1 Market overview

This chapter describes recent developments across our energy markets, providing a brief summary of the key market outcomes explored in more detail in chapters 2 to 6.

1.1 National Electricity Market

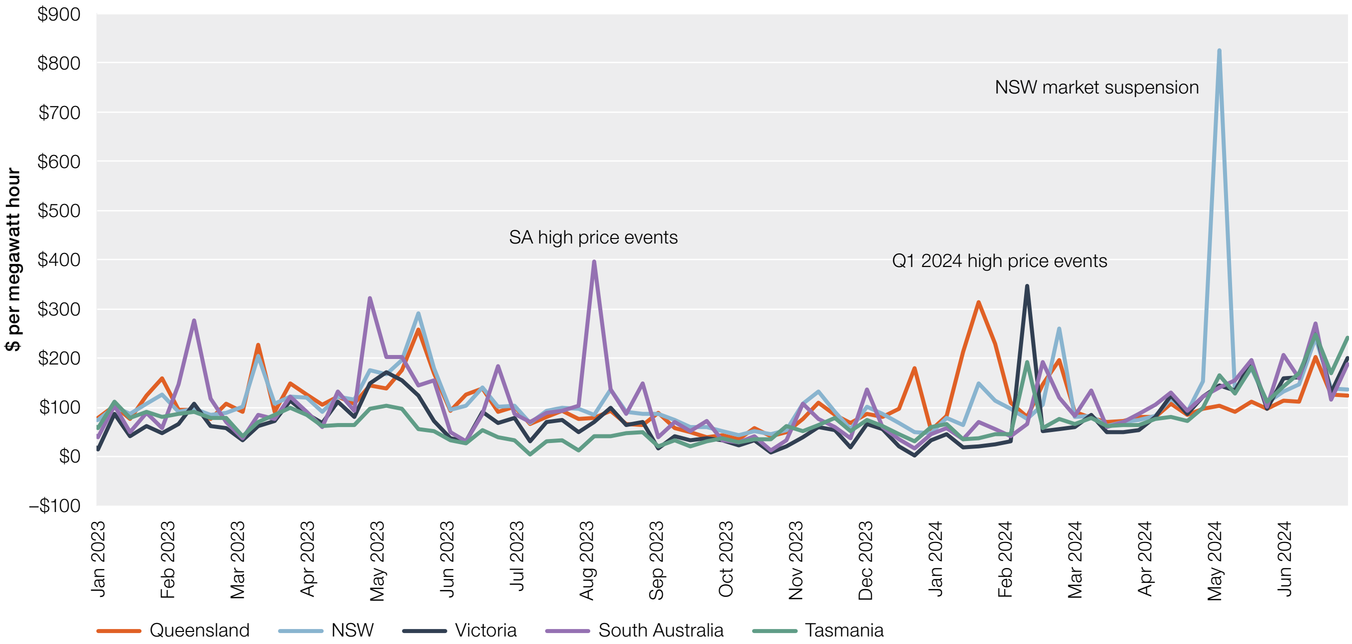
The National Electricity Market (NEM) continues to transition from a centralised system of large fossil fuel (coal and gas) generation towards an array of smaller scale, widely dispersed wind and solar generators, hydro-electric generation, grid-scale batteries and demand response. Entry of planned new capacity slowed in 2023–24 as projects have been delayed. 2.1 gigawatts of large-scale generation and storage were commissioned across the year. However, a substantial amount of the capacity commissioned to enter the market over 2023–24 is now forecast to enter the market in 2024–25, reaching 6.4 gigawatts at full output.

Wholesale electricity prices over 2023–24 were highly volatile, with fairly moderate conditions punctuated by high price periods across the NEM. Queensland recorded record peak demand levels during the hot and humid summer, which drove up prices. Meanwhile, storm damage affected supply in southern states in February 2024, driving up prices in Victoria. During the April to June 2024 quarter, periods of unusually cold weather, low wind output and lower water storage levels combined to increase demand and reduce supply, pushing up prices in all regions (Figure 1.1).

In New South Wales (NSW), network and generator outages, combined with generator rebidding, drove high price events in early May. As a result, the cumulative price threshold was breached for the first time since 2022. AEMO suspended the NSW market, a safety net mechanism that triggers administered prices in order to stabilise wholesale spot prices and reduce financial stress for market participants.

