energy Regulator, accessed 3 May 2023.

25 AER, Capital expenditure incentive guideline for electricity network service providers, Australian Energy Regulator, April 2023.

26 AER, Electricity network performance reports, Australian Energy Regulator, accessed 11 July 2023.

4.8 Reforms to support new technologies and services

In August 2023, the Australian Energy Market Commission (AEMC) published its final report setting out several recommendations and options to accelerate the deployment of smart meters in the National Electricity Market (NEM).[27] Smart meters are essential for the availability of more cost-reflective tariff structures and are likely to play an important role supporting the energy transition.

The AEMC's proposed reforms target all consumers having access to smart meters by 2030.

As one of a broader suite of innovations in network and communication technology – including interactive household devices and energy management and trading platforms – smart meters support change in energy markets. These innovations allow consumers to access real-time information about, and make informed decisions in managing, their energy use. If consumers choose to voluntarily reduce their energy use from the grid in peak periods (by shifting energy use or relying on battery storage), it can delay the need for costly network investment. Moreover, since demand for energy imports is increasingly at its minimum when solar generation is high, shifting consumption from peak periods can help reduce the costs of supply, manage minimum demand constraints (such as voltage issues) and draw more energy from a low emissions fuel source.

Previously, the roll-out of smart meters was market-led as part of the 'Power of Choice' reforms, which also included more cost-reflective network pricing (section 4.8.1) and incentives for demand management as a lower cost alternative to network investment (section 4.13.9).

The emergence of electric vehicles (EVs) can also help consumers manage their energy needs. The Australian Renewable Energy Agency (ARENA) is funding projects to assess different approaches to optimise the use of EVs. In April 2023, ARENA announced $70 million in funding to support innovation and management of charging stations, as part of the Driving the Nation funding pool.[28] Other projects funded by ARENA include the Depot of the Future Vehicle Electrification Project, testing the impact of large-scale fleet EVs[29], and the Jemena Dynamic EV Charging Trial, testing dynamic management of EV home charging.[30]

More generally, the Distributed Energy Integration Program (DEIP) – a collaboration of government agencies, market authorities, industry and consumer associations – aims to enhance consumers' benefits from using consumer energy resources, including benefits from access and pricing reforms.[31] The DEIP has also run a series of task forces to explore issues relating to integrating EVs into the energy system.

Improvements in energy storage and renewable generation technology are making it increasingly possible for some consumers to go off-grid. Standalone systems or microgrids – where a community is primarily supplied by local generation with no connection to the main grid – are gaining traction, particularly in regional communities that are remote from existing networks.

In 2020, the AEMC proposed rule changes to enable distribution network service providers to supply their customers using standalone power systems where it is cheaper than maintaining a connection to the grid.[32] The AEMC identified additional benefits of these systems, including improved reliability and reduced bushfire risks.[33] These proposed changes were made to the National Electricity Rules in February 2022 following a series of changes in the national electricity and retail laws.[34]

Under the reforms, customers who receive standalone systems will retain all of their existing consumer protections, including access to retail competition and existing reliability and safety standards. Cost savings arising from the use of lower cost standalone systems will flow through to all users of the distribution network through lower network prices.

27 AEMC, Final report – Review of the regulatory framework for metering services, Australian Energy Market Commission, 30 August 2023.

28 ARENA, ARENA targets better, more frequent EV charging stations, media release, Australian Renewable Energy Agency, 20 April 2023.

29 ARENA, Depot of the Future Vehicle Electrification Project, ARENAWIRE, Australian Renewable Energy Agency, last updated 2 May 2023.

30 ARENA, Jemena Dynamic Electric Vehicle Charging Trial, ARENAWIRE, Australian Renewable Energy Agency, last updated 8 February 2023.

31 The DEIP's Access and Pricing Working Group developed a rule change proposal on the prohibition on export charging, which the AEMC approved in its decision published June 2021.

32 Usually a combination of solar PV, batteries and a backup generator.

33 AEMC, Final report – updating the regulatory frameworks for distributor-led stand-alone power systems, Australian Energy Market Commission, May 2020.

34 AEMC, New rules allow distribution network businesses to roll out stand-alone power systems in the NEM, Australian Energy Market Commission, February 2022.

4.8.1 Tariff structure reforms

Traditionally, most households and small businesses have been charged the same network tariff component for using the distribution network regardless of how and when they use energy (that is, flat/single rate or non-cost-reflective network tariffs). Because flat tariffs are independent of when and how electricity is used, they don't reflect the relatively higher costs of a network built to supply electricity during peak periods. This means some consumers, such as those who primarily use electricity during peak periods, may not pay their full share of network costs under single rate tariff structures, while other consumers may pay more than their full share.

Importantly, distribution service providers do not charge network tariffs directly to end customers. Rather, network tariffs are charged to retailers, who then package the tariffs together with the cost of wholesale energy and other costs in their retail price offers to end customers. The network component makes up around 40% of a customer's final retail bill (Figure 7.2 in chapter 7). The retailer may pass on the network tariff signal as is or repurpose it into a different retail offer. It is up to the end customer to choose a retail offer that suits their needs.[35]

The National Electricity Rules require distribution service providers to make network tariffs more cost-reflective, to signal to retailers the true cost of their customers' use of the network.[36] The AER supports and encourages the reform to more cost-reflective tariffs through the tariff structure statement process.

Tariff reform can encourage more efficient use of networks, delay the need for network augmentation and investment, and spread network costs more equitably. Initially, reform focused on signalling costs during peak demand periods (which historically drove network investment). Recent reform has involved sending price signals to efficiently integrate consumer energy resources – such as rooftop solar, batteries and EVs – into distribution networks. This includes sending price signals to encourage the use of solar energy in the middle of the day to avoid excess solar (minimum demand) on the network.

Distribution network service providers are required to submit their tariff structure statements to the AER every 5 years, as part of the wider revenue determination process. With each tariff structure statement, network service providers are required under the National Electricity Rules to progressively move towards more cost-reflective tariffs.[37]

Progress towards increasing the number of customers seeing and responding to tariff signals of network costs has included:

- simplifying tariffs and modifying peak windows to provide clear, consistent signals
- designing tariffs that more closely reflect network costs, including two-way tariffs
- applying an 'opt-out' or mandatory assignment policy that increases the number of end customers whose retailers will face these more cost-reflective tariffs (a development from 'opt-in' assignment policies)
- integrating network pricing with areas such as network planning, demand management and direct procurement of network services; and trialling alternative approaches.

In August 2021, the AEMC made a rule change to integrate consumer energy resources, such as small-scale solar and batteries, more efficiently into the electricity grid. The key aspects of the rule change included providing clear obligations on distribution network service providers to provide export services, enabling new network tariff options that reward customers and strengthening customer protections and regulatory oversight by the AER.[38]

The rule change seeks to better manage minimum demand issues, support effective consumer energy resources integration and enable future market designs in which consumer generation and storage play a larger role.

Distribution network service providers may now signal the cost of serving energy export as well as energy consumption, where providing the export service imposes a cost on the network (also called two-way pricing). This means that customers with solar could be rewarded for exporting at times when the network needs it or charged

35 Energy Made Easy (www.energymadeeasy.gov.au) is a free Australian Government energy price comparison service for households and small businesses in NSW, Queensland, South Australia, Tasmania and the ACT that can be used to find and compare home and small business electricity and gas plans. The Victorian Government's Victorian Energy Compare website (compare.energy.vic.gov.au) offers the same service for households and small businesses in Victoria.

36 AEMC, National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014, rule determination, Australian Energy Market Commission, November 2014.

37 Distribution network service providers are now moving into the third round of submitting tariff structure statements.

38 AEMC, Final determination – Access, pricing and incentive and incentive arrangements for distributed energy resources, Australian Energy Market Commission, 12 August 2021, accessed 20 January 2022.

for exporting if it contributes to minimum demand. The rule change requires the AER to publish export tariff guidelines for the implementation of any two-way pricing that may be introduced in distribution network service providers' next round of tariff structure statements.[39]

Under the National Electricity Rules, subject to revenue recovery limits, distribution network service providers can trial alternative tariff structures (sub-threshold tariffs) during the regulatory period to support the introduction of innovative tariff structures. Network service providers have responded with a broad range of trials to explore innovative tariff approaches, covering solar sponges, EVs, critical peak pricing and two-way pricing. Examples of trials include:

- Ausgrid (NSW) – a super off-peak tariff trial with an additional 4-hour 'super off-peak' charge, used to encourage EV owners to charge their EVs away from the network peak.
- Essential Energy (NSW) – 2 trial tariffs aimed at large businesses – a sun soaker, two-way tariff trial and a weekly demand tariff trial. These trials are specifically aimed at helping customers with peaky loads, such as irrigators and EV charging stations, to manage their loads.
- SA Power Networks (South Australia) – a small business tariff trial with high peak prices, aimed at encouraging businesses with flexible load to shift energy use to during the day or overnight.
- Jemena (Victoria) – a community battery tariff trial for batteries with capacity up to 500 kVA. The purpose of this trial is to gain insights into the behaviour of battery operators in response to price signals.

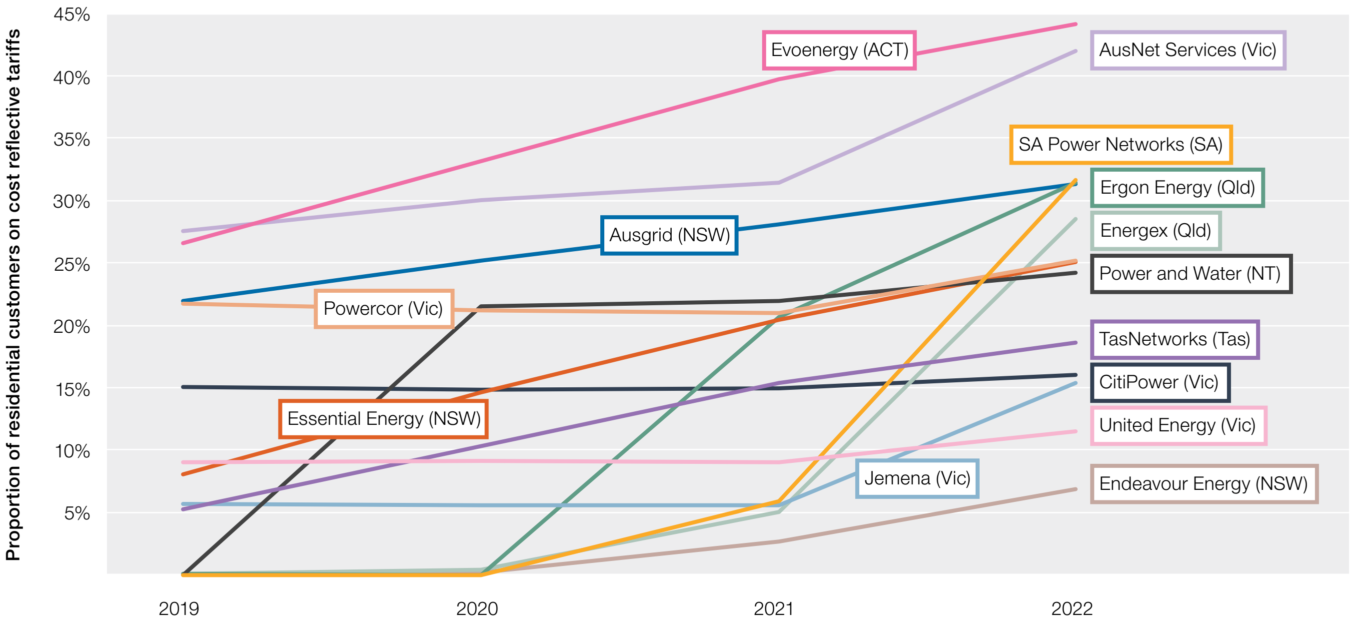
An example of the AER progressing cost reflectivity is its approval of SA Power Networks' use of a 'solar sponge' tariff for its residential customers. The solar sponge network tariff offers a lower charge during the day, when solar output is highest, to encourage customers to use electricity when it is more plentiful and less costly. Raising demand for grid-supplied electricity during the day can help manage voltage issues and thermal overloads associated with minimum demand, while shifting demand away from the evening peak when there is heavy strain on the network and costs are higher. SA Power Networks also introduced a demand tariff that offers discounted time of use rates and a seasonal peak demand component.

Other distribution network service providers have also incorporated, or plan to incorporate, 'solar soak' or 'solar sponge' tariffs to encourage energy use during the day. For example, Essential Energy (NSW) has proposed a tariff with export and reward charges, as well as low consumption prices during the day, to be its default residential cost-reflective tariff from 2028.

The National Electricity Rules require distribution network service providers to make their suite of tariffs progressively more cost reflective with each tariff structure statement. Figure 4.6 shows the proportion of residential customers whose retailer is facing cost-reflective network tariffs. We expect the proportion to continue to increase as distribution network service providers assign customers with smart meters to cost reflective tariffs, and more smart meters are rolled out.

39 AER, Export Tariff Guidelines, Australian Energy Regulator, 19 May 2022.

Figure 4.6 Residential customers on cost-reflective tariffs



Source: Annual RIN responses.

To date, the limited uptake of smart meters for residential and small business consumers outside Victoria has been a barrier to applying cost-reflective network tariffs. Smart meters, which measure electricity use in 30-minute blocks, are essential for most cost-reflective network tariffs to be applied.

In jurisdictions other than Victoria, where almost 100% of small consumers have smart meters, the rollout of smart meters is market-led. Installation rates vary across jurisdictions. New and replacement meters installed for residential and small business consumers must now be smart meters and other consumers can negotiate for a smart meter as part of their electricity retail offer. At 30 June 2022, around 57% of residential customers in the NEM had metering capable of supporting cost-reflective tariffs (including smart meters and manually readable interval meters).

Changes to the National Electricity Rules in 2017 transferred responsibility for metering from distribution network service providers to retailers. Additionally, from February 2019 retailers have been required to provide consumers with electricity meters within 6 business days of a property being connected to the network or with replacement meters within 15 days.[40]

In 2023, the AEMC reached the view that the roll-out of smart meters has progressed too slowly and recommended a larger role for distribution network service providers to expediate the roll-out.[41] The AEMC recommends distribution network service providers schedule the retirement of existing legacy meters and retailers take responsibility for replacing the retired meters with smart meters.

4.8.2 Ring-fencing

When 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 objective of ring-fencing is to provide a regulatory framework that promotes the development of competitive markets. It does this by providing a level playing field for third party providers in new and existing markets for contestable services.[42] Effective ring-fencing arrangements are an important mechanism for promoting increased choice of service providers for consumers and more competitive outcomes in markets for energy services.

Ring-fencing aims 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.

40 AEMC, National Energy Retail Amendment (Metering Installation Timeframes) Rule 2018, rule determination, December 2018, Australian Energy Market Commission, accessed 14 February 2022.

41 AEMC, Final report – Review of the regulatory framework for metering services, Australian Energy Market Commission, 30 August 2023.

42 The 2015 Power of Choice reforms (section 4.8) required the AER to develop the distribution ring-fencing guideline.

The AER publishes separate ring-fencing guidelines for transmission and distribution networks. Under the guidelines, network service providers identify and separate the costs and business activities of delivering regulated network services from the delivery of other services in competitive markets.

Under the distribution ring-fencing guideline, all distribution network service providers are required to annually report on their compliance to the AER. Despite the slight increase in 2022–23 the AER has generally observed fewer compliance issues and breaches since 2017–18. When breaches have occurred, distribution network service providers have generally communicated promptly with the AER, acted quickly to remediate any potential harms, and put a plan in place to prevent breaches from reoccurring. The introduction of civil penalties in February 2020 has continued to encourage improved compliance.

In December 2022, the AER granted a class waiver enabling distribution network service providers to provide reliability and emergency reserve trader (RERT) services using voltage management.[43] These services were identified by AEMO as a potential low-cost way of maintaining power system reliability. To help the AER monitor potential impacts on customers, distribution network service providers that provide services under the class waiver must provide additional quarterly reports. The information provided in these reports will help the AER to monitor the potential impacts on customers until the waiver expires on 15 April 2025.

The AER granted a further class waiver in February 2023 for distribution network service providers to install community-scale batteries with funding from the Australian Government's Community Batteries for Household Solar Program.[44] The waiver introduced additional conditions to prevent cross-subsidisation and discrimination and ensure consumers received the benefits from the program. This class waiver was tightly targeted to the expected 400 batteries under the program, noting that the benefits may be maximised in some instances by allowing batteries to provide both network and non-network services.

In March 2023, the AER released an updated ring-fencing guideline for electricity transmission networks.[45] The previous guideline was published by the Australian Competition and Consumer Commission (ACCC) in August 2002. Although several minor amendments were made to the guideline over the years, it had not changed substantially since its initial publication despite significant changes in the regulatory landscape and electricity market.

The amendments in the updated guideline seek to ensure the guideline remains fit for purpose in a changing regulatory landscape and electricity market.

The updated guideline took effect from 1 March 2023. The introduction of civil penalties for breaches of transmission ring-fencing requirements is expected to encourage compliance with the updated guideline.

4.9 Revenue

Electricity network businesses earn revenue for providing services to customers. While some services are regulated, others are provided through competitive markets. For transmission network service providers, this report focuses exclusively on components of revenues associated with delivering regulated services, referred to as prescribed transmission services. For distribution network service providers, it focuses exclusively on revenues associated with providing regulated distribution services – standard control services.[46]

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.

The AER updates the revenue targets each year to account for actual inflation, changes in the network service providers' allowed returns on debt, cost pass-throughs (section 4.9.3) and other factors. Interest rates and inflation are factors outside both the network service providers' and the AER's control. These uncontrollable factors are expected to place upwards pressure on the network service providers' allowed revenue in future years.[47]

43 AER, Reliability and Emergency Reserve Trader (RERT) via voltage management — Ring-fencing class waiver, Australian Energy Regulator, December 2022, accessed 26 July 2023.

44 AER, Batteries funded under the Commonwealth Government's Community Batteries for Household Solar Program – Ring-fencing class waiver, Australian Energy Regulator, February 23, accessed 26 July 2023.

45 AER, Ring-fencing guideline - electricity transmission - version 4, Australian Energy Regulator, March 2023, accessed 16 March 2023.

46 Standard control services may include network, connection and metering services. These services make up the bulk of the services provided by distribution businesses and are regulated by the AER.

47 AER, Rate of return – overview for consumers, Australian Energy Regulator, February 2023.

4.9.1 Revenue in 2022

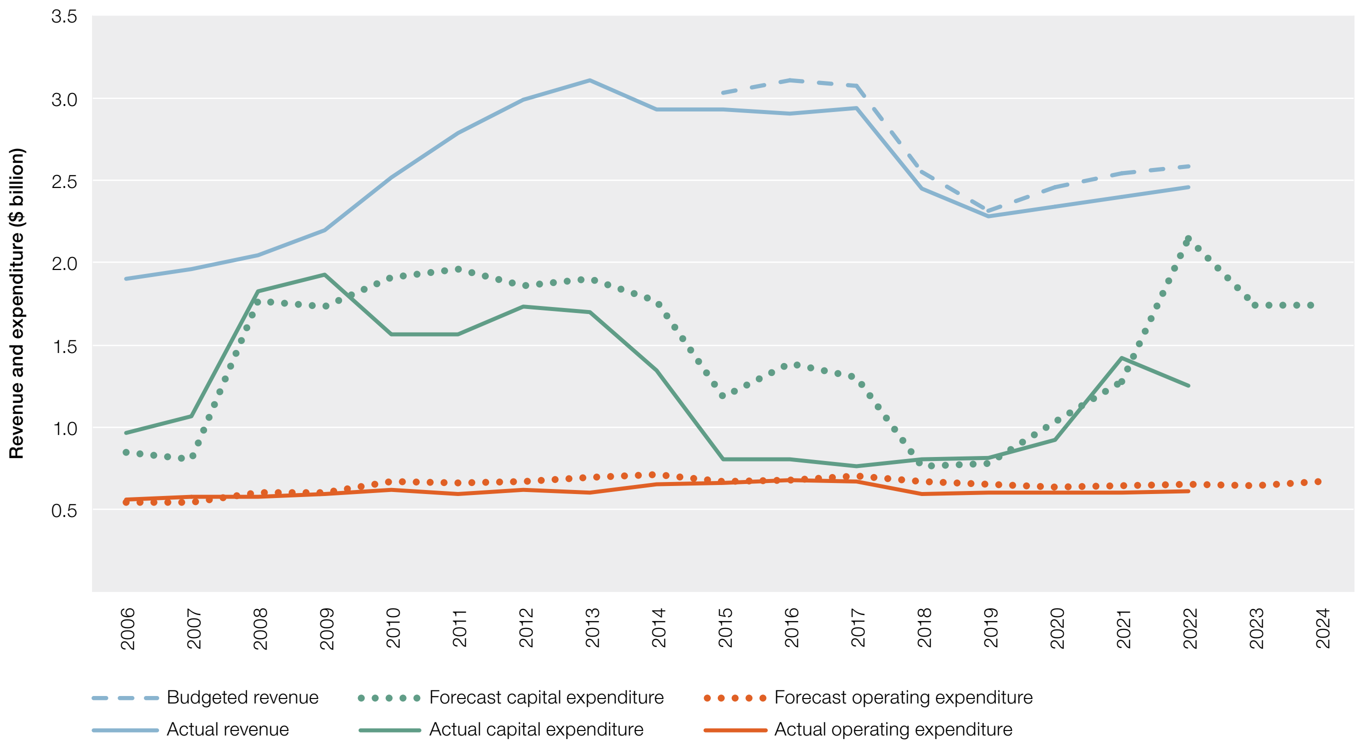
In 2022, network service providers earned $12 billion for providing services to customers, $10 million (0.1%) less than in the previous year. This marked the eighth consecutive year of decreases in aggregated transmission and distribution network revenue.

Table 4.2 and Figure 4.7 to Figure 4.10 provide a summary of the revenue network service providers earned for providing services to customers in 2022 and how it compared with previous years' targets and actuals.

Table 4.2 Revenue in 2022 – key outcomes

Service type	Revenue (actual) (2022)	Revenue (actual) (compared with 2021)	Revenue (actual) (compared with peak)
Transmission	$2.5b	▲$61m (▲3%)	▼$646m (▼21%) (2013)
Distribution	$9.4b	▼$71m (▼0.7%)	▼$4.0b (▼30%) (2014)
Total	$11.9b	▼$10m (▼0.1%)	▼$4.5b (▼27%) (2014)

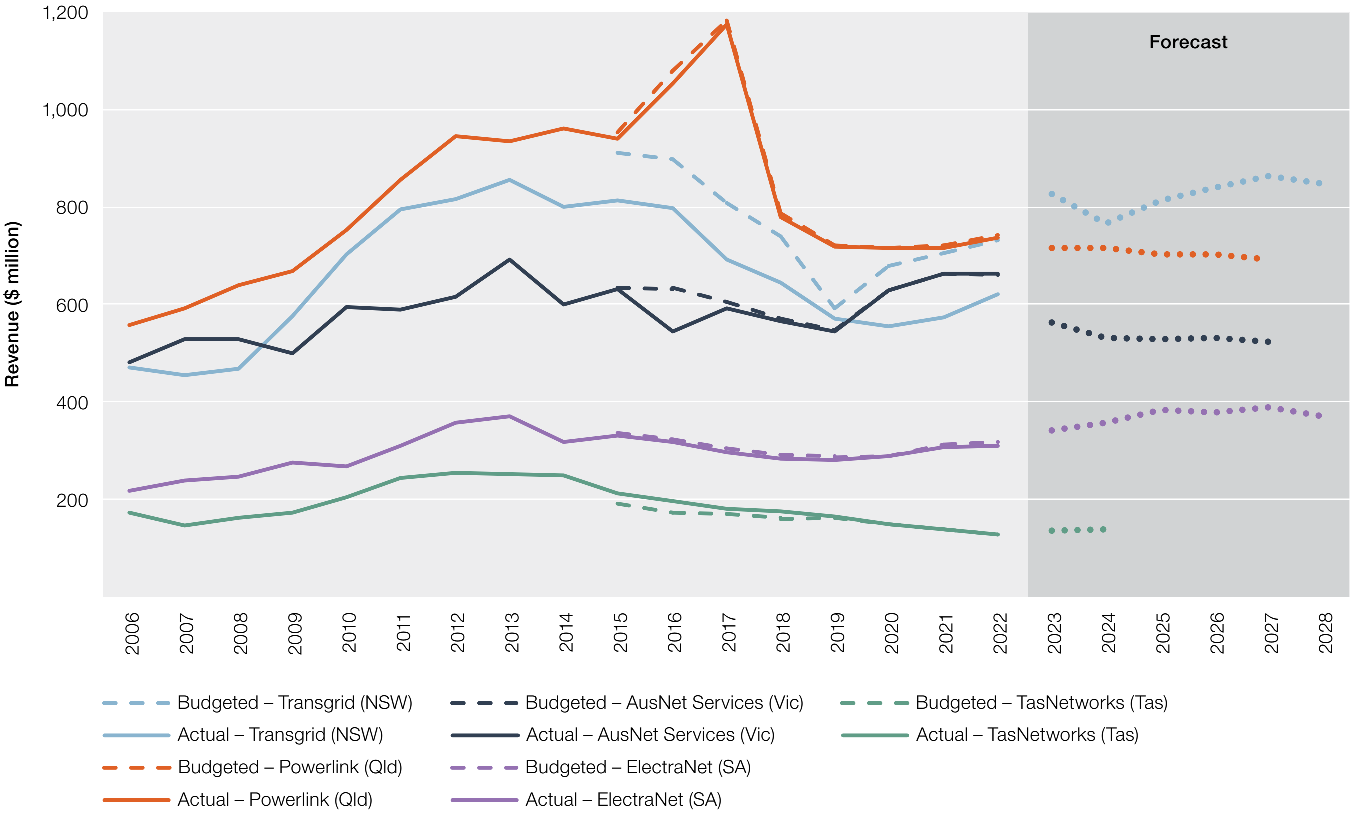
Figure 4.7 Revenue and key drivers – electricity transmission networks (aggregate)



Note: All data are adjusted to June 2022 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 other from sources such as inter-regional and intra-regional settlements residues or inter-regional settlements auction proceeds. The budgeted revenue shown in Figure 4.7 reflects the revenues 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.

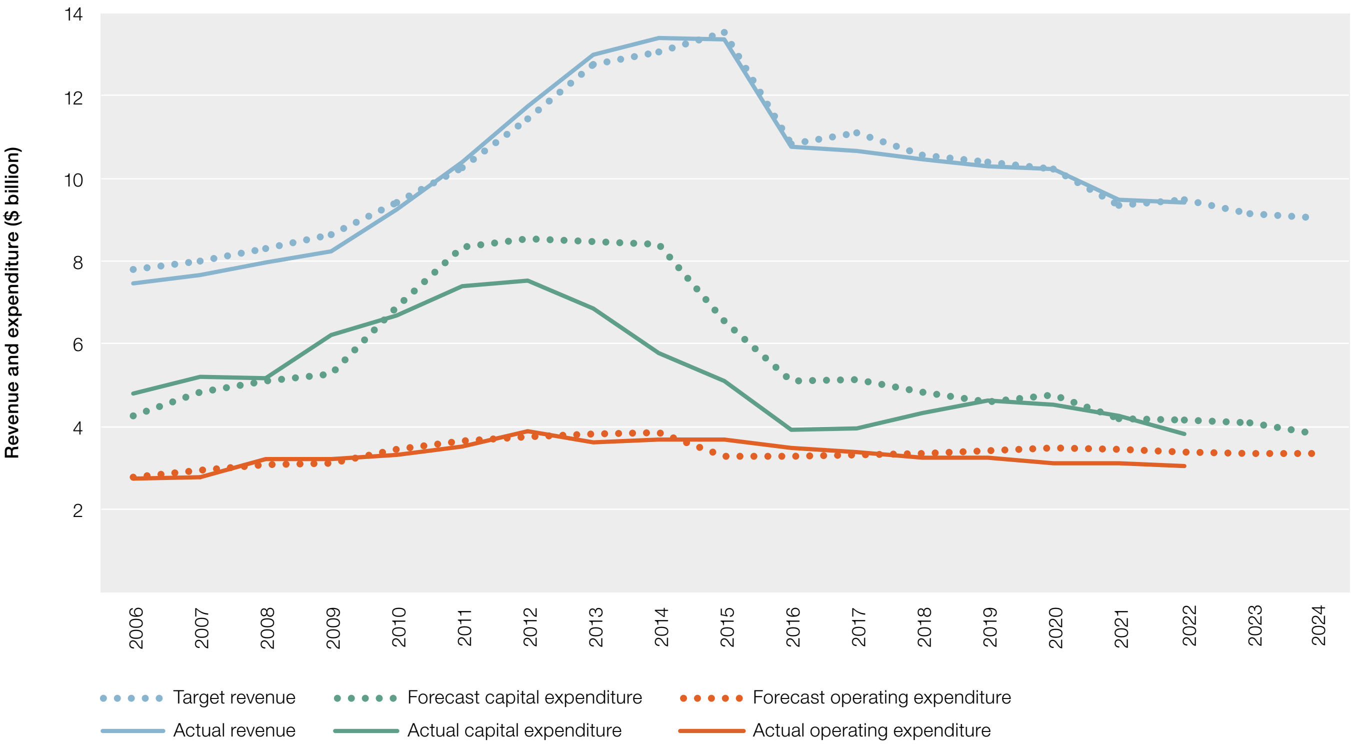
Figure 4.8 Revenue – electricity transmission networks



Note: All data are adjusted to June 2022 dollars. 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 other from sources such as inter-regional and intra-regional settlements residues or inter-regional settlements auction proceeds. The budgeted revenue shown in Figure 4.8 reflects the revenues budgeted to be collected from customers. Forecast revenue is derived from regulatory determinations but adjusted to present it on a comparable basis to actual revenues. 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. Assumptions are set out in the Figure 4.7 notes.

Source: AER modelling; annual reporting RIN responses.

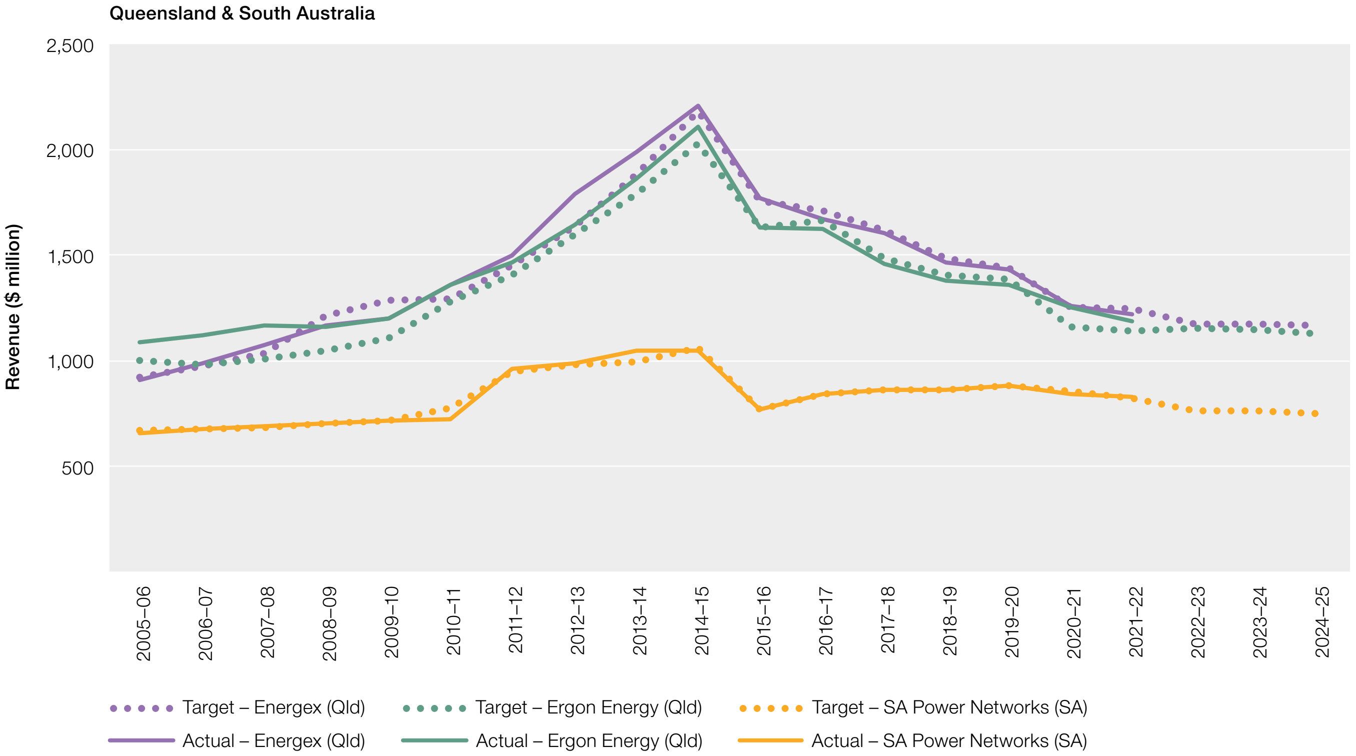
Figure 4.9 Revenue and key drivers – electricity distribution networks (aggregate)

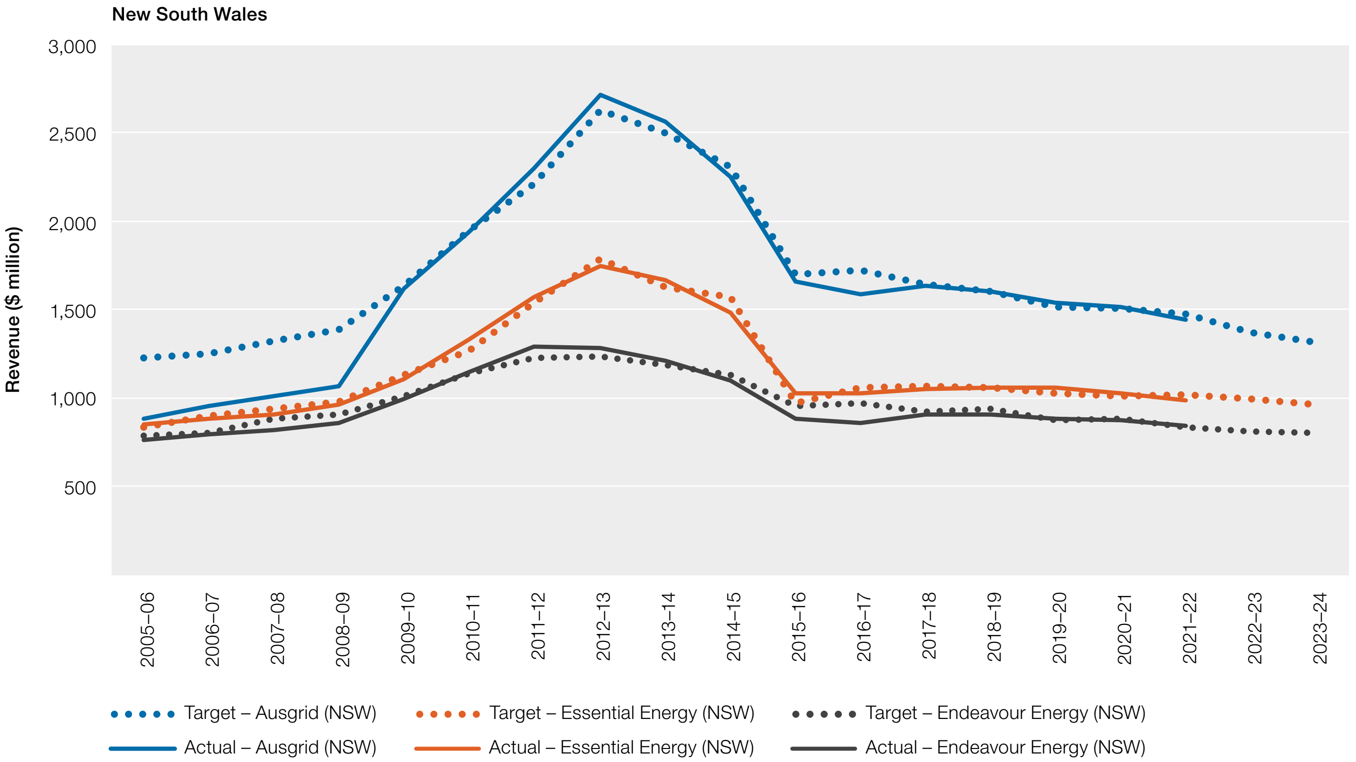


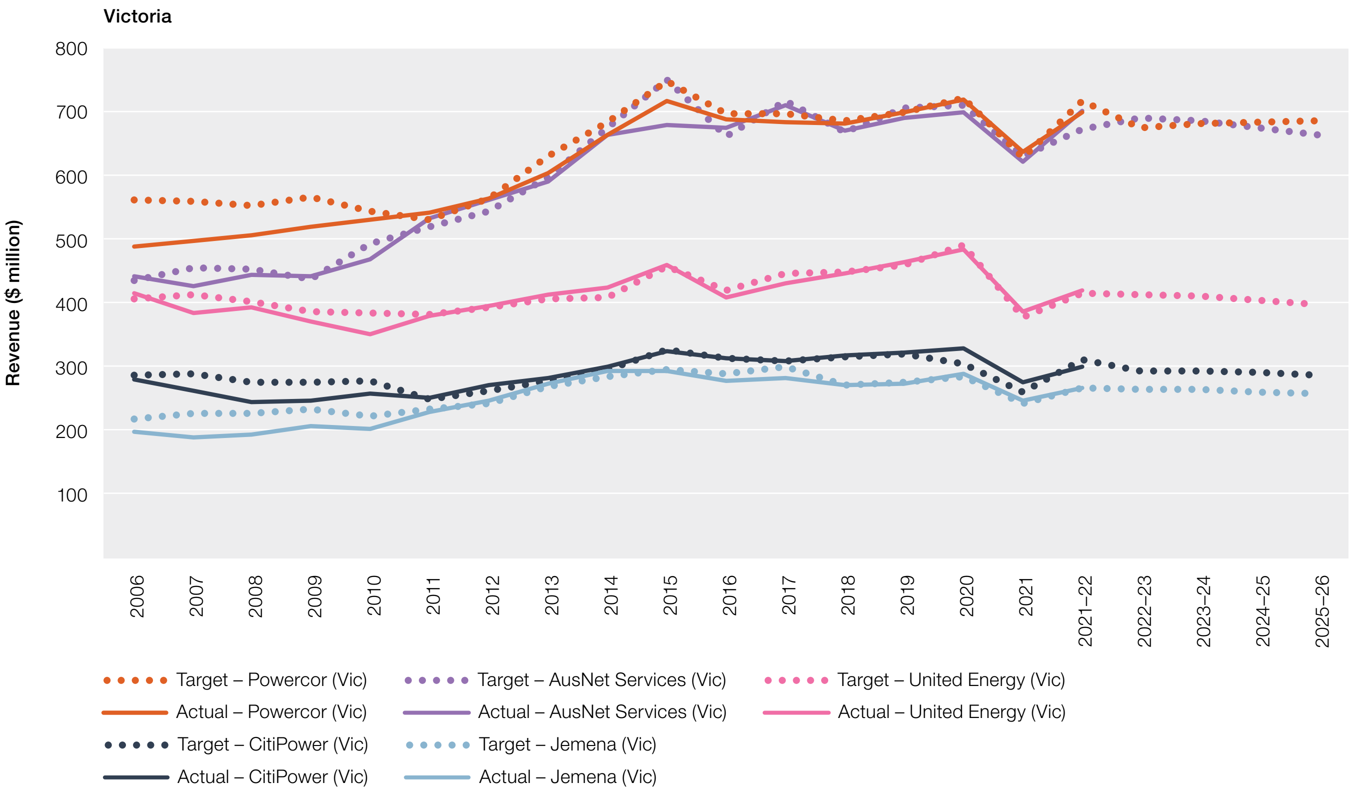
Note: All data are adjusted to June 2022 dollars. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Target revenue is derived from regulatory determinations but adjusted to present it on a comparable basis to actual revenues. 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. 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.

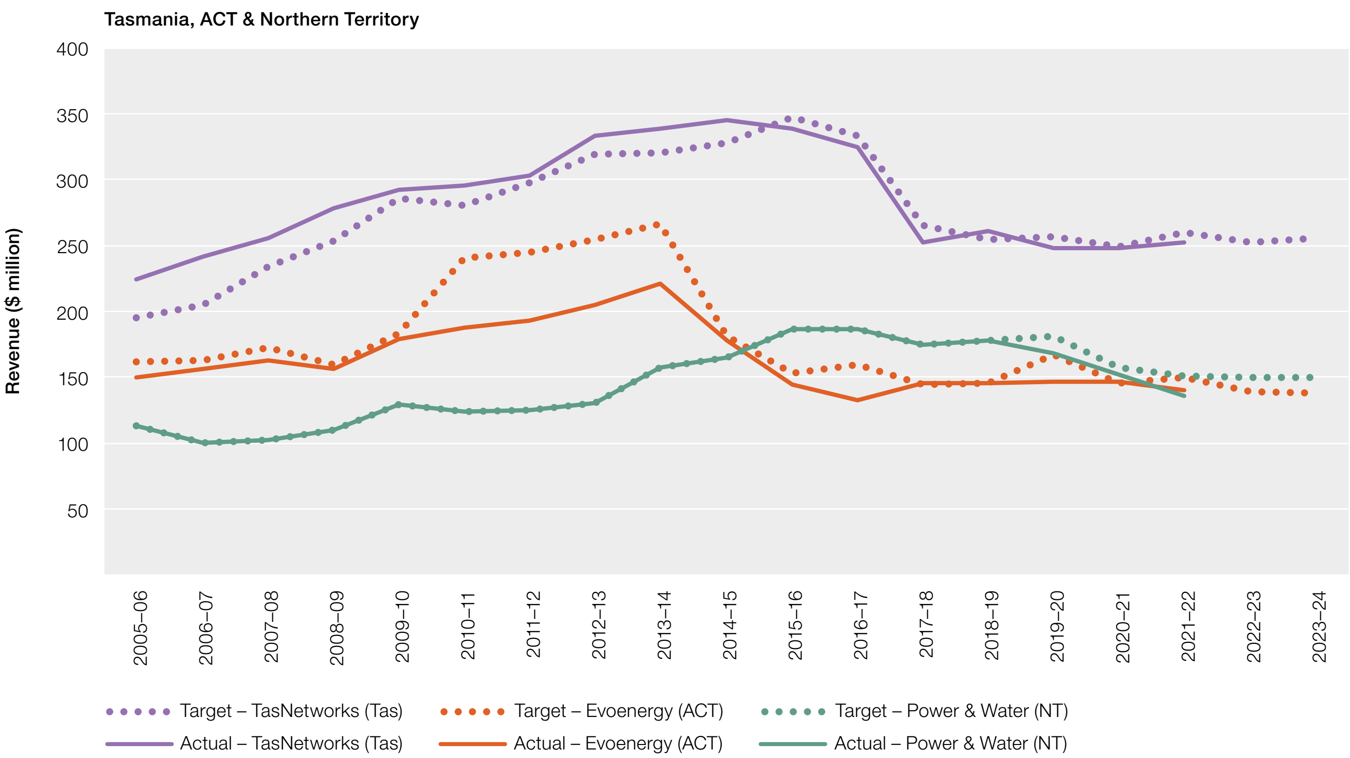
Source: Revenue: economic benchmarking RIN responses; capital expenditure: AER modelling, category analysis RIN responses; operating expenditure: AER modelling, economic benchmarking RIN responses.

Figure 4.10 Revenue – electricity distribution networks







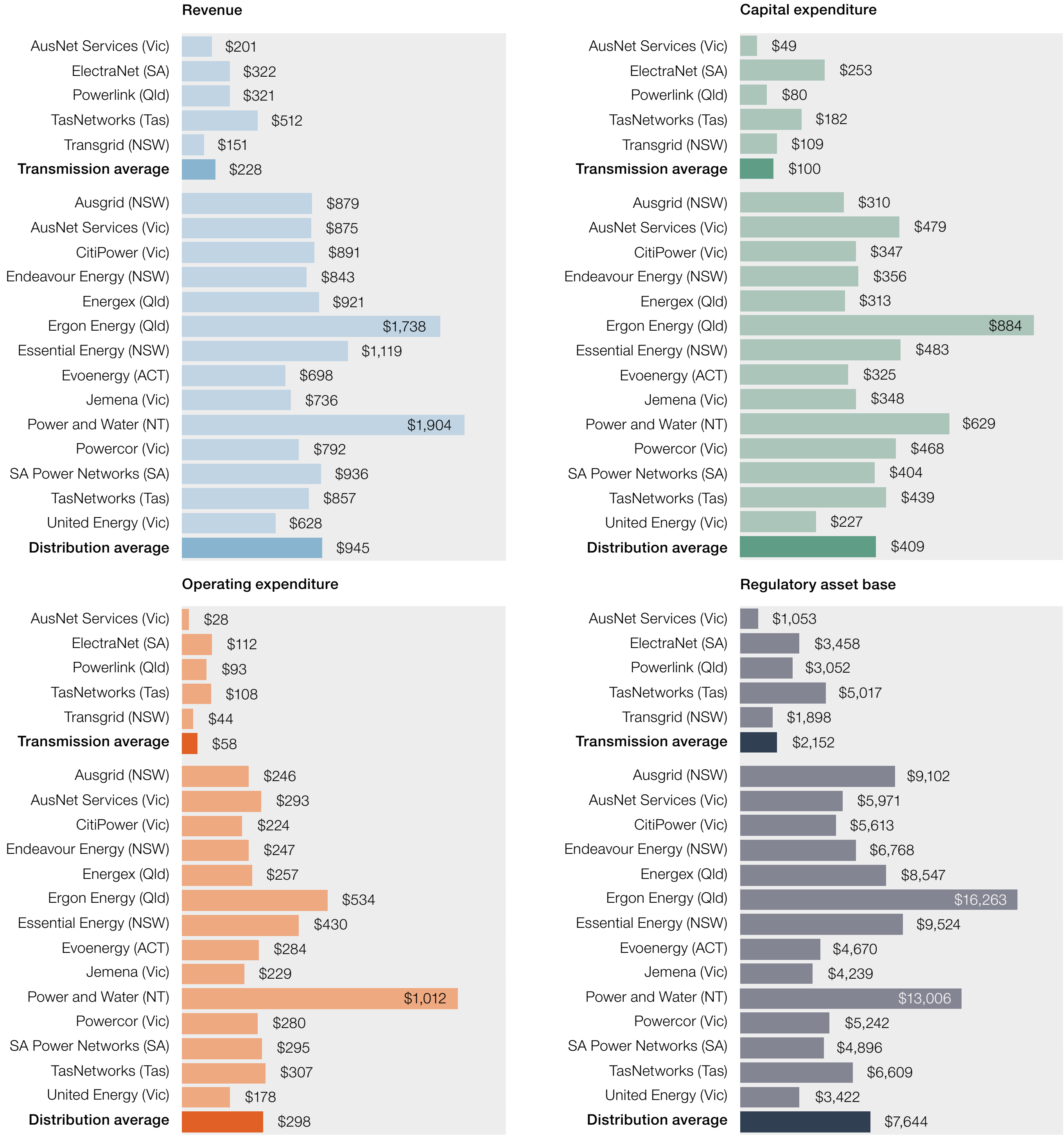


Note: All data are adjusted to June 2022 dollars. Most network businesses report on a 1 July to 30 June basis. The exception is the Victorian networks which have reported on a 1 January to 31 December basis. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). 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.

Source: AER modelling; annual reporting RIN responses.

Figure 4.11 summarises key financial indicators for electricity networks on a per customer basis, which allows for greater comparability across networks.[48 49]

Figure 4.11 Average per customer metrics – 2018 to 2022 (5 years)



Note: All data are adjusted to June 2022 dollars. In 2022 residential customers (a customer who purchases energy 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 Jemena (Victoria) and 82% for Essential Energy (NSW) – the differences did not materially affect the 'per customer' metric. Revenue, capital expenditure and operating expenditure are the annual averages over the 5 years to 30 June 2022. RAB is the actual closing RAB at 30 June 2022. For regulatory purposes, Northern Territory transmission assets are treated as part of the distribution system.

Source: AER revenue determinations and economic benchmarking RINs.

48 Per customer metrics allow for easier comparison of network businesses of different sizes. But multiple factors other than customer numbers – such as line length and terrain – have an impact on these indicators.

49 Transmission networks 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.

Forecast revenue for electricity network service providers is translated into a path of 'X-factors', which are locked in at the beginning of the regulatory period. These X-factors – alongside changes in inflation, incentive schemes and other factors – control the change in the maximum revenue 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.

Table 4.3 provides a summary of the AER's revenue determinations for all electricity network service providers for the current regulatory periods.

Table 4.3 AER electricity network revenue determinations – current regulatory period

Service type	Revenue (forecast)	Capital expenditure (forecast)	Operating expenditure (forecast)	Annual impact on residential bill
Transmission	\$12.9b (▼3%)	\$5.0b (▼29%)	\$3.4b (▲2%)	▲0.1%
Distribution	\$46.6b (▼15%)	\$20.0b (▼18%)	\$16.9b (▲0.9%)	▼0.4%
Total	\$59.5b (▼12%)	\$25.0b (▼21%)	\$20.3b (▲1.2%)	▼0.3%

Note: The current regulatory period is the period in place at 1 July 2023. Changes in revenue and expenditure are in relation to forecasts from the previous regulatory periods. Bill impact is the change in the average annual customer bill compared with the customer bill in the final year of the previous period, adjusted for inflation, assuming retailers pass through outcomes of the determination.

Source: AER estimates.

The key drivers behind lower revenues for most of the network service providers have been the changes in the allowed return on capital and, to a lesser extent, the net tax allowance. In the previous cycle of regulatory determinations, the allowed rate of return had decreased from the prior regulatory period, driven by lower interest rates. This led to significant downward pressure on network revenue. Recently that trend has reversed as interest rates have increased alongside higher inflation, putting upward pressure on network revenues.

4.9.2 Trends in network revenue

Revenues for network service providers increased by around 7% per year from 2006 to 2015, when network charges accounted for around 43% of retail electricity bills. The increases were more pronounced in Queensland and NSW than elsewhere. The drivers of these increases are set out in more detail in past State of the energy market reports. Key factors included:

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

Cost pressures began to ease when electricity demand 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 over 10% between 2009 and 2013, allowed rates of return approved for some network service providers fell to around 4.6% in 2022 (section 4.12).

Energy rule reforms phased in from 2015 also helped stem the growth in network revenue. 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 the service providers entered new 5-year regulatory cycles. However, consumers will continue to pay for the overinvestment in network assets from 2006 to 2013 for the remainder of the economic lives of those assets, which may be up to 50 years. In 2018, independent public policy think tank Grattan Institute called for the asset bases of some networks to be written down, so consumers would not continue to pay for that overinvestment.[50] The Australian Competition and Consumer Commission (ACCC) supported this position, particularly for government-owned networks in Queensland, NSW and Tasmania.[51]

Since 2017 network revenues have decreased, driven by a significant reduction in target revenue for the NSW based networks in 2015 and followed by a subsequent significant reduction for the Queensland based networks in 2016.

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 the network service providers, the AER now publishes information on network profitability. The AER's annual electricity network performance report provides detailed analyses of key operational and financial trends as well as key profitability measures.[52] The network performance report enables 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 investment on capital projects. Operating expenditure has always been lower than capital expenditure, but the difference 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 2015 weakening investment led to decreases in capital expenditure. In 2016 the amount of capital (53%) and operating (47%) expenditure almost reached parity. In recent years operating expenditure has eased as network service providers (especially distribution) implemented efficiency programs (section 4.14).

4.9.3 Pass-through events

The AER is responsible for assessing cost pass-through applications, wherein a network service provider may apply to seek the recovery of 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 4.4 summarises the cost pass-through applications approved by the AER in the 12-month period to 30 June 2023.

50 T Wood, D Blowers, K Griffiths, Down to the wire – a sustainable electricity network for Australia, Grattan Institute, March 2018.

51 ACCC, Retail Electricity Pricing Inquiry – final report, Australian Competition and Consumer Commission, June 2018.

52 AER, Electricity network performance reports, Australian Energy Regulator, accessed 11 July 2023.

Table 4.4 Cost pass-throughs

Network service provider	Pass-through event	AER approved ($ nominal)	Recovery period
Powerlink (Queensland)	Network support	$0.3 million	2023–24
Transgrid (NSW)	Network support	–$10.6 million	2023–24
ElectraNet (South Australia)	Insurance	$5.3 million	2023–24
ElectraNet (South Australia)	Network support	$2.2 million	2023–24
TasNetworks (Tasmania)	Network support	$0.2 million	2023–24
AusNet Services (Victoria)	Tax costs	$55.9 million	2023–24
Murraylink ((South Australia–Victoria)	Connection charge	–$0.9 million	2023–24
Energex (Queensland)	Natural disaster	$18.1 million	2024–25
Ausgrid (NSW)	NSW Roadmap Electricity Infrastructure Fund	$61.5 million	2023–24
Endeavour Energy (NSW)		$48.9 million	2023–24
Essential Energy (NSW)		$27.8 million	2023–24
Essential Energy (NSW)	Natural disaster	$2.2 million	2023–24
Powercor (Victoria)	Regulatory obligation	$14.0 million	2023–24 to 2025–26
SA Power Networks (South Australia)	Service standard	$5.8 million	2023–24 to 2024–25

Source: Cost pass-throughs.

4.10 Network charges and retail bills

Electricity network charges made up around 40% of a residential customer's energy bill in 2022 (Figure 7.2 in chapter 7). Distribution network services accounted for most of the costs (73% to 78%), with transmission network service costs (up to 21%) and metering costs making up the balance. Jurisdictional scheme costs, collected through network charges, are also material in some cases. For example, in the ACT, jurisdictional schemes relating mainly to large-scale feed-in tariffs:

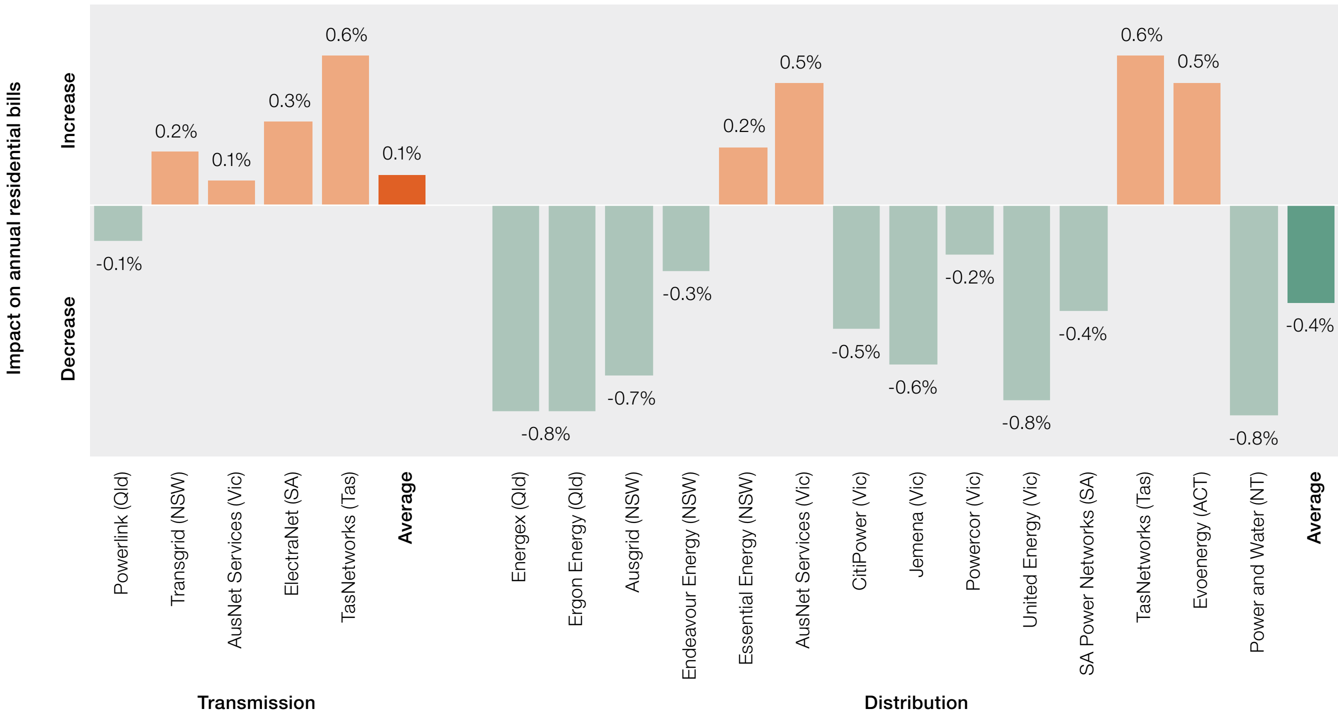
- materially increased energy bills over 2021–22, accounting for over 20% of total network charges[53]
- will materially reduce energy bills over 2022–23, accounting for a reduction of 30% in total network charges.[54]

The AER's most recent revenue determinations decreased residential energy bills by an average of 0.3% per year across all states and territories. This is the culmination of an average 0.1% increase in transmission costs and an average 0.4% decrease in distribution costs (Figure 4.12).

53 AER, Statement of reasons: Evoenergy's annual pricing proposal, Australian Energy Regulator, May 2021.

54 AER, Statement of reasons: Evoenergy's annual pricing proposal, Australian Energy Regulator, May 2023.

Figure 4.12 Impact of AER revenue determinations on residential customer electricity bill



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. The data account for changes in only network charges, not changes in other bill components. Outcomes will vary among customers, depending on energy use and network tariff structures.

Source: AER revenue determinations; additional AER modelling.

The most significant changes to network charges generally arise in the first year of a regulatory period. Recent examples range from a 9% reduction for Power and Water (Northern Territory) to a 1.6% increase for AusNet Services (Victoria). As part of its revenue determination process, the AER 'smooths' the initial revenue forecast to minimise volatility in prices over the regulatory period. Through this approach, initial changes are generally followed by stable prices or modest increases in later years.

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.

Among other factors, the annual processes update prices for changes in the consumer price index (CPI). Since June 2021, CPI has increased significantly. For example, over the 12 months to December 2022, applying to network prices over 2023–24, CPI increased by 7.8%. The Reserve Bank of Australia acknowledges it will take some time for inflation to return to the 2–3% target band. The central forecast is for headline inflation to decline to 4.5% by the end of 2023 and to reach 3% by mid-2025.[55] As these inflation results feed into annual pricing over coming years, they will continue to put upward pressure on prices.

55 RBA, Statement of Monetary Policy, Reserve Bank of Australia, August 2023.

4.11 Regulatory asset base

The regulatory asset base (RAB) for a network service provider represents the total economic value of assets that provide network services to customers.[56] 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 retail electricity bills long after the investment is made.

As part of the revenue determination process, the AER forecasts a network service provider's efficient investment requirements 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 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.

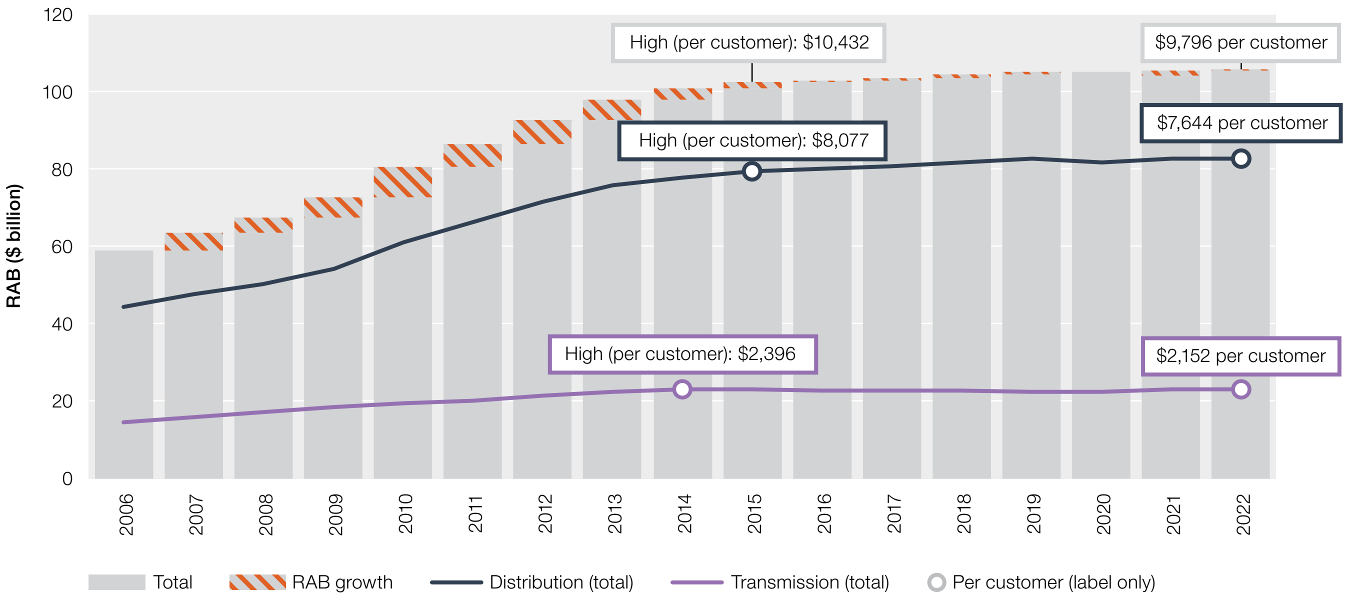
Escalating investment inflated the value of the total electricity network RAB from $58.7 billion in 2006 to $97.8 billion in 2013 – an increase of around 8% per year. Since then, network investment has steadied, as has the growth in the value of the total network RAB. From 2014 to 2022 the value of the total network RAB continued to grow but at a considerably slower rate of around 1% per year.

Recent RAB growth has been most pronounced for the ElectraNet (South Australia) and Transgrid (NSW) transmission service providers. This includes expenditure on Project EnergyConnect, which is a major transmission investment developed and approved through a regulatory investment test (RIT) (section 4.13.7). This trend is forecast to continue as major transmission network projects required to enable the reliable supply of low carbon energy enter development (section 4.13.6).

4.11.1 Regulatory asset base in 2022

As at 30 June 2022 the total combined value of the RAB for electricity network service providers was $105.8 billion, an increase of $378 million (0.4%) from the previous year (Figure 4.13).

Figure 4.13 Value of electricity network service provider assets (regulatory asset base)



Note: All data are adjusted to June 2022 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: AER modelling; economic benchmarking RIN responses.

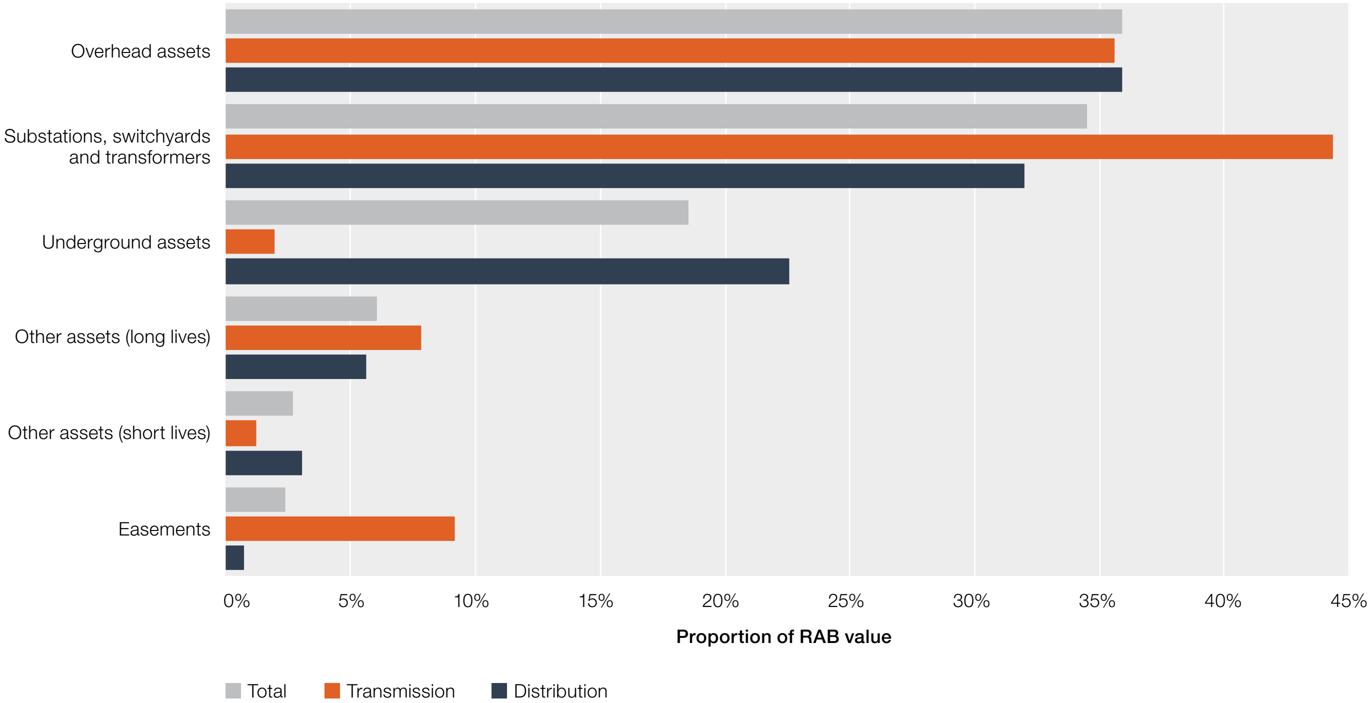
Network service providers receive a guaranteed return on their RAB. For this reason, they have an incentive to overinvest if their allowed rate of return exceeds their actual financing costs. Previous versions of the National Electricity Rules enabled significant overinvestment in network assets, which partly drove the sharp rise in network revenue from 2006 to 2015 (section 4.9). Under reforms introduced in 2015, the AER may remove inefficient investment from a network service provider's asset base if the service provider overspent its capital allowance, to ensure customers do not pay for it.

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

4.11.2 Overhead support structures

A network service provider's RAB is made up of many assets, which can be disaggregated 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 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 4.14).

Figure 4.14 Disaggregated value of electricity network assets (regulatory asset base)



Source: Economic benchmarking RIN responses.

Transmission towers and distribution poles are installed by network service providers to support overhead powerlines. Transmission towers are predominately made of steel, but distribution poles can be 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.

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 in 1924 – came about as an engineering solution to South Australia's lack of tall, termite-resistant hardwood for poles to carry powerlines and telephone wires.[57] 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.[58]

SA Power Networks' distribution network consists of more than 70,000 kilometres of overhead powerlines. However, overhead network assets only make up around 18% 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 considerably large size of the network service area.

57 P Sumerling and W Prest, Stobie Poles, SA History Hub, History Trust of South Australia, accessed 14 December 2020.

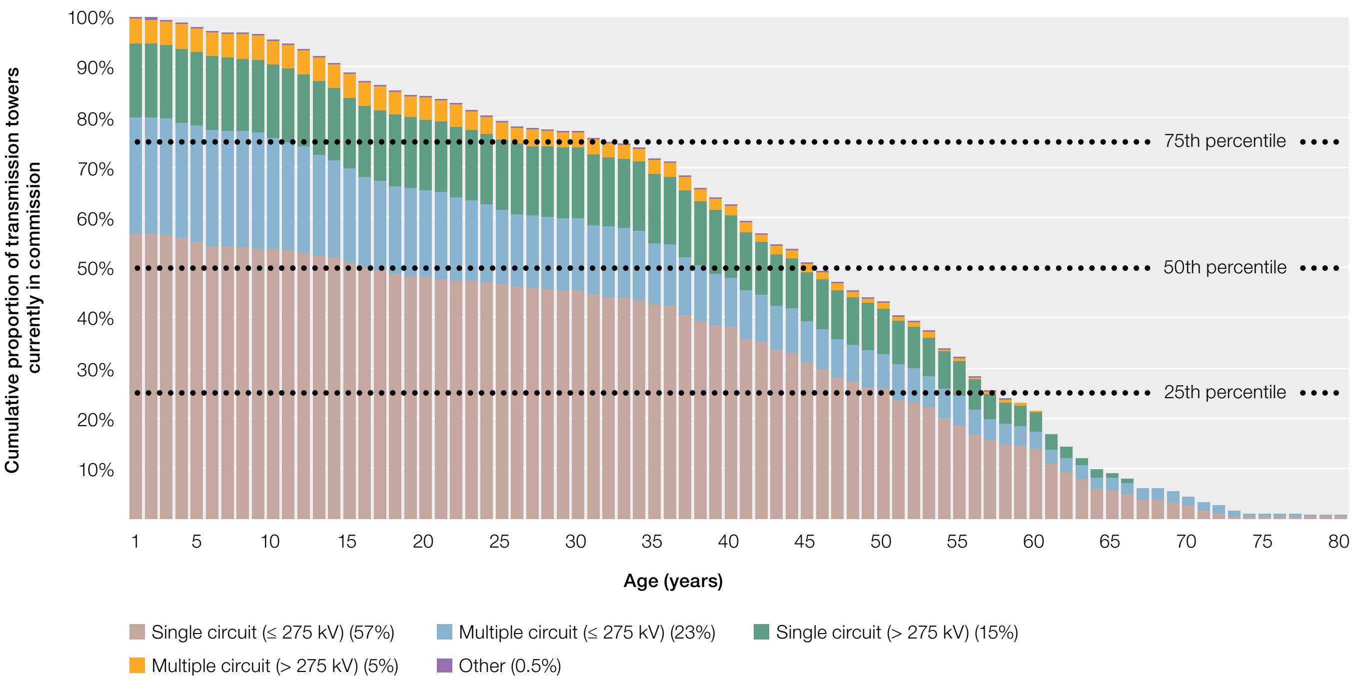
58 ABC News, Stobie poles are a South Australian icon, but how did they come about?, 31 March 2023, accessed 19 April 2024.

Due to the hard-wearing and near-indestructible nature of the distribution poles used in South Australia, the average age of SA Power Networks' poles in commission is significantly higher than those in any other network in the NEM.[59] 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.

Some service providers, such as Essential Energy (NSW) and Ergon Energy (Queensland), operate larger, rural distribution networks that are almost entirely above ground. Conversely, Evoenergy (ACT) and CitiPower (Victoria) operate smaller, urban distribution networks that are predominately underground. It is not surprising that predominately rural networks are more reliant on overhead poles than the networks operating in more urban environments.

The asset age profiles shown in Figure 4.15 and Figure 4.16 provide an overview of the age and quantity of towers and poles currently in commission. However, the asset age and tower/pole types vary considerably between the different networks.

Figure 4.15 Electricity transmission network towers

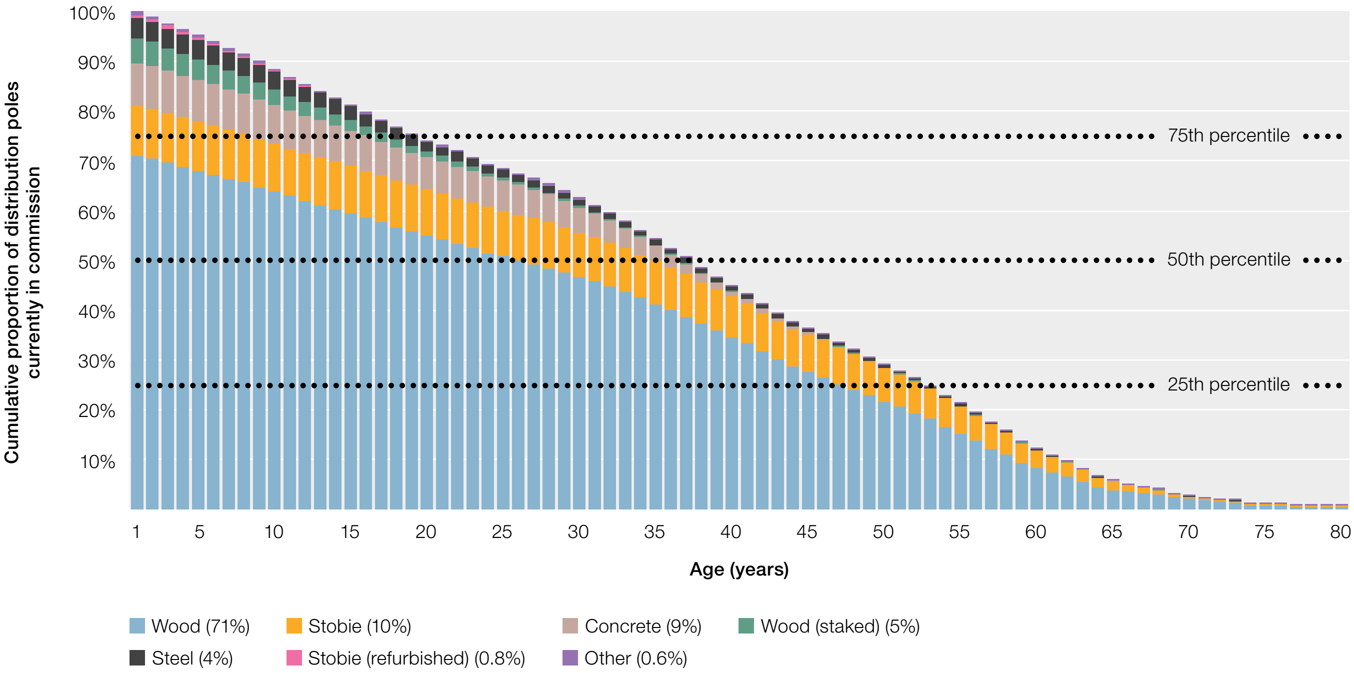


Note: kV: kilovolt.

Source: Category analysis RIN responses.

59 Despite the comparatively strong nature of Stobie poles, the extreme weather event in South Australia in November 2022 severely damaged a number network assets (ABC News, Storm clean-up continues as some northern SA communities lose access to phone services, 14 November 2022, accessed 23 March 2023).

Figure 4.16 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.

4.12 Rates of return

The shareholders and lenders that finance a network service provider expect a commercial 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 4.11) by the allowed rate of return.[60]

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 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 typically make up 30% to 50% of a network service provider's total revenue allowance. A small change in the allowed rate of return can have a significant impact on network revenue and a customer's energy 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%.[61] 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.

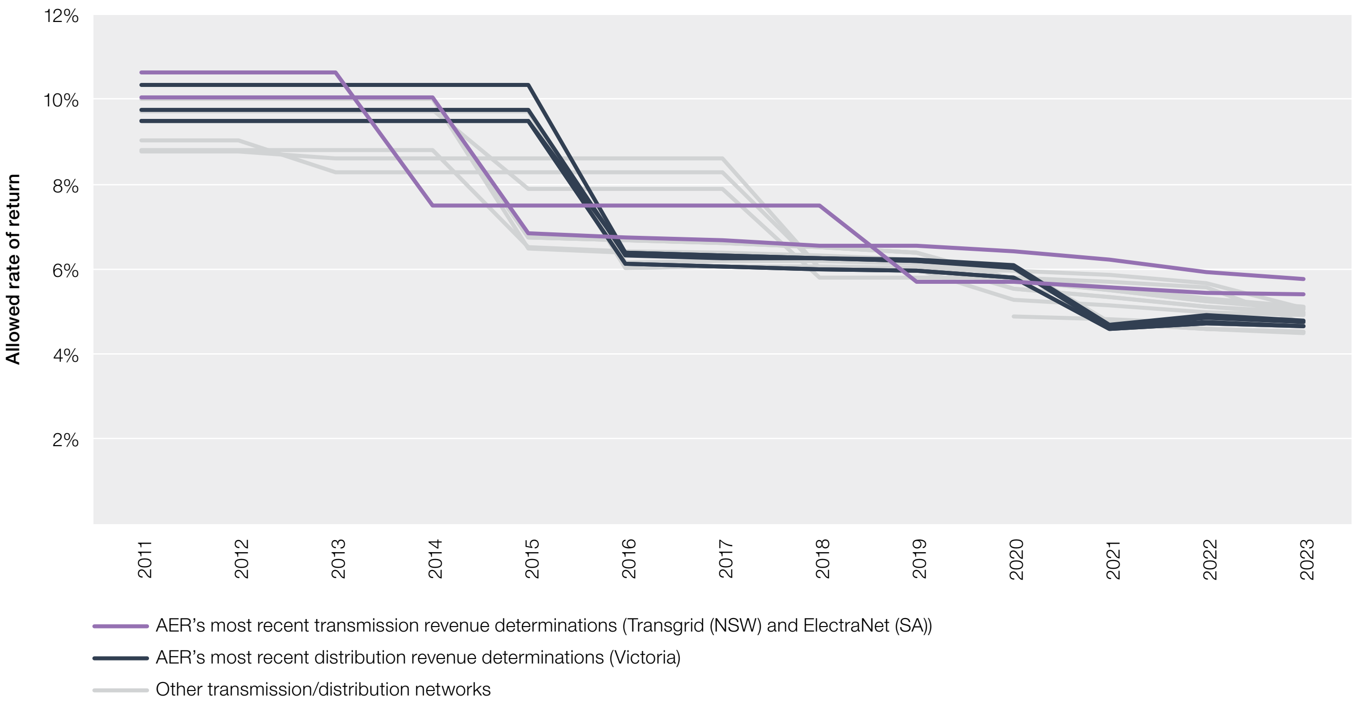
60 For example, if the rate of return is 5% and the RAB is $50 billion, then the return to investors is $2.5 billion. This return forms part of a network service provider's revenue needs and must be paid for by energy customers.

61 Average household bill calculation assumes: $2,000 average household bill, 50% network component (transmission + distribution), ignores demand impacts.

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 (Figure 4.17). The Australian Competition Tribunal increased some allowed rates of return following appeals by the network service providers.

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 4.17).

Figure 4.17 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, some key inputs into rates of return have increased. For example, 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. Annual yields on 10-year CGSs were as low as 0.6% in March 2020, but over 2023 (to mid-July) averaged around 3.6%. Similarly, annual yields on 5-year CGSs were as low as 0.25% in November 2020 but over 2023 (to mid-July) averaged around 3.4%.[62] If risk-free rates, or other key inputs, continue to increase they 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.[63]

In February 2023 the AER released its latest rate of return instrument, which binds all regulatory determinations from 25 February 2023 until the next revision of the Instrument.[64]

62 RBA, Capital Market Yields – Government Bonds – Daily – F2, Reserve Bank of Australia, accessed 14 July 2023.

63 The AER's Electricity network performance reports investigate network profitability and provide a more thorough analysis of actual returns than allowed/forecast returns.

64 AER, Rate of Return Instrument 2022, Australian Energy Regulator, accessed 22 March 2023.

4.13 Investment

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.

4.13.1 Capital expenditure in 2022

In 2022, network service providers outlaid $5.1 billion of investment (capital) expenditure, $605 million (11%) less than in the previous year and $1.2 billion (19%) less than was forecast. This ended a 4-year period of successive increases in network investment.

Table 4.5, Figure 4.18 and Figure 4.19 provides a summary of the capital expenditure outlaid in 2022 and how this compared with previous years' expenditure and forecasts.

Table 4.5 Capital expenditure in 2022 – key outcomes

Service type	Capital expenditure (2022)	Capital expenditure (compared with 2021)	Capital expenditure (compared with peak)
Transmission	$1.2b (▼42% than forecast)	▼$171m (▼12%)	▼$677m (▼35%) (2009)
Distribution	$3.8b (▼8% than forecast	▼$434m (▼10%)	▼$3.7b (▼49%) (2012)
Total	$5.1b (▼19% than forecast)	▼$605m (▼11%)	▼$4.2b (▼45%) (2012)

Note: Excludes AER determinations on transmission interconnectors.

