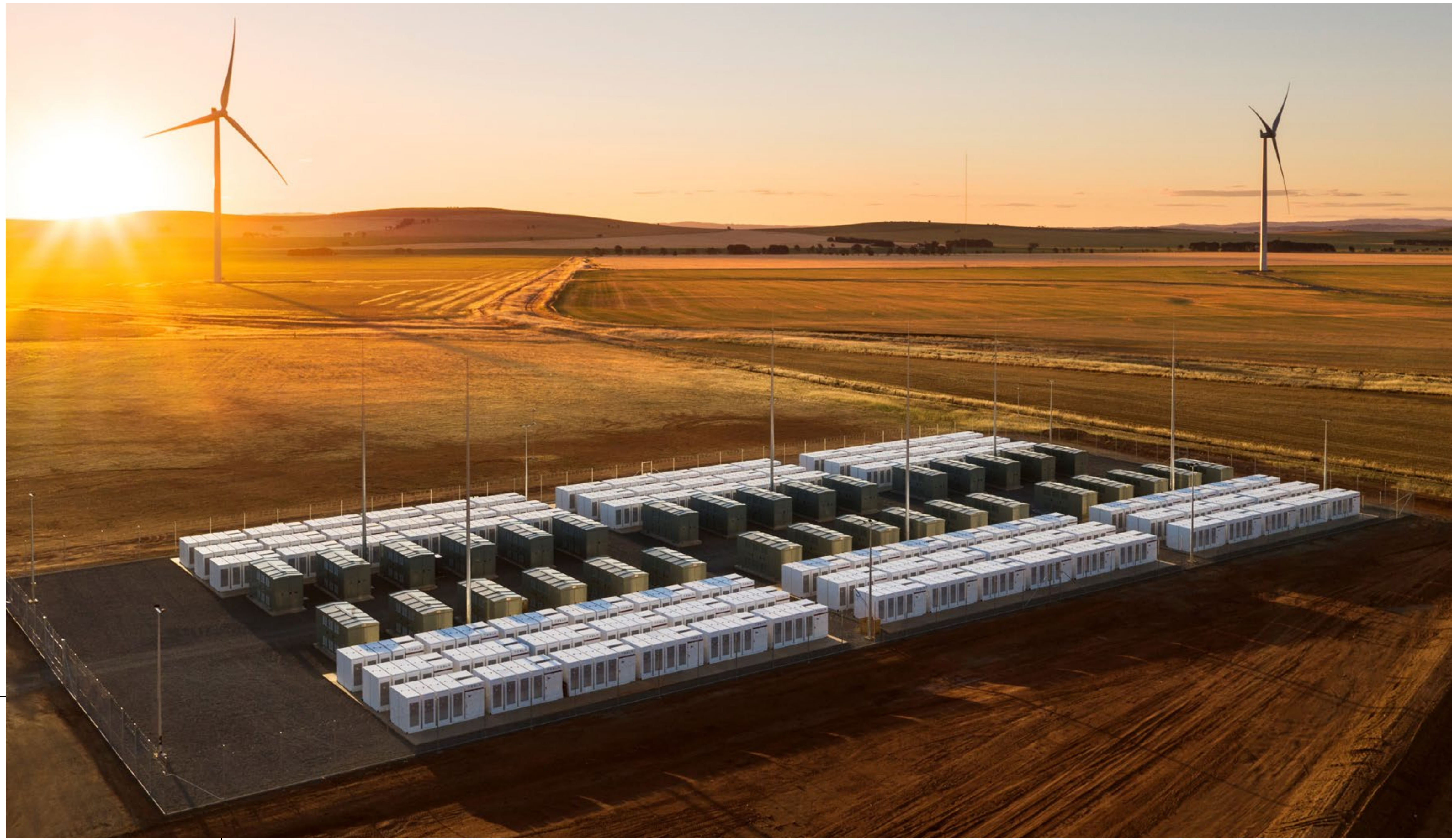
Image courtesy of Neoen



THE ELECTRICITY MARKET IN TRANSITION

Australia's electricity markets are undergoing a profound transformation from a centralised system of large fossil fuel (coal and gas) generation towards an array of smaller scale, dispersed generators, most of which use wind and solar technologies. The transition is particularly advanced in South Australia, which at times meets all electricity demand from renewables.

