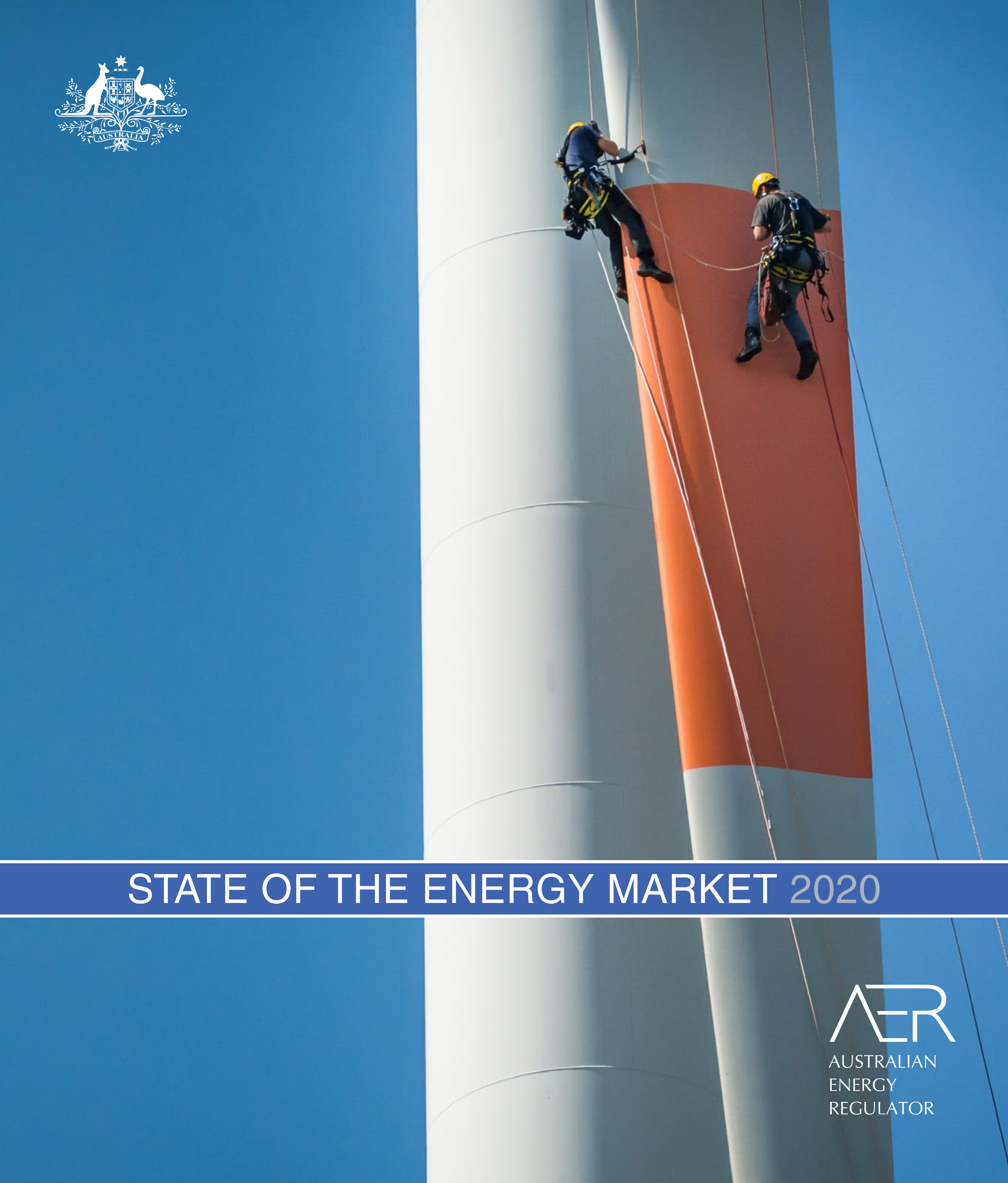


STATE OF THE ENERGY MARKET 2020

AUSTRALIAN
ENERGY
REGULATOR

Australian Energy Regulator

Level 17, 2 Lonsdale Street, Melbourne, Victoria 3000

Email: AERInquiry@aer.gov.au

Website: www.aer.gov.au

ISBN 978 1 920702 53 3

First published by the Australian Competition and Consumer Commission 2020

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: ASX Energy, the Australian Bureau of Statistics, the Australian Energy Market Commission, the Australian Energy Market Operator, the Australian Financial Markets Association, Bloomberg, the Clean Energy Regulator, CSIRO, Energy Consumers Australia, EnergyQuest, the Energy Security Board, KPMG, IRENA, Global-Roam and Greenview Strategic Consulting.

The AER also acknowledges Teslarati and Woodside for supplying photographic images.

Editor: Composed, Melbourne

Designer: Inspire Design, Melbourne

Cover image by Tarnero (Shutterstock)

STATE OF THE ENERGY MARKET 2020

AER

AUSTRALIAN ENERGY REGULATOR

PREFACE

Much is written about the energy transition and, indeed, for the first time we have dedicated a chapter to it in *State of the Energy Market 2020*. At the same time, with so many of us home due to COVID-19 and using more power, it's an important reminder that our focus must always remain on the interests of consumers. All of our work over the past year has been underpinned by exceptional market and consumer insight, of which there are few better examples than the AER's signature publication, *State of the energy market*.

Our market and regulatory frameworks exist to serve the long term interests of consumers, but meeting their diverse needs is challenging. There are still many consumers who may not want to, or simply cannot, effectively engage in what is a complicated market. The Australian Government introduced the Default Market Offer as a cap on the price that electricity retailers can charge consumers on standing offer contracts. The AER sets price caps in south east Queensland, NSW and South Australia. From July 2019 to January 2020, standing offer prices for residential consumers fell by 11–13 per cent in NSW, 12 per cent in South Australia, and 10 per cent in south east Queensland.

The AER recently commissioned a study from the Consumer Policy Research Centre on vulnerability. Vulnerability is multi-faceted, and all consumers can move in and out of vulnerability at different points, as demonstrated by COVID-19. Our Statement of Expectations released in the wake of COVID-19 extended payment plans to all residential and small business customers in financial stress and prevented their disconnection. Pleasingly, both networks and retailers quickly adopted these expectations. As reflected in Justice Hayne's commentary in the Royal Commission into banking and financial services, it is no longer enough for businesses to do the bare minimum to comply with the strict letter of the law.

The AER actively monitors and reports on energy market participants, and takes action to ensure compliance with the law and rules. Since 1 July 2019, the AER has issued 25 infringement notices, accepted three enforceable undertakings, commenced eight cases in the Federal Court, and conducted 10 retail audits. This is almost twice as many compliance and enforcement actions as the AER has initiated before.

This year the AER will complete its biennial review of the performance of the wholesale electricity market. Wholesale electricity prices have been the largest contributor to retail price rises over the past few years. This review will analyse longer term trends in wholesale prices and generator costs, and explore a number of emerging market trends.

Fortunately, stubbornly high wholesale electricity prices have finally begun to fall as large volumes of renewable energy enter the market and fuel prices fall. This should bring some relief to consumers in coming years.

The entry of large volumes of renewable energy means we need a stronger grid to support a least cost energy system. The AER has approved two new electricity transmission projects this year (Queensland – NSW, and NSW – South Australia) in record time to ensure we can meet the future needs of consumers.

Those active and engaged consumers among us long for smart homes and appliances that can be used to participate in the emerging energy marketplace. More rooftop solar photovoltaic (PV) and battery systems will require creative and nimble regulatory approaches to ensure the integration of these resources benefit all. More innovative network tariffs—such as the SA Power Networks' 'solar sponge' tariff that the AER approved this year—will be critical. The AER is also supporting investment in demand management innovations that will reduce the need to invest in network assets.

The national gas industry could also undergo significant change as some jurisdictions move towards a zero carbon emissions policy. This could have significant consequences for the future of gas pipeline networks. In response, the AER recently supported the future recovery of Jemena's investment in trialling the production of hydrogen from renewable energy for injection into its Sydney network.

If hydrogen trials such as Jemena's prove successful, the natural gas networks could be re-purposed to distribute hydrogen. If not, the economic life of the assets could be limited, raising questions in price reviews about levels of investment, how quickly assets should be depreciated, and the appropriate path of network prices over time.

Making well informed decisions about energy investment requires confidence in the policy and regulatory environment, along with a deep understanding of the marketplace. The many and varied interventions by governments and regulators are complex for industry and consumers alike. It's incumbent on us all to increase the transparency of and rationale for our evidence based decisions in plain language.

We will continue to build on our strong relationships with industry, consumers, business groups, regulatory counterparts and government stakeholders as we play our part in energy regulation and policy development. We understand there are investment decisions that depend on our decisions, and we will continue to work hard to be open and timely in our engagement.

We will continue to build on communicating the benefits of our website Energy Made Easy, #PowerToCompare, to deliver transparent and independent alternatives for consumers.

The *State of the energy market* has served as a valuable resource for decision makers across the policy, legal and regulatory spheres. I commend this resource to everyone who contributes to the governance, generation, distribution, transmission, supply and demand of energy in Australia.