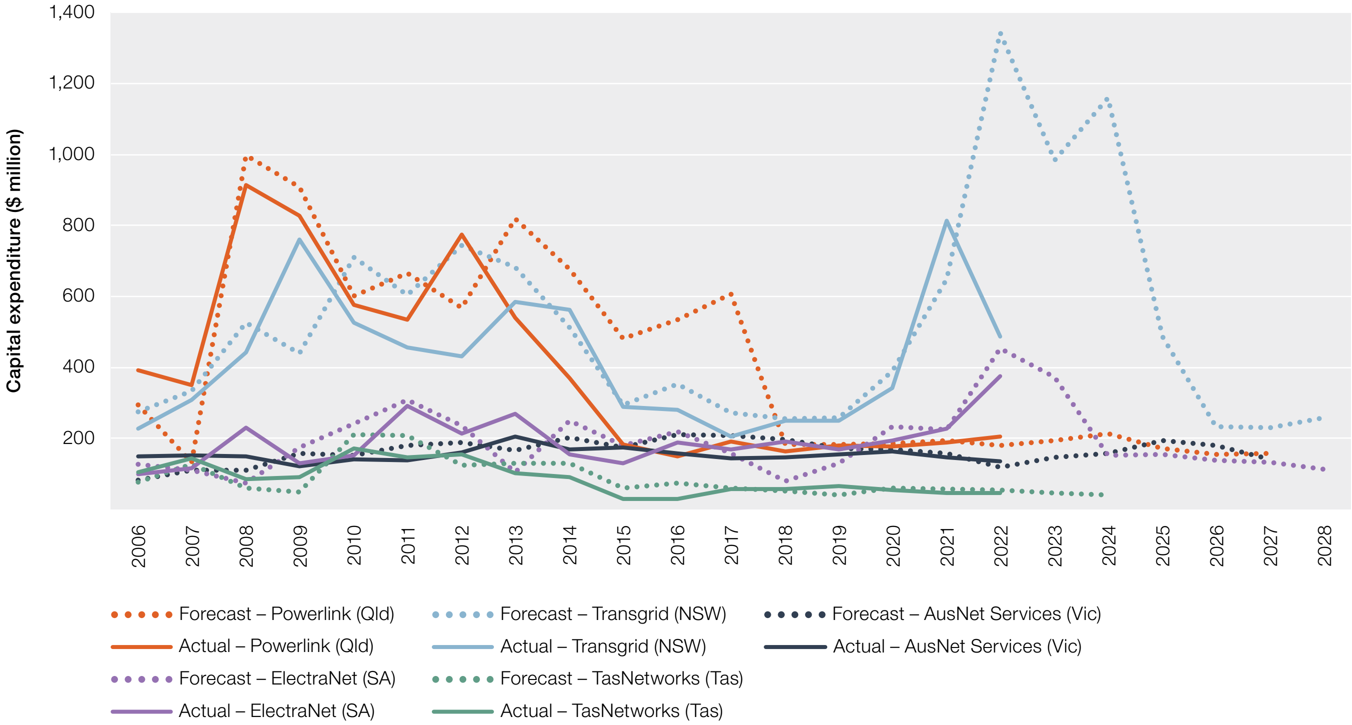
Significant investment in the transmission network is forecast to continue over the next few years (Figure 4.18). Between 2022 and 2026 the modelled cost of actionable Integrated System Plan (ISP) projects under the 2022 ISP – specifically Project EnergyConnect (Transgrid and ElectraNet) and the Queensland–NSW interconnector (QNI) project (Transgrid) – was around $12.7 billion.[65]

Further significant investment is also forecast for Transgrid's HumeLink project – a new 500 kilovolt transmission line that will connect Wagga Wagga, Bannaby and Maragle. Transgrid expects to commence construction on HumeLink in 2024.[66]

65 AEMO, 2022 Integrated System Plan, Australian Energy Market Operator, June 2022, p. 15.

66 Transgrid, HumeLink – fact sheet, accessed 18 September 2023.

Figure 4.18 Capital expenditure – electricity transmission networks

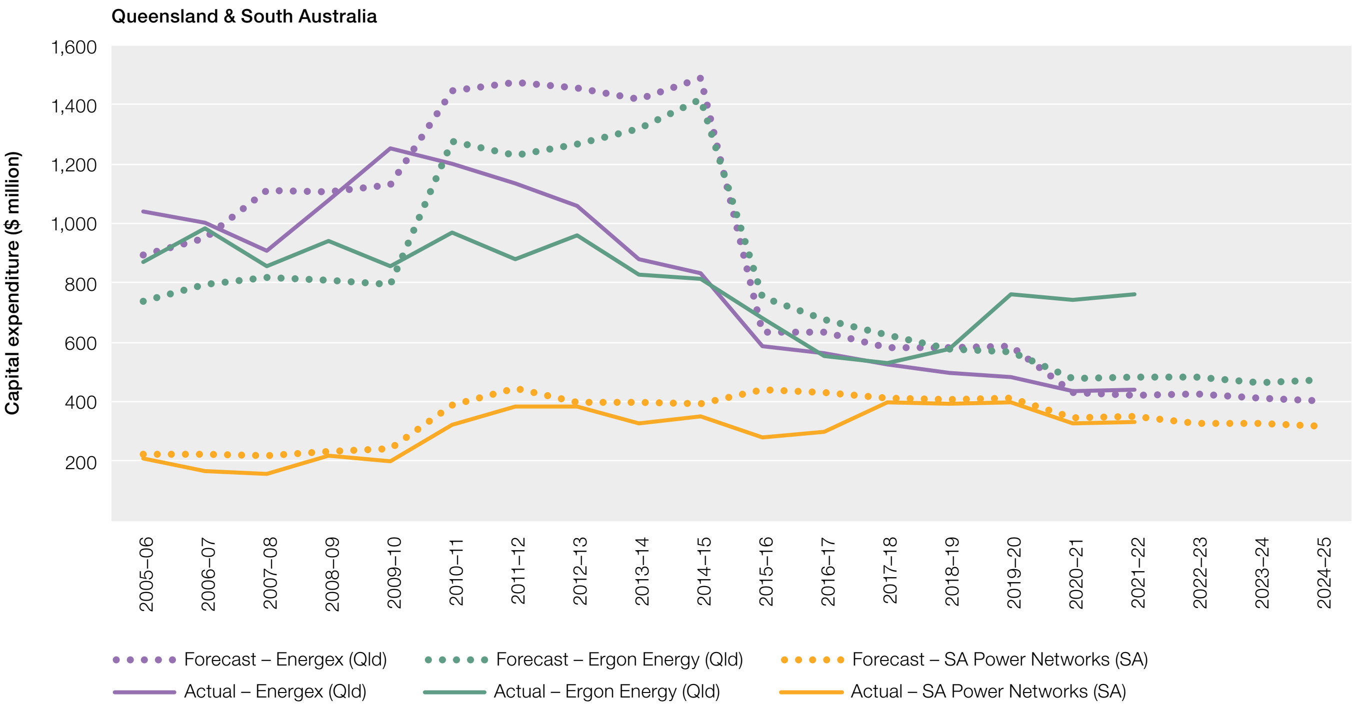


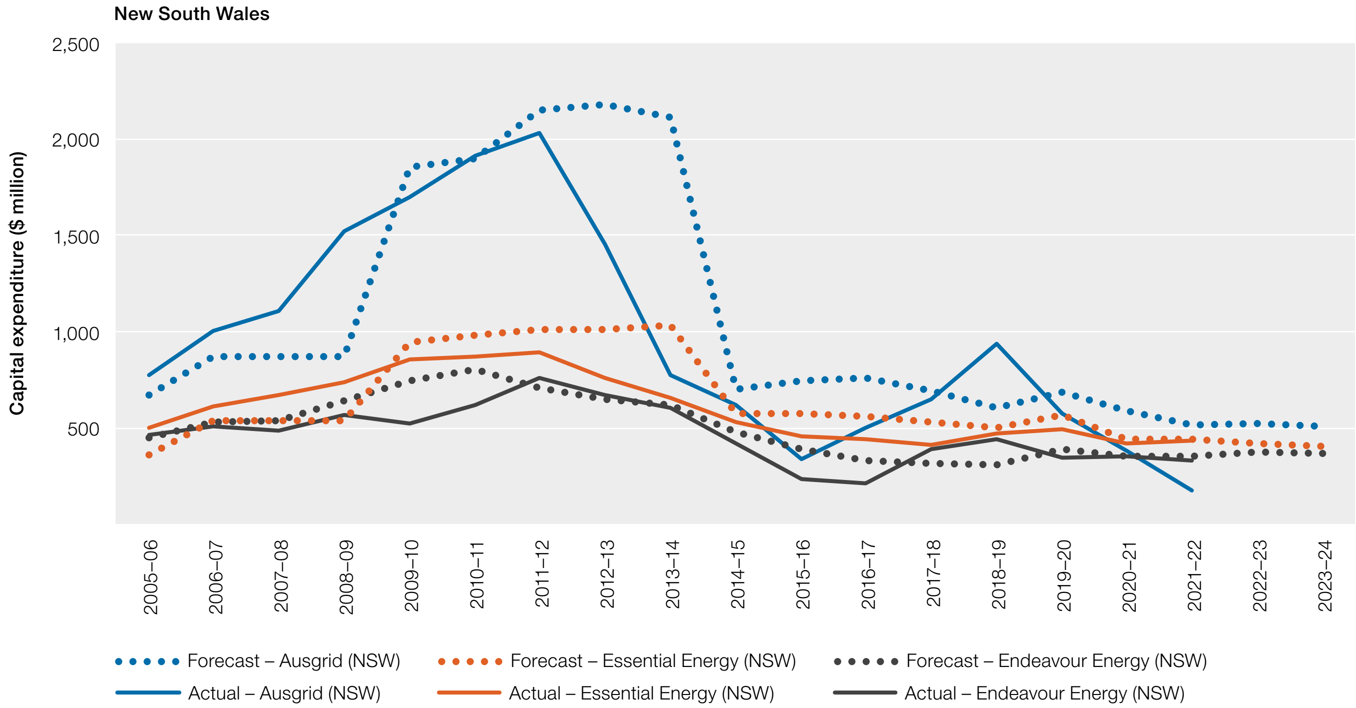
Note: All data are adjusted to June 2022 dollars. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Assumptions are set out in the Figure 4.7 notes.

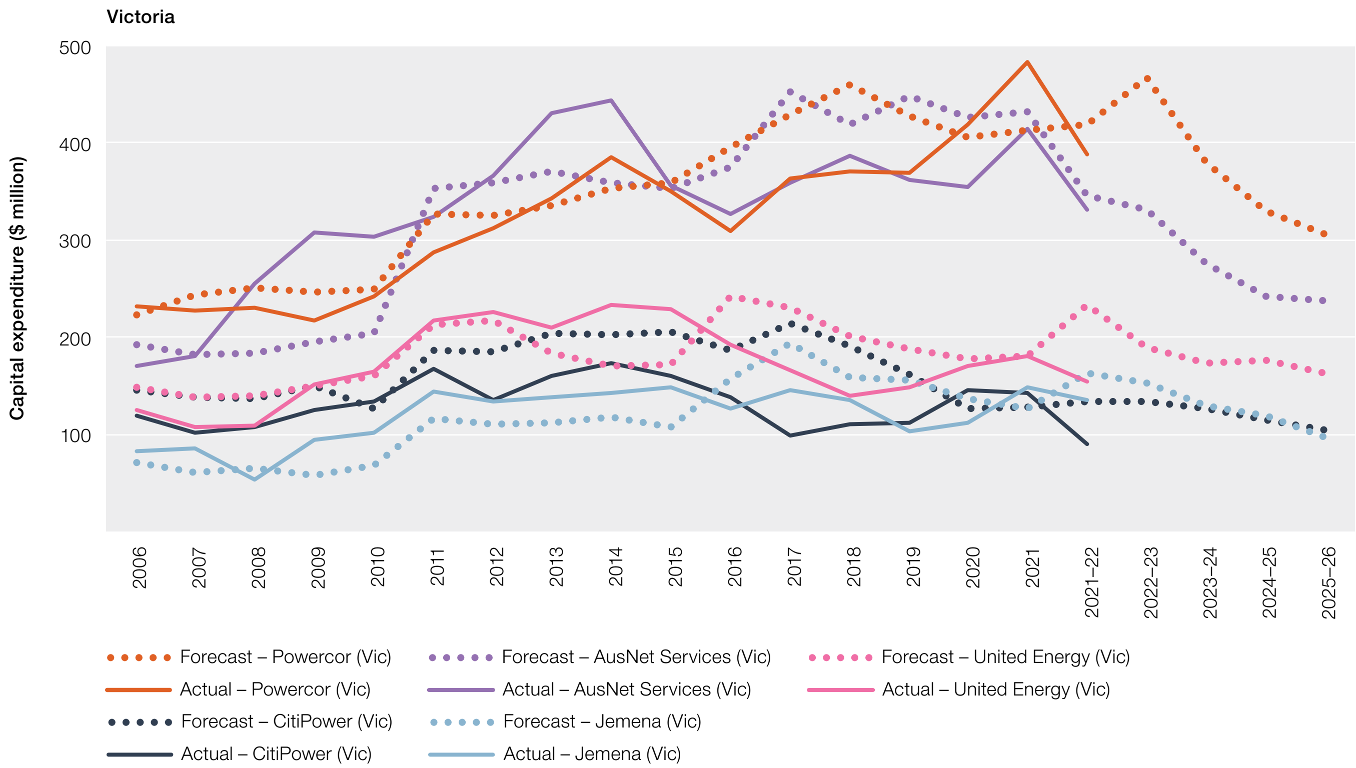
Source: AER modelling; annual reporting RIN responses.

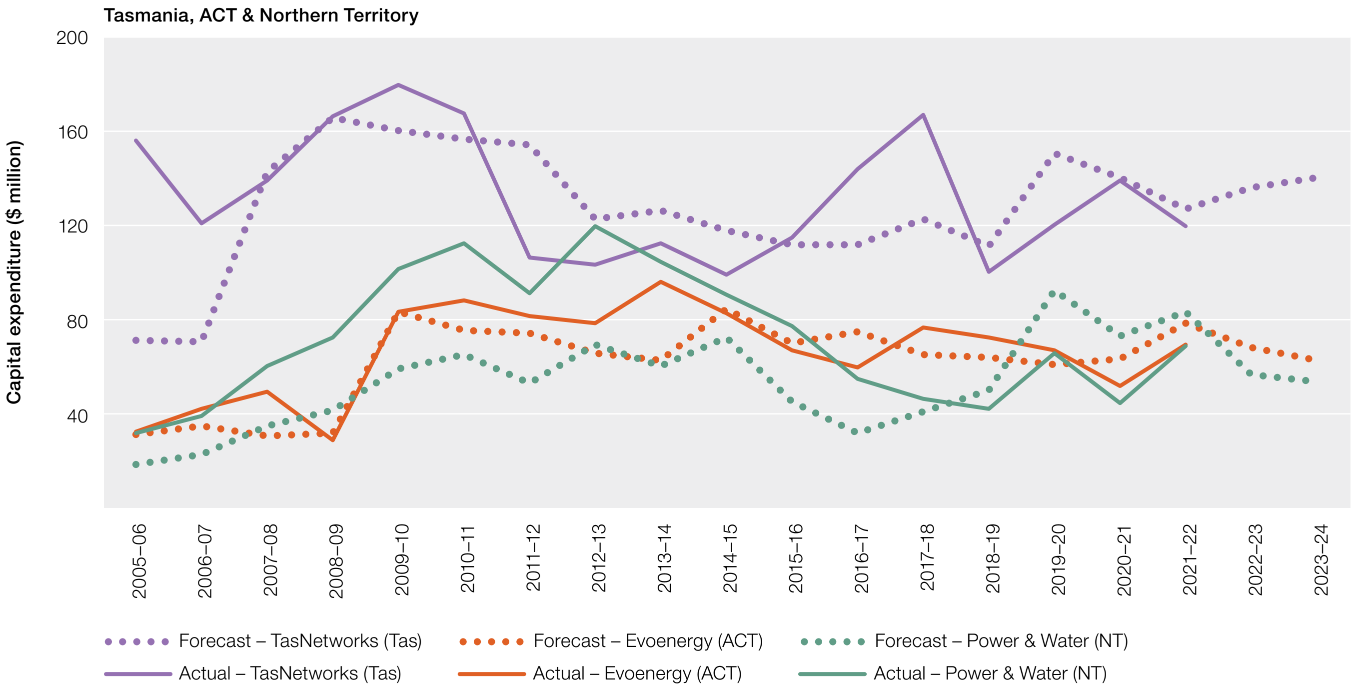
Forecast capital expenditure increased for both Transgrid (NSW) and ElectraNet (South Australia) in 2022 primarily due to the forecast costs associated with Project EnergyConnect. However, Transgrid's actual capital expenditure was significantly lower than forecast due in large part to its reprofiling of expenditure on Project EnergyConnect.

Figure 4.19 Capital expenditure – electricity distribution networks




New South Wales
Capital expenditure ($ million)
2,500
2,000
1,500
1,000
500
2005–06
2006–07
2007–08
2008–09
2009–10
2010–11
2011–12
2012–13
2013–14
2014–15
2015–16
2016–17
2017–18
2018–19
2019–20
2020–21
2021–22
2022–23
2023–24
Forecast – Ausgrid (NSW)
Actual – Ausgrid (NSW)
Forecast – Essential Energy (NSW)
Actual – Essential Energy (NSW)
Forecast – Endeavour Energy (NSW)
Actual – Endeavour Energy (NSW)


Victoria
Capital expenditure ($ million)
500
400
300
200
100
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2021–22
2022–23
2023–24
2024–25
2025–26
Forecast – Powercor (Vic)
Actual – Powercor (Vic)
Forecast – CitiPower (Vic)
Actual – CitiPower (Vic)
Forecast – AusNet Services (Vic)
Actual – AusNet Services (Vic)
Forecast – Jemena (Vic)
Actual – Jemena (Vic)
Forecast – United Energy (Vic)
Actual – United Energy (Vic)



Note: All data are adjusted to June 2022 dollars. In July 2021, Victorian distribution network service providers transitioned from reporting on a calendar year basis to a financial year basis. Assumptions are set out in the Figure 4.9 notes.

Source: AER modelling; annual reporting RIN responses.

Ergon Energy (Queensland) submitted that its substantial overspends in 2021 and 2022 were due to the need to address priority network safety and defect rectification programs, including defect rectifications and remediation works.[67]

4.13.2 Investment trends

Total investment in the electricity networks increased by an average of 8% per year from 2006 to 2012, when it peaked at $9.3 billion (Figure 4.7 and Figure 4.9).

In the 4-year period from 2006 to 2009, network service providers invested $2.6 billion (11%) more on capital projects than was forecast. However, this trend of overspending was soon to be reversed, with service providers underspending by $13.6 billion (18%) against forecast over the following 9 years (from 2010 to 2018) (Figure 4.20).

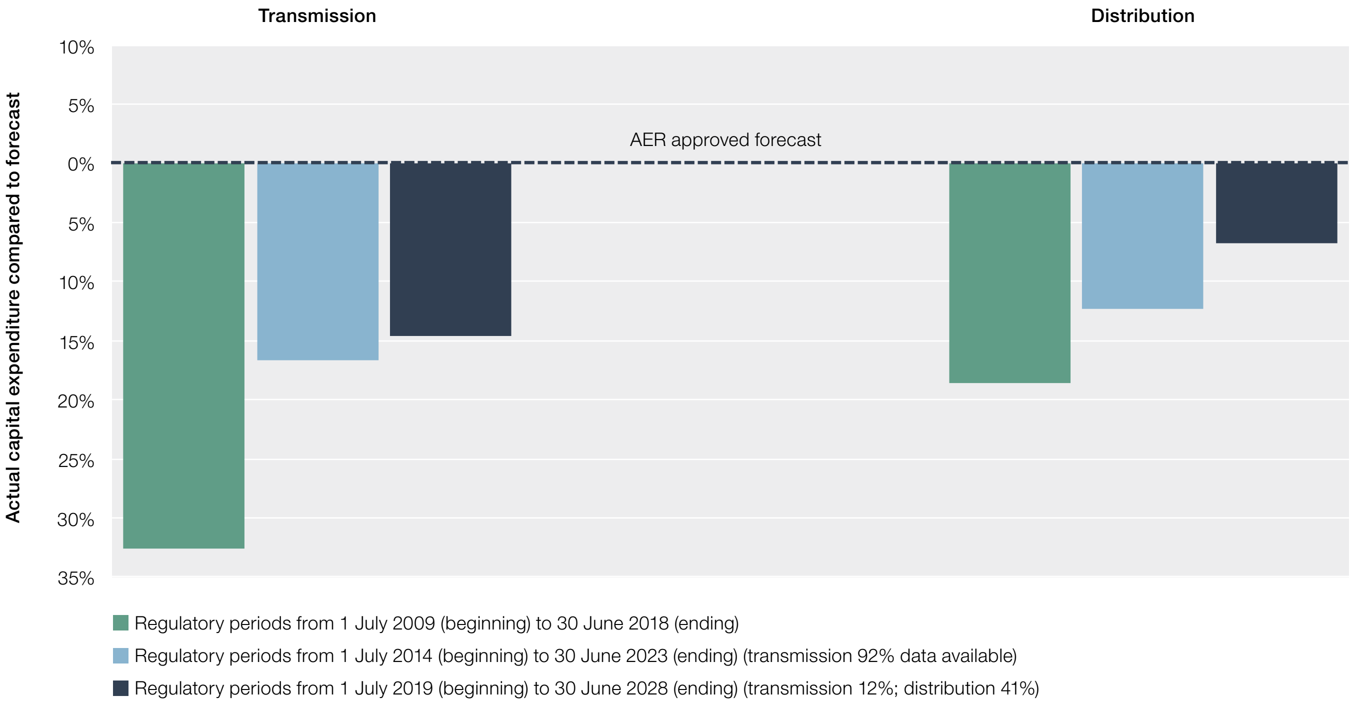
The disparity between forecast and actual investment has eased in recent years. This timing aligns with the AER's reforms to protect consumers from funding inefficient network projects (Figure 4.20).

Over the 5 years from 2013 to 2017, network service providers invested $10.2 billion (25%) less on capital projects than was forecast. In comparison, over the past 5 years (from 2018 to 2022), service providers invested $1.7 billion (6%) less than was forecast. The service providers reporting the most significant underspends over this period were NSW transmission network Transgrid, and the Power and Water (Northern Territory) and United Energy (Victoria) distribution networks, which collectively underspent by 24%.

As previously mentioned, both Transgrid's and ElectraNet's (South Australia) actual capital expenditure was considerably lower than forecast in 2022 primarily due to a reprofiling of expenditure on Project EnergyConnect.

67 Ergon Energy, 2021–22 Annual reporting RIN, 31 October 2022.

Figure 4.20 Capital expenditure against forecast



Source: AER modelling; annual reporting RIN responses.

The AER assesses capital expenditure drivers when forming its view on the prudency 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, the network service providers are required to undertake a cost-benefit analysis for new investment projects that meet cost thresholds.

In the AER's most recent revenue determinations, the most significant driver of forecast investment expenditure was the replacement of assets that are reaching the end of their life, and 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 4.2).

Box 4.2 Capital expenditure sharing scheme

The AER's capital expenditure sharing scheme (CESS) incentivises network service providers to keep new investment within the forecast levels approved in their regulatory determination. 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 following 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, the AER conducts an ex-post review of the network service provider's spending. Approved capital expenditure is added to the regulatory asset base (RAB) (section 4.11). However, if a service provider overspends its capital allowance, and the AER finds 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 its 2023 review of incentive schemes[a] the AER elected to amend the CESS and implement the Bright-Line Tiered Test. This will 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 has been designed to be asymmetric. Despite improvements in the AER's capital expenditure assessment toolkit and stakeholder engagement, a level of information asymmetry between the regulator, consumers and the network service providers remains. The scheme poses risks that network service providers may inflate their original investment forecasts. To manage this risk, the AER assesses 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 4.3) and service quality (Box 4.4). 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 4.16.1).

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

The changes to the CESS are supplemented by new 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.

a AER, Review of incentive schemes for regulated networks, Australian Energy Regulator, accessed 3 May 2023.

4.13.3 Changing composition of investment

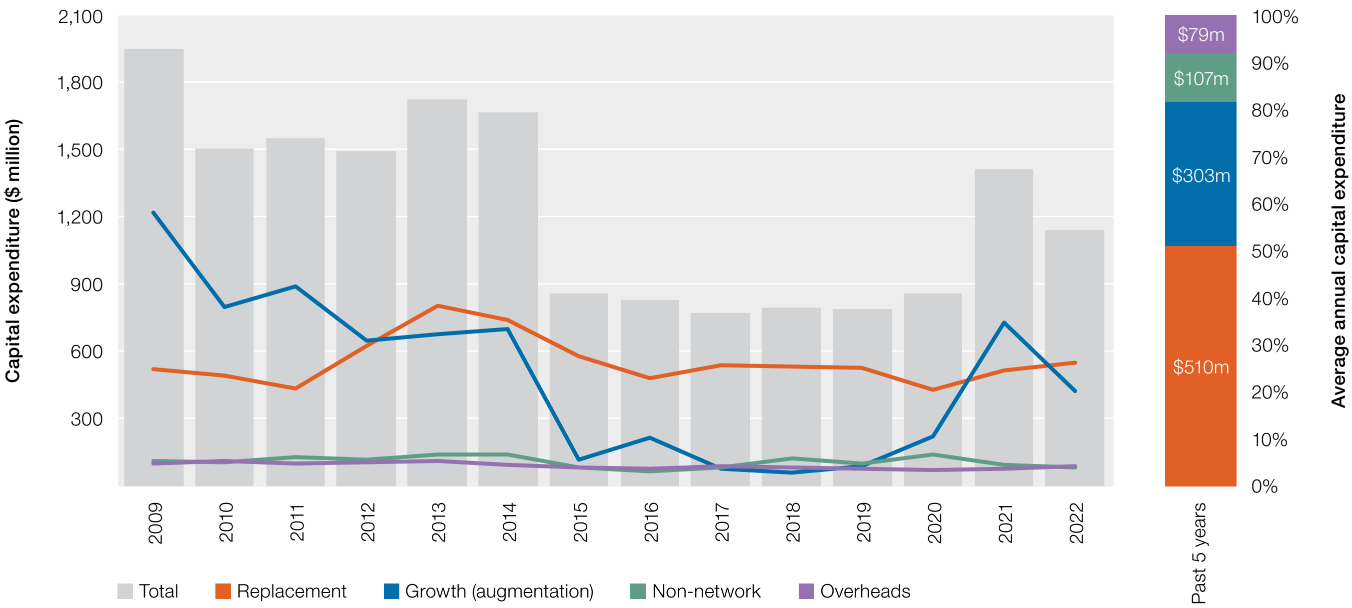
Over the last decade, network investment has been driven by replacement expenditure rather than growth-related expenditure (Figure 4.21 and Figure 4.22). Weaker than forecast demand for electricity, along with less stringent reliability obligations, led many network owners to postpone or abandon growth-related projects.

In 2022, network service providers invested $1.3 billion in growth-related projects, $215 million (14%) less than in the previous year but 30% more than the average spend from 2016 to 2020. The recent increase in growth-related expenditure has primarily been the result of Transgrid's (NSW) substantial investment in Project EnergyConnect, which aims to link up NSW and South Australia by 2024. As at May 2023, construction of ElectraNet's South Australian section of Project EnergyConnect was more than 50% complete and on track to be fully capable by mid-2026.[68]

Transgrid has also forecast substantial investment in developing HumeLink, which aims to connect Snowy 2.0 to the grid by 2026. In May 2023, Snowy Hydro announced it anticipates the timeline for full commercial operation of Snowy 2.0 will be delayed by until December 2028 at the earliest.[69]

Replacing existing assets continues to be the primary driver of capital expenditure for distribution networks, but growth-related expenditure is now also a significant driver for transmission networks.

Figure 4.21 Drivers of capital expenditure – electricity transmission networks (aggregate)



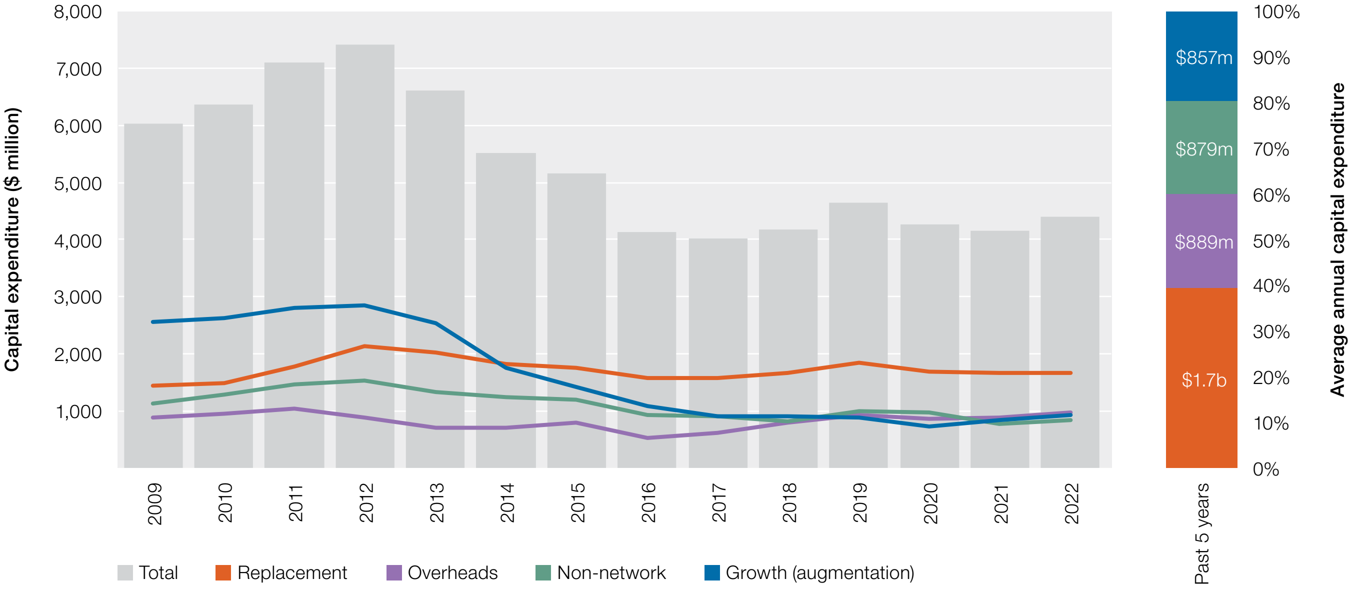
Note: All data are adjusted to June 2022 dollars. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Augmentation of the Victorian transmission network is carried out by AEMO; hence, AusNet Services reports $0 expenditure for augmentation carried out on the transmission network.

Source: Category analysis RIN responses.

68 *pv magazine*, ElectraNet tips interstate transmission link to be online by mid-2026, 8 May 2023.

69 Snowy Hydro, Snowy 2.0 – Project update, media release, Snowy Hydro, 3 May 2023.

Figure 4.22 Drivers of capital expenditure – electricity distribution networks (aggregate)



Note: All data are adjusted to June 2022 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.

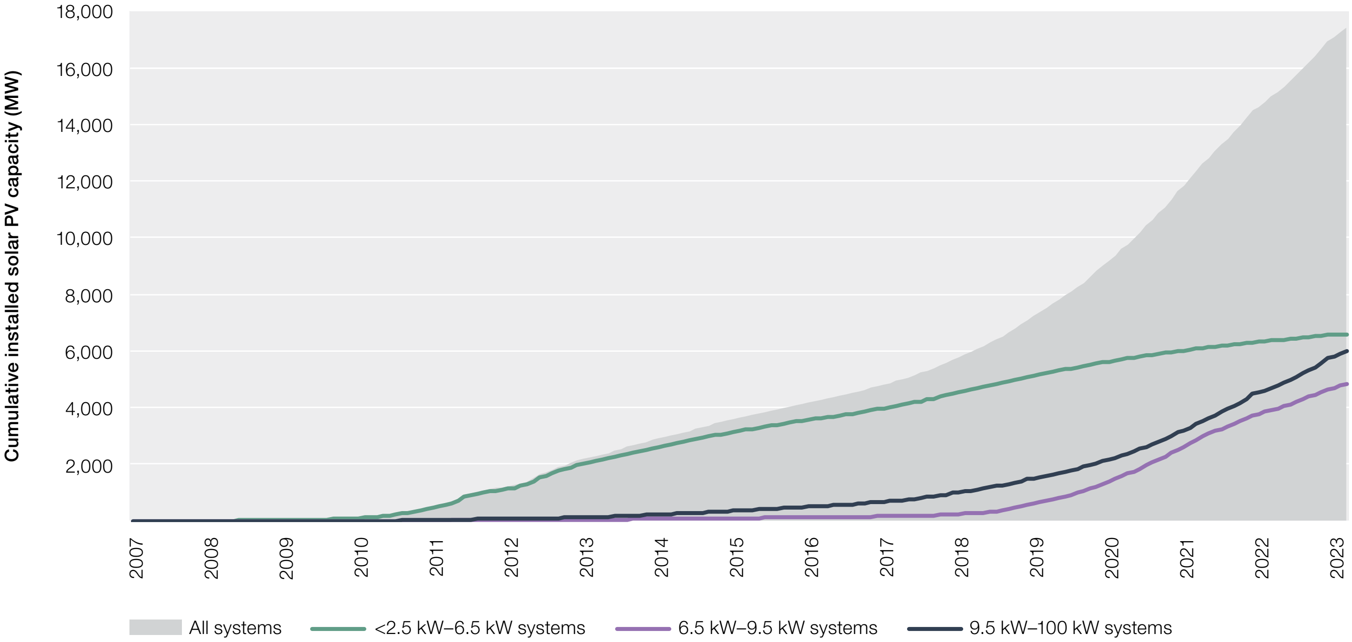
4.13.4 Valuing consumer energy resources

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 (CER) such as solar PV, batteries and electric vehicles now presents a significant, emerging area of expenditure.

Solar PV costs have decreased over time, which means it is now more affordable for consumers to install a larger system to cover a higher proportion of their energy consumption. Over the 3 years to 1 March 2023, the total installed capacity of smaller solar PV systems with a capacity of up to 6.5 kilowatts increased by 16%, while the total installed capacity of systems with a larger capacity of 6.5 to 100 kilowatts increased by 179% (Figure 4.23).[70]

70 Excludes Western Australia.

Figure 4.23 Cumulative installation of small-scale solar by system size



Note: kW: kilowatts; MW: megawatts; 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 2 June 2023.

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 of consumer energy resources 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.[71] 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.[72]

The AEMC, in its *Electricity network economic regulatory framework 2020 review*, noted that the central roles of networks in a future with high levels of consumer energy resources are likely to remain the same as today. Network service providers will continue to be responsible for transporting electricity and providing a safe, secure and reliable supply of electricity as a monopoly service provider. However, how they undertake this role could differ in several key respects. In particular, how the electricity distribution network is operated and the services provided by distribution network service providers could change.

An environment with high levels of consumer energy resources could mean that distribution network service providers need to alter aspects of their operation – from transporting electricity one-way to being platforms for multiple services, facilitating electricity flows in multiple directions and enabling efficient access for consumer energy resources so that they can provide the greatest benefits to the system as a whole. This change is likely to have implications for some features of the current regulatory framework.[73]

71 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.

72 AER, Draft DER integration expenditure guidance note, Australian Energy Regulator, 6 July 2021.

73 AEMC, Electricity network economic regulatory framework 2020 review, Australian Energy Market Commission, 1 October 2020.

In April 2023, the AER released its consumer energy resources strategy, which communicates its goal to enable 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. The strategy also provides an overview of how the various AER workstreams fit together holistically to achieve the goal.[74]

4.13.5 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 $7 million and for distribution projects that have an estimated capital cost of greater than $6 million.

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

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).

Until 2017 the regulatory test only applied to growth related investment, which had been the most significant component of network investment until 2014. Replacement expenditure has since overtaken growth investment on most networks (section 4.13.3); as such, the test now also applies to replacement projects. Other revisions were made to the test to ensure it adequately considers system security, emissions reduction goals and low probability events that would have a high impact.

In 2020 the AER published guidelines that prescribe the cost benefit analysis framework, consultation processes and forecasting practices that the Australian Energy Market Operator (AEMO) must apply when developing its Integrated System Plan (ISP). AEMO's 2022 ISP brought into effect the AER's guidelines to make the ISP actionable.[75] The guidelines include a cost-benefit analysis guideline[76], a forecasting best practice guideline and updates to the regulatory investment test for transmission (RIT-T) instrument[77] and application guidelines.[78] The guidelines are part of broader reforms that were led by the Energy Security Board (ESB), with changes made to the National Electricity Rules to streamline the transmission planning process while retaining rigorous cost-benefit analyses.

In August 2023, the AER published a report detailing the outcomes of its transparency review of AEMO's Inputs, Assumptions and Scenarios Report (IASR).[79] The IASR contains the inputs, assumptions and scenarios that AEMO proposes to use in its 2024 ISP. The AER assessed the adequacy of AEMO's explanation of how the inputs, assumptions and scenarios had been derived. The review is not intended to assess the merits of AEMO decisions, rather to form an opinion on the adequacy of AEMO's explanations.

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

74 AER, Consumer energy resources strategy, Australian Energy Regulator, 3 April 2023.

75 AER, Final decision – guidelines to make the Integrated System Plan actionable, Australian Energy Regulator, August 2020.

76 AER, Cost benefit analysis guidelines, Australian Energy Regulator, August 2020.

77 AER, Application guidelines – regulatory investment test for transmission, Australian Energy Regulator, August 2020.

78 AER, Guidelines to make the integrated system plan actionable, Australian Energy Regulator, August 2020, accessed 29 March 2022.

79 AER, Transparency review of AEMO 2023 Inputs, Assumptions and Scenarios Report, Australian Energy Regulator, accessed 31 August 2023.

4.13.6 AEMO's Integrated System Plan

AEMO's ISP provides a coordinated whole-of-system plan for efficient development of the power system in the National Electricity Market (NEM) to ensure needs are met in the long-term interests of consumers.

The ISP 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. AEMO identifies the network investments that are likely to optimise the net market benefits across future NEM development scenarios over the planning horizon as the optimal development path for the NEM.

The optimal development path includes 'actionable' ISP projects and future ISP projects, which can be progressed through the RIT-T process. It also identifies future ISP development opportunities such as distribution assets, storage or demand-side developments.

Significant investment in the transmission network is forecast over the next few years. The modelled cost of actionable ISP projects under the 2022 ISP was around $12.7 billion.[80]

In September 2023, AEMO provided an update to the 2022 ISP cost estimates to reflect supply chain constraints and global competition for electricity infrastructure assets.[81]

AEMO has prepared a new transmission cost forecasting approach for the 2024 ISP, which is due to be published in June 2024. AEMO's new cost forecasting approach has been developed in response to unprecedented cost increases across the sector in recent years. A key change in AEMO's new approach is the application of additional escalation factors for individual cost components – such as commodity prices (oil, aluminium, copper and steel) and land cost – beyond the economy-wide inflation rate.

As a result of AEMO's updated approach, project cost estimates are, depending on scope, approximately 30% higher (in real terms) than in the 2022 ISP.[82] AEMO expects transmission project costs will continue to increase beyond the rate of inflation while the sector adapts to markets pressures driven by the global race to net zero.

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 guidelines[83] and cost-benefit analysis guidelines.[84] 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.[85]

A 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 4.24 provides a visual summary of AEMO's 2022 ISP along with transmission expansion options that will inform the development of the 2024 ISP. Figure 4.24 also shows several of the smaller ISP projects that have been completed since the 2022 ISP was published, including:

- the QNI Minor interconnection upgrade
- the VNI Minor interconnection
- the Eyre Peninsula link.[86]

80 AEMO, 2022 Integrated System Plan, Australian Energy Market Operator, June 2022, p. 15.

81 AEMO, 2023 Transmission Expansion Options Report, Australian Energy Market Operator, September 2023.

82 AEMO, 2023 Transmission Expansion Options Report, Australian Energy Market Operator, September 2023, pp. 27–28.

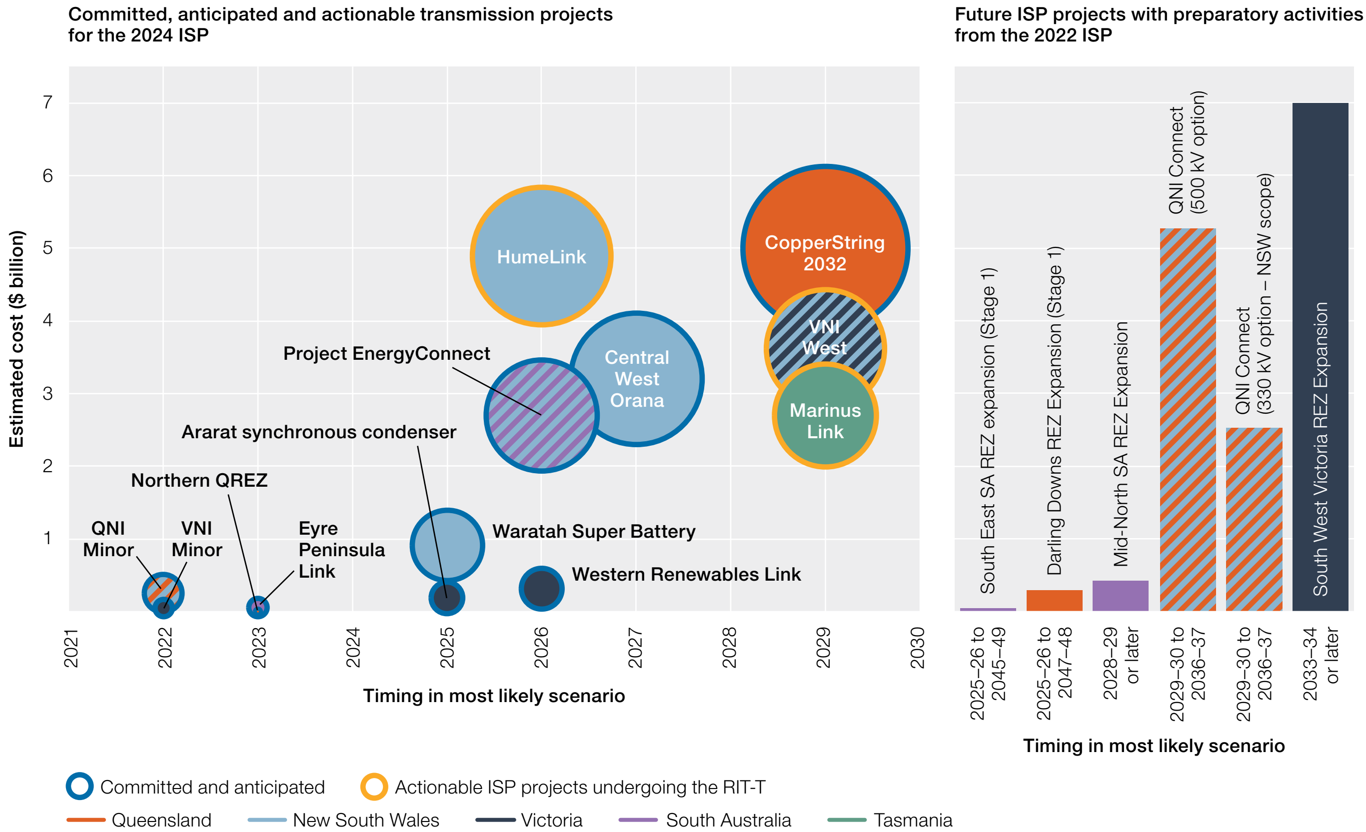
83 AER, Forecasting best practice guidelines, Australian Energy Regulator, August 2020.

84 AER, Cost benefit analysis guidelines, Australian Energy Regulator, August 2020.

85 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.

86 Transgrid, Queensland NSW Interconnector, June 2022; Transgrid, Victoria to NSW Interconnector, November 2022; ElectraNet, New transmission line powering the Eyre Peninsula, March 2023.

Figure 4.24 AEMO's integrated system plan



Note: Committed projects meet 5 criteria relating to planning consents, construction commencement, land acquisition, contracts for supply and construction of equipment and necessary financing arrangements. Anticipated projects are in the process of meeting at least 3 of the criteria. Data used to show the estimate costs of future ISP projects with preparatory activities was provided to AEMO by the transmission network service providers. Preparatory activities are intended to improve the conceptual design, lead time, location and cost estimates for transmission projects. The ISP may require preparatory activities for some future ISP projects. Future ISP projects are projects which address an identified need, form part of the optimal development path, and may be actionable ISP projects in the future.

Source: AER analysis, AEMO integrated system plan, June 2022, AEMO Transmission Expansion Options Report, September 2023.

4.13.7 Regulatory tests – recent activity

As at September 2023, 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.[87]

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.[88]

87 Victorian Government, VNI West and Western Renewables Link Ministerial Order, Victorian Government Gazette, 20 February 2023

88 AER, AEMO Victoria Planning and Transgrid: VNI West PACR, Australian Energy Regulator, 21 June 2023.

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 September 2023, the Tasmanian and Australian governments made a number of amendments to the existing Marinus Link agreement including:[89]

- focusing on delivering one cable initially, with subsequent consideration of a second cable to be considered at a later date
- working towards a delivery time frame as close as possible to 2028
- increasing the Australian Government's share of the funding to 49%, Tasmania's share decreasing to approximately 18% and Victoria's share remaining at 33%.

HumeLink

Transgrid (NSW) completed a RIT-T for HumeLink, a proposed 500 kilovolt transmission upgrade connecting Project EnergyConnect and Snowy 2.0 to Bannaby in southern NSW.

On 17 August 2022, the AER accepted Transgrid's HumeLink first part of stage 1 contingent project application of $71.5 million in revenue, paid by energy consumers, to deliver proposed early works for the HumeLink project.[90]

On 23 May 2023, Transgrid submitted the second part of its stage 1 contingent project application to seek $226.7 million in revenue for the procurement of equipment. Transgrid will submit a second stage contingent project application to the AER by the end of 2023, seeking to recover revenue for project implementation costs once the project has been committed to and a final cost estimate is available.

The AER's role is to review the reasonableness of the proposed costs within the stage 1 part 2 application to ensure consumers pay no more than necessary.

New England REZ Transmission Link and Sydney Ring

The 2 remaining actionable projects identified under the 2022 ISP are the NSW New England REZ Transmission Link and the Sydney Ring project.[91] These 2 projects will progress under the *Electricity Infrastructure Investment Act 2020* (NSW) rather than the ISP framework, so RIT-T processes are not expected for these projects.

4.13.8 Annual planning reports

Network service providers must publish annual planning reports identifying new investments that 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.[92] This results in network service providers providing data on geographic constraints to assist third parties in offering non-network solutions and to inform connection decisions at the transmission level.[93]

4.13.9 Demand management

Network service providers have options to manage demand on their networks to reduce, delay or avoid the need to install or upgrade expensive network assets. Managing demand in this way can minimise network charges. It can also increase the reliability of supply and reduce wholesale electricity costs.

89 Australian Government and Tasmanian Government, Joint media release, Investing in the future of Tasmanian energy with Marinus Link, 5 September 2023.

90 AER, Transgrid – HumeLink contingent project – Stage 1 part 2, Australian Energy Regulator, 23 May 2023.

91 AEMO, 2022 Integrated System plan, Australian Energy Market Operator, June 2022.

92 AER, Final decision: Distribution annual planning report template v.1, Australian Energy Regulator, June 2017; AER, Final decision: Transmission annual planning report guidelines, Australian Energy Regulator, December 2018.

93 For an example of the constraint data available, see the datasheets under Ausgrid, Distribution and transmission annual planning report and data map, accessed 28 July 2022.

The AER offers incentives for distribution 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 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 distribution 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.

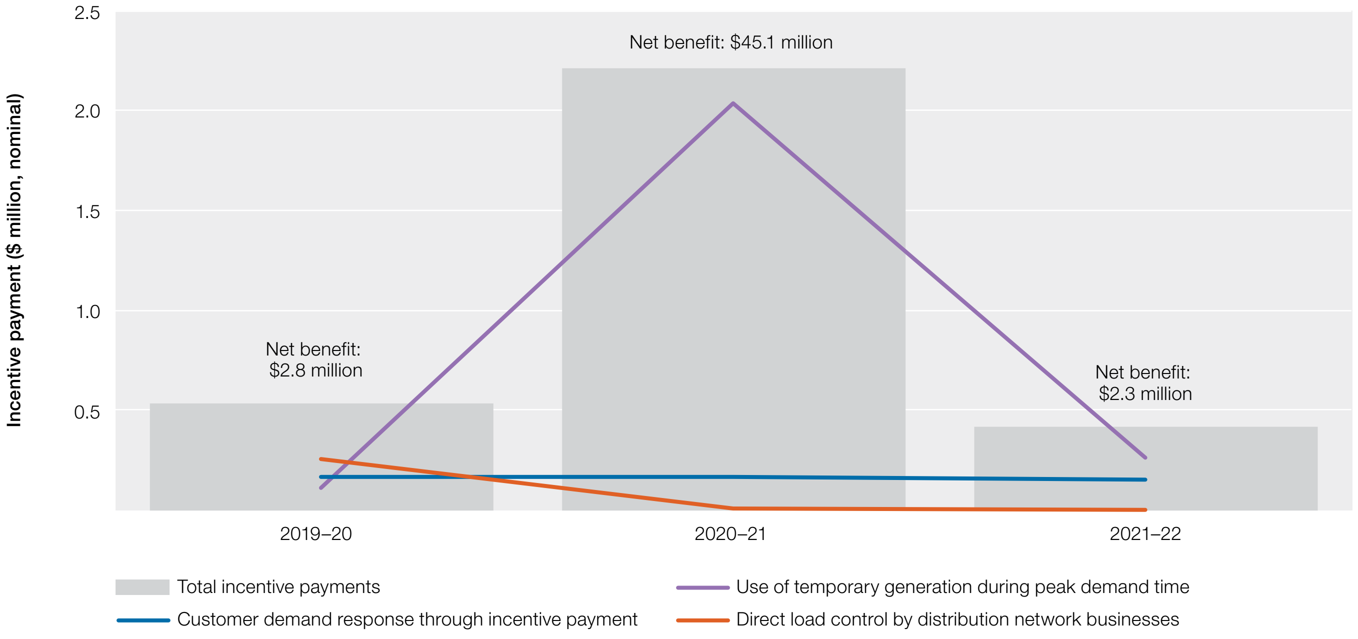
To receive an incentive payment, the network service provider must first submit a claim for its eligible projects[94] to the AER and provide information on how it is using demand management to deliver value to their customers. The AER uses the information provided to determine if the network service provider is eligible to receive an incentive payment.

Complementing this scheme, the AER operates a demand management innovation allowance mechanism (DMIAM).[95] [96] The DMIAM provides funding for network service providers to undertake research and development works to help them to develop innovative ways to deliver ongoing reductions in demand or peak demand for network services. A key 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 service providers appropriately use their funding. Any underspent or unapproved spending is returned to customers through revenue adjustments.

To date, the DMIS has delivered an estimated $50 million in benefits to consumers (at a cost of $3.2 million) by encouraging distribution service providers to defer replacement or augmentation capital expenditure in favour of pursuing demand management activities (Figure 4.25).[97]

Figure 4.25 Funding of demand management innovations – electricity distribution networks



Source: AER, Demand management incentive scheme (DMIS) assessment 2020–21 and 2021–22.

94 Eligible projects are set out in the AER's revenue determinations for each network service provider.

95 AER, Demand management incentive scheme and innovation allowance mechanism, Australian Energy Regulator, 14 December 2017.

96 AER, Demand management innovation allowance mechanism (transmission), Australian Energy Regulator, 27 May 2021.

97 For further information on the demand management incentive scheme see the reports published by the AER on Demand management incentive scheme (DMIS).

4.14 Operating costs

Network service providers incur operating and maintenance costs that account for around 35% of their annual revenue (Figure 4.5). As part of its 5-year regulatory review, the AER sets an allowance for each network service provider to recover the efficient 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 is guided by the forecasts in each network service provider's regulatory proposal. However, if the AER considers the proposed forecasts to be unreasonable then it may replace them with its own forecasts.

Alongside this assessment, the AER's efficiency benefit sharing scheme (EBSS) encourages network service providers to explore opportunities to lower their operating costs (Box 4.3).

Box 4.3 Efficiency benefit sharing scheme

The AER's 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. Efficiency gains occur if a network service provider spends less on operating and maintenance than forecast in its regulatory determination. Conversely, an efficiency loss occurs if the service provider spends more than forecast.

The regulatory framework allows a network service provider to keep the benefit (or incur the cost) if its actual operating expenditure is lower (higher) than forecast in each year of a regulatory period. The EBSS then allows a network service provider to keep those benefits (or incur those costs) for an additional period. 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 (Box 4.2). The EBSS incentives also balance against those of the service target performance incentive scheme (Box 4.4) to encourage network service providers to make efficient holistic choices between capital and operating expenditure in meeting reliability and other targets.

When the AER released the capital expenditure incentive guideline and EBSS in 2013[a] it estimated around 70% of the benefits from the EBSS would go to customers. In retrospect, customers have received closer to 80% of the benefits, due in large part to the impact the changes in rate of return parameters have had on network service providers.

Following its 2023 review of incentive schemes[b] the AER decided to retain the EBSS in its current format. AER analysis shows 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.

a AER, Expenditure incentives guideline, Australian Energy Regulator, accessed 30 May 2023.

b AER, Review of incentive schemes for regulated networks, Australian Energy Regulator, accessed 3 May 2023.

4.14.1 Operating expenditure in 2022

In 2022, network service providers spent $3.7 billion on operating costs, $46 million (1.2%) less than in the previous year.

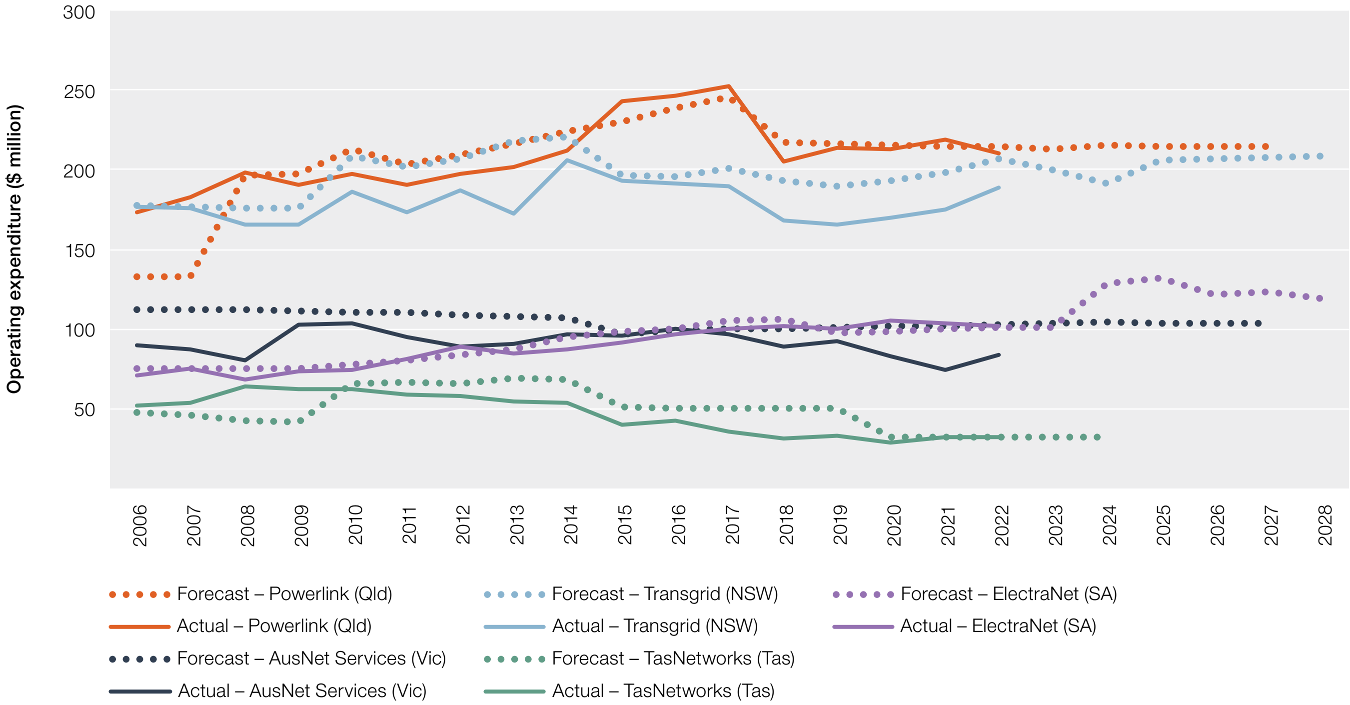
Table 4.6, Figure 4.26 and Figure 4.27 provide a summary of the operating expenditure outlaid in 2022 and how this compared with previous years' expenditure and forecasts.

Table 4.6 Operating expenditure in 2022 – key outcomes

Service type	Operating expenditure (2022)	Operating expenditure (compared with 2021)	Operating expenditure (compared with peak)
Transmission	$617m (▼6% than forecast)	▲$12m (▲2%)	▼$60m (▼9%) (2016)
Distribution	$3.0b (▼10% than forecast)	▼$58m (▼1.9%)	▼$836m (▼22%) (2012)
Total	$3.7b (▼9% than forecast)	▼$46m (▼1.2%)	▼$840m (▼19%) (2012)

Note: Excludes AER determinations on transmission interconnectors.

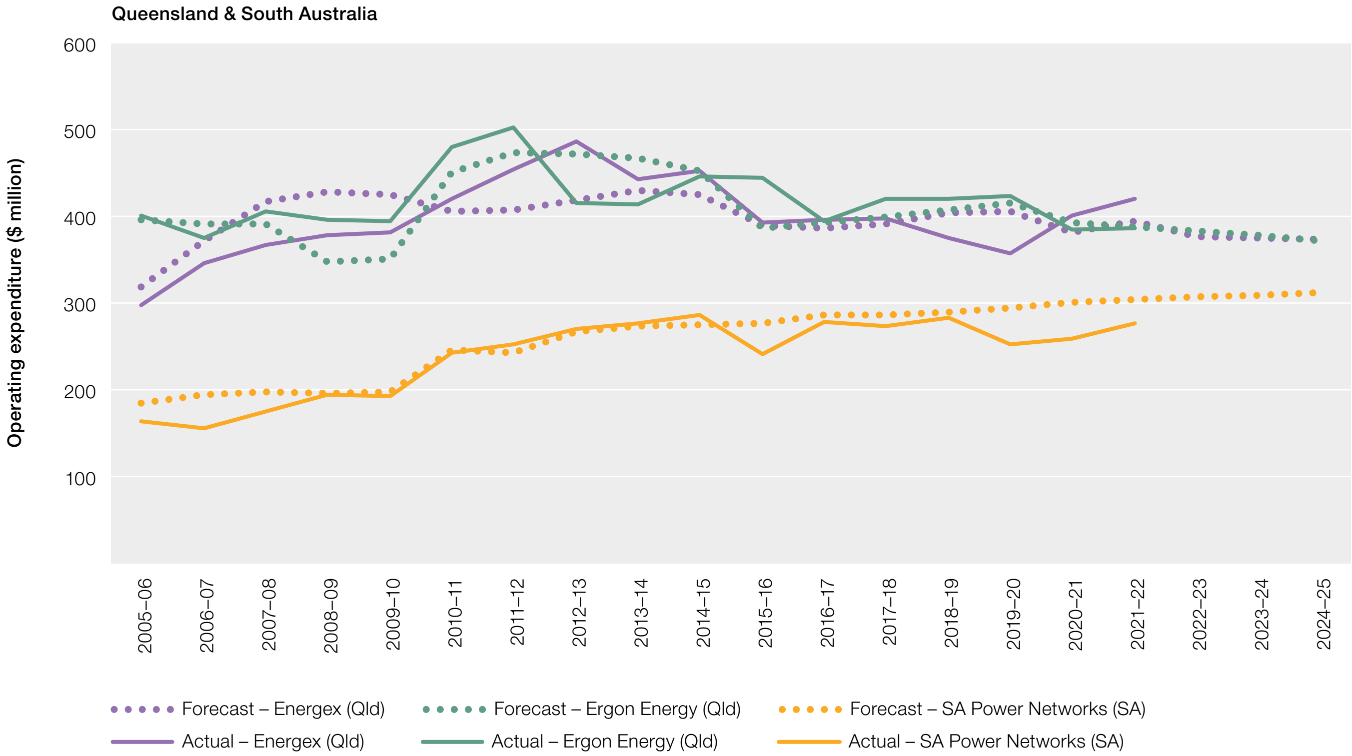
Figure 4.26 Operating expenditure – electricity transmission networks

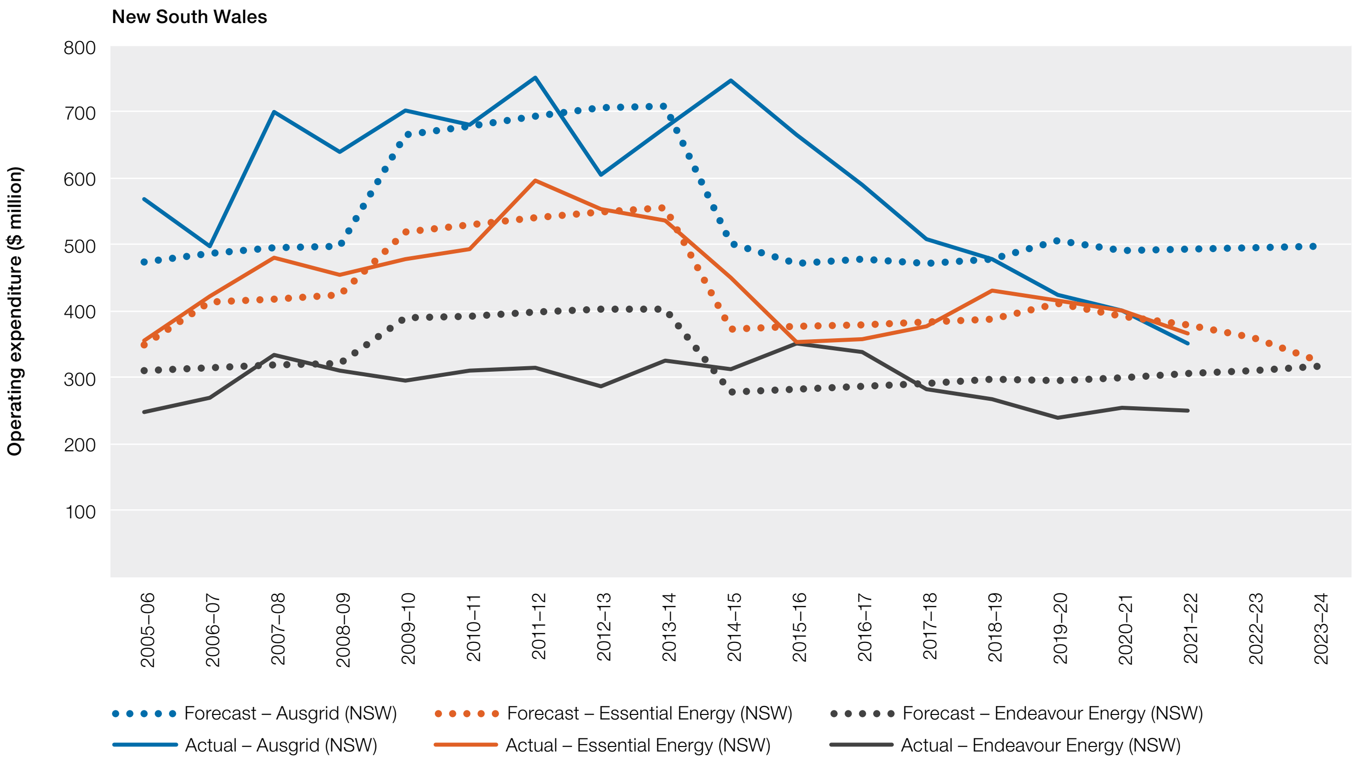


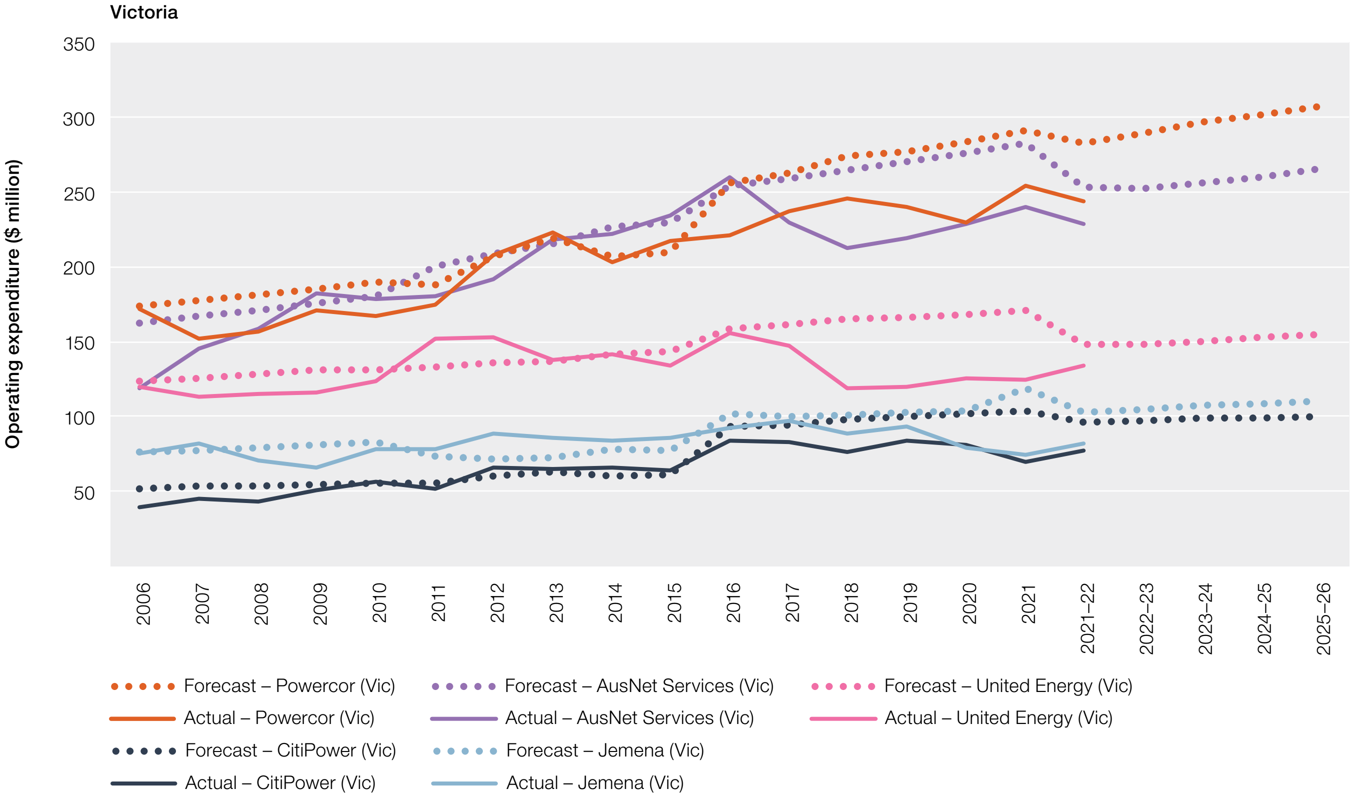
Note: All data are adjusted to June 2022 dollars. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Assumptions are set out in the Figure 4.7 notes.

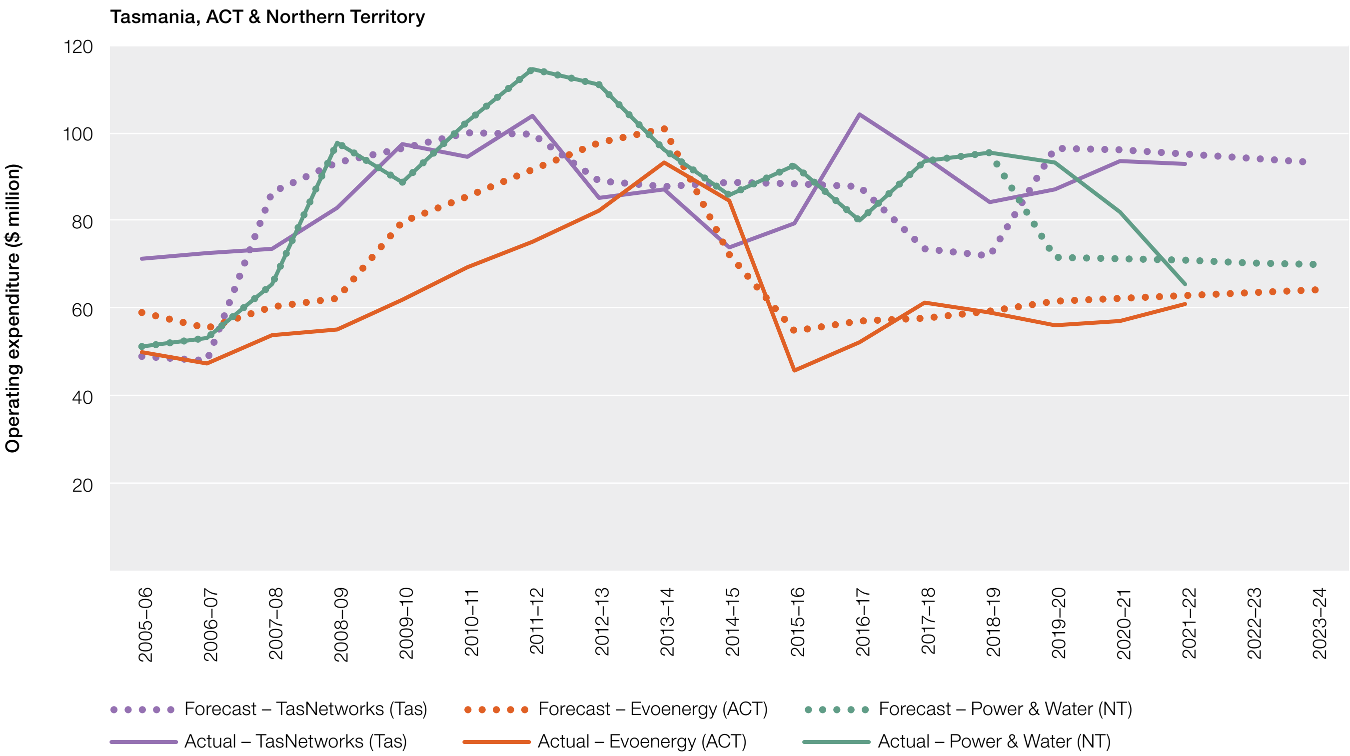
Source: AER modelling; annual reporting RIN responses.

Figure 4.27 Operating expenditure – electricity distribution networks









Note: All data are adjusted to June 2022 dollars. In July 2021, Victorian distribution network service providers transitioned from reporting on a calendar year basis to a financial year basis. Assumptions are set out in the Figure 4.9 notes.

Source: AER modelling; annual reporting RIN responses.

4.14.2 Operating cost trends

Total operating costs for the electricity networks increased by an average of 5% per year from 2006 until 2012, before peaking at $4.5 billion (Figure 4.7 and Figure 4.9).

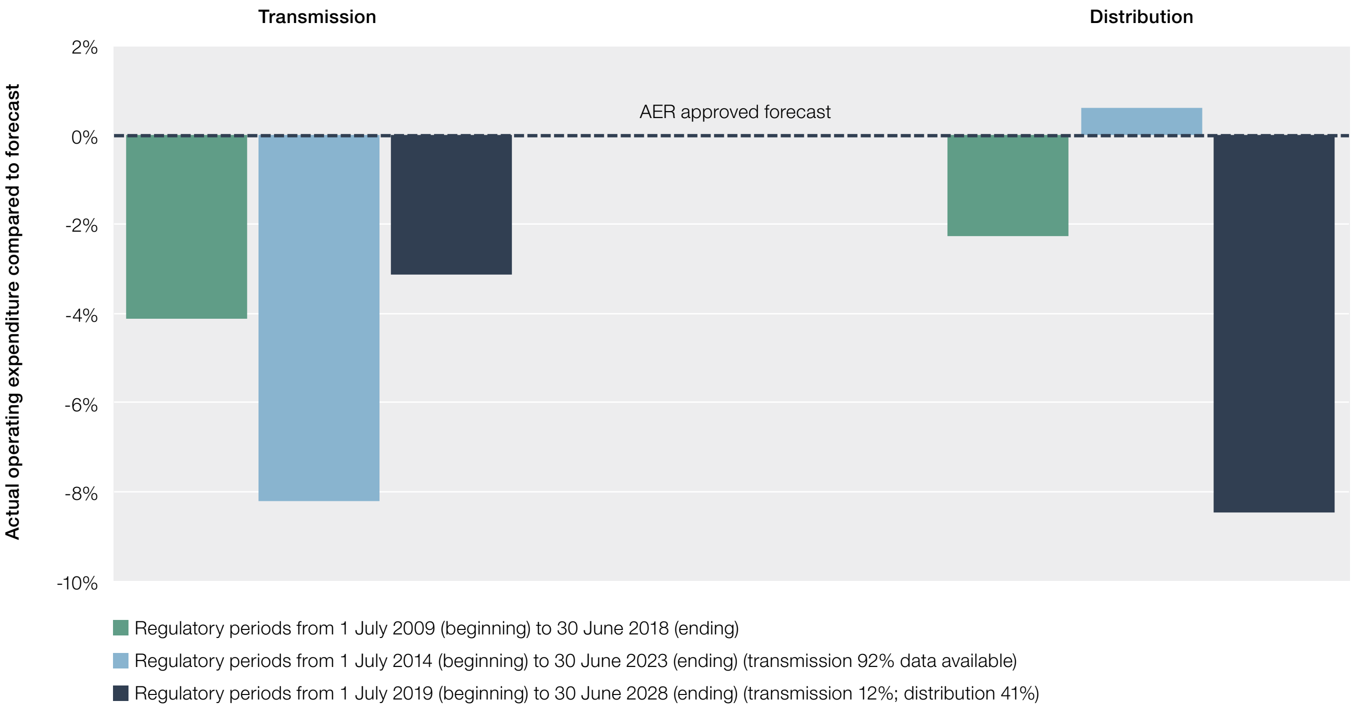
In recent years operating costs have decreased, largely due to network service providers implementing more efficient operating practices. However, the decrease in operating expenditure has been less marked than it has been for capital expenditure.

A number of network service providers implemented efficiencies in managing their operating costs from 2015, when the AER widened its use of benchmarking to identify operating inefficiencies in some networks.

Unlike capital expenditure, a network service provider's operating costs – such as marketing, payroll, insurance, inspection and maintenance, vegetation management, emergency response, and funds allocated for research and development – are largely recurrent and predictable. As such, actual operating expenditure against forecast has been far more stable over the past few regulatory periods than it has been for capital expenditure (Figure 4.28).

However, other factors such as reporting obligations, changes to connections charging arrangements, pricing reforms and greater use of non-network options (section 4.8) can also impact costs.

Figure 4.28 Operating expenditure against forecast



Source: AER modelling; annual reporting RIN responses.

A combination of AER incentives and network-driven efficiencies has contributed to significant cost reductions, especially among government-owned (or recently privatised) distribution network service providers in Queensland and NSW. Those savings – for example, from the uptake of technology solutions and from changes to management practices – are used to set lower operating expenditure forecasts, which has the effect of lowering network prices for customers.

4.15 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, customer numbers 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.[98]

The AER uses a forecast productivity growth rate when reviewing the operating expenditure forecasts of distribution network service providers. This growth rate – which has been applied in all regulatory determinations since March 2019 – reflects the productivity improvements that an efficient distribution 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.

4.15.1 Productivity trends

Productivity for most network service providers declined from 2006 to 2015. The decline was most evident among the distribution service providers and was largely driven by:

- rising capital investment (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

Productivity for transmission network service providers[99] decreased by 0.3% during 2021, primarily due to an increase in the capital input for overhead line capacity. The increase was largely driven by a winter peak in 2021 for some of Transgrid's (NSW) existing overhead line assets, rather than any additional network investment or an increase in the overhead line length.[100]

Viewed over a longer time frame, the productivity of transmission network service providers has declined at an average rate of 0.8% per year in the 15 years since 2006. Capital partial factor productivity – output per unit of capital expenditure – has declined at an average rate of 1.5% per year compared with average operating expenditure efficiency growth – output per unit of operating expenditure – of 0.7% per year over the same period.

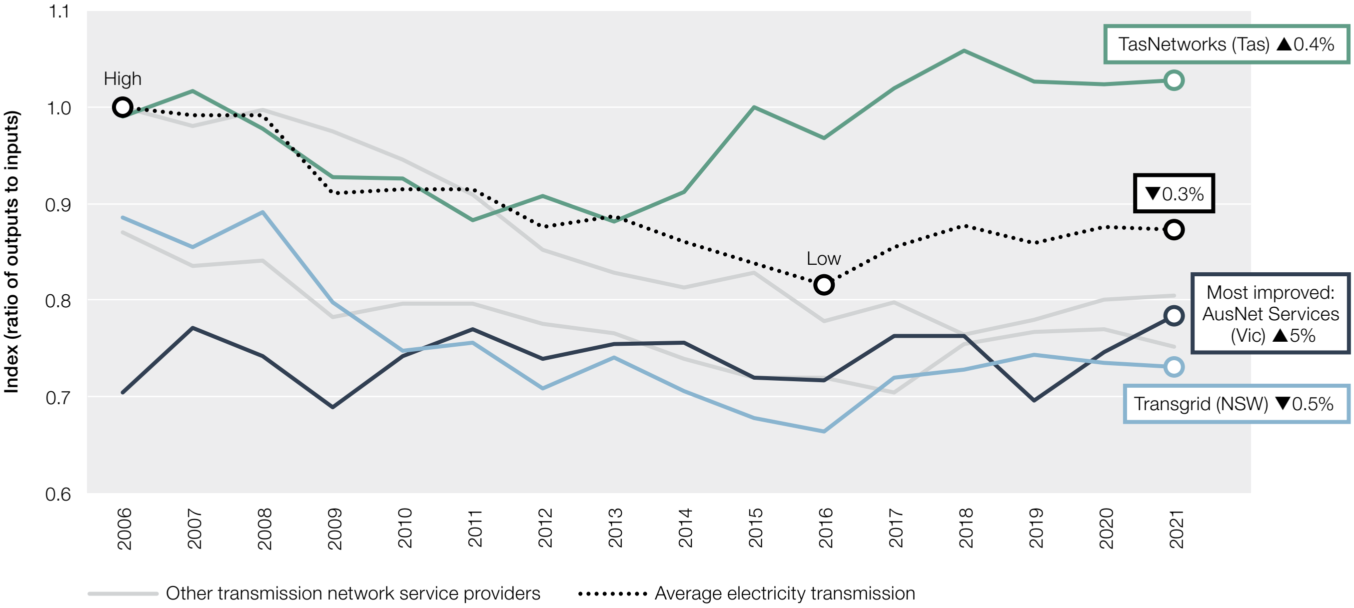
In 2021, 3 of the 5 electricity transmission network service providers in the NEM improved their productivity (Figure 4.29).

98 AER, Annual benchmarking report, electricity distribution network service providers, Australian Energy Regulator, November 2021, pp. 45–52.

99 As measured by total factor productivity (TFP).

100 AER, Annual benchmarking report - Electricity transmission network service providers, Australian Energy Regulator, 30 November 2022.

Figure 4.29 Productivity – electricity transmission networks



Note: Index of multilateral total factor productivity relative to the 2006 performance of ElectraNet (South Australia). The transmission and distribution indexes cannot be directly compared. 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 transmission networks.