Additionally, some energy customers are adopting their own 'behind the meter' energy solutions—namely, distributed energy resources (DER) that include rooftop solar photovoltaic (PV) installations, small batteries, electric vehicles and demand response. Customers may sell power generated from their solar PV systems and batteries into the grid (typically during the day), and draw power from the grid at other times. So, where power once moved in one direction, from large generators through transmission and distribution lines to end customers, two-way flows now occur.

A web of interrelated factors is driving this transition. Community concerns about the impact of fossil fuel generation on carbon emissions were a major catalyst for change, driving action by governments and businesses. In the electricity sector, government incentives for lower emissions generation encouraged investment in wind, solar farms and small scale solar PV systems. An environment of high energy prices gave further impetus to this transition, by driving customers to change their behaviour (to use energy more efficiently and to generate their own power).

As the uptake of renewables rose, economies of scale drove down construction and installation costs. Technologies also improved, further lowering costs. These developments reinforced incentives for further investment. This cycle helped establish Australia's solar PV and wind industries.

While renewable generation investment is growing strongly, some of the major fossil fuel power stations that supplied Australia's electricity over the past 50 years have been retired or announced for retirement as they near the end of their economic life. This transition raises challenges.

The weather dependent nature of renewable 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 requires better demand and supply forecasting to ensure firming capacity is available when needed.

The transition also poses risks to the technical security of the power system. The rising proportion of renewable generation is bringing more periods of low inertia, weak system strength, more erratic frequency shifts, and voltage instability.[1] And, with new plants locating in sunny or windy areas at the edges of the grid where network capacity is insufficient to serve them, solutions are needed to deliver energy to customers. Two-way power flows are creating similar pressure points in local distribution networks.

Finding the best ways to keep the power system reliable and secure as the generation mix changes is an ongoing challenge. Improved data and technology services are providing some solutions. New renewables plants, for example, are being engineered to provide synthetic inertia and other system security services that fossil fuel plants traditionally provided. During the transition, however, more frequent market interventions have been needed to maintain a reliable and secure power system. Strategic planning, policy and regulatory reforms are being implemented to guide the transition to optimise benefits for energy customers.

