2

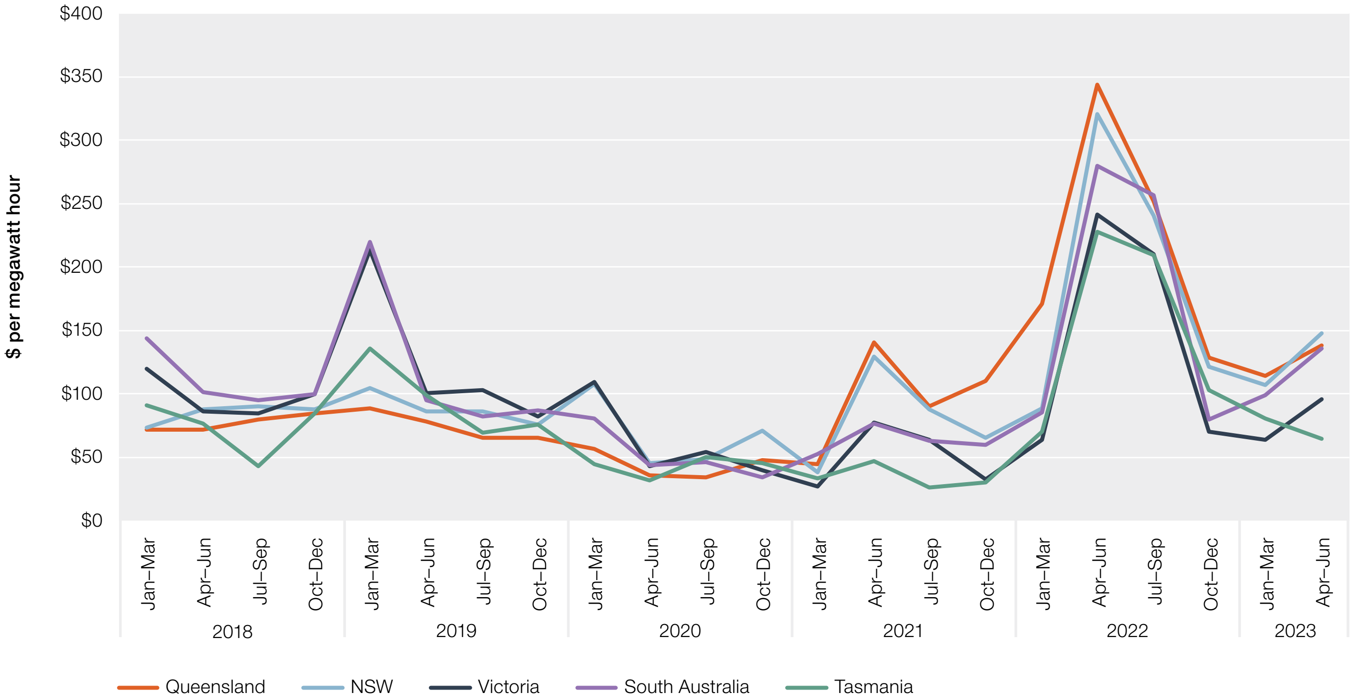
Market overview

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.