Distribution network productivity

Productivity for distribution network service providers[101] increased by 1.5% over 2021, primarily due to increases in reliability. The annual productivity growth rate for distribution network service providers was higher over the past 5 years (2017 to 2021) (0.6%) than it was over the preceding 5 years (2012 to 2016) (0.0%).[102]

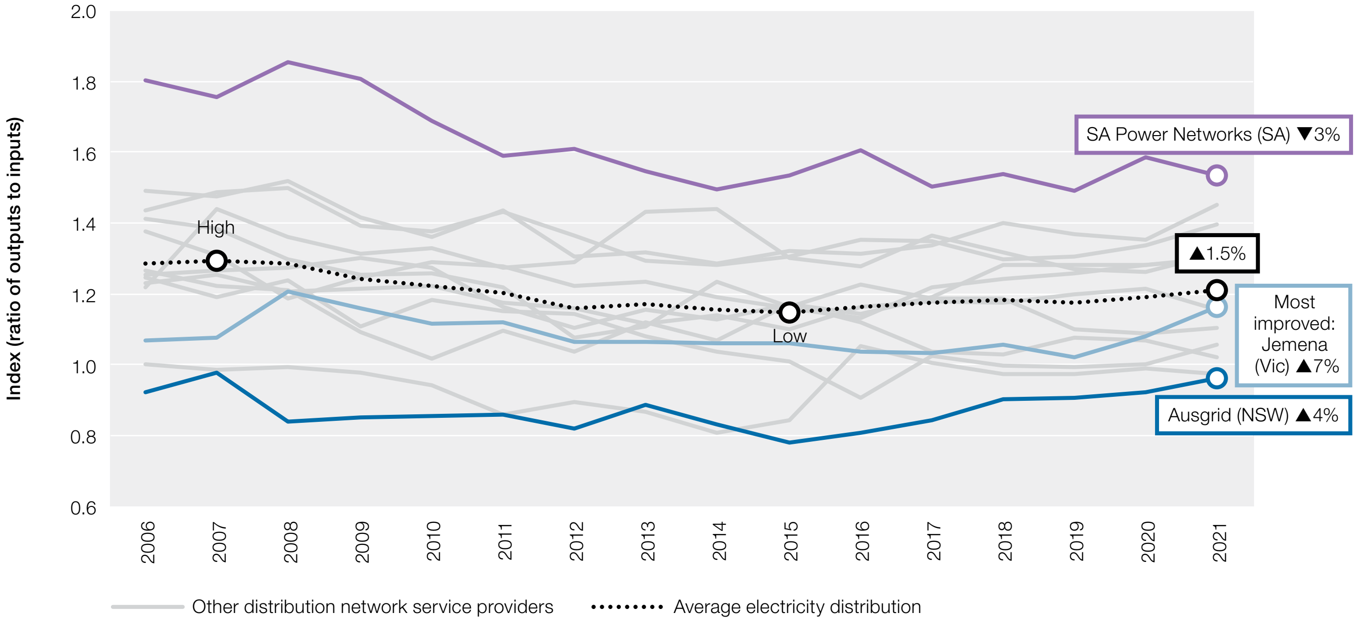
In 2021, 9 of the 13 distribution network service providers in the NEM improved their productivity. The time series data shown in Figure 4.30 highlights the variability in annual productivity for individual distribution network service providers. This variability emphasises the importance of considering single year changes in productivity, be it negative or positive, in the context of longer-term trends. 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 productive distribution network service providers in the NEM since at least 2006 (Figure 4.30).

101 As measured by multilateral total factor productivity (MTFP).

102 AER, Annual benchmarking report - Electricity distribution network service providers, Australian Energy Regulator, 30 November 2022.

Figure 4.30 Productivity – electricity distribution networks



Note: Index of multilateral total factor productivity relative to the 2006 performance of Evoenergy (ACT). The transmission and distribution indexes cannot be directly compared. 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.

4.15.2 Network utilisation

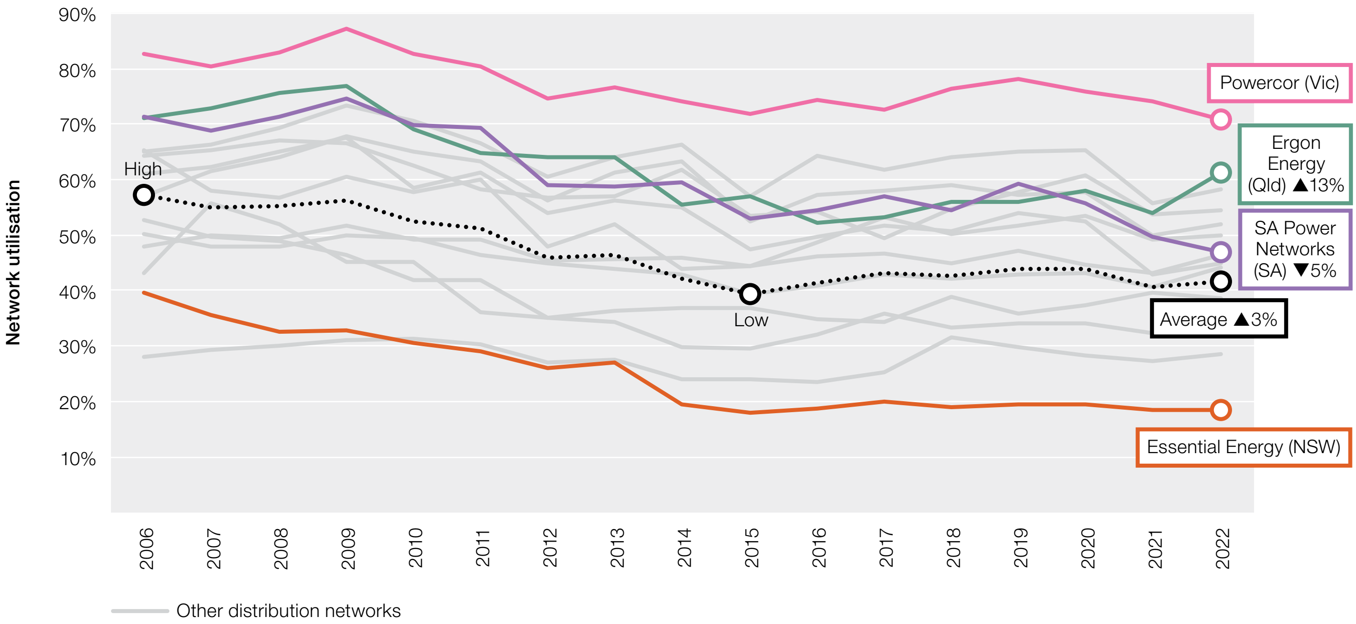
A network's utilisation rate indicates the extent to which a network service provider's assets are being used to meet the needs of customers at times of maximum demand. The utilisation rate can be improved through efficiencies such as using demand response (instead of new investment in assets) to meet rising maximum demand.

The average level of network utilisation among all distribution network service providers decreased from a high of 57% in 2006 to a low of 39% in 2015.[103] This followed significant investment by many network service providers at a time of weakening electricity maximum demand.

In 2022, maximum demand across the distribution networks increased by an average of 3% over the previous year, the largest proportional increase since 2017. As a result, overall network utilisation increased by 1.1 percentage points to 42% (Figure 4.31).

103 The available data does not extend back beyond 2006.

Figure 4.31 Network utilisation – electricity distribution networks



Note: Network utilisation is the non-coincident, summated raw system annual peak demand divided by total zone substation transformer capacity.
Source: Economic benchmarking RIN responses.

In 2022:

- privately owned distribution network service providers utilised 53% of network capacity
- fully or partly government-owned networks utilised only 35% of network capacity[104]
- 8 of the 9 most highly utilised distribution networks were privately owned.

Under-utilised assets raise the risk of asset stranding – whereby assets are no longer useful – unless network service providers respond to changing conditions. This risk may become more acute as the uptake of consumer energy resources (such as batteries) transforms the industry. The National Electricity Rules do not allow for RAB adjustments to remove historical investment in stranded assets. If network charges become inflated because of asset stranding, then electricity consumers – who pay for those assets – may look for opportunities to bypass the grid altogether.[105]

In August 2023, Energy Consumers Australia wrote that numerous factors indicate electricity demand is likely to increase over the coming years. 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 through additional network investment, will see distribution charges to customers decrease.[106]

4.15.3 Investment disconnect

The level of network productivity depends on how effectively a network service provider uses inputs[107] to deliver a range of outputs[108]. Capital expenditure is largely driven by the need to meet the maximum level of demand on the network. While average demand has declined since 2006 (driven in part by improved energy efficiency and increased self-consumption of solar PV), 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.

104 Section 4.4 provides information on network ownership.

105 T Wood, D Blowers, K Griffiths, Down to the wire – a sustainable electricity network for Australia, Grattan Institute, March 2018.

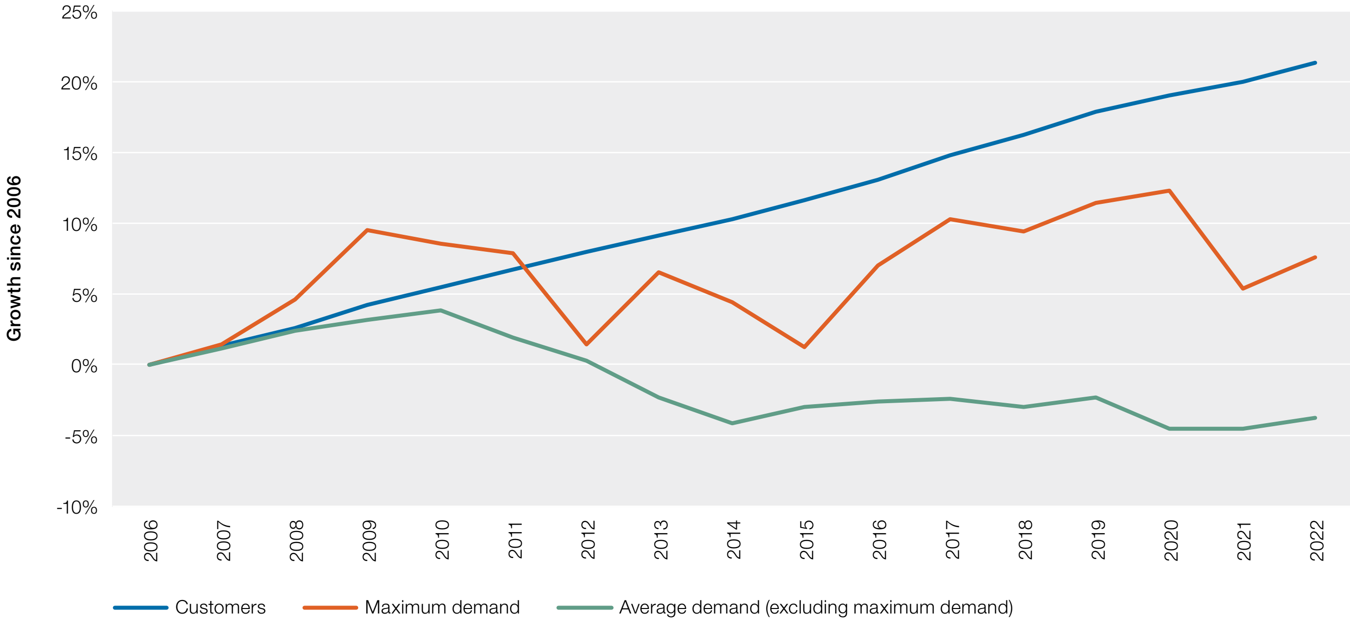
106 Energy Consumers Australia, The bECAuse Blog, 2 August 2023, accessed 6 August 2023.

107 Types of physical capital assets transmission networks invest in to replace, upgrade or expand their networks are transformers and other capital, overhead lines, and underground cables. Operating expenditure is an example of an intangible input.

108 Outputs include circuit line length, ratcheted maximum demand, energy delivered, customer numbers and network reliability.

As network demand becomes ‘peakier’, assets installed to meet demand at peak times – which occur 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 weakens productivity. The number of customers connected to the distribution network has steadily increased by 1.5% per year since 2006 and has outpaced growth in both maximum and average ‘non-maximum’ demand (Figure 4.32).

Figure 4.32 Growth in customers and demand – electricity distribution networks

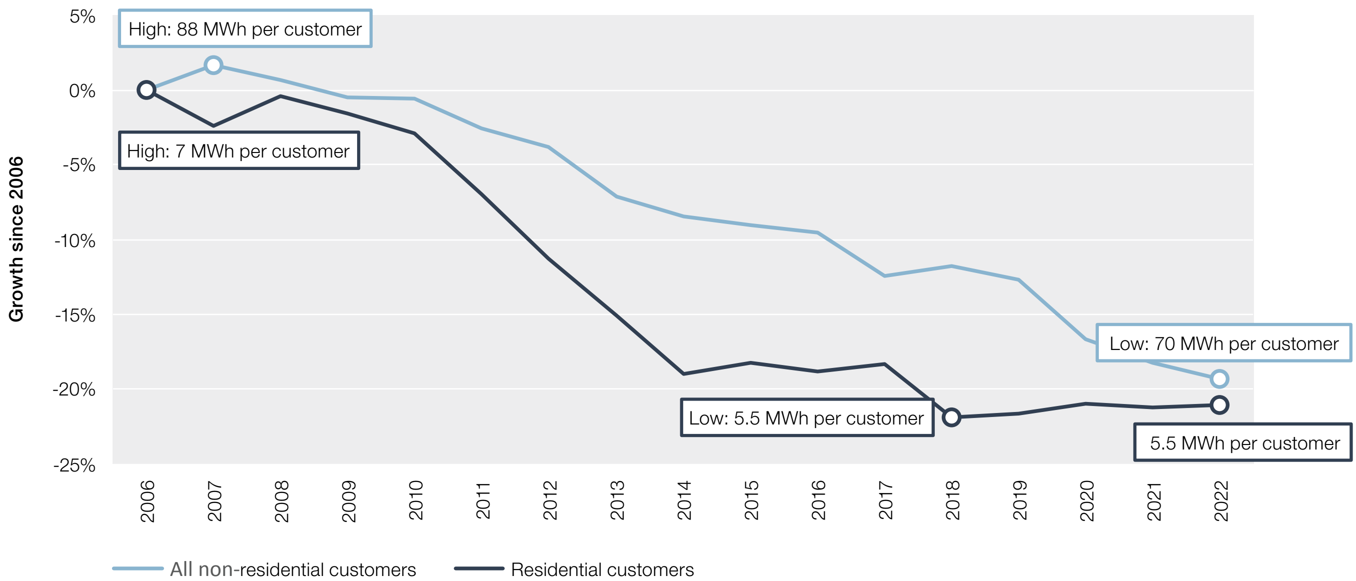


Note: Maximum demand is the network sum of non-coincident, summated raw system maximum demand (megawatts). Non-maximum demand is the total energy delivered (gigawatt hours) for the year, excluding the energy delivered at the time of maximum demand divided by hours in the year minus one. The data show 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 2022 the average residential customer consumed around 5.5 megawatt hours (MWh) from the distribution network, 21% less than it consumed in 2006. Over the same period the average usage per non-residential customer – including low voltage and high voltage customers – has decreased 19% (Figure 4.33).

Figure 4.33 Growth in average grid usage per customer – electricity distribution networks



Note: 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.

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
- housing and appliances becoming more efficient
- consumers reducing their energy use in response to higher prices
- reductions in demand from large industrial customers
- in 2021 the impact of COVID-19 on consumer behaviour.

4.16 Reliability and service performance

In this section, the term ‘reliability’ refers to the continuity of electricity supply to customers.[109] 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).

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 (including possums and birds). Peak 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 occur is widespread. For example, South Australia’s catastrophic network failures in September 2016 caused a state-wide blackout.[110]

Electricity outages impose costs on consumers. These costs include both economic losses resulting from lost productivity and business revenues and non-economic costs such as reduced convenience, comfort, safety and amenity.

Residential and business consumers desire 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. 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.

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. This approach factors in the value that consumers place on having a reliable power supply.

In September 2022, Energy Networks Australia (ENA) awarded Endeavour Energy (NSW) the Industry Innovation Award for its ‘Using a Network Digital Twin for Digital Emergency Response and Resilience’ initiative which was used to improve public safety and restoration response times to several floods in the Hawkesbury region over 2021–22.[111]

4.16.1 Valuing network reliability

Understanding the value that consumers place on reliability is important when setting reliability standards or network 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.

The AER develops new estimates of customers’ reliability valuations (VCR) every 5 years and updates these values annually. The values have a wide application, including as an input for:

- cost-benefit assessments, such as those applied in regulatory tests (section 4.13.5) that assess network investment proposals

109 The continuity of electricity supply from customers is also an element of service performance for networks with customers that export energy into the grid (for example, energy generated from rooftop solar PV). Reforms are underway to treat export services more clearly as distribution services. See AEMC, Rule determination: Access, pricing and incentive arrangements for distributed energy resources, Australian Energy Market Commission, August 2021.

110 AER, Investigation report into South Australia’s 2016 state-wide blackout, Australian Energy Regulator, accessed 17 July 2023.

111 Endeavour Energy, Endeavour Energy pioneers Neara digital twin in transition to modern grid, 13 December 2021, accessed 14 April 2023.

- assessing bonuses and penalties in the service target performance incentive scheme (Box 4.4)
- setting transmission and distribution reliability standards and targets
- informing market settings, such as wholesale price caps.

In December 2022, the AER updated the VCR based on a consumer price index (CPI) of 7.27%. The AER encourages network service providers, market operators and regulators that are required to apply the VCR to adopt the adjusted values from 18 December each year.[112]

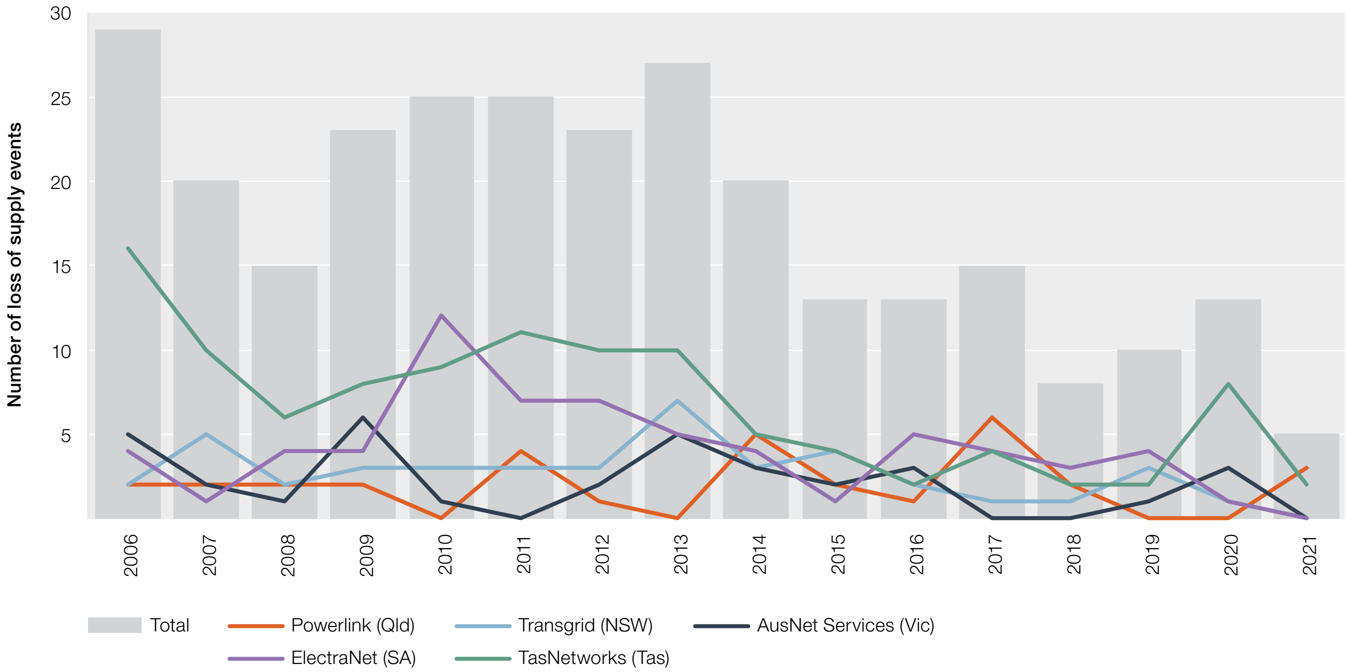
The AER will undertake its next review of the VCR in 2024.

4.16.2 Transmission network reliability

Transmission networks are engineered and operated to be extremely reliable, because a single interruption can lead to high impact or widespread power outages. To minimise the risk of outages occurring, the transmission networks are engineered with capacity to act as a buffer against credible unplanned interruptions.

In 2021 the NEM experienced 5 loss of supply events due to transmission failures, the fewest events in any year dating back to at least 2006 (Figure 4.34).

Figure 4.34 Network reliability loss of supply events – electricity transmission networks



Note: Loss of supply events are the times when energy is not available to transmission network customers for longer than a specified duration. The threshold varies across businesses, from 0.05 to 1.0 system minutes as published in AER decisions on the service target performance incentive scheme (STPIS). The thresholds may also vary between regulatory periods for each network. 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 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 brink of its secure operating limits.

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.

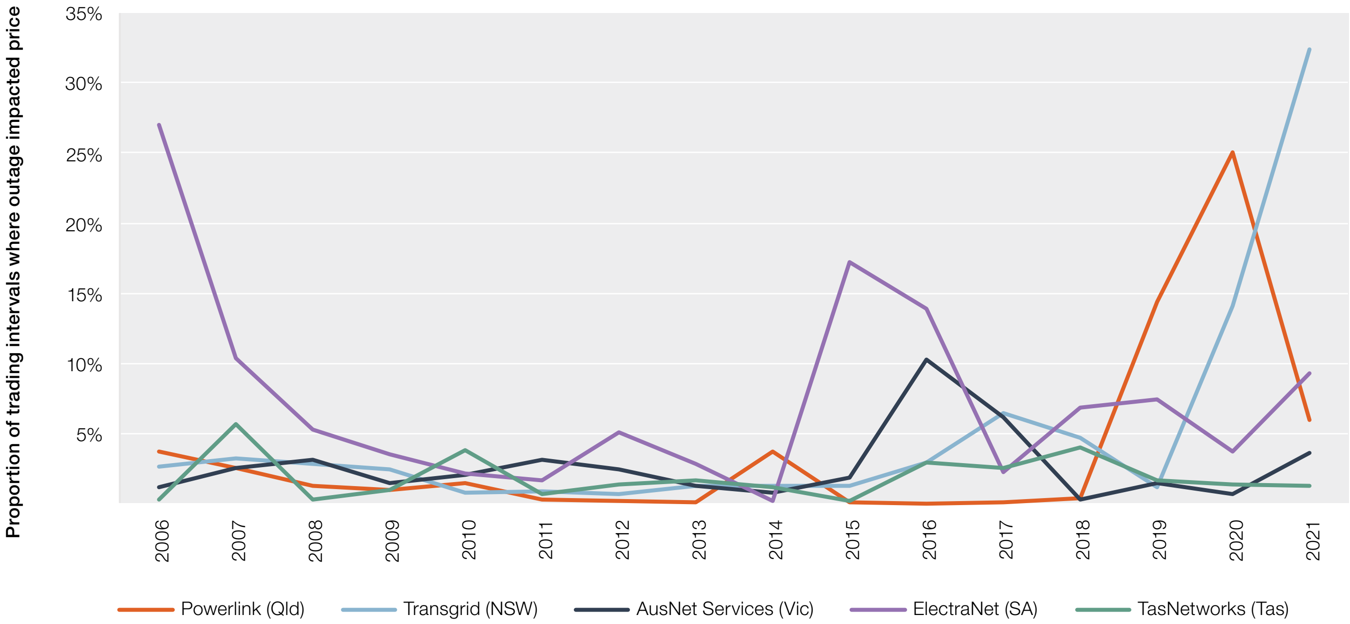
112 AER, Values of customer reliability, Australian Energy Regulator, accessed 23 March 2023.

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. Weakening energy demand reinforced the trend and for several years network congestion affected less than 10% of NEM spot prices. But ultimately, consumers have paid for the substantial costs of network investment.

Issues with network congestion re-emerged from 2015, in part due to outages associated with network upgrades in Queensland and cross-border interconnectors linking Victoria with South Australia and NSW. The level of congestion dropped in South Australia in 2017 following completion of an interconnector upgrade.

In 2021, the number of dispatch intervals impacted by the Transgrid (NSW) network increased significantly as a result of upgrades to the Victoria – NSW and Queensland – NSW interconnectors being undertaken (Figure 4.35).

Figure 4.35 Market impact of loss of supply events – electricity transmission networks



Note: Proportion of dispatch intervals each year when transmission network congestion impacted the National Electricity Market spot price by more than $10 per megawatt hour. The data exclude outages caused by force majeure events and other specific exclusions.

Source: Economic benchmarking RIN responses.

Not all congestion is inefficient. Reducing congestion through investment to augment transmission networks 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. For this reason, the AER offers incentives for service providers to reduce the market impact of congestion.

4.16.3 Distribution network reliability

For distribution networks, the reliability of supply – that is, how effectively the network delivers power to its customers – is the main focus of network performance. Around 95% of the interruptions to supply experienced by electricity customers are due to issues in the local distribution network.[113] The capital-intensive nature of the 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 outages – such as those resulting from asset overload or damage caused by extreme weather – provide no warning to customers, so they cannot prepare for the impact of an interruption.

113 AEMC, Final report – 2019 annual market performance review, Australian Energy Market Commission, 12 March 2020, p. 51.

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 in 2005 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.

Concerns that reliability-driven investment was driving up power bills led to a different approach to setting distribution reliability targets.[114] This 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 4.16.1). While the Queensland and NSW governments began to relax reliability standards from 2014, the assets built to meet the previously high standards remain and customers continue to pay for them.[115]

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 duration – or minutes off supply – the average customer experienced.[116]

The SAIFI and SAIDI metrics have generally been used to focus on the impact of unplanned outages. However, the impact of planned outages 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 recent regulatory determinations through the customer service incentive scheme (CSIS) (Box 4.5). Both the frequency and duration of planned interruptions to supply varies considerably among the distribution networks.

The specific characteristics of a distribution network can have a significant impact on the service provider's reliability performance. In particular, customer densities and environmental conditions differ across networks, which can materially impact the number of customers affected by an outage as well as a network service providers' response time. Levels of historical investment also affect reliability outcomes.

Central business district (CBD) and urban network areas have higher load and customer connection density. 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 duration interruptions.

For these reasons, care must be taken when comparing network reliability outcomes between distribution network service providers.

4.16.4 Distribution network reliability in 2021–22

In 2021–22 the average customer in the NEM experienced 1.55 interruptions to supply, a new record low and 1.2% fewer than in the previous year (Figure 4.36). This comprised:

- 1 unplanned (normalised for STPIS) interruption to supply – 3% more than the record low set in the previous year
- 0.25 unplanned (STPIS excluded) interruptions to supply – 5% fewer than in the previous year
- 0.30 planned interruptions to supply – 10% fewer than in the previous year.

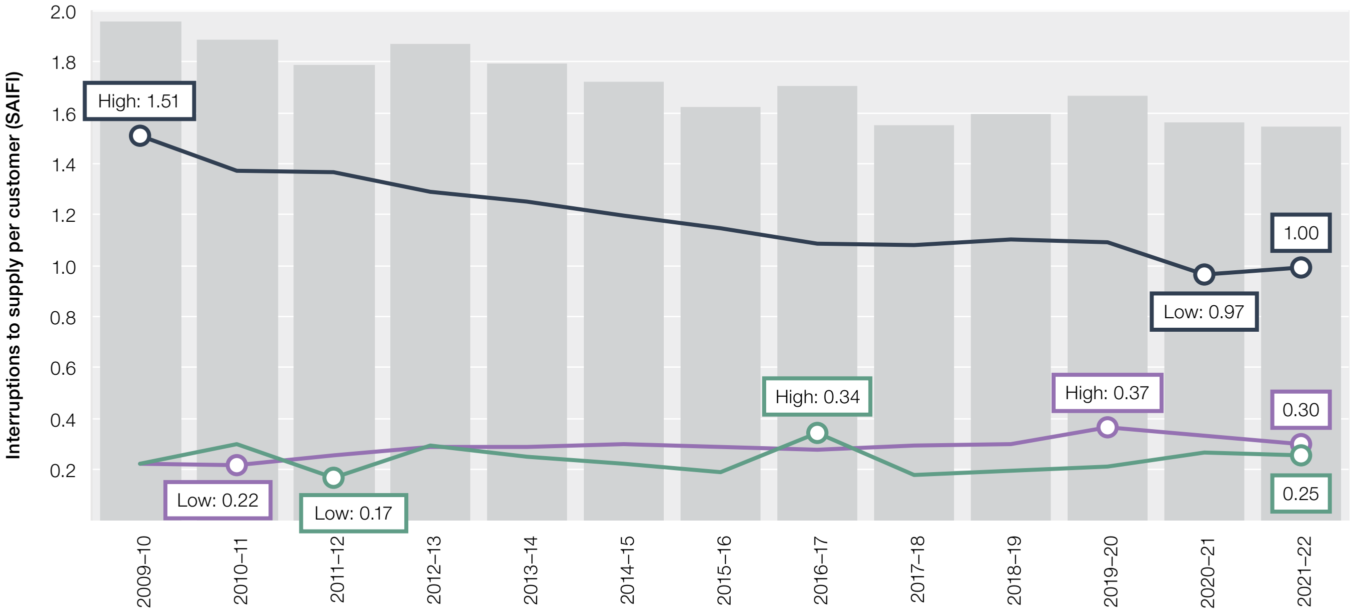
Despite the decrease in in total interruptions, 2021–22 marked only the second year in the available data series when customers experienced more unplanned interruptions (normalised for STPIS) to supply than in the previous year.

114 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.

115 ACCC, Retail Electricity Pricing Inquiry final report, Australian Competition and Consumer Commission, 11 July 2018, p. 109.

116 Unplanned SAIDI excludes momentary interruptions (3 minutes or less).

Figure 4.36 Interruptions to supply (SAIFI) – electricity distribution networks



Note: SAIFI: system average interruption frequency index.

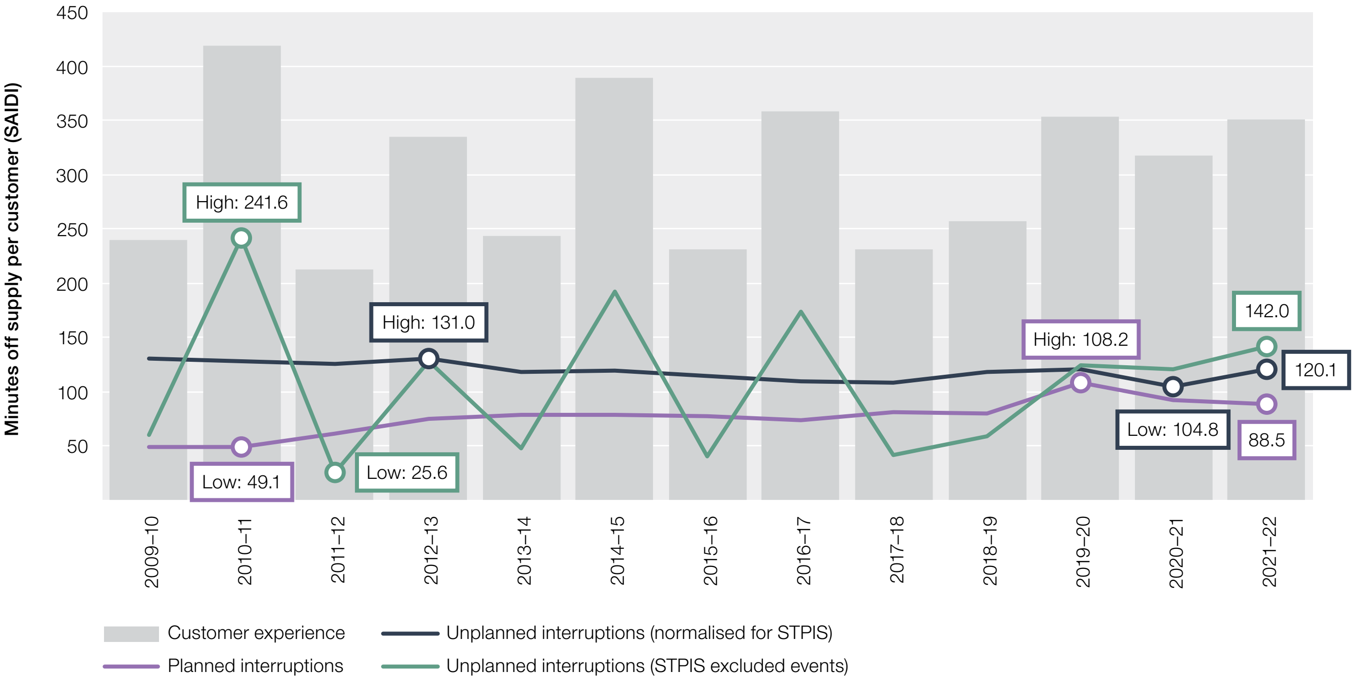
Data in Figure 4.36 shows interruptions to supply that lasted longer than 3 minutes. This is consistent with the definition of a sustained interruption in the AER's current service target performance incentive scheme (STPIS) (version 2.0, November 2018). The previous version of the STPIS (May 2009) defined 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.

In 2021–22 the average customer in the NEM experienced 350.6 minutes off supply – 10% more than in the previous year (Figure 4.37). This comprised:

- 120.1 unplanned (normalised for STPIS) minutes off supply – 15% more than the record low set in the previous year
- 142.0 unplanned (STPIS excluded) minutes off supply – 18% more than in the previous year
- 88.5 planned minutes off supply – 4% less than in the previous year.

Figure 4.37 Minutes off supply (SAIDI) – electricity distribution networks



Note: SAIDI: system average interruption duration index.

Data in Figure 4.37 shows minutes off supply for interruptions 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.

Over the 12-month period to 30 June 2022 asset failure was the most frequently reported reason for unplanned outages, accounting for 25% of all unplanned outages and 16% of all unplanned minutes off supply across the NEM. Over the same period weather events accounted for fewer (17%) unplanned outages, but a greater number of unplanned minutes off supply (31%). This demonstrates the destructive nature of weather events on the electricity network.

Several severe weather events resulted in significant unplanned minutes off supply during this period, including:

- 28 and 29 October 2021 – Victoria – thunderstorms and extreme wind[117]
- 27 February 2022 – Energex (Queensland) – severe storm and flooding[118]
- 28 February 2022 – Essential Energy (NSW) and Energex (Queensland) – severe storm and flooding.[119]

A third key cause of interruptions to supply is vegetation-related incidents. In the 12-month period to 30 June 2022 vegetation-related interruptions to supply were as frequent as those caused by weather events but resulted in 31% fewer minutes off supply (Figure 4.38).

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. Prior to 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 the 12-month period to 30 June 2023, ESV issued 21 fines to network service providers – 10 to Powercor, 6 to United Energy and 5 to AusNet Services – for failing to keep trees clear of powerlines.[120]

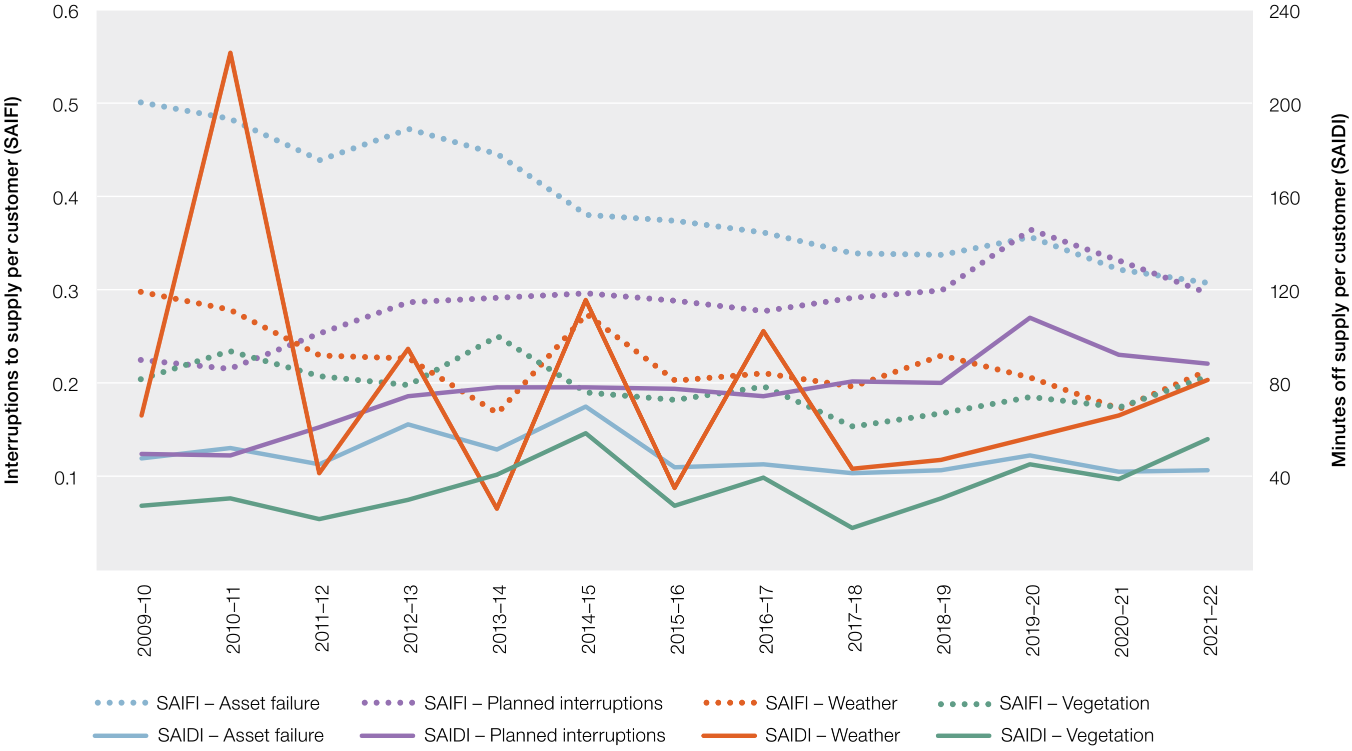
117 The Age, Thousands of properties without power as storm clean-up continues, 29 October 2021, accessed 20 March 2023.

118 ABC News, South-east Queensland battered by severe weather, floods as system lingers over Brisbane, 27 February 2022, accessed 20 March 2023.

119 ABC News, Lismore flood emergency sees people stranded on roofs, evacuation warning issued for entire NSW Northern Rivers, 28 February 2022, accessed 20 March 2023.

120 Electrical Connection, Energy safe fines stack with line clearance powers, 5 July 2023, accessed 21 July 2023.

Figure 4.38 Key drivers of interruptions to supply – electricity distribution networks



Note: SAIDI: system average interruption duration index. SAIFI: system average interruption frequency index.

Data in Figure 4.38 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 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.

In 2019–20 the average customer experienced significantly more frequent and longer planned interruptions to supply than in the past. This was driven by Ausgrid's (NSW) decision to temporarily pause all live work on its network for safety reasons.[121]

4.16.5 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.[122]

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 outages experienced by customers at the end of rural feeders.

121 Ausgrid, Live Work Project, accessed 5 May 2022.

122 AER, Amendment to the service target performance incentive scheme (STPIS) / Establishing a new Distribution Reliability Measures Guideline (DRMG), Australian Energy Regulator, November 2018.

Box 4.4 Service target performance incentive scheme

The AER applies a service target performance incentive scheme (STPIS) to 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 4.2) and efficiency benefit sharing scheme (EBSS) (Box 4.3) 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 outages 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 or penalties are available for exceeding/failing to meet performance targets under the scheme.

Following its 2023 review of incentive schemes[a] the AER decided to amend the market impact component (MIC) of the transmission STPIS in light of increasing transmission congestion. The review of the MIC is expected to commence in late 2023, which will allow any revisions to be picked up in time for the next Queensland and South Australian transmission reset processes. Because the Network Capability Incentive Parameter Action Plan (NCIPAP) is closely linked to the MIC, the AER will review the NCIPAP scheme alongside the MIC review.

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 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.[b]

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.

a AER, Review of incentive schemes for regulated networks, Australian Energy Regulator, accessed 3 May 2023.

b 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.

4.16.6 Incentives to avoid fire starts

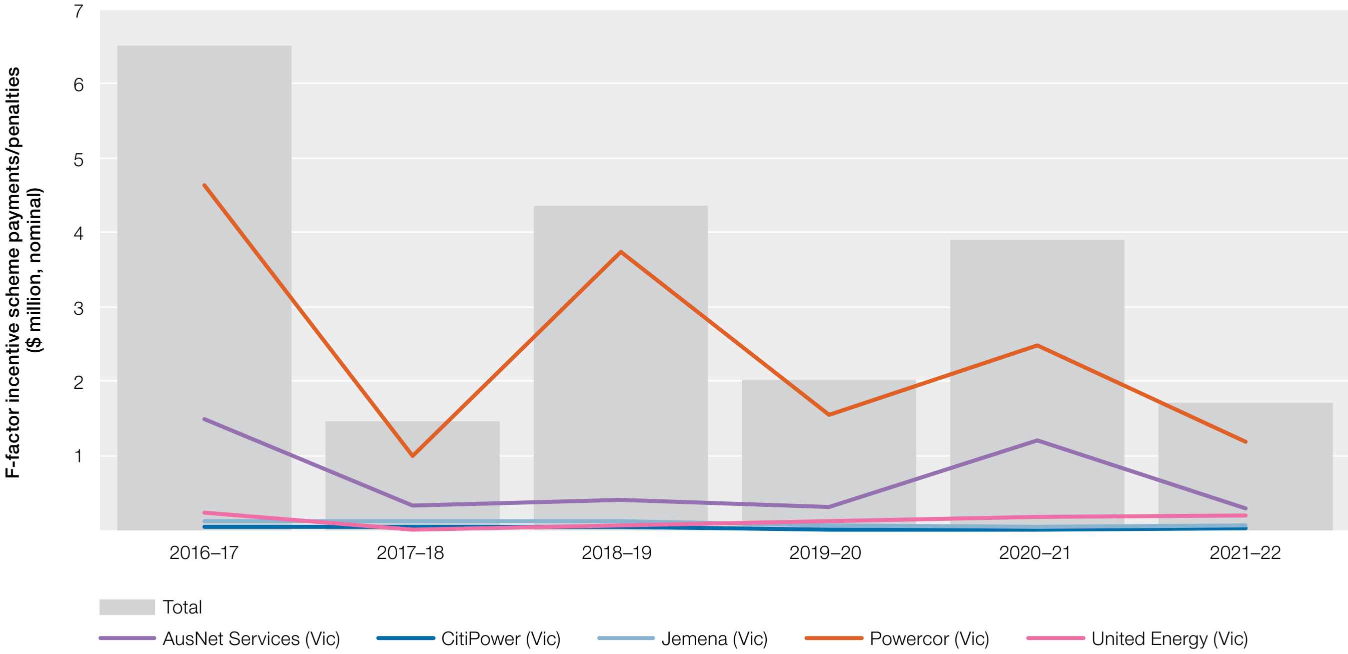
The AER administers the Victorian Government's f-factor scheme, an initiative that provides financial incentives to Victorian distribution service providers to minimise the number of fire starts within their networks in high fire danger zones and times.

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 2021–22 reporting period, incentive payments varied from a $12,000 reward for CitiPower with a totally CBD/urban network, to $1.2 million for Powercor with a predominately rural network. The impact of the incentive payments from 2021–22 will take the form of adjustments to the network businesses' regulated revenues in 2023–24.

Figure 4.39 F-factor incentive payments – Victorian distribution networks



Source: AER, Victorian electricity distributors' fire start reports for the July 2021–June 2022 reporting period.

4.16.7 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 time frames 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 (GSL) 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.[123] Victoria reports separately on network performance.[124]

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 4.5).[125]

123 AER, Annual retail markets report 2019–20, Australian Energy Regulator, November 2020.

124 ESC, Victorian energy market update, Essential Services Commission, 31 March 2022.

125 AER, Final – Customer Service Incentive Scheme, Australian Energy Regulator, 21 July 2020.

Box 4.5 Customer service incentive scheme

The AER's 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. The AER sets 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 ±0.5%.

The CSIS is a flexible 'principles based' scheme that can be tailored to the specific preferences and priorities of a service provider's customers. This flexibility allows for the evolution of customer engagement and the introduction of new technologies.

The CSIS provides safeguards to ensure the financial rewards/penalties under the scheme are commensurate with actual improvements/detriments to customer service. The incentives target areas of service that customers want to see improved.

The AER generally sets performance targets under the CSIS at the level of current performance. However, it may adjust the performance targets if the level of current performance is not considered to provide a good outcome for consumers.[a]

The incentive rates are tested with customers to confirm that they align with the value that customers place on the level of performance improvement/decline. This means that, even if a network service provider performs exceptionally well against its targets, customers will still benefit. In subsequent regulatory periods, the targets under the scheme will be adjusted and set in accordance with any improved level of customer service.

To date the CSIS has only been 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). In 2021–22 the outcomes of the CSIS were rewards of:

- $775,100 for AusNet Services
- $1.6 million for CitiPower
- $3.7 million for Powercor
- $2.2 million for United Energy.

a AusNet Services' historical performance for the complaints parameter was not considered acceptable. In this case using targets based on historical performance would not have the desired effect. As such, the performance target was calculated using industry-leading performance. Therefore, AusNet Services will only be rewarded for material improvements to customer service.

5 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.[1] Much of the chapter is focused on AEMO-facilitated markets, though for the first time includes information on bilateral commodity gas trades up to a year in duration.[2]

The main production basin in eastern Australia is the Surat–Bowen Basin in Queensland. There are smaller basins in South Australia, New South Wales (NSW), off coastal Victoria and in the Northern Territory. Combined, these basins account for around 37% of Australia's total gas production.[3]

The eastern gas market is interconnected by 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.

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. Australian exports accounted for 21% of global exports in 2022, exceeding that of Qatar (20%) and the United States (19%).[4] On the east coast, exports account for the majority of gas demand, significantly exceeding domestic consumption levels.[5]

Since the launch of the LNG export industry in 2015, gas producers have had the choice to export or sell gas domestically. Consequently, prices in the domestic market are influenced by international gas prices.

1 The Australian Energy Regulator (AER) has regulatory responsibilities in the eastern Australian gas market in Queensland, NSW, Victoria, South Australia, Tasmania and the ACT.

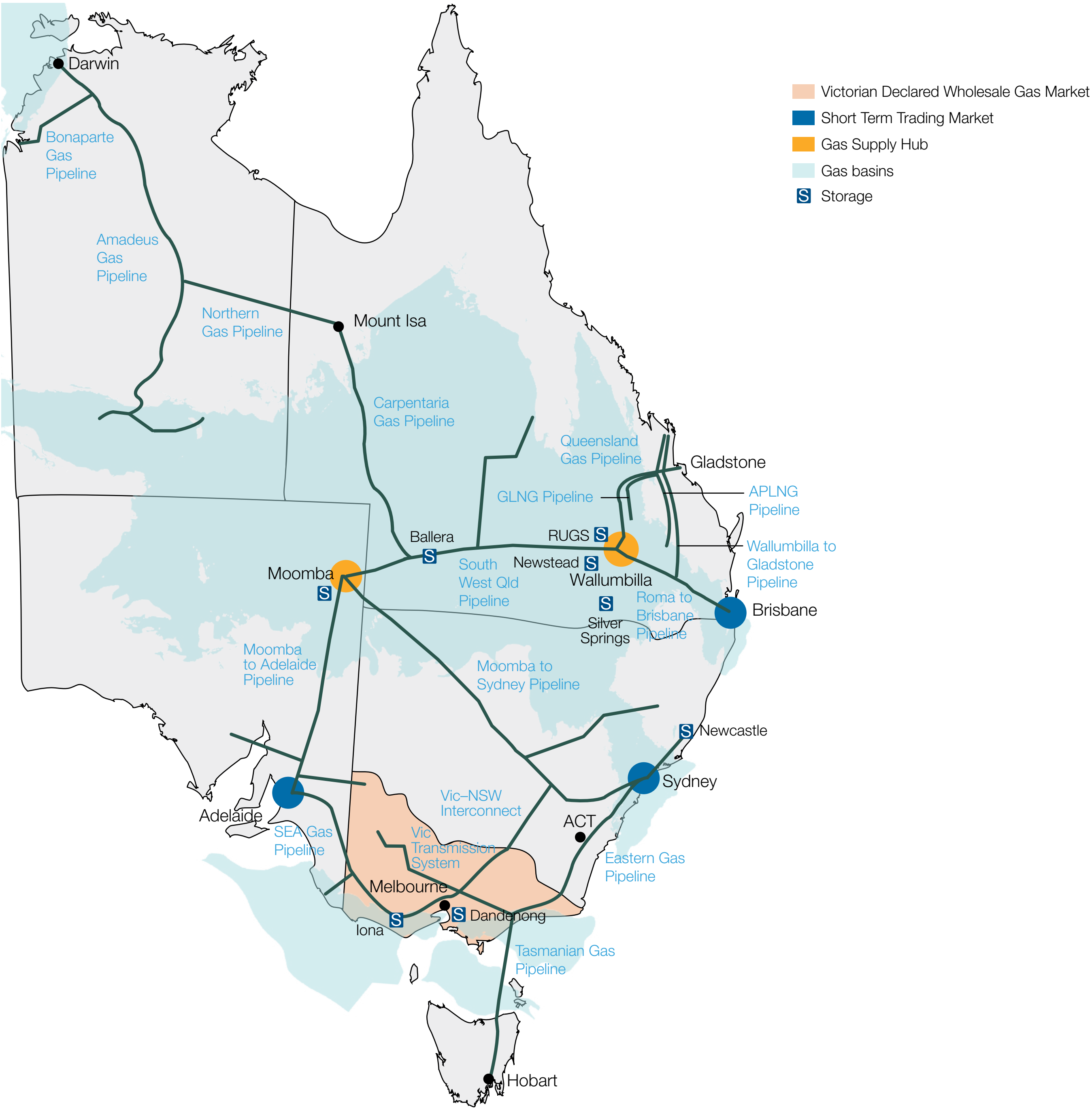
2 AEMO facilitated markets includes the Declared Wholesale Gas Market, the Short Term Trading Market hubs and the Gas Supply Hub. Bilateral commodity reporting under the Gas Rules commenced in 2023 adding to secondary bilateral transaction reporting since 2019.

3 71% of Australia's total gas reserves are conventional gas resources and 29% are unconventional (coal seam gas) resources. Surat–Bowen accounts for most of Australia's coal seam gas (CSG) production. Most of Australia's conventional gas resources are located off the north-west coast of Western Australia and at the end of 2020 they accounted for around 66% of total gas production.

4 Department of Industry, Science, Energy and Resources, Resources and energy quarterly, June 2023, p. 70.

5 Compared with residential and commercial, industrial, and gas generation demand, LNG demand accounted for over 70% of gas consumption on the east coast in 2022.
AEMO, *2023 Gas Statement of Opportunities*, March 2023, gas annual consumption.

Figure 5.1 Eastern gas basins, markets, major pipelines and storage



Source: AER; Gas Bulletin Board

Box 5.1 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 spot gas 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 a scheme to auction 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 a wider set of information on the export, reserve, storage, and domestic sale and swaps of gas.

The AER also has regulatory responsibilities for transmission and distribution pipelines (chapter 6) and retail markets (chapter 7).

We continue to engage with the 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.

The Economic Regulation Authority is the economic regulator for gas markets and pipelines in Western Australia and AEMO operates a spot gas market there.

5.1 Gas market snapshot

Since the last State of the energy market report:

- Prices in facilitated gas markets reached record high levels through the second half of 2022, peaking between $30 and $60 per GJ in August 2022 (section 5.3).
- So far in 2023, prices have moderated substantially and mostly remained at or below $12 per GJ through winter despite this being traditionally a time of high demand and high prices (section 5.3).
- These lower prices appear to have been a result of several favourable market dynamics, including mild weather conditions, reduced international price pressures, low demand and low gas-powered generation demand from the National Electricity Market (NEM) (section 5.3).
- Low prices have also contributed to and been supported by Iona storage remaining at record-high levels through winter, mitigating the risk of peak day gas shortfalls (section 5.5).
- Less positively, southern gas production continued to deplete reserves, increasing the risks of shortfalls. In particular, Longford peak day capabilities have declined from previous years due to legacy field depletion, which has led to a much stronger reliance on Queensland's northern supply sources flowing south to temperature-sensitive southern markets (section 5.5).
- Governments implemented significant market reforms and interventions to address market volatility and the risks of gas shortfalls (sections 5.10 and 5.11). Most notably, these included a $12 per GJ price cap on some gas trade, which has since been replaced with a mandatory gas code of conduct. This has been supported by 2 tranches of reliability measures.

5.2 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. Around 10% to 20% of gas is traded in these spot markets. All other gas trade is struck under confidential bilateral contracts separate to these markets.

5.2.1 Contract markets

The majority of gas in Australia is traded through bilateral contracts. Contract prices reflect expectations of future market conditions, but the spot markets can reflect short-term shifts in market conditions due to factors such as gas supply and gas storage levels, the timing of LNG shipments and conditions in the electricity market. As a result, the 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.

The 2 main levels of gas contracts (also known as gas supply agreements) are:

- offers by gas producers to very large customers, such as major energy retailers and gas-powered generators
- offers by retailers and aggregators that buy gas from producers and on sell it to commercial and industrial (C&I) customers.[6]

Long-term gas contracts traditionally locked in prices and other terms and conditions for several years. In recent years the industry has shifted towards shorter terms (1 to 2 years) for these contracts, with review provisions.[7]

5.2.2 Spot markets

Spot markets allow wholesale customers to trade gas without entering long-term contracts. Spot market trading can be a useful mechanism for participants to manage imbalances in their contract positions.

Several separate spot markets operate in eastern Australia – Victoria's Declared Wholesale Gas Market, the Short Term Trading Market, the Gas Supply Hub and a separate east coast wide market for transportation and compression services.

Victoria's Declared Wholesale Gas Market (DWGM)

Victoria's DWGM manages gas flows across the Victorian Transmission System. Participants submit daily bids ranging from $0 per gigajoule (GJ) (the floor price) to $800 per GJ (the price cap). 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.

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 scheduled withdrawals and offers by shippers to deliver gas, with a price floor of $0 per GJ and a cap of $400 per GJ. 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.

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6 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 2017–2025 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, and LNG and short-term transactions.

7 ACCC, Gas inquiry 2017–2020, interim report, Australian Competition and Consumer Commission, July 2018, August 2018, pp. 24, 49.

Gas Supply Hub (GSH)

Gas supply hubs at Wallumbilla in Queensland and Moomba in South Australia are a voluntary platform for gas trading. There are 5 standard product lengths that participants can use when trading at the gas supply hubs – balance of day, daily, day-ahead, weekly and monthly. Participants can trade gas 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 trade across different pipelines, thus pooling potential buyers and sellers into a single market.

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, respectively.

A significant proportion of trade occurs 'off-screen', which allows participants to use brokers to match trades on their behalf or leverage their existing bilateral arrangements to facilitate spot trades.[8]

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 enabled 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. This auction has been widely used to move gas between the east coast gas markets since its inception. From late 2022, participation in the auction increased significantly and set consecutive records for capacity won, with amounts procured more than double the highest levels observed across previous years (section 5.6.2).

5.2.3 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
- short-term LNG export transactions and short-term gas sales agreements, 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 to expand the scope of information reported (section 5.11.1).

8 While most gas trading occurs 'off-screen' (not traded through the gas markets), some of these trades are reported to the market operator and settled through the Gas Supply Hub trading platform.

5.3 Gas prices

Record high prices persisted for much of 2022, remaining at record levels throughout the final quarter despite dropping from the unprecedented levels observed over winter. The high prices were particularly evident in spot market prices and to a lesser extent in contract prices. Following the announcement of a $12 per GJ price cap on 9 December, prices reduced significantly even before the cap's introduction.

Export train outages from late December 2022 and late February 2023 saw additional supply availability in 2023. This led to supressed market prices at $12 per GJ or lower, with prices across the first half of the year generally below $15 per GJ most of the time. The exception was higher prices in May, as a result of planned and unplanned offshore maintenance outages at the Longford gas plant, which is the main southern supply source. Throughout the year, international prices have also continued to steadily decrease, putting downward pressure on local prices and increasing exporters' incentive to provide more gas to domestic users.

While the Longford extended outage from late April resulted in higher reliance on Iona's underground storage inventory, the reduced southern output also drove up demand to move gas south from Queensland supply sources. Most of this supply in March made its way down to the Sydney market. However, the amounts that flowed into Victoria were limited, partially influenced by planned compressor outages in the Victorian gas network. Further to this, planned maintenance on the Moomba to Sydney Pipeline constrained the level of gas that participants could obtain to flow south, which led to Sydney prices climbing as high as $30 per GJ briefly in late June when constrained supply capability was factored into the Short Term Trading Market's scheduling outcomes. Despite this, the level of gas being flowed south was higher than that for May in previous years.

Due to the combination of generally lower gas demand for electricity generation, milder winter temperatures driving lower winter demand, and low international prices alongside significant quantities of supply coming south, gas prices have been well below unprecedented levels observed last year.

5.3.1 Gas contract prices

The ACCC has access to gas contract information and reports on these prices through its gas inquiry.

Over previous years (2019 and 2020) domestic gas contract prices tended to track falling international prices, measured using LNG netback prices. However, prices offered for 2022 stabilised at the beginning of 2021.[9] Although prices increased over 2021 and 2022, domestic prices increased by less than international LNG prices, which were up by almost 230%. Since then, international LNG prices have markedly reduced back to mid-2021 levels and were on par with domestic gas market prices at the end of 2022–23. However, although international prices fell from record highs in 2022, they remain above long-term historical averages. This means that domestic offers linked to international gas prices exceeded historical east coast domestic gas market prices.[10]

Prices offered for east coast supply across 2023 increased sharply from March 2022, with the majority of offers exceeding $30 per GJ by August 2022.[11] Producer offers peaked in August, reaching over $70 per GJ. This reflected tight international market conditions. In comparison, retailer offers tracked below these levels at around $30 per GJ.[12] This was influenced by the high level of price volatility across mid-2022 and represented the highest price observation over the course of the inquiry, coinciding with a substantial increase in the price spread.[13]

In November 2022, 2023 offer prices decreased markedly. Producer offer prices fell to around $20 per GJ and short-term LNG netback prices also moderated from their peaks to just under $40 per GJ. Retail offers remained around $30 per GJ.[14] From 23 December, the Competition and Consumer (Gas Market Emergency Price) Order 2022 (section 5.10.8) came into effect for 12 months, with nearly all producer contracts from this period decreasing to $12 per GJ or less. Since the introduction of the price cap, the ACCC observed an increase in the volume of gas sold

9 LNG netback prices estimate the export parity price that a domestic gas producer would expect to receive from exporting its gas rather than selling it domestically.

10 ACCC, Gas inquiry 2017–2030, interim report, June 2023, Australian Competition and Consumer Commission, p. 38.

11 ACCC, Gas inquiry 2017–2030, interim report, January 2023, Australian Competition and Consumer Commission, p. 13.

12 ACCC, Gas inquiry 2017–2030, interim report, June 2023, Australian Competition and Consumer Commission, p. 11.

13 Between March and August, producer offers averaged nearly $20 per GJ, ranging from $10.15 per GJ to $65.25 per GJ. This influenced retailer offers to C&I customers above $30 per GJ.
ACCC, Gas inquiry 2017–2030, interim report, January 2023, Australian Competition and Consumer Commission, p. 14.

14 ACCC, Gas inquiry 2017–2030, interim report, June 2023, Australian Competition and Consumer Commission, p. 11.

under short-term gas supply agreements and traded on facilitated markets.[15] However, there was also a reduction in 2022 offers for supply in 2024 compared with 2021 offers for 2023 supply. Prices quoted for supply in 2023–24 fell from around $65 per GJ before the price cap to around $19 per GJ in April 2023.

Impacts of the $12 per GJ price cap on market trade

Given the short-term trading window in downstream markets is exempt from the price cap (section 5.10.8), and the changing trend towards an increased level of shorter-term trading in the upstream Gas Supply Hub (section 5.7.2), trading in east coast gas markets has overwhelmingly been exempt from the $12 per GJ price cap imposed in late 2022. Gas has frequently been available in these markets at prices at or below the cap, but this appears to have been caused by favourable market dynamics more than the effect of the cap.

Prices in these markets have fluctuated above and below the price cap in line with market dynamics, with mild winter conditions putting downward pressure on prices over the typically high gas demand periods. This was evident in March and May when upstream and downstream market prices declined and increased respectively due to specific changes in the supply-demand balance. Over March, LNG exporter outages saw excess gas supply sold into these markets alongside prices predominantly settling below $10 per GJ (section 5.3.3). In May, southern production and pipeline transportation constraints put upwards pressure on prices, occurring alongside rising demand resulting from a particularly cold end to autumn (section 5.5.2).

With short-term trading activity deliberately excluded from the government-imposed price cap to preserve market pricing signals, it is difficult to determine the exact effect this has had on reducing gas prices over 2023. However, these market dynamics have shown a move towards shorter-term trading with limited longer-term contracted supply offers continuing into 2023. There appears to have been less long-term gas available for contracting for terms that would have been covered by the price cap. Similarly, the ACCC reported in June 2023 that long-term gas contracting has fallen significantly.[16]

As part of the energy price relief plan announced in December 2022, the Australian Government has implemented a Mandatory Gas Code of Conduct (section 5.10.8) on 11 July 2023, extending to gas supply from 2024.

5.3.2 Short-term transaction reporting

From 15 March, information on east coast bilateral gas trades has been published on the Gas Bulletin Board summarising the reporting of short-term transactions to AEMO as part of new transparency measures. The information reported covers trade directly between parties conducted outside of the AEMO-facilitated markets and includes transactions with a contract length of 12 months or less. This information materially improves the comprehensiveness of data available on gas trade up to a year in length, of which bilateral trade is the majority.

Of this newly reported trade, the volume weighted average price for gas delivered over April to June 2023 was $13.80 per GJ. Prices of individual trades for delivery over the July to September and October to December 2023 quarters varied between $13.10 per GJ and $15.20 per GJ (Table 5.1). This suggests price expectations over the remainder of 2023 were in line with the range of trades observed over the April to June quarter of 2023.

Looking forward at reported transactions into 2024 and as far out as 2027, prices have been reported closer to $18 per GJ, materially above current levels. This could suggest market expectations of enduring upward price pressures. However, it may also indicate that buyers have been willing to pay a premium to secure longer-term gas.

15 ACCC, Gas inquiry 2017–2030, interim report, June 2023, Australian Competition and Consumer Commission, pp. 12, 54.

16 ACCC, Gas inquiry 2017–2030, interim report, June 2023, Australian Competition and Consumer Commission, p. 7.

Table 5.1 Forward pricing for short-term supply transactions

Period	Price (per GJ)	Range (per GJ)	Delivered quantity (PJ)
Q2 2023	$13.77	$11.49 – $16.12	10.7
Q3 2023	$14.73	$13.08 – $15.25	7.5
Q4 2023	$13.88	$13.23 – $14.24	9.6
2024	$17.47	$16.23 – $19.14	13.1
2025 to 2027	$17.70	$16.90 – $18.02	4.6

Note: The above prices and quantities are based on the actual delivered dates of the reported transactions and include all reported supply transactions and pricing structures. The volume weighted average price range is the minimum and maximum price accounting for all transactions on specific days of trade within that period. Forward trading prices are fixed, unlinked from any projection of a linked index price.

Source: AER analysis using Natural Gas Services Bulletin Board data.

As well as offering insights into forward trade, the trades reported so far since these reporting requirements commenced on 15 March 2023 suggest:[17]

- Most upstream trade takes place bilaterally – outside of the AEMO facilitated markets. Participants reported to the Bulletin Board supply transactions totalling 47 petajoules (PJ) compared with only 12.4 PJ traded through the Gas Supply Hub.[18]
- Producers (56%) and GPG gentailers (40%) sold the highest volumes of gas through reported bilateral trade.[19]
- Participants make extensive use of swaps, which they are also required to report. Almost 26 PJ of swap transactions have been reported to the Bulletin Board so far.[20]
- Most swap transactions are location swaps within Queensland as well as between Queensland and Victoria, where the majority of east coast gas production is concentrated.[21] In May, when Longford experienced production constraints coupled with constraints on the Moomba to Sydney Pipeline and higher demand, swap transactions were observed between Wallumbilla and delivery locations in the southern states that facilitated moving gas from north to south.

5.3.3 Spot market prices

Since notably reducing from volatile 2022 levels in mid-December, prices have largely stayed subdued over 2023 but remain above historical price levels (Figure 5.2). The decrease in wholesale market prices followed the Australian Government's announcement of a $12 per GJ cap on forward trades (section 5.10.8).

17 This comparison is based on all trades between 15 March 2023 and 30 June 2023 reported as short-term transactions to the Bulletin Board or traded through the Gas Supply Hub.

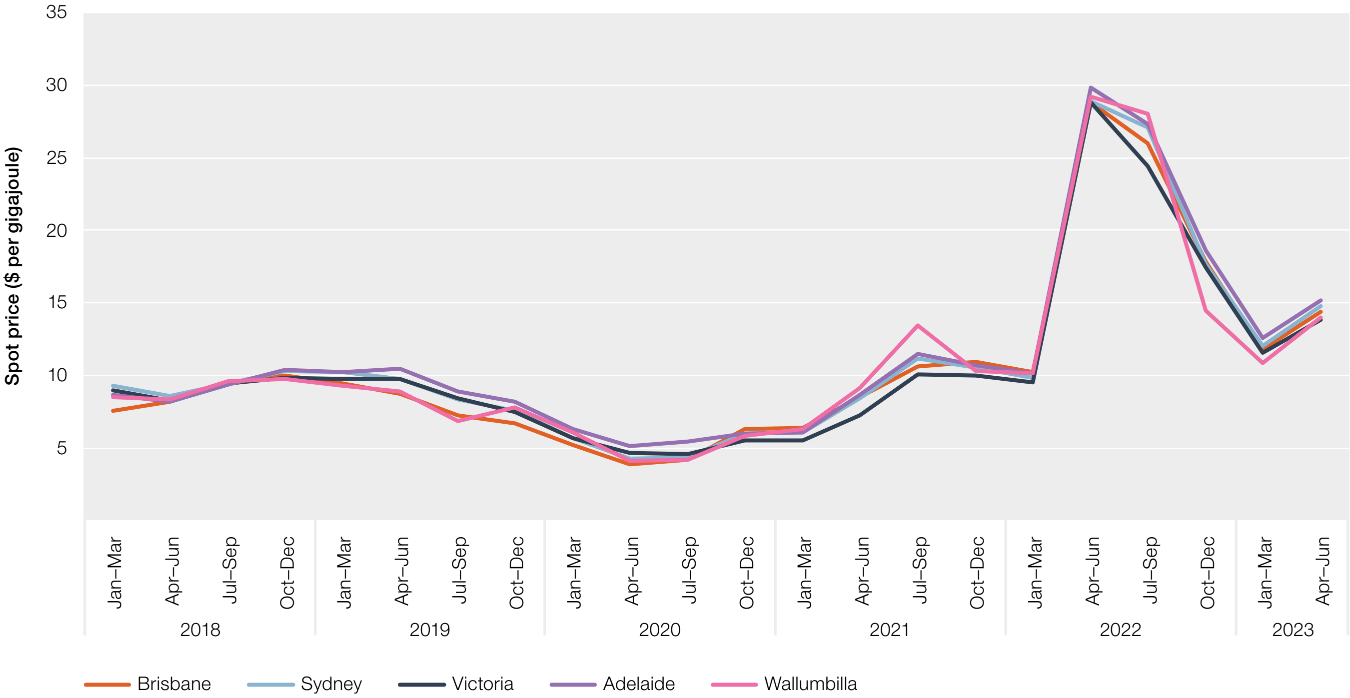
18 30.4 PJ of the 47 PJ reported in 2023 is for delivery in 2023.

19 Gas Powered Generation (GPG) gentailer refers to gas retailers that have gas-fired electricity generation assets. In this category, Energy Australia, Origin and Shell sold the most by volume and reflected almost 80% of gentailer sales; the other participants the AER classified as gentailers are Alinta, AGL, CleanCo, Engie and Hydro Tasmania.

20 When reporting short-term transactions to the Bulletin Board, sellers are required to identify if it is a supply transaction, location swap, time swap or swap of both time and location. Both parties to a swap transaction are required to report the transaction with the associated location and price information attached to the swap transaction.

21 The most popular swap locations in Queensland are the Wallumbilla high pressure trading point and the Roma to Brisbane in pipe trading point, while in Victoria most location swaps are at Longford. In New South Wales most of the location swaps are to Wilton, a delivery point into the Sydney STTM.

Figure 5.2 Eastern Australia 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 prices settled following unprecedented volatility in 2022

Prices across the gas markets reduced into August, averaging $17 per GJ for the month and diverging from high international prices, which continued to increase. Contributing factors included reduced demand for gas generation and gas heating as the weather warmed, with depleted southern storage levels at Iona starting to be refilled.

The fall in prices also coincided with the Victorian market coming out of an administered price cap state, incentivising participants to offer additional capacity to the market above their own portfolio requirements as tight supply and demand conditions eased. While prices rebounded over the following month and remained at record high levels for the end of the year, there was a significant decrease in market volatility, with lower NEM demand lessening the strong link between gas and electricity prices observed over mid-2022.

During the lower demand period in December, prices also decreased sharply from 9 December following the government's announcement of a $12 per GJ gas contract price cap for 2023. Prices then rebounded gradually over January, settling around $12 to $14 per GJ in the following months.[22]

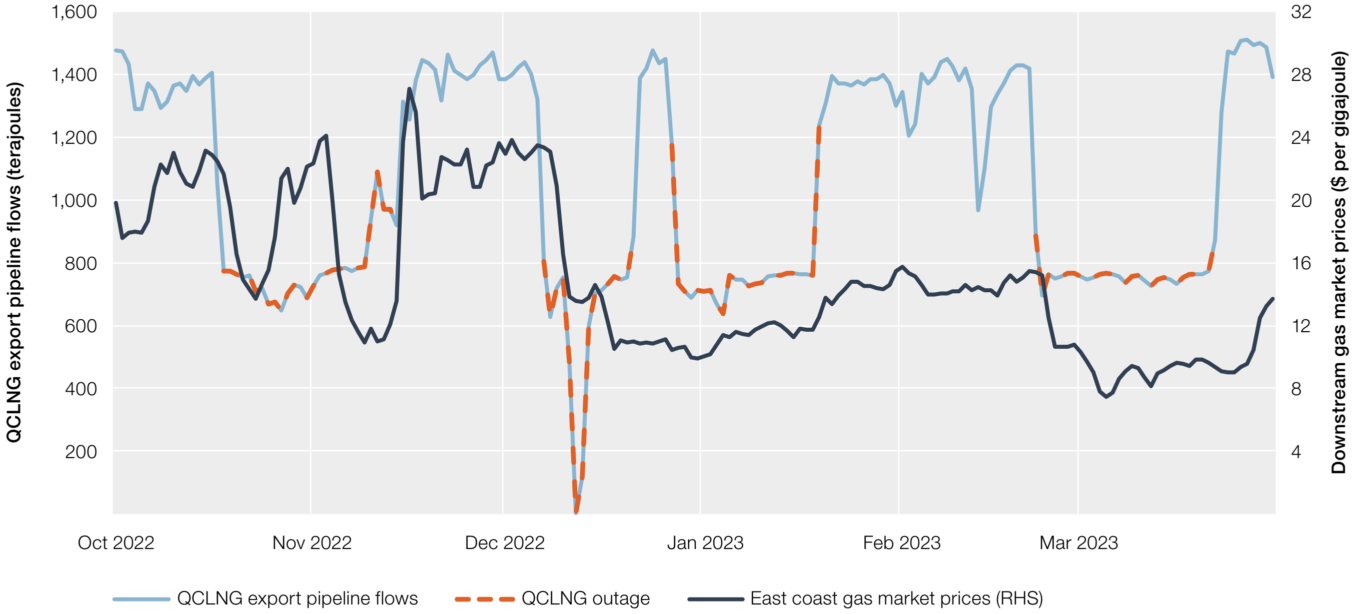
Gas prices in 2023

In the January to March quarter of 2023, gas spot market prices declined amidst substantial short-term trade. Lower market demand and additional gas availability during export train outages reduced pressure on gas prices, with low prices in March driving the quarterly average east coast market prices below $12 per GJ. A planned QCLNG export train maintenance outage from late February was extended out to 22 March, increasing the window of additional cheaper gas availability that helped to suppress prices across the east coast markets (Figure 5.3). This contributed to prices averaging under $10 per GJ across March, dropping as low as $7 per GJ in Brisbane and Victorian markets.[23]

22 The exceptions to this were average east coast gas market prices rising to $18.81 per GJ in May 2023 and low prices in March 2023 (Figure 5.4).

23 Relatively low gas generation levels in the National Electricity Market (NEM) also contributed to lower demand levels in and upstream of the gas markets (Figure 5.9), while steadily declining international gas prices also eased the upwards pressure on local prices that was evident in mid-2022 (Figure 5.6).

Figure 5.3 QCLNG maintenance outages and average east coast gas market prices



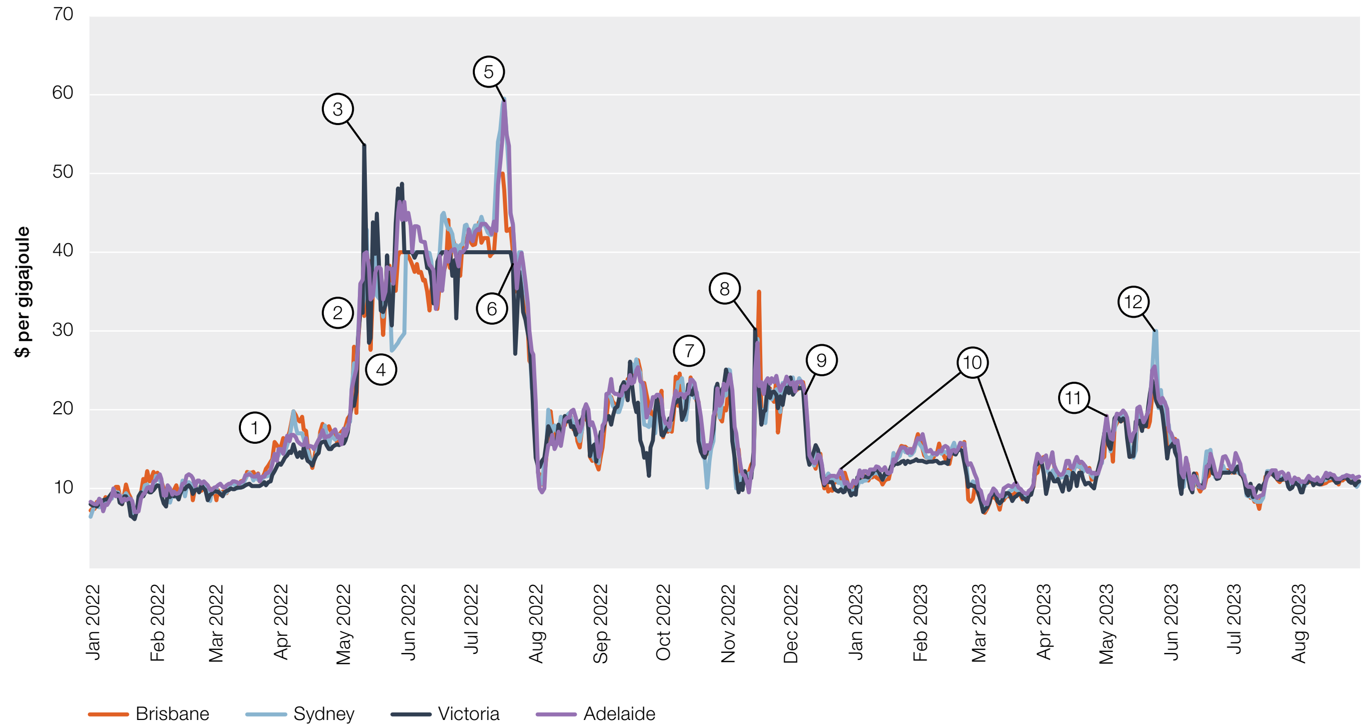
Source: AER analysis using Gas Bulletin Board and market price data (STTM and DWGM)

In the April to June quarter of 2023, average spot prices increased to roughly $14.50 per GJ. This was largely driven by higher prices in May, when prices in southern markets increased above $19 per GJ. The price increases for that month were driven by constraints on Victoria's Longford production facility, which provides most of the state's gas supply. While gas flows south from Queensland were high over the period, planned pipeline maintenance restricted more supply coming from the north that could have put downward pressure on the elevated prices. As a result, participants in the south were more reliant on Iona's underground storage during periods of higher demand. However, unlike in previous years, when substantial run-down on storage inventories reduced storage to critically low levels mid-winter, participants this year topped up storage levels to near full capacity heading into winter.[24] Prices decreased in subsequent months, averaging below peak levels observed over winter 2022 and 2021.

Figure 5.4 sets out an annotated timeline of key pricing events in 2022 and 2023 to date.

24 Refer to the AER Wholesale market quarterly report for Q2 2023 for a more detailed description of the interacting factors contributing to higher gas prices in May.

Figure 5.4 Daily gas spot prices



Note:
1. From late March 2022: Gas prices become increasingly volatile, with drivers of higher prices including a combination of cold weather, low wind levels, coal generation outages and elevated gas-powered generation, with some gas contracts reset at higher prices into the new quarter.
2. From early May 2022: Gas flowing north in contrast to gas flowing south in May 2021, coupled with increased gas demand for electricity generation (14 PJ in May compared with 10 PJ in April on mainland) influenced by baseload outages, with very high NEM prices.
3. 12 May 2022: Victoria, consecutive demand forecast increases and reduced $15 to $30 per GJ supply, with 211 TJ of controllable withdrawals further driving up demand (record price).
4. From late May 2022: Administered prices in Brisbane, Sydney and Victoria contribute to unprecedented gas market price volatility.
5. 15 and 18 July 2022: Record market price in Brisbane ($50.11 per GJ on 15 July), Adelaide ($59.23 per GJ on 18 July) and near-record in Sydney ($59.49 per GJ on 18 July).
6. From late July 2022: Victorian daily prices reduce below the $40 per GJ Administered Price Cap, with the cumulative 7-day price falling below the threshold and triggering the removal of the cap from 1 August.
7. Mid-September to mid-November 2022: Post-winter prices stabilise around $20 to $25 per GJ but remain historically high, with periodic dips below $20 per GJ driven by milder temperatures lowering southern market demand.
8. 15 to 18 November 2022: Record seasonal prices. Prices exceed record levels prior to May 2022 in the STTMs ($28.50 per GJ in Adelaide and $28.99 per GJ in Sydney on 16 November, $35 per GJ in Brisbane on 17 November), also high in Victoria ($30.25 per GJ on 15 November). Significant price variations triggered by ex-ante price decreases in Sydney (17 November) and Brisbane (18 November).
9. 9 December 2022: Government announces $12 per GJ gas contract price cap.
10. 27 December to 19 January and 22 February to 8 March: QCLNG planned maintenance outages influencing additional production capacity becoming available to downstream market participants.
11. May 2023: Cold weather and constrained supply from Longford influencing higher prices in Victoria, which flowed through to other markets.
12. 24 to 26 May 2023: Limits on Moomba to Sydney Pipeline flows impact the Sydney market, resulting in constraint pricing and high ex-ante prices.

Source: AER; AEMO (raw data).

5.3.4 2022 local prices and international price trends

Annual domestic prices increased over 2022, rising by 133% from the previous year. Price increases occurred alongside soaring international prices, but they were primarily driven by several overlapping local factors outlined below.

2022 average prices were driven up by particularly high prices that commenced from April and persisted throughout the winter months. Continued price volatility remained in the latter part of the year, albeit at much lower levels than the unprecedented increases in May, June and July.

Unprecedented price volatility from May to August 2022

Following a noticeable increase from late March, when prices are usually subdued before winter, spot market prices from May 2022 reached record highs. This reflected a series of overlapping factors, including:

- high international gas prices and changes to global supply and demand conditions, strengthening the incentive for producers to export LNG rather than supply into the domestic market
- significant demand from gas-powered generators due to other supply-side constraints in the NEM (section 5.4.1)
- demand pressures arising from residential heating demand in southern states following a particularly cold start to winter.