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

1.1 Drivers of change

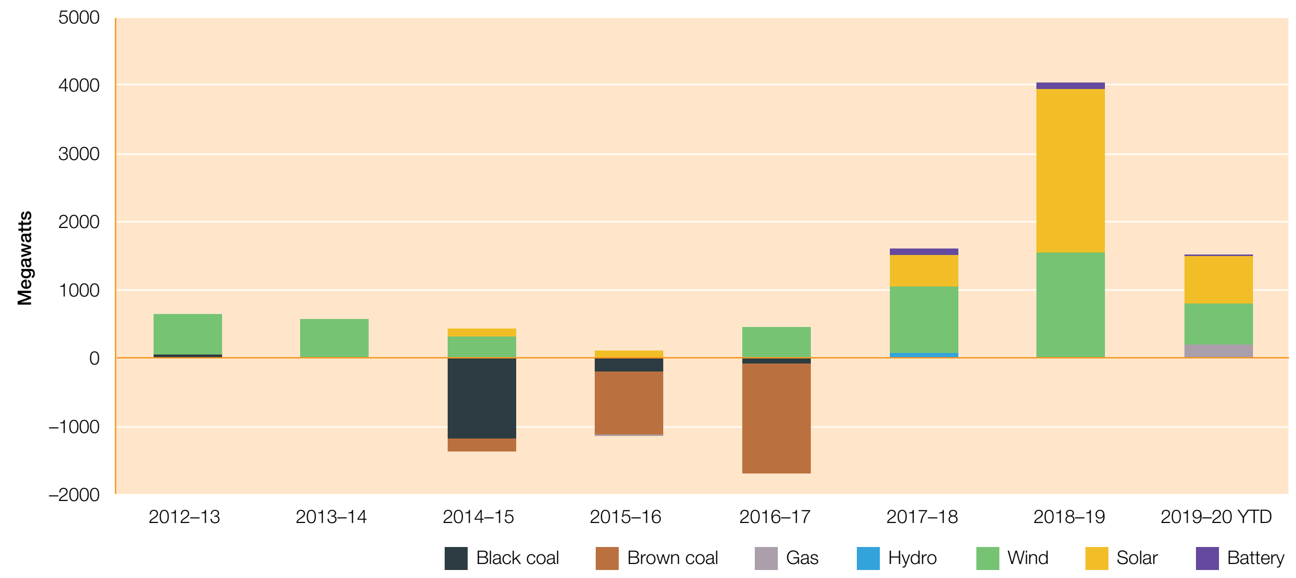
Community concerns about the impact of fossil fuel generation on carbon emissions, technology and cost changes, and an ageing coal fired generation fleet are among the factors driving Australia's energy market transition.

1.1.1 Action on climate change

Community concerns about the impact of fossil fuel generation on carbon emissions were a major catalyst for the transition underway in the electricity sector. Energy businesses responded to these concerns by changing their approach to generation investment. No energy business has invested in new coal fired generation in Australia since 2012 (figure 1.1).

1 Box 1.4 defines these terms.

Figure 1.1
Entry and exit of generation capacity in the NEM



Note: Capacity includes scheduled and semi-scheduled generation, but not non-scheduled or rooftop PV capacity. 2019–20 YTD includes data to 31 March 2020.

Source: AER; AEMO (data).

Instead, investment is targeting lower emission renewable technologies. Commercial businesses also moved to generate some of their energy requirements through solar PV systems.

Australian governments also took action. At a global level, Australia made international commitments under the Kyoto Protocol (2005) and the Paris Agreement (2016) to reduce its carbon emissions. It committed in Paris to reduce its carbon emissions by 26–28 per cent below 2005 levels by 2030. The agreement set no specific target for the electricity sector.

Australia's carbon emissions have risen since 2016 (figure 1.2). But the electricity sector's contribution lowered over this period, following the closure of coal fired generators in South Australia (in 2016) and Victoria (in 2017), and significant investment in wind and solar generation. Despite this change, the electricity sector remains the largest contributor to national carbon emissions, accounting for 34 per cent of Australia's total emissions.

Victoria's brown coal plants are the most emission intensive power stations in the National Electricity Market (NEM), followed by black coal plants and gas powered generation. Wind, hydroelectric and solar PV power stations generate negligible emissions. Fuel mixes vary across jurisdictions, with Victorian generation (mainly brown coal) having the highest emissions factor, and Tasmania (mainly hydro) having the lowest.[2]

Australia's policy settings to reduce carbon emissions in the electricity sector have changed direction many times. Current government policy focuses on financial incentives for private investment in lower emission generation (box 1.1). The schemes have encouraged significant investment in wind and solar farms, and small scale solar PV systems.