Clare Savage—Chair
June 2020

CONTENTS

SNAPSHOT

National Electricity Market

- As ageing coal generators exit the market, over 93 per cent of investment since 2012–13 has been in wind and solar plant, often located on the fringes of the grid.
- Renewable plant produced record output in 2019. Wind farms accounted for 8 per cent of output, and solar farms for 2.5 per cent. Rooftop solar photovoltaic systems met another 5.2 per cent of the market's electricity needs.
- Investment in wind and solar plant slowed from mid-2019, as technical issues with integrating new plant into the system delayed projects. Coordinated planning reforms aim to better integrate renewable plant, rooftop solar PV, demand response and battery storage into the system, with a focus on ensuring the transmission grid can meet transport needs.
- As the market transitions, intervention to manage power system security and reliability risks has risen, imposing significant costs on energy customers. The Australian Energy Market Operator has directed some generators to operate even when not economic, and constrained some low priced plant from operating. South Australia and, more recently, Victoria and Queensland have been the focus of these interventions.
- Investment in 'firming' capacity (such as fast start generation, demand response, battery storage and pumped hydro plant) is needed to fill supply gaps when a lack of wind or sunshine curtails renewable plant.
- The Reliability and Emergency Reserve Trader mechanism was activated in each of the past three summers to secure back-up supply, at a cost of $126 million. And the Retailer Reliability Obligation, launched in July 2019, was activated in January 2020 (in South Australia).
- Victoria at $126 per megawatt hour (MWh) edged South Australia ($125 per MWh) as the NEM's highest price region in 2019. Wholesale prices peaked early in the year, due to high fuel costs and periods of (weather driven) high demand. Generator outages in Victoria also impacted the market.
- Rising solar generation and weakening fuel costs eased wholesale prices from mid-2019, with prices for the first quarter of 2020 below $110 per MWh in all regions for the first time since 2015. But extreme weather contributed to record frequency control costs ($220 million) for that quarter.

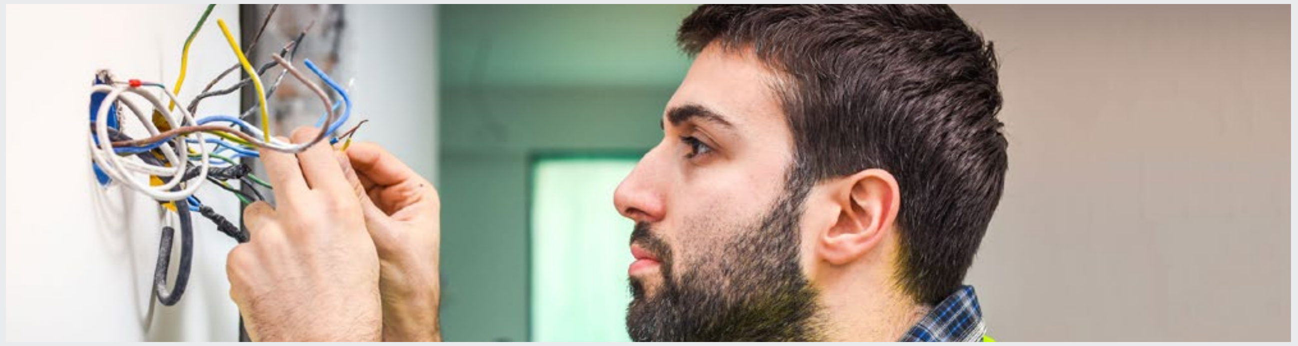
Eastern Australia gas

- Gas production in the northern gas basins rose to record levels in 2019, in response to (over-optimistic) forecasts of Asian liquefied natural gas (LNG) demand over the 2020 northern hemisphere winter.
- Gas producer agreements with the Australian Government to offer uncontracted supply to the domestic market helped ease domestic supply concerns. New gas supply from the Northern Territory (via the Northern Gas Pipeline) also mitigated risks.
- Policy reforms in 2019 made it easier to access gas pipelines needed to transport gas to markets. The reforms free up contracted pipeline capacity that is not being fully used, either through voluntary trade or mandatory day-ahead auctions. The auctions freed up over 40 petajoules of capacity across 10 pipelines in the first 13 months of operation, with most capacity auctioned at the reserve price of zero.
- LNG prices weakened as new international supply came online at a time when demand was slowing. In March 2020 intense price competition between Saudi and Russian oil producers, and COVID-19 related demand reductions dragged international oil prices to their lowest levels since 2003. Australian exporters reported the uncertainty stemming from COVID-19 and collapsing oil prices limited their ability to strike new gas supply agreements.
- Increased domestic supply, pipeline reforms and weakening global markets flowed through to domestic prices. Spot prices averaged $7–8 per gigajoule (GJ) in the fourth quarter of 2019, down from $10 per GJ a year earlier. Some trades in the first quarter of 2020 were being made at prices below $5 per GJ in southern markets, and below $4 per GJ in northern markets.
- Four LNG import terminals are being considered across South Australia, Victoria and New South Wales (NSW).

SNAPSHOT

Regulated energy networks

- Revenue forecasts in current regulatory periods are 13 per cent lower for electricity networks, and 14 per cent lower for gas networks, than in previous periods. Lower rates of return were a key driver of declining revenues.
- Electricity distribution revenue in 2019 hit its lowest point since 2011, and was 23 per cent lower than the peak recorded in 2015. Transmission revenue in 2019 was at its lowest level in over a decade.
- Network investment increased for the third consecutive year in 2019, including a 9 per cent rise for electricity distribution. But investment in 2019 remained 41 per cent below the peak recorded in 2012. The majority of forecast investment in distribution networks is to replace and refurbish old assets, rather than to expand the networks.
- Electricity networks are better managing their operating costs, partly in response to AER incentives and benchmarking. Productivity rose by 1 per cent in distribution networks and 2.2 per cent in transmission in 2018, mainly linked to efficiencies in operating expenditure. Distribution productivity grew for three consecutive years to December 2018, exceeding growth in the Australian economy as a whole.
- Distribution network businesses have managed reliability more effectively over the past decade, although factors such as extreme weather sometimes impact customer experience.
- A number of network businesses are trialing engagement models to identify their customers' needs, to help develop new regulatory proposals. AusNet Services (Victoria) engaged an independent customer forum to negotiate its proposal.
- Cost-reflective network tariffs encourage retailers to incentivise energy customers to switch their energy use from times of high demand to times of lower demand. As an example, SA Power Networks' 'solar sponge' tariff for residential customers offers lower network charges in the middle of the day when solar output is highest.
- The AER is supporting investment in demand management innovations that will reduce the need to invest in network assets. Supported projects include residential and grid scale battery storage projects, technology trials to manage demand through device control, and research into distributed energy platforms for demand management.



Retail energy markets

- The Australian Government introduced price caps on retailers' electricity standing offers from 1 July 2019. The AER sets the default market offer on standing offer prices in south east Queensland, NSW and South Australia. Victoria introduced a similar arrangement that sets standing offer prices at a level reflecting the costs of an efficient retailer in a contestable market.
- In the seven months to January 2020, standing offer prices for residential customers fell by 14–19 per cent in Victoria, 11–13 per cent in NSW, 12 per cent in South Australia, and 10 per cent in south east Queensland.
- But electricity standing offer prices remain higher than market offers. A customer switching from the median standing offer to the best market offer in their distribution zone could save up to 20 per cent ($300–400 in annual savings) in January 2020.
- Retailers are moving away from discounting towards simpler, more stable pricing. This shift coincided with reforms introduced in 2019 that restricted advertising based on large headline discounts. Offers with conditional discounts accounted for around two thirds of offers in Queensland, NSW, South Australia and the Australian Capital Territory (ACT) in 2018, but less than 20 per cent of offers by 2020.
- Three businesses—AGL Energy, Origin Energy and EnergyAustralia—continue to dominate the retail market, supplying 63 per cent of small electricity customers and 75 per cent of small gas customers in eastern and southern Australia. But smaller retailers are building market share.
- The AER is strengthening frameworks to support customers in vulnerable circumstances. It revised hardship guidelines in 2019, and published research (by the Consumer Policy Research Centre) in 2020 on regulatory approaches to customer vulnerability.
- The AER (www.energymadeeasy.gov.au) and Victorian Government (compare.energy.vic.gov.au) websites provide energy price comparisons of all readily available market offers. Enhancements to the Energy Made Easy website in early 2020 aim to simplify the user experience and increase the site's capability to compare innovative offers.


Source: AER

MARKET OVERVIEW

The COVID-19 pandemic has overshadowed other aspects of life in 2020, and the energy sector is not immune from its impact. The energy market has an important role to play in protecting and supporting businesses and the community through the pandemic and recovery. In April 2020 the Australian Energy Regulator (AER) released a Statement of Expectations to energy businesses, setting out principles that it expects them to follow during this period to avoid imposing unnecessary hardship on the community.[1]

In its compliance work, the AER is focusing on ensuring customers receive the support that they need, and the protections to which they are entitled. It is closely monitoring business compliance with provisions of the National Energy Retail Law, the National Energy Retail Rules and the exemption guidelines that protect customers facing payment difficulties. Initial commitments by energy retailers and some distribution networks have been encouraging, clearly looking to reduce the financial burden on impacted customers while COVID-19 related restrictions remain in place. But concerns have been raised around some retailers' interpretation of hardship disconnection principles.

The AER recognises the current heightened risks and costs facing energy businesses. For this reason, it is working with stakeholders to appropriately balance the risks and costs across the sector, and to ensure energy businesses receive any assistance they may need to remain viable. The AER in May 2020 proposed an urgent change to the National Electricity Rules to support electricity retailers as they provide payment assistance to customers, by allowing them to defer payments of network charges by up to six months for customers affected by the COVID-19 pandemic. The proposal builds on voluntary support measures being provided by network businesses under Energy Networks Australia's Networks' Relief Package.