Despite these high price events and overall volatility, wholesale prices were lower across all regions of the NEM in 2023–24 than in the previous year, influenced by record high prices during winter 2022.

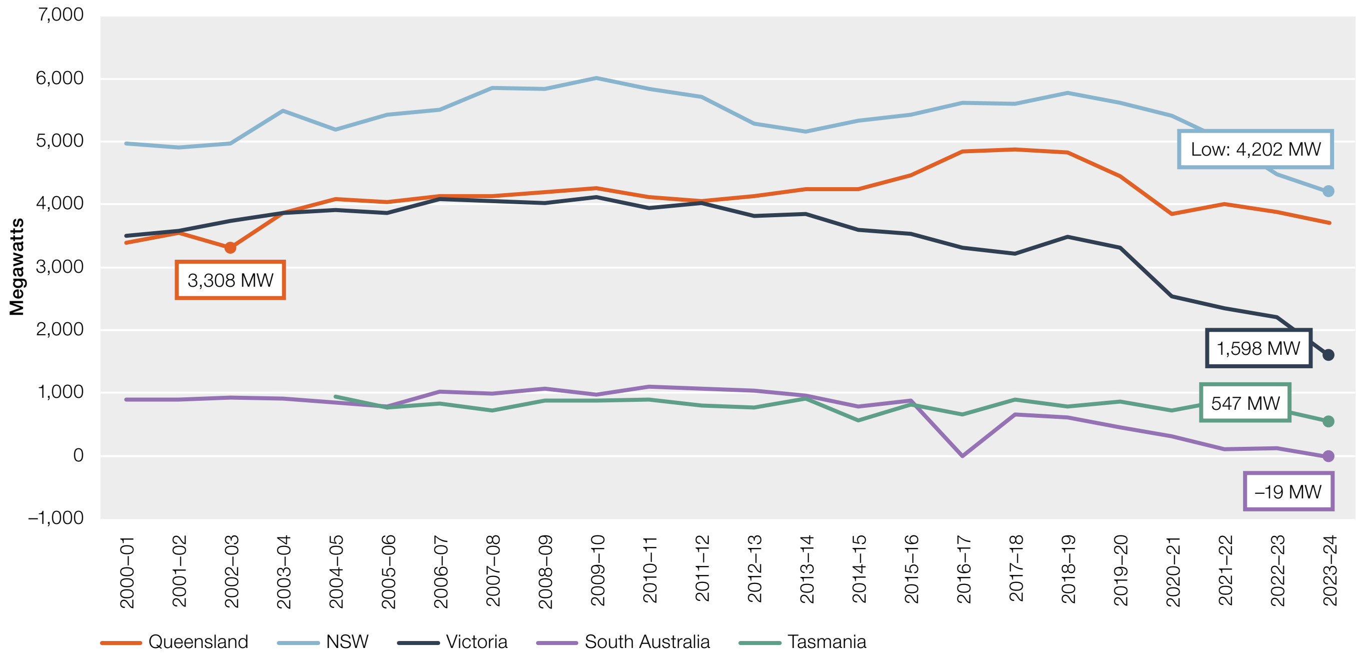
Figure 1.1 Weekly wholesale electricity prices



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

In 2023–24, record lows in minimum demand were set across all regions except Queensland. Output from rooftop solar continues to increase in line with ongoing installations by households, further reducing grid demand during the middle of the day across the NEM (Figure 1.2).