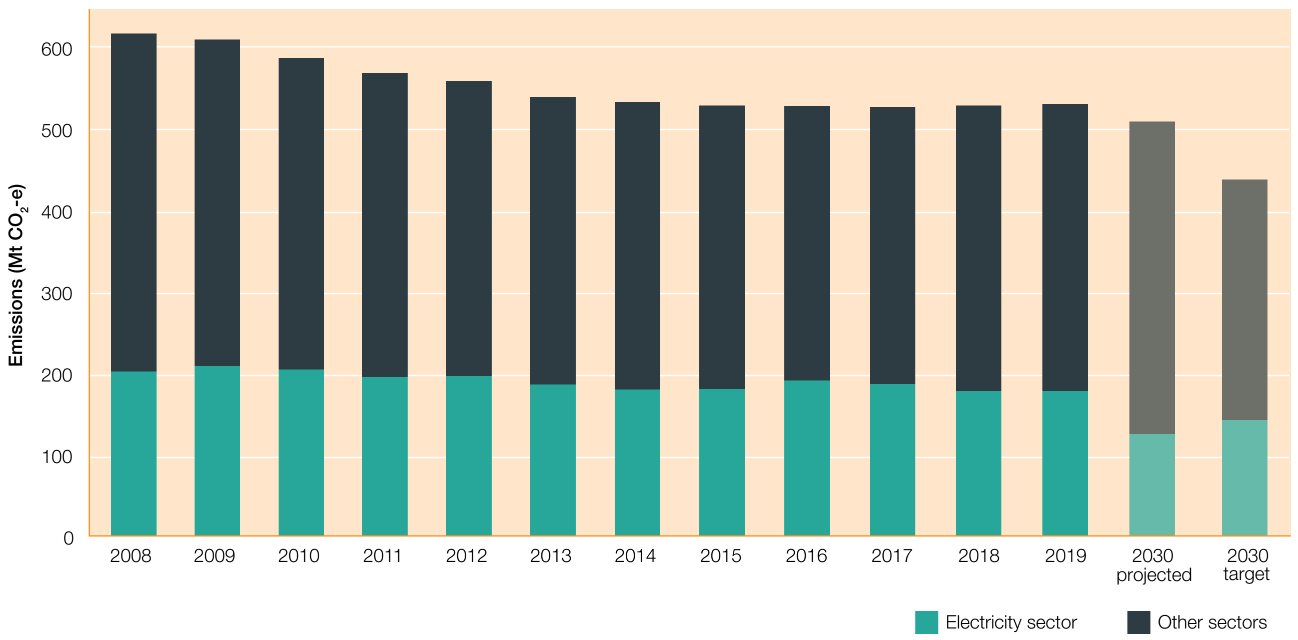
Alongside national policies, several state and territory governments set renewable energy targets that are more ambitious than the national scheme. Programs encouraging new renewable entry typically support these targets.

1.1.2 Technology and cost changes in the renewables sector

While government policies on climate change helped drive the surge in renewable energy, the declining costs of renewable plant (both at commercial and small scale levels) accelerated the shift. Improvements in plant technologies and the scale benefits of an expanding market are significant factors driving these cost improvements.

2 Department of the Environment and Energy, *National greenhouse accounts factors, August 2019*, 2019.

Figure 1.2
Australia's carbon emissions



Mt CO_2-e, million metric tonnes of carbon dioxide equivalent.

Note: Electricity sector emissions exclude stationary energy, transport and fugitive emissions.

The 2030 target is based on Australia's Paris commitment of a 26 per cent reduction on 2005 emissions levels, and assumes a proportional contribution by the electricity sector.

Projected 2030 emissions are as forecast by the Department of Industry, Science, Energy and Resources in December 2019 in the absence of policy intervention.

Source: Department of Industry, Science, Energy and Resources, *Quarterly update of Australia's national greenhouse gas inventory*, June 2019; Department of the Environment and Energy, *Australia's emissions projections*, December 2019.