These factors led to events that increased participant uncertainty during a time of very tight supply-demand conditions, including:

- the suspension of a market participant resulting in administered pricing mechanisms being applied in short-term trading markets alongside the Retailer of Last Resort (RoLR) mechanism being triggered[25]
- high cumulative prices in Victoria accruing due to sustained high market prices, which triggered administered pricing due to the Administered Price Cap (APC) being exceeded
- distorted price signals resulting in participants reducing their offers to the market to retain gas supply quantities in their portfolios
- AEMO invoking the first ever activation of the Gas Supply Guarantee (GSG) mechanism to ensure the availability of gas supply to gas-fired electricity generators (section 5.10.2) – this encouraged increased flows south from Queensland to meet upstream and downstream demand requirements in southern regions
- high gas generation requirements on numerous days coinciding with high downstream gas market demand, putting further pressure on gas market supply and driving high prices in the electricity market
- the run-down of Iona underground storage levels in Victoria to near critical low levels by mid-winter,[26] which then led to multiple notifications about threats to system security in Victoria from 11 July, culminating in the notification of potential shortfalls across the whole south-eastern region from 19 July until the end of September
- low Iona storage levels also led to:
  - the re-activation of the GSG out to the end of September following an industry conference
  - the direction to market participants to cease sourcing gas supply from the Victorian market for electricity generation to balance volatile supply and demand requirements.

Linkages between domestic and international prices

The growth in Queensland's LNG exports from late 2020, combined with other factors including state-based moratoriums on gas development and a tightened supply-demand balance, has placed increasing pressure on east coast domestic markets.

Over 2021, a severe northern hemisphere winter combined with shipping constraints drove up Asian prices early in the year. Later in the year, competition between Asian, European and South American buyers combined with higher demand from replenishment of European storage levels. This led to higher prices in late 2021 over the northern hemisphere winter. In early 2022, the Russian[27] invasion of Ukraine put upwards pressure on global oil and gas prices. Bans on Russian oil drove countries to diversify their supply and to decrease dependence on Russia for both oil and gas, sending ripple effects across global supply chains.

In 2022 further pressure from gas-powered generation heading into the higher demand winter period contributed to driving gas market prices up to unprecedented levels. This coincided with a particularly cold start to winter, which drove higher east coast demand. This in turn led to domestic prices converging with surging international prices in mid-2022 (Figure 5.5). The curtailment of Russian gas supply to Europe drove up international LNG demand from alternative supply sources. While Russian gas supply to Europe was maintained and underground storage levels increased, netback prices briefly reduced below $30 per GJ in mid-2022, resulting in international prices briefly

25 The Retailer of Last Resort (RoLR) scheme is a mechanism used to transfer retail customers to other entities in the event of a retailer failure, to ensure those customers continue to receive electricity and gas.

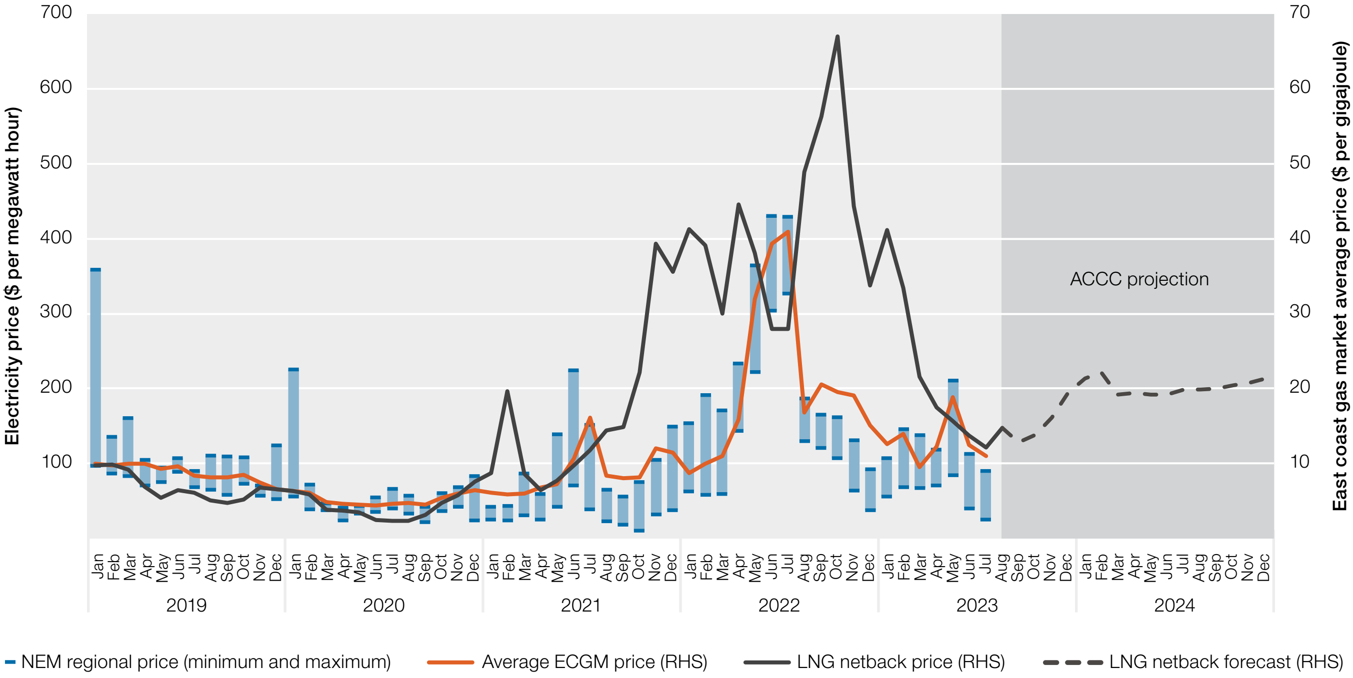
26 Optimum storage levels at Iona must remain above 6 PJ to sustain the required pressure levels in the tank for the facility to ensure adequate supply requirements can be met.

27 Russia is one of the biggest global producers of both oil and gas commodities.

dipping below domestic price levels. However, subsequent Russian supply threats resulting in pipeline flow reductions, and an explosion at Freeport LNG that took a significant amount of US LNG off the market, drove prices back up in August.

In 2023, international gas fuel supply risk reduced as storage inventories grew, particularly in Europe. This resulted in international prices continuing to decline, falling to levels observed one year prior. While international prices converged with domestic gas market prices, they remain above historical averages. This means that domestic offers linked to international gas prices exceeded the prices historically seen in the east coast domestic gas market.

Figure 5.5 Comparison of east coast gas market, NEM and LNG netback prices

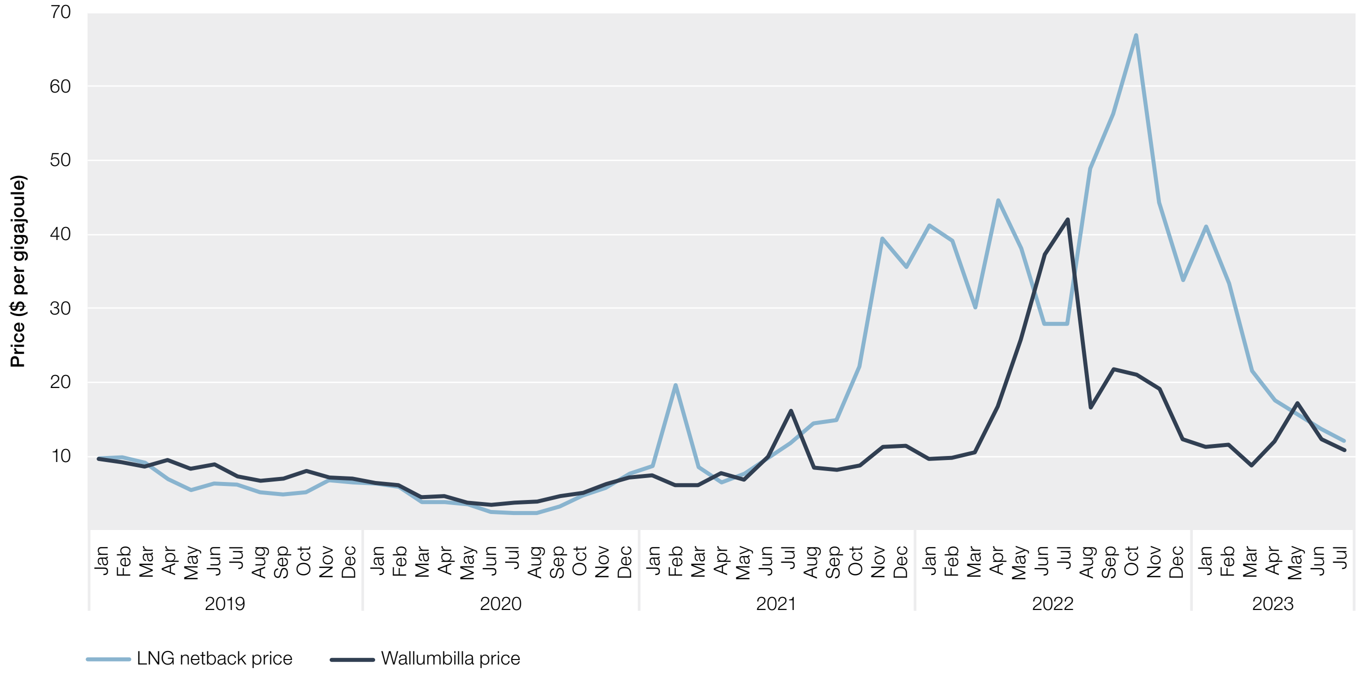


Note: ECGM is east coast gas market. NEM is National Electricity Market. The LNG netback price calculates the export parity price and subtracts the cost of liquefaction and transport required to produce and deliver LNG to international customers. LNG netback forecast 28 July 2023.

Source: AER analysis of NEM, Short Term Trading Market, Victorian Declared Wholesale Gas Market and ACCC LNG netback price data.

Seasonal factors are also strong drivers of international demand and prices for gas, typically increasing during the northern hemisphere winter. Policy measures that influence gas use and broader economic factors can also be strong drivers of changes internationally.

Figure 5.6 LNG netback and Wallumbilla prices



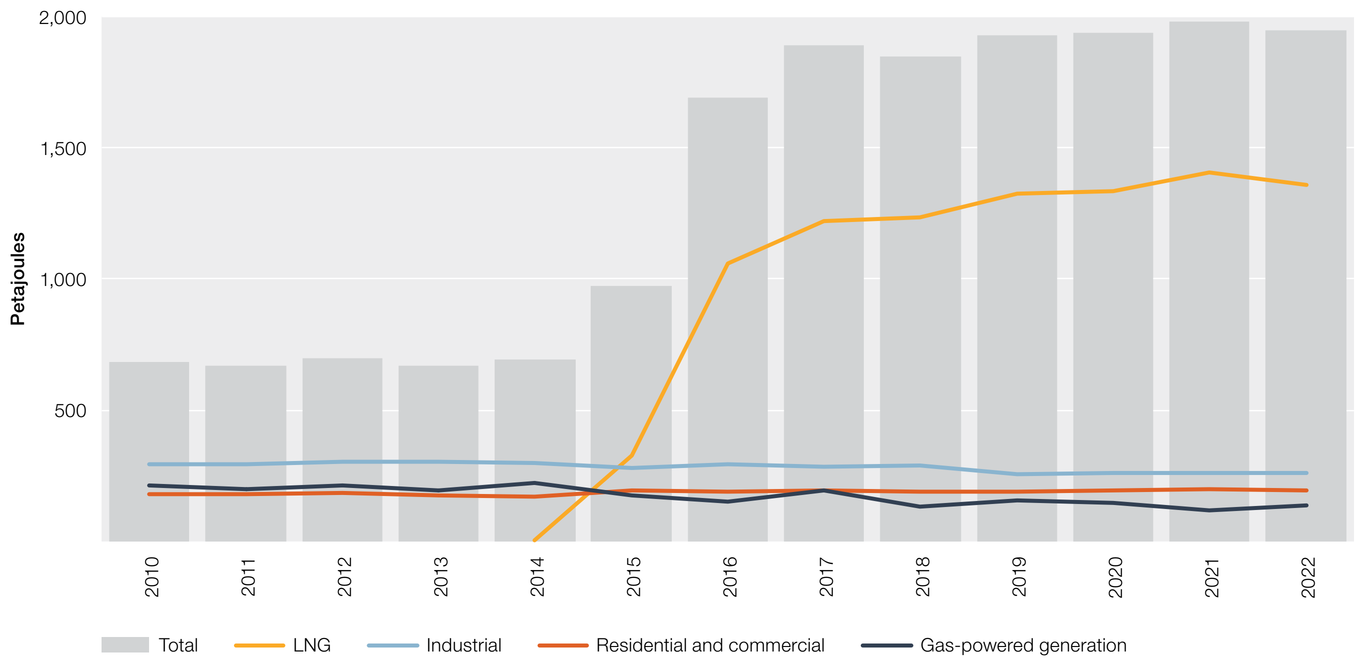
Note: The LNG netback price calculates the export parity price and subtracts the cost of liquefaction and transport required to produce and deliver LNG to international customers.

Source: AER analysis of Gas Supply Hub data; ACCC (LNG netback prices).

5.4 Gas demand in eastern Australia

Around 70% of domestic gas production in eastern gas markets (excluding the Northern Territory) is exported and the balance is sold into the domestic market (Figure 5.7).

Figure 5.7 Eastern Australian gas demand



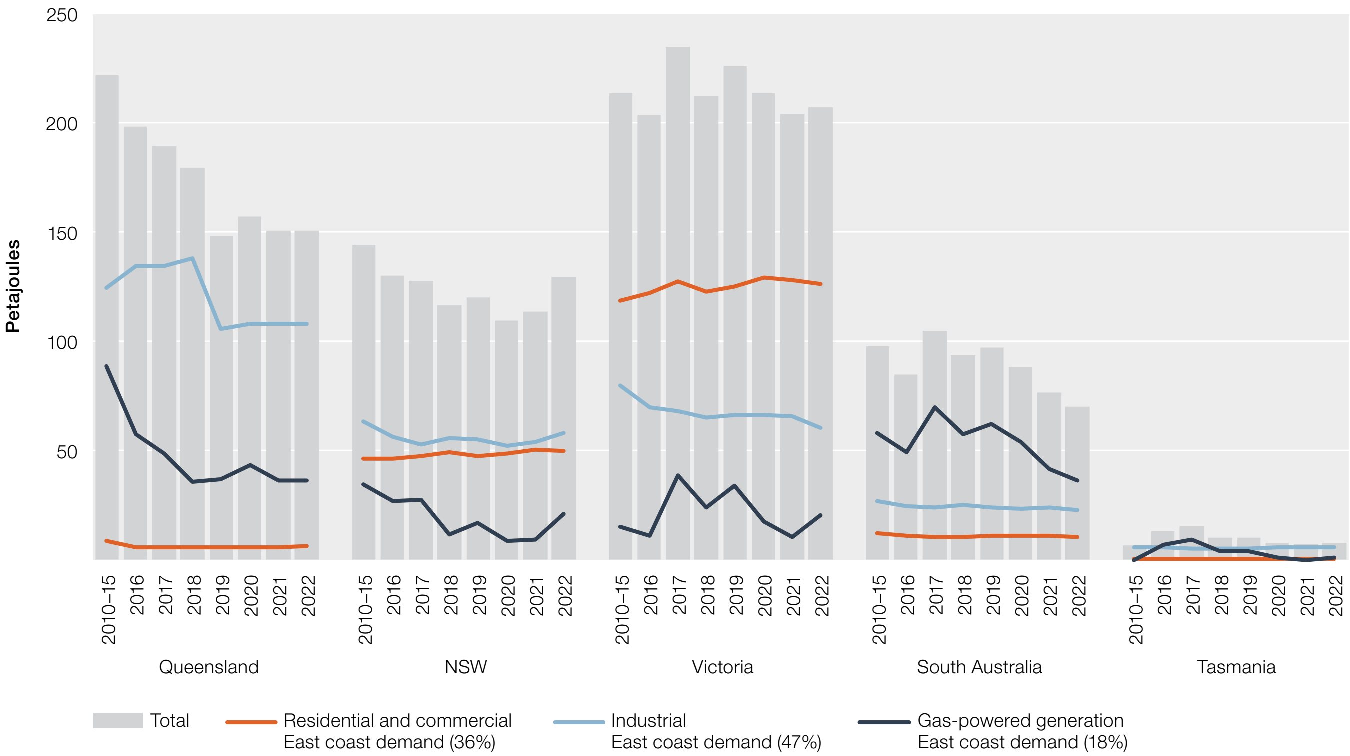
Source: AEMO, *2023 Gas Statement of Opportunities*, March 2023.

5.4.1 Domestic demand

Domestic customers in eastern Australia used around 590 PJ of gas in 2022 (Figure 5.8). These customers included industrial businesses, electricity generators, commercial businesses and households.

Industrial customers consumed 44% of gas sold to the domestic market. 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 5.8 Eastern Australian gas demand by state



Note: Data for 2010–15 is average annual consumption over that period.
Source: AEMO, *2023 Gas Statement of Opportunities*, March 2023.

Residential and commercial customers accounted for 33% of domestic gas demand, but this share varies from state to state. For example, in Victoria more than 60% of gas is consumed by small residential and commercial customers, who use gas mostly for heating and cooking. In Queensland, where much fewer households are connected to a gas network, the share of gas consumed by residential and commercial customers falls to 4%.

The electricity sector is another major source of gas demand, accounting for 23% of domestic gas use in 2022, down from 29% in 2017. South Australia and Queensland used the most gas-powered generation (GPG) in 2022 (each on par using 31% of GPG in the NEM). 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 factors, including unforeseen events.[28]

Domestic gas use in 2022 and 2023

In 2022, GPG gas usage was 20.7 PJ – almost double that of 2021 (10.5 PJ). This was driven by higher gas generation demand from late May, influenced by multiple coinciding factors. An early winter cold snap occurred, combined with low solar and wind generation levels, driving up domestic gas consumption and gas generation requirements.[29]

28 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 recent years.

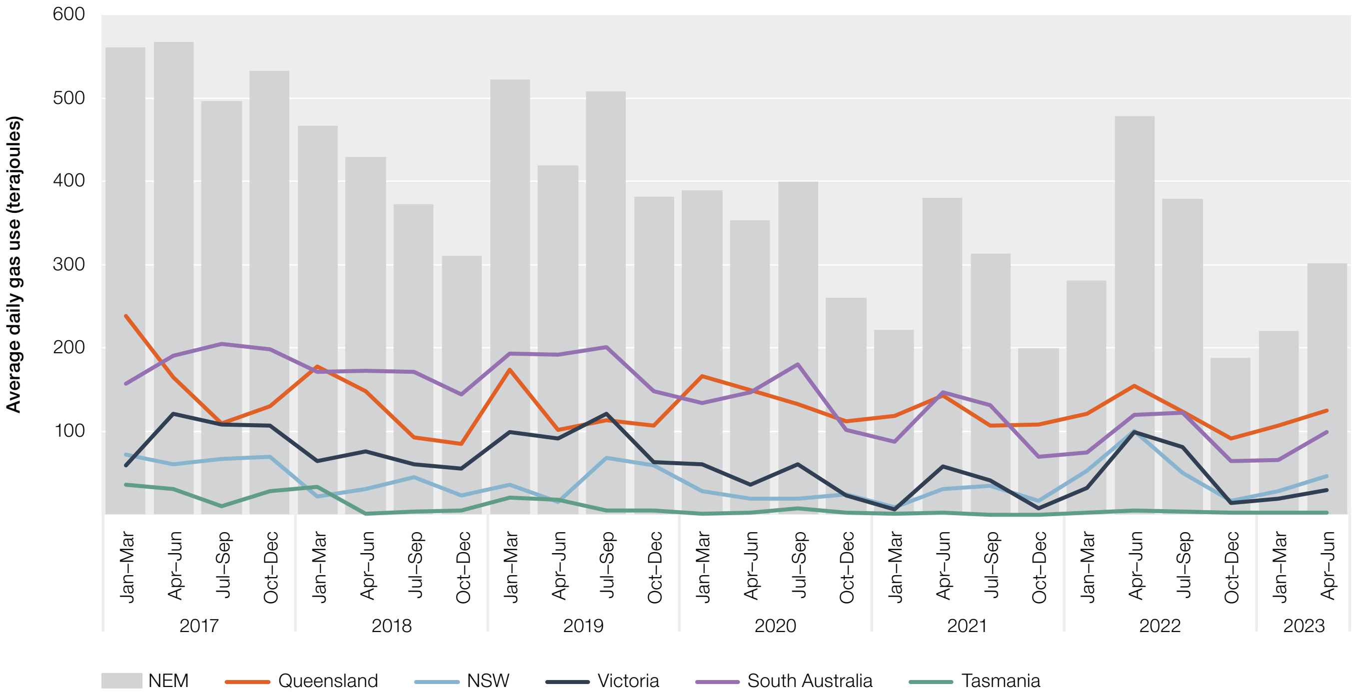
29 While large commercial and industrial demand was the lowest since market start (65 PJ) due to the closure of the Mobil refinery and mothballing of a Qenos plant in Altona, and Saputo Dairy Australia winding down its Maffra facility, small commercial and residential demand (128 PJ) was at its third highest level since market start (after 2020 and 2017).

This was further impacted by continued high demand resulting from reduced coal generation in Victoria and NSW, with some facilities impacted by flooding that also put limits on hydroelectric generation output. Further to this, planned and unplanned electricity network outages limited access to cheaper generation in the Queensland and South Australian regions of the NEM, all occurring at a time of high electricity demand. To get around limitations on gas supply, some generators switched to running their gas generation assets on liquid fuels.

The combination of very high fuel prices, fuel constraints and fuel rationing led to unprecedented NEM prices and AEMO suspending the electricity market. High gas prices and the suspension of a gas market participant also resulted in successive administered price periods coming into place across multiple downstream gas markets.

Over 2023 to date, GPG has been down from levels observed in previous years.

Figure 5.9 Quarterly gas demand for gas-powered generation



Source: AEMO; National Electricity Market (NEM) generation data and heat rates (gigajoules per megawatt hour).

5.4.2 Liquefied natural gas exports

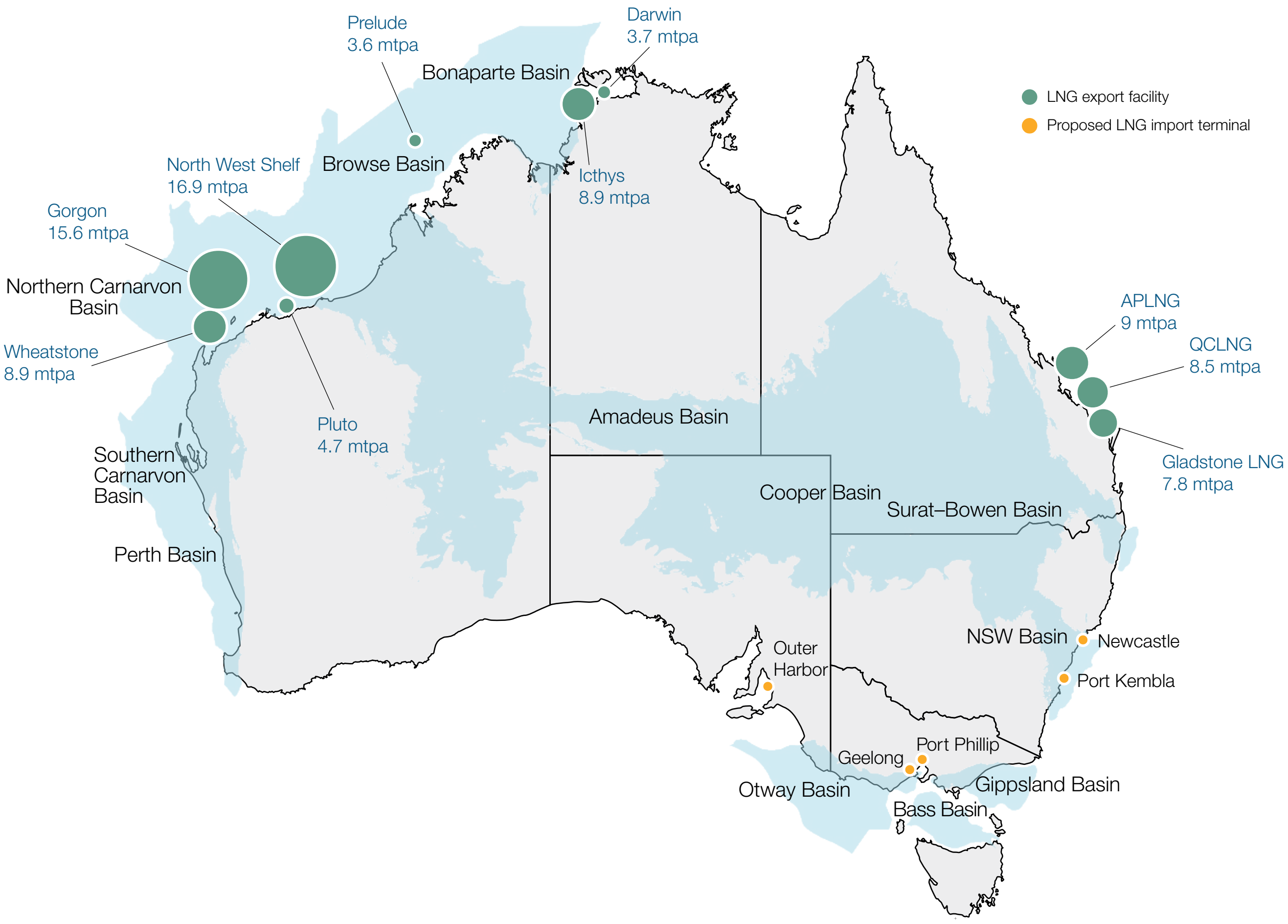
Most of the gas produced in eastern Australia is exported as liquefied natural gas (LNG).

In eastern Australia, export gas is liquefied in processing facilities in Queensland to make it economic to store and ship in large quantities (Table 5.2). Australia also operates 5 LNG projects in Western Australia and 2 in the Northern Territory (Figure 5.10).

In 2022 LNG exports totalled $91 billion, up from $49.8 billion in 2021, making gas Australia's second largest resource and energy export behind iron ore and putting Australia on par with Qatar as the world's largest LNG exporter in 2022.[30] These export levels are expected to be overtaken by Qatar and the United States due to significant growth in coming years.

30 EnergyQuest, *EnergyQuarterly*, March 2023; Department of Industry, Science, Energy and Resources, Resources and energy quarterly, December 2022.

Figure 5.10 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; DISER, Resources and energy quarterly, June 2023.

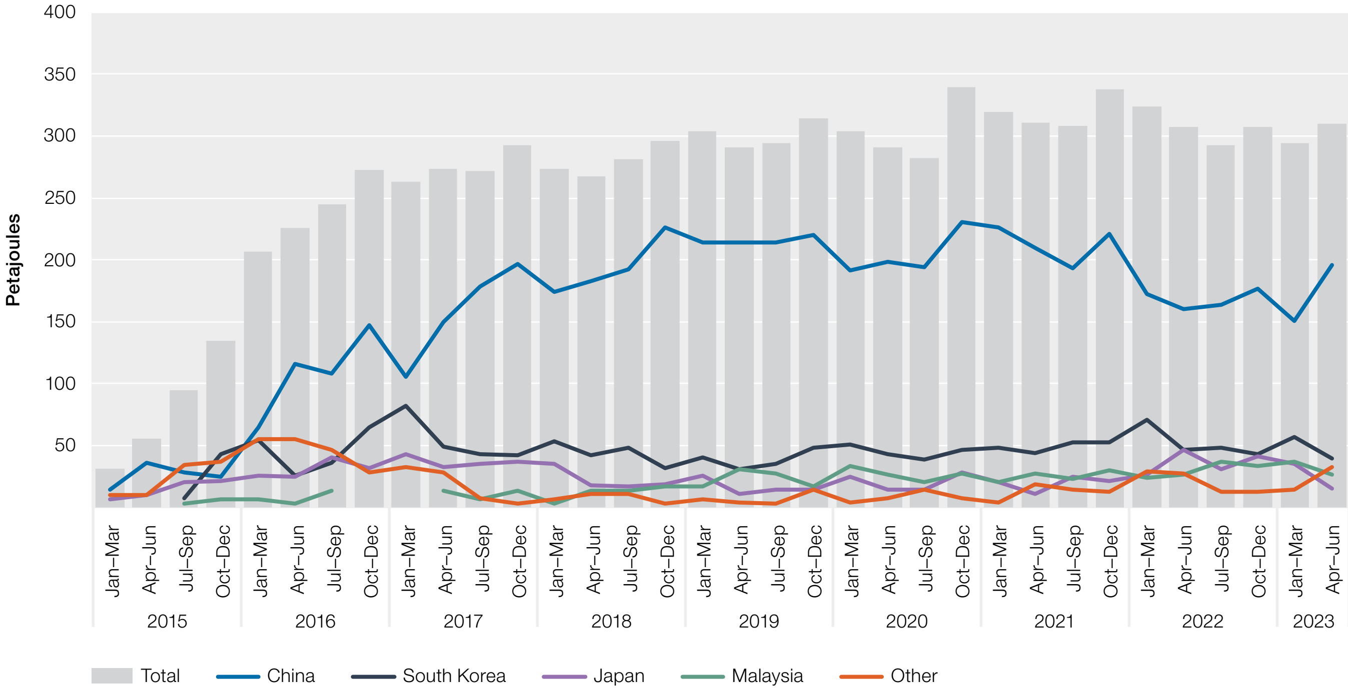
Queensland's LNG industry comprises 3 major projects, which source gas mainly from the Surat–Bowen Basin:

- The Queensland Curtis LNG (QCLNG) project has capacity to produce 8.5 million tonnes of LNG per annum (mtpa). Shell (73.75%), CNOOC (50% equity in Train 1) and Tokyo Gas (2.5% equity in Train 2) own the project.
- The Gladstone LNG (GLNG) project has capacity to produce 7.8 mtpa. Santos (30%), Petronas and Total (27.5% each) and Kogas (15%) own the project.
- The Australia Pacific LNG (APLNG) project has capacity to produce 9 mtpa. Origin Energy and ConocoPhillips (37.5% each) and Sinopec (25%) own the project.

These LNG projects control close to 90% of 2P reserves in eastern Australia.[31] They also source gas from other producers through long-term contracts and spot markets. East coast gas exports are typically lower mid-year, when domestic demand increases in winter, and higher over summer as northern winter conditions drive up international demand.

31 ACCC, Gas inquiry 2017–2030, interim report, January 2023, Australian Competition and Consumer Commission, January 2023, p. 7. 2P reserves represent proven and probable reserves (probable reserves are deemed 50% likely to be commercially recoverable).

Figure 5.11 Eastern Australian gas exports



Source: AER analysis using Gladstone Port Corporation data.

East coast LNG exports in 2022 reduced by around 45 PJ compared with last year's record level. APLNG operated above capacity across most of 2022, contributing to near record eastern Australian production levels (Figure 5.11 and Figure 5.13).

China is the primary market for eastern Australian LNG, accounting for 55% of exports in 2022 (674 PJ). These exports decreased significantly from the previous year's 851 PJ volume (67%), falling to their lowest level since 2017. While China's LNG demand is expected to continue to grow, supported by expanded industrial and residential gas use, high prices and lockdowns over 2022 influenced reduced imports alongside higher pipeline supply and domestic production. China has offset reduced Australian supply by sourcing additional imports from Russia, which increased by 77% in the 3 months following the invasion of Ukraine.[32]

Conversely, while Chinese imports declined over 2022, Korean and Japanese east coast imports increased to their second highest level since 2017. The Republic of Korea, the other main source of east coast LNG demand, increased their imports by over 10 PJ from last year to 208.7 PJ.[33] This followed the easing of restrictions aimed at reducing coal generation from April 2022, with the South Korean government subsequently extending its tariff exemption on LNG imports until the end of March 2023.[34] Japanese imports also rose to 144.9 PJ, just less than the 148.6 PJ record set in 2017, with Australian exports offsetting reduced imports from the United States and Qatar.[35]

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).

32 Department of Industry, Science, Energy and Resources, Resources and energy quarterly, June 2022, p. 77; Department of Industry, Science, Energy and Resources, Resources and energy quarterly, December 2022, p. 73.

33 Compared to 216.1 PJ record demand set over 2017.

34 Department of Industry, Science, Energy and Resources, Resources and energy quarterly, December 2022, p. 74.

35 Department of Industry, Science, Energy and Resources, Resources and energy quarterly, December 2022, p. 74.

5.5 Gas supply in eastern Australia

Gas supply to the northern gas market is largely supplied from Queensland's Surat–Bowen Basin. But gas is also sourced from the Cooper Basin in South Australia and from the Northern Territory. At times, southern gas is also transported north to meet LNG export demand. Gas from the northern fields is also required to supplement Victorian gas production to meet domestic gas demand in southern Australia over winter.

After consecutive yearly increases, exports drove a ramp up in production from Queensland's Roma gas fields, peaking in 2021.[36] While exports remained high in 2022, Roma production decreased to 4,034 terajoules (TJ) per day as LNG projects eased export levels slightly from the previous year (Figure 5.11 and Figure 5.13). The 129 TJ per day decrease was largely offset by a 115 TJ per day increase in southern production, which supplied an additional 10 PJ into Queensland over 2022 compared with 2021 (Figure 5.19).

Background

From 2021, to avoid export controls, Queensland's LNG producers entered into a series of Heads of Agreement with the Australian Government, committing to offer uncontracted gas to domestic buyers on competitive terms before offering it for export.[37] On 29 September 2022 a new Heads of Agreement was signed with exporters, which resulted in the government's decision not to trigger the operation of the Australian Domestic Gas Security Mechanism (ADGSM) for 2023 (section 5.10.1).

In 2023, east coast gas users have become more reliant on northern production because of the continuing decline in Victoria's Gippsland Basin output due to the depletion of legacy fields supplying the Longford gas plant.[38] While annual southern production forecasts have decreased, the short-term maximum daily forecast in 2023 increased from previous AEMO gas statement of opportunities (GSOO) reports. However, annual production from southern fields is expected to reduce from 392 PJ in 2023 to 255 PJ in 2027.[39]

Current conditions

Over winter 2023, peak day output from Longford was forecast at 915 TJ per day in the 2023 GSOO, but this reduced to 860 TJ per day coming into the winter months. Actual peak day production reached 793 TJ in winter 2023, well below the facility's maximum production level of 1,046 TJ in winter 2022.[40] This resulted in Victoria relying more on gas flows south from Queensland from May 2023. These higher southern flows were assisted by the completion of upgrade works on the South West Queensland and Moomba to Sydney pipelines in June (section 5.8.3).[41]

Gas supply from Iona was also better managed this winter, with the storage facility in an improved position to mitigate potential shortfalls compared with periods of rapid draw-down to very low levels mid-winter in 2021 and 2022. Upgrades to the facility had also increased storage capacity before winter, with works to add additional pipeline compression and additional capacity via the western outer ring main (WORM) project expected to be commissioned from late September to early October. This allows for additional gas flows across the Victorian transmission system and enables Iona to supply and refill from the Victorian market at higher rates (section 5.8.3).

These brownfield solutions have assisted in ensuring southern gas demand is met, but risks of peak day shortfalls remain. Low levels of gas-fired generation requirements in the electricity market have assisted in not putting upward pressure on gas prices this winter.

Upcoming greenfield plans, such as the Senex Atlas, Cooper Otway and Santos Narrabri projects, are important in meeting demand but will not become available in the short term and will be insufficient to fill the longer-term supply gap.[42] AEMO's 2021 outlook had improved from previous years due to planning progress for AIE's Port Kembla LNG import terminal. However, despite pipeline expansions taking place to facilitate the delivery of this gas to east coast markets, AIE was unable to secure sufficient interest in contracting supply to justify the relocation of a floating storage and regassification unit (FSRU) to receive and supply the gas in coming years.

36 Queensland gas production reached consecutive record levels from 2013 to 2021.

37 The LNG projects use various methods to sell more gas domestically, including selling short-term gas on the Wallumbilla Gas Supply Hub, launching expression of interest (EOI) processes for customers for long-term gas contracts, and entering bilateral arrangements for short-term and long-term gas contracts.

38 Longford is the largest and most flexible source of southern gas supply.

39 AEMO, 2023 gas statement of opportunities, Australian Energy Market Operator, March 2023, p. 48.

40 Actual maximum winter production output from Gippsland production facilities in 2022 was 1,126 TJ; AEMO, 2023 gas statement of opportunities, Australian Energy Market Operator, March 2023, p. 6.

41 APA, east coast grid expansion project.

42 EnergyQuest, *EnergyQuarterly*, June 2023, pp. 31–32.

Outlook

Despite improved short run supply forecasts, the longer-term outlook remains uncertain. Supply outlooks across 2024 to 2026 are forecast to be improved, yet production over this period is expected to become increasingly reliant on uncertain and undeveloped sources of supply. Potential supply shortfalls have been forecast to occur in southern states from 2023 and across the east coast from 2027. While more supply and associated infrastructure is clearly needed, most of the proposed projects to facilitate additional production have been delayed, with supply not expected to commence until 2025 or 2026. 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.[43]

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.

In response to this ongoing supply uncertainty, the Australian Government and some state governments launched initiatives to encourage new projects to supply the domestic market (section 5.10).

5.5.1 Gas reserves and production

Eastern Australia had 37,101 PJ of 'proven and probable' (2P) gas reserves in March 2023, having produced almost 2,000 PJ of gas in 2022 (Table 5.2).

Ownership is highly concentrated in some gas basins, but more diverse across the east coast (Figure 5.1). APLNG owns the majority of reserves in eastern Australia through an incorporated joint venture with Origin Energy, ConocoPhillips and Sinopec.

Table 5.2 Gas basins serving eastern Australia

	Gas production – 12 months to December 2022			2P gas reserves (March 2023)	
Gas basin	Petajoules	Share of eastern Australian supply	Change from previous year	Petajoules	Share of eastern Australian reserves
Surat–Bowen (Qld)	1,477	75.3%	-3%	29,252	79%
Cooper (SA–Qld)	80	4.1%	-13%	1,024	3%
Gippsland (Vic)	310	15.8%	7%	1,687	5%
Otway (Vic)	48	2.5%	37%	600	2%
Bass (Vic)	5	0.2%	-34%	24	0.1%
Sydney, Narrabri, Gunnedah (NSW)	3	0.1%	-16%	7	0.02%
Amadeus (NT)	15	0.8%	-2%	220	1%
Bonaparte (NT)	24	1.2%	-45%	4,287	12%
Eastern Australia total	1,962	–	-3%	37,101	–
Domestic gas sales	572	–	-2%	–	–
LNG exports	1,390	–	-3%	–	–

Note: 2P: proven plus probable reserves estimated to be at least 50% sure of successful commercial recovery.
Totals may not add to 100% due to rounding. 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.

Source: EnergyQuest, *EnergyQuarterly*, March 2023.

Queensland's Surat–Bowen Basin holds 79% of gas reserves in eastern Australia and supplied 75% of gas produced in 2022. Queensland's 3 LNG projects produced close to 95% of the basin's output in 2022.

43 ACCC, Gas inquiry 2017–2030, interim report, January 2023, Australian Competition and Consumer Commission, January 2023, p. 125.

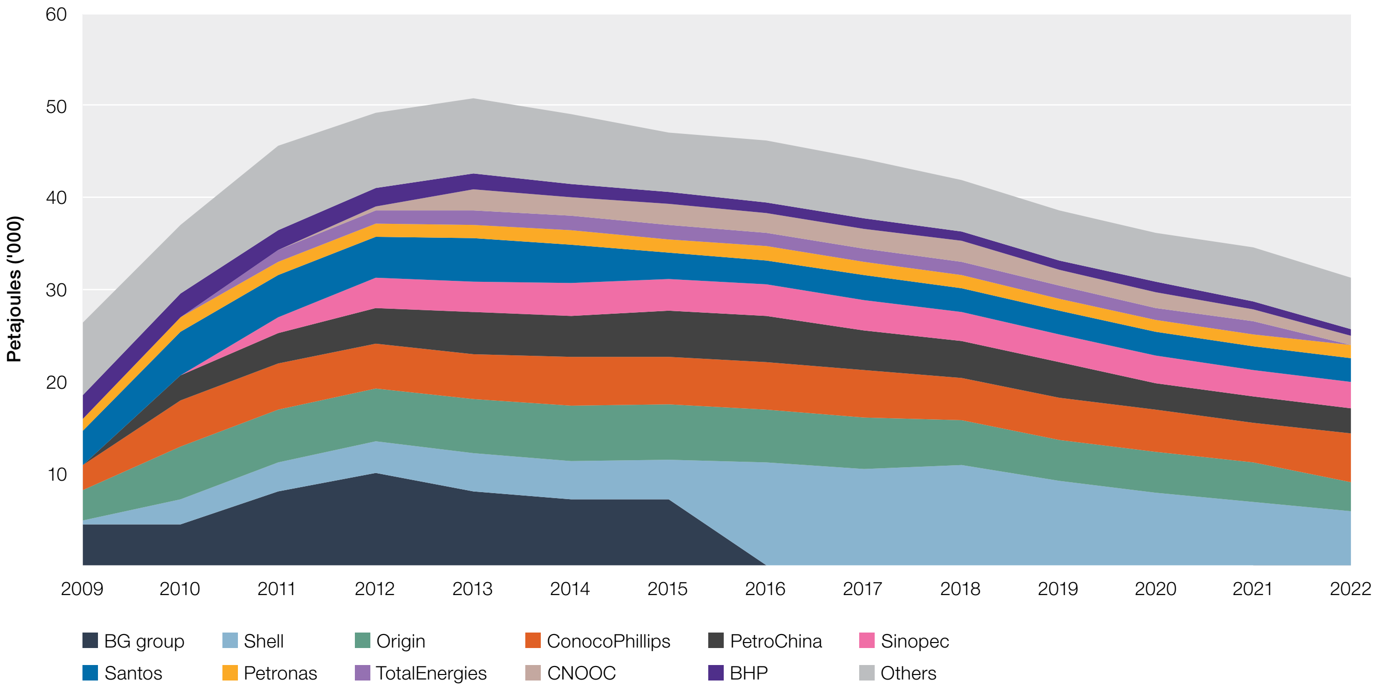
Victorian basins account for 7% of eastern Australian reserves but these reserves are declining, largely due to anticipated decreases from Gippsland legacy fields. This is important because Victoria is the highest domestic consumer of gas. AEMO forecasts a steep decline in southern field production in the coming years. The Gippsland Basin is the largest Victorian basin, while the Bass and Otway basins are smaller.

The Cooper Basin in central Australia has over 1,000 PJ of eastern Australia's 2P reserves and accounted for 4% of gas production in 2022. Reserves in the basin have declined over the past decade. The Cooper 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 resources[44] (around 2,264 PJ) but only 6 PJ of 2P reserves and negligible current production. Santos received approval to develop reserves near Narrabri in the Gunnedah Basin; however, appeals against the approval have delayed the project. The final investment decision depends on project approvals being cleared (section 5.8.1).

The Northern Territory has the Bonaparte Basin and the smaller Amadeus Basin. The basins are estimated to have over 4,500 PJ of 2P reserves. Most gas produced is converted to LNG for export.

Figure 5.12 Market shares in 2P gas reserves in eastern Australia

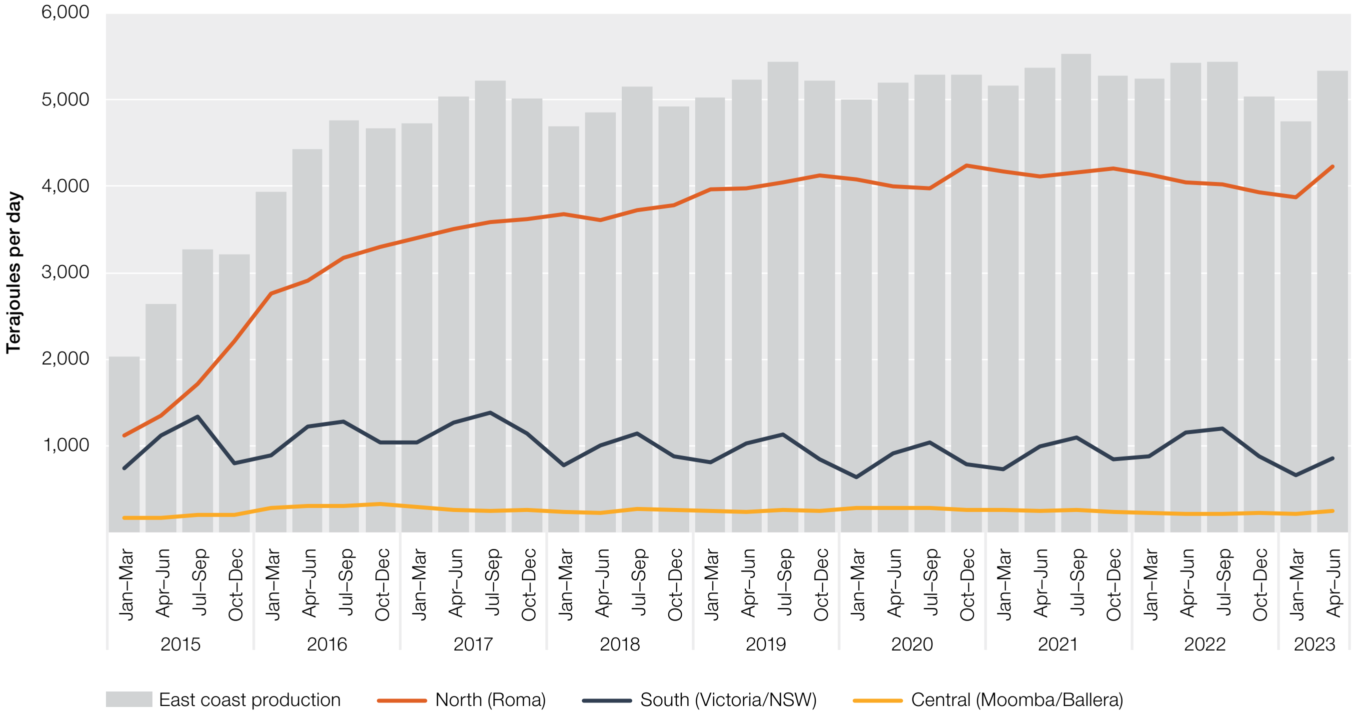


Note: Aggregated market shares in 2P (proven and probable) gas reserves in the Surat–Bowen, Gippsland, Cooper, Otway, Bass and NSW basins. 2P reserves are those for which geological and engineering analysis suggests at least a 50% probability of commercial recovery.

Source: EnergyQuest, *EnergyQuarterly* (various years).

44 2C contingent resources are reserves estimated to be potentially recoverable from known deposits, but which are not currently considered to be commercially recoverable.

Figure 5.13 Eastern Australia gas production



Source: AER analysis of Gas Bulletin Board data.

Record quarterly production levels occurred over the first 2 quarters of 2022 before declining in the October to December quarter to their lowest level since 2018, then continuing to decline in the January to March quarter of 2023 to their lowest level since 2017. Over the April to June quarter of 2023, production levels finished the financial year below 2021 and 2022 levels.

Southern production has been particularly low over 2023, with Longford running down its supply from the depleting legacy fields in the Gippsland Basin. Gas production in Queensland again rose to near record levels in the April to June quarter of 2023 (Figure 5.13), with elevated LNG export levels despite declining international prices (Figure 5.5).[45] This was also accompanied by strong demand from participants to bring significant quantities of gas south to offset lower southern production levels (Figure 5.19).

Production in Gippsland is transitioning from old to new fields, but it is not yet clear how much the new gas fields can produce. Production from the Longford plant has been falling and the plant is becoming less reliable, with plant constraints and maintenance outages increasingly disrupting production. Although AEMO's 2023 production forecasts have improved from 2022, actual production output at the facility is significantly down from the previous year.[46]

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. 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. 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.
The drawdown of southern supply has led to a projected 44 PJ shortfall in the south for 2024 alongside a 71–135 PJ surplus in the north. Projected domestic supply from LNG exporters is expected to range between 27 PJ and 90 PJ.[47]

45 LNG exports in the April to June quarter increased following lower levels of gas exports across the past financial year.

46 AEMO, 2023 Victorian gas planning report, Australian Energy Market Operator, March 2023, p. 5.

47 ACCC, Gas inquiry 2017–2025, interim report, June 2023, Australian Competition and Consumer Commission, June 2023, p. 10.

5.5.2 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:

- large facilities using 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 day[48] – 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
  - Moomba Lower Daralingie Beds (LDB) storage (South Australia) has a nameplate storage capacity of 70 PJ, with a delivery capability of under 5 TJ per day[49]
  - Silver Springs storage (Queensland) has a nameplate storage capacity of 45 PJ, with a delivery capability of 8 TJ per day[50]
  - Roma Underground Gas Storage (RUGS, Queensland) has a nameplate storage capacity of 54 PJ, with a delivery capability of up to 50 TJ per day[51]
- LNG storage 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[52] – 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 (VTS) to cater for short-term peak requirements and manage threats to system security
- 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.[53] 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 of 2022 reached their lowest levels since reporting began. This brought average storage levels down to a third of capacity (Figure 5.14).[54] Iona replenished significantly at the end of 2022, reaching its highest end of year storage level since reporting commenced. However, draw down of supply from the other large facilities has continued, with declining pressure in the storage wells adding to constraints on supply capability.[55] In June 2022, Newcastle gas storage reduced all the inventory in their LNG storage tank for the first time since the facility started operating. The facility did not commence refilling significant quantities until December.

48 The maximum supply rate achieved in 2021 with a nameplate capacity of 530 TJ per day was 455 TJ.

49 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.

50 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.

51 Following the continuing depletion of storage levels, short-term outlooks progressively reduced delivery capacity to 50 TJ per day as storage declined to 30 PJ (from 16 March), then 40 TJ per day as storage dropped to 27.6 PJ (from 27 May). Supply capability has since increased to 50 TJ per day.

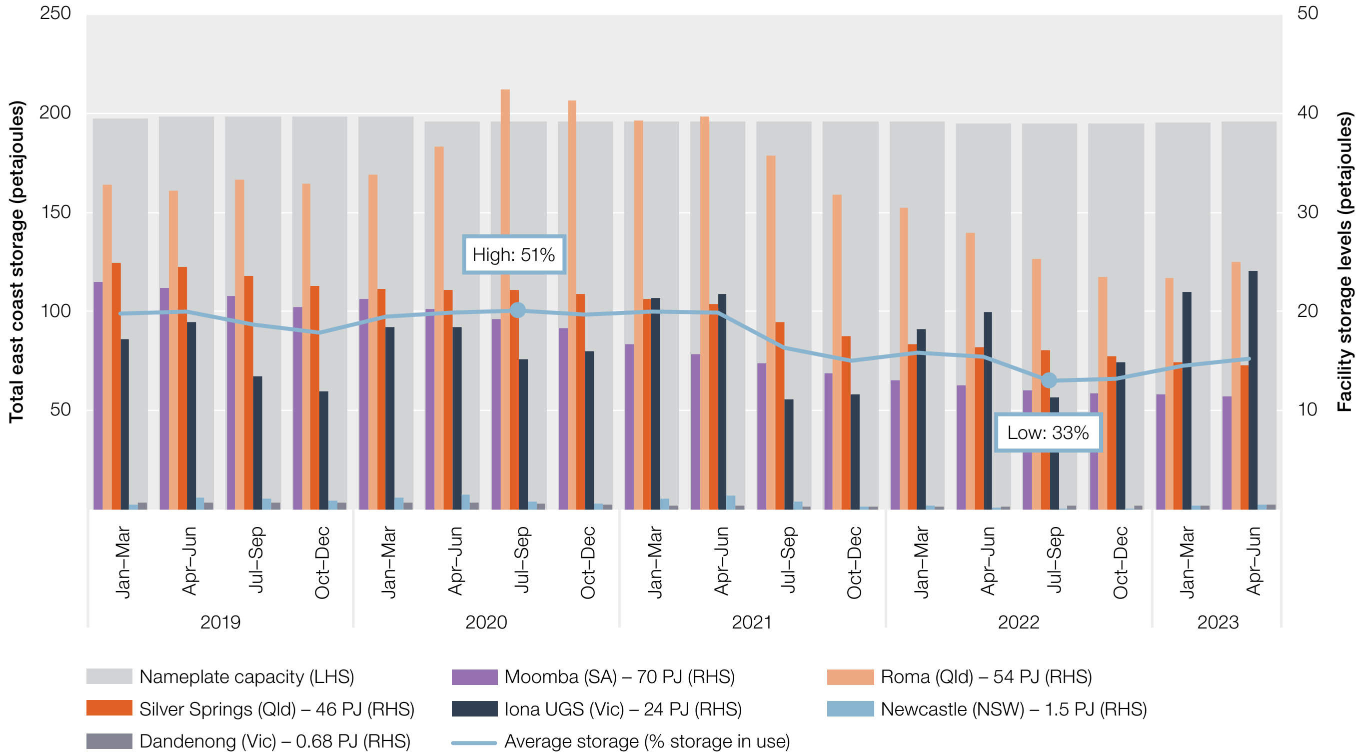
52 The Dandenong LNG storage facility reached record low levels in 2021 (since the commencement of the Declared Wholesale Gas Market in 1999), driven by a reduction in contracted capacity for winter. Following a rule change by the AEMC, AEMO has now contracted gas storage supply at the facility and acts as a buyer and supplier of last resort to mitigate potential supply shortfalls, with the facility close to full capacity at the beginning of winter 2023.

53 ACCC, Gas inquiry 2017–2030, interim report, January 2023, Australian Competition and Consumer Commission, February 2023, pp. 86–87.

54 Storage levels fell to record lows across all east coast facilities in 2022, with this trend continuing at most facilities in 2023.

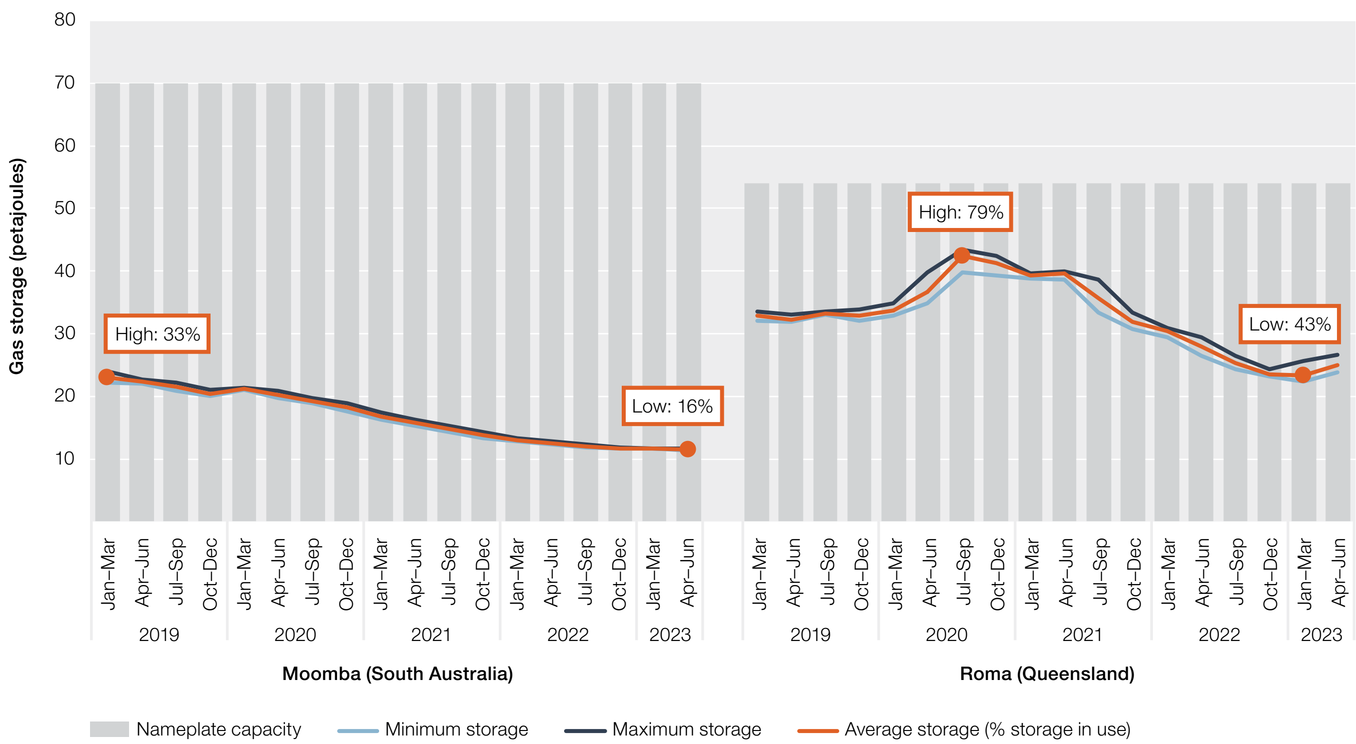
55 For example, Moomba has reduced its nameplate supply capability from 100 TJ per day when it commenced reporting in late 2016, with current storage levels below 12 PJ limiting its physical injection capacity as low as 3 TJ per day since June 2022.

Figure 5.14 Gas storage in eastern Australia



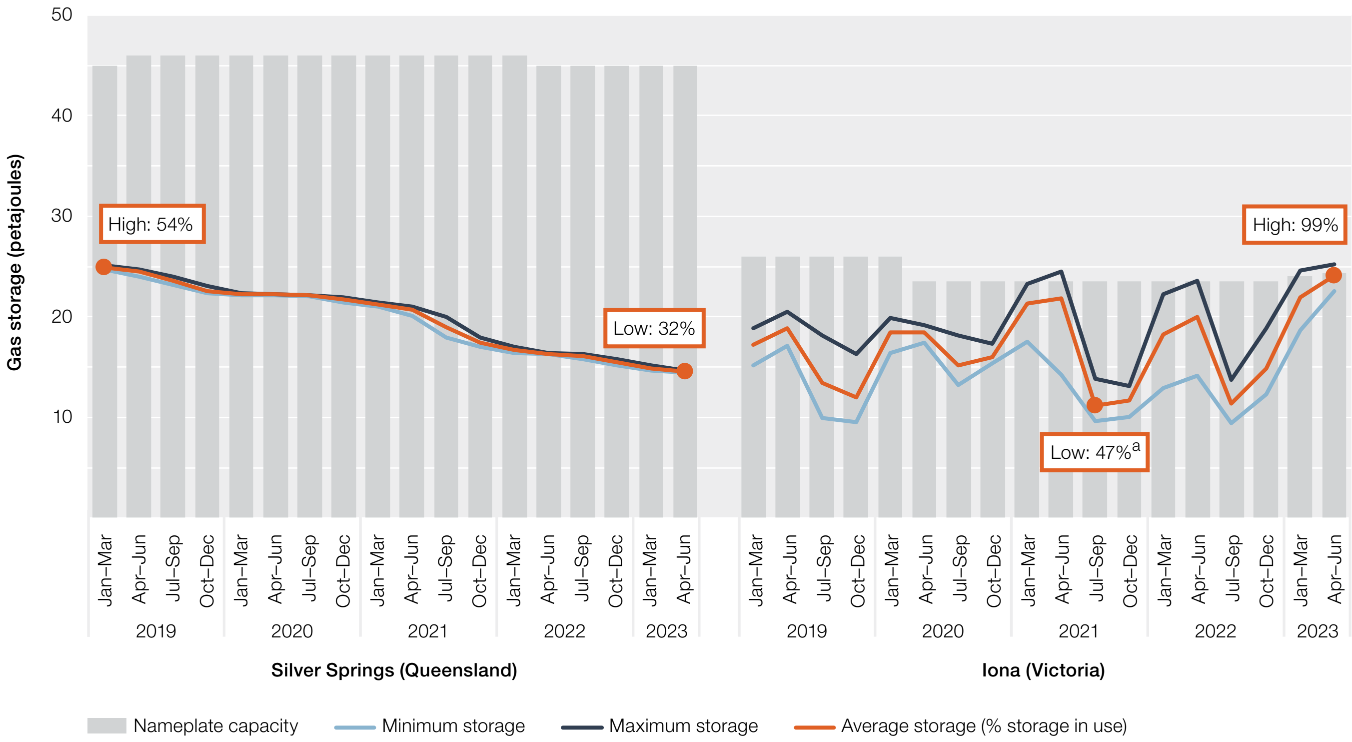
Note: Petajoule (PJ) value next to each facility reflects nameplate capacity.
Source: AER analysis of Gas Bulletin Board data.

Figure 5.15 Large gas storage facilities – Moomba (South Australia) and Roma (Queensland)



Source: AER analysis of Gas Bulletin Board data.

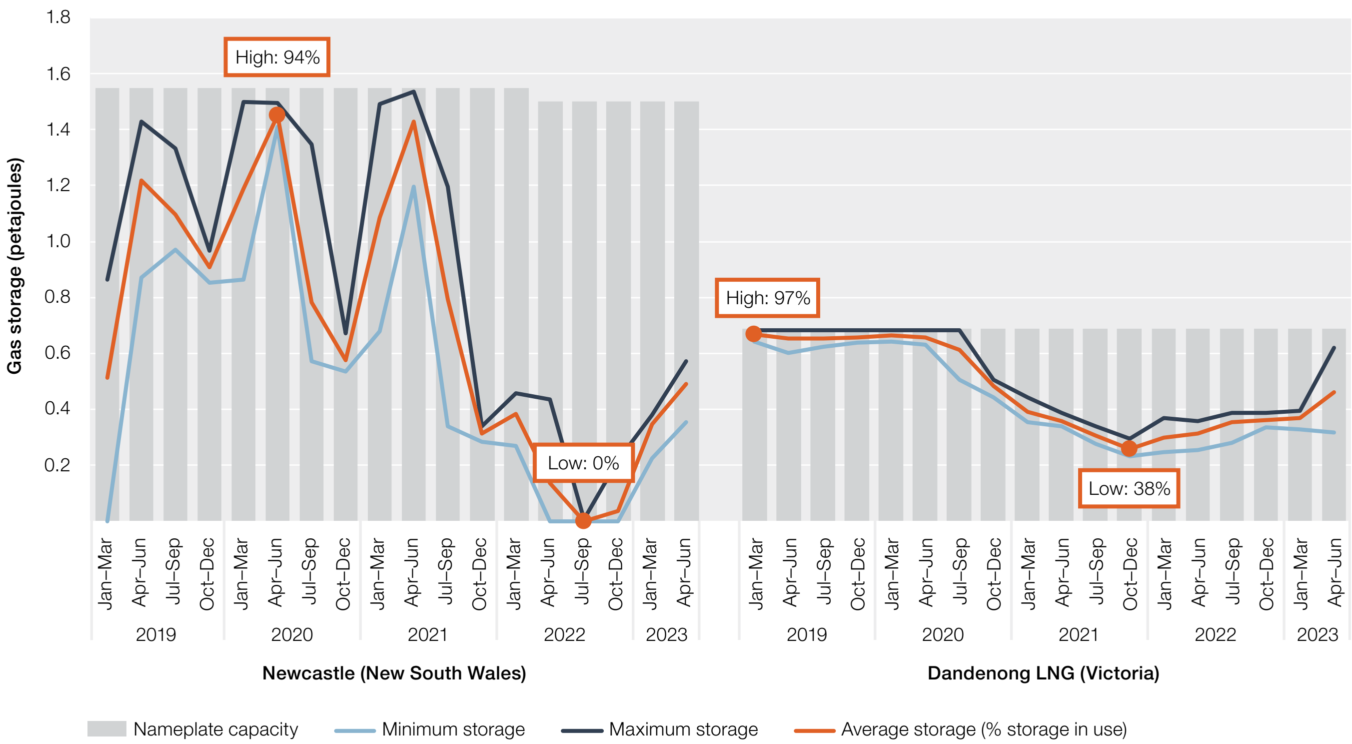
Figure 5.16 Large gas storage facilities – Silver Springs (Queensland) and Iona (Victoria)



Note: a Lower storage inventory, lower proportionally for October to December 2018.

Source: AER analysis of Gas Bulletin Board data.

Figure 5.17 Small LNG gas storage facilities – Newcastle (NSW) and Dandenong (Victoria)

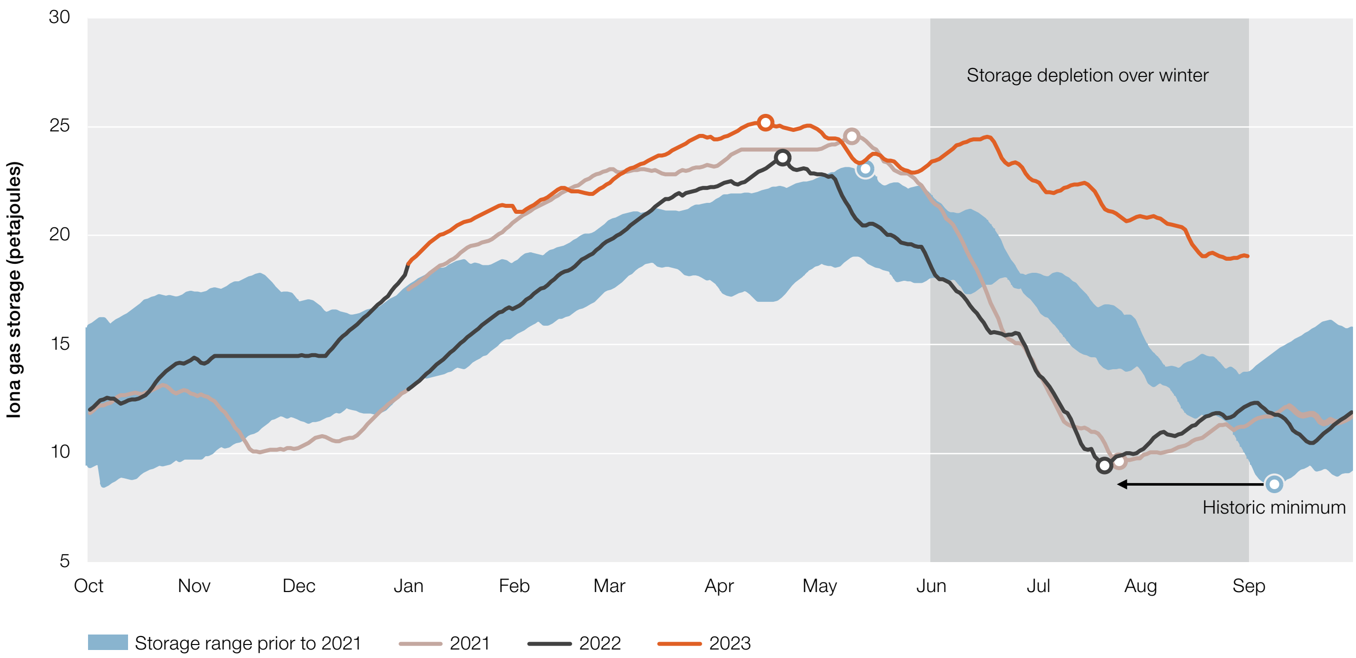


Source: AER analysis of Gas Bulletin Board data.

Investments to develop or expand storage capacity are under way.[56] Lochard Energy expanded Victoria's Iona facility in 2018 and made further improvements to the gas processing facility that progressively became operational from 2021.[57] This operates more dynamically than other storage facilities, with a larger capacity to inject and withdraw gas on any given day. Further expansion of storage capacity is currently taking place and supply capacity is expected to increase from 558 TJ per day to 570 TJ per day by early 2024. However, this capability is currently limited by existing pipeline capacity.[58] Storage capacity at the facility could also potentially increase by 3.3 PJ by 2026.[59] An expansion through their Heytesbury (HUGS) development is currently in the planning phase.[60]

In recent years, Victoria has become increasingly reliant on gas storage inventory from Iona. In 2021 and 2022, storage levels fell to their lowest point since reporting commenced. The significant draw down 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.[61] Recent upgrades have improved supply rates; however, this has also led to storage inventory being drawn down quicker than could have previously been achieved. Supply trends in 2021 and 2022 reducing to these low levels earlier into winter (minimum levels have historically been observed from the end of winter) demonstrate an increasing risk of supply being insufficient to meet demand on peak days. In 2023, upgrades to increase storage capacity at the facility and provide additional supply capacity, combined with pipeline upgrade works to increase supply and refill capacity at the facility, have improved Iona's ability to hold more gas and replenish its gas inventories. Despite a particularly cold end to autumn leading to Iona being relied on over May, the facility headed into winter in a good position and storage was topped up into June as gas flows south from Queensland increased following upgrades to the main pipeline routes in Queensland and NSW.[62] Winter 2023 storage levels were maintained at their highest level since reporting commenced.

Figure 5.18 Iona underground storage, low storage levels in winter 2021 and 2022



Source: AER analysis of Gas Bulletin Board data.

Further to this, the much smaller Dandenong LNG storage facility fell to particularly low levels in June 2022 following a reduction in participants contracting the emergency supply. While much smaller than Iona, the facility plays an important role in mitigating curtailment during potential supply shortfalls, providing critical system security to avoid pressure drops at the Dandenong city gate. Due to the high potential for the facility to be needed over winter 2023 as

56 ACCC, Gas inquiry 2017–2030, interim report, January 2023, Australian Competition and Consumer Commission, February 2023, p. 142.

57 Following Lochard's takeover from EnergyAustralia in 2015, the storage facility's capacity has expanded significantly from a 390 TJ per day supply capacity to 530 TJ per day (17 March 2021), 545 TJ per day (28 January 2022) and 558 TJ per day (1 January 2023).

58 The South West Pipeline (SWP) is currently undergoing upgrades to increase pipeline capacity that will support higher injection rates from the Iona storage facility. Further expansion of the storage facility could raise supply capacity to 600–700 TJ per day.

59 Lochard Energy, Heytesbury Underground Gas Storage (HUGS) Project, fact sheet.

60 The Heytesbury Underground Gas Storage (HUGS) Project to expand storage capacity proposes to develop existing depleted reservoirs and supply gas through the construction of a new underground gas pipeline.

61 The AEMO notice highlighted the possibility of reduced injection capability due to low pressure, increasing the risk of curtailment on peak demand days.

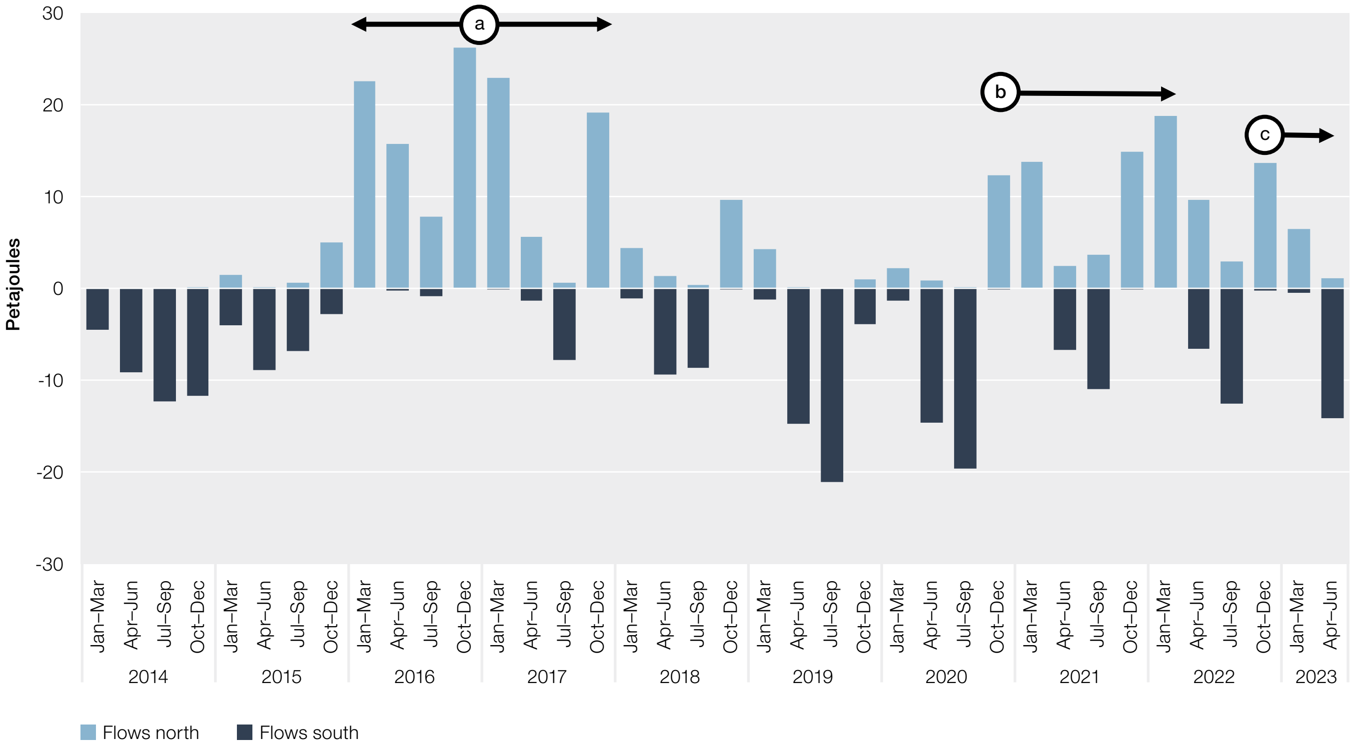
62 The cold temperatures in May coincided with constraints limiting gas flows south from Queensland and an outage at the Longford production facility.

supply at Longford drops off, Energy Ministers submitted an urgent rule change in August 2022 to give the AEMO power to contract underutilised LNG storage capacity in Victoria before winter 2023.[63] Subsequent refilling saw the storage facility close to full capacity by mid-June.

5.6 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 5.19).

Figure 5.19 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.

Source: AER analysis of Gas Bulletin Board data.

Northerly gas flows increased from late 2020 in line with record export pipeline flows (Figure 5.11) and reduced flows south over winter periods (Figure 5.19, note b). However, from May 2023 southerly flows increased significantly, exceeding levels observed over the past decade. While flows south over May were higher than May's monthly flows in previous years, demand to bring additional gas south was higher than capacity to do so.[64]

Due to recent upgrades on the South West Queensland and Moomba to Sydney pipelines, there is now additional capacity to bring more Queensland gas supply south to offset reduced southern production levels (section 5.8.3).[65] Observed gas flows south have remained strong into winter, despite exports increasing back to near record levels from the April to June quarter this year.

Following the increase in Moomba to Sydney Pipeline capacity from June, day-ahead auction activity increased, with most capacity won bringing gas south from Moomba – 1.9 PJ in June and 2.16 PJ in July – accounting for over 85% of capacity won. The Moomba to Adelaide Pipeline also climbed to the highest levels observed at the facility from May

63 Energy Ministers Meeting, Communique, 12 August 2022.

64 This was due to planned maintenance constraints on the Moomba to Sydney Pipeline (MSP), leading to little or no unutilised transportation capacity being available through the day-ahead auction. Surplus demand for southward delivery capacity on the MSP was 1.5 PJ, significantly outweighing capacity ultimately won on the route (0.7 PJ).

65 Pipeline upgrades increased SWQP and MSP capacity from June 2023.

with over 1.1 PJ won to bring gas south over May out to the end of July. However, in contrast to this, while most capacity won on the South West Queensland Pipeline was on routes to bring gas south at the start of 2023, this trend reversed from May with only minimal activity on southern delivery routes.

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. An example is an agreement between Shell and Santos to swap at least 18 PJ of gas.[66] Under the agreement, Shell draws on its CSG reserves to meet part of Santos's LNG supply obligations in Queensland, while Santos diverts gas from the Cooper Basin to meet demand in southern Australia.[67] The swap allows the producers to increase supply to the domestic market, while enabling Shell to avoid transporting gas on the South West Queensland Pipeline, which is contracted to near full capacity. To improve transparency, from 2023 participants' reporting requirements were expanded to encompass a range of bilateral arrangements, including physical swaps (section 5.11.1).

5.6.1 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, in 2021 APA announced the first stage of an expansion of the South West Queensland Pipeline and Moomba to Sydney Pipeline to increase delivery capacity from northern fields to southern markets (section 5.8.3).

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 5.1). 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. Additionally, the Northern Gas Pipeline provides eastern Australia's pipeline interconnection with the Northern Territory (section 5.8.5). 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 in managing 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 pipelines 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 5.6.2).

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.[68]

Investments to develop or expand transmission capacity are underway (section 5.8.3).

Pipeline ownership

Australia's gas transmission sector is privately owned (chapter 6). 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 5.11.2 and Table 6.1).[69]

66 Santos, 'Santos facilitates delivery of gas into southern domestic market' [media release], August 2017.

67 EnergyQuest, *EnergyQuarterly*, March 2020.

68 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.

69 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 6 outlines the various tiers of regulation.

5.6.2 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 even need to flow across multiple pipelines with different owners.

Access to transmission pipelines on key north–south transport routes is critical for gas customers. But many critical pipelines have little or no spare, uncontracted capacity, making it difficult to negotiate access. In addition, many pipelines face little competition and charge monopolistic prices.

Capacity on some pipelines is fully contracted to gas shippers, who do not fully use it. Reforms introduced in March 2019 made it easier to access this capacity, giving other parties an opportunity to procure capacity through trading platforms or win auctioned quantities – see section Pipeline capacity trading (day-ahead auction).

Capacity can be acquired in 2 ways. First, the capacity trading platform allows shippers to sell any capacity they do not expect to use. Second, any unused capacity not sold in this way must be offered at a mandatory day-ahead auction. Any shipper can bid at the auction, which is finalised shortly after the nomination cut-off time a 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.[70]

Pipeline capacity trading (day-ahead auction)

In 2023 the AER reported on the continued increase in the popularity of the day-ahead auction.[71] Since the commencement of the auction in March 2019, over 250 PJ of contracted but unnominated pipeline capacity has been won across 14 of the 22 auction facilities.[72]

Around 80% of all capacity procured was won at the reserve price of zero dollars and almost two-thirds of this capacity has been won on 4 key pipelines: the South West Queensland Pipeline (SWQP) and Moomba Sydney Pipeline (MSP), which facilitate gas flows south and north between spot markets; the Eastern Gas Pipeline (EGP) and the Roma Brisbane Pipeline (RBP), which facilitate flows to gas-powered generators.

Over the January to March quarter 2023, auction quantities exceeded the previous record quarterly trade level by 24%, reaching 38.5 PJ (almost 3 to 4 times more than Q1 levels over previous years). Of this capacity, 12.9 PJ was traded on gas routes that transport gas between northern and southern markets (SWQP/MSP), with record levels won on both pipelines. There were also record levels of trade on the EGP (4.8 PJ), Berwyndale to Wallumbilla Pipeline (2.8 PJ) and the Wallumbilla Compression Facilities (9.2 PJ).

While decreasing markedly from the first quarter's record levels, quantities won across the April to June quarter continued to exceed previous record levels for Q2.

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.[73]

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.

However, auction activity on some pipelines remains low. In particular, the AER reported on the limited trade on the Moomba to Adelaide Pipeline and SEA Gas Pipeline System supplying the Adelaide market, although participation is increasing.[74] Under-utilisation of these pipelines may result from higher fees and lower activity levels in Adelaide compared with other markets. Auction fees can discourage smaller players, in particular. While most capacity is won

70 While participants can win capacity for $0 per GJ, additional charges and registration fees make the real cost slightly higher.

71 AER, Wholesale markets quarterly – Q4 2022, Australian Energy Regulator, February 2022; AER, Wholesale markets quarterly – Q1 2023, Australian Energy Regulator, April 2023.