Alongside impacts on energy customers and retailers, the COVID-19 outbreak intensified pressures already building in gas markets. In March 2020 international oil prices crashed to their lowest levels since 2003, from the combined impacts of the Saudi Arabia – Russia oil price war and COVID-19 related demand reductions. Domestically, collapsing demand led wholesale spot gas prices in the first quarter of 2020 to settle at their lowest quarterly levels in four years. Wholesale electricity prices also eased from mid-2019, reflecting lower fuel costs for fossil fuel generation and rising levels of renewable generation.

1 The electricity market in transition

While dealing with the disruptive impacts of COVID-19, the energy sector is also in the midst of its own transition from a centralised system of large fossil fuel (mainly coal) generation towards a decentralised system of widely dispersed, relatively small scale renewable (mainly wind and solar) generators (figure 1).

If well managed, the transition can deliver significant benefits. Renewable energy is a relatively cheap fuel source, and if integrated efficiently into the power system, it can deliver low cost sustainable energy. For individual consumers, the uptake of solar photovoltaic (PV) and battery systems—supported by well designed control systems—can help them save on power bills and manage their energy use in ways to suit their needs, while also empowering them to take initiative on environmental concerns.

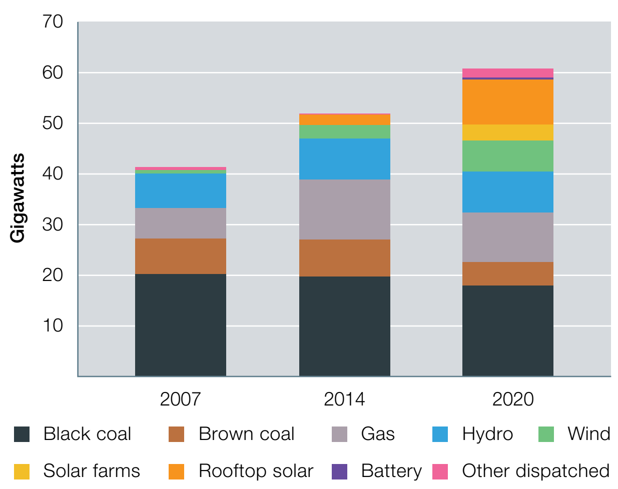
But integration issues have arisen because much of this new generation is located in sunny or windy areas at the edges of the grid with relatively weak transmission network capacity. Further, the fossil fuel plant being replaced traditionally provided critical technical stability services such as inertia and system strength. The ability of wind and solar plant to provide these services has been limited. As a result, the rising proportion of renewable generation is bringing more periods of low inertia, weak system strength, more erratic frequency shifts, and voltage instability.[2] This volatility has consequences, such as the rising cost of procuring market services to keep system frequency within safe limits.

An ongoing challenge is to find the best ways to keep the power system reliable and secure as the generation mix changes. The weather dependent nature of wind and solar generation creates a need for 'firming' capacity (such as fast start generation, battery storage and pumped hydro plant) to fill supply gaps when a lack of wind or sunshine curtails renewable plant. Greater weather driven volatility also requires better demand and supply forecasting, to ensure firming capacity is available when needed.

More frequent market interventions have occurred to maintain a reliable and secure power system. As an example, the Australian Energy Market Operator (AEMO) used the Reliability and Emergency Reserve Trader (RERT) mechanism in each of the past three summers to secure back-up supply, at a cumulative cost to the market (and energy customers) of around $126 million.[3]

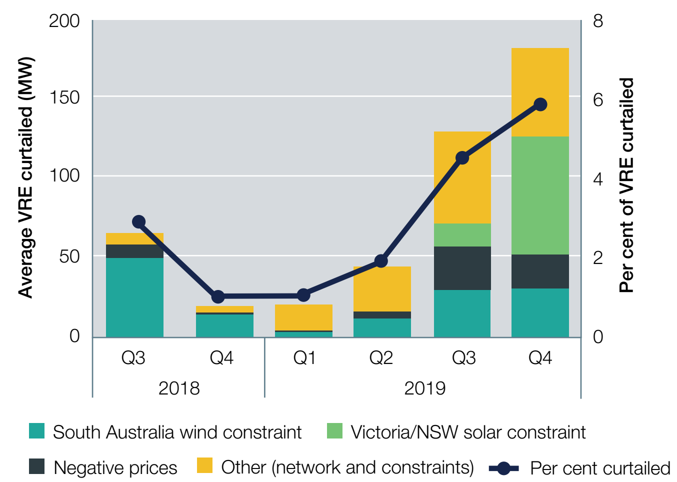
1 AER, *Statement of Expectations of energy businesses: protecting consumers and the market during COVID-19*, 9 April 2020.

Figure 1
A changing generation mix



Note: January (summer) capacity.
Source: AER; AEMO (data).

Figure 2
Curtailment of renewable generation



MW, megawatt; VRE, variable renewable energy.
Source: AEMO, *Quarterly energy dynamics Q4 2019*, February 2020.

To manage security issues, AEMO has been directing generators to operate even if it is not economic for them to do so, and constraining some low priced plant from operating (figure 2). South Australia and, more recently, Victoria and Queensland have been the focus of these interventions. AEMO also de-energised transmission lines in Victoria.

AEMO instructed load shedding—a last resort option for managing system security—twice in 2019. The load was shed in Victoria on 24 January 2019 (75 megawatts (MW)) and 25 January 2019 (100 MW).

Strategic planning, and policy and regulatory reforms are guiding the energy market transition in ways that will optimise benefits for energy customers. Market bodies are exploring how best to manage reliability risks, with a focus on encouraging investment in resources with the flexibility to manage sudden demand or supply fluctuations. A longer term focus is on expanding the role of demand response to manage risks. To manage more imminent threats, the Retailer Reliability Obligation (RRO) launched in July 2019 requires retailers and large energy customers to cover their electricity requirements by either owning dispatchable generation or securing contracts with third parties, whenever AEMO identifies a reliability gap in the market. The AER enforces compliance with the RRO.

New rules to address technical security risks include an obligation on transmission network businesses to maintain minimum levels of system strength and inertia if AEMO identifies a shortfall. Declared shortages of inertia and system strength are in place in South Australia, and inertia and fault level shortfalls were declared in Tasmania in November 2019. Additionally, AEMO declared fault level shortfalls in north west Victoria and north Queensland in December 2019 and April 2020 respectively.

Another reform requires connecting generators to 'do no harm' to levels of system strength needed to maintain the power system security. And, from June 2020, all capable generators and batteries must provide primary frequency response support whenever called on to manage a supply–demand imbalance. Market bodies are also exploring longer term solutions for sourcing security services, including the development of new markets for inertia, system strength and voltage control. Supporting these developments, the Australian Renewable Energy Agency (ARENA) and Clean Energy Finance Corporation (CEFC) increased their focus on funding technologies and business models that efficiently integrate renewables into the system.

Aside from reliability and security challenges, Australia's energy market transition poses risks to the efficient investment and use of energy infrastructure. Key issues are the efficient location of new generation, and the coordination of generation and transmission investment.

AEMO's Integrated System Plan is a roadmap for the efficient future development of the National Electricity Market (NEM). As part of that development, the plan identifies network investment needed to accommodate anticipated new generation connections. It prioritises the bolstering of the interconnection of NEM regions, to allow more generation trade among regions to reduce energy costs and enhance reliability and security.

Alongside this plan, policy makers are changing elements of the energy market design to improve locational signals for new generation investment, and to coordinate investment across the generation and transmission sectors. Reforms also target the creation of renewable energy zones so clusters of generators can share the costs of connecting to the shared transmission network, and contribute to wider network improvements.

Reforms to make network tariffs more cost reflective will support the more efficient use of networks and demand management, as discussed below.

2 National Electricity Market

The transition underway in the electricity market is still in its early stages. Fossil fuel generators continued to produce 77 per cent of electricity in the NEM in 2019. But many older generators are nearing the end of their life and becoming less reliable. Around 15 per cent of the NEM's coal generation capacity in 2010 has since retired, and a further 29 per cent is scheduled to retire by 2035.

The profitability of coal plant has also been challenged by slumping demand for grid supplied electricity in the middle of the day, when rooftop solar PV generation is at its maximum. Despite these pressures, profits and share prices for some coal generating businesses have shown resilience. This resilience may reflect ongoing tightness in the supply–demand balance. The AER is monitoring the market to identify any competition concerns as the market transitions, and will publish its next round of findings in December 2020.

Wind and solar generation are filling much of the supply gap left by coal plant closures. Over 93 per cent of generation investment since 2012–13 has been in wind and solar capacity, driven partly by government subsidies under the renewable energy target scheme, and by funding from ARENA and the CEFC.

Around 4000 MW of grid scale generation was added to the NEM in 2018–19, but capacity additions have since slowed, partly as a result of issues with integrating new plant into the power system. Only 1400 MW of capacity was commissioned in the nine months to March 2020. But rooftop solar investment continued to grow steadily, adding 1600 MW of capacity in 2018–19, and another 1400 MW in the nine months to March 2020.

Wind plant accounted for over 40 per cent of new generation investment in 2019. Wind farms produced 8.2 per cent of the NEM's electricity in 2019, and recorded an 18 per cent year-on-year rise in output. Its penetration is especially strong in South Australia, where it provided 38 per cent of the state's electricity output in 2019.

Commercial solar farms have been slower to develop in Australia, but a pipeline of projects reached commissioning stage in 2019. Solar farms accounted for 2.5 per cent of output in 2019, and that contribution is set to rise as new projects come on stream. Generation by rooftop solar PV systems rose strongly over the past decade, and met 5.2 per cent of the NEM's electricity requirements in 2019.