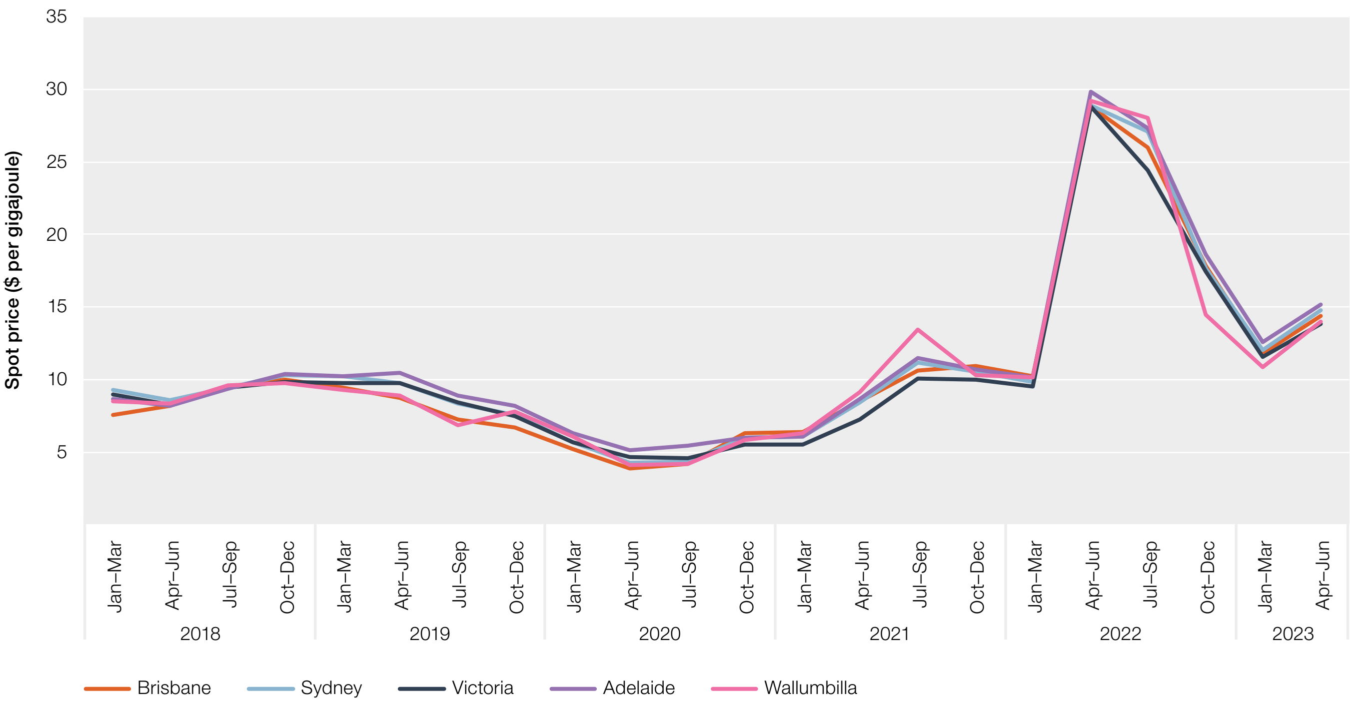
The imminent exit of much of the NEM's coal-fired generation, which accounted for just less than 60% of the NEM's generation output in 2022, has prompted AEMO to forecast reliability gaps (risk of unserved electricity demand) as early as 2024 in some regions. AEMO's forecasts of these shortfalls are 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.

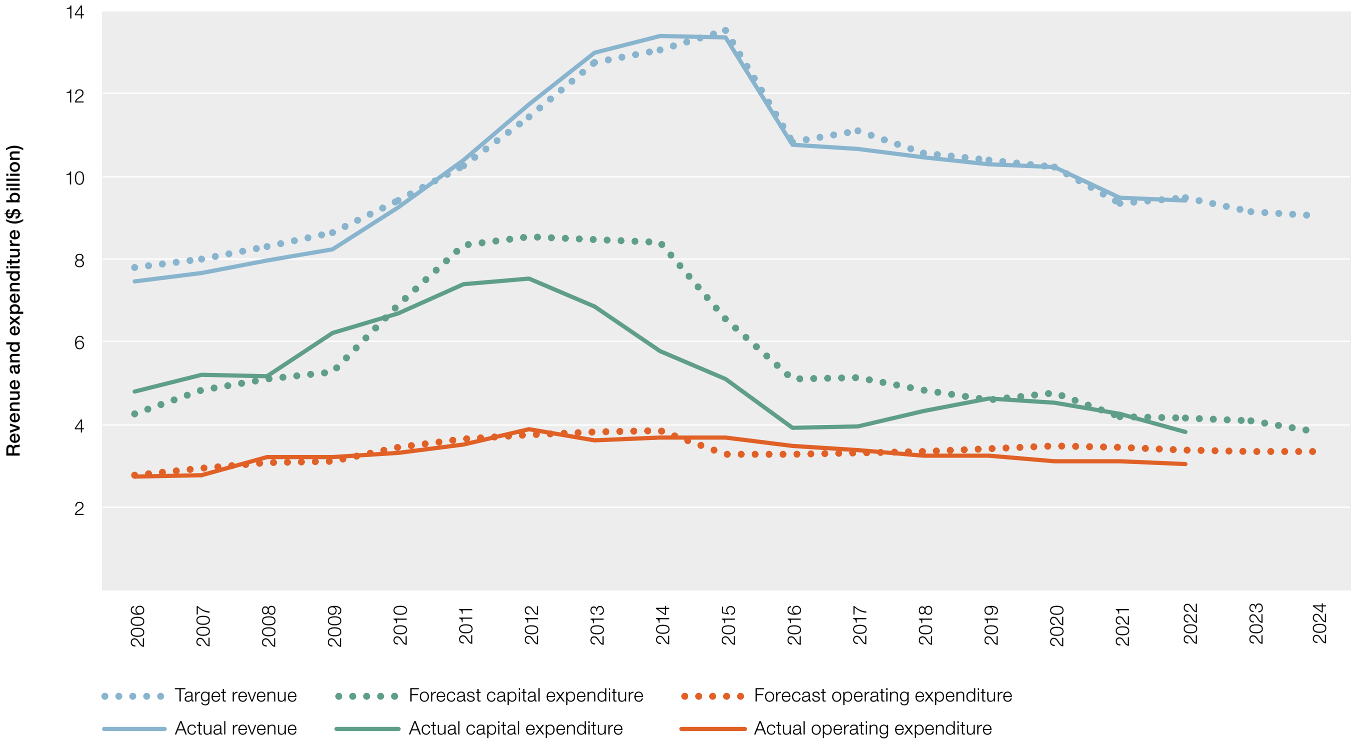
From mid-2023, pipeline expansions on the supply corridor from Queensland to Sydney and Victoria have increased deliverable capacity into southern markets. Further expansions in Victoria over spring 2023 are set to provide higher flexibility to move gas in and out of storage at Iona's underground facility. 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:

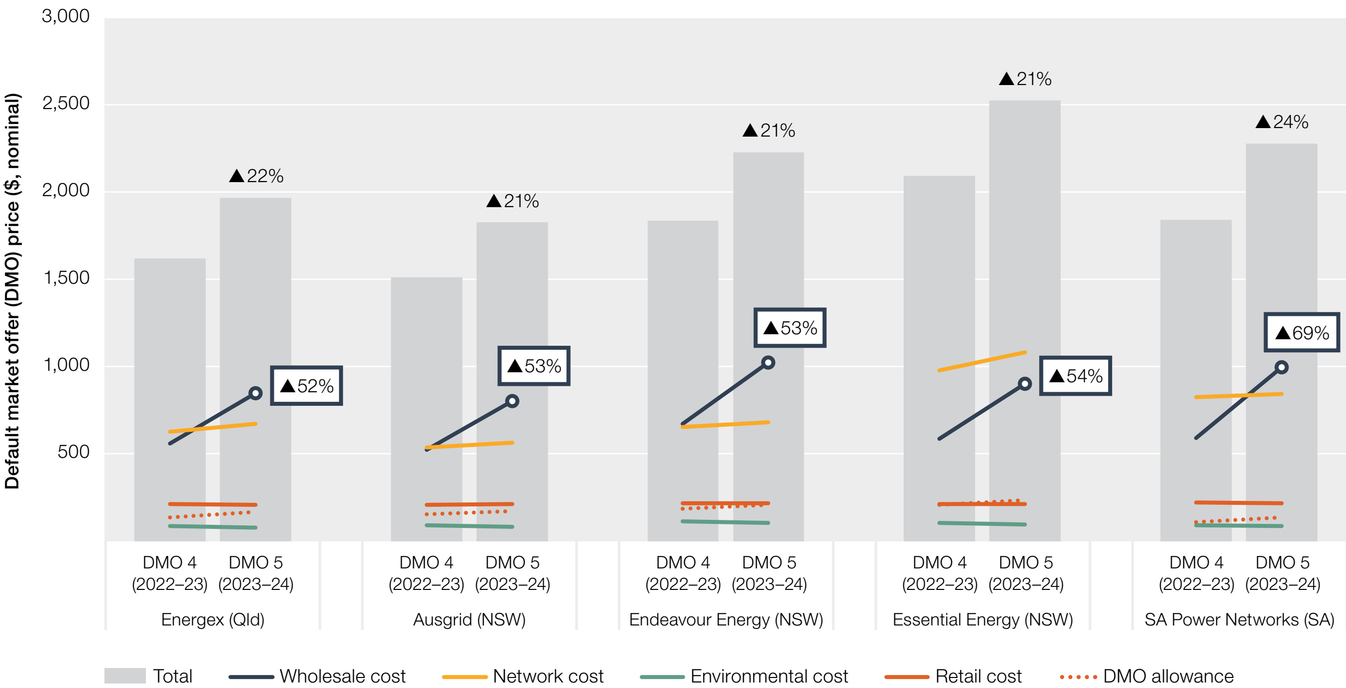
- Investment in gas transmission was significantly higher (144%) than in the previous year, due to APA Victorian Transmission System's (Vic) expansion of the South West Pipeline and its construction of the Western Outer Ring Main project
- In contrast, there was a significant fall in investment in gas 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).