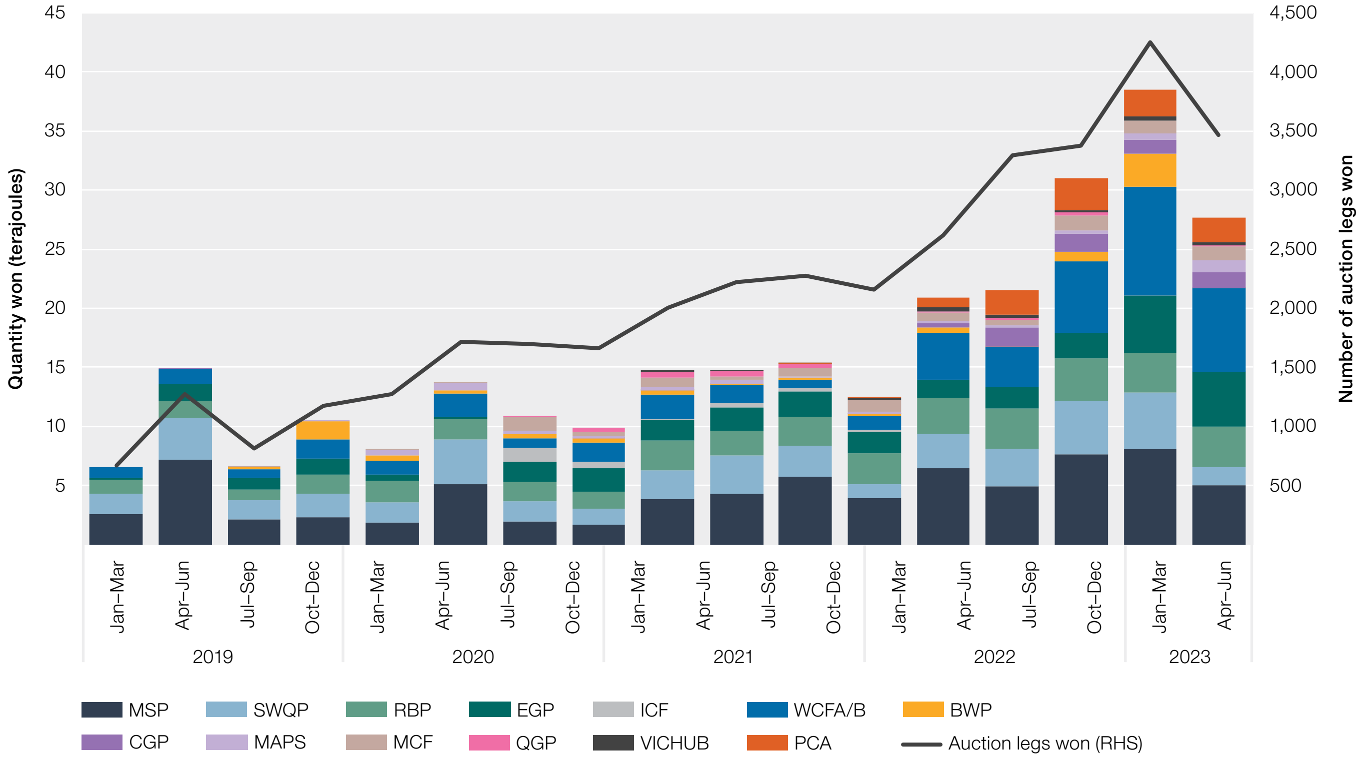
72 There has been no significant activity on the voluntary capacity trading platform since its introduction.

73 AER, Pipeline capacity trading – two-year review, March 2021, Australian Energy Regulator, p. 23.

74 The Port Campbell to Adelaide pipeline (SEA Gas) had over 2 PJ of capacity traded each quarter since mid-2022; however, trade levels on the Moomba to Adelaide Pipeline remain low, rarely exceeding 0.5 PJ over a quarter.

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.

Figure 5.20 Day-ahead auction quantities won, by facility



Note: 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; QGP: Queensland Gas Pipeline; RBP: Roma to Brisbane Pipeline; SWQP: South West Queensland Pipeline; VicHub (eastern Victoria); WCFA/B: Wallumbilla compression facilities.

Source: AER analysis of day-ahead auction data.

5.7 Trade in east coast gas markets

Gas markets were more liquid in 2022 than in previous years, with trade levels in the Gas Supply Hub increasing significantly and trading activity on the day-ahead auction continuing to set consecutive quarterly records from April 2022 into 2023.

The continued drawdown of southern production reserves has left those states more reliant on Queensland gas supplies going forward, with physical gas flows south in May up significantly from previous years. With some long export train maintenance outages across the first quarter of 2023, market participants appeared to capitalise on the availability of the extra gas available to domestic customers.[75] This included:

- exporters and producers offered record volumes of gas into the Gas Supply Hub and supplied record Q1 volumes in downstream markets
- traders bought record volumes (2.6 PJ) of gas through the Gas Supply Hub
- traders also sold record volumes of gas into downstream markets (2.64 PJ) at higher prices than the hub purchases, suggesting the gas was being on-sold from the hub to metropolitan markets.

Trade in gas commodity and transportation markets set records in the January to March quarter, with forward trade increasing later in the quarter. There were record deliveries at Wallumbilla and an increase in forward trading at the end of March, with volumes traded concentrated around deliveries over winter months (Figure 5.21). Record transportation capacity was acquired through the day-ahead auction – more than 3 times the volume of trade

75 AER, Wholesale markets quarterly – Q1 2023, Australian Energy Regulator, April 2023.

compared with any previous first quarter and above levels won over any previous quarter (Figure 5.20). While quantities of transportation capacity won at auction reduced in the April to June quarter, they remained higher than Q2 levels in previous years.

Domestic gas prices had increased significantly in April 2022 ahead of the increased southern demand for gas heating over winter, with unprecedented price increases occurring over the following months.[76] This led to multiple markets being placed in administered states and resulted in distorted pricing signals across the east coast as participants held on to their contracted supply. It also compelled contingency market outcomes to mitigate risks of short-term supply shortfalls from late May. Prices remained above historical levels and did not ease significantly until mid-December 2022, with prices heading into 2023 settling at roughly $10 to $15 per gigajoule.

Uncertainty around the availability of sufficient supply levels beyond 2022 has also coincided with delays in bringing new supply sources online.

5.7.1 Victoria's Declared Wholesale Gas Market (DWGM)

Around 40 participants traded in the Victorian market in 2022. The market's participants include energy retailers, power generators and other large gas users, and traders.

Volumes traded in the Victorian market rose by 7% in 2022. Since mid-2019, quarterly flows of gas into Victoria through the Culcairn injection point have increased consistently, particularly across the winter months. The majority of this is by operators of gas-powered generation, but other participants have been increasing their deliveries recently, facilitated by the day-ahead auction. In 2023, quarterly spot trade picked up in Q1, rising from a low of 12.5% of demand in the fourth quarter of 2022 to almost 19% over January to March 2023.

The volume of trade in the Victorian gas futures market decreased by 21% in 2022 from 2021 after increasing by 17% from 2020. This was the lowest level of futures trading observed since 2018. Ultimately, this quantity still accounts for only a small proportion (less than 5%) of the total volume traded in the market.

5.7.2 Gas Supply Hub (GSH)

In 2022, 21 participants traded at the gas supply hubs, 20 of which were active, with numerous off-market trades facilitated by a broker participant.[77] LNG export businesses and gas producers were among the most active participants in 2022, closely followed by gentailers.[78]

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 include large industrial users and traders.

In 2022, 20 participants traded on-screen, with 15 actively trading. Similarly, 21 participants traded off-screen, with 20 of them active. On average, participants executed around 322 trades per month in 2022 – an increase of 69% from 2021.

In the first half of 2023 approaching winter, there was very little forward trade through the Gas Supply Hub. This was markedly different to the trade activity observed over the same periods in 2021 and 2022, during which trade at Wallumbilla materially exceeded gas delivered at the hub. This indicated a substantial volume of forward trade. This trend in previous years suggests participants sought to lock in gas supply approaching winter, whereas trading activity in 2023 shows a trend towards more shorter-term trading for delivery closer to the date of trade. The lower volumes of forward trade suggest a greater reliance on spot market trade to meet participants' demand levels over winter (Figure 5.21).

Wallumbilla hub activity

Users of the Wallumbilla hub include the LNG projects, gas-powered generators and, more recently, trader participants taking advantage of the day-ahead auction to arbitrage prices between Wallumbilla and the downstream markets.

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76 Potential upcoming shortfalls in southern gas supply, due to depleted legacy gas reserves in the Gippsland Basin, may be driving suppliers to set higher prices to limit further run-down of existing supply before a possible significant southern supply shortfall over winter 2023. Considering underlying contract positions reviewed in previous ACCC gas inquiry reports, local contract links to international oil and gas prices would potentially be impacted by international price increases following Russia's invasion of Ukraine.

77 We consider a participant 'active' if it makes at least 12 trades in a year. The broker is not included as an active trader.

78 Gentailers are participants that own electricity generation assets and retail market portfolios.

Following a rebound in trade over 2021 driven by an increase in off-screen activity, further growth occurred across 2022, particularly during the period of volatile pricing that took place mid-year over Q2 and Q3 (Figure 5.21). Notably, off-screen products tend to involve larger volumes of gas than on-screen alternatives do. In 2022 off-screen trade levels hit a record high, with close to 32 PJ traded. This was driven by higher volumes being traded for longer-term deliveries, including monthly product and strip trades of daily products.[79] From mid-2022, delivered quantities have exceeded previous quarterly records across consecutive quarters.[80]

However, ultimately, 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 2022 gas traded through the Wallumbilla hub accounted for 15.9% of total gas flows through pipelines in the Wallumbilla bulletin board zone, almost double that of the previous year. In total, 36.6 PJ of gas was traded over 2022 and 16.9 PJ was traded across the first half of 2023.

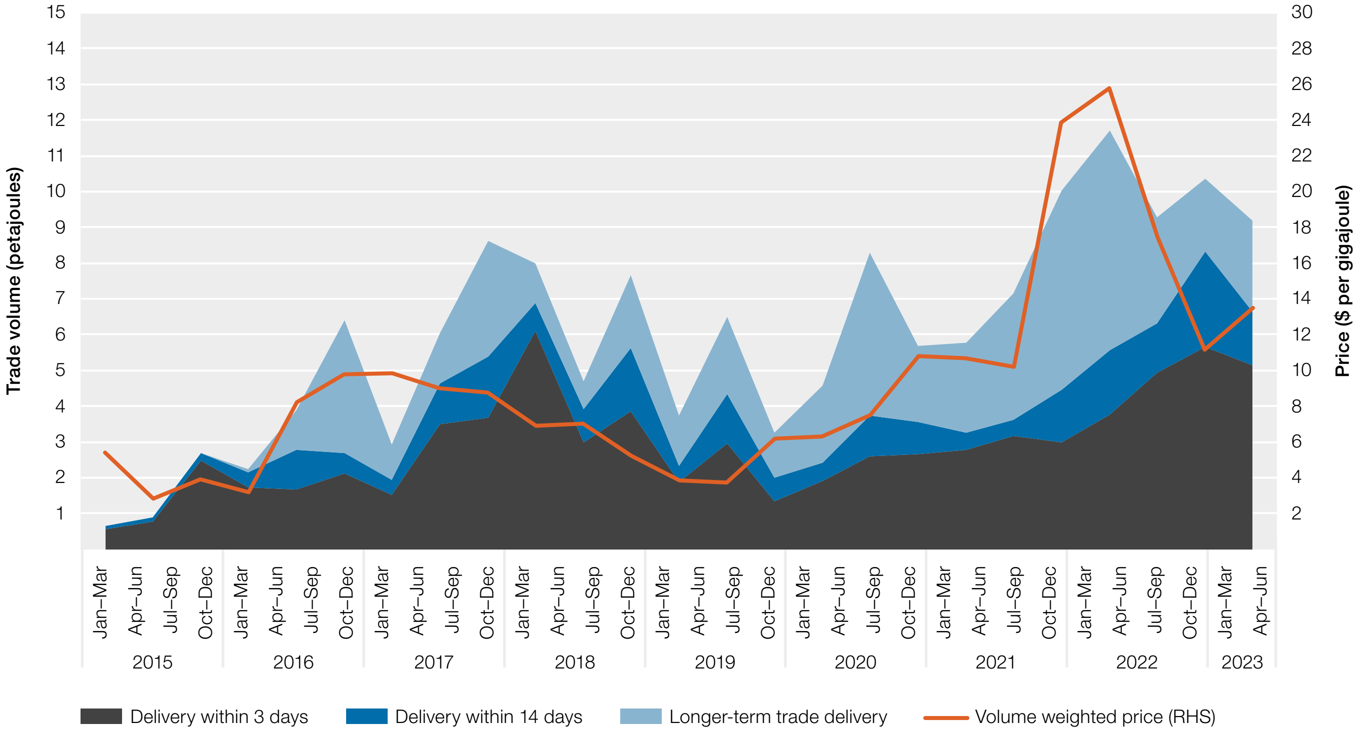
Moomba hub activity

Trade at Moomba has been slow to develop. The first trade was executed in September 2017, with 141 trades 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, in 2023 an upturn in trade has seen quantities traded over the first half of the year exceeding previous yearly trade levels, reaching 1.75 PJ. This was partially driven by an upturn in trade levels on the Moomba to Sydney Pipeline.

Victoria and Sydney activity

Trade levels at the Culcairn (Victoria) and Wilton (Sydney) trading locations have occurred in small volumes, reaching a total of 264 TJ and 1,699 TJ, respectively, to date.[81]

Figure 5.21 Gas Supply Hub – increase in shorter-term trade



Note: Volume weighted average price includes all GSH products (excluding capacity trading platform) at all locations, excluding brokered sales.
Source: AER analysis of Gas Supply Hub data.

79 Strip trades, introduced in late 2020, allow participants more flexibility, providing the ability to bundle a string of daily products together over a selection of days, which can be traded further out (for delivery periods similar to monthly products).

80 Delivered quantities: July–September 2022 (13.6 PJ), October–December 2022 (10.5 PJ), January–March 2023 (10.1 PJ) and April–June 2023 (7.2 PJ).

81 Quantities traded from 2021 up to 30 June 2023.

5.7.3 Short Term Trading Market (STTM)

In 2022, 39 participants traded in the Sydney STTM and the Adelaide and Brisbane markets had 26 and 22 participants, respectively. 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 the fourth quarter of 2022, gas traded through the STTM met around 20% of demand in Sydney, 18% in Adelaide and around 10% in Brisbane. These levels increased close to twofold in Adelaide and Brisbane in 2023, reaching around 32% and 19% respectively over the January to March quarter.

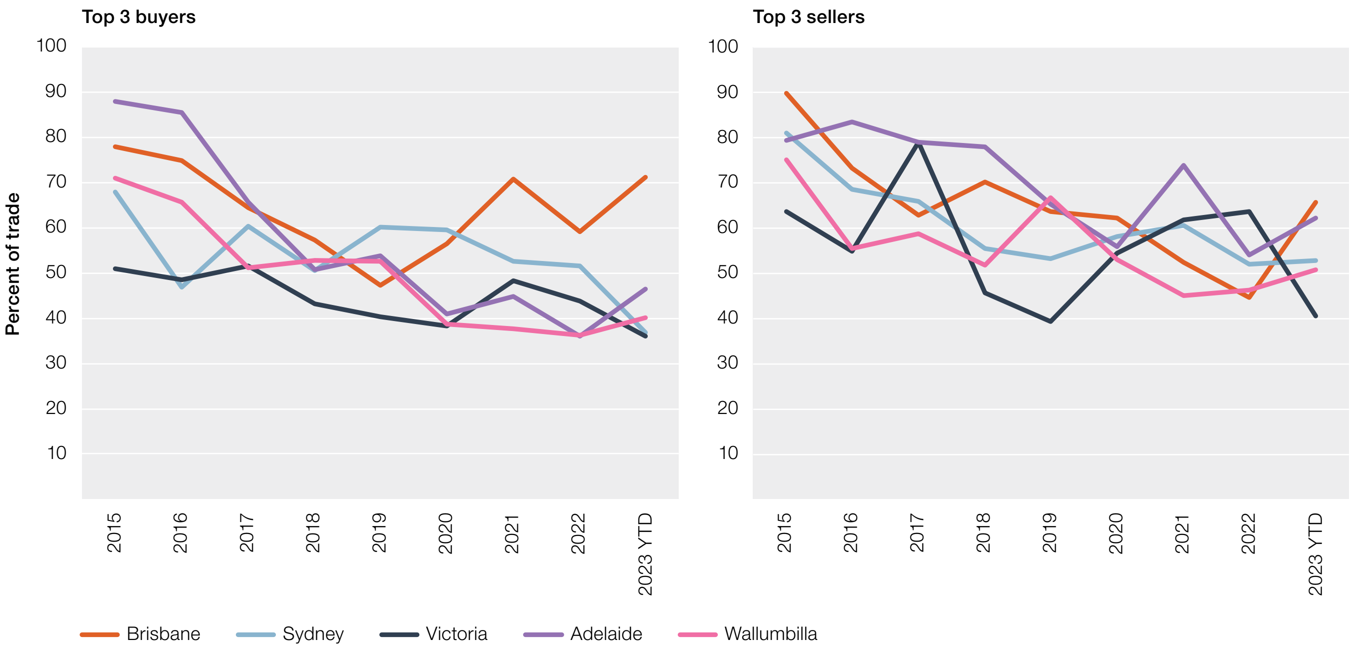
Traded volumes at the Sydney market were down slightly from record levels observed in 2021 – 97.7 PJ of net trade in 2022 was 6% lower than the previous year. Spot trade in the Adelaide and Brisbane markets for 2022 also fell by 18.5% (20 PJ) and 13.8% (32 PJ), respectively.

Trading profiles varied across the markets. Concentration across the top 3 sellers fell in Adelaide, Sydney and Brisbane from 2021 to 2022 and rose slightly in Victoria and Wallumbilla (Figure 5.22). Among the top 3 buyers, market concentration decreased over 2022, particularly in Brisbane. Importantly, the diversity of large suppliers participating in the spot markets is increasing. Similarly, in 2022 trader participants' share of gas scheduled into the STTM remained high despite reducing from record levels over 2021. This continued into 2023 with record quarterly sales by traders in the downstream markets over January to March (over 2.6 PJ). These participants took advantage of cheap capacity won on the day-ahead auction to arbitrage prices between markets.

In 2022 participants used the DWGM more heavily, with retailers and industrial participants being prominent gas purchasers and trade primarily dominated by those with gas generation assets. The latter group of participants accounted for around 68% of trade in the DWGM in 2022, compared with around 57% in 2021.

Despite traditionally benefiting from lower spot prices, high spot market exposure can be highly risky for spot market participants. In 2022, while spot prices early in the year were as low as $6.10 per gigajoule (GJ), volatile pricing over winter saw pricing between mid-May and late July largely in the vicinity of $27.12 to $59.49 per GJ. This resulted in 2023 contract offers increasing significantly compared with the prices offered in 2021, which ranged between $6.79 and $16.33 per GJ. Over 2022, contract offers for gas delivery in 2023 were between $8.61 and $71.54 per GJ.

Figure 5.22 Top 3 buyers and sellers in eastern Australian gas markets



Note: Year-to-date (YTD) to 30 June 2023.

Source: AER analysis of data from the Gas Supply Hub, Short Term Trading Market and Victorian Declared Wholesale Gas Market.

5.8 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 *2023 gas statement of opportunities* continues to highlight 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.

5.8.1 Gas field development

Numerous projects have been progressing to bring additional supply to the domestic market:

- In Queensland, Senex agreed to supply 10% of the reserves of its Atlas expansion project (up to 42 PJ) in the Surat Basin to AGL and 14 PJ of gas to Orora's glassmaking plant over 10 years starting 2025. Senex also agreed to supply BlueScope's Port Kembla plant with 20 PJ of gas from 2026 following a similar contingent arrangement with Visy, contributing to a total of 130 PJ in deals from 2025. The expansion plans to increase annual production by 60 PJ by the end of 2025. An earlier expansion of the facility commissioned in the July to September quarter of 2022 saw production increased from 12 PJ to 18 PJ over the January to March quarter of 2023.
- Gas production from the Meridian joint venture increased to 3.1 PJ in the January to March quarter of 2023 (34 TJ per day) following the drilling of one development well. The WestSide/Mitsui partnership plans to drill 350 wells in the Bowen Basin to supply GLNG.[82]
- 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, the Otway Phase-3 Development (OP3D) project is targeted to bring additional gas to the market before winter 2025.[83] Cooper entered into a long-term gas sales agreement (GSA) with AGL to supply up to 10 PJ per year for up to 6 years.[84]
- 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.[85] While additional gas is expected to be processed at Longford from 2026, supply is not expected to increase winter capacity to levels provided by their depleting legacy field production.[86]
- 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 (producing over 10 PJ across Q2 2023). Beach has also prioritised the ongoing development of its Yolla West field and deferred FID for Trefoil, which is now considered as potential supply.[87]
- 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 is voluntarily committed to the domestic market. However, appeals against the project's approval have delayed any final investment decision, which now depends on project approvals being cleared.[88]

82 The partners began supplying GLNG in 2015 under a 20-year deal linked to oil prices. EnergyQuest, *EnergyQuarterly*, June 2023, p. 122.

83 Athena sources gas from the Otway Basin's Casino, Henry and Netherby fields, some of which was formerly processed at Iona (Casino).

84 Gas Sales Agreement with AGL for the next phase of Otway Basin development and exploration.

85 ExxonMobil, Opportunities for the Gippsland Basin and Australia's energy transition, 22 March 2022.

86 AEMO, 2023 Victorian gas planning report, Australian Energy Market Operator, March 2023, p. 63.

87 AEMO, 2023 Victorian gas planning report, Australian Energy Market Operator, March 2023, p. 63.

88 The Australian Government approved the project in November 2020, with the conditions of approval consistent with those set by the NSW Independent Planning Commission.

Regulatory 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.[89] 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 CSG or any onshore petroleum until 30 June 2020.[90] In March 2021 the government committed the ban on fracking and CSG exploration to the Victorian Constitution.[91] Onshore conventional gas exploration recommenced from July 2021.
- 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.[92]
- 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.[93] 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' Narrabri gas project.[94] 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.[95]

5.8.2 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 (FSRU). While development of import terminals have been delayed over the past year, proponents of these projects remain committed to their continuing development.[96]

- Australian Industrial Energy's (AIE) terminal at Port Kembla (NSW) is no longer classified by AEMO as an anticipated project due to uncertainty around the contracting of gas supply. In 2021 AIE and Jemena signed a project development agreement to connect to the Eastern Gas Pipeline, with modifications set to allow bidirectional flows to deliver gas to Sydney and Victoria (Section 5.8.3). These infrastructure modifications are on track to be completed by December 2024 but the import facility is not expected to be operational before 2026.
- Venice Energy's proposed terminal at Port Adelaide (South Australia) is projected to potentially supply gas by 2026.[97] However, gas deliveries to Victoria are currently constrained due to the SEAGas Pipeline, currently only able to flow gas out of Victoria, and the limited available capacity on the South West Pipeline.
- Viva Energy's Geelong (Victoria) Gas Terminal project was projected to deliver gas as early as 2024. The project would require the duplication of the South West Pipeline. Viva was expected to make a final investment decision on the project by the end of 2022; however, the Victorian Minister for Planning requested supplementary information to their Environmental Effects Statement in March 2023.

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89 Hydraulic fracturing, also known as fracking, is a process that 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.

90 Department of Economic Development, Jobs, Transport and Resources (Victoria), Onshore gas community information, August 2017.

91 Victorian Government, Enshrining Victoria's ban on fracking forever [media release], March 2021.

92 Department of State Growth (Tas), Tasmanian Government policy on hydraulic fracturing (fracking) 2018, DSG website, accessed 28 May 2021.

93 Department of Planning and Environment (NSW), Initiatives overview, July 2018.

94 Department of Planning and Environment (NSW), 'Community views on Narrabri Gas Project to be addressed' [media release], 7 June 2017.

95 Prime Minister of Australia and Premier of New South Wales, 'NSW energy deal to reduce power prices and emissions' [media release], January 2020.

96 Energy Quest, *EnergyQuarterly*, June 2023, p. 23.

97 AEMO, 2023 Gas Statement of Opportunities, Australian Energy Market Operator, March 2023, p. 65.

- Vopak's import terminal in Port Phillip Bay (Victoria) is expected to be completed in 2026. An environmental plan was submitted to the Victorian Government in December 2022.[98]
- EPIK ceased development of a Newcastle import terminal due to the project being economically unfeasible.[99]

5.8.3 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.

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)[100] and the Moomba to Sydney Pipeline (MSP).[101] The expansion enables more gas flow on pipelines where capacity is fully or close to fully contracted.[102] 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).[103] This was the first of 3 stages of a 25% increase in transportation capacity.[104]
The additional proposed expansion stages include:

- Stage 2 – a 59 TJ per day increase to the nominal capacity from Queensland to the southern markets, with an additional compressor station constructed on both the SWQP and MSP. This will bring the 453 TJ per day increase from stage 1 up to 512 TJ per day on the SWQP, with the 475 TJ per day capacity on the MSP to increase by 90 TJ to 565 TJ per day. Subject to foundation contracts, this stage is expected to be commissioned in the January to March quarter 2024.
- Stage 3 – a further 92 TJ per day expansion with increases to capacity on both pipelines is currently in initial design phases and is subject to customer demand and project approval.[105]

South West Pipeline, Western Outer Ring Main (WORM) project

APA is also upgrading the Victorian Transmission System (VTS), building a 51 km high pressure transmission pipeline to address a key capacity constraint currently limiting the connection of existing gas supply from the west of the state to demand in the north and east. The transportation of gas will also be assisted by the upgrade of the existing compressor station at Wollert. The project is expected to be completed from late September to early October 2023.

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 demand. Limited capacity on the SWP restricts supply being provided from Port Campbell in the state's west. Following the completion of the WORM, the maximum daily capacity will increase from 447 TJ to 476 TJ on peak demand days.[106]

AEMO forecasts show the SWP constraining flows towards Melbourne during peak demand periods, when the full capacity of the Iona underground gas storage (UGS) facility is most needed. Further expansions of the SWP are proposed, to bring its capacity in line with the capacity of Iona UGS (section 5.8.4), following completion of the WORM.

98 Oil & Gas Journal, Vopak submits Victorian LNG import terminal environmental plan, 23 December 2022.

99 AEMO, 2023 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.

100 The SWQP connects to the Northern Territory through 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. AEMO, *2022 Gas Statement of Opportunities*, Australian Energy Market Operator, March 2022, p. 51.

101 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.

102 ACCC, Gas inquiry 2017–2025, interim report, January 2022, Australian Competition and Consumer Commission, February 2022, p. 15.

103 Stage 1 of the expansion includes an additional compressor on the SWQP and an additional compressor between Moomba and Young on the MSP.

104 AEMO, 2022 Victorian gas planning report, Australian Energy Market Operator, March 2022. pp. 76–77.

105 This potential expansion is expected to add a further 25% to the Stage 1 (12%) and Stage 2 (13%) increases. ACCC, Gas inquiry 2017–2025, interim report, January 2022, Australian Competition and Consumer Commission, February 2022, p. 67.

106 Based on AEMO modelling of a 1-in-20 (5% probability of exceedance) peak system demand day. AEMO, 2022 Victorian gas planning report, Australian Energy Market Operator, March 2022. P. 9.

The WORM was one of 4 priority projects implemented to address shortfalls highlighted in the 2021 Victorian gas planning report.

Further expansions are not yet committed because they are subject to approval under APA's Access Arrangement. However, they have been proposed 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.[107]

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 5.8.2) at Kembla Grange at a capacity of 522 TJ per day. 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.[108]

The earliest practical completion of the EGP expansion project in 2024 aligns with the planned completion of the delayed Port Kembla project. Potential future expansion, including the installation of a compressor at Kembla Grange, will increase daily capacity to supply as much as 323 TJ into Victoria and 550 TJ towards Sydney. Onshore infrastructure remains on track for completion in December 2024.[109]

5.8.4 Storage expansion

Iona underground gas storage (UGS)

Lochard Energy upgraded their underground storage facility to increase supply capabilities to 570 TJ per day,[110] with 1 PJ of additional storage capacity following the drilling of a new storage well. Well pad construction of the Seamer 2 well in a field adjacent to Iona's existing field was completed in November 2021 before ministerial approval of the operational plan on 28 January 2022.[111] However, daily supply capacity into Melbourne via the South West Pipeline will be constrained to 476 TJ when the WORM project is completed – expected in late 2023 (section 5.8.3).

Further upgrades after the development of the Heytesbury Underground Gas Storage (HUGS) project have been proposed to add additional pipeline assets and approximately 3 PJ of additional storage capacity through construction of a new wellsite at Mylor, Fenton Creek and Tregony (MFCT) gas fields.[112] The project would increase capacity following the development of existing depleted reservoirs, with daily supply capacity increasing to 620 TJ.[113] Proposed construction would commence in October 2023 for completion by 2024, but is subject to regulatory approvals and market requirements that could delay the commencement of the project to October 2024.

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 in 2024 and 2025, before operating as an underground storage facility. Golden Beach Energy received $32 million from the Australian Government in 2022 to accelerate development of the project.[114] The facility was projected to have a storage capacity of 12.5 PJ but would require 43 PJ of production to be procured over a 2-year period before being used as a storage facility.[115] In May 2023, the Minister for Energy and Resources accepted Golden Beach Energy's environment plan to drill the Golden Beach-2 appraisal well.[116]

107 AEMO, 2022 Victorian gas planning report, Australian Energy Market Operator, March 2022, p. 14.

108 AEMO, 2022 Victorian gas planning report, Australian Energy Market Operator, March 2022, pp. 75–76.

109 AEMO, 2023 Gas Statement of Opportunities, Australian Energy Market Operator, March 2023, p. 65.

110 Nameplate supply capacity increased from 530 TJ per day to 545 TJ per day on 28 January 2022. Storage capacity will increase from 23.5 PJ to 24.5 PJ.

111 Lochard Energy, Seamer 2 Project – Community Update, January 2022.

112 Lochard Energy, Our HUGS Project, April 2022.

113 AEMO, 2022 Gas Statement of Opportunities, Australian Energy Market Operator, March 2022, p. 55.

114 The Hon Angus Taylor MP, Unlocking critical local gas production and storage, 21 March 2022.

115 ACCC, Gas inquiry 2017–2025, interim report, January 2022, Australian Competition and Consumer Commission, February 2022, p. 68.

116 Earth Resources, Golden Beach Gas Project, 20 June 2023.

5.8.5 Northern Territory gas

Jemena's Northern Gas Pipeline began delivering gas from the Northern Territory to Queensland in January 2019. Current nameplate capacity of the pipeline is 90 TJ per day, but Jemena plans to increase this to 200 TJ per day by 2025.[117] This plan would also extend the pipeline to connect the Beetaloo Basin directly to the Gas Supply Hub.

2021 east coast supply from the Northern Territory averaged around 55 TJ per day until October, before declining in 2022. Supply over the first half of 2022 was down to an average of just over 30 TJ per day to the end of August, before Blacktip production issues led to Mt Isa deliveries reducing to essentially 0 TJ per day from early September and into December. Since then, average supply from the Northern Territory has averaged just under 23 TJ per day up to mid-2023. The low pressure in the pipeline forced Jemena to temporarily shut down the pipeline due to safety concerns, requiring Mt Isa to be supplied from east coast production sources. This contributed to reduced supply and increased demand in east coast markets over late 2022.

5.8.6 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.[118] 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.[119]

Government initiatives can also play a role in reducing gas demand. The ACT initially removed mandatory gas connection requirements for new homes, before legislating a stop to new gas connections from 2023. Other initiatives, such as the Victorian Gas Substitution Roadmap and Energy Upgrades program, have identified electrification as the best solution to achieve a short-term reduction to gas consumption levels.[120]

5.9 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 the 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.

Over 2022–23, 2 of the AER's compliance and enforcement priorities related to gas markets:

- ensuring service providers meet information disclosure obligations and other Part 23 National Gas Rules obligations
- ensuring timely and accurate gas auction reporting by registered participants.

High-quality market information is vital to improve transparency among participants and promote competition.

The AER undertook a range of compliance and enforcement activities in support of these priorities, including:

- following an industry-wide review of service provider compliance against Part 23 reporting requirements, we issued a compliance bulletin in September 2022 outlining expectations of non-scheme pipeline service providers' compliance with numerous information disclosure obligations

117 Jemena, 'Jemena partners with shale gas experts to develop Beetaloo' [media release], November 2020.

118 ACCC, Gas inquiry 2017–2025, interim report, January 2021, Australian Competition and Consumer Commission, February 2021, pp. 73–74.

119 ACCC, Gas inquiry 2017–2025, interim report, January 2020, Australian Competition and Consumer Commission, February 2020, p. 74.

120 AEMO, 2022 Gas Statement of Opportunities, Australian Energy Market Operator, March 2022, p. 23.

- continued targeted reviews of recovered capital values reported by specific pipeline operators
- issued $630,000 of infringement notices for alleged breaches of record-keeping and report requirements under the National Gas Rules relating to the day-ahead auction
- developed guidelines for Part 10 and Part 18A obligations following the revocation of Part 23 in March 2023, covering publication requirements for non-scheme pipelines and standalone compression and storage facility service providers
- published a compliance bulletin on new obligations under the gas pipeline reforms in June 2023.[121]

More detail on the AER's compliance and enforcement work is outlined in the annual compliance and enforcement report 2022–23.[122] More information on AER observations of short-term transactions under the new Gas Market Transparency measures is available in the Wholesale markets quarterly report.[123]

5.10 Government intervention in gas markets

In response to concerns around the adequacy of gas supplies to meet domestic demand, the Australian Government and some state and territory governments have intervened in the market.

5.10.1 Australian Domestic Gas Security Mechanism

The Australian Domestic Gas Security Mechanism (ADGSM) empowers the Australian Government Minister for Resources to require LNG projects to limit exports, or find offsetting sources of new gas, if a supply shortfall is likely.[124] The Minister may determine in the preceding September whether a shortfall is likely in the following year and may revoke export licences if necessary to preserve domestic supply.

To avoid export controls, Queensland's LNG producers entered agreements with the government committing to offer uncontracted gas on reasonable terms to meet expected supply shortfalls.[125] They also committed to offer gas to the Australian market on competitive market terms before offering any uncontracted gas to the international market.[126] Following a review by the Australian Government Department of Industry, Science, Energy and Resources, the scheme was extended until 2030.[127]

On 29 September 2022 the Australian Government announced it had signed a new Heads of Agreement (HoA) with LNG exporters, indicating that they would offer an estimated additional 157 PJ of gas to domestic customers in 2023 through a combination of supplying uncontracted gas and utilising existing and improved gas marketing methods. This resulted in the Australian Government's decision not to trigger the operation of the ADGSM for 2023.[128]

5.10.2 Gas Supply Guarantee

Facility and pipeline operators developed the Gas Supply Guarantee (GSG) as a mechanism to meet commitments to the Australian Government to ensure enough gas is available to meet peak demand periods in the NEM.[129] The mechanism was originally scheduled to finish in March 2020, but the Australian Government extended the guarantee to March 2023.[130]

AEMO triggered the GSG for the first time on 1 June 2022.[131] 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 following the notification of a threat to system security (TTSS) in Victoria due to insufficient storage, after directing 2 generators to cease taking gas from the Victorian market until 30 September 2022 (with the GSG and TTSS to remain in effect until sufficient supply is available).[132]

121 AER, Compliance bulletin – new obligations on gas pipeline, compression and storage service providers, Australian Energy Regulator, 7 June 2023.
122 AER, Compliance and enforcement report 2022–23.
123 AER, Wholesale markets quarterly report, Q2 2023, Australian Energy Regulator, July 2023, p. 22.
124 Department of Industry, Science Energy and Resources, *Australian Domestic Gas Security Mechanism*, July 2018.
125 Department of Industry, Science, Energy and Resources, *Securing Australian domestic gas supply*, DISER website, accessed 28 May 2021.
126 The agreement specifically notes that LNG netback prices, as referenced by the ACCC, play a role in influencing domestic gas prices.
127 Department of Industry, Science, Energy and Resources, *Australian Domestic Gas Security Mechanism review*, January 2020.
128 Johnson Winter Slattery, *Commonwealth enters new Heads of Agreement to safeguard Australia's east coast domestic gas market*, October 2022.
129 AEMO, *Gas supply guarantee*, Australian Energy Market Operator website, accessed 28 May 2021.
130 AEMO, *Gas supply guarantee guidelines consultation final determination*, Australian Energy Market Operator, March 2020.
131 AEMO, *Gas supply guarantee*, Australian Energy Market Operator, accessed 28 May 2021.
132 AEMO, AEMO takes further steps to manage tight gas supplies, Australian Energy Market Operator, 19 July 2022.

5.10.3 Additional powers for AEMO

On 12 August 2023 Energy Ministers agreed to take a range of actions to support a more secure, resilient and flexible east coast gas market. These actions sought to address winter 2023 east coast gas supply adequacy concerns that were raised in ACCC and AEMO reporting.

The actions include regulatory amendments providing additional powers to the Australian Energy Market Operator (AEMO) to manage gas supply adequacy and reliability risks ahead of winter 2023 (tranche 1) and longer-term solutions to manage threats to the east coast gas market (tranche 2).[133] The tranche 1 initiatives provide the regulatory framework covering:

- data transparency to assess supply-demand trends and determine the likelihood of a threat to reliability or adequacy of gas supply
- identification, communication and publication of information about actual or potential threats to signal an east coast gas system response
- powers to issue directions to gas industry participants to resolve potential or actual threats to system security (including a compensation framework)
- the ability for AEMO to trade in natural gas to maintain or improve reliability or adequacy of gas supply.

A Bill giving effect to these changes commenced on 27 April 2023, alongside supporting regulations. The corresponding Rule amendments came into effect on 4 May 2023.[134]

5.10.4 State government schemes

To encourage gas exploration, the Queensland Government grants exploration authorities for 'domestic only' exploration tenements.

As part of this grants program, it released almost 70,000 km^2 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 km^2 of land in September 2020, with over 15% tagged for domestic supply.[135] In 2021, the Queensland Government announced it would make 14,100 km^2 available for oil and gas exploration.[136] In June and July 2022, the Queensland Exploration Program released prospect tenders for petroleum and gas exploration (8 areas, 14,420 km^2) and greenhouse gas storage (14,500 km^2).[137]

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.[138]

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 of an unlocking an additional 50 PJ per year by 2023.[139]

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.

5.10.5 ACCC gas inquiry

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).[140]

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133 AEMO, East Coast Gas Reforms, Australian Energy Market Operator.

134 National Gas (South Australia) (East Coast Gas System) Amendment Act 2023; National Gas (South Australia) (East Coast Gas System) Amendment Regulations 2023; National Gas Amendment (East Coast Gas System) Rule 2023.

135 Queensland Government, 'Queensland gas exploration ramping up' [media release], September 2020.

136 Queensland Government, 2021 Queensland Exploration program, November 2021, accessed 28 June 2022.

137 Queensland Government, *Queensland Exploration Program*, Business Queensland website, accessed 25 May 2023.

138 NSW Government, *Memorandum of understanding – NSW energy package*, 31 January 2020.

139 Australian Government, 'Energy and emissions reduction agreement with South Australia' [media release], April 2021.

140 ACCC, *Gas inquiry 2017–2030*, Australian Competition and Consumer Commission, accessed 24 May 2023.

5.10.6 Electrification of liquefied natural gas production

On 8 February 2020 the Australian Government announced it would allocate up to $1.5 million to work with the Queensland Government and industry on electrifying the Curtis Island LNG facilities. The production facilities currently use their own gas as a power source in production. Partly electrifying these processes would make available up to 12 PJ of gas for delivery to the domestic market.

The first project will be a 100 MW Pleasant Hills Solar Project in Queensland developed by TotalEnergies and Gentari Renewables. The solar farm will supply renewable energy to the Roma field's gas production and processing facilities, which feed into the Gladstone LNG export project.

5.10.7 National hydrogen strategy

The Australian Government identified hydrogen as a potential fuel to facilitate cuts to emissions across energy and industrial sectors. As part of this strategy, the government is looking at introducing hydrogen to the gas distribution network as part of the mix with natural gas. Currently, hydrogen can be added to gas pipelines at concentrations of up to 10% to supplement gas supplies and a number of trials are being explored.

In July 2020 the Australian Renewable Energy Agency (ARENA) shortlisted 7 projects to be considered as part of its $70 million fund to develop large-scale electrolysers, 3 of which are based in eastern Australia.[141] In April 2023 ARENA launched a $25 million funding round to support research and development of large-scale renewable hydrogen.

In February 2023 Australian Government Ministers agreed to lead jurisdictions in a review of the National Hydrogen Strategy.[142]

5.10.8 Competition and Consumer (Gas Market Emergency Price) Order

On 23 December, the Competition and Consumer (Gas Market Emergency Price) Order 2022 came into effect for 12 months.[143]

The Order introduced a price cap on gas of $12 per GJ (and does not apply in Western Australia) during the price cap period set as 12 months, effectively 2023 gas supply. Generally, the price cap applies to gas producers and affiliates of gas producers (regulated producers).

There are several exceptions, including gas to be exported as LNG, retailers that meet certain criteria, trades on the Short Term Trading Market (STTM) or Declared Wholesale Gas Market (DWGM), near term (next 3 day) trades and offers on the Gas Supply Hub (GSH) Exchange.

Separate to the exceptions, the Order also allows the Minister to grant exemptions. The Minister has delegated the power to grant a gas price cap exemption to the ACCC.[144] The delegation commenced on 23 December 2022.

Further information on the price cap, the process of applying for an exemption (including information requirements) and the ACCC's process after receiving an exemption application can be found on the ACCC's website.[145]

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.[146] 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 incentivise investment to meet ongoing medium-term demand

141 ARENA, *Seven shortlisted for $70 million hydrogen funding round*, Australian Renewable Energy Agency, accessed 28 May 2021.

142 DCCEEW, *National Hydrogen Strategy review*, Department of Climate Change, Energy, the Environment and Water, accessed 25 May 2023.

143 Australian Government, Competition and Consumer (Gas Market Emergency Price) Order 2022, December 2022.

144 A list of exempted entities is available on the ACCC's website (Gas price exemptions register).

145 ACCC, Gas cap price exemption, Australian Competition and Consumer Commission, December 2022.

146 DCCEEW, Mandatory Gas Code of Conduct, Department of Climate Change, Energy, the Environment and Water, 11 July 2023.

- 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.

5.11 Gas market reform

On 30 September 2022, National Cabinet agreed to establish the Energy and Climate Change Ministerial Council (ECMC) within the streamlined model of Australia's federal relations architecture, replacing the Energy National Cabinet Reform Committee (formerly the COAG Energy Council). Energy Ministers, along with the ECMC, direct gas market reforms, which regulatory and market bodies implement.[147] A key focus of reform is to address information gaps and asymmetries in the market.

In its inaugural meeting on 24 February 2023, the ECMC agreed to 5 strategic priorities, which will be reviewed annually alongside the terms of reference.[148] The ECMC also agreed to expedite a package of carefully designed measures expanding the Australian Energy Regulator's (AER) gas and electricity market monitoring powers.[149] 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.[150]

Reform stems from findings by bodies that include the AEMC, the ACCC and the Gas Market Reform Group. 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.

5.11.1 Gas Bulletin Board reforms

The Gas Bulletin Board 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. 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 related to price and volume in the shorter-term gas market, including how gas is exported overseas and how it is traded here in Australia. In particular, the AER now monitors the export, reserve, storage and domestic sale and swaps of gas to report more comprehensively on competition.

Price and reserves transparency

With gas markets shifting towards shorter-term contracts, and suppliers using EOI processes, the transparency of price and other market information is critical. 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.[151]

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 Resources Reporting and Facility Developments and LNG and Short Term Transactions. [152]

147 The Energy Advisory Panel includes the AER, the AEMC, AEMO and the ACCC. On 19 May 2023, state and federal energy ministers voted unanimously to disband the Energy Security Board, replacing it with a new specialist advisory panel to fast-track new connections of renewable energy sources to the east coast grid.

148 Energy and Climate Change Ministerial Council.

149 Department of Climate Change, Energy, the Environment and Water, gas and electricity market monitoring powers.

150 AER, AER welcomes new powers to keep watch on wholesale gas markets, news release.

151 ACCC, Gas inquiry 2017–2030 – LNG netback price series, Australian Competition and Consumer Commission.

152 AEMO, Reserves Resources Reporting and Facility Developments and LNG and Short Term Transactions.

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 the energy.gov.au website.[153]

5.11.2 Pipeline reforms

Recent reforms to the National Gas Law (NGL) and National Gas Rules (NGR) have significantly changed the way gas pipelines are regulated. In March 2022, Energy Ministers agreed to a package of gas pipeline regulatory amendments to deliver a simpler regulatory framework. The reforms aim to limit the exercise of market power, facilitate better access to pipeline capacity and provide greater support for commercial negotiations between shippers and service providers through increased transparency of information and improvements to the negotiation framework and dispute resolution mechanisms.

Key changes have been made to the following elements:

- the greenfields incentive regime[154]
- regulatory powers to determine the form of regulation to which a pipeline should be subject
- service provider information disclosure requirements[155]
- numerous other clarifications and refinements.

Under the new regime, all transmission and distribution pipeline service providers will be required to provide third party access where it is sought, subject to available exemptions.[156]

The new reforms have abolished the concept of 'light regulation', subjecting all pipelines to a range of uniform access, transparency and ring-fencing requirements. All pipelines are now classified as either scheme or non-scheme pipelines, with scheme pipelines subject to a stronger form of regulation based on the 'full regulation' regime.[157] Non-scheme pipelines are subject to a lighter commercially oriented form of regulation and dispute resolution mechanism.

There are also requirements on standalone compression and storage facility service providers to publish standing terms of services offered and information on individual prices paid by shippers. Pipelines are now required to publish actual prices payable instead of weighted average prices that they previously reported.

The reforms also require the AER to regularly and systematically monitor service providers' behaviour and report on this to the Ministerial Council on Energy every 2 years. The information that the AER must monitor and report on includes the actual prices charged, non-price terms and conditions for pipeline services, financial information reported by service providers, outcomes of access negotiations, service providers compliance with ring fencing requirements, dealings with associates and their compliance with other requirements of the NGL and NGR. An aggregated version of the MCE report will also be published by the AER on its website as soon as practicable.[158]

More information on the new regulatory framework is available in chapter 6.

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153 Department of Industry, Science, Energy and Resources, Regulatory amendments to increase transparency in the gas market, 19 November 2020.

154 Greenfields (new) pipeline projects are eligible for a greenfields incentive determination (which protects the pipeline from becoming a scheme pipeline for up to 15 years from commissioning) and a greenfields price protection determination (which specifies prices for pipeline services that are binding on an arbitrator in the event of an access dispute).

155 For pipeline service providers – Part 10 of the NGR and for standalone compression and storage facilities – Part 18A of the NGR.

156 Exemptions to reporting obligations are available to facilities with no third-party users, where facilities would be exempt from all reporting obligations. Single user pipelines, or those with a capacity of less than 10 TJ per day are able to seek an exemption from the obligation to publish historical and service usage information.

157 Previous concepts of 'full regulation', 'light regulation' and 'Part 23 regulation' are described in previous State of the energy market reports. Full regulation involved negotiation and arbitration with reference tariffs approved by the regulator and contained a regulatory-oriented dispute resolution mechanism.

158 Pursuant to section 63B(4) of the NGL.

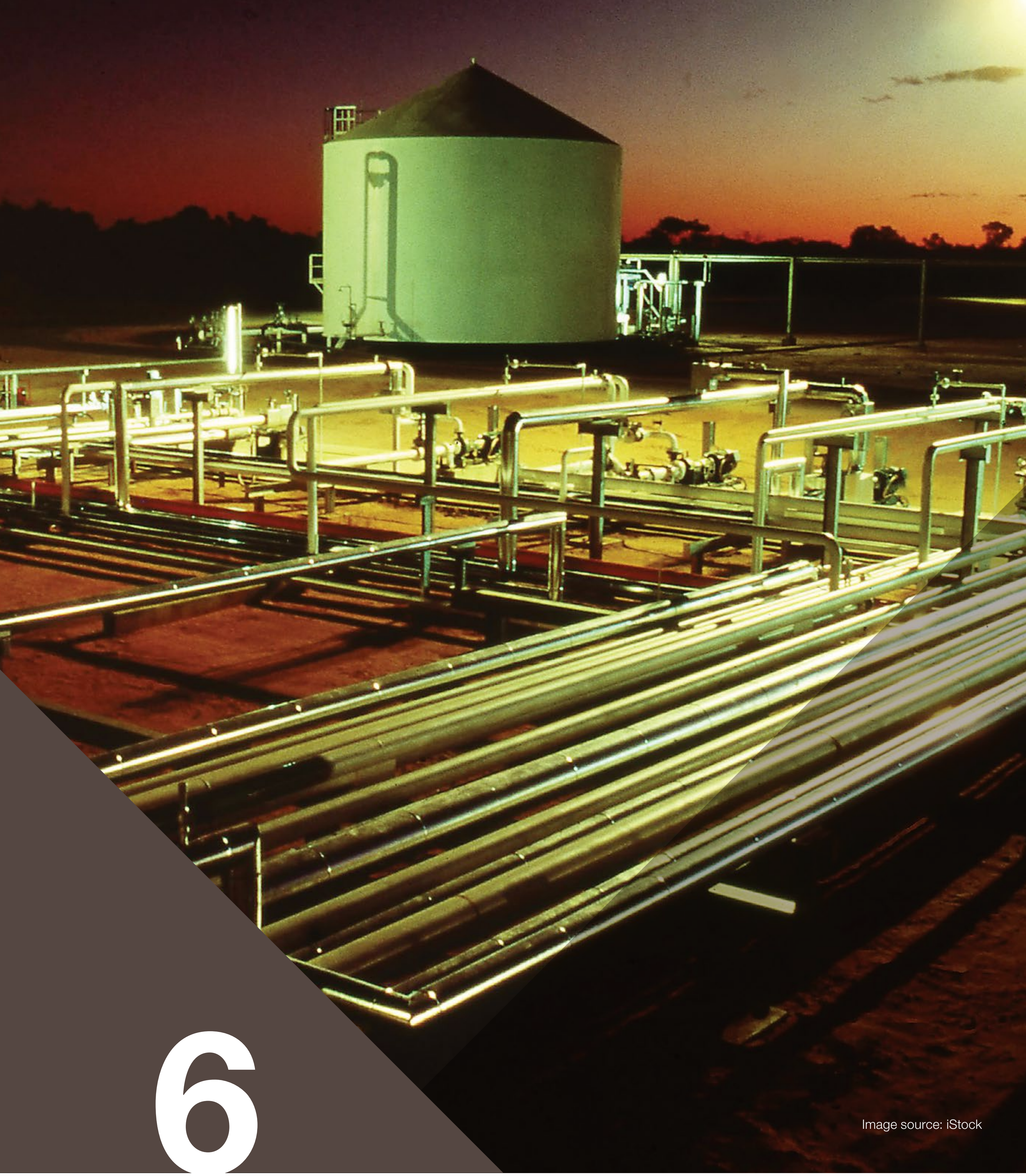


Image source: iStock

6 Regulated gas pipelines

Australia's gas pipeline infrastructure consists of transmission and distribution pipelines. Together, these pipelines transport gas from upstream producers to residential, commercial and industrial customers. The role of the transmission pipelines is to carry gas from 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.

This chapter covers the scheme pipelines regulated by the AER, which is the regulator in all states and territories except Tasmania and Western Australia.[1]

6.1 Snapshot

In December 2022, the AER finalised the access arrangement for the Victorian transmission pipeline APA Victorian Transmission System. The terms of this access arrangement and the reference prices determined by the AER are now set through to 31 December 2027.

In June 2023, the AER finalised access arrangements for 3 Victorian distribution pipelines – AusNet Services, Australian Gas Networks and Multinet Gas Networks. The access arrangements and reference prices for these distribution pipelines are now set through to 30 June 2028.

Over the 12-month period to 30 June 2022, AER determinations covered access prices for 9 pipeline service providers:

- Those service providers earned $40 million (2.4%) less revenue than in the previous year and $111 million (6%) less than the average annual revenue earned over the previous 5 years[2] (section 6.7).
- The overall decrease in revenue from the previous year was driven by distribution pipeline Australian Gas Networks (South Australia) (down 9%) and transmission pipeline Roma Brisbane Pipeline (Queensland) (down 8%) (section 6.7).
- Investments in scheme pipelines were primarily made to replace aging mains pipelines (section 6.10).

In March 2023 a package of reforms was introduced, which updates the regulatory framework applying to regulated gas pipelines (section 6.4). The AER is currently undertaking processes to implement these reforms. Among other changes, the AER will now be responsible for making determinations on the form of regulation, which will determine whether any other pipelines should be regulated under the building block regulatory model.

6.2 Gas pipeline characteristics

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 reverse direction transport. Gas can also be stored (parked) in a pipeline 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.

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 6.1).

Distribution pipelines are installed underground and consist of high, medium and low-pressure mains. 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.

The services provided by transmission pipelines are evolving to meet changing market needs, but distribution pipelines tend to offer fairly standard services – namely, allowing gas injections into a pipeline, conveying gas to supply points and allowing gas to be withdrawn.

1 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.

2 Excludes revenue earned by Amadeus Gas Pipeline. Amadeus Gas Pipeline's actual revenue is confidential because it contains commercially sensitive information.

Gas is distributed to most Australian capital cities, major regional areas and towns. Queensland and Victoria each have multiple 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.[3] In 2022, distribution pipelines supplied natural gas to almost 4.3 million residential customers and over 110,000 commercial and industrial customers (Figure 6.3).

The total number of customers on the distribution pipelines increased by 1.2% in 2022. However, this increase marked the lowest annual growth in distribution customers within the available data (dating back to 2012).

In 2022, residential customers accounted for more than 97% of the total distribution customer base but only consumed around 50% of the total gas delivered. The other 3% of customers were either industrial or commercial customers and consumed the remaining 50% of the gas delivered.

The capital base of the transmission and distribution service providers for which the AER sets access prices is worth a combined $12.3 billion (Figure 6.2 and Figure 6.3).[4]

Box 6.1 Changing forms of regulation

Recent reforms to improve and simplify the gas pipeline regulatory framework have resulted in several significant changes to the National Gas Law and National Gas Rules (section 6.4).

Prior to the reforms, the National Gas Law provided for the following forms of regulation:

- full regulation for scheme pipelines
- light regulation for scheme pipelines
- Part 23 (National Gas Rules) regulation for non-scheme pipelines that provided third party access to pipeline services.

Under the new regulatory framework, gas pipelines are classified as either:

- scheme pipelines, or
- non-scheme pipelines (section 6.4.1).

Expansions of the capacity of a pipeline are treated as part of the same pipeline.

Previous publications of the State of the energy market focused on the pipeline service providers for which the AER assesses the terms and conditions of access to nominated reference services using a building block approach to assess the service provider's efficient costs (section 6.6). Prior to the reforms this included all fully regulated scheme pipelines.

In this report we continue to focus on the pipeline service providers we have focused on in the past[a] – the pipeline service providers that were previously classified as 'full regulation'.

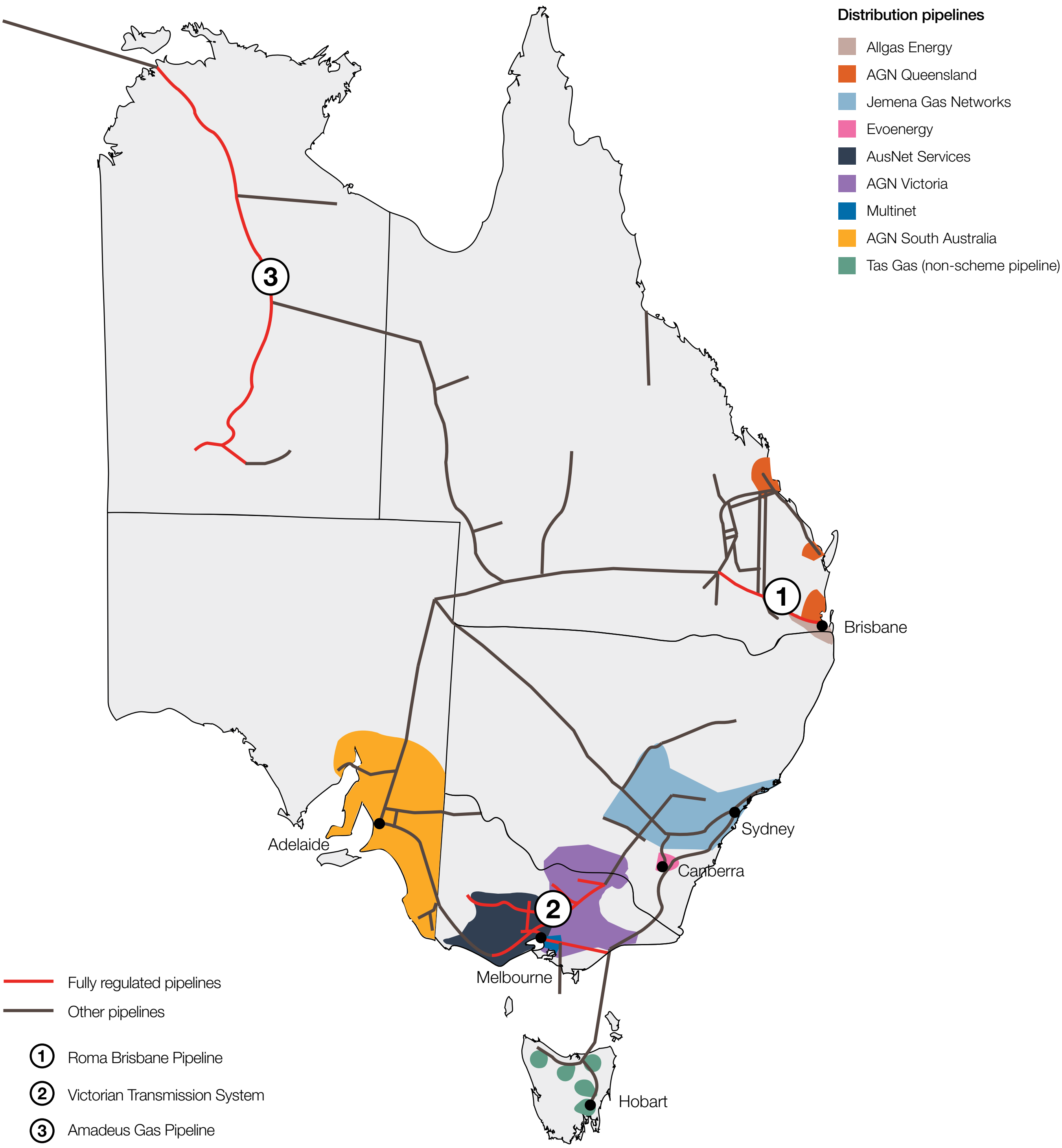
While the newly classified 'scheme pipelines' capture both 'full and light regulation' pipelines any reference to 'scheme pipelines' within this report refers exclusively to those previously classified as fully regulated (unless otherwise stated).

a Three transmission pipeline service providers – Roma Brisbane Pipeline (Queensland), APA Victorian Transmission System (Victoria) and the Amadeus Gas Pipeline (Northern Territory) – and 6 distribution pipeline service providers in NSW, Victoria, South Australia and the ACT.

3 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.

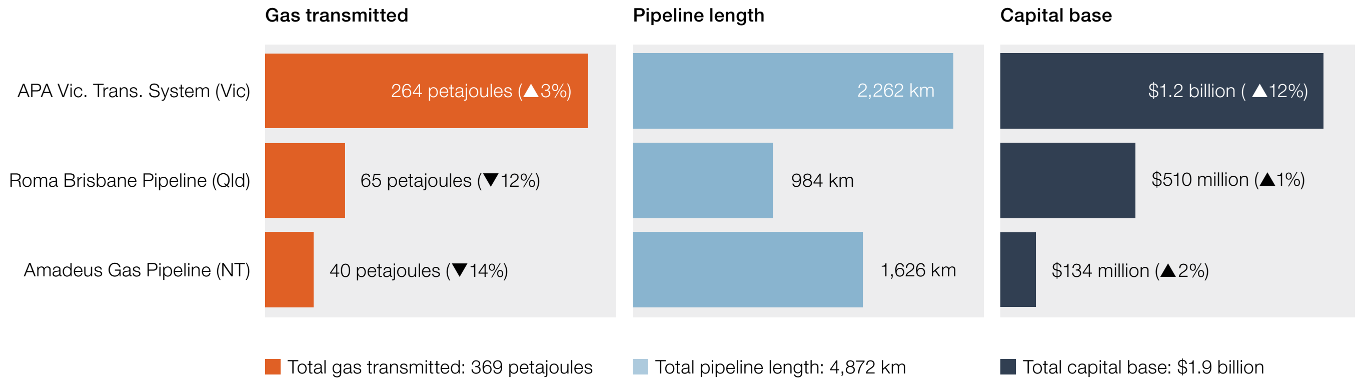
4 Capital bases capture the total economic value of assets that are providing pipeline services to customers. These assets have been accumulated over time and are at various stages of their economic lives.

Figure 6.1 Major gas transmission and distribution pipelines



Source: AER.

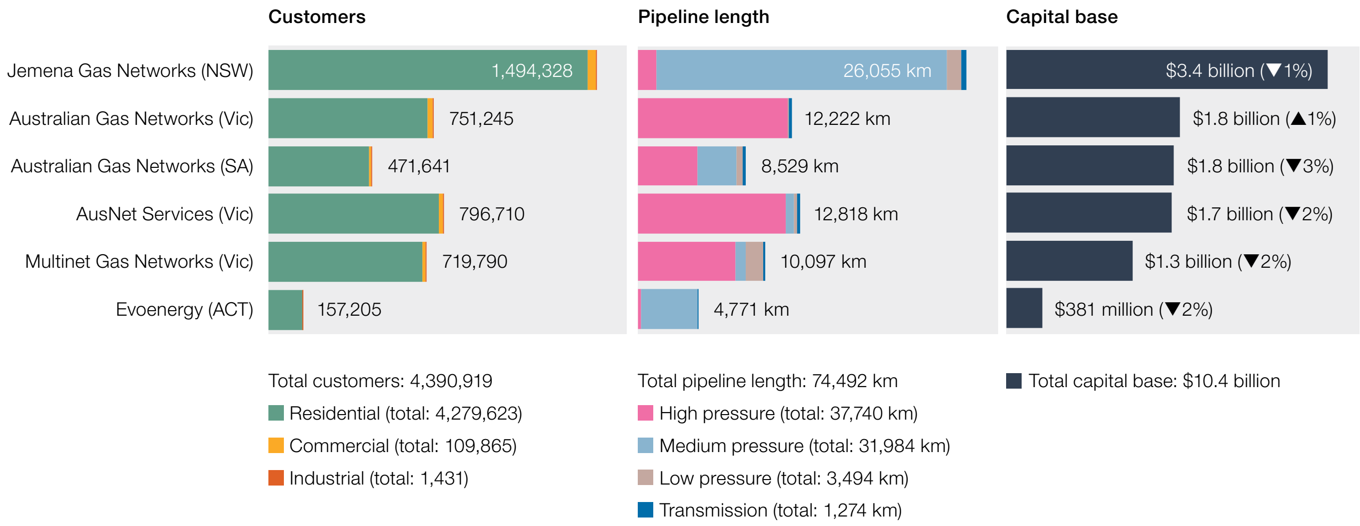
Figure 6.2 Gas transmission pipelines regulated by the AER



Note: Capital base is adjusted to June 2022 dollars. The capital base is the forecast value of pipeline assets based on the closing capital base at 30 June 2022, except for APA Victorian Transmission System (31 March 2022). 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 6.3 Gas distribution pipelines regulated by the AER



Note: Capital base is adjusted to June 2022 dollars. The capital base is the forecast value of pipeline assets based on the closing capital base at 30 June 2022, except for the Victorian distribution pipelines (31 December 2022).

Source: AER access arrangement decisions and annual regulatory information notices (RINs).

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 and on-sell it to consumers
- commercial and industrial users
- liquefied natural gas (LNG) exporters, which buy gas directly from producers and contract with a pipeline service provider to transport it to export terminals.

Distribution service providers transport gas to energy customers, but they do not sell gas. Energy retailers purchase gas from producers and pipeline services from pipeline service providers and sell them as a packaged retail product to their customers. Many retailers offer both gas and electricity products.

6.3 Gas pipeline ownership

Australia's gas pipelines are privately owned. The publicly listed APA Group (APA) 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) and Cheung Kong Infrastructure Holdings Limited (CKI Group), which operates Australian Gas Networks. State Grid Corporation of China and Singapore Power International also have interests in the publicly listed AusNet Services (Victoria).

Table 6.1 summarises ownership of key gas transmission pipelines.

Table 6.1 Ownership of key gas transmission pipelines

Pipeline service provider	Location	Capacity (TJ/day)	Regulatory status	Owner
Roma Brisbane Pipeline	Qld	211 (145)	Scheme pipeline	APA Group
Victorian Transmission System (GasNet)	Vic	1,169	Scheme pipeline	APA Group
Amadeus Gas Pipeline	NT	165	Scheme pipeline	APA Group
South West Queensland Pipeline (Wallumbilla to Moomba)	Qld–SA	453 (340)	Non-scheme pipeline	APA Group
Queensland Gas Pipeline (Wallumbilla to Gladstone)	Qld	149 (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	1,430	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	1,560	15-year no coverage	Origin Energy 37.5%, ConocoPhillips 37.5%, Sinopec 25%
Moomba to Sydney Pipeline	SA–NSW	489 (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	350	Non-scheme pipeline	Jemena (State Grid Corporation of China 60%, Singapore Power 40%)
Vic–NSW Interconnect	Vic–NSW	223 (226)	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	Non-scheme pipeline	Jemena (State Grid Corporation of China 60%, Singapore Power 40%)
Bonaparte Pipeline	NT	108	Non-scheme pipeline	Energy Infrastructure Investments (APA Group 19.9%, Marubeni 49.9%, Osaka Gas 30.2%)

Note: TJ/day: terajoules per day.
For bi-directional pipelines, reverse capacity is shown in brackets.

Source: AER; ACCC, interim reports of gas inquiry 2017–2025; corporate websites; Gas Bulletin Board.

Table 6.2 summarises ownership of gas distribution pipelines.

Table 6.2 Ownership of 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 Network	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: AER gas pipeline performance data; corporate websites.

6.4 Regulating gas pipelines

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 the opportunities and incentives to charge higher prices than they could charge in a competitive market. This poses risks to consumers because pipeline charges make up a significant portion of residential gas bills (chapter 7).

The National Gas Law and National Gas Rules set out the regulatory framework for gas pipelines. The regulatory objective of the National Gas Law is to promote efficient investment in, and operation and use of, gas services for the long-term interests of consumers in terms of the price, quality, safety, reliability and security of supply of gas. The National Gas Rules set out revenue and pricing principles, including that pipeline service providers should have a reasonable opportunity to recover efficient costs.

In May 2023, Energy Ministers agreed to amendments to the national energy laws to incorporate an emissions reduction objective into the National Gas Objective. The amendments are designed to ensure governments and market bodies have the necessary legislative and regulatory levers to keep Australia's energy sector affordable, secure and reliable, in the best interest of consumers. This amendment is expected to take place in late 2023.

In March 2023, a regulatory package commenced operation to implement reforms to gas pipeline regulation. These reforms were agreed on by Energy Ministers and are intended to deliver a simpler regulatory framework, increased market transparency and improved access to pipelines on fair terms.[5]

The reforms have significantly changed the way in which gas pipelines are regulated. Under the reforms:[6]

- The 3 previous forms of regulation (full or light regulation for scheme pipelines, and non-scheme pipelines) have been condensed into 2 forms of regulation. Under the new regulatory framework, gas pipelines are classified as either 'scheme' or 'non-scheme' pipelines, and expansions of the capacity of a pipeline are treated as part of the same pipeline.
- The AER is now responsible for determining the form of regulation by applying a form of regulation test.
- Pipeline service providers may apply to the AER for a greenfields incentive determination and a greenfields price protection determination prior to commissioning new pipelines.
- All pipeline service providers must publish prescribed transparency information under a unified information disclosure framework. Additionally, standalone compression and storage facilities are required to publish standing terms and price information. The AER has a role in monitoring and reporting on this information.
- All pipelines are subject to the same access negotiation frameworks and ring-fencing requirements.

5 Australian Government, Reform package to improve gas pipeline regulation takes effect, Department of Climate Change, Energy, the Environment and Water, accessed 13 June 2023.

6 AER, Compliance bulletin – new obligations on gas pipeline, compression and storage service providers, Australian Energy Regulator, 7 June 2023, accessed 14 June 2023.

Throughout 2023 the AER has sought stakeholder views when developing several new guidelines and templates to operationalise the reforms.[7]

6.4.1 Forms of regulation

Under the reforms the AER has assumed responsibility for determining the level of regulation that will apply to gas pipelines (through form of regulation determinations), the way new pipelines may be regulated (through greenfield determinations) and the classification and reclassification of pipelines. Before the reform this role was fulfilled by the National Competition Council and the jurisdictional minister.

Under the reforms, 'light regulation' has been abolished. All pipelines are now subject to a range of uniform access, transparency and ring-fencing requirements.

Scheme pipelines are now subject to a stronger form of regulation, including a regulatory-oriented access dispute resolution process. Service providers operating scheme pipelines are required to periodically submit an access arrangement to the AER for approval.[8] Service providers operating non-scheme pipelines are subject to a lighter form of regulation, a commercially oriented access dispute resolution process, and are not required to submit an access arrangement.

All new pipelines will be non-scheme pipelines when they are commissioned.

6.4.2 Pipeline classification and reclassification

The AER will implement a simplified approach to pipeline classifications and reclassifications under the new gas regulatory framework.[9]

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/authorisation. For new pipelines, if the jurisdictional licence contains no classification, the pipeline service provider must apply to the AER for a classification decision.[10] A service provider may apply to the AER for reclassification if it considers it has been wrongly classified.

6.4.3 Greenfields pipeline projects

Before the reforms commenced, '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 unless satisfied that all the coverage criteria were satisfied.

Under the reforms, greenfields pipeline projects may apply to the AER (before commissioning) for a greenfields incentive determination. They may also apply for a greenfields price protection determination, either as part of the greenfields incentive determination application process or later if they obtain a greenfields incentives determination.[11]

6.4.4 Prescribed transparency information for pipelines

Part 10 of the National Gas Rules prescribes the new transparency information requirements that apply to all scheme and non-scheme pipeline service providers. This information is to assist users of the pipeline in negotiations with the pipeline service provider.

Prior to the reforms, service providers of light regulation pipelines and non-scheme pipelines were required to prepare prescribed transparency information under Parts 7 and 23 of the National Gas Rules, respectively. These Parts are now repealed and have been replaced by Part 10.

7 AER, Pipeline regulatory determinations and elections guide, Australian Energy Regulator, 16 June 2023, accessed 14 August 2023.

8 A pipeline is a scheme pipeline if it was a covered pipeline (other than a light regulation pipeline) immediately before 2 March 2023.

9 AER, Pipeline regulatory determinations and elections guide, Australian Energy Regulator, 16 June 2023, accessed 14 August 2023.

10 AGS, Legal briefing - Gas pipeline reforms, 17 March 2023, accessed 14 June 2023.

11 AGS, Legal briefing - Gas pipeline reforms, 17 March 2023, accessed 14 June 2023.

Exemptions from certain requirements are available for pipeline service providers that meet the exemption criteria. 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[12] civil penalty provision under the National Gas (South Australia) Regulations.[13]

6.4.5 Ring-fencing requirements

Under the reforms, all pipelines are now subject to a set of requirements which previously only applied to some pipelines.[14] These include ring-fencing requirements. A service provider must, within 5 business days after entering into or varying an associate contract (whether approved or not), give the AER written notice of the contract or variation together with a copy of the contract (or the contract as varied). The requirement is classified as a conduct provision and tier 2 civil penalty provision under the National Gas (South Australia) Regulations.[15]

The National Gas Rules provide for a service provider to apply for an exemption from the ring-fencing requirements.

6.4.6 Monitoring and surveillance

Under the reforms, the AER is required to monitor the behaviour of pipeline service providers, including the prices charged for providing pipeline services, the information published by pipeline service providers, outcomes of access negotiations, dealings with associates and compliance with ring-fencing requirements.

Aside from these newly assigned monitoring and surveillance responsibilities, the AER already publishes an annual gas network performance report. The report provides an in-depth analysis of key outcomes and trends in the operational and financial performance of the transmission and distribution pipelines which, under the new framework, are classified as scheme pipelines. The report balances regular high-level reporting on a core set of measures with more detailed analyses on specific focus areas representing emerging issues of stakeholder interest.[16]

The 2023 gas network performance report is due to be published in late 2023.

6.5 Setting gas access prices

Pipeline service providers earn revenue by selling capacity to customers needing to transport gas. A customer purchases access to that 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).

As with electricity, the AER uses a building block approach to assess a pipeline service provider's efficient costs. The AER draws on a range of inputs to assess efficient costs, including cost and demand forecasts and revealed costs from experience. Unlike electricity, the approach is not formalised in published guidelines. An exception is the allowed rate of return assessment, for which a common AER guideline applies to both electricity and gas.

6.5.1 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 costs. 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 4, Box 4.3), but it is written into each service provider's access arrangement rather than being set out in a general guideline.

A number of pipeline service providers have proposed adopting a capital expenditure sharing scheme (CESS). The National Gas Rules do not mandate such schemes, but they allow the AER to approve their use to incentivise service providers to efficiently maintain and operate their pipelines.

12 Tier 1 provisions carry maximum penalties for corporations of $10 million, or if greater, 3 times the benefit obtained from the breach if this can be determined, or if not, 10% of annual turnover.

13 Government of South Australia, National Gas (South Australia) Regulations, accessed 14 June 2023.

14 AGS, Legal briefing - Gas pipeline reforms, 17 March 2023, accessed 14 June 2023.

15 Government of South Australia, National Gas (South Australia) Regulations, accessed 14 June 2023.

16 AER, Gas network performance report, Australian Energy Regulator, December 2022.

The Victorian distribution pipeline service providers were the first to implement a CESS as part of their 2018–2022 access arrangements. The AER subsequently approved Jemena Gas Networks' (NSW) request for a CESS for its 2020–2025 access arrangement and requests by Australian Gas Networks (South Australia) and Evoenergy (ACT) for their 2021–2026 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 4, Box 4.2). 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 around 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 incentives that are applied to electricity network service providers – such as those relating to service performance and demand management – are not available to gas pipeline service providers.

6.5.2 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 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 an 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, with staggered review timing to avoid bunching. 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 includes 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.

6.5.3 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.[17]

17 AER, Better Resets Handbook - Towards consumer-centric network proposals, Australian Energy Regulator, 18 November 2022, accessed 26 June 2023.

In the most recent round of access arrangement reviews, Victorian-based distribution pipeline service providers AusNet Services, Australia Gas Networks and Multinet Gas Networks engaged early and widely on their proposed access arrangements and demonstrated a strong commitment to building dialogue with both consumers and advocates. However, the lengthy nature of these engagements meant that a lot of the discussions pre-dated subsequent significant policy and economic changes.[18] [19] [20]

In preparing access arrangement proposals, the service providers conducted further engagement (both independently and jointly) with stakeholders to understand and respond to the concerns raised in the initial proposal.

The AER, in reviewing APA Victorian Transmission System's most recent access arrangement proposal, found that the service provider fell short of the expectations in the Better Resets Handbook for consumer partnership.[21]

The AER noted that APA Victorian Transmission System made progress in its consumer engagement compared with previous resets. The service provider's engagement on its revised proposal stopped at 'informing' stakeholders of its planned response to the AER's draft decision and left little room for influence or exploration of alternatives. The AER considered the service provider, in both its initial and revised proposal, focused on justifying its proposed positions rather than engaging with stakeholders on what alternative positions and options may be available.

We note the AER is not the only industry body focusing on consumer engagement by pipeline service providers. Each year Energy Networks Australia[22] and Energy Consumers Australia[23] recognise an Australian energy network that demonstrates best practice consumer engagement.

In September 2022, Victorian distribution pipeline service providers – AusNet Services, Australian Gas Networks and Multinet Gas Networks – won the 2022 Energy Networks Industry Consumer Engagement Award. The award recognised the 3 pipeline service providers' coming together to design and deliver a clear and consistent stakeholder engagement program which provided a single forum to discuss issues of importance to the sector.[24]

6.5.4 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.[25]

The information 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 include:

- accelerating asset depreciation (Box 6.3)
- 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 6.6.2) 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

18 AER, Draft decision – AusNet Services access arrangement 2023-28, Australian Energy Regulator, 9 December 2022, accessed 29 March 2023.
19 AER, Draft decision – AGN access arrangement 2023-28, Australian Energy Regulator, 9 December 2022, accessed 29 March 2023.
20 AER, Draft decision – MGN access arrangement 2023-28, Australian Energy Regulator, 9 December 2022, accessed 29 March 2023.
21 AER, APA Victorian Transmission System - Access arrangement 2023–27, Australian Energy Regulator, 9 December 2022, accessed 26 June 2023.
22 The national industry body representing Australia's electricity transmission and distribution and gas distribution networks.
23 The independent, national voice for residential and small business energy consumers.
24 ENA, Consumer engagement report, Energy Networks Australia, 15 December 2022, page 4.
25 AER, AER tackles gas pipeline regulation in an uncertain future, Australian Energy Regulator, November 2021.

- the prudency of allowing regulated service providers to recover expenditure from customers that is for repurposing gas assets to potentially transport renewable gases in the future
- the increased demand risk that regulated service providers may face under price cap regulation if gas demand falls persistently.

State and territory governments are already taking measures to reduce residential and small commercial consumers' reliance on gas. For example, the ACT Government's Climate Change and Greenhouse Gas Reduction (Natural Gas Transition) Amendment Bill 2022 establishes the legal framework to end new fossil fuel gas connections in the ACT.[26]

Further, 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.[27] Victoria has committed to halve emissions by 2030 as an early step towards meeting the national target of net zero emissions by 2050.[28] This will likely mean a limited role for gas beyond this date.

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. For example, the Gas Substitution Roadmap found that an existing detached dual-fuel home with rooftop solar photovoltaic (PV) that moves from using gas for heating, hot water and cooking to using efficient electric appliances could reduce its average energy bill by around $1,250 per year. For a household without solar, going all-electric could save around $1,020 per year.[29]

In July 2023, the Victorian Government announced that from January 2024 all new homes requiring a planning permit will be required to be all-electric. This means new homes and residential subdivisions that require a planning permit cannot connect to the gas network.

6.6 Building blocks of gas pipeline revenue

The AER uses a 'building block' approach to assess a gas pipeline service provider's revenue needs (Figure 6.4). Specifically, it forecasts how much revenue the service provider will need to cover:

- a commercial return to investors that fund the pipeline service provider's assets and operations
- efficient operating and maintenance costs
- asset depreciation costs
- taxation costs.

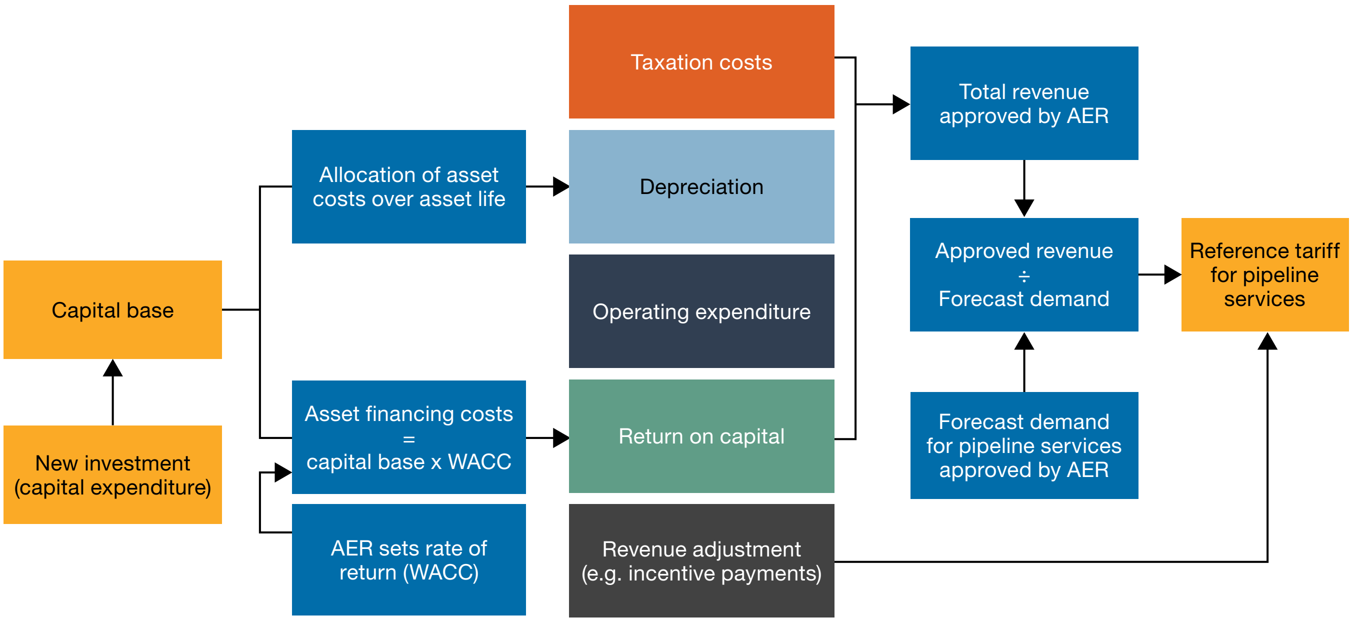
26 ACT Government, ACT reaches milestone preventing new fossil fuel gas connections, media release, 8 June 2023.