Figure 1.2 Minimum grid demand

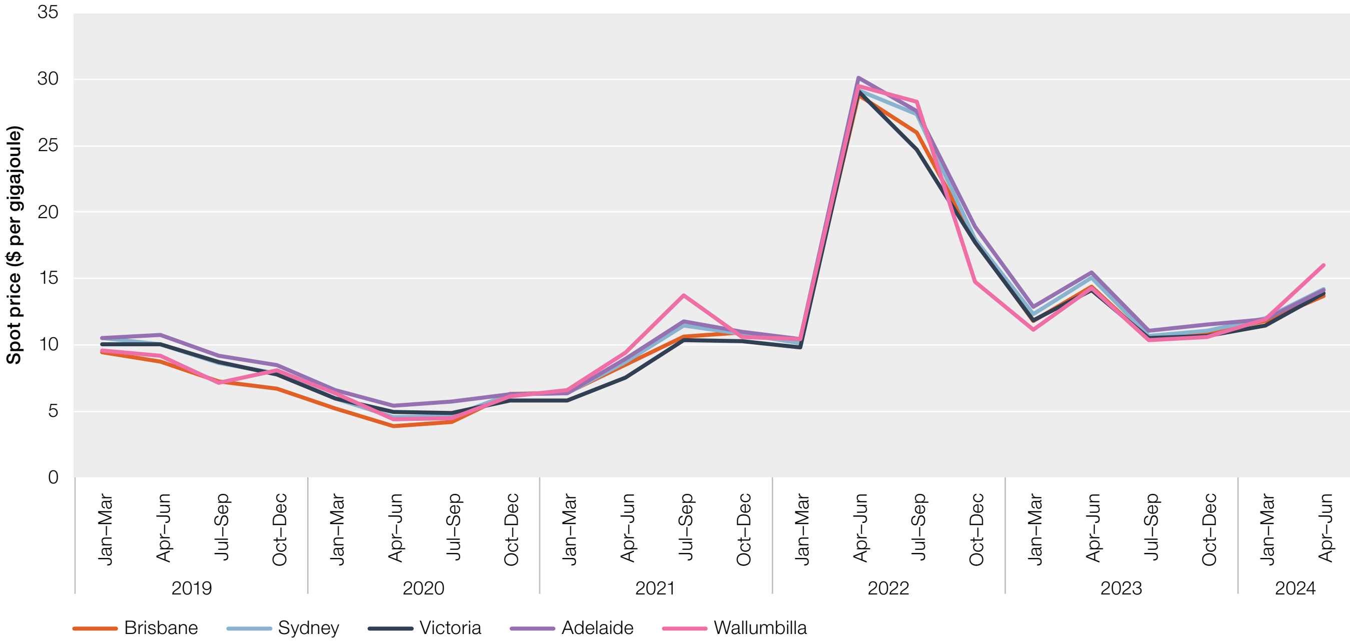


Note: Minimum 30-minute grid demand (including scheduled and semi-scheduled generation, and intermittent wind and large-scale solar generation) is for any time during the year. Data excludes consumption from rooftop solar systems. The low value for South Australia in 2016–17 is due to the Black System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

1.2 Gas markets in eastern Australia

Gas prices stabilised from mid-2023, with milder winter conditions lowering demand and influencing a significant reduction from the unprecedented high prices of mid-2022. Prices remained stable until a stretch of cold weather and constrained southern production in late May 2024 put upwards pressure on the market (Figure 1.3).