Technological advancements and cost reductions in grid scale wind and solar generation have outpaced predictions made a decade ago. This shift appears to be continuing. The International Renewable Energy Agency (IRENA) reported the global levelised cost of onshore wind generation fell by 35 per cent between 2010 and 2018. Over the same period, it reported the global levelised cost of large scale solar PV fell by 77 per cent. In Australia, the Commonwealth Scientific and Industrial Research Organisation (CSIRO) and Australian Energy Market Operator (AEMO) in December 2019 estimated a levelised cost of electricity (LCOE) in 2020 for large scale solar PV and onshore wind of around $50 per megawatt hour (MWh). They forecast the cost of onshore wind will continue to reduce marginally to 2050, but the cost of large scale solar PV will reduce by almost half in that time.[3]

The substantial cost reductions observed in wind and solar technology have made these renewables the lowest cost option for new build generation. The CSIRO found the cost of those technologies is significantly lower than construction costs for new black coal and brown coal generators (and significantly lower than the cost of coal generation with carbon capture and storage).[4] The lifecycle costs of wind and solar generators are now becoming competitive with the operational costs of the current fleet of conventional generators.

The cost reductions observed in wind generation are largely driven by advancements in turbine technology. Over the past two decades, the diameter of the rotors and hub heights increased significantly, resulting in larger turbines. This development increased capacity factors (the amount of electricity that can be generated over a specific period)

3 CSIRO, *GenCost 2019–20: preliminary results for stakeholder review, Draft for review*, December 2019.

4 CSIRO, *GenCost 2019–20: preliminary results for stakeholder review, Draft for review*, December 2019.

Box 1.1 Emission reduction policies and the electricity industry

Australia's key policy initiatives in recent years to reduce carbon emissions from electricity generation are outlined below.

Renewable energy targets

The Australian Government launched a national renewable energy target (RET) scheme in 2001, and has since revised it several times. The scheme applies different incentives for large (such as wind and solar farms) and small (such as rooftop solar photovoltaic (PV)) scale energy supply. It requires energy retailers to buy renewable energy certificates for electricity generated by accredited power stations or from the installation of eligible solar hot water or small generation units. The certificates allow renewable generators to earn revenue above what they earn from selling electricity in the wholesale market.

Amendments to the RET scheme in 2015 set the 2020 target for energy from large scale renewable projects at 33 000 gigawatt hours (GWh). Sufficient renewable generation was committed by September 2019 to meet this target.[a] The Australian Government's policy is to not increase the target beyond the 2020 requirement, and to not extend or replace the target after it expires in 2030.[b]

Some state and territory governments set renewable energy targets that are more ambitious than the national scheme:

- The Victorian Government set a legislated target of 25 per cent of the state's electricity to be sourced from renewable resources by 2020, and 40 per cent by 2025.
- The Queensland Government has an unlegislated target of 50 per cent renewable generation by 2030.
- The Australian Capital Territory (ACT) has a legislated target of 100 per cent of Canberra's electricity being met by renewable generation by 2020.

To support these targets, state and territory governments run programs encouraging investment in renewables:

- The Victorian, Queensland and ACT governments offer 'contracts for difference'[b] to new renewable generation investments, awarded through reverse auctions.[c]
- The Queensland Government established CleanCo, which is a new generation company to directly invest in renewable and gas firming capacity.
- The Victorian, South Australian, Queensland and ACT governments operate schemes that provide grants, rebates or loans to support small scale solar PV and battery systems.

In the past, state and territory governments also offered incentives such as premium feed-in tariffs to support the installation of residential solar PV systems. Those schemes are closed to new entrants. More generally, state and territory governments operate energy efficiency schemes that encourage households and small business customers to reduce their electricity demand.

ARENA and CEFC

The Australian Government established the Australian Renewable Energy Agency (ARENA) in 2012 to fund the research, development and commercialisation of renewable technologies. The agency funds innovative projects that would otherwise struggle to attract sufficient funding or be potentially lost to overseas markets.