27 Victorian Government, Victoria's Gas Substitution Roadmap, Department of Energy, Environment and Climate Action, accessed 11 June 2023.

28 Australian Government, Australia's long-term emissions reduction plan, Department of Climate Change, Energy, the Environment and Water, accessed 11 June 2023.

29 Victorian Government, Victoria's Gas Substitution Roadmap, Department of Energy, Environment and Climate Action, accessed 11 June 2023.

Figure 6.4 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.

Pipeline assets have long lives, so investment costs are recovered over the economic life of the assets. The amount recovered each year is called depreciation and it 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 40% of revenues (52% for transmission and 38% for distribution) in the current access periods. The returns are calculated by multiplying:

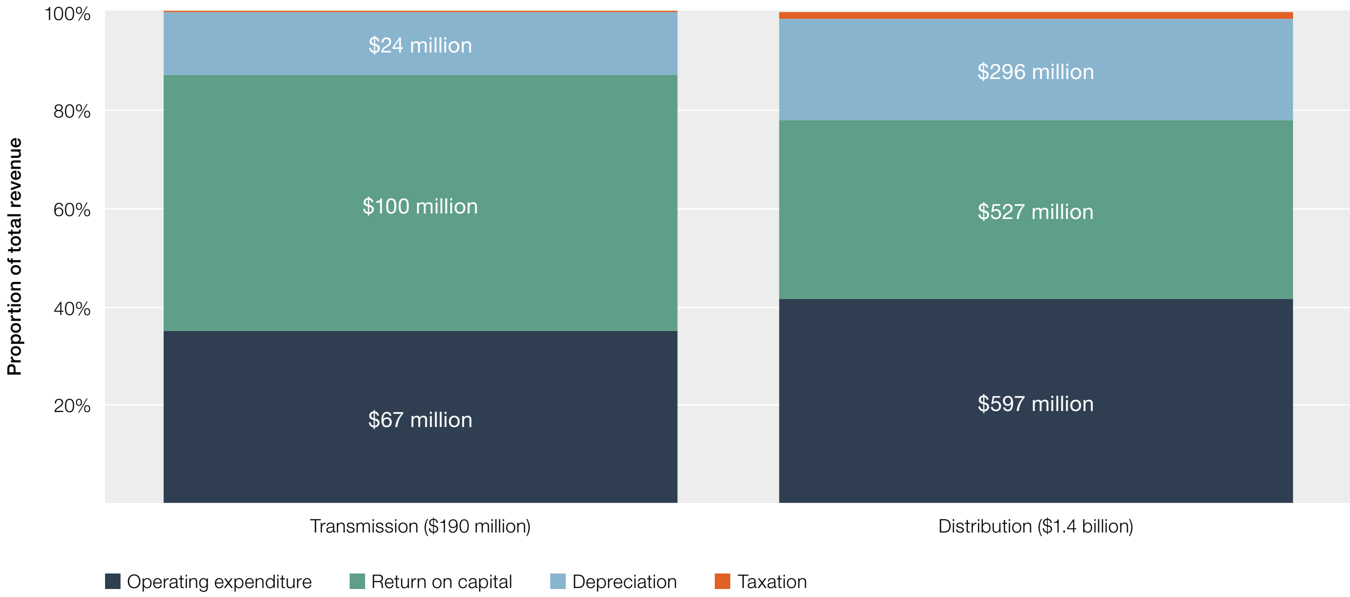
- the value of the pipeline service provider's capital base
- the rate of return that the AER allows based on the forecast cost of funding those assets through equity and debt.[30]

Operating and maintenance costs are also forecast to cause around 42% of revenue requirements (35% for transmission and 43% for distribution) in the current access periods. Overheads, taxation and other costs account for the remainder of a pipeline's revenue. Figure 6.5 illustrates the composition of pipeline revenues in current gas transmission and distribution access arrangements.

Pipeline service providers can also earn additional revenue through regulatory incentive schemes that encourage the efficient management of operating and capital expenditure programs (section 6.5.1).

30 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 pays when it borrows money to invest.

Figure 6.5 Composition of average annual gas pipeline revenues



Note: Composition of average annual gas pipeline revenue – current periods as at June 2023. All data are adjusted to June 2022 dollars. Gas pipeline service providers also receive bonuses or penalties that impact on annual pipeline revenues. These bonuses/penalties are not material and are not considered in Figure 6.5.

Source: Post tax revenue modelling used in AER determination process.

6.6.1 Recent AER access arrangement decisions

In December 2022, the AER approved forecast revenue of $613 million ($123 million per year) for APA Victorian Transmission System for the current access period (1 January 2023 to 31 December 2027). The AER's final decision affects the component of a customer bill relating to gas transmission tariffs, which represents approximately 2.3% of a Victorian retail gas consumer's annual bill.[31]

In June 2023, the AER approved combined forecast revenues of $3.2 billion ($644 million per year) for Victorian gas pipelines AusNet Services, Australia Gas Networks and Multinet Gas Networks for the current access period (1 July 2023 to 30 June 2028) (Table 6.3). The AER's final decisions affect the component of a customer bill relating to gas distribution tariffs, which represents approximately 24% on average of a Victorian retail gas consumer's annual bill.

The total combined forecast revenue is $320 million (9%) more than the forecast revenue used to determine tariffs in the previous access period. The combined revenue allowances included increases in operating expenditure, return on capital and depreciation, which were marginally offset by decreases in revenue adjustments and net tax allowance.

31 AER, APA Victorian Transmission System - Access arrangement 2023–27, Australian Energy Regulator, 9 December 2022, accessed 26 June 2023.

Table 6.3 Recent AER access arrangement determinations

Service provider	Revenue	Capital expenditure	Operating expenditure	Annual impact on residential bill
APA Victorian Transmission System (Vic)	$613m (▲6%)	$225m (▼16%)	$176m (▲18%)	▲0.2%
AusNet Services (Vic)	$1.1b (▲5%)	$397m (▼24%)	$354m (▲19%)	▲1.3%
Australia Gas Networks (Vic)	$1.2b (▼1.7%)	$402m (▼33%)	$495m (▲30%)	▲0.7%
Multinet Gas Networks (Vic)	$983m (▼5%)	$622m (▲43%)	$422m (▲0.1%)	▲1.2%

Note: Changes in revenue and expenditure are in relation to forecasts from the previous access arrangement periods. Bill impact is the change in the average annual customer bill compared with the customer bill in the final year of the previous period, adjusted for inflation, assuming retailers pass through outcomes of the determination.

Source: AER estimates.

6.6.2 Gas consumption and demand forecasts

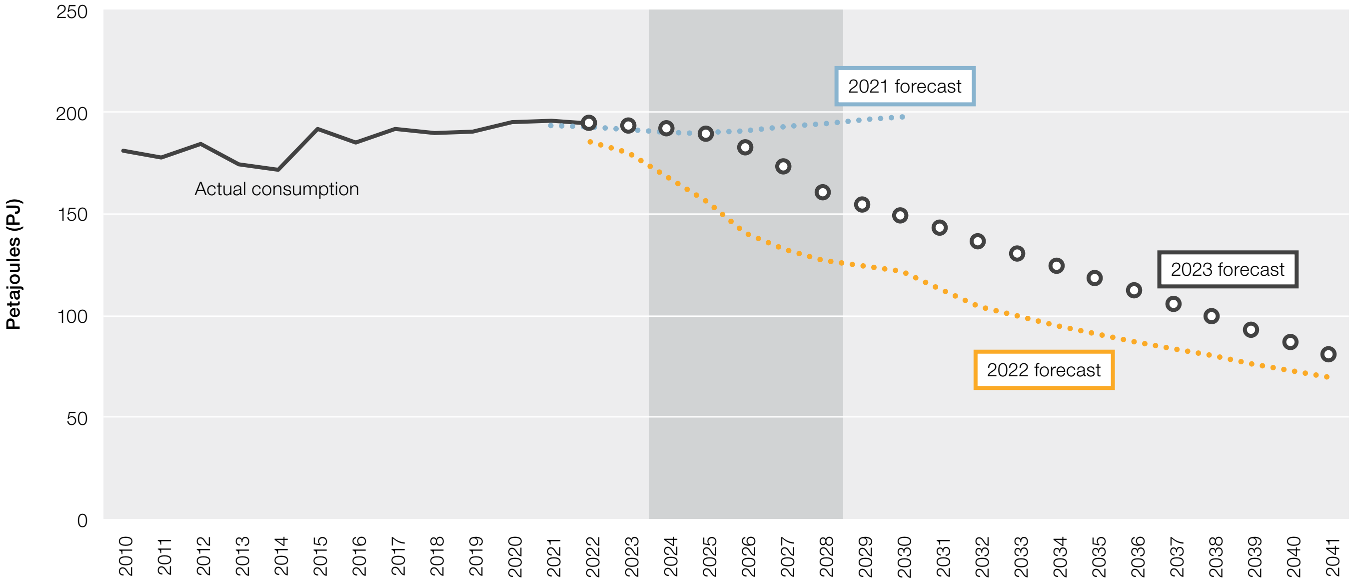
The Australian Energy Market Operator (AEMO), through its *2023 Gas Statement of Opportunities* (GSOO),[32] forecasts the adequacy of gas supplies to meet the needs of consumers in central and eastern Australia. The 'orchestrated step change' scenario is now considered the most likely scenario, wherein consumers are forecast to embrace opportunities to reduce emissions through electrification where technically and commercially practical, as well as investing in energy efficiency applications.

The AER used AEMO's 2023 GSOO demand forecasts to inform its final decisions for Victorian distribution pipelines AusNet Services, Australia Gas Networks and Multinet Gas Networks for the current access period. AEMO forecasts a 32% decrease in gas consumption by 2041, 59% for the residential and commercial sectors and 12% for the industrial sector. Residential and small commercial consumption is forecast to gradually decline in the short term, with more significant fuel switching in the medium to longer term as the economy transitions to meet net zero emissions goals.

AEMO's electrification forecasts were updated for the 2023 GSOO considering an observably slower rate of fuel switching than was evident in the 2022 GSOO forecast. The updated electrification forecasts had a discernible impact on the 2023 GSOO gas consumption forecasts, particularly for consumers in the residential and commercial sectors (Figure 6.6).

32 AEMO, 2023 Gas Statement of Opportunities, Australian Energy Market Operator, 28 April 2023, accessed 12 June 2023.

Figure 6.6 AEMO's forecast gas consumption – residential/commercial customers

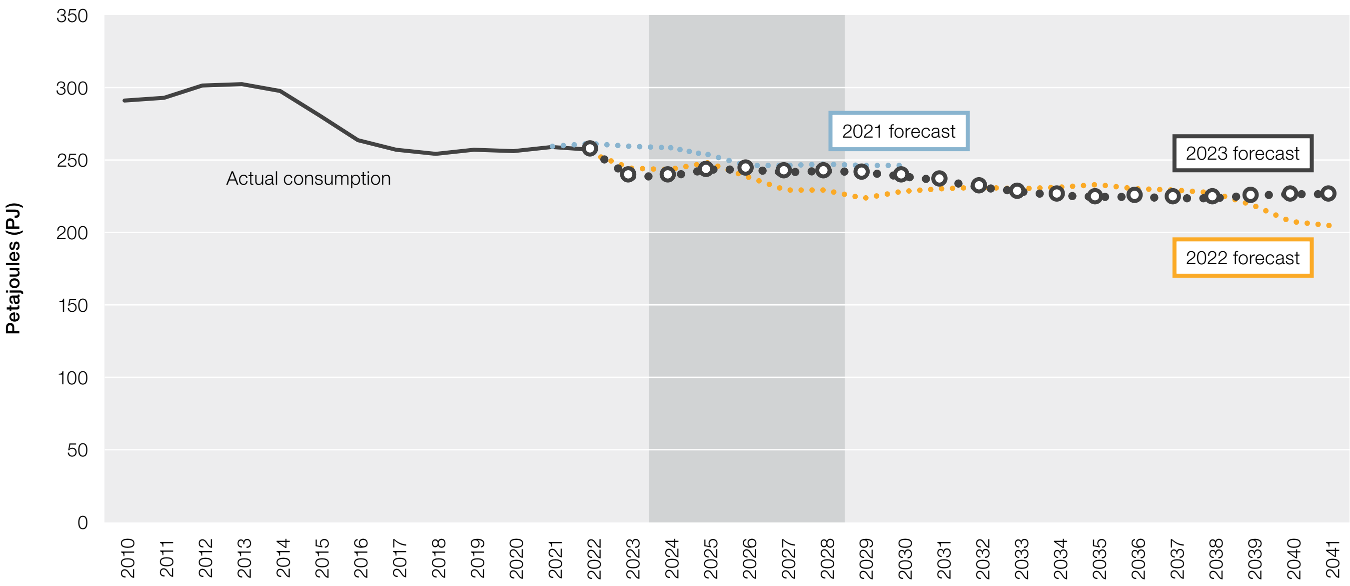


Note: Residential and commercial customers include consumers on volume-based tariffs. The shaded section reflects the period covered in the AER's most recent access arrangement decisions (1 July 2023 to 30 June 2028) (section 6.6.1).

Source: AEMO, 2023 Gas Statement of Opportunities, March 2023.

The industrial sector features a sharp decline in forecast natural gas consumption in the near term, driven by the closure of Incitec Pivot's Gibson Island facility in Brisbane in January 2023. A more gradual decline is forecast over the longer term, predominantly driven by customers switching away from natural gas to hydrogen. While electrification is expected to impact all sectors, the processes and the associated costs for industrial customers are likely to make the transition slower and more difficult than for the residential and commercial sectors (Figure 6.7).

Figure 6.7 AEMO's forecast gas consumption – industrial customers



Note: Industrial customers includes metered sites with annual consumption greater than 10,000 gigajoules (GJ) or maximum hourly quantity (MHQ) greater than 10 GJ. The shaded section reflects the period covered in the AER's most recent access arrangement decisions (1 July 2023 to 30 June 2028) (section 6.6.1).

Source: AEMO, 2023 Gas Statement of Opportunities, March 2023.

The AER closely examined AusNet Services', Australia Gas Networks' and Multinet Gas Networks' proposed capital and operating expenditures to ensure customers still reliant on gas are paying no more than necessary for safe, reliable and secure supply. Part of the reason for the decline in forecast demand on these pipelines is because of the increasing number of customers who are expected to significantly reduce their reliance on gas appliances or to leave the gas network completely. This raises important and contentious issues of cost, equity and safety.

Transformation in the energy system and the explicit policy goal of reaching net zero emissions by 2050 create considerable uncertainties in future gas demand expectations. The decline in demand for gas is expected to accelerate, but there is uncertainty as to how quickly the acceleration will happen, what the path to small customer 'electrification' will look like and whether gas pipelines will have any ongoing role in transporting hydrogen or biogas. Declining throughput on remaining connections will put upwards pressure on gas haulage. If this eventuates in future periods, 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.[33]

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 obligation on pipeline service providers to continue to offer the same services while meeting the same regulated standards means many costs won't necessarily fall as demand falls.

Box 6.2 Temporary disconnection versus permanent abolishment of gas connections

The AER, through our assessments of AusNet Services', Australia Gas Networks' and Multinet Gas Networks' recent access arrangements, 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. As such, the cost of permanently disconnecting the premises has been a deterrent for customers wanting to move away from gas.

To narrow the price difference between temporary and permanent gas disconnection services, and the associated safety risks it appears to be creating, the AER has determined an upfront cost of $220 for connection abolishment with the remainder added to the regulated revenue we use to set haulage tariffs and shared between all customers.[a]

This is not a change to the total costs that distribution pipeline service providers will be allowed to recover for connection abolishment services. It only changes the way in which costs are recovered.

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.

a AER, AER decision supports Victorian gas consumers in energy transition, Australian Energy Regulator, 2 June 2023, accessed 12 June 2023.

33 CSIRO and Dynamic Analysis, Consumer impacts of the energy transition: Modelling report, Energy Consumers Australia, July 2023, pp. 21–22, accessed 31 August 2023.

6.7 Revenue

All gas transmission and distribution service providers operating scheme pipelines are regulated under a 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 keeps the additional revenue. Conversely, if actual demand is less than forecast revenue the service provider is exposed to the shortfall.

Table 6.4 provides a breakdown of the revenue pipeline service providers earned in 2022 and how this compared with previous years.

Table 6.4 Revenue in 2022 – key outcomes

Service type	Revenue (2022)	Revenue (compared with 2021)	Revenue (compared with peak)
Transmission	$205m	▼$0.7m (▼0.3%)	▼$28m (▼12%) (2012)
Distribution	$1.4b	▼$40m (▼2.7%)	▼$297m (▼21%) (2015)
Total	$1.6b	▼$40m (▼2.4%)	▼$300m (▼15%) (2015)

Note: Amadeus Gas Pipeline's actual revenue is not considered in Table 6.4 as it contains commercially sensitive information.
Source: AER estimates.

Table 6.5 provides a snapshot of the key forecasts from the AER's revenue decisions for the current access arrangement periods and how they compare with forecasts from the previous periods.[34]

Table 6.5 AER gas revenue determinations – current access arrangements

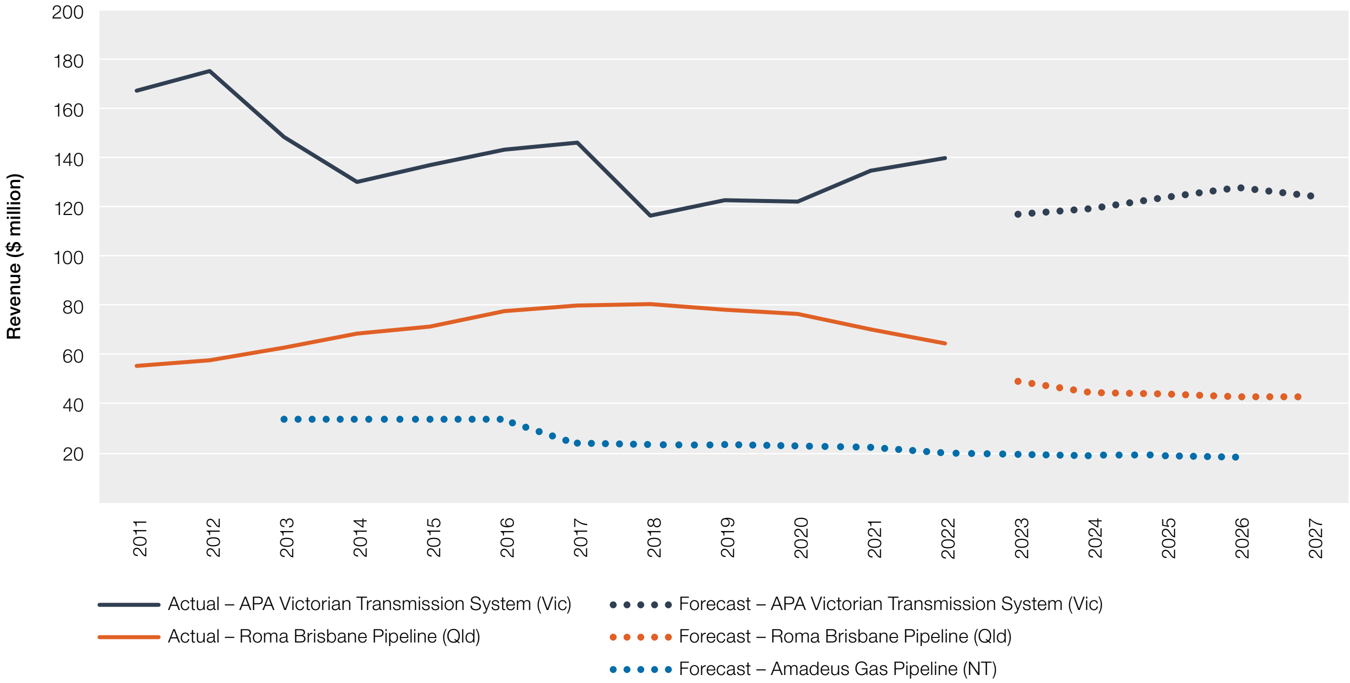
Service type	Revenue	Capital expenditure	Operating expenditure
Transmission	$933m (▼0.7%)	$279m (▼23%)	$329m (▲10%)
Distribution	$6.8b (▼2.2%)	$2.9b (▼14%)	$3.0b (▲14%)
Total	$7.7b (▼2%)	$3.2b (▼15%)	$3.3b (▲14%)

Source: AER estimates.

The total revenue forecast for transmission service providers includes decreases in revenue adjustments and net tax allowance, which are largely offset by increases in operating expenditure, return on capital and depreciation.

34 The current access arrangement period is the period in place at 1 July 2023.

Figure 6.8 Revenue – gas transmission pipelines

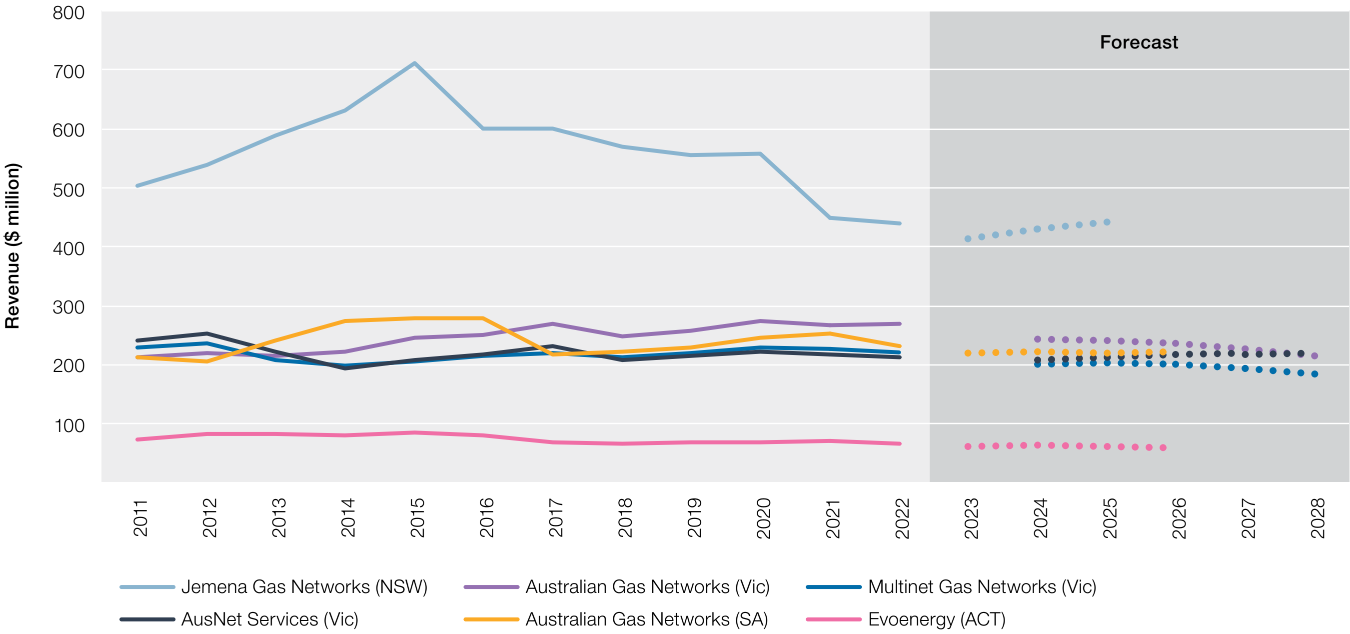


Note: All data are adjusted to June 2022 dollars. APA Victorian Transmission System (Vic) reports on a calendar year basis (year ending 31 December). All other pipeline businesses report on a financial year basis (year ending 30 June). The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Amadeus Gas Pipeline's actual revenue data is confidential.

Source: AER modelling; annual reporting RIN responses.

Revenues for most of the distribution pipeline service providers are forecast to decrease in the current access arrangement period. The drivers behind the decreases in forecast revenue are the reductions in return on capital and net tax allowance offsetting the forecast increases in operating expenditure and depreciation.

Figure 6.9 Revenue – gas distribution pipelines



Note: All data are adjusted to June 2022 dollars. Victorian gas 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). From 1 July 2023 the Victorian pipeline service providers will also report on a financial year basis. No revenue forecasts were developed for the Victorian pipeline service providers for the 6 month (1 January to 30 June 2023) transition period. 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 been increasing in recent years, both of which put upward pressure on gas pipeline revenue drivers (section 6.9), similar to what has occurred for electricity networks.

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 (Victoria) has justified the need for capital expenditure to finance its South West Pipeline and Western Outer Ring main projects. These projects have been deemed necessary to avert shortfalls and increase capacity between existing sources of natural gas supply. [35]

6.8 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.

While the forecast demand for natural gas continues to decline (section 6.6.2), new gas infrastructure investments and ongoing asset maintenance are necessary to ensure the reliability and safety of gas supply in the short term. The impact of new investment adds to the value of the capital base, the cost of which will be recovered across a declining base of customers, pushing gas prices up for those remaining customers.[36]

Box 6.3 Accelerated depreciation to address asset stranding risk

The AER, in its recent final decisions on the access arrangements for the Victorian gas transmission and distribution pipelines, allowed for some accelerated depreciation of assets. The combined value of asset bases to be recovered across these Victorian pipelines for their remaining lives is around $6 billion. Bringing forward the recovery of assets while pipeline use remains relatively high has increased costs to consumers of the pipeline in the short term, but reduced the pool of depreciation to be recovered from consumers in the future when pipeline use is expected to be lower.

Accelerating the rate at which assets are depreciated is pertinent given the uncertain future for gas pipelines in Victoria. It is important to start taking small steps now to manage the equitable recovery of the cost of the assets from what will be a declining, and sometimes vulnerable, customer base over time.

The Australian Energy Market Operator (AEMO) forecasts a material decline in gas volumes over the next 20 years (section 6.6.2). There is also considerable uncertainty around likely medium to long-term forecast volumes of customer abolishment (Box 6.2). Further, the future role for hydrogen and other renewable gases is uncertain at this time.

The Victorian Government's Gas Substitution Roadmap commits to achieve net zero emissions by 2050 (section 6.5). This will likely mean a limited role for natural gas beyond this date. The roadmap includes several initiatives that will reduce the role for gas in Victoria, such as 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.

While these changes are likely to eventuate, the pace of change remains uncertain. We consider that approving some amount of accelerated depreciation is consistent with our information paper 'Regulating gas pipelines under uncertainty' (section 6.5.4), wherein we stated, '… the opportunity and flexibility for adjustment is greatest when we act as soon as we can to minimise the adverse impact of a decline in gas demand'.

The AER seeks to strike a balance between determining an appropriate level of accelerated depreciation and the impact it will have on price stability (section 6.6). For example, we did not allow the full amount of accelerated depreciation sought by some of the Victorian gas distribution service providers. We instead allowed a smaller start to accelerated depreciation that balanced the price impacts in the short term with the need for longer term price stability.

We consider that accepting some accelerated depreciation leaves open the option to change course at future reviews, where more accelerated depreciation or reversals at a future date may be required to promote efficient growth (including negative growth) of the market as required under the National Gas Rules.

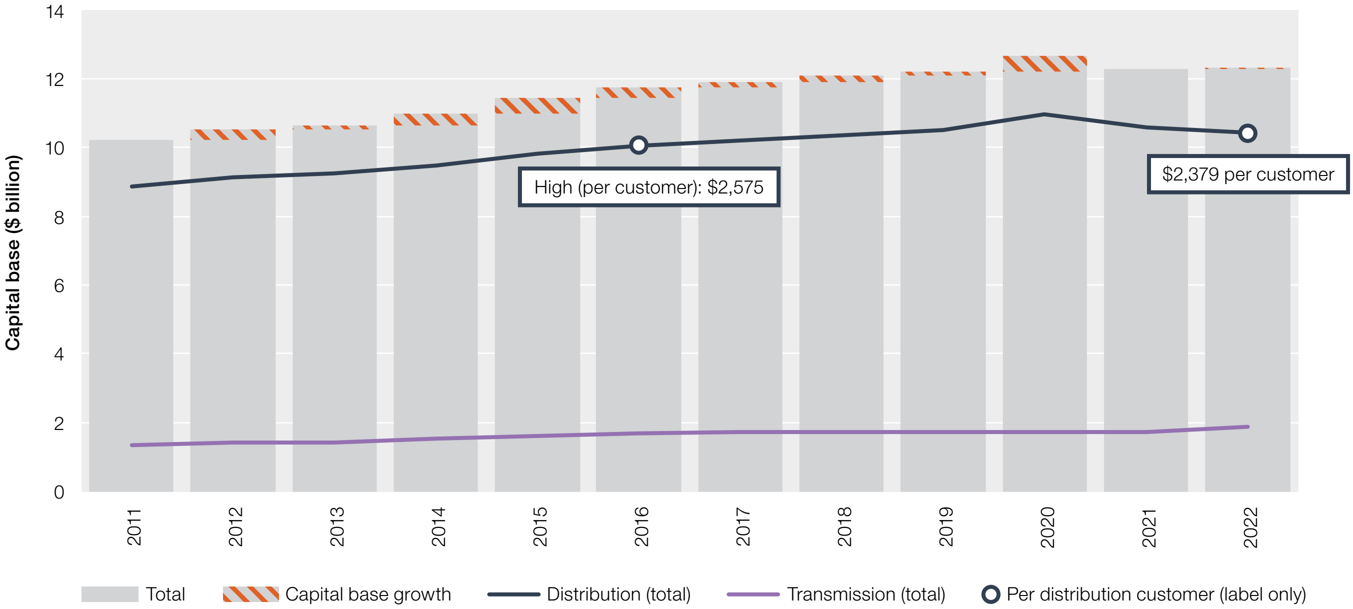
35 AER, APA Victorian Transmission System - Access arrangement 2023–27, Australian Energy Regulator, 9 December 2022, accessed 26 June 2023.

36 AER, Submission to Victoria's Gas Substitution Roadmap consultation paper, Australian Energy Regulator, 2 August 2021, accessed 11 June 2023.

6.8.1 Capital base in 2022

As at 30 June 2022 the value of the capital base for gas pipeline service providers was $12.3 billion, a decrease of $10 million (0.1%) from the previous year (Figure 6.10).

Figure 6.10 Value of gas pipelines assets (capital base)



Note: All data are adjusted to June 2022 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.

6.9 Rates of return

The shareholders and lenders that finance a gas pipeline service provider expect a commercial 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 by the allowed rate of return.[37]

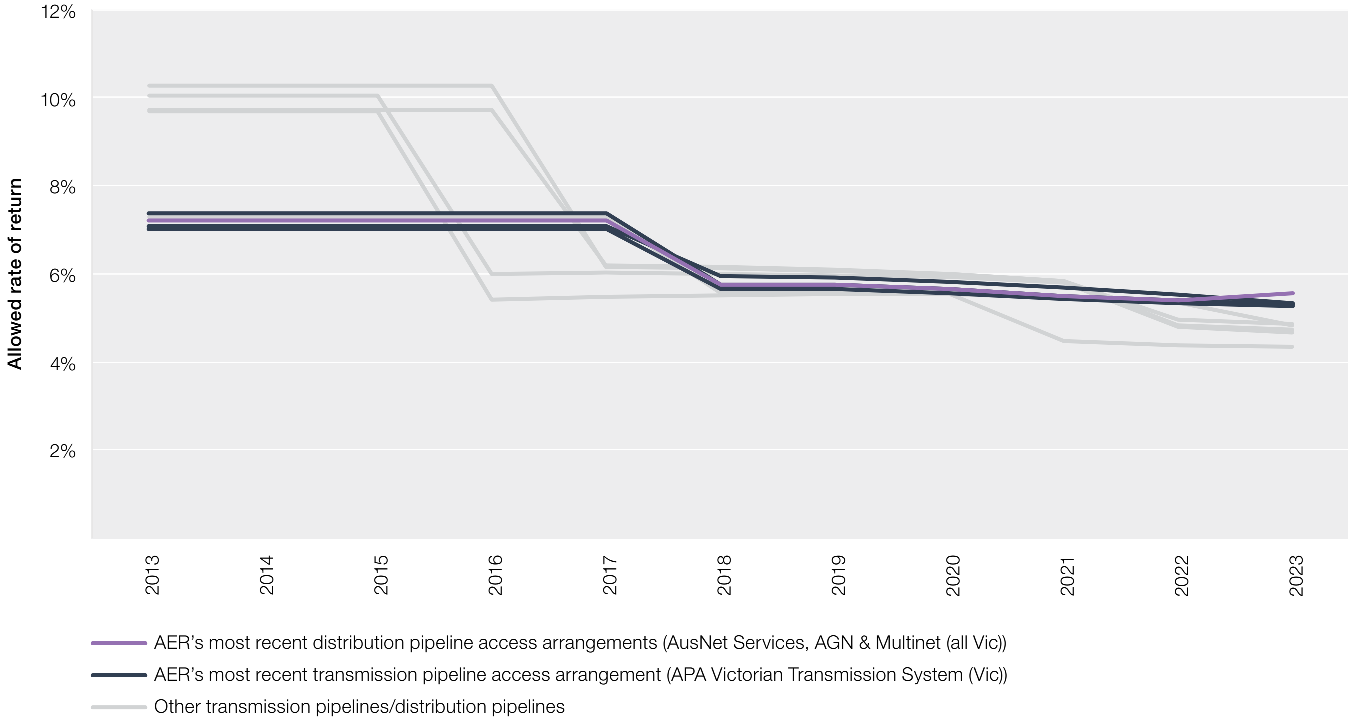
Lower financing costs and updated estimates of rate of return parameters have contributed to the average allowed rate of return declining from around 10% at the beginning of the 2010s, to less than 6% in 2023 (Figure 6.11). This reduction translated to significantly lower forecast pipeline revenue requirements.

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, which binds all access arrangements from 25 February 2023 until it is revised again.[38]

37 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 business's revenue needs and must be paid for by customers.

38 AER, Rate of Return Instrument 2022, Australian Energy Regulator, accessed 22 March 2023.

Figure 6.11 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, some key inputs into rates of return have increased. For example, 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. Annual yields on 10-year CGSs were as low as 0.6% in March 2020, but over 2023 (to mid-July) have averaged around 3.6%. Similarly, annual yields on 5-year CGSs were as low as 0.25% in November 2020 but over 2023 (to mid-July) have averaged around 3.4%.[39] If risk-free rates, or other key inputs, continue to increase they will put upward pressure on pipeline revenue over coming years.

6.10 Investment

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 bi-directional flows.

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 6.1), the AER assesses whether investments are prudent and efficient based on criteria in the National Gas Rules.

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.

Changes in demand can lead to pipeline assets becoming 'stranded', wherein they are prematurely written down, devalued or even reclassified as liabilities. Stranded asset risk may act sufficiently as a deterrent for excess pipeline investments and may reduce the need for strong financial incentives to reward expenditure underspends.

There is little a pipeline service provider can do to counteract the effects of a declining customer base, other than limiting new expenditures and managing prices to minimise disconnections by customers. However, the costs to maintain a gas pipeline do not decrease in proportion to gas demand decline.[40] The pipeline assets are likely to

39 RBA, Capital Market Yields – Government Bonds – Daily – F2, Reserve Bank of Australia, accessed 14 July 2023.

40 Lucas Davis, Catherin Hausman, Energy Institute at Haas, Who will pay for legacy utility costs?, March 2022.

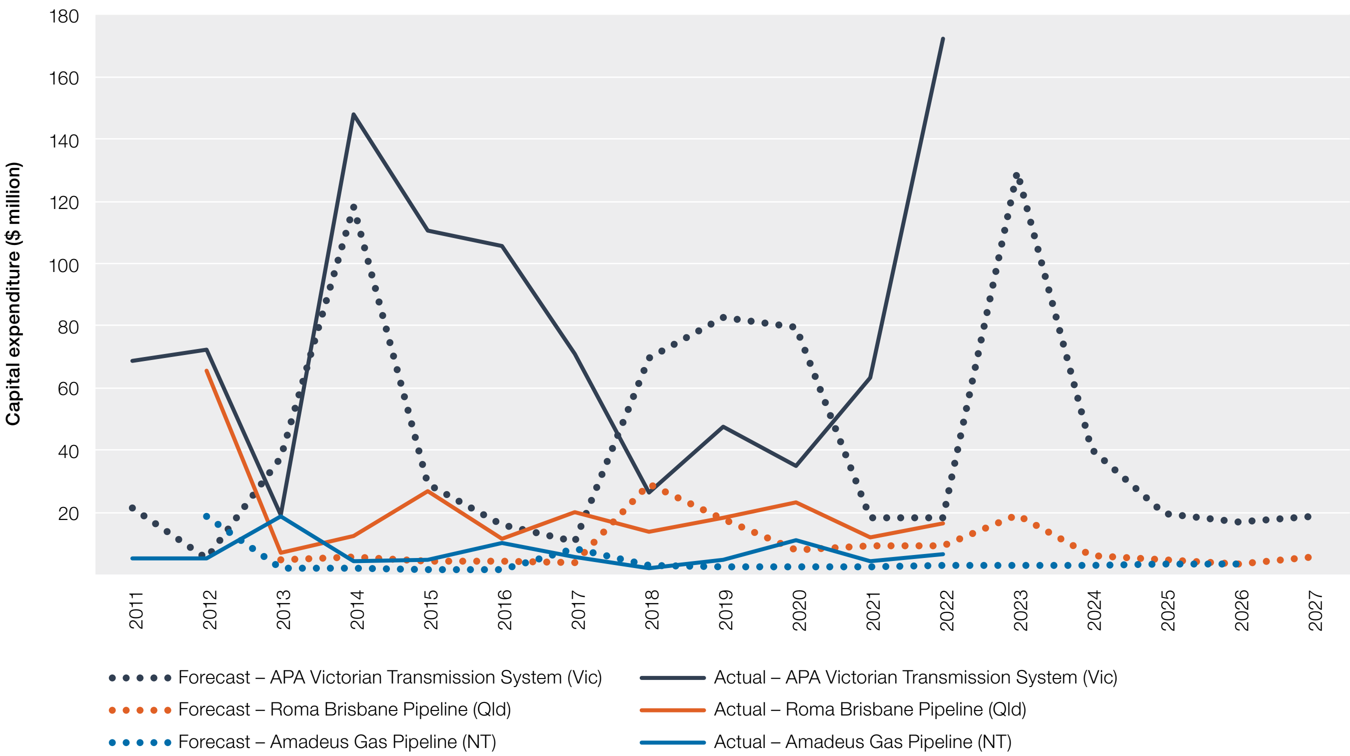
remain in use and the regulated service providers will incur ongoing maintenance and replacement costs to maintain safe and reliable reference services for the remaining customers on the network, subject to any partial shutdowns of the network.

Table 6.6 provides a breakdown of the amount of investment pipeline service providers undertook in 2022 and how this compared with previous years' expenditure and forecasts. The significant increase in capital expenditure on transmission pipelines in 2022 was driven by APA Victorian Transmission System's (Vic) expansion of the South West Pipeline and its construction of the Western Outer Ring Main project.

Table 6.6 Capital expenditure in 2022 – key outcomes

Service type	Capital expenditure (2022)	Capital expenditure (compared with 2021)	Capital expenditure (compared with peak)
Transmission	$195m (▲534% than forecast)	▲$115m (▲144%)	2022 = peak
Distribution	$519m (▼9% than forecast)	▼$103m (▼17%)	▼$171m (▼25%) (2015)
Total	$714m (▲18% than forecast)	▲$12m (▲1.7%)	▼$118m (▼14%) (2015)

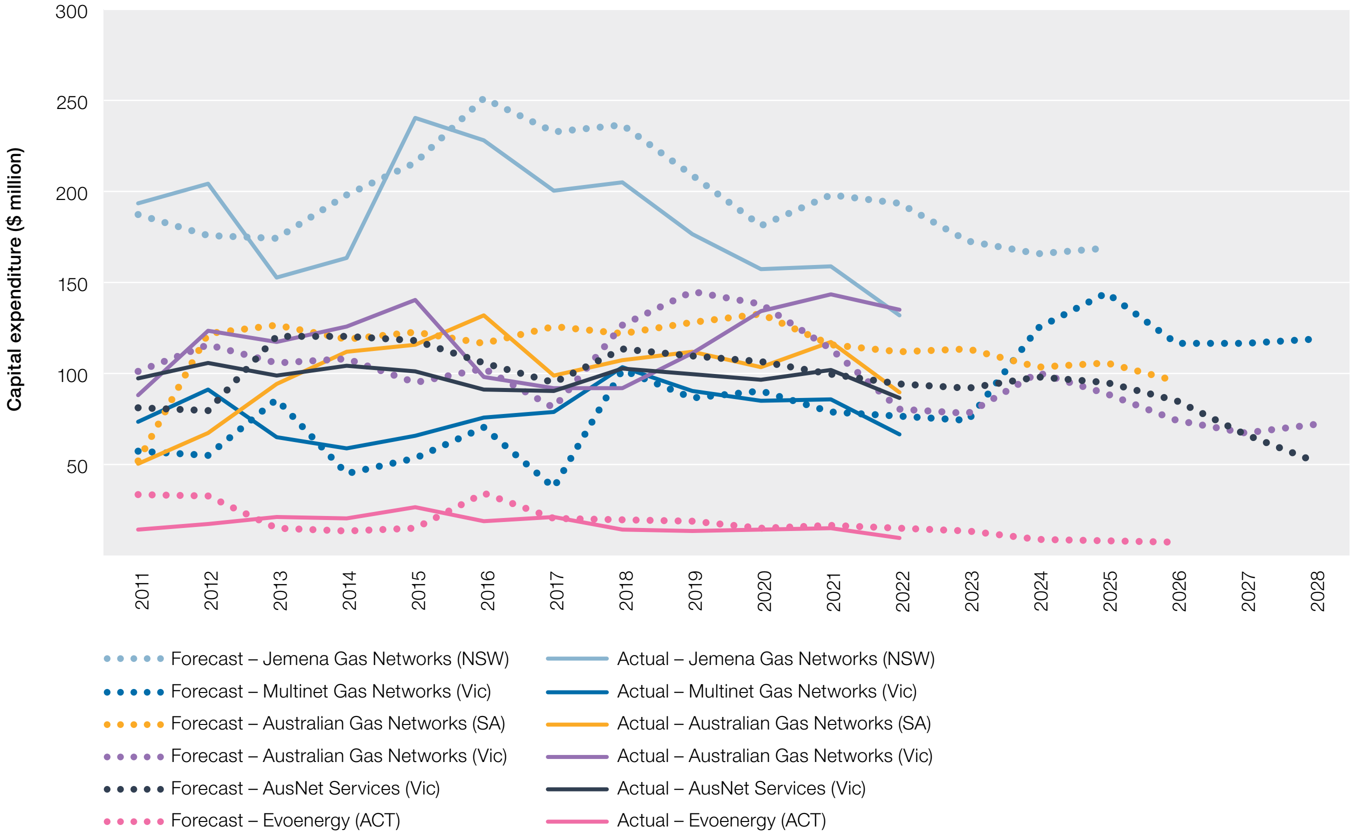
Figure 6.12 Capital expenditure – gas transmission pipelines



Note: All data are adjusted to June 2022 dollars. APA Victorian Transmission System (Vic) reports 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; annual reporting RIN responses.

Figure 6.13 Capital expenditure – gas distribution pipelines



Note: All data are adjusted to June 2022 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). From 1 July 2023 the Victorian pipeline service providers will also report on a financial year basis. From 1 July 2023 the Victorian pipeline service providers will also report on a financial year basis. To enable reporting on equivalent terms forecasts for the Victorian pipeline service providers for the 6-month transitional period (1 January to 30 June 2023) have been doubled. 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.

6.11 Operating costs

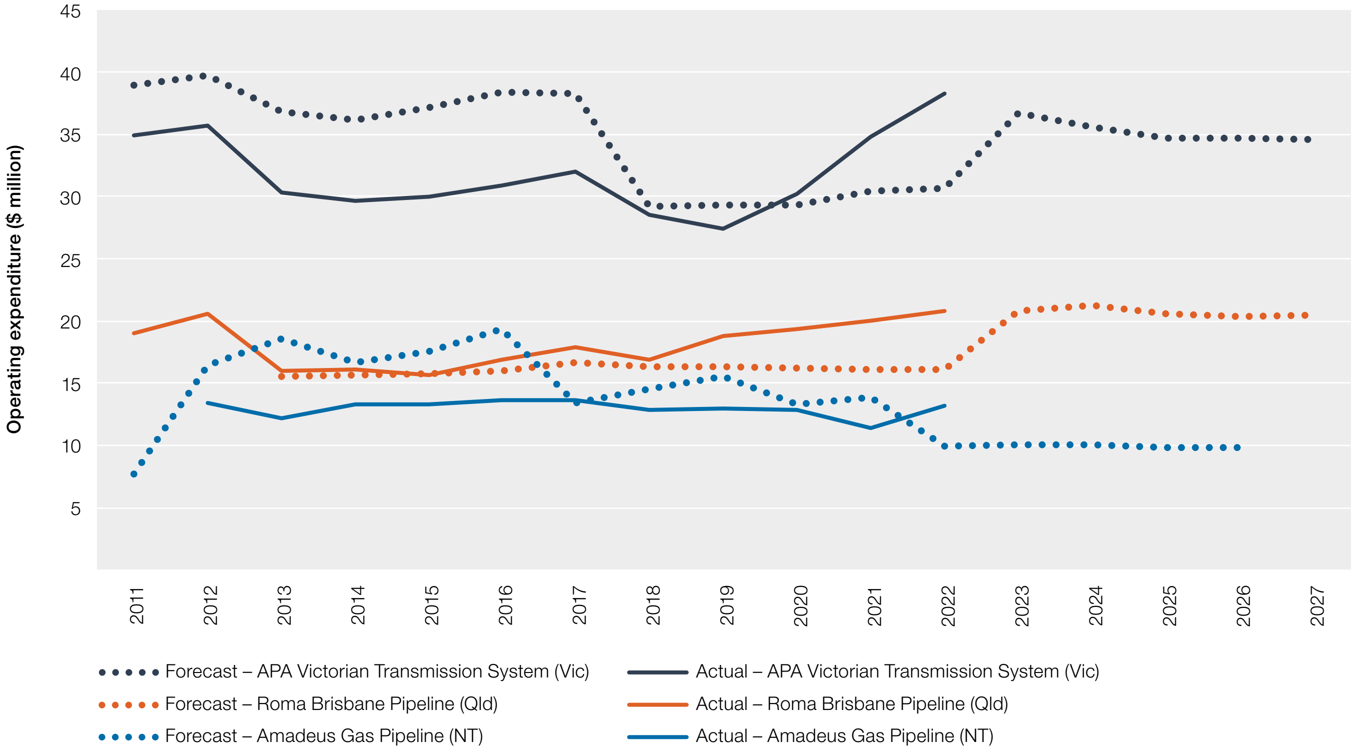
Pipeline service providers incur operating and maintenance costs that absorb around 42% of their annual revenue (35% for transmission and 43% for distribution) (Figure 6.5). When assessing a pipeline service provider's efficient operating and maintenance costs, the AER considers cost drivers such as forecast customer growth, expected productivity improvements, changes in labour and non-labour prices and changes in the regulatory environment. Pipeline service providers are subject to an efficiency carryover mechanism, which incentivises them to reduce operating expenditures where efficient to do so.

Table 6.7 provides a breakdown of pipeline service providers' operating costs in 2022 and how this compared with previous years' expenditure and forecasts.

Table 6.7 Operating expenditure in 2022 – key outcomes

Service type	Operating expenditure (2022)	Operating expenditure (compared with 2021)	Operating expenditure (compared with peak)
Transmission	$72m (▲28% than forecast)	▲$6m (▲8%)	2022 = peak
Distribution	$476m (▼15% than forecast)	▲$9m (▲1.9%)	▼$44m (▼8%) (2012)
Total	$556m (▼10% from forecast)	▲$17m (▲3%)	▼$41m (▼8%) (2012)

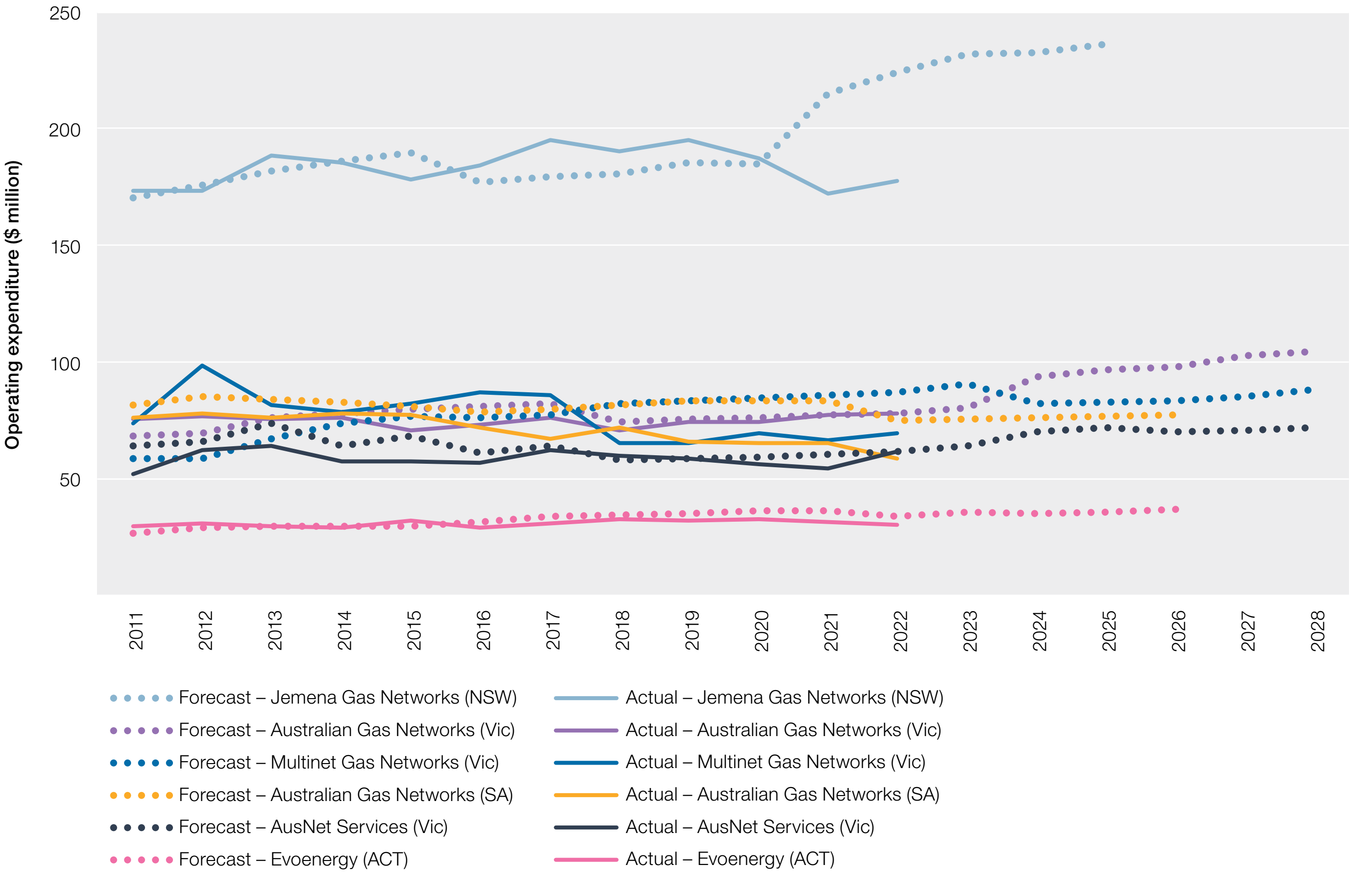
Figure 6.14 Operating expenditure – gas transmission pipelines



Note: All data are adjusted to June 2022 dollars. APA Victorian Transmission System (Vic) reports 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; annual reporting RIN responses.

Figure 6.15 Operating expenditure – gas distribution pipelines



Note: All data are adjusted to June 2022 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). From 1 July 2023 the Victorian pipeline service providers will also report on a financial year basis. From 1 July 2023 the Victorian pipeline service providers will also report on a financial year basis. To enable reporting on equivalent terms forecasts for the Victorian pipeline service providers for the 6-month transitional period (1 January to 30 June 2023) have been doubled. 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.

Image source: iStock

7 Retail energy markets

Retail energy markets are the final link in the energy supply chain, providing an interface for energy retailers to sell electricity, gas and energy services to residential and small business customers.[1] The National Energy Customer Framework (NECF) and the Energy Retail Code of Practice (Victoria) regulates the sale and supply of electricity and gas to retail customers.[2]

Retailers purchase electricity and gas either from direct contracts with suppliers or from wholesale markets and on-sell it to consumers.[3] Consumers are generally able to choose the retailer they purchase energy from based on the price and suitability of services available.[4]

Retailers are exposed to financial risk through spot price volatility in wholesale electricity and gas markets. To manage this, most retailers purchase hedging contracts that limit part or all of the wholesale price they pay (section 3.5). Hedging enables retailers to offer stable prices to consumers, so that consumers have more predictable energy bills instead of bearing the financial risk of more volatile wholesale energy prices.

Consumers continue to seek more autonomy over their energy costs through installation of consumer energy resources – such as rooftop solar and home batteries – with residential solar PV installed in the National Electricity Market (NEM) now exceeding 17 gigawatts (GW). This is equivalent to 23% of generation capacity across the NEM (chapter 3).

Following the significant market events in winter 2022, retail electricity offers (both market and standing) increased across NEM regions.[5] This is the largest increase since 2012–13 based on median offers over the period (Figure 7.4 and Figure 7.5).[6] Gas offers increased in all regions, with Victoria seeing the most significant increases. The change was largely driven by material increases in wholesale energy costs of both gas and electricity. Further analysis and more up-to-date data will be provided in the AER's forthcoming Annual retail markets report 2022–23.[7]

As higher wholesale energy costs continue to flow through to retail costs, price increases will continue to be felt by customers. Governments have implemented significant measures to shield consumers from affordability pressures through fuel price caps on coal and gas, energy relief funds, and investigating how demand-side resources can ease pressure and support an orderly energy transition.

1 Residential customers and business customers (who consumer 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.

2 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 30 August 2023.

3 Electricity generally must be purchased through the National Electricity Market, but gas is more likely to be purchased directly from suppliers (around 85%) than through the Domestic East Coast Gas Market.

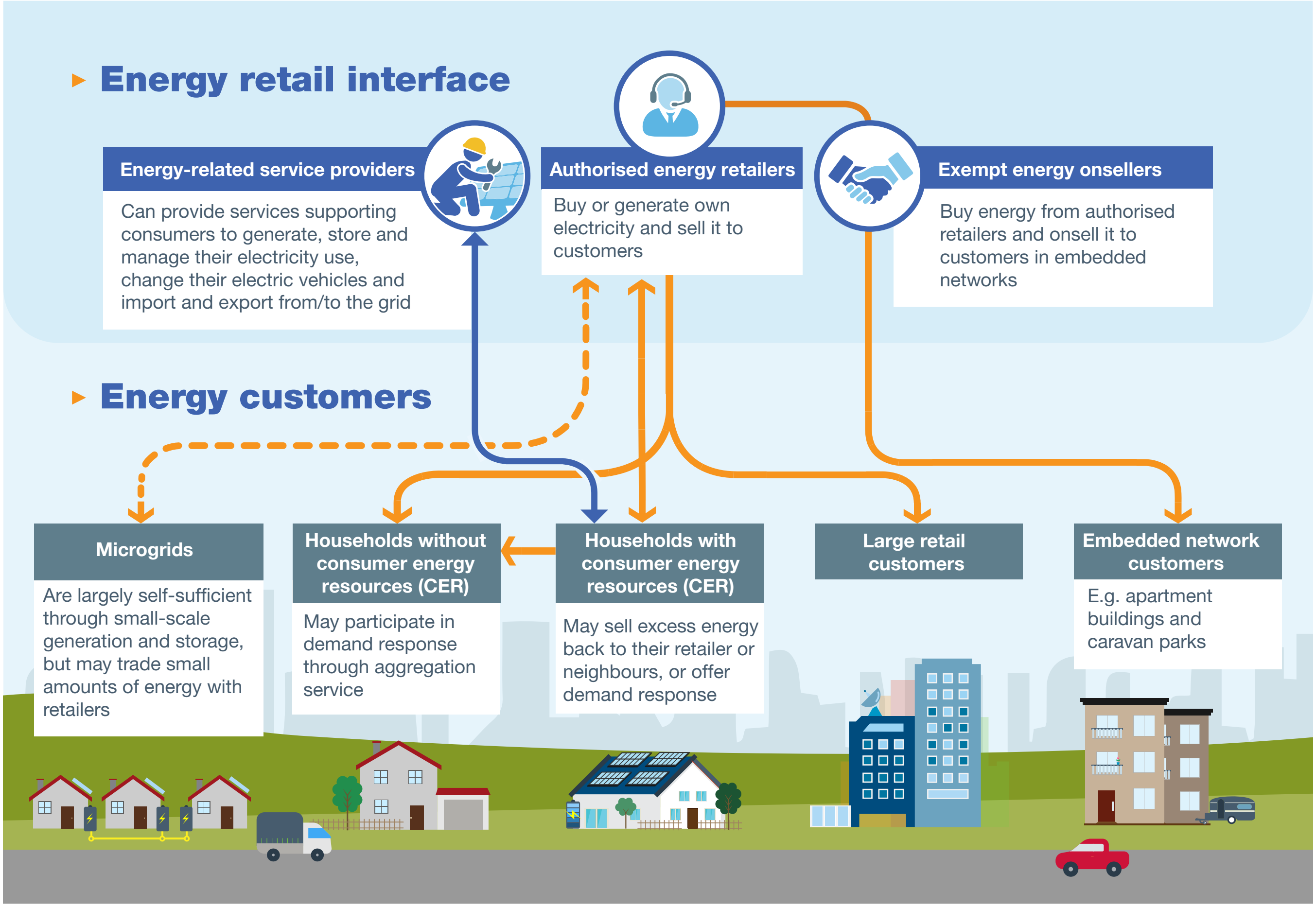
4 Consumers in embedded networks – such as those in some apartment buildings, retirement villages or caravan parks where the site owner sells the electricity – may have less opportunity to choose a retailer. This could be because of the different metering and wiring arrangements of the embedded network, or lack of authorised retailers that will provide an 'energy only' contract. Consumers experiencing vulnerability may also face challenges in choosing a retailer (see section 7.6.7 for more information).

5 Based on available offers displayed over time on government price comparison websites Energy Made Easy and Victorian Energy Compare. Pricing data is aggregated across multiple pricing areas within some electricity and gas distribution networks.

6 Based on data informing Figure 7.4 and Figure 7.5 and equivalent data and charts in previous years' State of the energy market reports.

7 The AER's annual Retail markets report is published in November, and Retail energy market performance updates are published quarterly.

Figure 7.1 Retail energy market supply chain



Box 7.1 The AER's role in retail energy markets

The Australian Energy Regulator (AER) regulates retail energy markets in jurisdictions that have implemented the National Energy Retail Law, including electricity and gas customers in Queensland, New South Wales (NSW), Victoria (electricity connection for retail customers only), South Australia, the Australian Capital Territory (ACT) and Tasmania (electricity customers only). We provide protections and support for energy consumers (particularly residential and small business customers) so they can participate confidently and effectively in those markets.

We are responsible for:

- setting a price cap on standing offers for electricity in south-east Queensland, NSW and South Australia – this cap also acts as a reference price for market offers
- maintaining an energy price comparator website (energymadeeasy.gov.au) 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
- developing guidelines for energy retail, wholesale, distribution and transmission markets, and corporate and consumer matters
- monitoring and enforcing compliance (by retailers, exempt sellers and distribution network service providers) with obligations in the 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
- reporting on the performance of the market and energy businesses, including information on energy affordability and trends in disconnection of customers for non-payment of energy bills.

7.1 Retail market snapshot

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

- Retail prices declined from the significant market events of winter 2022 but remained higher than previous years due to higher wholesale and contract prices (section 7.4).
- These pressures were reflected in higher default market offer (DMO) prices for 2023–24 (section 7.3.2), with standing offers revised upwards from 1 July 2023.
- Market offers, typically reset in July each year, are trending upwards to accommodate higher wholesale prices. Bill increases from August (monthly billing cycles) to October 2023 (quarterly billing cycles) are likely to occur.
- With slow wage growth and broader cost-of-living pressures, consumers are not well-placed to absorb sharp increases in energy prices. Energy affordability will likely continue to be a challenge for the foreseeable future.
- Consumer debt levels may continue to escalate from late 2023 to early 2024. Increased debt levels and other indicators of financial difficulties have already been observed in early 2023 data.
- The AER released its *Towards energy equity* strategy and Better Bills Guideline to address concerns about the impact of these market developments on consumers experiencing vulnerability, who may be less able to adopt technology, modify their energy use or shop around for a cheaper energy contract.
- In December 2022 the Australian Government announced measures to limit gas and coal prices through temporary price caps, provide energy bill relief for households and businesses and drive investment in clean energy generation and storage.
- In its 2023–24 Budget, the Australian Government provided up to $3 billion towards energy bill rebates of up to $500 for eligible households and $650 for eligible small businesses. State and territory governments commenced rolling out the rebate schemes in all NEM regions in July 2023.

7.2 Energy market regulation

Five jurisdictions – Queensland, NSW, South Australia, Tasmania and the ACT – apply a common national framework for regulating retail energy markets. The framework applies to electricity retailing in all 5 jurisdictions and to gas retailing in Queensland, NSW, South Australia and the ACT.

The Retail Law operates alongside the Australian Consumer Law to protect small energy consumers in their electricity and gas supply arrangements. It sets out protections for residential consumers and small businesses.[8] Victoria does not apply the national framework but applies similar regulatory provisions.[9]

The Retail Law and equivalent arrangements in Victoria focus on consumer protections related to the traditional retailer–customer relationship. Protections are generally stronger for consumers supplied through an authorised retailer than consumers in embedded networks or entering solar power purchase agreements.[10]

State and territory-based regulators regulate electricity prices in regional Queensland, Victoria, Tasmania and the ACT.[11] Since 1 July 2019 the AER has set caps on 'standing offer' prices[12] for electricity through the default market offer in jurisdictions without state-based price regulation (section 7.4).

This chapter focuses on the 5 jurisdictions where the AER has regulatory responsibilities, but also covers the Victorian market where possible. Western Australia and the Northern Territory apply separate regulatory arrangements and are not covered in this report.

7.2.1 Sellers and resellers of energy services

Market participants that sell and resell energy and services to consumers are classified into:

- those authorised as retailers under the Retail Law
- those exempt from the requirement to be authorised[13]
- those offering energy products and services beyond the scope of the Retail Law – such as energy management services, solar and storage products and off-grid energy systems.

Only customers of authorised retailers enjoy the full protections in the Retail Law, which is administered and enforced by the AER. Other consumers may be covered by the broader Australian Consumer Law, which is administered and enforced jointly by the ACCC and the state and territory consumer protection agencies.

7.2.2 Authorised energy retailers

Under the Retail Law a person must hold a retailer authorisation (unless exempt from the requirement) to sell electricity or gas. The AER issues retailer authorisations and seeks to ensure compliance with consumer protection and other obligations under the Retail Law. An authorisation covers energy sales to consumers in all 5 participating jurisdictions.[14]

The AER and the Essential Services Commission (ESC) (Victoria) are responsible for authorising new retailers into the energy market.

8 The thresholds for who meets the criteria of a residential customer or small business varies between jurisdictions. For example, in jurisdictions where the Retail Law applies, it includes those consuming fewer than 100 megawatt hours (MWh) of electricity or 1 terajoule (TJ) of gas per year. For electricity, in South Australia, small electricity customers are those consuming fewer than 160 MWh per year. In Tasmania, the threshold is 150 MWh per year.

9 Changes to the Victorian framework, including recommendations adopted from the Thwaites *Independent review into the electricity & gas retail markets in Victoria* (August 2017), have seen greater divergence between the Victorian and national frameworks.

10 Embedded networks are private electricity networks serving multiple customers, such as at caravan parks and shopping centres.

11 These include the Queensland Competition Authority in regional Queensland, Essential Services Commission in Victoria, Independent Competition and Regulatory Commission in the ACT and Office of the Tasmanian Economic Regulator in Tasmania.

12 Standing offers apply where a customer does not enter a market contract. The terms and conditions of standing offers are prescribed in the National Energy Retail Rules and include consumer protections not required in market retail contracts, such as access to paper billing, minimum periods before bill payment is due, a set period for reminder notices, and no more than one price change every 6 months.

13 In Victoria, where the Retail Law does not apply, retailers must hold a licence issued by the Essential Services Commission or seek an exemption from this requirement.

14 See the AER website for a public register of authorised retailers and authorisation applicants.

7.2.3 Exempt energy sellers

An energy seller may apply to the AER or the ESC (Victoria) for an exemption from authorisation if it only intends to supply energy services to:

- a limited customer group (for example, at a specific site or incidentally through a relationship such as a body corporate)
- supplement its customers' primary energy connection
- sell or supply electricity ancillary to telecommunication services, such as data centres.

As of August 2023, over 3,700 unique businesses were registered in the AER's public register of exemptions to on-sell energy within an embedded network (that is, a small private network whose owner sells electricity to other parties connected to the network).[15] Shopping centres, retirement villages, caravan parks and apartment complexes are examples of entities that might run an embedded network. Solar power purchase agreement providers are also covered by the AER's and ESC's exemptions frameworks.

The Australian Energy Market Commission (AEMC) cited stakeholder estimates that up to 500,000 consumers purchase energy through embedded networks.[16] Exemption holders must follow strict conditions and meet a range of obligations to their customers (detailed in the AER's guidelines). Conditions are based on the obligations that apply to authorised retailers and distribution network service providers, but are a lighter, less prescriptive form of regulation.

7.3 Energy bills

Energy bills are a primary way for energy retailers to communicate with 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 others available to them. Independent comparator websites provided by the AER (energymadeeasy.gov.au) and the Essential Services Commission (Victoria) (compare.energy.vic.gov.au) enable customers to upload data from their most recent energy bills to assess against other market offers available to them (section 7.7.9).

Customers who can regularly review and, when necessary, change to a better offer usually pay lower prices. However, offers can vary significantly and hundreds of offers may be available to customers at any one time. Advertised offers frequently change, as do the terms and charges attached to an offer over time. Customers routinely report finding it difficult to compare and determine which offer is best for their situation.

7.3.1 Better Bills Guideline

Consumers expect bills to be simple, easy to understand and a source of information about how and when to pay. However, energy bills have historically been cluttered, complex and confusing, creating an unnecessary barrier for consumers to participate effectively in energy retail markets and find the best deal.

To address this, in March 2022 the AER released the Better Bills Guideline (Version 1). The guideline outlined requirements for retailers to prepare and issue bills that make it easy for small customers to understand billing information.

In January 2023, following public consultation, the AER published an updated Better Bills Guideline (Version 2).[17] Key amendments included providing clarity on the 'better offer' and self-read information requirements and, following an AEMC Rule change in October 2022, giving retailers more time to comply with the new provisions in the Guideline.[18]

The guideline limits the amount of content allowed on the first page of bills so that consumers can see the essentials at first glance. It requires the retailer to clarify whether they have a better offer available, under the heading 'Could you save money on another plan?'. Elsewhere on the bill, retailers must include a simple summary of the existing plan, stating the key features and when any benefits are due to expire.

15 The number of unique businesses registered as exempt energy sellers does not equate to the number of embedded network sites, as a business may on-sell to customers across multiple sites.

16 AEMC, Updating the regulatory frameworks for embedded networks, Australian Energy Market Commission, 20 June 2019.

17 AER, Better Bills Guideline – Version 2, Australian Energy Regulator, 30 January 2023.

18 AEMC, National Energy Retail Amendment (Delaying implementation of the AER Billing guideline) Rule 2022 No. 2, Australian Energy Market Commission, 13 October 2022.

The guideline aims to make it easier for consumers to:

- pay their energy bills
- understand the bill calculation and ensure their bill conforms to their contract
- query their bill
- access interpreter services and seek financial assistance
- report a fault or emergency
- understand their usage to help them use energy efficiently, compare offers and consider new types of energy services.

In July 2023, the AER notified authorised retailers that the guideline applies to all small customers of an authorised retailer, including those within embedded networks. In August 2023, the AER updated the guideline to require retailers to provide standard information about energy relief rebates.[19]

7.3.2 Components of electricity bills

Retail energy bills are largely reflective of the cost of producing and supplying energy. A typical residential electricity retail bill comprises the following costs:

- wholesale energy purchased through spot and hedge wholesale markets (including managing the risk of wholesale price volatility and price variances across regions)
- network costs, including transporting electricity through transmission and distribution networks, feed-in tariffs for rooftop solar PV systems and metering costs
- costs associated with complying with environmental schemes, such as renewable energy targets and energy efficiency measures
- servicing customers, including provision of billing and customer service
- marketing campaigns to attract and retain customers
- the retailer's margin (profit).

The proportion of each cost as a component of electricity bills varies by jurisdiction.

7.3.3 Wholesale costs

Wholesale costs are a significant component of electricity bills. Retailers purchase energy in wholesale markets for sale to customers. Retailers generally charge their customers fixed prices for energy but need to purchase energy at variable prices in wholesale markets. This means that retailers are exposed to price risk, where they may need to purchase energy at higher prices than they charge their customers. Retailers generally manage this risk by considering price volatility when setting retail contract prices and by entering hedge contracts that lock in prices for their future wholesale purchases (chapter 3). Alternatively, they might own generation assets or enter demand response contracts to manage risk (section 7.7.4).

7.3.4 Network costs

The AER regulates network charges, which cover the efficient costs of building and operating electricity networks and provide a commercial return to the network service provider's financiers. Across the NEM, distribution costs are the largest component of network costs. Transmission costs are the next biggest component and metering costs make up the balance.

Several factors will have an impact on network costs, such as where the customer is being served (central business district, urban or rural), area density and local terrain. Network costs are generally higher for consumers located in less densely populated areas. The relative efficiency of each network service provider also partly explains differences in network costs (chapter 4, section 4.15.1).

There are likely to be upward pressures on regulated network costs over the new few years, driven by inflation, the impact of higher interest rates and forecast increases in capital expenditure (chapter 4, section 4.13).

19 AER, Better Bills Guideline – Version 2 update, Australian Energy Regulator, accessed 28 August 2023.

7.3.5 Environmental costs

Environmental costs are associated with environmental schemes at both national and state levels, requiring retailers to procure electricity from renewable sources and improve customer energy efficiency. Around 70% of environmental costs are attributable to the national Renewable Energy Target (RET), including both large-scale and small-scale developments. At state levels, environmental costs include rebates for customer energy resources, feed-in tariffs for solar PV installations and state government operated energy efficiency schemes.

7.3.6 Retail costs

Retail costs fall into 2 main categories:

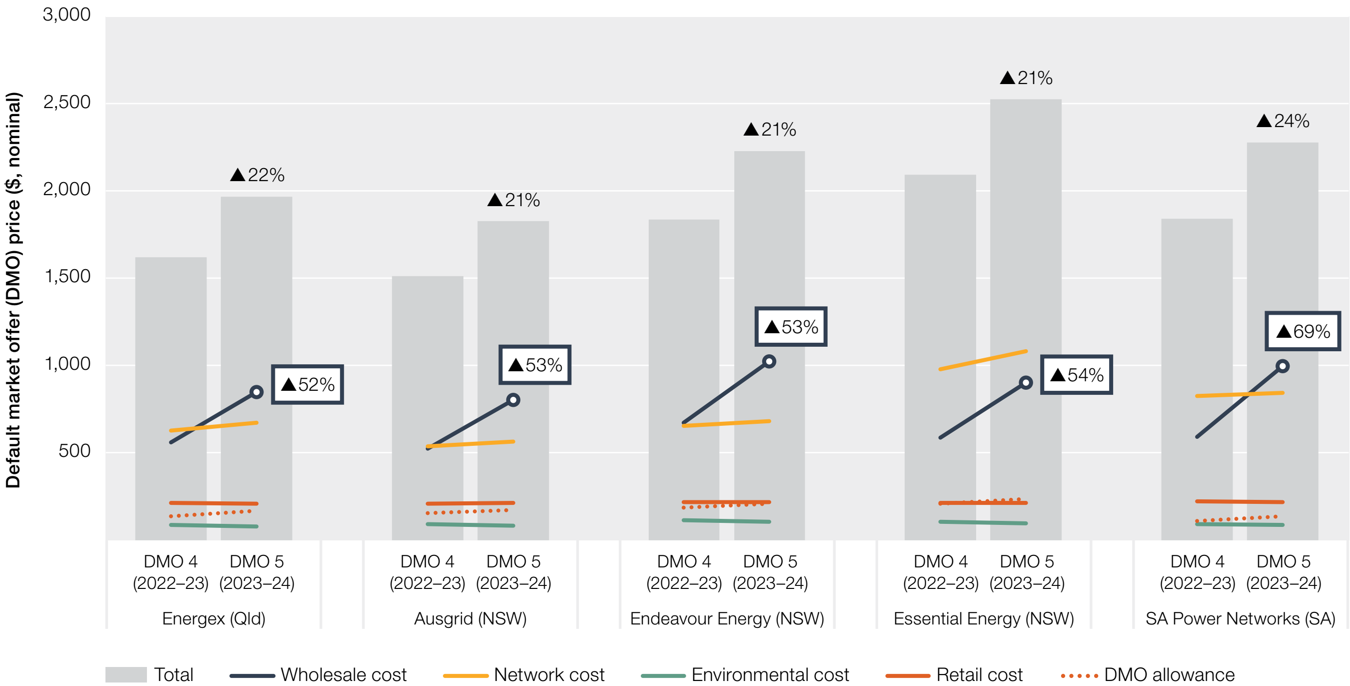
- Costs of servicing customers, such as managing billing systems and debt, handling customer enquiries and complying with regulatory obligations. These costs do not vary significantly across jurisdictions.
- Customer acquisition and retention costs, such as marketing and other activities to gain or retain customers. These costs tend to be higher in jurisdictions with high rates of customer switching. In theory, these costs should be offset by reduced retailer profit margins that are driven down due to competition, but there is a risk that competition may increase energy bills for customers if the costs of competing outweigh competition benefits from efficiency and innovation.

7.3.7 Components of the default market offer

The AER calculates a representative retail price each year known as the default market offer (DMO) reference price. The cost components of each DMO reference price include wholesale, network, environmental and retail costs and margin. The DMO acts as both a price cap for standing offers, as well as a reference price that discounts and market offers must be measured against. The role of the DMO is further discussed in section 7.3.9.

In May 2023, the AER published the DMO 5 determination, which illustrates the proportions of each cost component and changes from the preceding year (Figure 7.2).

Figure 7.2 Components of the default market offer



Note: Comparison of cost components calculated for the 2022–23 (DMO 4) and 2023–24 (DMO 5) prices, for residential customers without controlled load. Prices include GST. Values are nominal. In previous years this data was measured in cents per kilowatt hour and included totals for all NEM regions, enabling like-for-like comparison to Figure 7.3. This data was unavailable for 2023.

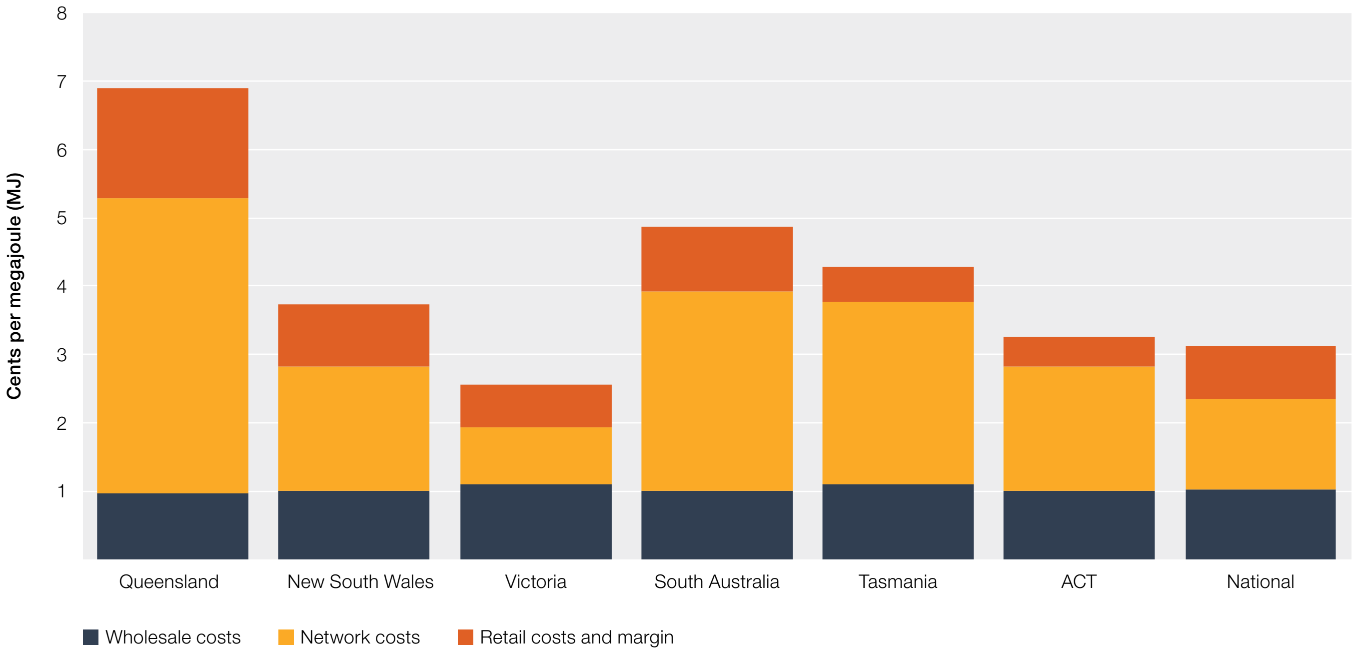
Source: AER, Default market offer prices 2023–24, May 2023.

Wholesale costs were calculated to make up 28% to 36% of retail electricity bills for the 2022–23 DMO 4. In 2023–24, this has increased sharply to between 36% and 46% of the overall price.

7.3.8 Components of gas bills

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 regularly analyse the different cost components. Estimates from the most recent comprehensive data (published in 2017) show that nationally, gas pipeline charges made up over 40% of a residential gas bill in that year, on average.

Figure 7.3 Composition of a residential bill – gas



Note: Data are estimates at 2017. Average residential customer prices excluding GST (real $2018–19). Percentages may not add to 100% due to rounding.

Source: Oakley Greenwood, Gas price trends review 2017, March 2018.

Analysts suggest that residential gas bill prices remained relatively steady from 2017 until 2022 (Figure 7.11), but it is likely the proportions of gas bill components have changed. Due to the historical lack of transparency in pricing in gas wholesale markets and segments of gas transportation, it is difficult to estimate these changes with confidence. However, a range of indicators suggest that changes in both level and proportion of gas bills may be material.

The ACCC published an analysis of gas retail bill components in June 2021 and observed that retail margins up to 2018 reflected the influence of legacy gas contracts with cheap prices.[20]

The ACCC expected that the proportion of gas supplied through those legacy contracts was likely to decline materially from 2021. Wholesale costs and retail margins after that time would be impacted by wholesale market conditions at the time of renegotiation, by the prices at which retailers were able to replace legacy contracts with new gas supply agreements and by the extent of competition in gas retail.

Since 2017, revenue per customer on scheme pipelines subject to the building block regulatory model has stayed relatively steady and, in some cases, decreased materially (chapter 6). However, those pipelines make up only a proportion of transportation requirements because key north to south transmission pipelines are not subject to that form of regulation.

More analysis on gas wholesale markets and regulated gas pipelines is set out in chapters 5 and 6.