Figure 1.3 Eastern Australian gas market prices

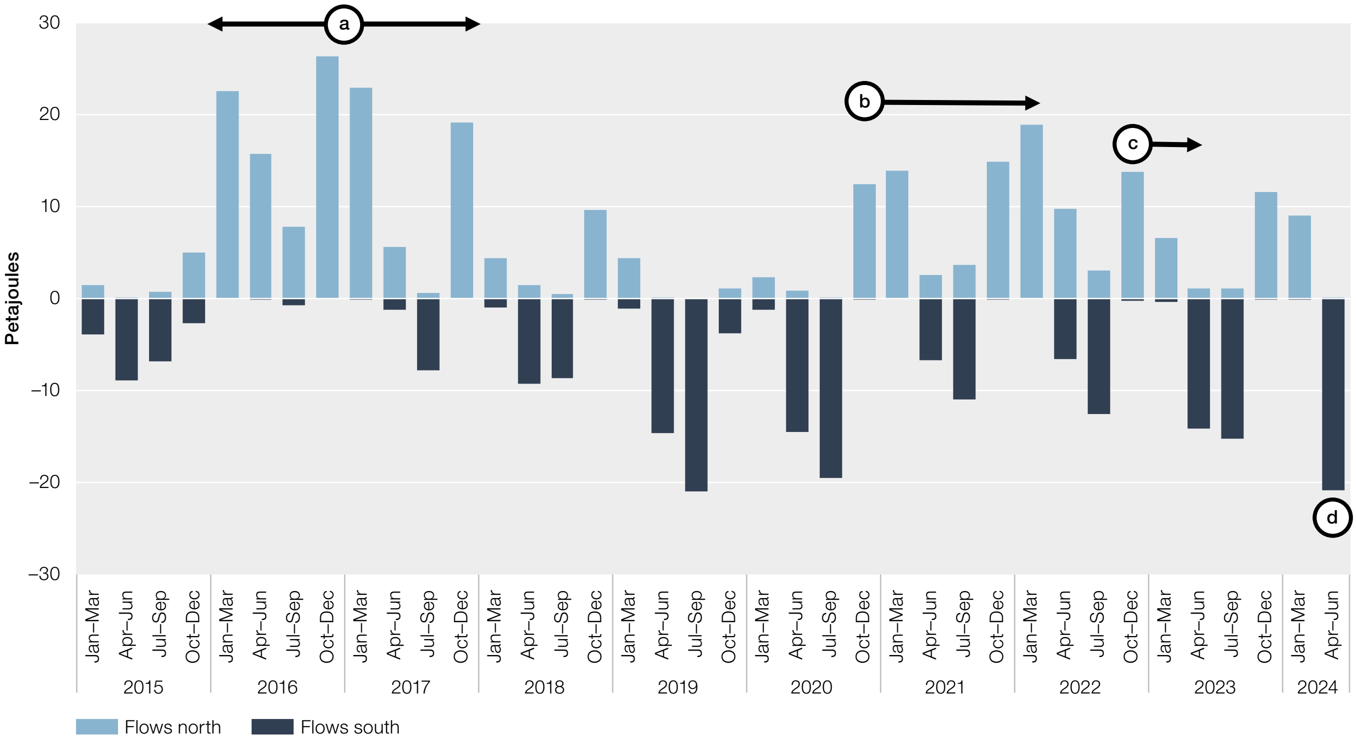


Note: The Wallumbilla price is the volume weighted average price for day-ahead, on-screen trades at the Wallumbilla gas supply hub. Brisbane, Sydney and Adelaide prices are ex-ante. The Victorian price is the average daily weighted imbalance price.

Source: AER analysis of gas supply hub, Short Term Trading Market and Victorian Declared Wholesale Gas Market data.

In 2023–24, the seasonal pattern in gas markets continued, with gas flowing north to export markets during summer and south in winter to meet demand for heating. This remained the case in early 2024, despite reduced production from the Longford facility in Victoria, with exports for the quarter at the highest level observed for the start of the year.

Figure 1.4 North–south gas flows in eastern Australia



Note: Flows on the QSN (Queensland / South Australia / New South Wales) Link segment of the South West Queensland Pipeline (flowing through the Moomba location).

a 2016 to 2017: Increased southern production to meet LNG demand.

b Late 2020 onwards: record LNG exports continue to rise.

c Late 2022 onwards: LNG exports reduce closer to 2019 levels.

d Winter 2024: additional compressors commissioned on the Moomba to Sydney Pipeline and South West Queensland Pipeline in May and June. Expanded capacity facilitates record monthly gas flows south in June (close to 11 PJ).

Source: AER analysis of Gas Bulletin Board data.

In late 2023, demand for gas reached a record low, alongside lower levels of gas-powered generation. While this continued over the summer, the second quarter of 2024 saw spikes in gas-powered generation output to offset low wind and solar generation. This demonstrates the interdependencies between our electricity and gas markets.

In mid-2024, transportation capacity upgrades were completed on the north–south pipeline corridor to increase the ability to flow more gas south and reduce existing gas supply constraints. This delivered more supply from Queensland to southern markets. As a result, and due to elevated southern market demand over winter, record gas flows south from Queensland were evident in June 2024 (Figure 1.4).

Concerns about potential gas shortfalls have prompted a range of potential market responses. These include further gas development, LNG imports, transmission pipeline solutions and demand response. AEMO's *Gas Statement of Opportunities* reports have repeatedly highlighted the risk of both short-term and long-term shortfalls in the east coast gas markets, particularly due to the depletion of legacy gas fields in Victoria's offshore Gippsland Basin. However, several projects that could help fill the supply gap have either stalled, been postponed or abandoned.

In response to concerns around the adequacy of gas supplies to meet domestic demand and prolonged price volatility seen in 2022, the Australian Government and some state and territory governments have intervened in the market. These interventions have included measures to increase supply stability, reduce demand, limit price volatility and provide additional monitoring powers to market bodies.

In addition, 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. Since 2017, the Minister has been able to determine if a shortfall is likely in the following year and may revoke export licences if necessary to preserve domestic supply.