From its inception, ARENA has invested around $1.5 billion in close to 500 projects, with a combined value of $5.5 billion. The projects include solar PV, hybrid, solar thermal, bioenergy, ocean, hydrogen, geothermal, grid integration, battery and pumped hydro storage projects. ARENA's focus since 2019 is on projects that integrate renewables into the electricity system, accelerate the development of hydrogen energy supply, and support industry efforts to reduce emissions.[d]

The Clean Energy Finance Corporation (CEFC) was launched in 2012 as a government owned green bank to promote investment in clean energy. The fund provides debt and equity financing (rather than grants) for projects that will deliver a positive return. CEFC finance of around $5.5 billion has delivered 1.6 gigawatts (GW) of large scale solar capacity and 2 GW of wind capacity, and significant investment in storage and energy efficiency.[e]

Additionally, ARENA and the CEFC jointly manage the Clean Energy Innovation Fund, which provides debt and equity for clean energy projects at early stages of development that require growth capital.

Carbon pricing

A carbon pricing scheme operated in Australia from 1 July 2012 to 1 July 2014. The scheme placed a fixed price on carbon of $23 per tonne of carbon dioxide equivalent emitted. The emission intensity of National Electricity Market (NEM) generation fell by 4.7 per cent over the two years that carbon pricing was in place. This drop in emission intensity, combined with lower NEM demand, contributed to a 10.3 per cent fall in total emissions from electricity generation over those two years.

Climate Solutions Fund

Under the Australian Government's Climate Solutions Fund (called the Emissions Reduction Fund until February 2019), the government pays for emission abatement through 'reverse' auctions run by the Clean Energy Regulator. Ten auctions were held to March 2020, with spending of $2.3 billion to abate 193 million tonnes of carbon emissions (an average price of $12.06 per tonne of abatement). Purchases steadily declined over recent auctions, from 50 million tonnes of abatement in the third auction, to an average of less than 2 million tonnes in the past three auctions.[f]

Many funded projects involved growing native forests or plantations, otherwise known as carbon farming. The electricity sector made less than 2 per cent of the carbon abatements under the scheme. Participating electricity projects mostly capture and combust waste methane gas from coal mines for electricity generation.[g]

Following a review of the scheme, the government in May 2020 announced an expansion of the scheme, including the scoping of carbon capture and storage technology.[h]

a. Clean Energy Regulator, '2020 Large-scale Renewable Energy Target capacity achieved', Media release, 4 September 2019.

b. Commonwealth, *Parliamentary Debates*, House of Representatives, 18 September 2018, 9325 (The Hon. Angus Taylor MP, Minister for Energy).

c. Contracts for difference provide a hedge for the holder by locking in future wholesale electricity prices (section 2.7).

d. ARENA, *ARENA at a glance, Q3 2019*, 2019.

e. CEFC, *FY19 investment update—accelerating Australia's sustainable transition to lower emissions*, July 2019.

f. Auction results published by the Clean Energy Regulator, available at: www.cleanenergyregulator.gov.au/ERF/Auctions-results.

g. Projects do not necessarily connect to the NEM.

h. The Hon. Angus Taylor MP (Minister for Energy and Emissions Reduction), 'Building on the success of the Emissions Reduction Fund', Media release, 19 May 2020.

and made areas with lower wind speeds economic for wind generation development.[5]

In 2019 the IRENA reported the maximum size of the wind turbines deployed was 4.3 megawatts (MW). By comparison, the average turbine deployed in 2000 was only 1 MW (figure 1.3). This shift represents a significant increase in the capability of wind generation over the past 20 years.[6]