20 ACCC, Gas inquiry 2017–25 interim report, Australian Competition and Consumer Commission, January 2023, section 5.

7.3.9 How retail prices are set

Energy retailers in southern and eastern Australia are responsible for setting prices for energy market offers. Market offers are energy contracts advertised by retailers that consumers actively enter into. Alongside market pricing, government agencies regulate prices for electricity standing offers. Standing offers are energy contracts that consumers are placed on by default if they do not enter into a market contract.[21]

Between 2009 and 2016, electricity retail price regulations were removed in Victoria, South Australia, NSW and south-east Queensland following a determination by the AEMC that markets in those states were effectively competitive. In July 2019, governments reintroduced forms of price control in response to later market reviews, as summarised in Table 7.1.

Table 7.1 Price controls by NEM region

Region	Mechanism	Administrator	Approach
South-east Queensland NSW South Australia	Default market offer	AER	Sets a cap on standing offer electricity prices for residential and small business customers and provides a reference price for comparing offers.
Victoria	Victorian default offer	Essential Services Commission	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	Determines an annual regulated electricity price for residential and small business customers to enable comparison of offers. No price cap is imposed. The Queensland Government subsidises Ergon Energy 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	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	ACT Independent Competition and Regulatory Commission	Sets a cap on electricity prices for residential and small business customers with authorised retailer ActewAGL and provides a reference point for other customers comparing offers.

Source: AER, Default market offer prices 2022–23 – Final determination, May 2023; ESC, Victorian Default Offer, accessed 21 August 2023; Queensland Competition Authority, Regional customers, accessed 21 August 2023; Tasmanian Economic Regulator, Pricing – Approvals, accessed 21 August 2023; Independent Competition and Regulatory Commission, Price Regulation of Electricity Supply, accessed 21 August 2023.

Gas price deregulation occurred along similar time frames to electricity price deregulation but price controls have not been reintroduced. In July 2017 NSW became the last jurisdiction to deregulate retail gas prices for small customers.

In June 2020 the Australian Government introduced further price protections. Under Part XICA (which relates to prohibited conduct in the energy market) of the *Competition and Consumer Act 2010*, retailers are required to pass on to customers any sustained and substantial decreases in the costs of electricity. The ACCC is responsible for investigating contraventions and published guidelines in May 2020.[22] In April 2021, the ACCC published its findings on retailers' compliance with the legislation and stated they had approached retailers that may not have adequately passed on cost savings to their customers.[23] The ACCC continues to monitor compliance with Part XICA, which also prohibits certain behaviour by generators in relation to access to electricity hedging contracts and spot market bidding.

21 AER, Default market offer prices 2022–23 – Final determination, Australian Energy Regulator, May 2023, accessed 5 September 2023, section 3.1.

22 ACCC, Guidelines on Part XICA – Prohibited conduct in the energy market, Australian Competition and Consumer Commission, 11 May 2022, accessed 11 August 2023.

23 ACCC, $900 million in electricity bill savings available to households [media release], Australian Competition and Consumer Commission, 13 April 2021, accessed 15 September 2022.

Box 7.2 Default market offer

The default market offer (DMO) is the maximum price an electricity retailer can charge a standing offer customer each year based a set amount of usage.[24] DMO prices vary by customer type, including residential customers with controlled load, residential customers without controlled load and small business customers without controlled load. 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.

The scheme was introduced in 2019, following concerns raised by the Australian Competition and Consumer Commission (ACCC) that standing offer contracts:

- were not working as an effective safety net
- were unjustifiably expensive, with retailers having incentives to increase standing offer prices as a basis to advertise artificially high discounts
- penalised customers who had not taken up a market offer, making them a form of 'loyalty tax'.

The AER determines DMO prices each year for residential and small business customers in NSW (Endeavour, Essential Energy and Ausgrid), south-east Queensland (Energex) and South Australia (SA Power Networks). The scheme caps how much retailers can charge in their standing offers, but it does not cap customers' bills.

The default prices also act as a reference against which retailers must compare their market offers to make it easier for consumers to compare offers across providers. The DMO scheme provides a fallback for those who do not engage in the market and has reduced unjustifiably high standing offer prices.

Table 7.2 shows DMO pricing since implementation by region. The AER's pricing methodology has been revised over this time and more information on the approaches and methodologies is set out in the supporting documentation for each DMO determination. However, increases between July 2022 (DMO 4) and July 2023 (DMO 5) remain largely driven by sharp wholesale price spikes in all regions, and corresponding increases in retail energy prices can also be observed in market and standing offers in 2022–23 (Figure 6.4).

Table 7.2 Default market offers for residential customers without controlled load ($, nominal), since 2019[25]

	NSW	South-east Queensland	South Australia
DMO 1 (2019–20)	$1,467 – $1,957	$1,570	$1,941
DMO 2 (2020–21)	$1,462 – $1,960	$1,508	$1,832
Change from previous year	0.5% lower to 0.2% higher	3.9% lower	5.6% lower
DMO 3 (2021–22)	$1,393 – $1,907	$1,455	$1,716
Change from previous year	6.0% to 2.7% lower	3.5% lower	6.3% lower
DMO 4 (2022–23)	$1,512 – $2,092	$1,620	$1,840
Change from previous year	8.5% to 14.1% higher	11.3% higher	7.2% higher
DMO 5 (2023–24)	$1,827 – $2,527	$1,969	$2,279
Change from previous year	20.8% to 21.4% higher	20.5% higher	22.6% higher

Source: AER, Default market offer prices 2023–24, 25 May 2023; AER, Default market offer prices 2022–23, 26 May 2022; AER, Default market offer prices 2021–22, 27 April 2021; AER, Default market offer prices 2020–21, 30 April 2020; AER, Default market offer prices 2019–20, 30 April 2019.

24 Customers on standing offers may pay more than the DMO price if they use more electricity than the annual usage amount assumed when determining the DMO.

25 Prices are estimated annual bill prices for residential customers without controlled loads.

7.4 Retail energy prices

The 2022–23 financial year saw increases to electricity and gas retail prices, primarily due to a sharp increase in wholesale costs following winter 2022. Wholesale price fluctuations tend to flow through to retail costs in the months following those fluctuations, as longer-term contract positions are adjusted.

From October 2022 to June 2023, wholesale electricity prices declined across all regions. However, wholesale prices remain high by historical standards. While they remain so, they will continue to put upward pressure on retail prices.

Similar to electricity, 2022 was a volatile year for retail gas prices. Average wholesale gas prices began increasing in 2021 and reached record highs in mid-2022 (Figure 5.2). Wholesale gas cost increases can take longer to flow through to retail prices compared with electricity. With anticipated supply constraints, gas retail prices will likely continue to face upward pressure.

7.4.1 Electricity price movements

In electricity markets, customers on market offers had bigger increases in bills compared with those on standing offers. Savings historically available to customers by shopping around for the best market offer may be less available as standing and market offer prices are converging (Figure 7.4). Retailers are finding it harder to manage their exposure to volatile wholesale prices through hedging contracts, which is particularly challenging for smaller retailers. From May to December 2022, 6 retailers formally exited the market while others stopped taking new customers or urged existing customers to switch retailers.[26]

Across NEM jurisdictions, estimated electricity bills increased by 9% to 20% in 2022–23 from the previous year, following 2 consecutive years of decreases.[27] This was primarily due to a sharp increase in wholesale prices, reaching record highs in mid-2022. The drivers of increased wholesale prices included more frequent and longer outages of aging coal generation plant, increased power system security costs, extreme weather affecting supply in NSW and Queensland, slowing investment in new generation capacity and global pressures on coal and gas prices linked to factors such as Russia's invasion of Ukraine.

Electricity bills for customers on market offers increased in all regions in the 2022–23 financial year except for Ergon Energy (Queensland), which has remained stable since 2016–17 relative to other distribution regions.[28]

While standing offers have historically been higher than market offers, they have almost converged in all regions apart from TasNetworks (Tasmania). In some instances, market offers have been priced above standing offers and large discounts or savings for customers are becoming less common. While potential savings may be accessed by customers able to use price comparator websites and effectively navigate information provided by retailers, taking up a market offer no longer guarantees receiving their cheapest deal.[29] Standing offers also increased markedly in all distribution regions except for CitiPower (Victoria) and Evoenergy (ACT).

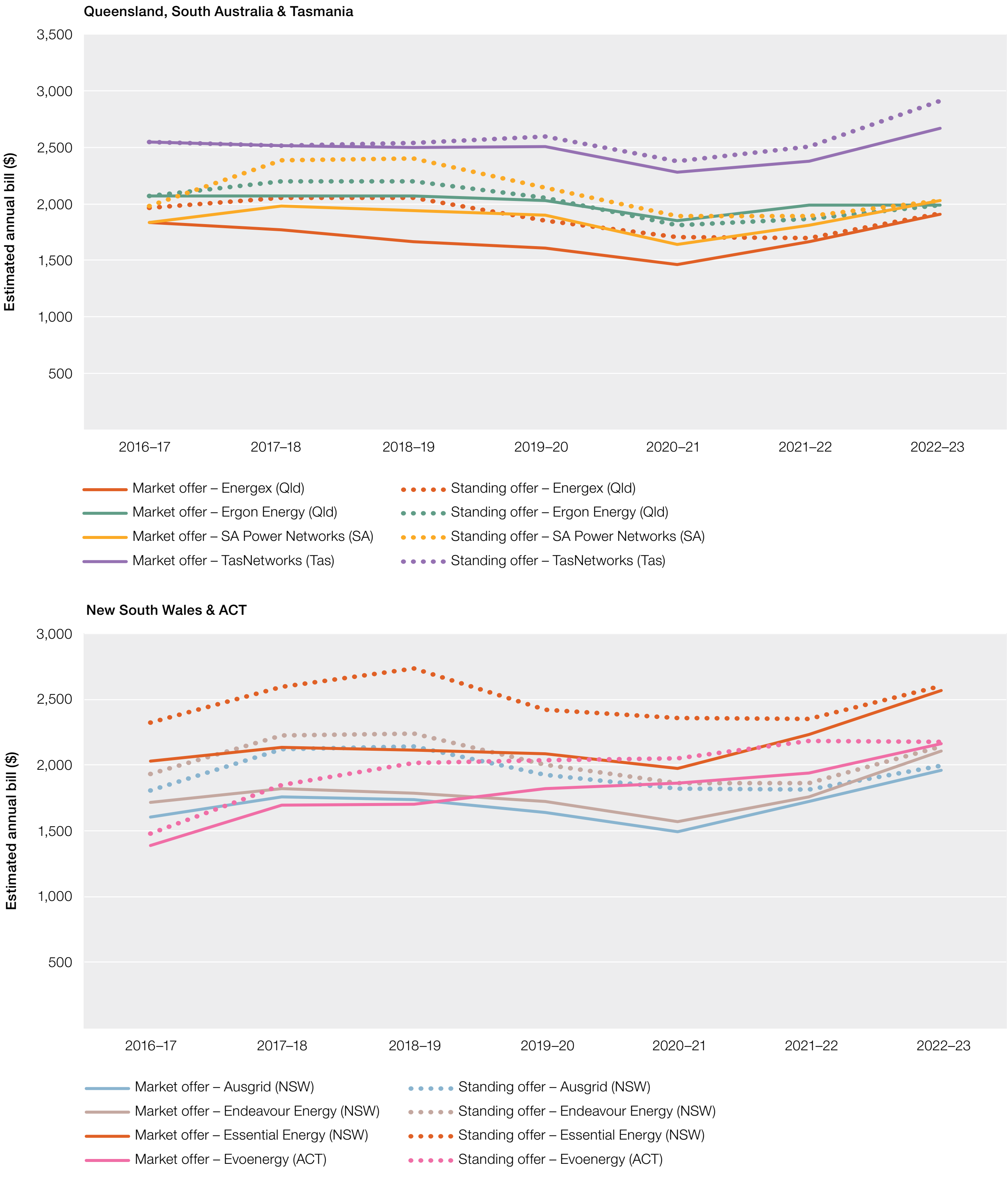
26 ACCC, Electricity Market Inquiry Report, Australian Competition and Consumer Commission, 8 December 2022.

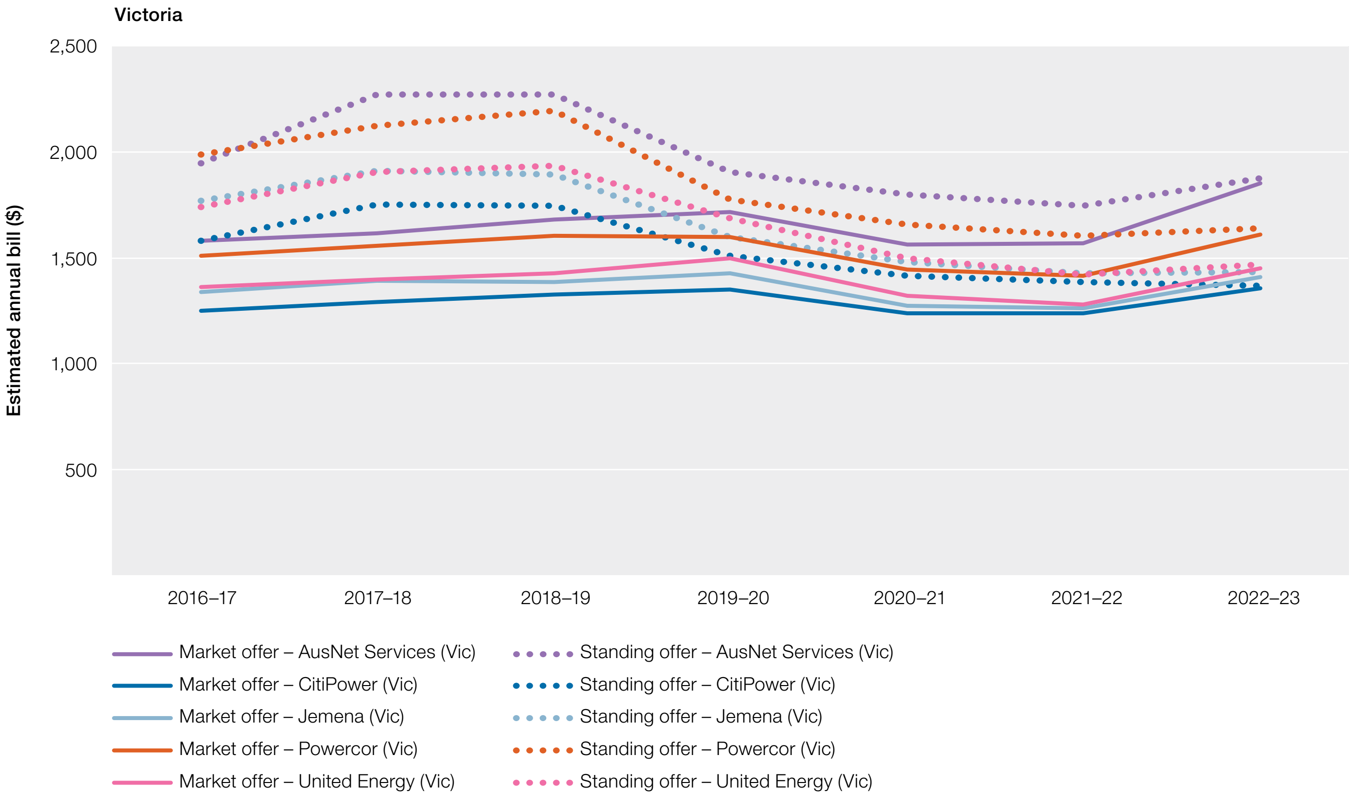
27 AER, Annual retail markets report 2021–22, Australian Energy Regulator, 30 November 2022.

28 Ergon Energy is owned by the Government of Queensland and serves regional customers. As a non-competitive retailer with regulated prices, their market offers are limited, with the majority of customers on standing offers.

29 AER, Annual retail markets report 2021–22, Australian Energy Regulator, 30 November 2022.

Figure 7.4 Electricity bills for customers on market and standing offers





Note: Ergon Energy's standing offer prices are set by the Queensland Competition Authority (QCA). TasNetworks' standing offer prices are set by the Office of the Tasmanian Economic Regulator (OTTER). Standing offer prices on the Victorian distribution networks are set by the Essential Services Commission (ESC). Evoenergy's standing offer prices are set by the Independent Competition and Regulatory Commission (ICRC). Energex, SA Power Networks, Ausgrid, Endeavour Energy and Essential Energy's standing offer prices are set by the retailers (capped at DMO). Based on single rate offers for residential customers and average consumption in each distribution area. Average consumption for 2020–21 has been applied to all periods. Some offers listed may not be available to all customers in a region. The AER will update its analysis on more recent offers in the Annual retail performance report 2023. On Ergon Energy's network there are few market offers available and some offers are restricted to specific geographic areas.

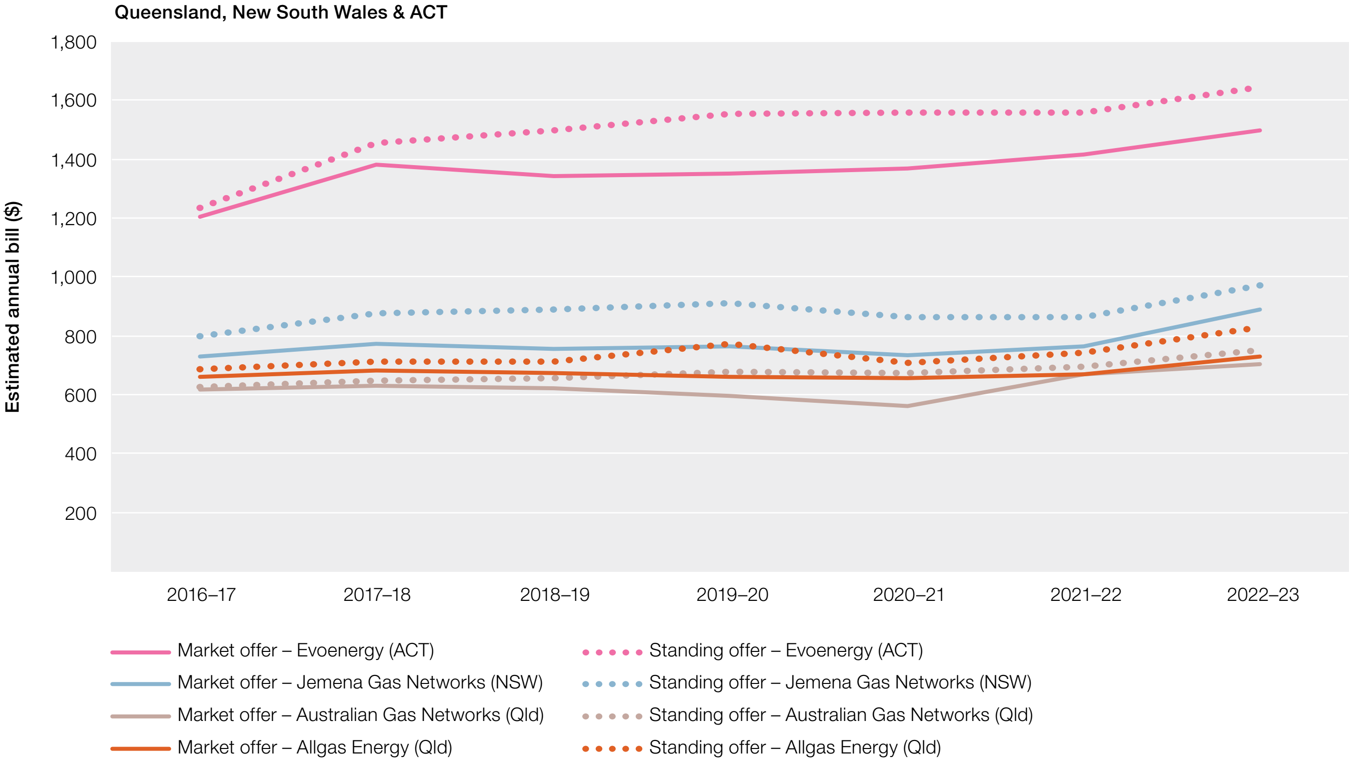
Source: Victorian Energy Compare (DELWP). Consumption based on Economic benchmarking regulatory information notice (RIN) responses.

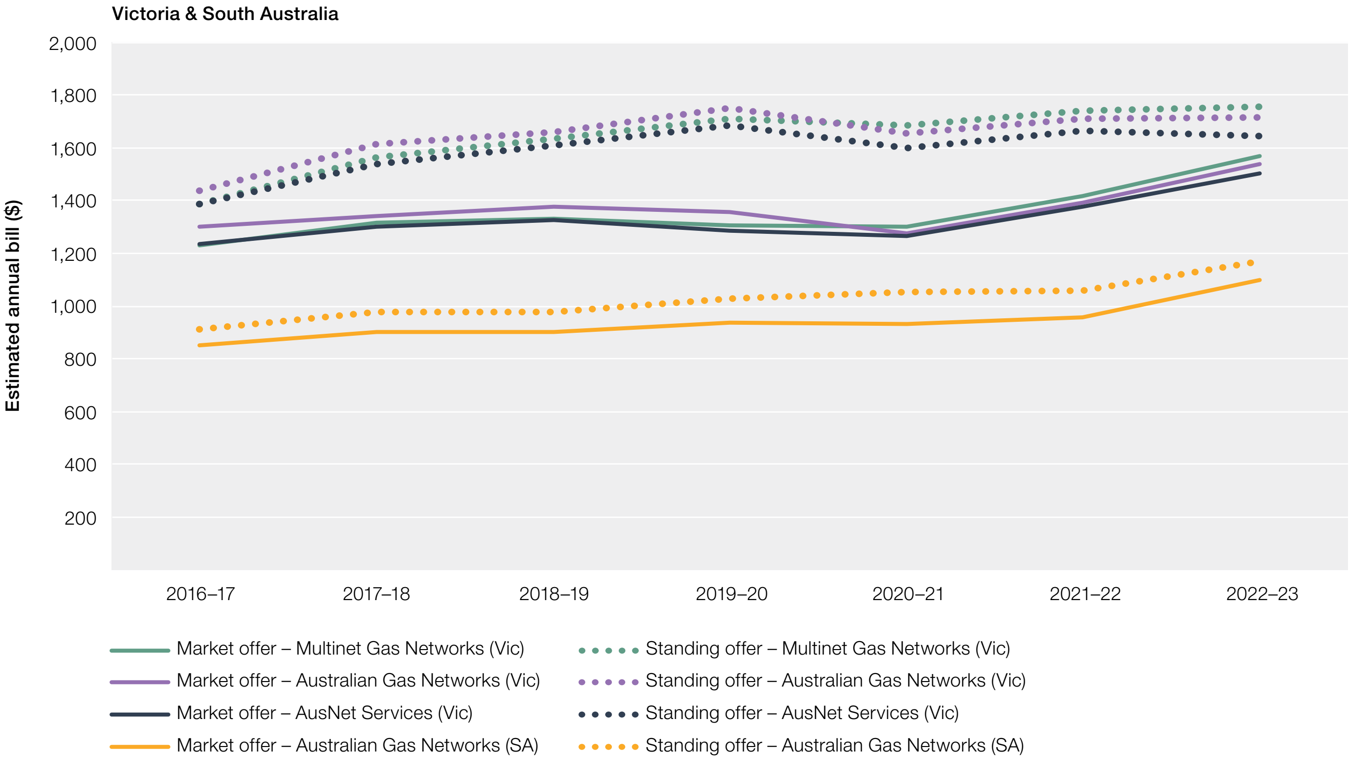
7.4.2 Gas price movements

In 2022–23, market offers for gas increased in every jurisdiction (Figure 7.5). Estimated annual customer bills in 2022–23 ranged from $703 in Queensland to $1,647 in the ACT.[30] Standing offer prices for gas also increased across jurisdictions except for Victoria, where they remained relatively stable (Figure 7.5). Gas market offers increased in all jurisdictions and standing offers increased except for some networks in Victoria, where they remained static or reduced slightly (Figure 7.5).

30 Estimated annual customer bills for generally available flat rate offers, by distribution company.

Figure 7.5 Gas bills for customers on market and standing offers





Note: Based on offers for residential customers and estimated consumption in each jurisdiction.

Source: AER analysis using offer data from Energy Made Easy (AER) and Victorian Energy Compare (DELWP). Consumption based on Frontier Economics report to the AER, *Residential energy consumption benchmarks,* December 2020.

7.4.3 Electricity price forecasts

Forecasting remains difficult given the impacts of price caps and potential future government interventions. However, there are a range of factors that may put ongoing upward pressure on retail prices.

Wholesale costs

While wholesale prices have subsided since a peak in 2022, the market remains vulnerable to supply or demand shocks. Reliability issues with coal-fired generation assets and managing the increasingly peaky shape of customer demand could also put upward pressure on wholesale costs.

Network costs

In coming years, the impact of high inflation and higher costs of capital will flow through to network costs. With new and higher jurisdictional scheme costs and previously under-recovered distribution revenues in some regions, this is likely to put upward pressure on electricity prices.

Retail costs

The retail component of costs may also face upward pressure due to inflation and increased costs in managing debt for small customers, particularly small business customers. Costs associated with meeting the AEMC's recommendation to accelerate deployment of smart meters to 100% of small customers by 2030[31] could also put upward pressure on retail costs.

Environmental costs

Environmental costs are expected to decrease across all regions. While large-scale RET costs are likely to increase, this is more than offset by a projected decline in the cost of the small-scale renewable energy scheme from 2022–23 to 2023–24. Despite expectations that the rate of small-scale installations in 2023 and 2024 will remain similar to 2022, overall costs are expected to decrease due to the shortening of the deeming period. Differences in jurisdictional energy efficiency schemes mostly account for variations to total environmental costs by region.[32]

7.5 Energy use

Consumers' energy costs are split between fixed charges and charges based on how much energy consumers use. Usage charges are the largest component of energy bills for most households.[33] A consumer's energy use significantly impacts energy affordability (section 7.6). Energy use varies by household size, thermal efficiency, appliance quality, heating and cooling needs and lifestyle. Some consumers use both electricity and gas, and others only use electricity. This means that a consumer's use of electricity or gas on its own may not be indicative of their total energy consumption.

Residential customers in Tasmania and the ACT use the most electricity (per customer) in the NEM. Residential customers on CitiPower's (Victoria) and Jemena's (Victoria) networks use the least. Customers in Victoria and the ACT tend to use the most gas. Key drivers of greater electricity and gas use are climate (with greater heating requirements in jurisdictions such as Tasmania, Victoria and ACT). Where gas connections are high, heating is generally provided by gas use rather than electricity use (Victoria and ACT). Gas use in these jurisdictions is 6 to 7 times higher in winter than over summer.[34]

Over the past 10 years, the overall amount of energy residential consumers are demanding from the NEM has decreased. This is largely driven by households using electricity generated by rooftop solar PV systems, which as at 30 June 2023 provides an estimated 17 GW of capacity connected to the NEM. This is equivalent to 23% of generation capacity across the NEM.[35]

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31 AEMC, Review of the regulatory framework for metering services, Australian Energy Market Commission, 30 August 2023.

32 ACIL Allen, Default Market Offer 2023–24, 23 May 2023.

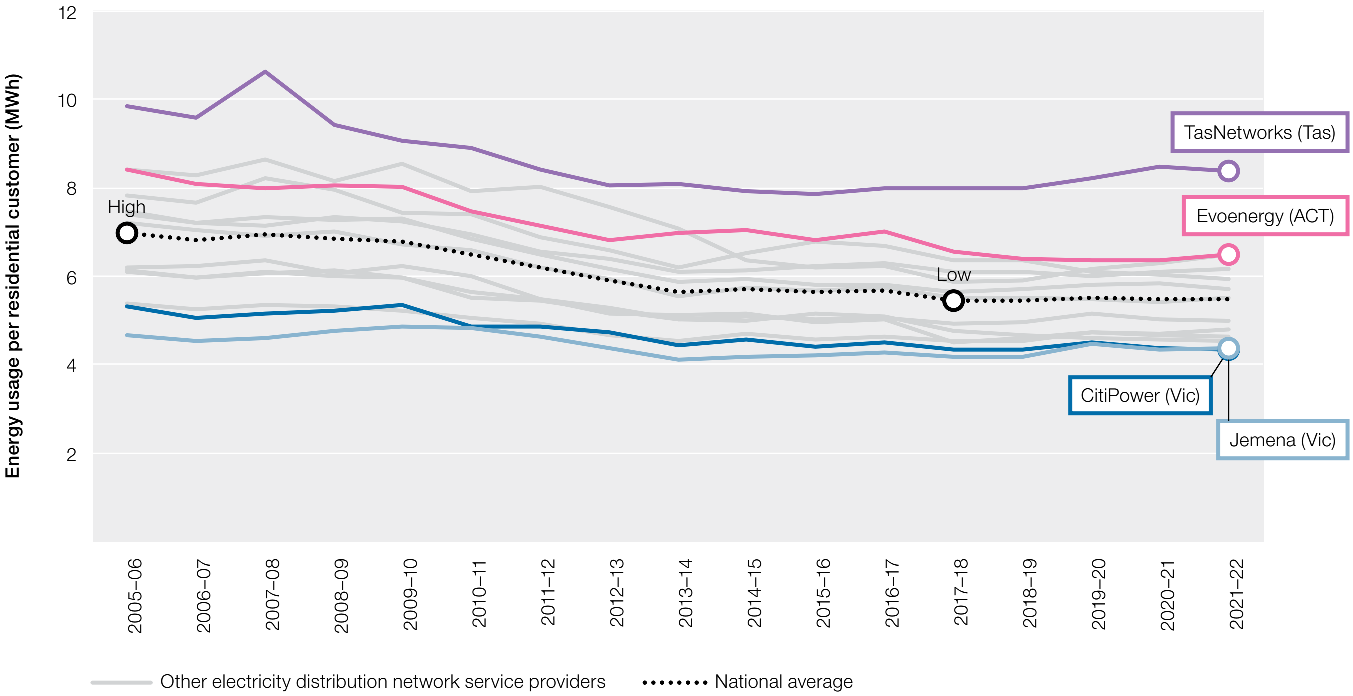
33 Most energy offers include usage charges as well as a fixed supply charge. Some offers also include membership fees or additional charges for metering.

34 Frontier Economics, Residential energy consumption benchmarks, final report for the Australian Energy Regulator, December 2020, accessed 15 September 2022, p. 26.

35 Capacity generated by rooftop solar is subtracted from demand (rather than traded in the NEM). With rooftop solar output records set over the summer of 2022–23, when rooftop solar reached a record 11,504 MWh, the rapid uptake of rooftop solar continues to be the major contributing factor to reduced grid demand.

Improved energy efficiency of new homes and appliances is also contributing. Minimum energy efficiency ratings for new residential houses was first introduced in 2004 through the Nationwide Housing Energy Rating Scheme (NatHERS) and energy efficiency ratings for appliances were introduced in 2012 through the Greenhouse and Energy Minimum Standards (GEMS).[36] More recently, state and territory governments are implementing measures to reduce residential and small commercial consumers' reliance on gas (section 6.5.4).

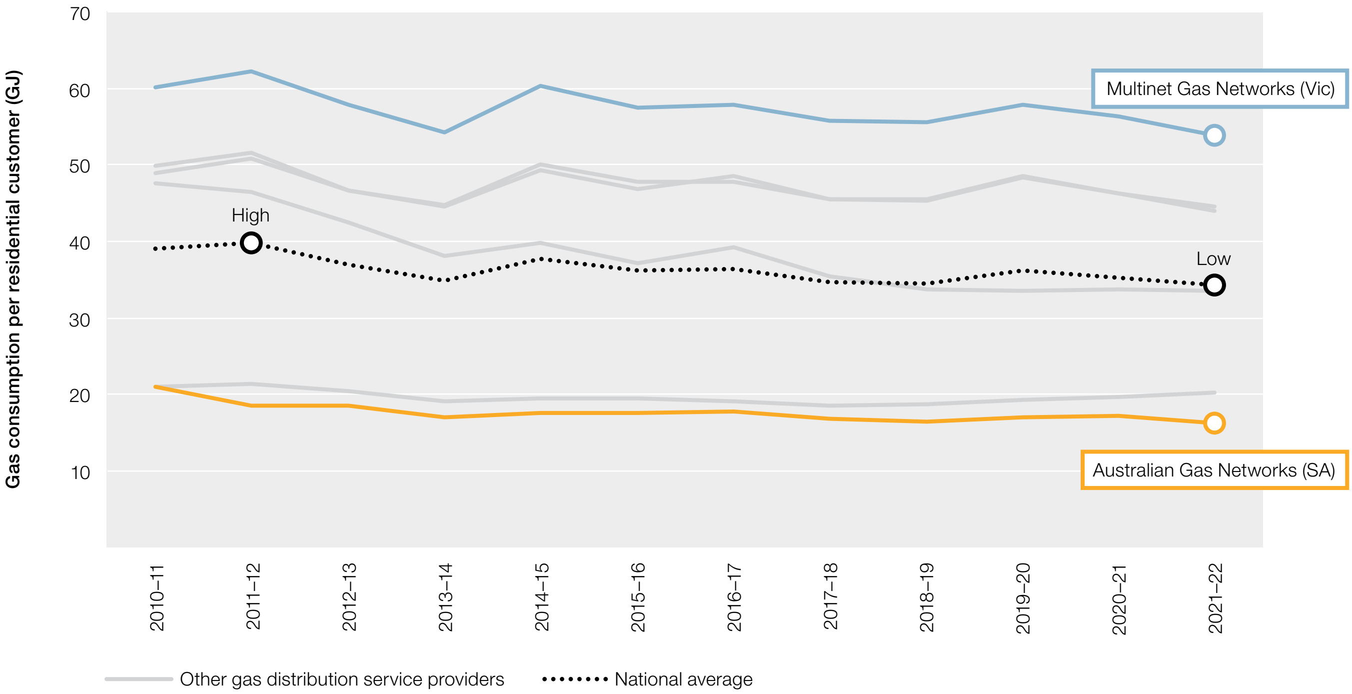
Figure 7.6 Energy use per residential customer – electricity



Note: MWh: Megawatt hour.
Source: Regulatory information notices (RIN) responses.

36 NatHERS was initiated in 1993 by the Australian and New Zealand Minerals and Energy Council to provide a standardised approach to rating the thermal performance of Australian homes. GEMS came into effect on 1 October 2012, when the GEMS Act was established to create a national framework for appliance and equipment energy efficiency in Australia.

Figure 7.7 Energy use per residential customer – gas



Note: GJ: Gigajoule.

Source: Regulatory information notices (RIN) responses.

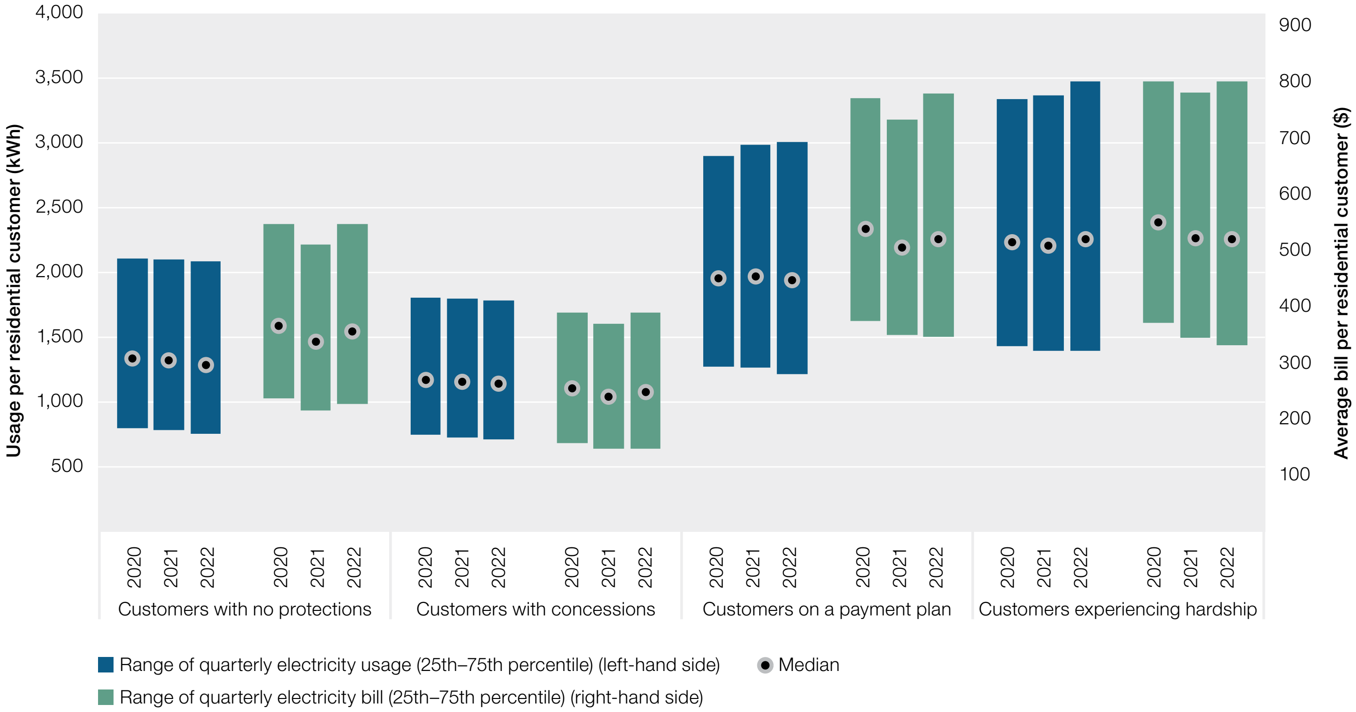
Overall, as the energy market transitions to variable renewable energy, the reported average energy use outcomes are likely obscuring a widening gap between those households with the capacity to adopt new technology or modify energy use, and those unable to do so (due to cost, residential tenancy laws or other barriers). The former group is likely experiencing a substantial reduction in electricity use, while electricity use among other households has likely remained relatively consistent over time, and these customers are likely spending more on electricity compared with 10 years ago.

Considering that the main drivers of the reduction in energy use – rooftop solar and energy efficient housing – are not equally accessible to all consumers, it is not surprising that at more granular level, a disparity in energy use across different customer types can be observed.

Figure 7.8 shows customers without protections,[37] and those on concession, use significantly less energy than payment plan and hardship customers, who accordingly also have higher bills.

37 Protections include concessions that are applied to energy bills, payment plans and hardship arrangements and insights from this data assumes that consumers without protections have been correctly identified as not eligible for them.

Figure 7.8 Electricity use and average bill by residential customer type



Note: kWH: Kilowatt hour.

Source: ACCC, Inquiry into the National Electricity Market, June 2023.

7.5.1 Impact of energy efficiency of homes on energy use

For consumers living in older homes, there is a significant deficit in average thermal efficiency of existing homes compared with the new 7 star minimum standard. Data from NatHERS certificates for assessments on existing homes shows these homes have an average energy rating of between 2 and 3 stars compared with an average rating of between 6 and 7 stars for certificates issued since 2016 for new homes.[38]

Studies by project partners under the RACE for 2030 program have explored different upgrades to existing homes and the impact on energy use.[39] Under their modelling of detached 4-bedroom houses in Victoria, NSW and Western Australia, energy use was reduced by between 18% and 99% (Table 7.3) depending on which of the 4 different upgrade options were applied.

38 CSIRO, Australian housing data portal, accessed 20 August 2023.

39 The Reliable Affordable Clean Energy for 2030 Cooperative Research Centre (Race for 2030 CRC) is a 10-year, $350 million Australian research collaboration involving industry, research, government and other stakeholders.

Table 7.3 Reductions in energy use for upgraded homes compared to baseline

Annual energy use (electricity and gas) (kWh)	Victoria	New South Wales	Western Australia
Baseline	12,655	9,604	9,827
Upgrade 1 – improved roof, wall and floor insulation, pipe lagging and draught sealing	8,734 (31%)	7,918 (18%)	7,603 (23%)
Upgrade 1 + Upgrade 2 – addition of ceiling fans, reverse cycle air condition and double-glazed windows	7,298 (42%)	7,815 (19%)	7,215 (27%)
Upgrade 1 + Upgrade 3 – efficient appliances, LED lighting and a clothesline to reduce the need for a dryer	5,210 (59%)	3,476 (64%)	3,577 (64%)
Upgrade 1 + Upgrade 4 – addition of solar PV and a hot water heat pump	2,169 (83%)	669 (93%)	710 (93%)
All upgrades	103 (99%)	0 (100%)	4 (100%)

Note: Examples of baseline homes include: a detached home with a usable area of 202 m^2, living area with dining and kitchen, 4 bedrooms, 2 bathrooms, a theatre room and garage; or a terraced home with a usable area of 124 m^2 distributed across 2 floors, including a living and dining room, 3 bedrooms, one bathroom, 2 balconies and a carport.

Source: DISER, Race for 2030, Pathways to scale: Retrofitting One Million+ homes, p. 45.

7.6 Energy affordability

Energy is an essential service. It is essential to almost everyone's daily lives, health, wellbeing and employment. An equitable energy market should provide affordable and reliable energy, be inclusive of all consumers and should not create or compound harms and barriers to participation. Energy equity, particularly affordability, remains a significant concern in energy markets.

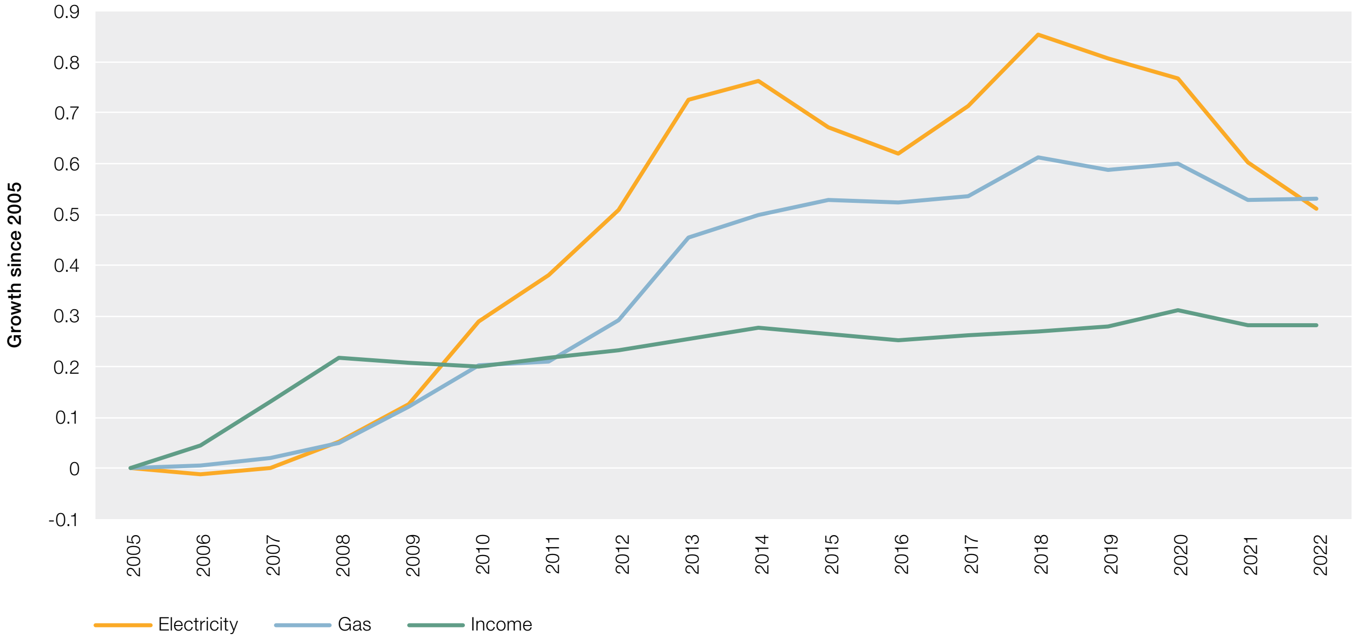
Energy affordability is impacted by a customer's energy use, energy contract and prices, income, living costs, ability to participate effectively in energy markets and extent to which they may be experiencing vulnerabilities. Energy bills can be a significant burden for households even in times of relatively low energy prices.

From June 2022 to June 2023, electricity bills are estimated to have increased significantly across NEM regions.[40] This is the largest increase since 2012–13. While electricity bill increases have been outpaced by growth in other cost-of-living pressures since 2019, data indicates that both gas and electricity prices have increased faster than wages since 2005 (Figure 7.9). Consumers are spending a larger portion of their income on energy, while also having to contend with other cost-of-living pressures.

Subdued wholesale market conditions over the past few years (prior to 2022) did flow through to retail prices, which had a positive impact on affordability across all jurisdictions in 2020–21 (Figure 7.9). However, to the extent the foreseeable upward pressures on wholesale, network and retail costs translate to higher bills, this will challenge energy affordability.

40 Estimated bill costs are based on available offers displayed over time on government price comparison websites Energy Made Easy and Victorian Energy Compare. Pricing data is aggregated across multiple pricing areas within some electricity and gas distribution networks. Bill estimates across areas are not directly comparable because each is based on average consumption in the relevant area.

Figure 7.9 Energy prices and income



Note: Inflation adjusted.

Source: Electricity and gas index – ABS, Consumer Price Index, various years; income index – ABS, Household Income and Wealth, Australia, various years.

Retail energy prices paid by consumers depend on where a customer lives, the network services required to supply their energy, competition between retailers in their area, 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.

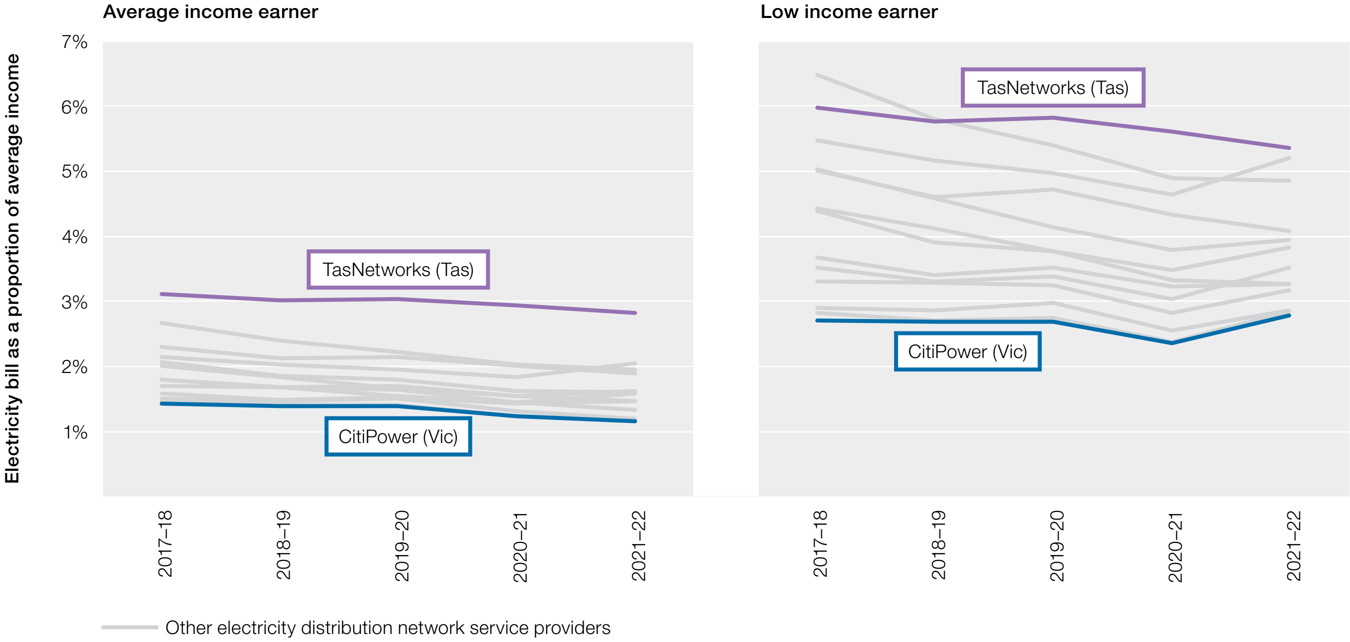
This means that affordability challenges are not split evenly across all consumer types. The evidence suggests that affordability differs substantially based on factors such as geographical location and income levels. For example, retail energy prices are typically higher in regional and remote areas than in urban areas, mostly due to higher 'per customer' network costs required to operate geographically longer networks to areas with lower population density, such as Ergon Energy (Queensland) (Figure 4.11).

On the mainland, estimated annual customer electricity bills in 2021–22 ranged from $1,273 for a customer in urban Victoria to $1,971 for a customer in rural NSW.[41] This is likely driven by both electricity prices and the different energy use profiles. Regional differences are also driven by gas consumption across regions. For example, Victoria, being the highest user of gas, has the lowest proportion electricity bill and the highest proportion gas bill.

Anticipated bill increases in financial year 2023–24 will impact average income earners, whom, up to the end of 2022, continued to spend around 1.2% to 2.1% of their income on electricity (Figure 7.10). However, increases will hit low-income earners, who are already paying between 2.8% and 5.4% of their income on electricity, much harder. While this will be partly offset by energy bill relief and other cost-of-living rebates, it will be important for retailers to actively identify and support customers with challenges paying bills through payment plans and hardship programs.

41 Estimated annual customer bills for generally available flat rate offers by distribution company.

Figure 7.10 Affordability of median market offers – electricity

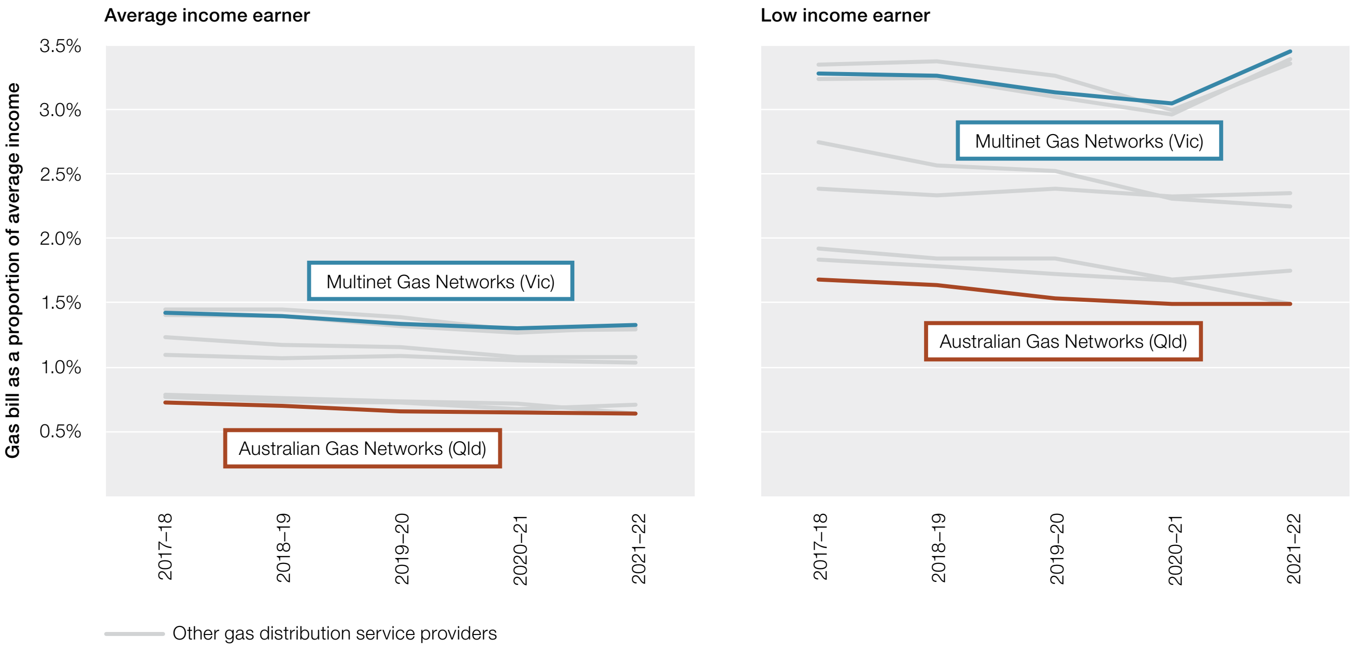


Note: Based on offers for residential customers in each jurisdiction. Average household consumption for the financial year ending June of each period was used in annual bill calculations. Proportion refers to mean disposable income. Use of average incomes across jurisdictions may overstate affordability 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 (DELWP). Consumption estimates based on Economic benchmarking regulatory information notice (RIN). Income data are unpublished ABS estimates of household disposable income.

Gas bills as a proportion of income have remained static since 2016–17, at around 0.6% to 1.3% of income. However, between 2020–21 and 2021–22, gas bills as a proportion of income spiked for Victorian customers. Because customers in Victoria use a lot more gas than customers in other regions, increased prices (due to both local supply and international prices) have a greater impact relative to their income, as it makes up more of their overall energy usage.

Figure 7.11 Affordability of median market offers – gas



Note: Based on single rate offers for residential customers and average consumption in each distribution area. Using mean disposable income for all and low-income households by state or territory. 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 (DELWP). Income data are unpublished ABS estimates of household disposable income. Consumption based on Frontier Economics report to the AER, Residential energy consumption benchmarks, December 2020.

7.6.1 Disparity of energy affordability between different types of consumers

Customers experiencing vulnerability[42] are likely to face additional challenges keeping energy bills low because they may be less able to implement some of the most effective means of reducing energy bills, including modifying energy use, making home energy efficiency upgrades, adopting new technologies and shopping around for better deals. As such, customers experiencing vulnerability are more susceptible to periods of high energy prices and disproportionately represented in the number of customers experiencing debt, hardship and disconnection.[43]

Consumers living in older, less energy-efficient homes could be spending significantly more on their energy use according to the *Race for 2030 H2: Opportunity Assessment Enhancing home thermal efficiency Final Report May 2023*, which notes that retrofitting an existing Australian home and reducing home energy use by up to 9,000 kilowatt hours (kWh) per year could reduce an average home energy bill by up to $1,600 per year.[44]

Having both the autonomy and the resources to modify energy use plays an important role in energy affordability. There are 2 key aspects of this:

- Consumers without access to energy saving or self-generating measures, such as rooftop solar PV systems, may be more likely to live in less energy efficient housing with high-consuming appliances, have higher energy bills and experience financial hardship. For example, in Energy Consumers Australia's (ECA) Consumer Behaviour Survey, 22% of respondents were interested in reducing the cost of their household energy bills through smart appliances but were also facing financial pressure or might struggle to afford the upfront costs on top of their household bills.[45]
- Consumers living in rental properties are generally reliant on property owners to make property improvements to reduce energy use, and property owners may lack incentives to make these improvements. This split incentive will be worse in areas where demand for rental properties is high, or where consumers, who may be living with vulnerabilities, are not in a position to make requests for renovations or hold out for a more thermally efficient rental property.

The AER's *Annual retail markets report 2021–22* provides more in-depth assessments of affordability.[46]

7.6.2 Policy measures and regulatory reforms aimed at improving affordability

Energy price relief

In response to the significant market events of winter 2022, the Australian Government announced an Energy Price Relief Plan in December 2022.[47] The plan included implementing coal and gas price gaps, an investment scheme to unlock investment in clean dispatchable capacity to support reliability and mitigate the risk of future price shocks, and an Energy Bill Relief Fund to provide targeted energy bill relief for small customers.

All state and territory governments in the NEM commenced implementing energy bill relief measures under the Energy Bill Relief Fund from 1 July 2023. Under the fund, those who receive an eligible government payment or hold an eligible concession card will receive rebates off their energy bills. Conditions, payment amount and timing vary between jurisdictions.[48]

The Queensland Government is delivering its energy bill relief support through its cost-of-living relief package. Households receiving the $372 Queensland Electricity Rebate will automatically receive an additional $700 rebate on their electricity bill in 2023–24. All other Queensland households will automatically receive a $550 rebate on their electricity bill in 2023–24.[49]

42 The AER's definition of 'customers experiencing vulnerability' can be accessed in AER, Towards energy equity strategy, Australian Energy Regulator, 20 October 2022, p. 4.

43 AER, Towards energy equity strategy, Australian Energy Regulator, 20 October 2022.

44 DISER, Race for 2030, Pathways to scale: Retrofitting One Million+ homes, December 2021, p. 31.

45 Calculation based on ECA respondents to question *How likely would you be to use smart appliances to reduce the cost of your household's energy bills?* and AER analysis of underlying data.

46 AER, Annual retail markets report 2021–22, Australian Energy Regulator, 30 November 2022.

47 DCCEEW, Energy Price Relief Plan, Department of Climate Change, Energy, the Environment and Water, accessed 9 September 2023.

48 For further information see DCCEEW, Energy Bill Relief Fund for households, Department of Climate Change, Energy, the Environment and Water, accessed 9 September 2023.

49 DCCEEW, Energy bill relief for households, Queensland, Department of Climate Change, Energy, the Environment and Water, accessed 9 September 2022.

Energy efficiency of homes

Australian governments are also implementing energy efficiency measures to help reduce overall household energy use. Noting that there were more than 9 million existing homes in Australia with the majority having a NatHERS energy rating below 3 stars, the Australian Government and state and territory governments have been developing a trajectory towards low energy buildings that includes specific actions for existing homes. This includes a National Framework for Disclosure of Residential Energy Efficiency Information, a National Framework for Minimum Rental Energy Efficiency Requirements and improvements to existing energy and appliance efficiency programs.

In October 2022, the Australian Government announced its forthcoming National Energy Performance Strategy and released a discussion paper, which included residential building energy use as one of 5 strategic focus areas. It notes that Australia's residential building sector accounts for around 24% of electricity consumption and specifically mentions the need to consider low-income households, renters, people living in apartments and people living in regional, remote communities, and the importance of ensuring energy security for First Nations communities.[50]

State and territory governments have implemented initiatives to help low-income households improve their energy efficiency or install solar PV systems:

- In Victoria, the Household Energy Savings Package offers energy efficiency heating and cooling systems for low-income households and energy upgrades of social housing properties. The program also includes a one-off $250 Power Saving Bonus to help households that have at least one resident receiving payments under an eligible concession program.
- In the ACT, the free ActSmart Household Energy Efficiency Program, delivered by St Vincent de Paul, offers practical ways for people in lower-income households to reduce their energy and water bills. Energy efficiency assessors visit homes to help consumers find ways to reduce energy and water use and save money.
- South Australia's Retailer Energy Productivity Scheme offers free or discounted energy efficiency and energy productivity activities, but it is not specifically targeted at low-income households. The South Australian Government has also supported a virtual power plant project that supplies, installs and maintains solar and home battery systems for Housing SA tenants at no cost to the tenant.[51]

Sections 7.6.3 to 7.6.6 provide an interim update on customer debt, payment plans, hardship programs and disconnections. This data will be more thoroughly examined in the AER's forthcoming Annual retail markets report 2022–23, due for publication in November 2023.

The AER's quarterly retail performance reports provide more detail on the data and interdependencies between the different debt assistance and financial difficulty metrics provided by retailers.[52]

7.6.3 Assisting customers in energy debt

In response to COVID-19, many retailers locked or extended debt levels, allowing customers to accumulate more debt than in the pre-COVID years. Since then, the proportion of customers in energy debt has increased while retailers seek to transition customers back towards a business-as-usual scenario. Cost-of-living pressures and recent energy price spikes, while partially offset by concessions and rebates in some jurisdictions, have contributed to debt levels remaining higher than pre-COVID years.

As of March 2023, the overall number of customers across NEM regions with energy debt increased by 11% since 30 June 2022. The biggest increases were in the ACT (25%) and Tasmania (21%). There may be multiple factors driving increases in the ACT, including the primary retailer ActewAGL contacting customers proactively in late 2022 to support them managing debt into the new year. In Tasmania, the increase may be due to resumption of business-as-usual debt collection practices since June 2022 by primary retailer Aurora, following a period of relatively relaxed debt collection practices during COVID-19.

Queensland was the only region with a decrease in customers in energy debt (–7%) (Figure 7.12). This is likely due to the Queensland Government's $175 energy bill rebate from 1 August 2022 and relatively stable prices for customers on the highly regulated Ergon Energy network. Compared with pre-COVID-19, the number of customers with energy debt has increased in all jurisdictions apart from the ACT. In Tasmania the numbers have more than doubled.

50 DCCEEW, National Energy Performance Strategy: consultation paper, Department of Climate Change, Energy, the Environment and Water, 10 November 2022.

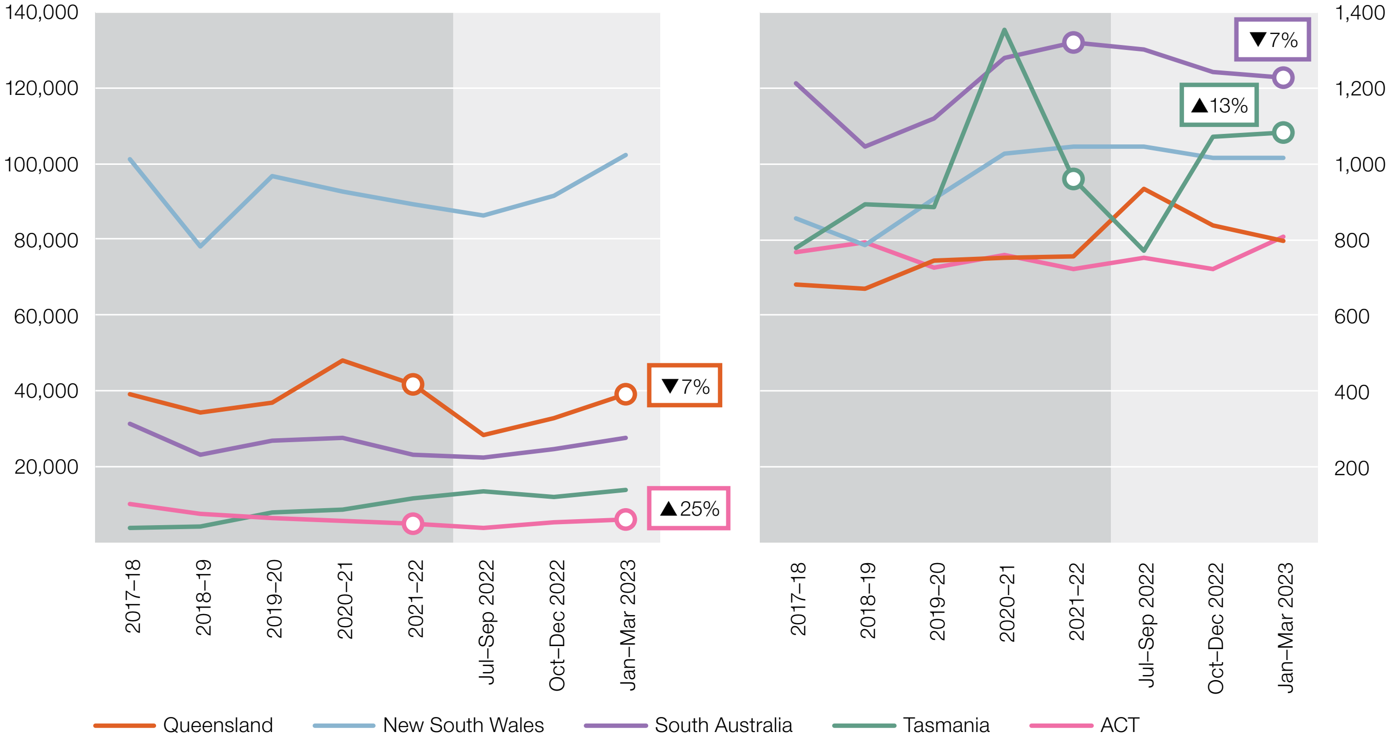
51 Government of South Australia, South Australia's Virtual Power Plant, accessed 16 September 2022.

52 AER, Performance reporting, Australian Energy Regulator, accessed 28 August 2023.

As of March 2023, the average amount of customer debt per customer increased in Queensland (5%), the ACT (12%) and Tasmania (13%) compared with June 2022. NSW and South Australia saw slight decreases of 3% and 7%, respectively. However, in all jurisdictions, average energy debt remains elevated compared with pre-COVID-19 levels in 2017–18 and 2018–19.

Further analysis and more up-to-date data will be provided in the forthcoming Annual retail markets report 2022–23, due for publication in November 2023.

Figure 7.12 Residential 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 2022–23*, June 2023.

7.6.4 Payment plans

Under the Retail Law, retailers are obligated to provide payment plans to customers experiencing payment difficulties.[53] Payment plans allow settlement of overdue amounts in periodic instalments and are typically the first assistance offered by retailers to customers who show signs of payment difficulties. The AER's Sustainable Payment Plans Framework guides retailers on negotiating affordable payment plans with customers needing assistance to manage debt.[54] The framework has been adopted by most retailers servicing small customers.

While concerning that debt and hardship are increasing, the increase in customers on payment plans can also indicate earlier and more effective retailer engagement and may result in fewer disconnections. As of 31 March 2023, there was a 7.7% increase in customers participating in payment plans compared with the same time in the previous year.[55]

Further analysis and more up-to-date data will be provided in the forthcoming Annual retail markets report 2022–23, due for publication in November 2023.

53 National Energy Retail Law (South Australia) Act 2011, Part 2, Division 7, Section 50 – Payment plans.

54 AER, Sustainable payment plans, a good practice framework for assessing customers' capacity to pay, Version 1, Australian Energy Regulator, July 2016, accessed 15 September 2022.

55 AER, Quarterly retail performance report, Q3, 2022–23, Australian Energy Regulator, 28 June 2023.

7.6.5 Hardship programs

The Retail Law requires energy retailers in Queensland, NSW, South Australia, the ACT and Tasmania to develop and maintain a customer hardship policy that underpins how they identify and assist customers facing difficulty paying their energy bills. The AER's Customer Hardship Policy Guideline requires retailers to ensure their programs are easily accessible and include a standard statement explaining how they will help customers. It puts greater onus on retailers to identify customers who may need assistance.[56]

Assistance under a retailer's hardship program can include:

- extensions of time to pay a bill and tailored payment options
- advice on government concessions and rebate programs
- referral to financial counselling services
- review of a customer's energy contract to ensure it suits their needs
- energy efficiency advice, such as an energy audit, and help to replace appliances to help reduce a customer's bills
- waiver of late payment fees.

As part of their hardship policies, retailers must take into consideration a customer's capacity to pay. In Victoria, the hardship assistance equivalent is called the payment difficulty framework.[57]

As of 31 March 2023, the proportion of residential electricity customers on hardship programs compared with June 2022 increased slightly in NSW (30 basis points (bps)), South Australia (30 bps), the ACT (20 bps) and Tasmania (20 bps). Queensland remained unchanged. The proportion of gas small customers on hardship programs increased over the same period by between 10 and 20 basis points in Queensland, NSW and South Australia, and remained unchanged in the ACT (Figure 7.13).

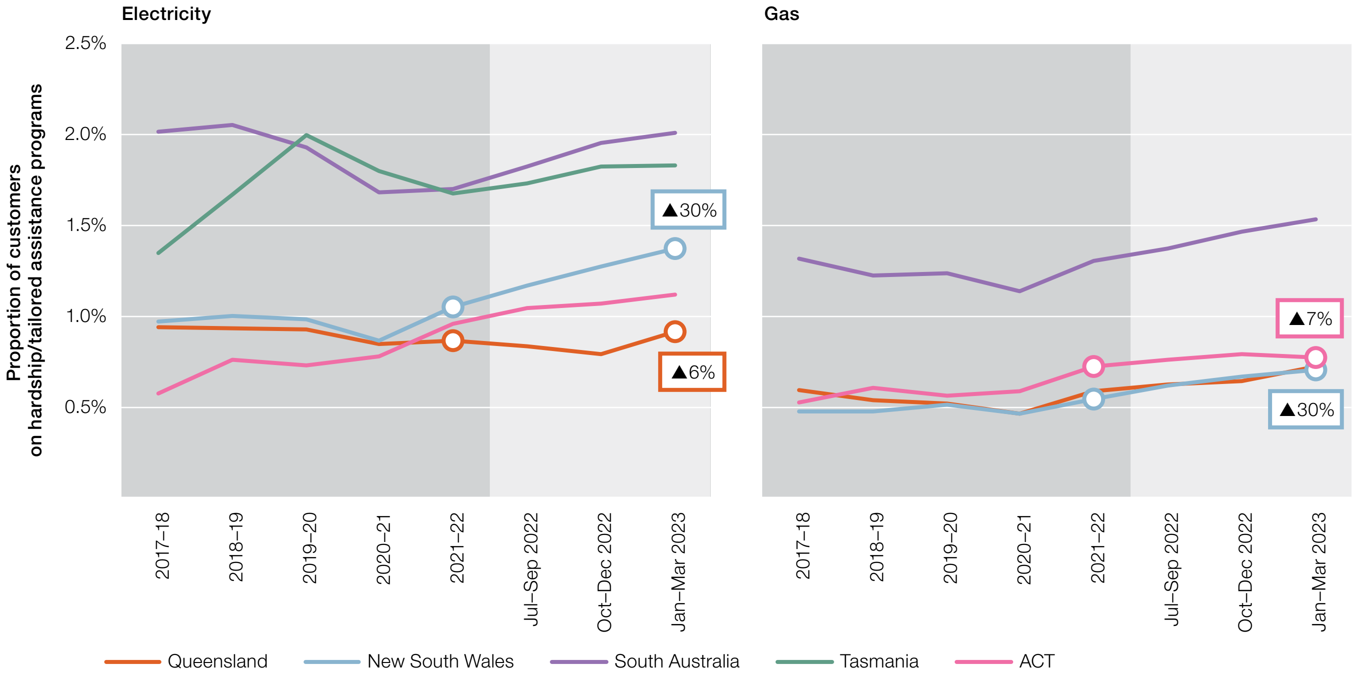
Analysis in the AER's forthcoming Annual retail markets report 2022–23, due for publication in November 2023, will provide a more complete picture. It is encouraging to note a 28% decrease in average debt on entry to a hardship program, indicating earlier and more effective engagement by retailers with customers experiencing debt in March 2023 compared with the previous year.[58]

56 AER, Hardship protections a right not a privilege, media release, Australian Energy Regulator, 29 March 2019, accessed 15 September 2022.

57 In 2019 the Victorian Government introduced its payment difficulty framework – a series of rules that provide strong and more consistent hardship assistance for Victorian energy consumers. These rules ensure minimum entitlements to all customers (known as 'standard assistance') and further minimum entitlements to customers with arrears ('tailored assistance').

58 AER, Quarterly retail performance report, Q3, 2022–23, Australian Energy Regulator, 28 June 2023.

Figure 7.13 Small customers on hardship/tailored assistance programs



Note: The y axis represents % of customers in hardship.
Source: AER, *Quarterly retail performance report, Q3 2022–23*, June 2023.

The AER's annual retail markets report and quarterly retail performance reports provide a more in-depth assessment of customers experiencing payment difficulties and hardship.[59]

7.6.6 Disconnecting customers for non-payment

Disconnection for non-payment of bills should be viewed as a last resort and only occur after the strict processes set out in the Retail Rules have been followed.

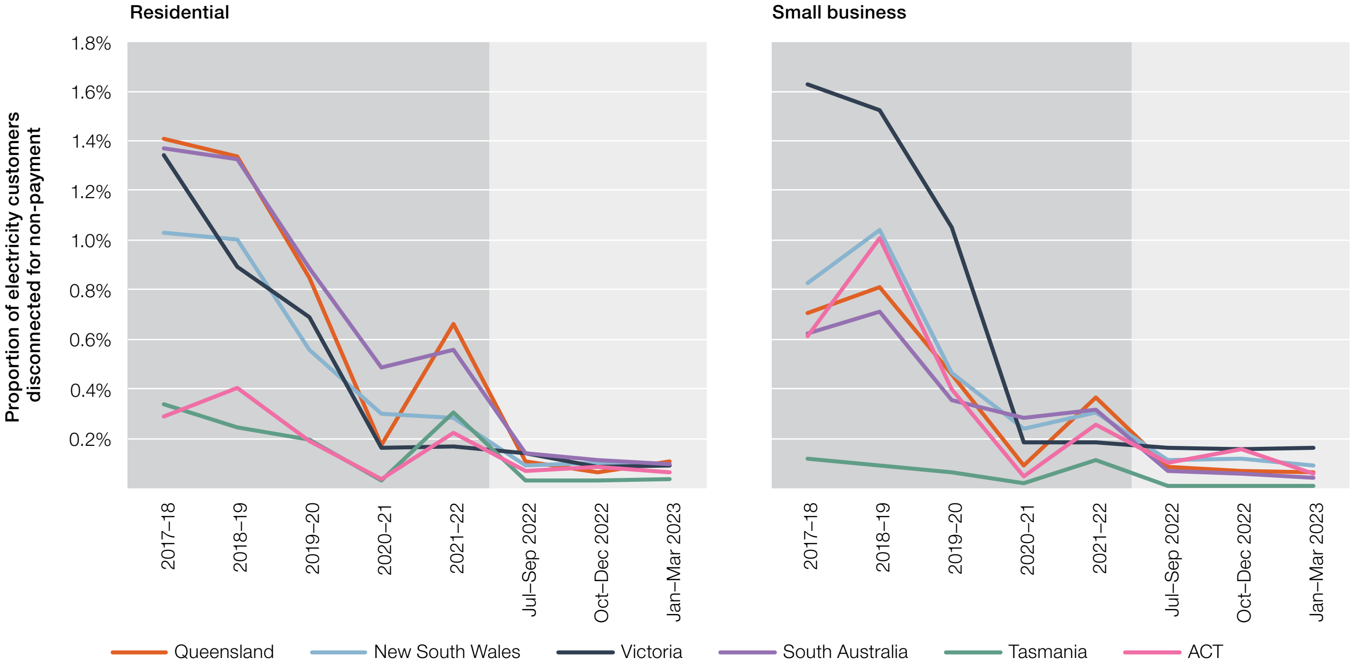
Disconnection is not permitted in certain circumstances – such as when a customer's premises are registered as requiring life support equipment, a customer on a hardship program is meeting their payment obligations or a customer's debt is below $300.

The rate of disconnections remains significantly lower than in pre-COVID-19 years. This is encouraging because the AER's Statement of Expectations directing retailers not to disconnect small customers during COVID-19 lapsed on 30 June 2021.[60] The persistence of low disconnection rates for both electricity and gas small customers suggests ongoing behavioural change by retailers (Figure 7.14 and Figure 7.15). Where disconnection did occur, customer debt levels at the time of disconnection were higher than in the previous year.

59 AER, Performance reporting, Australian Energy Regulator, accessed 28 August 2023.

60 AER, Statement of Expectations of energy businesses: Protecting customers and the energy market during COVID-19, Australian Energy Regulator, 29 June 2021.

Figure 7.14 Disconnection for failure to pay – electricity



Note: Based on customers with an amount owing to a retailer that has been outstanding for 90 days or more, at 31 March 2023, for all states except Victoria, which is at 30 June 2023.

Source: AER, *Quarterly retail performance report, Q3 2022–23*, June 2023; ESC, Victorian energy market dashboard, accessed 30 June 2023.

Figure 7.15 Disconnection for failure to pay – gas

Note: Based on customers with an amount owing to a retailer that has been outstanding for 90 days or more, at 31 March 2023, for all states except Victoria, which is at June 2023.

Source: AER, *Quarterly retail performance report, Q3 2022–23,* June 2023; ESC, Victorian energy market dashboard, accessed 30 June 2023.

7.6.7 Improving our approach to consumer vulnerability

In October 2022 the AER launched *Towards energy equity – A strategy for an inclusive energy market*.[61] This strategy is focused 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 outlines 15 actions that the AER will deliver over the next 3 years, in alignment with 5 core objectives:

- 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.

Since publication of the strategy, the AER has progressed many of the actions set out in the strategy. Updates for several of these are provided below.

Action 1: Improve protections for consumers affected by family violence

New family violence protections commenced in the Retail Rules on 1 May 2023. These new obligations are designed to improve energy retailers' response to, and support of, customers experiencing family violence across National Energy Customer Framework jurisdictions. The relevant obligations have since been classified as tier 1 civil penalties. Ahead of the commencement of the new rules, the AER released an interim guidance note in April 2023 outlining energy retailers' key responsibilities to customers affected by family violence and setting out the AER's compliance expectations.[62]

Family violence has been added as an enduring Compliance and Enforcement Priority from 1 July 2023 and the AER will continue to act where there are serious issues impacting consumers affected by family violence. The AER will conduct a review of retailer family violence policies, and seek stakeholder feedback, with a view to updating the guidance note in 2024.

Action 2: Develop a toolkit to help consumer-facing energy businesses identify vulnerability

The AER has undertaken a literature review and engaged with stakeholders, including financial counsellors and retailers, to develop an understanding of current industry practices and consolidate existing information on best practice for identifying vulnerable consumers. The AER plans to share the findings in late 2023.

Action 4: Implement Better Bills Guideline

The AER commenced consultation on Version 2 of the Better Bills Guideline in September 2022, with the updated guideline released in January 2023. Version 2 clarified the better offer and self-read information requirements and aligns the guideline with the AEMC's determination to change the date retailers must comply with the guideline's new billing provisions to 30 September 2023.

The AER continues to engage and respond to retailers regarding compliance with the Better Bills Guideline as they prepare for full implementation. The AER will review compliance with the guideline following 30 September 2023 and subsequently provide guidance to industry on good practice.

Action 5: Improve AER's communications channels to assist energy consumer literacy

During the year, the AER has been active across traditional and digital communication channels in support of this action. Three consumer literacy campaigns have been run during the year – one to educate people about the Default Market Offer (DMO), an Energy Made Easy (EME) smart energy campaign and a Language other than English (LOTE) campaign.

The project to redevelop the AER website has continued and will shortly move into the testing phase. A user-centred methodology has been used to improve access to information. Similarly, work on a consumer-friendly writing style guide is nearing completion.

61 AER, Towards energy equity strategy, Australian Energy Regulator, 20 October 2022.

62 AER, Interim guidance note – family violence rule, Australian Energy Regulator, 12 April 2023.

Action 7: Improve outcomes for consumers in embedded networks

The AER will address this action through a broader review of the exemptions framework for embedded networks. The AER plans to publish an issues paper in late 2023 and the review is intended to run through to mid-2025.

Action 13: Review consumer protections for future energy services

The AER has concluded there is a strong case for reforming the National Energy Customer Framework to ensure consumers are adequately protected against potential harms arising from new energy services that emerge as part of the energy transition. This recommendation, along with detailed risk analysis, will be provided to Energy Ministers before the end of 2023.

Action 15: Advocate for sector-wide 'game changer' reforms

The AER has been working with sector stakeholders to drive systemic change to provide better outcomes for consumers experiencing vulnerability and to better share the risk of managing vulnerability across the energy sector. A leadership group of senior stakeholders from industry, government, market bodies, ombudsman schemes and consumer advocates has been established to consider how to deliver potential solutions to address this problem. The AER is planning to present a proposed package of reforms that is supported by key stakeholders to government in late 2023.

7.7 Competition in retail energy markets

Competition in retail energy markets is necessary to stimulate innovation and ensure better quality, lower cost products and services for customers. The AER balances supporting competition by 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.

Regulatory reforms since 2018 reflect concerns outlined in the ACCC's Retail Electricity Pricing Inquiry June 2018, namely that markets had not delivered sufficient benefit to consumers by way of competition.[63] The reforms have sought to encourage more competitive behaviours from retailers, support consumers to engage more closely with the market and make it easier to compare retail offers so that retailers compete more aggressively through lower prices and better products.

Customers in embedded networks have historically lacked retail choice. In June 2019 the AEMC proposed new arrangements that would begin shifting embedded networks into the national regime, improving protections and access to retail market competition for their customers.[64] Since then, the AER has prioritised customers in embedded networks within its compliance and enforcement activities and introduced reforms, including a new policy ensuring embedded network customers can access hardship protections and ombudsman schemes (section 7.8.4).

Other consumers may be experiencing vulnerability and may not have the opportunity to shop around for the best market offer. It is important they are not further disadvantaged by higher energy bills.

7.7.1 Market concentration

Origin Energy, AGL Energy and EnergyAustralia (the 'big 3') are the largest energy providers in Australia. The big 3 retailers have a significant share in the residential electricity and gas markets of NSW and South Australia and a lesser but still substantial share of the Queensland and Victorian markets. Although their market share continues to decline, as of March 2023 the big 3 still served at least 60% of residential and small business electricity customers and 80% to 90% of residential and small business gas customers (Figure 7.17).