The closure of two major brown coal power stations—Northern (South Australia) in May 2016 and Hazelwood (Victoria) in March 2017—triggered several years of rising wholesale electricity prices. The Hazelwood closure withdrew 5 per cent of the NEM's total capacity, much of which was usually offered at low prices. After the closure, more expensive black coal and gas plant began to set spot prices more frequently.

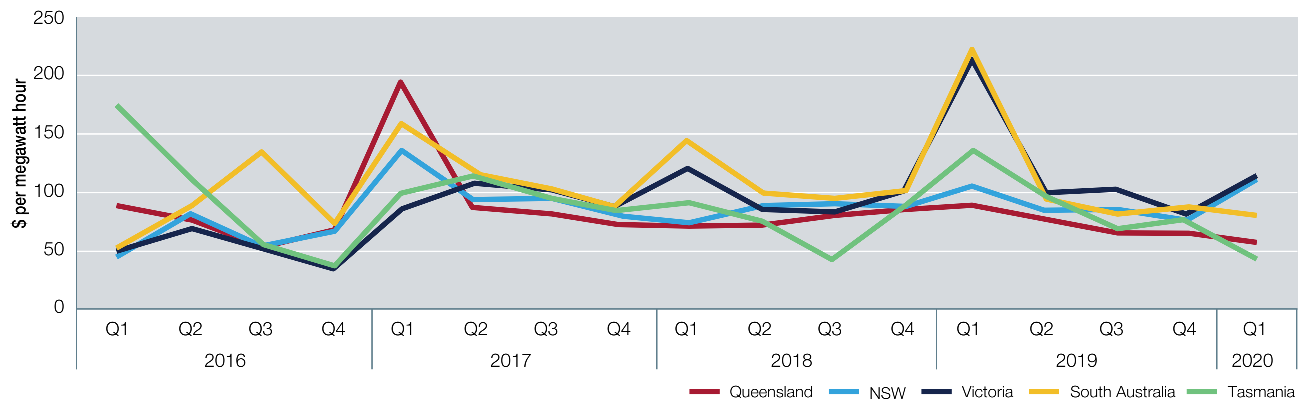
Prices remained elevated in most regions through to 2019, when they averaged close to $100 per megawatt hour (MWh)—just short of the record ($105 per MWh) set in 2017 (figure 3).

Victoria ($126 per MWh) edged out South Australia ($125 per MWh) as the NEM's highest price region in 2019. The state more than doubled its 2016 average ($52 per MWh) before the closure of Hazelwood. Hot weather combined with plant failures led to Victoria ($216 per MWh) and South Australia ($223 per MWh) setting record prices in the first quarter of 2019. Other contributing factors included dry conditions (which constrained hydrogeneration) and high fuel costs for gas powered generation.

Victorian prices remained unseasonably high for much of 2019, exacerbated by an unplanned outage at Loy Yang A that ran for several months and removed 11 per cent of low cost generation from the region. Outages at the Yallourn and Mortlake power stations compounded the situation, contributing to average prices settling above $100 per MWh in Victoria in the second and third quarters of 2019.

Queensland prices averaged $75 per MWh in 2019, which was the lowest average for any NEM region. A substantial rise in solar capacity contributed to Queensland being the only region with a lower year-on-year average price, despite growth in electricity demand. New South Wales (NSW) prices averaged $89 per MWh in 2019—which was the second lowest average for any NEM region—but were 4 per cent higher than in 2018. Coal supply issues caused the state's Mount Piper power station to operate at reduced output for several months during the year. In Tasmania, below average rainfall constrained hydrogeneration, and a six week disruption on the Basslink interconnector disrupted trade with the mainland. As a result, the region recorded a 30 per cent price rise, averaging $95 per MWh in 2019.

Figure 3
Quarterly wholesale electricity prices



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

The market was volatile in 2019, with 397 trading intervals settling above $300 per MWh. Much of this volatility occurred in Victoria, South Australia and Tasmania, linked to extreme weather and high system demand early in the year, and generator outages in Victoria. Significant volatility returned in early 2020, again linked to extreme weather. Bushfires impacted the market, causing transmission lines to trip and limiting generation. At times, the transmission interruptions led to market separation between regions, as occurred between NSW and Victoria on 4 January 2020. Spot prices hit the cap of $14 700 per MWh on multiple days during the bushfire period.

Market volatility also reflected in an increasing occurrence of negative prices. The market set a record number of negative prices in the second half of 2019. These price events typically occur when weather conditions are optimal for renewable generation, and electricity demand from the grid is low. The geographic grouping of renewable generators intensifies the effect, because when conditions are favourable for one wind or solar farm in an area, they tend to be favourable for other wind or solar farms in the area too. The phenomenon is particularly apparent in South Australia and Queensland, which are regions with a high penetration of solar (grid scale and rooftop solar PV) generation (figure 4).

The market in early 2020

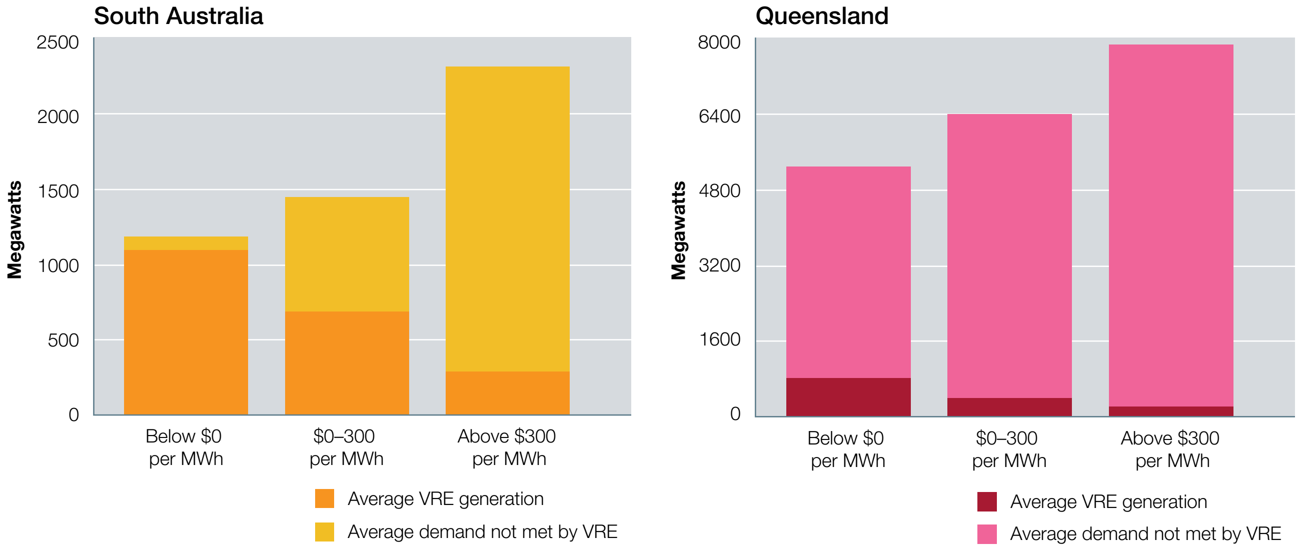
Lower demand—largely driven by a generally mild summer—and lower coal and gas fuel costs caused a reversal in market conditions in early 2020. Wholesale electricity prices in the first quarter were the lowest first quarter prices observed since 2012 in Queensland, 2015 in Tasmania and 2016 in South Australia. More generally, the first quarter of 2020 marked the first time since 2015 that first quarter prices were below $110 per MWh in all regions.

These averages, however, mask exceptional volatility. At the start of the first quarter, extreme weather conditions and bushfires drove short bursts of high prices in January 2020 across NSW, Victoria and South Australia. Yet, weather conditions in the quarter were generally mild, resulting in lower levels of summer demand. In addition, lower gas and coal fuel costs and rising levels of low priced solar generation kept pressure off prices.

In February 2020 South Australia was isolated from the rest of the NEM after storms damaged transmission infrastructure. The separation meant South Australia was required to provide its own frequency stability services, resulting in record quarterly costs of $227 million for frequency control ancillary services (FCAS)—six times the FCAS costs in the first quarter of 2019.

As the quarter progressed, the COVID-19 pandemic began to affect expectations in contract markets. Volumes of electricity futures contracts for the second and third quarters of 2020 fell by 11 per cent in the last two weeks of March 2020. By late March 2020, baseload futures for first quarter 2021 contracts in Victoria and South Australia had eased 30 per cent off their peak in late October 2019.

Figure 4
Renewable generation and negative prices, 2019



MWh, megawatt hour; VRE, variable renewable energy.
Source: AER; AEMO (data).

3 Eastern Australian gas markets

The launch of Queensland's liquefied natural gas (LNG) export industry in 2015 placed significant pressure on Australia's eastern gas market. Relatively higher international gas prices began to bear on domestic gas prices at a time when state based moratoriums on gas development limited options for new domestic supply. Higher gas prices weakened gas demand by industrial customers and gas powered generators. In Queensland, gas generation slumped from 22 per cent of electricity output in 2014 to 8 per cent in 2019. A similar squeezing occurred in NSW.

Different conditions prevailed in Victoria and South Australia, where coal generation retirements and outages on remaining plant made gas generation critical to meeting electricity demand despite higher fuel costs. The share of gas powered generation in electricity supply rose between 2015 and 2019 from less than 2 per cent to 7 per cent in Victoria, and from 37 per cent to 48 per cent in South Australia.