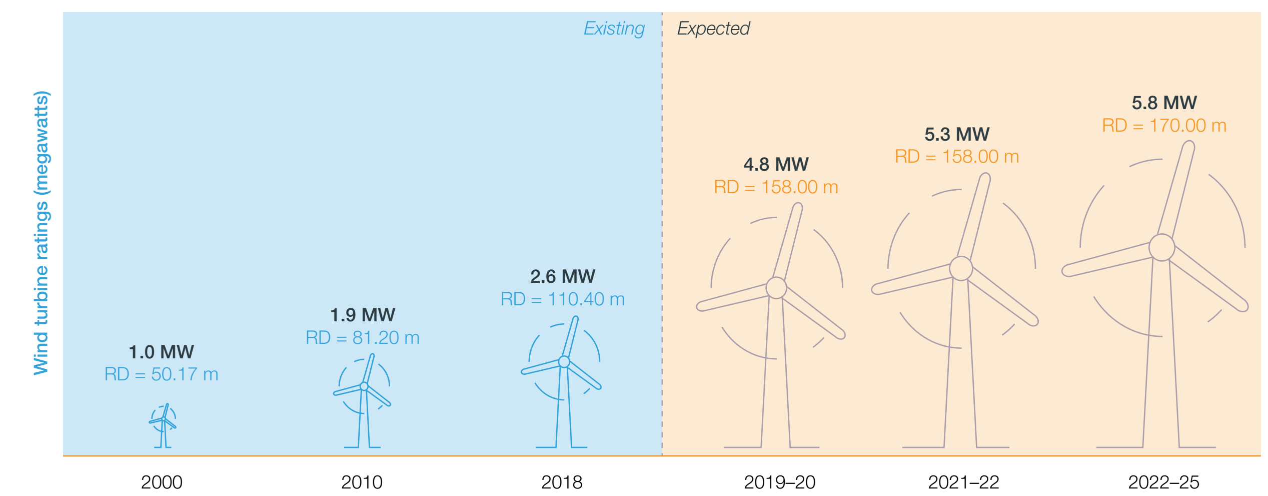
Solar cost reductions were mainly driven by lower panel costs, and by continued reductions in the costs of supporting equipment (such as inverters, transformers and rack/frame mounts) and installation costs.

Battery costs have also fallen. Bloomberg estimated lithium ion battery pack prices fell by around 85 per cent between 2010 and 2018.[7] The cost reductions were driven by technology innovation (with increased energy density at the cathode and cell level), improved manufacturing, and economies of scale. The CSIRO projected weaker cost reductions as the technology matures, but considered costs reductions may again accelerate from around 2025 as global capacity for battery manufacturing rises to meet the demand for electric vehicles.[8]

5 IRENA, *Future of wind: deployment, investment, technology, grid integration and socio-economic aspects*, 2019.
6 IRENA, *Future of wind: deployment, investment, technology, grid integration and socio-economic aspects*, 2019.

7 Bloomberg New Energy Finance, *New energy outlook 2019*, 2019.
8 CSIRO, *GenCost 2019–20: preliminary results for stakeholder review, Draft for review*, December 2019.

Figure 1.3
Wind turbine development



MW, megawatts; RD, rotor diameter.

Source: International Renewable Energy Agency, *Future of wind: deployment, investment, technology, grid integration and socio-economic aspects*, 2019.

1.1.3 Deteriorating economics of fossil fuel generation

The declining costs of renewable generation coincided with the deteriorating economics of fossil fuel generation, making the latter less competitive in the market:

- The ageing of Australia's coal fired generation fleet is causing more frequent and longer unplanned outages, and higher operating and maintenance costs.
- The rapid escalation of solar PV generation is lowering electricity demand during the day, reducing output from coal fired generators at these times.
- Fuel costs rose significantly for New South Wales (NSW) black coal plant from mid-2016 to late 2018, and for gas plant from 2015 to 2018, but eased for both in 2019.

Despite these challenges, profits and share prices for some coal generators have shown resilience. This resilience may reflect ongoing tightness in the electricity supply–demand balance, particularly following the recent closures of large coal plant in South Australia and Victoria. The Australian Energy Regulator (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.

An ageing coal fleet

Australia's coal fired generators are ageing. Some have been retired, and others are nearing the end of their economic life. There are 18 large coal fired power stations operating in the NEM, with a median age of 34 years: five in NSW (median of 38 years), three in Victoria (median of 36 years) and 10 in Queensland (median of 23 years).