Growth in the number of alternative (Tier 2) retailers contributes to effective retail competition by providing a more diverse mix of offers in the market.[65] Since winter 2022, the significant growth in the number of Tier 2 retailers – observable from 2017–18 – has slowed (Figure 7.16). While Tier 2 retailers continue to improve market share, they are doing so at a slower rate.

Since the market conditions of winter 2022, smaller retailers are finding it harder to manage exposure to volatile wholesale electricity prices. Further, sharp increases in wholesale energy costs will likely subdue interest from new

63 ACCC, Retail Electricity Pricing Inquiry—Final Report June 2018, Australian Competition and Consumer Commission, 30 June 2018.

64 AEMC, Updating the regulatory frameworks for embedded networks, Australian Energy Market Commission, 30 June 2019, accessed 15 September 2022.

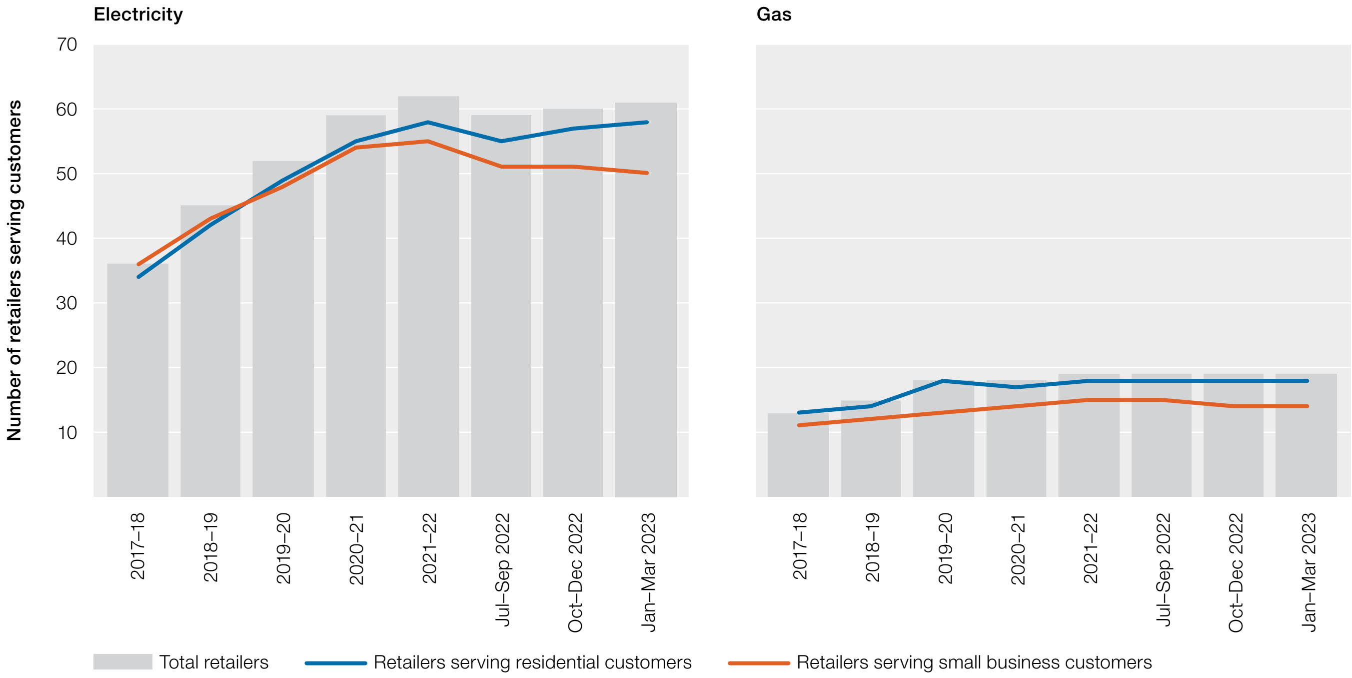
65 Tier 2 retailers include any retailer that is not Origin Energy, AGL Energy, EnergyAustralia, nor one of the primary regional government-owned retailers – Ergon Energy (Queensland), ActewAGL (ACT) and Aurora Energy (Tasmania).

market entrants until wholesale prices stabilise. This could weaken retail market competition and contribute to poorer outcomes for consumers.[66] Access to competitively priced hedging contracts had already been identified by standalone retailers as a barrier to entry and further expansion in 2020.[67]

Regions with stronger levels of continuous retail price regulation are also heavily concentrated, including Ergon Energy in regional Queensland, Aurora Energy in Tasmania and ActewAGL. These primary retailers are government-owned (wholly or in part) businesses with little activity outside their home jurisdiction and were previously the sole regulated provider of retail electricity in that jurisdiction.[68] Due to a lack of competition and ongoing price regulation, the degree of market concentration in those regions remains stable (Figure 7.17).

Gas markets are generally less competitive than electricity markets, given their smaller scale and persistent issues in sourcing gas and pipeline services in some jurisdictions, and much higher levels of concentration (Figure 7.18).

Figure 7.16 Energy market – number of retail brands



Source: AER, *Quarterly retail performance report, Q3 2022–23*, June 2023; ESC, Victorian energy market dashboard, accessed 30 June 2023.

In its *Victorian Energy Market Report 2020–21*, the Essential Services Commission (Victoria) (ESC) noted the significant market share of larger retailers.[69] The ESC found customer preference to be 'both persistent and striking', given survey responses indicated price is the most important factor when switching and that large energy retailer offers are generally more costly than small and medium retailer offers. This issue is explored further in section 7.7.10.

7.7.2 Electricity

Between 1 July 2022 and 31 March 2023, the number of customers serviced by Tier 1 retailers decreased, by 0.16%, whereas the number of Tier 2 customers increased by 2.7%. Tier 2 retailers have increased their share of small customers in each year since at least 2016–17.[70] Over that period each of the big 3 retailers has lost ground, with Origin Energy the most impacted.

66 AER, Wholesale electricity market performance report – December 2022, Australian Energy Regulator, 15 December 2022, p. 56.

67 AEMC, 2020 Retail Energy Competition Review, Australian Energy Market Commission, 30 June 2020, accessed 15 September 2022.

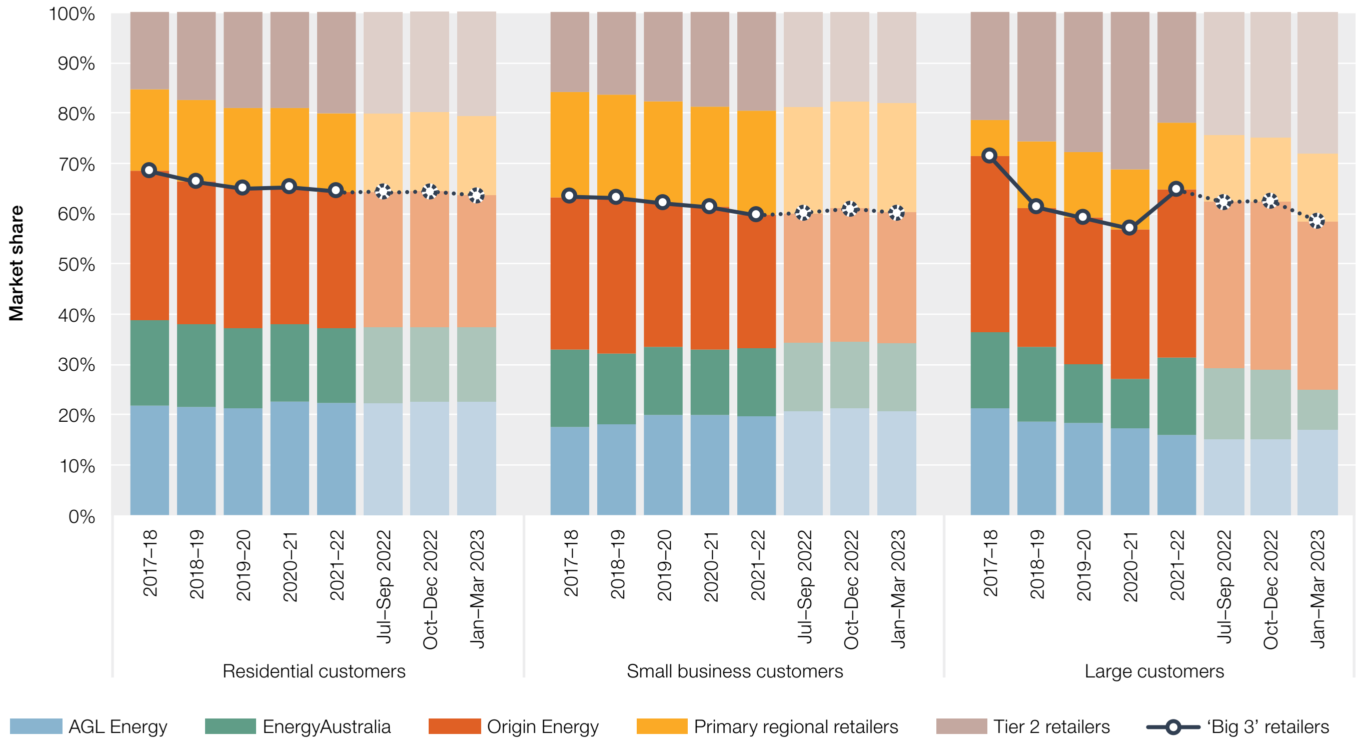
68 AER, Annual retail market report 2021–22, Australian Energy Regulator, 30 November 2022.

69 Large retailers in Victoria include the big 3 plus Lumo Energy, Red Energy and Simply Energy.

70 Retail customer numbers are not available prior to 2016–17.

Between 1 May 2022 and 31 July 2023, 11 Tier 2 retailers exited the market through the Retailer of Last Resort scheme, impacting approximately 34,000 customers who were (at least initially) transferred to Tier 1 retailers.[71] While the relatively small number of customers impacted has not materially impacted market concentration data (Figure 7.17), the lack of new Tier 2 market entrants due to current market conditions could weaken competition in retail markets.

Figure 7.17 Energy retail market share – electricity



Note: All data as of 31 March 2023. Data includes customers in Queensland, NSW, South Australia, Tasmania and the ACT. Some differences may occur between annual and quarterly data to account for retailers revising their data when making their annual submission.

Source: AER, *Quarterly retail performance report, Q3 2022–23*, June 2023.

In NSW, the big 3 retailers serve 77% of small electricity customers, making it the most concentrated jurisdiction. Snowy Hydro (owned by the Australian Government and trading as Red Energy and Lumo Energy) serves 7% of small customers, with the remaining 13% served by other Tier 2 retailers.[72]

7.7.3 Gas

As with electricity, AGL Energy, Origin Energy and EnergyAustralia are the dominant retailers in the gas market, serving just over 1.8 million (79% of a total 2.3 million) residential customers.[73] In the 9 months from June 2022, the big 3 retailers' share of the small customer market decreased from 81.3% to 79.7%.[74] Conversely, over the same period Tier 2 retailers increased their share of the market. In gas markets, the big 3 retailers have continued to lose their small customer market share to Tier 2 retailers since 2016–17 (Figure 7.18).

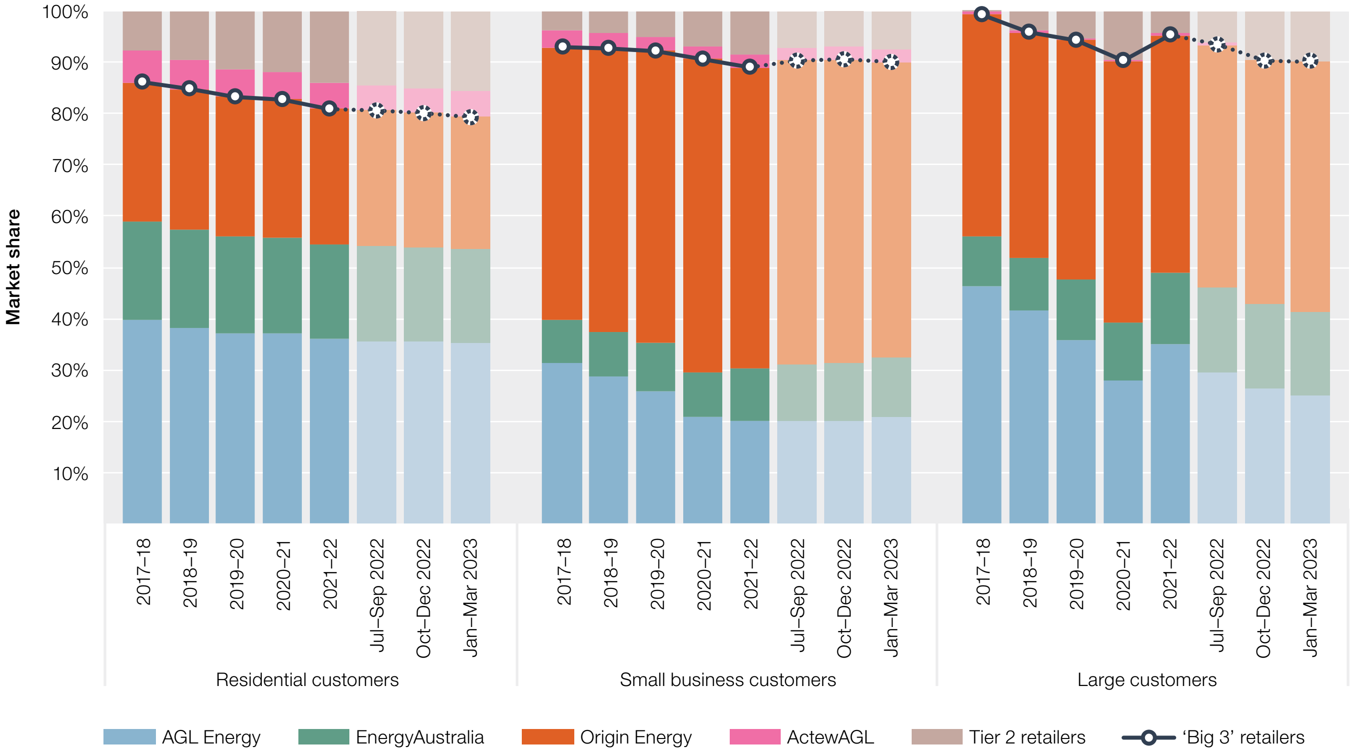
71 Includes Retailer of Last Resort data from 1 October 2022 and 31 July 2023, discussed earlier in this section.

72 Use of state-wide data masks levels of market concentration within some parts of regions with multiple distribution zones (Queensland and NSW). For example, market concentration is likely to be higher in regional NSW than in Sydney.

73 Includes customers in Queensland, NSW, South Australia and the ACT. Does not include Victoria.

74 AER, Quarterly retail performance report Q3, 2022–23, 28 June 2023.

Figure 7.18 Energy retail market share – gas



Note: All data as of 31 March 2023. Data includes customers in Queensland, NSW, South Australia and the ACT.
Source: AER, *Quarterly retail performance report, Q3 2022–23*, June 2023.

7.7.4 Vertical integration

In the electricity sector, many generators and retailers have integrated to become 'gentailers'. Operating at either end of the energy supply chain is referred to as 'vertical integration', which provides benefits to energy retailers and generators by enabling them to manage price volatility in wholesale markets, with less need to hedge their positions in futures (derivatives) markets. These savings could then be passed on to consumers through lower retail prices. However, this strategy can reduce liquidity in derivatives markets, posing a barrier to entry or expansion for 'independent' retailers that are not vertically integrated.

Vertical integration also occurs in gas, but to a lesser extent. Interests in upstream gas production or storage can complement gas retailing or gas-powered electricity generation.

7.7.5 Consumer engagement

Many energy consumers can actively participate in retail energy markets and enter into a market contract with their retailer of choice.[75] Market contracts allow retailers to tailor their energy products, offering different tariff structures, discounted prices, carbon offsets, non-price incentives, billing options, fixed or variable terms and other features. Most consumers are currently on a market contract.

Customers without a market contract are placed on a standing offer with the retailer that most recently supplied energy at their premises (or, for new connections, with the retailer designated for that area). Standing offers were intended to provide a safety net for customers unable or unwilling to engage in the market, with prescribed terms and conditions and a suite of consumer protections that the retailer cannot change.

In July 2019, following a period of price deregulation, the ACCC determined that customers on standing offers were paying excessively high prices, disproportionately impacting customers experiencing vulnerability and/or facing barriers to participate in the market.[76] Since then, standing offer electricity prices have been set or capped by regulators in all jurisdictions (section 7.3.9).

75 While full retail contestability applies in all regions, not all customers can access offers from a retailer other than their host retailer. Further, many customers within embedded networks are still limited to energy supply through their embedded network operator.

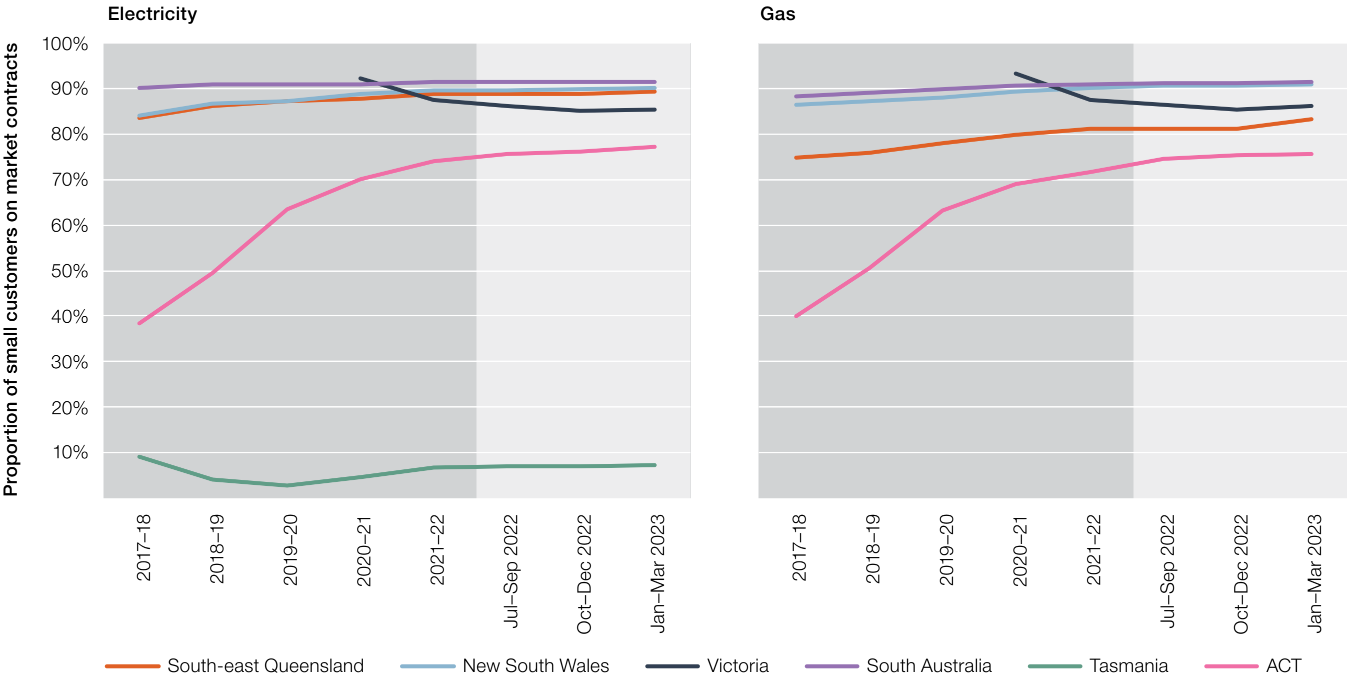
76 ACCC, Retail Electricity Pricing Inquiry—Final Report June 2018, Australian Competition and Consumer Commission, accessed 1 September 2023.

While customers on market contracts historically paid less, on average, than those on standing offers, more recently average prices paid by both cohorts are converging (section 7.4.1). Further, customers on market contracts do not necessarily receive the best price available. Contracts with expired benefits may be priced close to, or, in some instances, higher than the standing offer, meaning consumers need to continuously renegotiate or switch market contracts to maintain better prices.

Most standing offer customers have contracts with Tier 1 retailers. This reflects the position of these retailers as incumbents – the retailer that purchased the customer base at the time retail contestability was introduced – allowing them to retain customers that have never taken up a market contract and may face additional barriers to actively participate in the market.

However, in regions serviced by primary regional retailers, most customers are on standing offers. As partially government-owned retailers with ongoing price regulation, they have maintained strong market concentration, faced limited retail competition and have delivered relatively stable pricing for customers. As such, small customers in those areas have had less motivation and opportunity to pursue market offers. In Tasmania, new entrant retailers have offered market contracts to residential customers since early 2019, but the proportion of customers on market contracts remains comparatively low; the Tasmanian Government set standing offer prices that attracted Aurora Energy's market customers to switch back to the standing offer (Figure 7.19).

Figure 7.19 Small customers on market contracts



Note: Standing and market offer shares are based on the number of small customers at 31 March 2023 except Victoria (June 2023). Queensland electricity numbers exclude customers in regional Queensland, who largely remain on standing offers.

Source: AER, *Quarterly retail performance report, Q3 2022–23*, June 2023; ESC, Victorian energy market dashboard, accessed 30 June 2023.

7.7.6 Consumer participation

Competition in retail energy markets is intended to drive innovation, resulting in a wider range of products and services to meeting different customer preferences and demands. However, for a range of reasons, many consumers face barriers to actively participate in the market and secure the best offer for their situation. This can exacerbate existing structural inequalities, whereby those who can least afford it are paying higher energy rates.

Customer surveys regularly report that customers find the energy market difficult to navigate In June 2023, Energy Consumers Australia (ECA) reported that 2 in 5 Australians do not feel there is enough easy-to-understand information available to make informed decisions about energy.[77] Retailers have adopted marketing strategies that make it difficult and time-consuming for customers to directly compare offers. This reinforces a lack of trust and low levels of engagement.

77 ECA, Evidence base to support the development of an effective communications campaign for energy consumers, Energy Consumers Australia, 27 July 2023.

Reforms in 2019 sought to make it easier for customers to compare offers by simplifying and standardising how retailers must present offers. The reforms require advertised discounts to be quoted against a 'reference bill', being the default market offer set by the AER (section 7.3.7).

The Better Bills Guideline, which commenced in March 2022, also seeks to make it easier for consumers to engage with the energy market by providing information to help them understand and compare their plan, identify whether their retailer may be able to provide a better offer, or consider options for new types of energy services (section 7.3.1).

The AER has also developed a suite of translated, shareable content for consumers who speak a language other than English.[78] Covering 8 languages, the content provides information on:

- how to save money on energy bills
- how to get help when having trouble paying bills or if having a dispute with a retailer
- what happens if their energy provider goes out of business.

These reforms may improve customer engagement, but further inclusion considerations include:

- cultural practices
- lived experience of disability
- low levels of literacy combined with complexity in energy markets, concepts and terms
- status quo bias for consumers to stay with their default retailer or plan.
- Market developments such as the rollout of smart meters and cost-reflective tariffs are adding additional layers of complexity to the market, making it harder for consumers to confidently engage. Other major barriers to consider include lack of trust towards energy institutions, providers and the government, and a lack of a single source of easy-to-understand information.[79]

Improving outcomes for all consumers, in particular consumers experiencing vulnerability, will need further targeted measures. The AER's *Towards energy equity* strategy focuses on consumers experiencing vulnerability, drawing on research by the Consumer Policy Research Centre on understanding experiences of vulnerability and how different regulatory approaches can support consumers experiencing vulnerability (section 7.6.7).

7.7.7 Customer satisfaction

A customer's level of satisfaction with retail energy markets depends on several factors and can be influenced by price, perceived value for money, reliability, customer service, confidence in engaging with the market, technology uptake, ability to switch and retailer behaviour. Following sharp reductions in customer satisfaction with energy companies in 2018, Energy Consumers Australia's consumer sentiment surveys indicate consumer satisfaction and confidence is slowly improving (Figure 7.20).

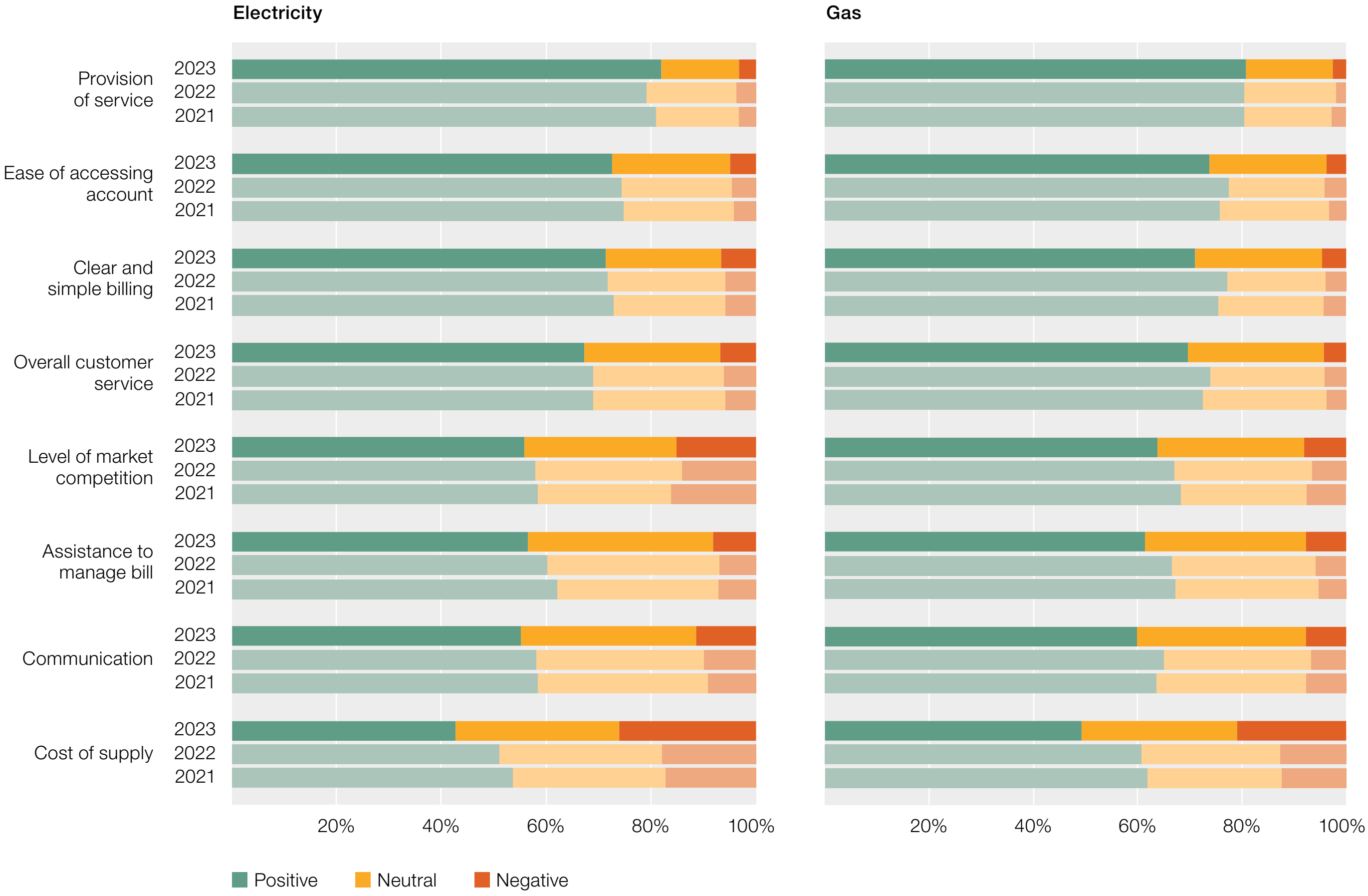
Results from the June 2023 survey indicated an overall increase in positive sentiment since 2021, but that the cost of supply was an increasing concern, with 'dissatisfaction with value for money' being one of the main reasons for customer switching (Figure 7.20). Most respondents (60%) were concerned that electricity and gas will become unaffordable for some Australians over the next 10 years.[80]

78 AER, Translated information to help energy consumers, Australian Energy Regulator, accessed 4 September 2023.

79 ECA, Evidence base to support the development of an effective communications campaign for energy consumers, Energy Consumers Australia, 27 July 2023.

80 ECA, Energy consumer sentiment survey June 2023, Energy Consumers Australia, accessed 2 July 2023.

Figure 7.20 Responses from energy consumer sentiment survey



Source: Energy Consumers Australia, *Energy consumer sentiment survey*, June 2023.

7.7.8 Consumer data right

The Australian Government is extending the Consumer Data Right (CDR) to cover the energy sector.[81] This will allow consumers to require their energy retailer to share their data with an accredited service provider such as a comparison site. Giving consumers the right to safely transfer their energy data (such as their current energy deal and consumption patterns) to third parties of their choice should make it easier for them to make product choices, while promoting competition between retailers.

Tier 1 retailers were required to comply with non-complex consumer data requests from 15 November 2022, and for complex requests from 15 May 2023. Compliance time frames for other retailers has varied between November 2021 and May 2024, depending on the number of customers and complexity of the data request.[82]

7.7.9 Price comparison websites and switching services

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. Independent price comparator websites are run by the AER and Victorian Government.

The AER operates an online price comparator Energy Made Easy (energymadeeasy.gov.au) 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. The website is available to consumers in jurisdictions that have implemented the Retail Law (Queensland, NSW, South Australia, Tasmania and the ACT). The Victorian Government operates a similar online price comparator, Victorian Energy Compare (compare.energy.vic.gov.au).

81 Australian Government, Consumer Data Right rollout, accessed 5 September 2023.

82 Australian Government, CDR in the energy sector, accessed 5 September 2023.

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.

In 2019 the ACCC and the AEMC recommended that the government prescribe a mandatory code of conduct to ensure price comparator and broker services act in the best interests of consumers.[83] The code would require the disclosure of commissions from retailers, show results from cheapest to most expensive, disclose the number of retailers and offers considered and provide a link to government comparator websites.

In 2022, a voluntary code was developed by the Energy Charter that partly addresses the ACCC and AEMC recommendations.[84] For example, the code provides for disclosures of commercial interests and other factors that could mislead consumers. However, it does not provide for sanctions for non-compliance or an independent dispute resolution process.

7.7.10 Customer switching

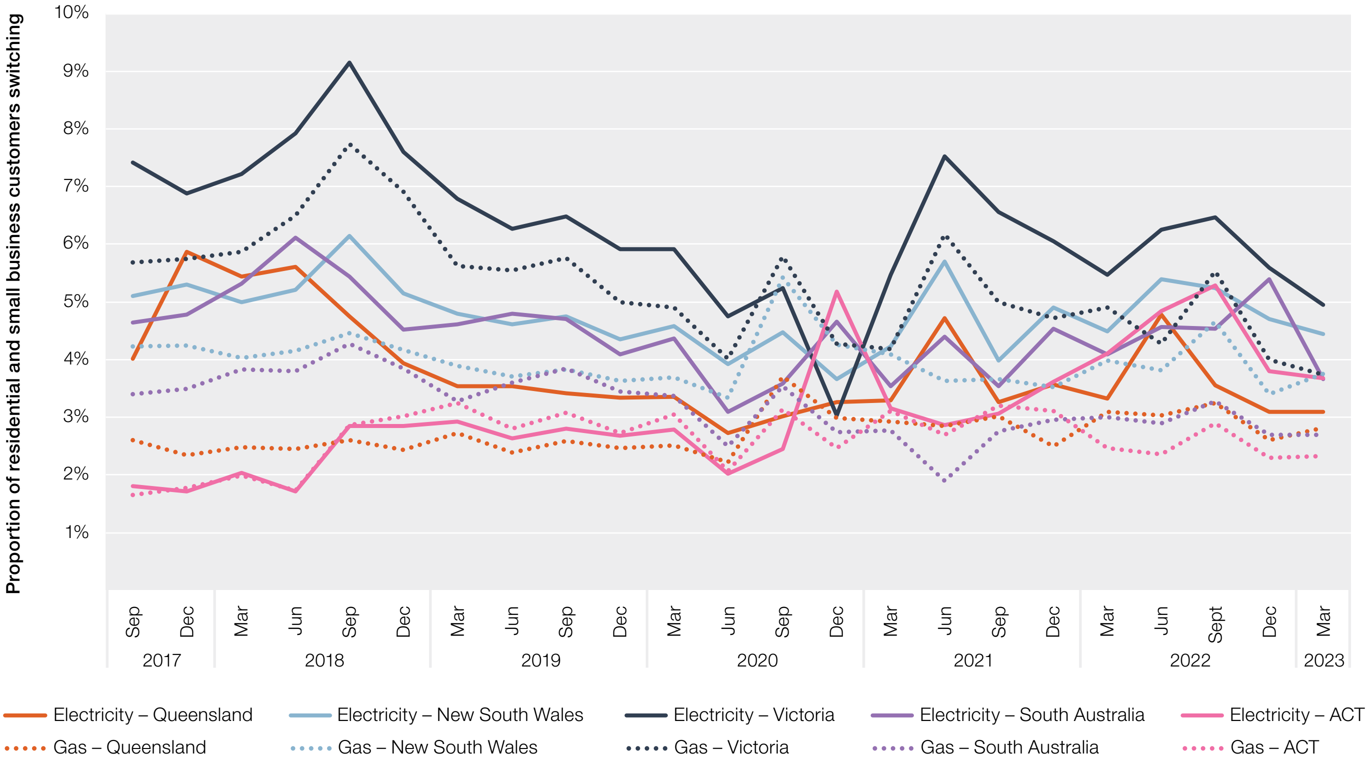
The rate at which customers switch retailers can be used to indicate the level of engagement in the market. But switching rates should be interpreted with care – switching may be low in a competitive market if retailers deliver good-quality, low-priced services that give customers no reason to change. Data on switching rates does not capture customer movements to new contracts with the same retailer, so it understates customer activity in the market. Conversely, switching data captures when an existing customer moves house and signs a new contract, even if it is with the same retailer (thus overstating customer activity).

Switching rates are typically lower in gas than in electricity. This may reflect fewer retailers participating in gas, meaning less choice and fewer potential customer savings. As a secondary fuel, gas is also typically a lower cost for consumers, so it may not receive the same attention.

83 ACCC, Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry – final report, Australian Competition and Consumer Commission, June 2018, accessed 15 September 2022, p. 282; AEMC, 2019 Retail Energy Competition Review, Australian Energy Market Commission, p. 282.

84 The Energy Charter, National Customer Code for Energy Comparators & Energy Moving Services, May 2022, accessed 15 September 2022.

Figure 7.21 Switching activity – small customers



Source: AER, *Quarterly retail performance report, Q3 2022–23*, June 2023.

Reforms introduced in December 2019 aimed to make it easier for customers to switch retailer by allowing them to transfer within 2 days of a cooling-off period expiring.[85] The intention of this change was to limit retailers relying on 'save' activity (retailers contacting customers who try to switch and giving them a better offer to encourage them to stay) rather than competing for outside customers by offering better products and services, and to allow customers faster access to prices and products they want.

In many markets, engagement by even a limited number of customers can drive lower prices and product improvements that benefit all consumers. This is less true for energy markets, where retailers can easily identify and then price discriminate against inactive customers. Many market offers include benefits that expire after one or 2 years – customers who do not switch regularly may find themselves paying higher prices than necessary. As a result, a critical part of the AER and other regulators' reform agenda is supporting consumers to understand impending changes in their energy contract and helping them find better offers, either with the same or an alternative retailer.

For example, the National Energy Retail Rules require retailers to notify small electricity and gas customers before any change in their benefits and provide advance notice of any price change.[86] In Victoria, retailers must also prominently display their 'best offer'[87] on customers' bills – every 3 months for electricity and every 4 months for gas – along with advice on how to access it. The Better Bills Guideline has brought this requirement to the rest of the NEM jurisdictions.

At the end of a fixed-term contract, retailers must inform customers in writing about their options, such as setting up a new contract or moving to another retailer. Retailers must ensure consumers are aware that they will be put onto a standing offer if they choose not to enter a new market contract with their current retailer.

Despite recent reforms focused on improving consumers' access to information about better offers, switching activity appears to be relatively flat. It is difficult to observe any improvement in competitive outcomes for consumers from switching data alone without considering other information, such as customer satisfaction and energy affordability metrics.

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85 AEMC, National Energy Retail Amendment (Reducing Customers' Switching Times) Rule 2019 No. 2, Australian Energy Market Commission, 19 December 2019, accessed 15 September 2022.

86 AEMC, National Energy Retail Amendment (Notification of the end of a fixed benefit period) Rule 2017 No. 2, Australian Energy Market Commission, 7 November 2017; AEMC, National Energy Retail Amendment (Advance notice of price changes) Rule 2018 no. 3, Australian Energy Market Commission, 27 September 2018.

87 Using a customer's past usage and comparing what they pay on their current offer against the cheapest generally available offer.

7.7.11 Retailer activity and barriers to entry

Following the significant market events of winter 2022, the steady growth of new retailers entering the market has slowed (Figure 7.16). The high, volatile wholesale prices and reduced liquidity in contract markets following these events has likely deterred new entrants. In turn, this can compromise innovation and competition in the market.[88] Therefore, ensuring an orderly energy transition to minimise the risk of similar future events is integral to maintaining effective competition in retail energy markets.

While those events were unprecedented, retailers have noted other barriers to entry, such as:

- reintroduction of standing offer price caps
- limited access to competitive risk management contracts as a barrier to entry or expansion in South Australia, with almost half of all retailers in 2020 considering that contract market liquidity in South Australia was too low[89]
- application of multiple regulatory frameworks – particularly in Victoria, which has a separate Energy Retail Code – due to the compliance costs this imposes; retailers considered the divergence of Victorian regulations from other jurisdictions has widened since 2019[90]
- access to reasonably priced gas and pipeline capacity as barriers to entry and expansion, especially in Victoria – the Pipeline Capacity Trading and Day Ahead Auction reforms that commenced in March 2019 sought to reduce these barriers by increasing transparency in the gas market and improving access to unused pipeline capacity through a day-ahead auction and a capacity trading platform.

7.7.12 Product differentiation

In a competitive market, retailers offer a range of products and services to attract and retain customers. Energy retailers compete primarily on price. But since the introduction of standing offer price caps and restrictions around discounting, retailers are looking to differentiate their products in other ways.

Retailers can differentiate products by offering more price certainty or, alternatively, rewarding customers who are willing to be flexible in how and when they use energy. As technology improves, more products offering energy management services or linking to batteries, solar PV output or electric vehicles, including delivering additional revenue to consumers through virtual power plants, are becoming more common (section 7.9).

Some retailers also offer other incentives, such as carbon offsets, sign-up discounts and product add-ons and rewards, or they partner with other businesses. Bundling of products such as phone and internet alongside energy has also increased.

Retailers have also applied conditional discounts to attract customers. The proportion of residential market customers with conditional discounts has steadily tracked down over the past 5 years. In 2022, 15% of residential customers in NSW had conditional discounts, compared with 65% in 2018.[91] Similar trends are observable across NEM regions. Recent analysis by the ACCC shows that customers on energy plans with conditional discounts pay similar prices to customers without conditional discounts, and that while plans with conditional discounts may be cheaper upfront, they can cost more in the longer term.[92]

7.7.13 Offer structures

Electricity retailers typically use one of 3 tariff structures in their offers:[93]

- Single-rate or 'flat' tariffs apply a daily (fixed) supply charge plus a simple usage charge for the electricity that a consumer uses.
- Time-of-use tariffs apply different pricing to electricity use at peak and off-peak times. Lower prices at off-peak times encourage consumers to shift their energy use to those times. It is intended to better reflect the prices retailers pay for electricity and encourage consumption during cheaper time periods.

88 ACCC, Inquiry into the National Electricity Market – November 2022 Report, Australian Competition and Consumer Commission, 23 November 2022.

89 AEMC, 2020 Retail Energy Competition Review, Australian Energy Market Commission.

90 AEMC, 2020 Retail Energy Competition Review, Australian Energy Market Commission.

91 ACCC, Inquiry in the National Electricity Market: June 2023 Report, Australian Competition and Consumer Commission, 30 June 2023.

92 ACCC, Inquiry in the National Electricity Market: June 2023 Report, Australian Competition and Consumer Commission, 30 June 2023.

93 Gas offers have less variability in tariff structure, with flat tariffs typically applied. Usage charges may vary based on the overall volume of gas consumed and the time of year.

- Demand tariffs charge a consumer based on their maximum point-in-time demand at peak times. Consumers can reduce their energy costs by shifting demand to off-peak periods. But even one day of high use at peak times will lead to higher charges for the whole billing period. This structure is intended to encourage consumers to stagger their energy use and reduce congestion on the network at peak times, also reducing system costs.

Retailers vary the levels of fixed and variable tariff components to appeal to different consumers. For example, consumers with low energy use may prefer an offer with a lower fixed charge but higher usage charges, while a consumer with flexibility around when they use energy may prefer an offer with lower off-peak charges or free weekend energy use.

Some retailers are trialling other price structures. Fixed price or subscription tariffs, where customers pay a (yearly or monthly) fee based on their typical electricity use, focus on simplicity and bill certainty. At the other end of the pricing spectrum, tariffs that pass through wholesale market spot prices allow consumers to dynamically interact with the wholesale market. These tariffs are best suited to consumers with battery storage who can adjust their use of grid-supplied electricity during high price periods.

New dynamic products are emerging as battery storage systems and electric vehicles become more affordable and as accessibility to consumer energy data improves (section 7.9). Some of these products have a time-of-use pricing structure but with rates set to encourage charging/discharging of batteries or electric vehicles at specific times. These products may also come with 'add-on' services, such as automated systems that learn consumers' electricity use patterns and charge/discharge batteries to maximise value. Some offers allow consumers to become part of a virtual power plant that aggregates multiple household solar and battery systems to provide power for network support or frequency control ancillary services or to engage in wholesale price arbitrage.

Similar to conditional discounting, dynamic products could cost consumers much more if they are unable to conform their energy use to the terms of the agreement. Because of this, they may only be suited to some types of consumers.

7.7.14 Non-price competition

In addition to competing on price and tariff structure, many retailers offer other incentives to entice customers. Financial incentives may include credit for continuing with a plan for a minimum period, for signing up online or through a partnering business or for referring a friend to the retailer.

Several retailers offer reward schemes that provide deals and discounts on a range of products and services. Non-financial benefits include carbon offsets for electricity use and product add-ons such as digital subscriptions. Retailers sometimes partner with another business to provide these additional benefits (for example, Alinta Energy partners with Kayo Sports to offer new customers a complimentary subscription to its online streaming service and Origin Energy partners with Woolworths' Everyday Rewards program).

Retailers increasingly offer products or services alongside electricity and gas to appeal to customers looking for the convenience of a single service provider. Internet and phone services, as well as solar PV and battery products, are offered by several energy retailers. AGL Energy also offers an electric vehicle subscription service.

7.8 Compliance, enforcement and customer complaints

Compliance and enforcement outcomes are 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 12 months following the significant market events of June 2022 posed new and greater challenges for consumers, with energy affordability and cost-of-living pressures mounting and impacting all consumers, but particularly those experiencing vulnerability.

In the 2022–23 financial year, the AER undertook a range of compliance and enforcement actions specifically relating to consumers experiencing vulnerabilities, such as financial disadvantage and health issues requiring life support equipment, and consumers in embedded networks (sections 7.8.2, 7.8.3 and 7.8.4). Key actions included:

- accepting a court enforceable undertaking by Trinity Place Investments Pty Ltd to contact and refund customers after it admitted to overcharging consumers for electricity by approximately $34,000 between December 2019 and January 2023
- receiving a $67,800 payment for one infringement notice issued to CovaU and a court enforceable undertaking for alleged failure to present the prices for its standing offers (also known as standard contracts) on its website

- releasing a joint compliance bulletin with the ACCC to remind retailers of their obligations around communicating pricing changes to their customers
- initiating enforcement proceedings against AGL and 3 subsidiaries, alleging that in 2020 and 2021 AGL failed to notify customers that they had been overcharged as a result of AGL making deductions through Centrepay payments.[94]

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.[95] AER's compliance functions cover all NEM regions, excluding the energy retail market in Victoria, which is regulated by the Essential Services Commission (Victoria).

7.8.1 Compliance and enforcement priorities for 2023–24

The AER has settled its compliance and enforcement priorities for 2023–24, which sees some updated areas of focus:

- improve outcomes for customers experiencing vulnerability, including by improving access to retailer 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
- support power system security and an efficient wholesale electricity market by focusing on generators' compliance with offers, dispatch instructions, bidding behaviour obligations and providing accurate and timely capability information to AEMO
- improve market participants' compliance with performance standards and standards for critical infrastructure
- clarify obligations and monitor compliance with reporting requirements under the new Gas Market Transparency Measures.

The AER will also act where serious issues impact consumers experiencing vulnerability, such as life support customers and customers impacted by family violence.

7.8.2 Customers in hardship

In the 2022–23 financial year, key compliance measures undertaken by the AER to better support customers in hardship included:

- continuing to work with community sector participants to develop a more proactive approach to identifying hardship trends, including delivery of capacity-building events to promote broader understanding of provisions such as hardship and payment plans
- provision of written materials to retailers reminding them of their obligations to promptly identify customers in financial difficulty and offer appropriate payment plans, including the AER's expectations of best practice for retailers engaging with consumers demonstrating hardship indicators
- issuing 4 retailers with compulsory information-gathering notices to check compliance with hardship protections and preparing to share learnings in late 2023.

7.8.3 Life support

The AER has an enduring priority to ensure retailers comply with obligations under the Retail Law that safeguard customers requiring life support equipment. All retailers and distribution network service providers operating under the Retail Law and Retail Rules are required to comply with these obligations – failure do so could have dangerous and even fatal consequences.

94 The AER alleges that 575 customers – most if not all of whom would have been experiencing vulnerability including financial disadvantage – were impacted, and that AGL failed to use best endeavours to refund the overcharges within the required time periods. Centrepay is a bill paying service whereby people receiving Centrelink payments, such as job seeker, can elect to have regular deductions made for essential goods and services.

95 Further information is available in the AER's Annual compliance and enforcement report 2022–23, 26 July 2023.

In August 2022, Aurora Energy paid $203,400 in penalties following the AER issuing 3 infringement notices relating to alleged breaches of retailer obligations for life support customers under the Retail Law, including failing to send:

- information packs to customers within 5 days of the customer advising of life support equipment requirements
- reminder notices to customers who had not returned a medical confirmation form
- a deregistration notice to customers before deregistering their life support registration.

7.8.4 Embedded networks

Many consumers in embedded networks (section 7.2.3), particularly those in residential parks, social housing and retirement and nursing homes, are likely to have lower incomes and be more likely to experience vulnerability. To improve outcomes for consumers in embedded networks, the AER introduced new obligations on exempt sellers under version 6 of the Retail Exempt Selling Guideline, released in July 2022.[96]

The updated guideline introduces a new hardship policy condition to ensure residential customers in embedded networks who experience payment difficulties due to hardship can access adequate support to better manage their energy bills.

To support compliance with the updated guideline, the AER:

- published a range of fact sheets clearly explaining the rights and obligations of exempt sellers and their customers[97]
- engaged widely with ombudsmen, industry and consumer groups, including through webinars and public forums
- published translated and easy English facts sheets for small businesses and consumers, outlining their rights and protections[98]
- published practical steps that off-market customers can take if their exempt seller fails, including alternative retailer options
- wrote to all exempt sellers to inform of their obligations under the new policy.

In October 2022, the AER published a draft Network Exemptions Guideline for public consultation.[99] Key concerns raised by stakeholders include the inherent vulnerability of consumers in embedded networks and the disadvantage associated with challenges they may face accessing competitive energy offers. The AER is reviewing the exemptions framework for embedded networks under the *Towards energy equity* strategy (section 7.6.7).

The AER maintains ongoing investigations relating to embedded networks, including an alleged failure by an embedded network operator to join an energy ombudsman scheme and alleged failures to undertake appropriate registrations with AEMO or AER while owning, operating or controlling an embedded network.

7.8.5 Customer complaints

Customer complaints can cover issues such as billing discrepancies, wrongful disconnections, the timeliness of transferring a customer to another retailer, supply disruptions, credit arrangements and marketing practices.

Customers can lodge a complaint directly with their retailer in the first instance. If a customer is unable to resolve an issue with their retailer, they can then take the complaint to the jurisdictional energy ombudsman scheme, which offers free and independent dispute resolution.

The number of electricity and gas complaints received by energy retailers decreased markedly across all jurisdictions in 2021–22 except in the ACT, where complaints increased by 28% (Figure 7.22). This trend was observable in the previous year, and may be due to COVID-19-related disruptions to the business operations of primary retailer ActewAGL and rising energy prices.

96 AER, Retail Exempt Selling Guideline, Australian Energy Regulator, 15 July 2022.

97 AER, AER releases factsheets on exempt selling, Australian Energy Regulator, 28 July 2022.

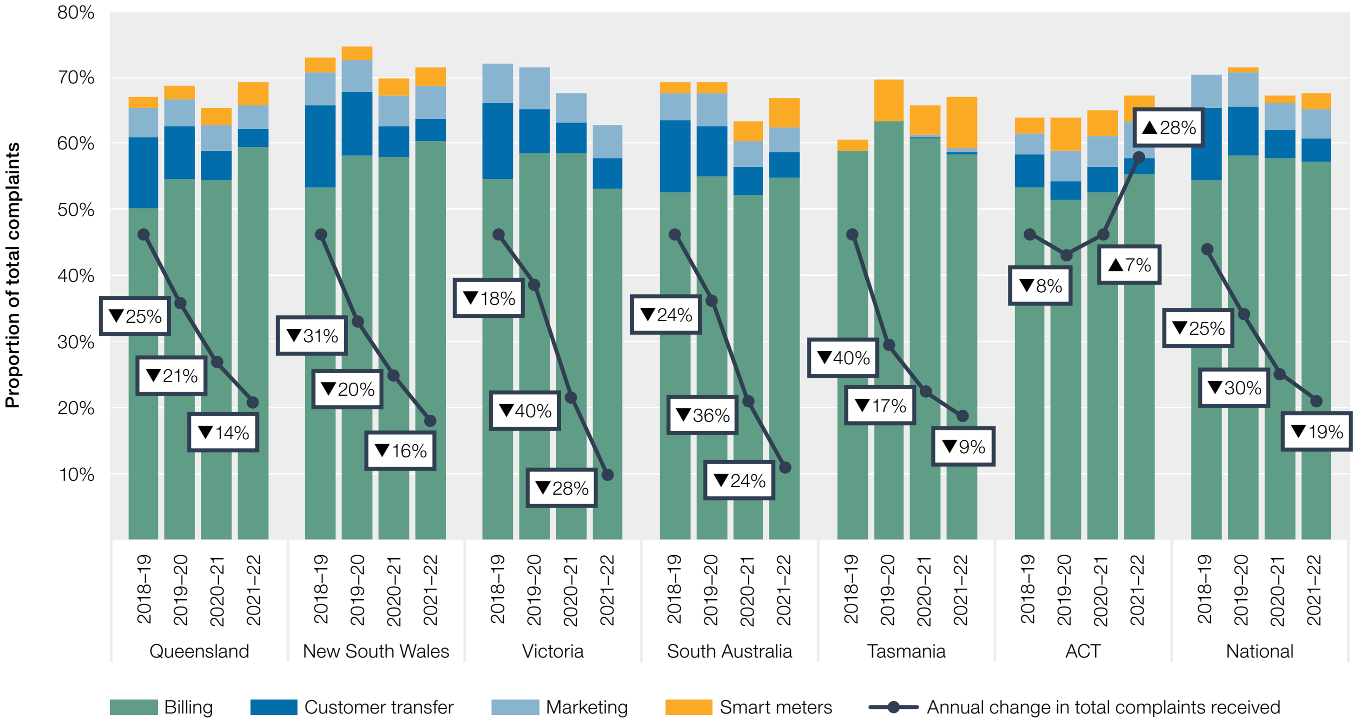
98 AER, Consumers in embedded networks, Australian Energy Regulator, accessed 30 August 2023.

99 AER, Draft Network Exemptions Guideline (version 7), Australian Energy Regulator, 31 October 2022.

The overall decline in complaints received by retailers is in line with stronger consumer protections introduced in response to the COVID-19 pandemic. The AER's Statement of Expectations (and the equivalent Victorian response) prevented disconnection, debt collection and credit default listing for customers experiencing financial stress. The continued trend of lower overall complaints following the formal cessation of those measures in June 2021 suggests ongoing behavioural change by retailers.

It is not surprising that billing complaints have increased in most jurisdictions as consumers' primary concern is unexpectedly high bills. Other billing issues include errors, incorrect tariffs, estimation of energy use, fees and charges, and back billing. The AER expects to see billing complaints continue to increase as retail energy prices continue to rise.

Figure 7.22 Complaints received by energy retailers

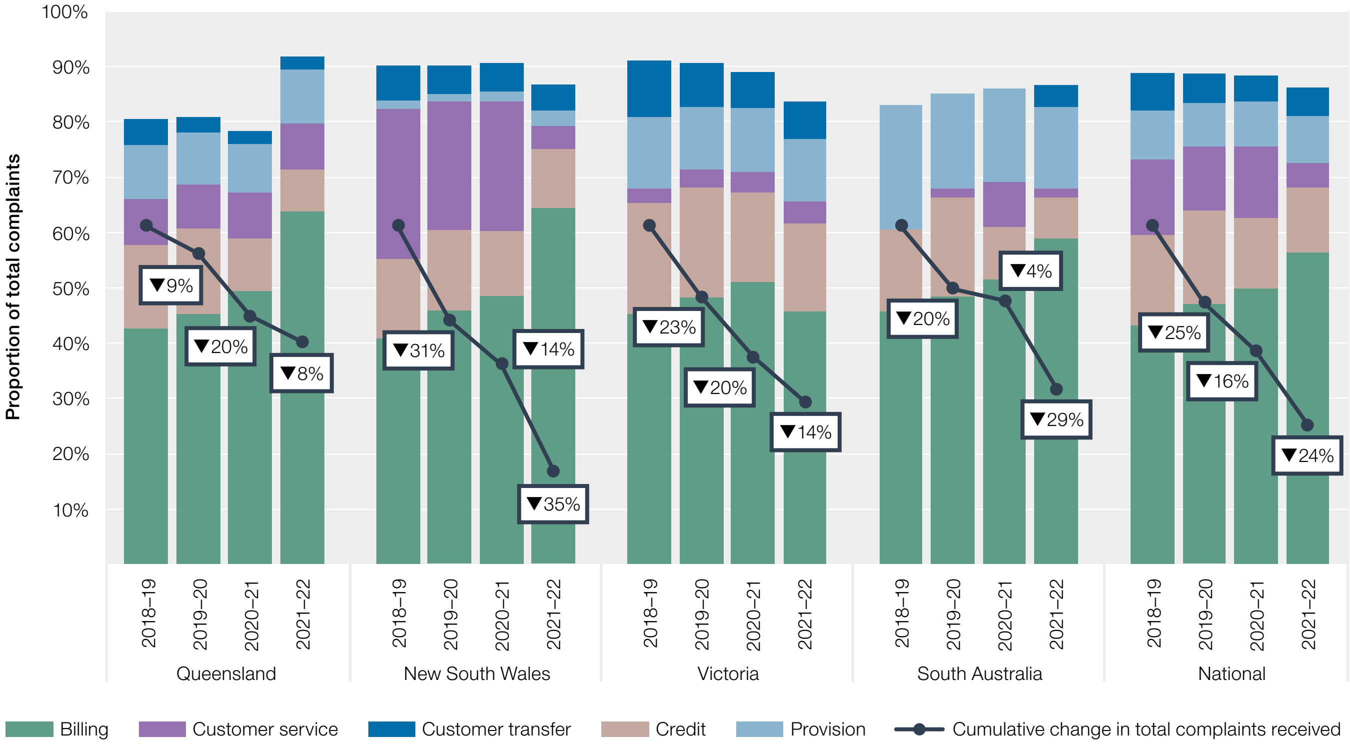


Note: Billing includes complaints about prices, billing errors, payment arrangements and debt recovery practices. Customer transfer includes complaints about timeliness of transfer, disruption of supply due to transfer and billing problems directly associated with a transfer. Marketing includes complaints about sales practices, advertising, contract terms and misleading conduct. Smart meters includes all complaints related to metering contestability. Complaints do not sum to 100% as some customer complaints defined as 'other' are not included in the above data. 'Other' complaints relate to issues outside the retailer's control – for example, complaints about price rises due to wholesale and network costs.

Source: AER, *Quarterly retail performance report, Q3 2022–23*, May 2023; ESC, Victorian energy market dashboard, data as of 30 June 2023.

The overall number of electricity and gas complaints received by jurisdictional energy ombudsmen schemes has also continued to trend downward, while complaints about billing have increased significantly (Figure 7.23). Because ombudsmen schemes require customers to raise complaints with their retailer in the first instance, assessing retailers' complaint data in conjunction with ombudsman complaint data can provide an indication of the effectiveness of retailers' dispute resolution outcomes.

Figure 7.23 Complaints received by jurisdictional energy ombudsmen



Note: Annual change in total complaints data includes all cases recorded by ombudsman schemes for electricity and gas industries. Annual change in total complaints data includes enquiries and complaints in relation to energy retailers, distribution networks and embedded network operators. Specific complaint type data includes all cases recorded by ombudsman schemes for electricity, gas and water industries. The proportion of water related complaints is immaterial.

Source: Annual reports by ombudsman schemes in Queensland, NSW, Victoria and South Australia.

7.9 The evolving electricity market

As the NEM rapidly transitions towards renewable energy generation, solutions such as energy storage and demand response are required to balance supply and demand. Demand response involves consumers changing their energy use in response to price or other market signals to contribute towards grid stability. Small household-level changes to grid consumption, when done at strategic times by large numbers of consumers, can deliver significant benefits to a system increasingly driven by variable renewable energy. Flexible demand response may also avoid the need to invest in dispatchable generation or grid-scale storage to ‘top up’ intermittent wind and solar generation.

As the NEM’s regulatory framework evolves to keep pace, and consumer energy resources (CER) such as rooftop solar, home batteries and electric vehicles become more widely adopted, consumers will have greater opportunities to participate in demand response. This will unlock benefits such as lower energy bills and credits in exchange for:

- shifting electricity use drawn from the grid to times of peak supply, such as the daytime ‘solar sponge’ when rooftop solar generation is peaking and demand is lower, and minimising use during periods of high demand and lower supply
- reducing overall energy drawn from the grid by optimising rooftop solar, home battery storage, electric vehicle batteries and energy efficiency measures
- selling electricity back to the grid at times when demand comes close to or outstrips supply.

This is great news for some consumers. Recent CSIRO research found that, when combined with home energy efficiency improvements, converting to electric vehicles and appliances could save an average household up to $2,250 per year.[100] Conversely, the CSIRO modelling found that consumers who continue to use cars and appliances powered by fossil fuels will face escalating bills.[101]

100 ECA, Stepping Up: A smoother pathway to decarbonising homes, Energy Consumers Australia, accessed 5 September 2023.

101 ECA, Stepping Up: A smoother pathway to decarbonising homes, Energy Consumers Australia, accessed 5 September 2023.

ECA recommends enhanced and coordinated planning across all tiers of government to avoid worsening the gap between households that can actively participate in transitioning energy markets and those that cannot. This would include measures such as:

- encouraging customer uptake of electric vehicles to leverage the ability for electric car batteries to optimise the grid and reduce energy prices
- reducing barriers for apartment dwellers and renters to electrify their homes
- carefully planning for the decline of household gas use, ensuring safeguards are in place for consumers less able to transition as prices likely escalate.[102]

In 2021, the Energy Security Board released the CER Implementation Plan[103], which outlines reforms that are required to unlock the benefits of the rapid uptake of consumer energy resources, while also reducing the risks created by the speed and scale of the change program to support their integration.

The ESB program has been aimed at ensuring consumer energy resources are optimised at a system-wide level so that:

- demand reductions, especially at peak periods, are maximised – taking pressure off generation requirements and local network constraints
- any network investments required to integrate consumer energy resources are efficient and cost-effective.

The effective integration of consumer energy resources into the electricity system presents a significant opportunity to lower electricity costs for all electricity consumers. By effectively integrating these resources, it is possible to avoid the need for more costly grid and generation investment. Increasingly, energy service providers are entering the market offering energy services that enable consumers to sell their electricity back into the grid at times when it is needed. However, the success of these services will require effective consumer engagement and for consumers to have trust and confidence that these new services will work for them.

Key objectives of the CER Implementation Plan include rewarding consumers for their flexible demand and generation, supporting energy market innovation, ensuring effective consumer protections are in place and allowing networks to accommodate consumer energy resources and manage security as well as providing visibility and tools to the system operator to operate a safe, secure, reliable system.

Through the plan, the ESB and market institutions have focused on identifying regulatory gaps and developing solutions to key issues, including governance and compliance with CER technical standards, consumer protection frameworks, CER interoperability and data transparency.

As the ESB's term draws to a close in 2023, emphasis will shift towards working with governments and sector stakeholders to progress reform and harness opportunities to effectively integrate consumer energy resources. It is important that market and regulatory arrangements support integration of consumer energy resources, demand-side participation and new technologies and do so in a way that empowers and protects consumers. Harnessing CER assets and the new energy services that they enable is critical for an orderly and cost-effective energy transition.

Key reforms that have been progressed under the plan are outlined in Table 7.3.

102 ECA, Stepping Up: A smoother pathway to decarbonising homes, Energy Consumers Australia, accessed 5 September 2023.

103 ESB, Integration of consumer energy resources (CER) and flexible demand, Energy Security Board, accessed 5 September 2023.

Table 7.3 Progress towards the CER Implementation Plan

Reform	Progress
Update governance and compliance arrangements for technical standards to ensure CER technologies can effectively integrate with the NEM and can communicate across different parties within the market, including AEMO, electricity distribution network service providers and retailers. Effective governance of standards helps to promote integration of consumer energy resources, as well as system security and reliability.	The AEMC has published a final report with recommendations for implementing CER technical standards, including their regulation by jurisdictions and energy market bodies.[104]
Provide policy direction and advice on the implementation of flexible export limits, allowing export limits on consumer energy resources to be varied based on available network capacity.	On 31 July 2023, the AER released a set of priority actions for flexible export limit, focusing on 4 themes of increased consistency across jurisdictions, increased transparency, stronger governance and increased consumer understanding.[105]
A proposed change to the electricity rules to allow consumers to engage a separate provider for their consumer energy assets (such as EV charging, solar panels and/or battery devices), and facilitate the active participation of consumer energy resources and flexible demand in the provision of market services.	On 27 July 2023, the AEMC published a directions paper that responded to stakeholder input to the proposed rule change, as well as a methodology paper for the cost-benefit analysis that will inform the rule change.[106] The Draft Determination is due 12 October 2023.
Review the consumer protections framework to ensure it remains fit for purpose in a transitioning retail energy market in which consumers can purchase new energy services (e.g. load management and virtual power plant services) that go beyond traditional retail services.[107]	The AER published an options paper in October 2022 that proposed 3 different regulatory models for stakeholder feedback, including taking a more tiered approach to the current framework to recognise the more diverse range of energy products and services, or moving to a principles-based or outcomes-based framework. The AER plans to provide advice to Energy Ministers in late 2023 on the case for reform of the consumer protections framework and potential reform models.[108]

7.9.1 Rooftop solar PV

The uptake of rooftop solar PV systems continues to grow across the NEM. There were over 274,000 new installations in 2022 and, as of January 2023, more than 2.9 million households and businesses have installed rooftop solar PV systems (Figure 7.24). Ongoing subsidies provided by the Australian Government and some state governments, combined with falling costs of solar PV systems, have helped to sustain the growth in new installations.

In 2021, all NEM regions set new records for installed capacity, with a 9% overall increase compared with the previous record set in 2020 (2,687 MW in 2021 and 2,470 MW in 2020). While the overall rate of installations across NEM regions slowed in 2022, this was likely due to supply chain issues and severe weather events.

As of 30 June 2023, there was a total 17,683 MW installed rooftop solar capacity registered across NEM regions (Figure 3.14). The Clean Energy Council anticipates rooftop solar installations to continue to increase in 2023 and beyond, as consumers are motivated to offset high energy prices.[109]

104 AEMC, Final report: Review into consumer energy resources technical standards, 21 September 2023.

105 AER, Review of regulatory framework for flexible export limit implementation, Australian Energy Regulator, accessed 5 September 2023.

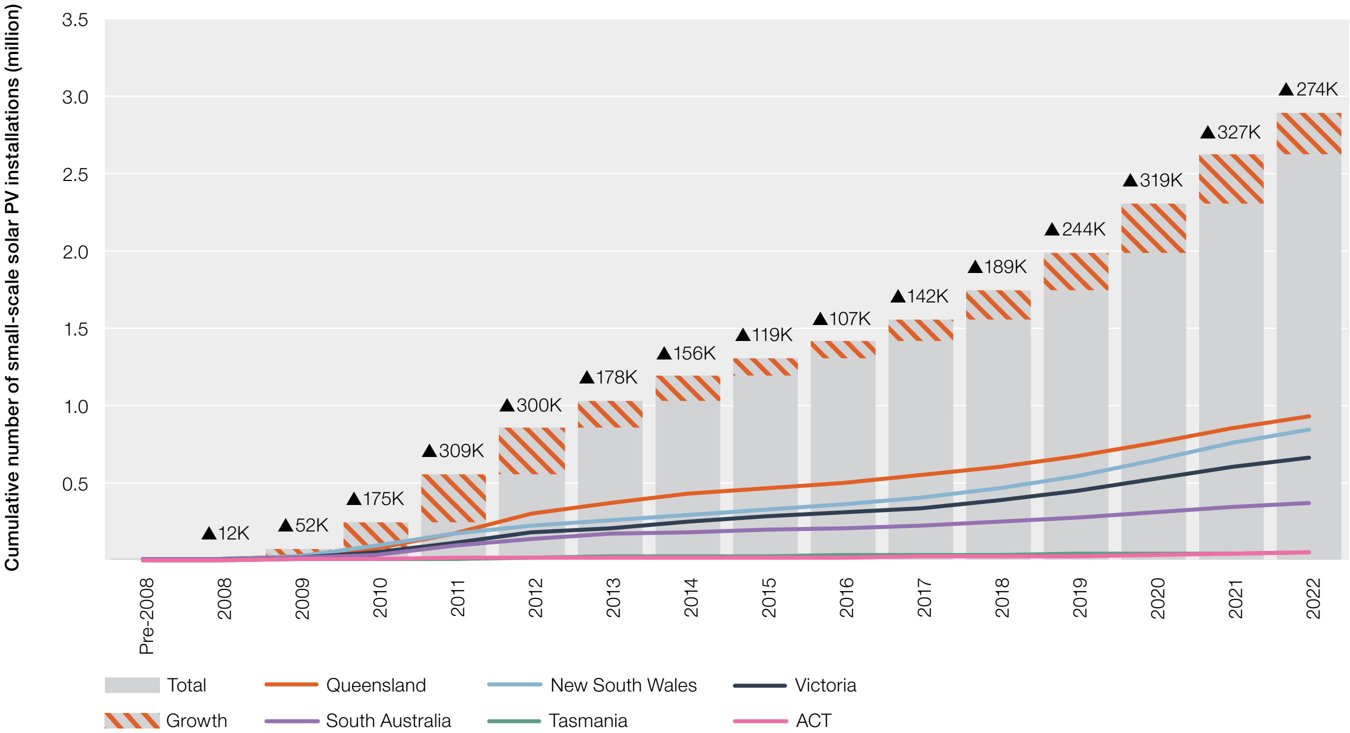
106 AEMC, Unlocking CER benefits through flexible trading, Australian Energy Market Commission, accessed 5 September 2023.

107 AER, Review of consumer protections for future energy services, Australian Energy Regulator, 9 December 2022.

108 AER, Review of consumer protections for future energy services, Australian Energy Regulator, 9 December 2022.

109 Clean Energy Council, Clean Energy Australia Report 2023, 17 April 2023.

Figure 7.24 Small-scale solar PV installations



Note: Small-scale generation units have a capacity of no more than 100 kilowatts (kW) and a total annual electricity output of less than 250 megawatt hours (MWh).

Source: Clean Energy Regulator, Postcode data for small–scale installations, data as of 30 June 2023.

Consumers generally sell unused electricity produced by solar PV systems to their retailer, in exchange for a feed-in tariff. This tariff is generally a flat per kilowatt hour value and is not linked to the actual value of the excess electricity to the NEM. Excess solar PV generation has created network congestion, resulting in some networks limiting the amount of excess electricity that consumers can export to the grid. Flexible export limits are intended to incentivise consumers to time their exports to when additional energy is needed.

7.9.2 Demand response through smart technology

Smart meters

Smart meters measure how much electricity is used at a premises and at what times. This data is shared in 5-minute or 30-minute intervals with the energy user, retailer and network operator. Access to real-time data allows for retailers to charge different prices depending on when the energy is consumed, which supports demand response and, ultimately, grid stabilisation. Many retailers now offer 'time-of-use' tariffs; low and in some instances zero tariffs for electricity used during peak solar generation – roughly between 10 am and 3 pm. Customers without smart meters generally cannot access time-of-use tariffs.

Smart meters also enable distribution network service providers to monitor power quality and act more rapidly when supply interruptions occur. A well-managed smart meter rollout can help optimise the grid, resulting in fewer outages, less need for costly infrastructure upgrades and increased penetration of cheaper renewable energy. As with other energy transition technologies, there is risk of some users being 'left behind', unable to take advantage of innovative technologies and retail offers if the smart meter rollout does not ensure appropriate safeguards are in place to protect consumers.

On 30 August 2023, the AEMC released its final report of the review of the regulatory framework for metering services.[110] The AEMC recommended a target that all NEM customers have a smart meter by 2030. The AEMC recommended that customers experiencing vulnerability are well supported, including with any property remediations necessary to install smart meters.[111] The reforms focus on:

- improving safeguards to consumers against unexpected cost increases and improved information for informed decision-making, as well as improved meter installation processes
- supporting effective use of smart meter data, by ensuring consumers can access their own energy use data in real-time and ensuring distribution network service providers can access power quality data in their service area to better support efficient network operation and planning, for consumers' long-term benefit.[112]

In Victoria, nearly all small customers have a smart meter (96% to 99% depending on customer segment and distribution network service provider) due to a mandated rollout of smart meters in 2006. In other NEM regions the rollout is slower, ranging from 26% to 66%.[113]

Smart technology and devices

Customers with smart meters can participate in demand response programs run by retailers, distribution network businesses or third-party energy providers. Demand response refers to a temporary shift or reduction in electricity use by consumers to support power system stability.

The simplest demand response programs offer consumers financial incentives to reduce electricity consumption when they receive an alert from their retailer or network service provider. More sophisticated programs include technologies that optimise solar PV and storage systems; and load control devices that automatically reduce power consumption from appliances such as air conditioning, hot water systems or pool pumps if required. Automating consumer participation in these programs is likely to result in increased uptake.

The Australian Renewable Energy Agency (ARENA) has funded several 'virtual power plant' trials that coordinate output from small-scale solar and battery systems to provide services equivalent to a large-scale generation plant.[114]

These opportunities provide a new source of competition across the supply chain. Demand response can be deployed in the wholesale or frequency control ancillary service (FCAS) markets to manage or limit price spikes and can also be used by networks to manage system constraints. A demand response mechanism that allows consumers to directly offer demand response into the wholesale market commenced in the NEM in October 2021 but is restricted to large customers. Small customers are limited to offering wholesale demand response through programs offered by their retailer.

However, dynamic demand also increases complexity and puts a heavier burden on retailers and consumers to behave responsively, rather than to passively receive electricity prices as set by AEMO and the NEM Dispatch Engine (NEMDE). Research shows that consumers already have a low level of engagement in the energy market and many do not have the energy literacy to make informed choices that best suit their needs. This then puts further reliance on retailers and other energy service providers to create and innovate energy products and services that either help consumers manage their energy use in response to price signals or make these decisions on behalf of consumers. In ECA's October 2021 Consumer Behaviour Survey, only 67% of respondents in Victoria knew they had a smart meter, despite Victoria installing smart meters in more than 97% of households through a targeted installation scheme.[115] At the Energy and Climate Change Ministerial Council meeting in February 2023, Ministers agreed on a national energy literacy program to be further explored by Energy Consumers Australia to address knowledge gaps and ensure consumers are exposed to consistent, targeted and accessible messaging.[116]

Where the benefits rely on consumers purchasing different forms of technology, this will exacerbate equity gaps between consumers – for example, between consumers who own their home and consumers who rent.

110 AEMC, Review of the regulatory framework for metering services – Final report, Australian Energy Market Commission, 30 August 2023.

111 For example, some properties – particularly those in apartment complexes – may have insufficient meter board space for the newer, larger smart meters, or the meter box may have asbestos components, requiring costly upgrades before a smart meter can be installed.

112 AEMC, Review of the regulatory framework for metering services – Final report, Australian Energy Market Commission, 30 August 2023.

113 The proportion of small customers with smart meters varies by customer segment and DNSP. For the latest data see AER, Electricity DNSP Operational performance data 2006-22, Australian Energy Regulator, 7 July 2023.

114 ARENA, At a Glance, Australian Renewable Energy Agency, 30 June 2023.

115 ECA, Consumer Behaviour Survey, Energy Consumers Australia, October 2021, accessed 15 September 2022.

116 DCCEEW, Energy and Climate Change Ministerial Council Meeting – 24 February 2023, Department of Climate Change, Energy, the Environment and Water, accessed 5 September 2023.

Recent regulatory reforms have focused on ensuring the arrival of new technologies and consumer energy resources are integrated into the regulatory framework. However, as observed in the energy use section of this chapter, there is a risk that the focus on active or 'digital' energy efficiency has meant that other forms of energy efficiency (such as thermal efficiency of housing, which has the benefit of being 'set and forget') may be lagging.

To offset the widening equity gap between different types of consumers, measures will also need to be accessible by low-income households or consumers experiencing barriers to engagement. These barriers could arise through factors such as not having the literacy or numeracy skills to navigate the energy market, dealing with ill physical or mental health, or having limited financial resources or autonomy over their energy use.

Home batteries and electric vehicles

Battery storage and smart appliances enable consumers to optimise their electricity use, reducing the amount of power they need to withdraw from (and inject into) the network. Batteries are usually paired with rooftop solar PV systems. While only 6.6% of the solar PV systems installed in the NEM in 2022 had an attached battery system, this is a significant improvement over 2021, where only a little over 3% had an attached battery system.[117]

Electric vehicles, like dedicated batteries, can draw electricity from the grid or rooftop solar, and potentially draw energy from the vehicle battery to power the home or sell back to the grid. Electric vehicle uptake in Australia has been slower than in other developed countries, but the number of electric vehicles is beginning to accelerate as costs fall and charging infrastructure is expanded. There were almost 40,000 electric vehicles sold in Australia in 2022, up from around 21,000 in 2021 and 6,900 in 2020.[118]

Although electric vehicles are still a small part of the market, electricity retailers are beginning to develop offers that reflect the specific needs of electric vehicles, including price incentives to encourage charging and discharging of batteries or electric vehicles at strategic times to support grid stability. The ESB has consulted on how to integrate electric vehicles in its implementation plan for consumer energy resources on the expectation that electric vehicle uptake will increase. Earlier this year, the Australian Government released its National Electric Vehicle Strategy. The strategy sets out the Government's vision to increase the uptake of electric vehicles to reduce emissions and improve the wellbeing of Australians.[119]

7.9.3 Standalone power systems

Standalone power systems generate and distribute electricity but are not physically connected to the main grid. Standalone power systems can serve an individual or community (microgrids) and usually consist of renewable generation units, battery storage and back-up generation. Improvements in energy storage and renewable generation technology are enabling more customers to take up this form of energy supply. In some regional and remote areas, standalone power systems are a lower cost option than connecting to the grid.

Before 2022, standalone power systems were not covered by the Retail Law and Rules, which meant those customers were not afforded the same protections and reliability standards as NEM customers. In early 2021, energy ministers began consulting on regulatory changes to make it easier for distribution network businesses to offer standalone power systems (where economically efficient to do so) while maintaining appropriate consumer protections and service standards.[120]

From 1 August 2022, standalone power systems were made more accessible and safer for consumers. Distribution network service providers can now connect customers to a standalone power system where it may be cheaper, safer and more reliable than connection to the grid. These will become regulated standalone power systems and customers connected to regulated standalone power systems receive an equivalent level of consumer protections and will pay for their electricity in the same way as grid customers.

117 Clean Energy Regulator, Solar PV systems with concurrent battery storage capacity by year and state/territory, data at 30 June 2023, accessed 4 September 2023.

118 Electric Vehicle Council, State of Electric Vehicles, July 2023, accessed 5 September 2023.

119 DCCEEW, National Electric Vehicle Strategy, accessed 5 September 2023.

120 Energy Ministers, Stand–Alone Power Systems Priority 1 Rule Amendments, Explanatory note for stakeholder consultation, Department of Climate Change, Energy, the Environment and Water, March 2021, accessed 15 September 2022.

Abbreviations

1P	proven (gas reserves)
2P	proved plus probable (gas reserves)
3P	at least 10 per cent probability of being commercially recoverable (gas reserves)
5MS	5-minute settlement
ABS	Australian Bureau of Statistics
ACCC	Australian Competition and Consumer Commission
ACT	Australian Capital Territory
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AFMA	Australian Financial Markets Association
AGN	Australian Gas Networks
APLNG	Australian Pacific LNG
ARENA	Australian Renewable Energy Agency
ASX	Australian Securities Exchange
BESS	battery energy storage system
C&I	commercial and industrial
CBA	cost–benefit analysis
CBD	central business district
CCGT	combined cycle gas turbine
CCP	Consumer Challenge Panel
CEFC	Clean Energy Finance Corporation
CER	consumer energy resources
CESS	capital expenditure sharing scheme
CoAG	Council of Australian Governments
COVID-19	coronavirus disease 2019
CPI	consumer price index
CSG	coal seam gas
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CSIS	customer service incentive scheme
DEIP	Distributed Energy Integration Program
DER	distributed energy resources
DMIA	demand management innovation allowance
DMIS	demand management incentive scheme

DMO	default market offer
DWGM	Declared Wholesale Gas Market
EBSS	efficiency benefit sharing scheme
ECA	Energy Consumers Australia
ENA	Energy Networks Australia
EOI	expression of interest
ESB	Energy Security Board
ESC	Essential Services Commission
EV	electric vehicle
FEX	FEX Global
FCAS	frequency control ancillary services
GAP	Gas Acceleration Program
GJ	gigajoule
GLNG	Gladstone LNG
GSH	Gas Supply Hub
GSL	guaranteed service level
GST	goods and services tax
GW	gigawatt
GWh	gigawatt hour
Hz	Hertz
HHI	Herfindahl–Hirschman index
ICT	information and communication technology
IRENA	International Renewable Energy Agency
ISDA	International Swaps and Derivatives Association
ISP	integrated system plan
km	kilometre
kW	kilowatt
kWh	kilowatt hour
LCOE	levelised cost of electricity
LNG	liquefied natural gas
MAIFI	momentary average interruption frequency index
MJ	megajoule
MOS	market operator services
MLF	marginal loss factor
MLO	market liquidity obligation
$MtCO_2$-e	million metric tonnes of carbon dioxide equivalent
mtpa	million tonnes per annum
MW	megawatt
MWh	megawatt hour
NEM	National Electricity Market
NSW	New South Wales
NT	Northern Territory
OCGT	open cycle gas turbine
OTC	over-the-counter
PJ	petajoule

PST	pivotal supplier test
PV	photovoltaic
QCLNG	Queensland Curtis LNG
RAB	regulatory asset base
RERT	reliability and emergency reserve trader
RET	Renewable Energy Target
REZ	renewable energy zone
Retail Law	National Energy Retail Law
RIN	regulatory information notice
RIT	regulatory investment test
RIT–D	regulatory investment test – distribution
RIT–T	regulatory investment test – transmission
RRI	Rate of Return Instrument
RRO	Retailer Reliability Obligation
SAPS	stand-alone power systems
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
STPIS	service target performance incentive scheme
STTM	Short Term Trading Market
TJ	terajoule
TJ/d	terajoules per day
TW	terawatt
TWh	terawatt hour
UNGI	Underwriting New Generation Investment program
VPP	virtual power plants
WACC	weighted average cost of capital

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