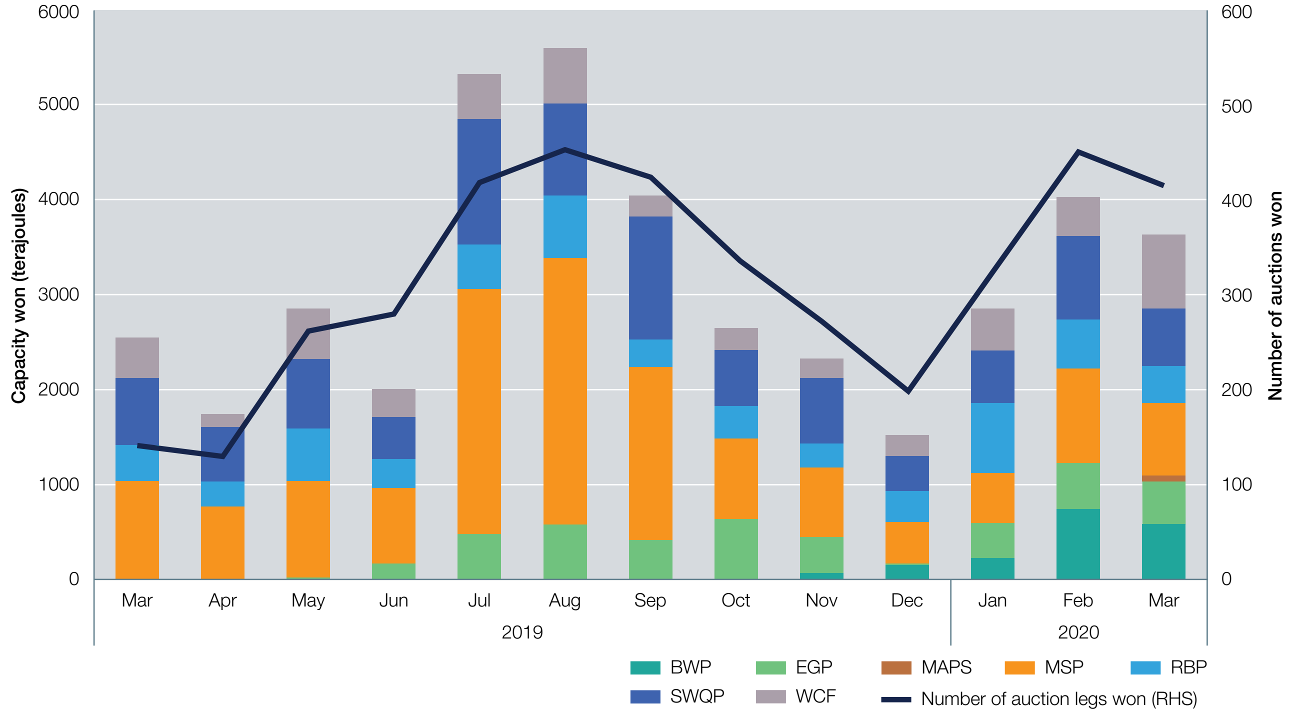
Gas market conditions changed significantly in 2019. Gas production in the northern gas basins rose to record levels, in response to (over-optimistic) forecasts of Asian LNG demand in the northern hemisphere 2019–20 winter. Agreements between gas producers and the Australian Government led to all uncontracted supply being offered to the domestic market on competitive terms before being offered for export. New gas supply from the Northern Territory (via the Northern Gas Pipeline) also improved domestic supply conditions.

Policy reforms making it easier to access critical gas pipelines mitigated pressures in the domestic market too, by enabling gas customers to transport gas at lower cost. The reforms introduced in March 2019 make available to third parties any contracted pipeline capacity that is not being fully used. The capacity may be offered voluntarily in the first instance or failing that, by mandatory day-ahead auction.

The day-ahead auction created access to over 41 petajoules (PJ) of capacity across 10 pipelines in the first 13 months of its operation (figure 5). Over 80 per cent of that capacity was auctioned at the reserve price of zero. Access to low or zero cost pipeline capacity is allowing shippers to move relatively low priced northern gas into southern markets, easing pressure in those markets. The AER estimates the auctions effectively reduced spot gas prices by as much as $0.76 per GJ in Sydney, and up to $0.17 per GJ in Victoria, over the six months to September 2019.[4]

4 AER, *Wholesale markets quarterly—Q3 2019, November 2019*. pp. 52–3.

Figure 5
Day-ahead auction of pipeline capacity



BWP, Berwyndale to Wallumbilla; EGP, Eastern Gas Pipeline; MAPS, Moomba to Adelaide Pipeline; MSP; Moomba to Sydney Pipeline; RBP, Roma to Brisbane; SWQP, South West Queensland Pipeline; WCF, Wallumbilla compression facilities.
Source: AER analysis of AEMO day-ahead auction data.

International market conditions have also shifted. Asian LNG prices weakened significantly in 2019, as new capacity in the United States, Australia and Russia came online at a time when the Chinese economy was slowing and Japan continued its switch away from gas powered generation. In March 2020 international oil prices crashed to their lowest levels since 2003, from the combined impacts of intense price competition between Saudi and Russian oil producers, and COVID-19 related demand reductions. At times, they settled in negative territory. Australian exporters reported the uncertainty stemming from COVID-19 and collapsing oil prices limited their ability to strike new gas supply agreements.[5]

The combination of domestic supply increases, pipeline reforms and weaker international market conditions are flowing through to domestic prices (figure 6). Monthly spot prices averaged $10 per GJ across all markets in the fourth quarter of 2018. By mid-2019 prices had eased in most markets, mirroring the decline in LNG prices that began a few months earlier. By the fourth quarter of 2019, prices in all spot markets averaged around $7–8 per GJ. This trend continued into 2020, with first quarter price averages at their lowest since 2016 in all markets. Some trades were being made at prices below $5 per GJ in southern markets, and below $4 per GJ in northern markets.

As a result of the changed market conditions, forecasts of Australia's supply–demand balance have become more optimistic. The Australian Competition and Consumer Commission (ACCC) in 2020 forecast eastern Australia's gas supply in 2020 to be 2025 PJ—around 200 PJ above forecast domestic and LNG demand.[6] But AEMO forecast supply gaps could emerge by 2024, as Victorian production wanes.[7] Both AEMO and the ACCC argue more exploration and development in southern Australia, pipeline capacity expansions, or the commissioning of LNG import terminals could mitigate the supply risk.

Four LNG import terminals are being considered across South Australia, Victoria and NSW. State governments have also taken steps to expand domestic gas production. The

5 EnergyQuest, *Energy quarterly*, March 2020, p. 53.

6 ACCC, *Gas inquiry 2017–2025, Interim report, January 2020*, February 2020, p. 27. Based on forecast production from proved plus probable (2P) reserves.
7 AEMO, *2020 Gas statement of opportunities*, March 2020, p. 44.

Figure 6
Eastern Australia gas spot 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 6 am schedule price.

Source: AER analysis of Gas Supply Hub, short term trading market and Victorian declared wholesale gas market data.

NSW Government has targeted injection of an additional 70 PJ of gas per year into the NSW market, which could be sourced from local basins or imported. In Victoria, the government will allow conventional onshore gas exploration to recommence from July 2021.

As the compliance and enforcement body for gas markets, the AER is monitoring the introduction of reforms, including the day-ahead trading in underused pipeline capacity and the provision of accurate information to the Gas Bulletin Board. In 2019 it strengthened its reporting on the market by launching online gas industry statistics and quarterly market reports.

4 Regulated energy networks

The AER regulates the costs of transporting electricity and gas through transmission and distribution networks. The bulk of these costs, which account for around 40 per cent of a residential customer's energy bill, occur in distribution networks.

Inaccurate energy demand forecasts and stringent energy reliability standards drove over-investment in electricity networks for several years. Coupled with a sharp rise in financing costs (caused by the global financial crisis), this investment drove a 66 per cent real increase in the electricity network revenues over the nine years to 2015.

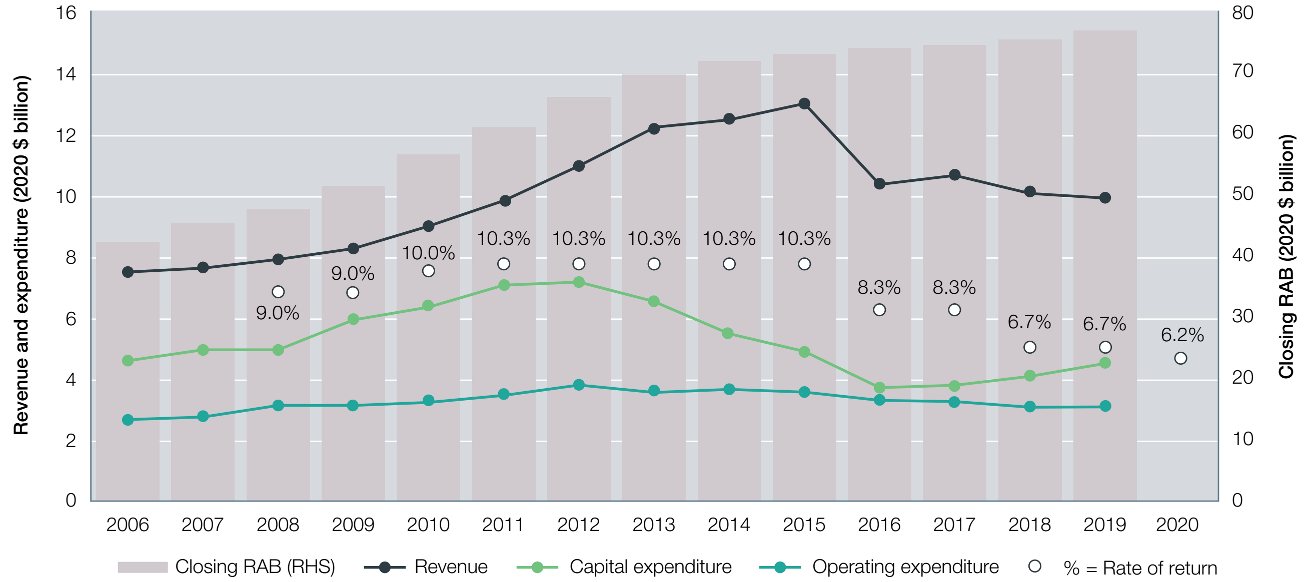
High financing costs similarly impacted gas pipeline revenues in that same period. Financial markets have since stabilised, cutting allowed rates of return for network businesses from as high as 10 per cent for several years from 2009, to around half that level in 2020. Weakening electricity demand forecasts also caused investment projects to be delayed or shelved. And reliability standards were softened, bringing them more into line with values that customers place on reliability.