Following the introduction of this mechanism, Queensland's LNG producers entered agreements with the government, committing to offer uncontracted gas on reasonable terms to meet expected supply shortfalls. They also committed to offer gas to the Australian market on competitive market terms before offering any uncontracted gas to the international market. In 2023, following a review by the Australian Government, the scheme was extended until 2030. The changes made to the ADGSM introduced more flexibility to activate the mechanism to secure domestic supply on a quarterly basis, rather than the yearly timeframe in the previous regulations.

The new reforms came into place on 30 March 2023 with a newly negotiated Heads of Agreement with east coast LNG exporters in place until 1 January 2026. To prevent a gas supply shortfall, an additional 157 petajoules of gas was committed to the east coast market in 2023.

1.3 Electricity networks and regulated gas pipelines

Over the 12-month period to 30 June 2023, electricity network service providers collected $12.5 billion in revenue for delivering core regulated services,[1] 2.9% less than in the previous year. Over the same period, $1.6 billion in revenue was collected for providing access (selling capacity) to parties needing to transport gas, 9% less than in the previous year.[2]

As at 30 June 2023, the total combined value of the regulatory asset base (RAB) for electricity network service providers was around $116 billion, an increase of $1.7 billion (1.5%) from the previous year. The total combined value of the capital base for gas pipeline service providers was around $13.3 billion, an increase of $31 million (0.2%) from the previous year.

As part of the revenue determination process, network service providers submit expenditure proposals. The AER assesses the proposals and determines efficient investment requirements over the forthcoming regulatory period. Efficient investment approved by the AER is added to the RAB (or 'capital base' for regulated gas pipelines) at the end of each regulatory period on which the service provider earns returns. Over time, depreciation on existing assets is deducted from the asset base and returned to shareholders. As such, the value of a service provider's asset base[3] will grow over time if approved new investment exceeds depreciation.

Over the 12-month period to 30 June 2023, electricity network service providers invested $6.8 billion on capital projects, $1.1 billion (20%) more than in the previous year. The recent increase in growth-related expenditure in the electricity transmission network has been driven by Transgrid's (NSW) substantial investment in Project EnergyConnect – a major new interconnector between NSW and South Australia – stage 1 of which is expected to be completed in December 2024.[4]

Significant investment in the electricity transmission network is expected to continue over the next few years, with early works commencing on the VNI West project between Victoria and NSW and the AER approving a $4.0 billion cost application for the Humelink project in NSW. Subject to a financial investment decision by the proponent, Humelink is likely to be completed by 2026–27 (Figure 1.5).

Despite the increased spend on capital projects, network service providers spent $372 million (2.9%) less on electricity network costs and $165 million (9%) less on gas pipeline costs than in the previous year. As the RAB/capital base is only adjusted at the end of the regulatory period and not on an annual basis, the year-on-year relationship between revenue and capital expenditure incurred is not linear.

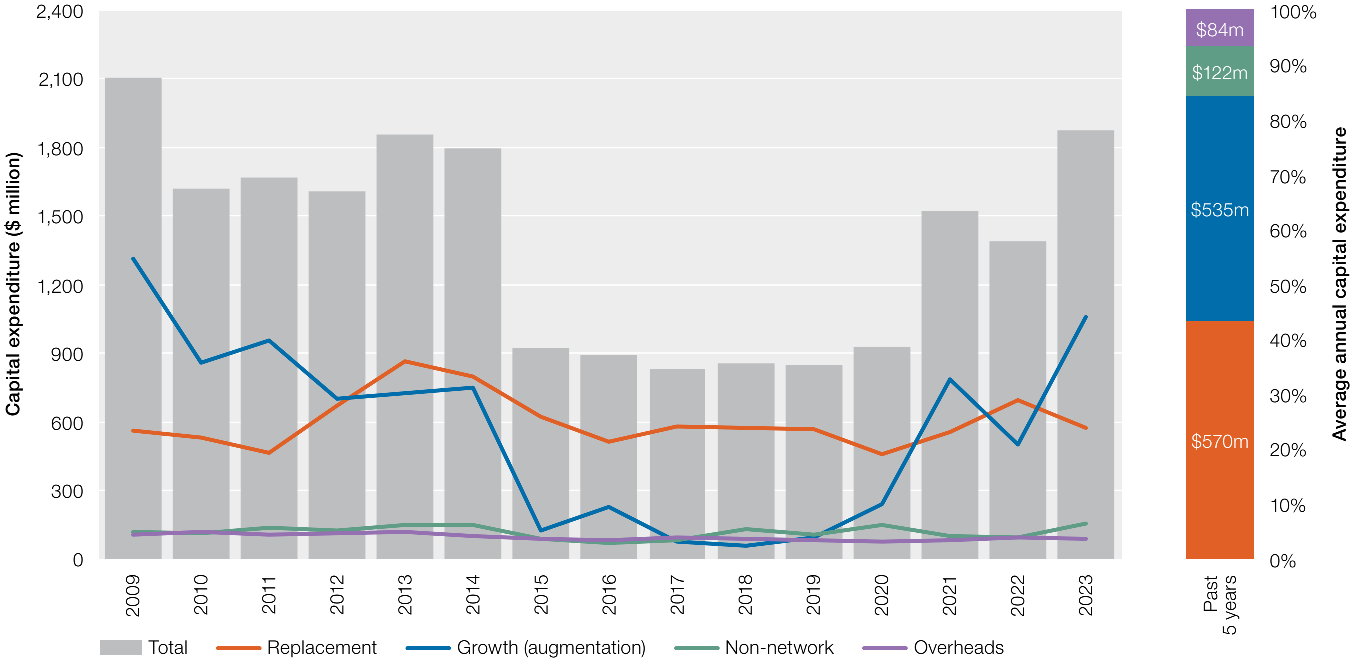
1 Prescribed transmission services for transmission network service providers and standard control services for distribution network service providers.