More recently, electricity networks began to implement operating efficiencies to better control their costs, partly in response to the AER applying benchmarking tools to set operating cost allowances, and launching new incentive schemes.

Higher productivity helped drive lower operating costs in several networks. Productivity rose by 1 per cent in distribution networks and 2.2 per cent in transmission networks in 2018, mainly driven by efficiencies in operating expenditure. Distribution productivity grew for three consecutive years to December 2018, exceeding growth in the Australian economy as a whole.

Improved network reliability also supported high productivity. Most customer outages originate in distribution networks. But distribution outages became less frequent in eight of the past nine years, and the average outage duration remained stable or lessened in nine of the past 10 years.

Figure 7
Electricity distribution revenue and drivers



RAB, regulatory asset base.

Note: Victorian network businesses report on a 1 January – 31 December basis. All other network businesses report on a 1 July – 30 June basis. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

All data are CPI adjusted to June 2020 dollars.

Rates of return are weighted average cost of capital (WACC) forecasts in AER revenue decisions and Australian Competition Tribunal decisions for transmission networks. The rates of return shown represent the highest rate applicable to the distribution network businesses in each year.

Source: AER modeling, economic benchmarking regulatory information notice (RIN) responses, category analysis RIN responses.

These shifts reflect in all but one of the AER's decisions made since January 2019 setting lower revenues for network businesses than in their previous regulatory periods.

Electricity distribution revenue decreased by 2 per cent in 2019 following a 5 per cent decrease in 2018 (figure 7). Revenue in 2019 hit its lowest point since 2011, and was 23 per cent lower than the peak recorded in 2015. Transmission revenue eased by 1 per cent in 2019 following a 10 per cent decrease in 2018, and is now at its lowest level in over a decade.

Declining network revenue since 2016, combined with rising customer numbers, have translated into lower network charges in retail energy bills for most customers. Current AER decisions reduced distribution charges in residential electricity bills by an average 0.6 per cent across all states and territories. Outcomes are more varied in the transmission sector, which has different cost drivers (figure 8).

While network revenues have decreased since 2015, network investment increased for the third consecutive year in 2019, including a 9 per cent rise for electricity distribution.

Despite this increase, total network investment remained 41 per cent below the peak recorded in 2012.

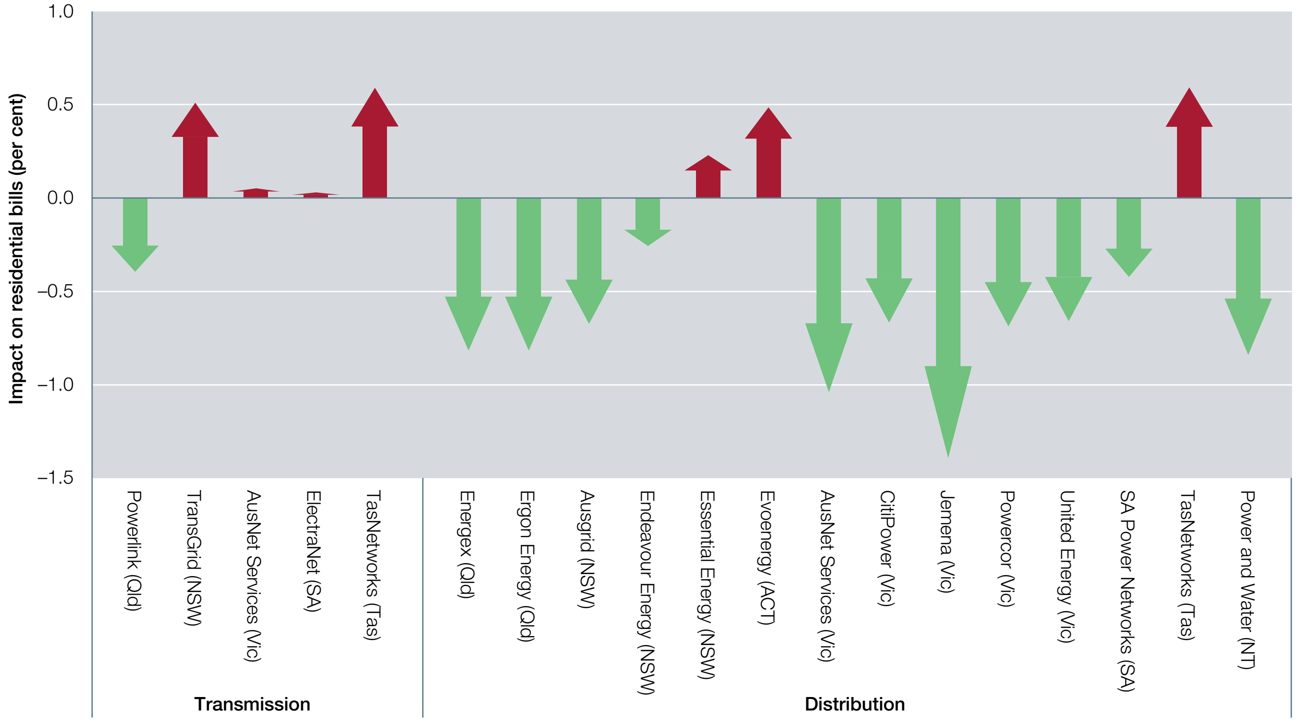
The composition of investment is also changing. The majority of forecast investment in distribution networks is to replace and refurbish old assets, rather than spending on new assets.

Network investment should be driven by how much customers are prepared to pay for a reliable and secure electricity supply. The AER in December 2019 published estimates of the value that customers place on avoiding long unplanned network outages. It found business customers tend to place a higher value on reliability than residential customers do, although residential customers are concerned about long outages, particularly at peak times. The AER will draw on these values when assessing future network proposals for new investment.

New approaches to regulation

The AER encourages innovative approaches to network regulation to achieve better outcomes for energy customers. A number of businesses are trialling engagement models

Figure 8
How AER revenue decisions affect residential customer electricity bills



Note: Estimated impact of latest AER decision on the network component of a residential electricity bill for a customer using 6500 kilowatt hours of electricity per year. Revenue impacts are nominal and averaged over the life of the current decision.

The data account for only changes in network charges, not changes in other bill components.

Outcomes will vary among customers, depending on energy use and network tariff structures.

Source: AER revenue decisions and additional AER modeling.

to identify their customers' needs as a basis for developing new regulatory proposals. Agreement between network businesses and their customers can help ensure network design and development reflect customer preferences on issues such as reliability and access to distributed energy resources. It can also expedite the regulatory process, reducing costs for businesses and energy customers alike.

While engagement processes are improving, consumer groups report the quality of engagement varies across network businesses. They argue the businesses should engage in meaningful engagement earlier in the process (such as 'deep dive' workshops), and engagement should be at the 'consult', 'involve' or 'collaborate' end of the spectrum, rather than just 'inform'.

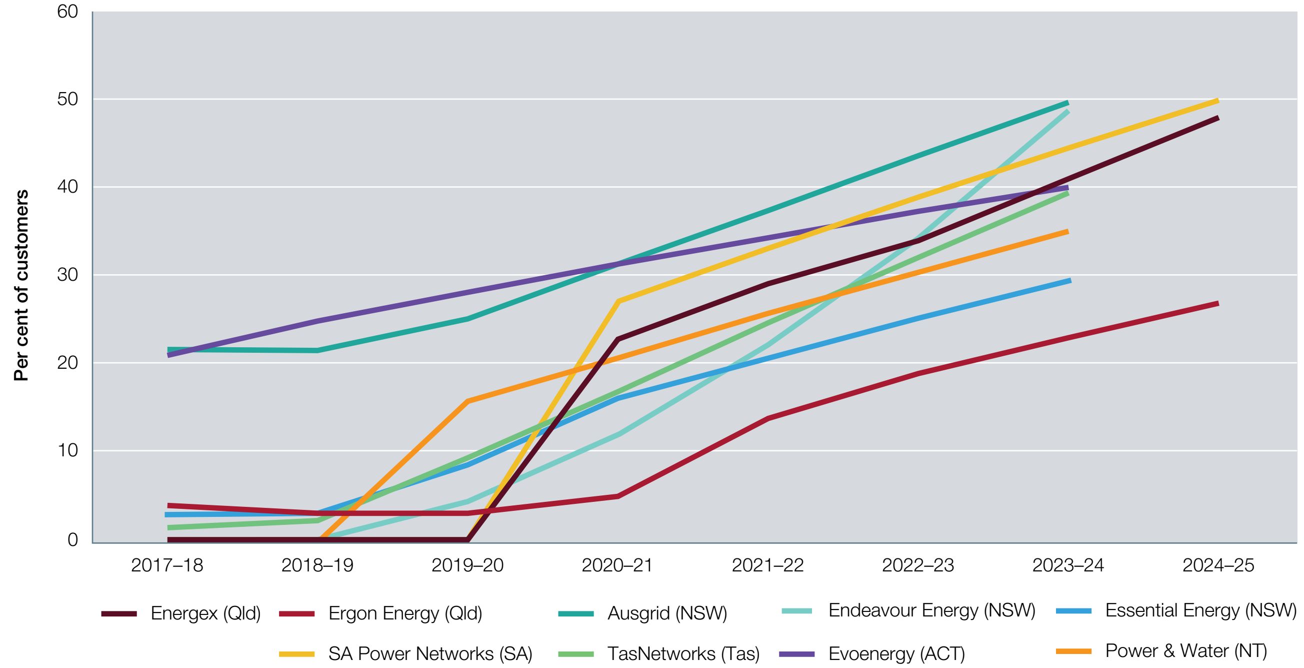
The AER is trialling one early engagement approach in partnership with Energy Networks Australia and Energy Consumers Australia. The first business to trial the model, AusNet Services engaged an independent customer forum to negotiate its regulatory proposal.

Customer engagement included interviews, field visits, commissioned research, observations (such as focus groups, deep dives, workshops and public forums) and reviews (of complaints data, guaranteed service level data and reliability data, and of AusNet Services customer research). This engagement illustrated the complexity of consumer preferences. As an example, customers supported sensible investment by AusNet Services to allow solar exports, so this energy is not wasted and helps reduce all customers' bills. Further, they supported sharing the costs among customers and with government.[8] AusNet Services lodged its regulatory proposal in January 2020, which the AER is now assessing.

Adapting to an evolving market

The growth of distributed energy resources, and innovations in network and communications technology are changing the role of energy networks. Regulatory reforms are being rolled out to unlock the benefits of these changes. Electricity

Figure 9
Projected assignment of cost-reflective tariffs for residential customers



Source: AER analysis of unpublished forecasts supplied by regulated electricity distribution businesses.

distributors are progressively making their network tariffs more cost reflective, for example. Tariff reforms reduce charges at times of low demand, and raise them at times of peak demand when the networks are under strain. Networks levy the new tariff structures on retailers, which then have discretion to set their charges to customers as they see fit.

Cost reflective prices encourage retailers to incentivise energy customers to switch their energy use away from times of high demand to times of low demand, and to operate distributed energy resources such as rooftop solar PV systems and batteries in ways that minimise network stress. Network businesses forecast that up to half of all customers in NSW, Tasmania, the ACT and Northern Territory will be on cost reflective network tariffs by 2024–25 (figure 9).

The AER is supporting network transformation in other ways. It offers incentives for distribution network businesses to manage demand on their networks in ways that will reduce the need to invest in expensive network assets. In September 2019, the AER approved expenditure on residential and grid scale battery storage projects, technology trials to manage demand through device control, and research into distributed energy platforms for demand management. As an example, it is supporting Essential Energy's involvement in a virtual power plant scheme to help manage peak demand on the business's NSW network.

The proposed introduction of a 'regulatory sandbox' toolkit will make it easier for network businesses to develop and trial innovative energy technologies and business models.[9] The toolkit will allow participants to trial smaller scale innovative concepts under relaxed regulatory requirements, on a time limited basis.

AEMO has targeted investment in strategic electricity transmission projects as being critical for supporting the integration of renewable technologies into the market. The AER is amending the cost–benefit test (that is, the regulatory investment test) that it administers for investment proposals, to fast track it for strategic projects such as interconnectors linking networks in different jurisdictions. In early 2020 it fast tracked its determinations that the test had been satisfied for a new interconnector linking South Australia with NSW, and for an upgrade to the Queensland–NSW Interconnector (QNI). The purpose of the faster assessments was to support the timely completion of these projects.

9 AEMC, *Regulatory sandbox arrangements to support proof-of-concepts trials*, 26 September 2019.

5 Retail energy markets

High energy prices and poor perceptions of retailer behaviour have heightened focus on retail energy markets from 2017. Industry assessments found ‘competition … is currently not delivering the expected benefits to consumers’[10] and ‘the retail market has developed in a manner that is not conducive to consumers being able to make efficient and effective decisions about the range of available offers in the market’.[11]

Regulatory reforms targeting these concerns were progressed in 2018 and 2019, aimed at strengthening customer protections, encouraging customers to engage (to their benefit) in the market, and making it easier for customers to compare retail offers. A central reform was the introduction of price caps on retailers’ standing offers from 1 July 2019. Governments introduced a default market offer because standing offer contracts were found to no longer work effectively as a safety net. Standing offer prices had become unjustifiably expensive, and penalised customers who had not taken up a market offer.

The AER sets the default market offer as a cap on standing offer electricity prices in south east Queensland, NSW and South Australia.[12] The price cap is not intended to mirror the lowest price in the market. Rather, it strikes a balance among reducing unjustifiably high prices, allowing retailers to recover costs in servicing customers, and providing customers and retailers with incentives to participate in the market. Victoria introduced a similar but separate default offer that sets standing offer prices at a level that reflects the costs of an efficient retailer in a contestable market. The introduction of price caps has reduced standing offer prices (as intended), but has not been reflected in lower priced market offers by retailers.

Reforms also introduced a ‘reference bill’ to simplify and standardise how retail offers are presented. Any advertised discounts by retailers must be based against the default offer.

These changes followed reforms in 2018 that require retailers to notify small customers before any change in their benefits, alert customers to any expired benefits, and provide advance notice of any price change under an existing contract. In Victoria, retailers also must inform customers on their energy bills whether they are on the retailer’s lowest offer.

Customer trust, or confidence that the market is working in their interests, rose marginally to 33 per cent in December 2019, from 31 per cent a year earlier. Likewise, customer satisfaction with competition in energy markets rose in all markets except south east Queensland, averaging across the NEM a positive rating of 52 per cent.[13]

Since 2018 electricity retail prices for residential customers have plateaued or fallen in most regions, after significant rises in preceding years. The change was due to factors that include new price and advertising regulations, flatter wholesale costs, and reductions in network costs.

Wholesale costs were the main driver of elevated retail electricity prices from 2015 to 2018. Those costs have since moderated in most regions, and tracked lower in Australia in 2019–20 as more low cost renewable generators came online, and as fuel costs for black coal and gas plant eased. This moderation in wholesale prices was yet to be fully reflected in retail prices in January 2020. It can take time for wholesale cost changes to work their way through to retail prices, because retailers typically lock in a portion of their wholesale costs in advance through hedge contracts.

In the seven months to January 2020, standing offer prices for residential customers fell in every region that introduced standing offer price caps in July 2019 (figure 10). Prices fell by 14–19 per cent in Victoria, 11–13 per cent in NSW, 12 per cent in South Australia, and 10 per cent in south east Queensland.[14]

Market offers did not mirror this fall in standing offer prices, remaining relatively steady in NSW, Queensland and South Australia, and increasing in Victoria. Some higher priced market offers that link to standing offer prices did lower, however. But the lowest priced offers also disappeared in some regions. These factors significantly narrowed the price range in available offers between June 2019 and early 2020. In June 2019, for example, the median standing offer by distribution zone was around 28 per cent higher than the median market offer. By January 2020 the gap had narrowed to 6 per cent.

10 AEMC, *2018 retail energy competition review*, *Final report*, June 2018, p. i.
11 ACCC, *Restoring electricity affordability and Australia’s competitive advantage, Retail Electricity Pricing Inquiry—final report*, June 2018, p. 134.
12 Other jurisdictions already had price regulation in place.

13 Energy Consumers Australia, *Energy Consumer Sentiment Survey*, December 2019.
14 Both market and standing offer electricity prices rose in those regions with previously established jurisdictional price regulation—namely, Tasmania, the ACT and regional Queensland.

Figure 10
Movement in energy bills for customers on market and standing offers

Note: AER estimates based on generally available offers for residential customers on a ‘single rate’ tariff structure.

Annual bills and price changes are based on median market and standing offers at June 2018, June 2019 and January 2020, using average consumption in each jurisdiction: NSW 5881 kWh (electricity), 22 855 MJ (gas); Queensland 5699 kWh, 7873 MJ; Victoria 4589 kWh, 57 064 MJ; South Australia 4752 kWh, 17 501 MJ; ACT 6545 kWh, 42 078 MJ.