2 Excludes revenue earned by Amadeus Gas Pipeline (Northern Territory). Amadeus Gas Pipeline's actual revenue is confidential because it contains commercially sensitive information.

3 Asset bases and capital bases are indexed using actual inflation.

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

Figure 1.5 Drivers of capital expenditure – electricity transmission networks (aggregate)



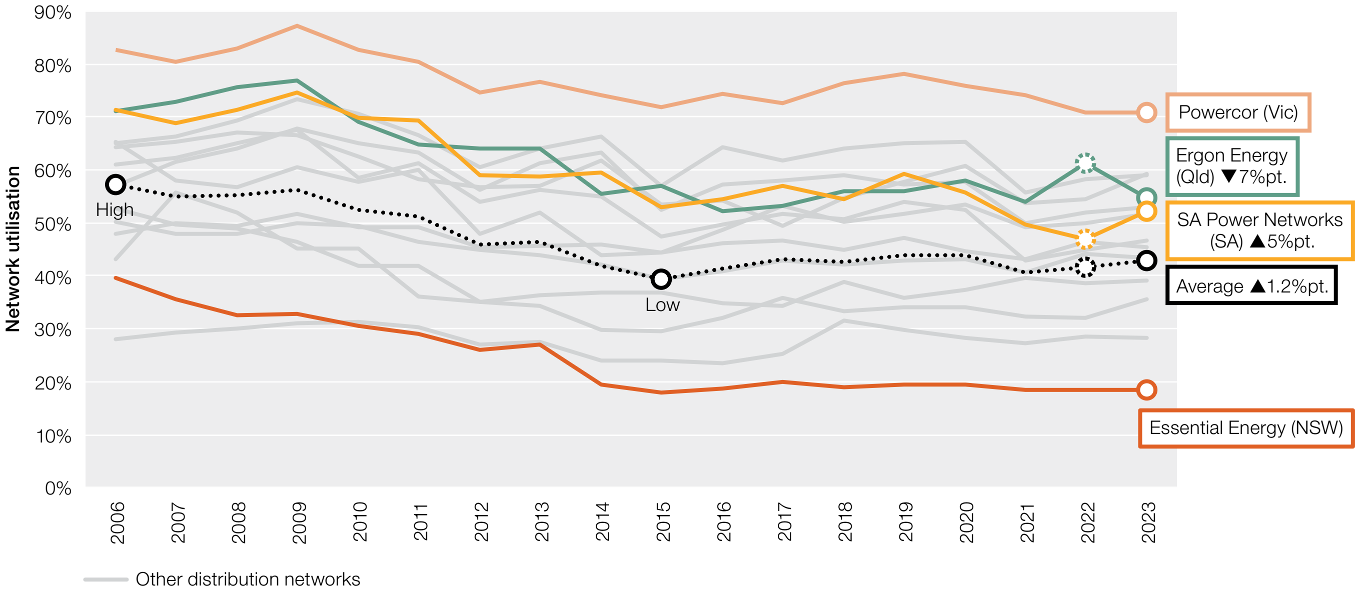
Note: All data are adjusted to June 2023 dollars. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Augmentation of the Victorian transmission network is carried out by AEMO; hence, AusNet Services reports $0 expenditure for augmentation carried out on the transmission network.