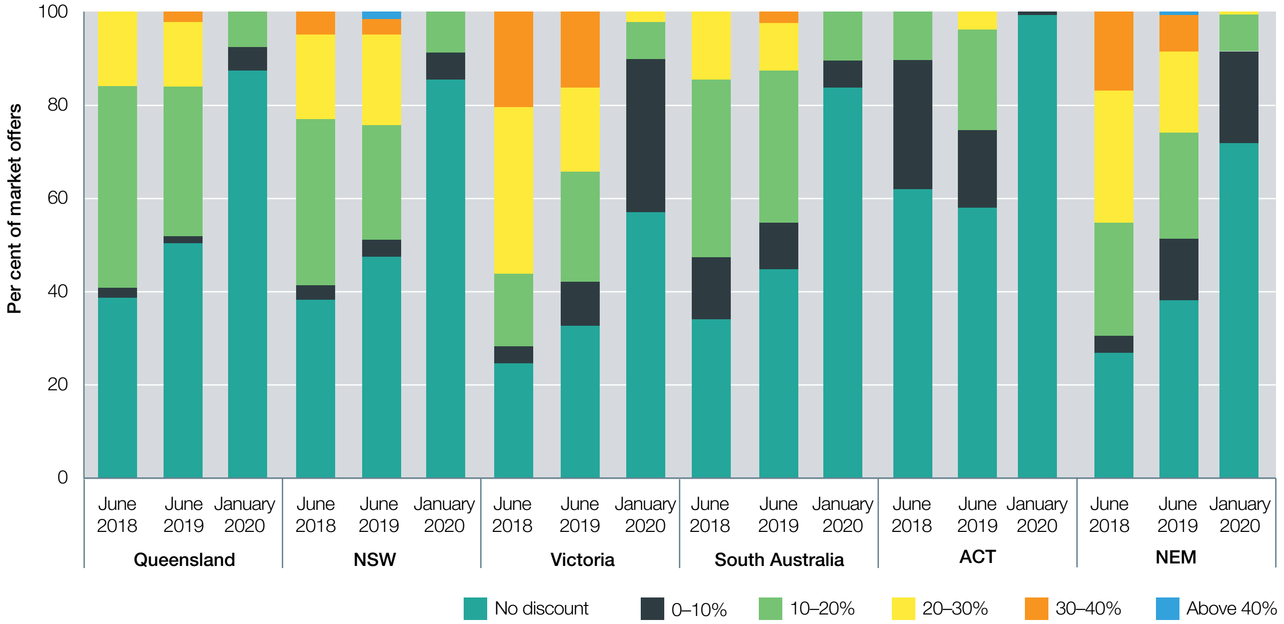
Market offer prices include all conditional discounts.

Source: Energy Made Easy (www.energymadeeasy.gov.au); Victoria Energy Compare (compare.energy.vic.gov.au).

Despite this shift, customers can still benefit by engaging with the market. A customer switching from the median standing offer to the best market offer in their distribution zone could save up to 20 per cent ($300–400 in annual savings) in January 2020. Customers already on market offers could also save, because the lowest priced market offers averaged 7–8 per cent lower than median market offers (and 12–18 per cent lower in Victoria), representing an annual saving of around $100–200.

In gas, recent retail price movements were more varied. Retail prices fell by 6 per cent in the east of Victoria, but rose up to 3 per cent in the west of the state over the seven months to January 2020. In NSW, market offer prices rose by 5 per cent, while standing offer prices were flat. The reverse was true in South Australia, where standing offer prices rose by 6 per cent. Prices in other regions were generally flat. Gas wholesale costs—the key driver of rising retail gas prices from 2015–17—stabilised over 2018 and eased significantly from early 2019.

Figure 11
Conditional discounts for residential electricity market offers



Note: Advertised discounts in generally available market offers.
Source: AER; Energy Made Easy (www.energymadeeasy.gov.au); Victoria Energy Compare (compare.energy.vic.gov.au).

In gas, the gap between market and standing offer prices remains significant. At January 2020 median market offers were 8–21 per cent lower than median standing offers.

Competitive environment

Some evidence emerged in 2019 of improved competition in the retail energy market. Market concentration lowered as smaller retailers grew their customer base in established markets, and expanded into new markets. Three businesses—AGL Energy, Origin Energy and EnergyAustralia—continued to dominate in 2019, supplying 63 per cent of small electricity customers and 75 per cent of small gas customers in eastern and southern Australia. But ‘second tier’ retailers have built significant market share in some regions. Snowy Hydro, Alinta Energy and Simply Energy have emerged as strong ‘gentailers’, while smaller retailers have gradually built market share (with 8 per cent of electricity customers and 4 per cent of gas customers in 2019).

Retailers are moving away from discounting towards simpler, more stable pricing. This move coincided with reforms introduced in 2019 that restricted advertising based around large headline discounts. Before reform (in 2018), around two thirds of electricity offers offered discounts conditional on the customer meeting terms such as on time payment (figure 11). The discounts offered 10–40 per cent off a customer’s bill. By January 2020, offers with guaranteed prices (no conditional discounts) comprised over 80 per cent of offers in Queensland, NSW, South Australia and the ACT. A majority of conditional discounts were for less than 10 per cent off the base price.

Although discounting reforms apply in electricity only, practices in gas followed similar trends.

While the size of discounts has decreased, this change has not worsened outcomes for customers. The size of previous discounts was often deceiving, because retailers measured discounts off different price bases. The size of discounts may reduce further following a rule change in February 2020 that limits conditional discounts to the reasonable cost savings that a retailer could expect if a customer satisfies the conditions attached to the discount.

Additionally, retailers are offering a wider range of products and services, such as leveraging off the uptake of solar PV and battery technology to offer contracts that give customers greater control over their electricity costs. Other retailers are focusing on products that are simple to understand and provide a high level of bill certainty.

These offers include fixed price contracts (where the customer pays a fixed amount regardless of how much energy they use) and subscription offers (where a customer pays a set amount each period to cover their expected electricity use).

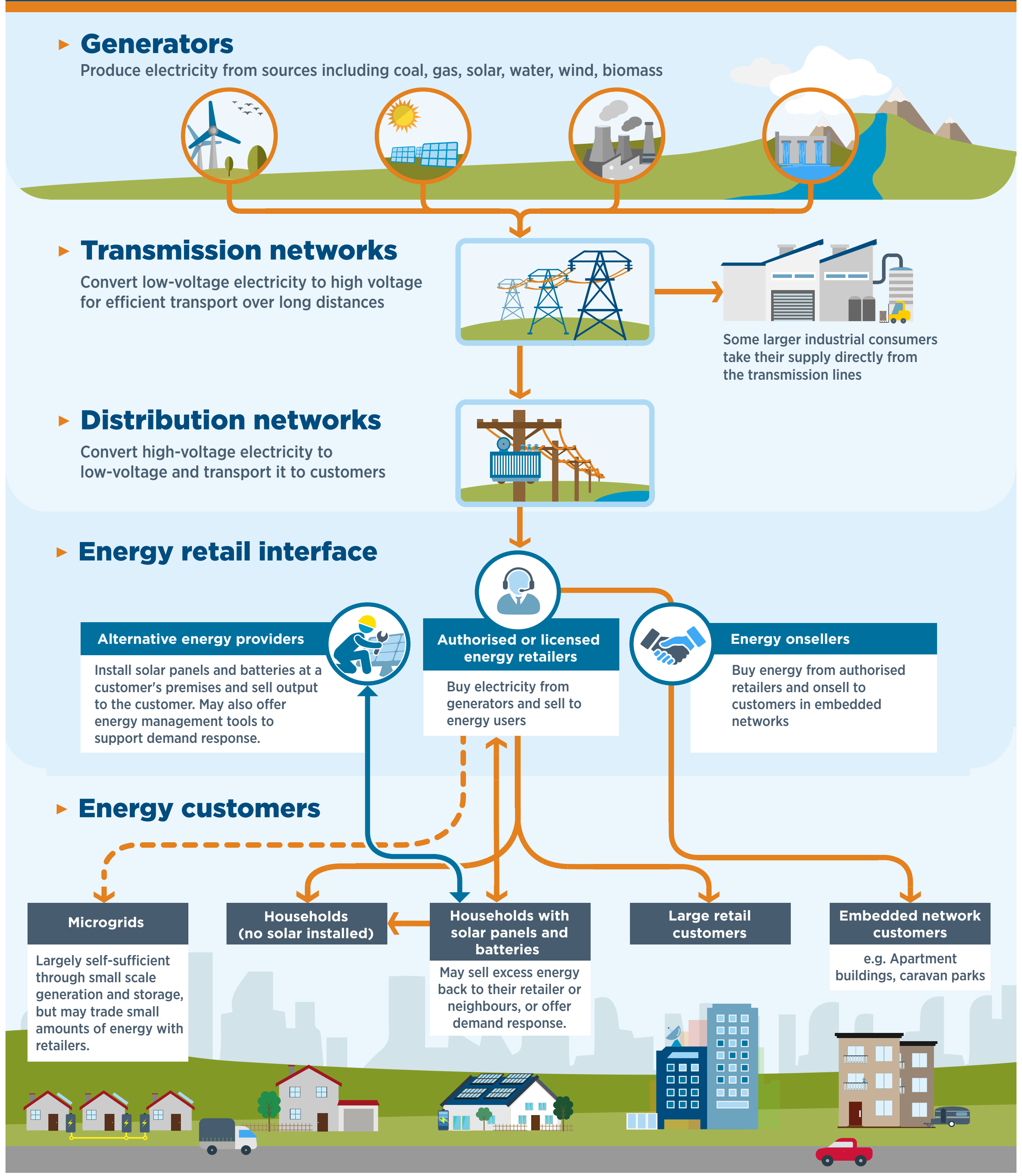
Customers in vulnerable circumstances

While energy prices have moderated, they continue to be a source of financial pressure for customers in vulnerable circumstances. Payment plans and hardship programs are the key mechanisms in place to support customers facing payment difficulties. The AER has focused on improving frameworks around these tools to promote better customer outcomes, releasing a Sustainable Payment Plans Framework in 2017 and a revised hardship guideline in 2019.

To better understand issues facing customers in vulnerable circumstances, the AER in 2020 published research (by the Consumer Policy Research Centre) on regulatory approaches to customer vulnerability.[15] The report will inform the AER’s approach in this vital area.

15 CPRC, *Exploring regulatory approaches to consumer vulnerability, A report for the Australian Energy Regulator*, November 2019.

Infographic 1—Electricity supply chain



Infographic 2—Gas supply chain