Source: Category analysis RIN responses.

In 2023, a 2% increase in maximum demand, coupled with a slight decrease in electricity distribution network capacity, saw the overall distribution network utilisation rate increase to 43%, the highest since 2020 (Figure 1.6). The AER is encouraging network service providers to, where possible, increase the rates of network utilisation by utilising existing capacity before investing in new assets. Opportunities to increase electricity network utilisation may also be found through electrification, load shifting and generation management.

For the gas distribution pipelines, under-utilised assets raise the risk of asset stranding – whereby assets are no longer useful – unless network service providers respond to changing conditions.

Figure 1.6 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. The changes identified in the labels refer to the relative change in utilisation in percentage points over the previous year.

Source: Economic benchmarking RIN responses.

Despite spending less on network services, reliability outcomes continued to improve when compared with historical levels. Electricity consumers experienced the fewest unplanned interruptions to supply on record, as well as a reasonably low number of unplanned minutes off supply (both measures exclude the impacts of major events). The relatively low number of minutes off supply experienced by the average NEM customer in 2022–23 was in part driven by the lack of catastrophic weather events throughout the year. While some network customers were impacted by isolated severe weather events – such as flooding in NSW and severe thunderstorms in South Australia – the weather in 2022–23 was generally mild compared with the previous 3 years.

Investment in gas pipelines increased slightly from the previous year, driven by APA Victorian Transmission System's expansion of the South West Pipeline and its construction of the Western Outer Ring Main project. Investment in gas pipelines continues to be driven by expenditure on new gas connections and by several major programs to replace old steel or cast-iron distribution pipes with plastic pipes.

State and territory governments are already taking measures to reduce residential and small commercial consumers' reliance on gas.

In November 2020, the NSW Government released its Electricity Infrastructure Roadmap – a 20-year plan to transform the state's electricity system into one that is affordable, clean and reliable for everyone. Gas will continue to play an important role in the energy transition and the NSW Government aims to maximise investments through its Electricity Infrastructure Roadmap and renewable energy zones (REZ).

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.[5] Victoria is taking steps to speed up the transition to renewable energy with the goal of achieving a 45–50% reduction in emissions by 2030, 75–80% reduction by 2035 and net zero by 2045.[6] 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.

5 Victorian Government, Victoria's Gas Substitution Roadmap, Department of Energy, Environment and Climate Action, accessed 18 July 2024.
6 Victorian Government, Victoria's Gas Substitution Roadmap, Department of Energy, Environment and Climate Action, accessed 18 July 2024.

The pace of change in Victoria has continued to accelerate, with the introduction of rule changes to reduce new and existing gas connections. Since 1 January 2024, all new homes in Victoria requiring a planning permit are required to be all-electric. This means new homes and residential subdivisions that require a planning permit can no longer connect to the gas network.

The ACT Government's Climate Change and Greenhouse Gas Reduction (Natural Gas Transition) Amendment Bill 2022 established the legal framework to end new fossil fuel gas connections in the ACT.[7] In June 2024, the ACT Government announced its intention to invest in an all-electric, zero emissions future for Canberra with the release of a new Integrated Energy Plan (IEP). The IEP sets out the next stage of work for the ACT's transition over the next 20 years, including a range of government commitments to support consumers through the transition.[8] Falling gas demand also has implications for how gas network costs are allocated to customers and the AER's approach to approving access arrangements for regulated gas pipelines.

1.4 Retail energy markets

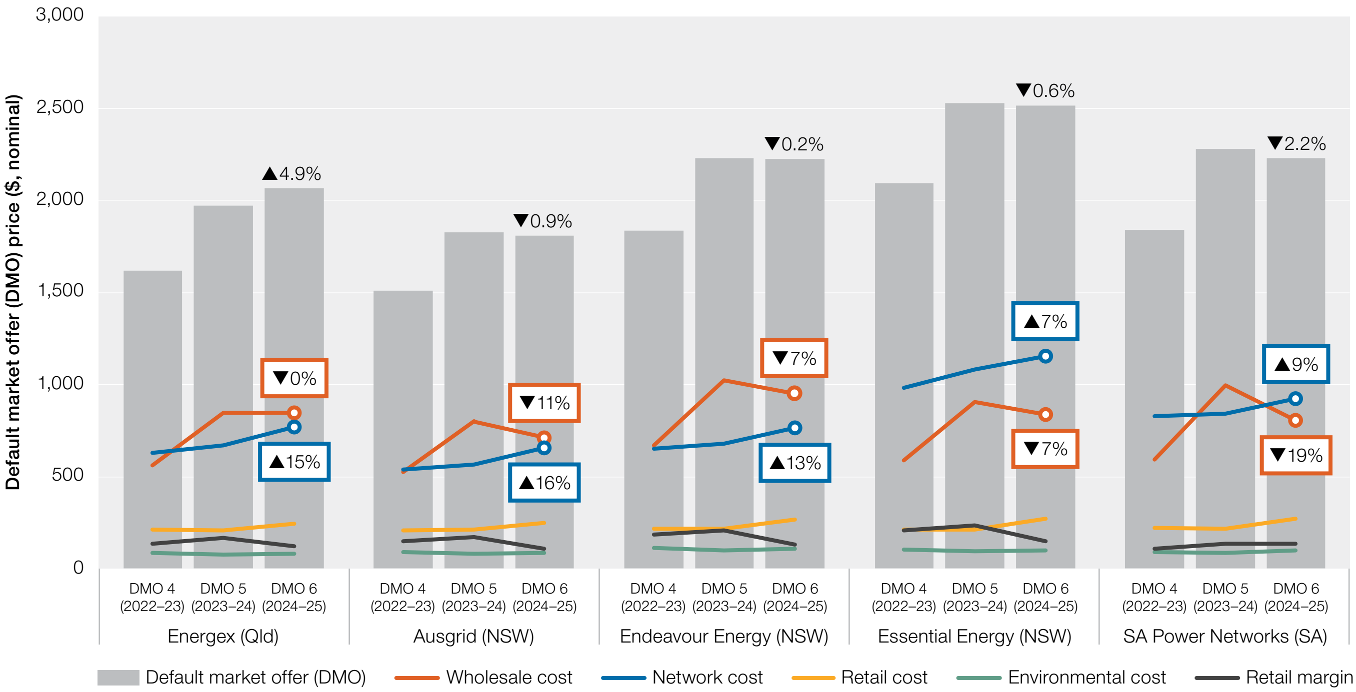
Consumers continue to invest in consumer energy resources such as rooftop solar and home batteries. Residential rooftop solar capacity now exceeds 20 gigawatts (GW), equivalent to 25% of registered generation capacity across the NEM, reflecting an increase of 2.9 GW from the previous year.

In 2023–24, electricity bills increased for customers on both standing and market offers in all NEM regions. Gas bills increased for customers on standing offers in all NEM regions and for customers on market offers in all NEM regions except for Queensland.

Wholesale electricity costs eased in the second half of 2023 following the record highs of 2022. For networks, the external economic effects of higher interest rates and higher inflation contributed to increased regulated revenues compared with previous regulatory periods. This, in combination with higher expenditure requirements for a number of networks, is likely to place upward pressure on networks' costs. The AER's calculation of the 2024–25 electricity default market offer (DMO 6) reference price decreased for customers in NSW and South Australia and increased for customers in South East Queensland (Figure 1.7). This also reflects that increased retail costs were mostly offset in many regions by the lower allowances (including margins) that the AER allowed retailers.

7 ACT Government, ACT reaches milestone preventing new fossil fuel gas connections, media release, 8 June 2023.
8 ACT Government, Electrifying Canberra, media release, 19 June 2024.

Figure 1.7 Components of the default market offer



Note: Comparison of cost components calculated for the 2022–23 (DMO 4), 2023–24 (DMO 5) prices and 2024–25 (DMO 6) 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 6.3. As at September 2024, this data was unavailable for 2024.

Source: AER, Default market offer prices 2023–24, July 2024.

The Australian and state and territory governments provided significant assistance with electricity bills during 2023–24. However, energy debt and hardship measures suggest that broader cost-of-living pressures, combined with energy price rises, continue to put pressure on consumers' ability to pay. Average debt levels per customer have increased in most regions. More customers are accessing hardship programs, which is an important form of assistance. However, we also saw customers in these programs struggling to meet ongoing energy costs.