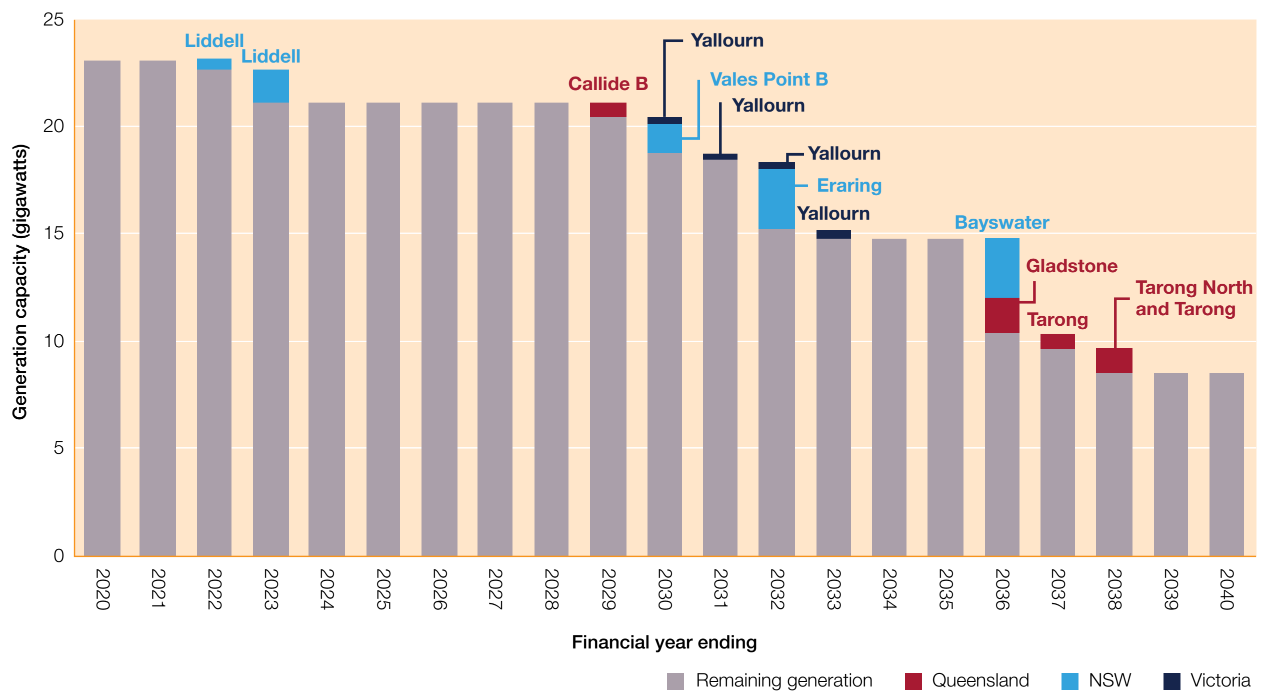
Recent closures include the Northern Power Station in South Australia (2016) and Hazelwood in Victoria (2017). The ageing plants had become increasingly unprofitable as a result of rising maintenance costs, coal supply issues, and market penetration by other plant technologies. The Northern and Hazelwood plants closed after 31 and 53 years of operation respectively.

In announcing the closure of Northern, Alinta Energy described the plant as 'increasingly uneconomic', citing declining electricity demand in South Australia, the performance of the plant, and workplace safety considerations.[9] Hazelwood was the most emission intensive power station in the Organisation for Economic Co-operation and Development (OECD) when it closed. Announcing the closure, Hazelwood's owner Engie described the power station as having experienced 'difficult market conditions' and 'reached the end of its productive life'.[10]

Further coal plant closures are foreshadowed, with around two thirds of total coal fired generating capacity announced for closure over the next 15 years (figure 1.4). Those closures would leave Mount Piper in NSW (1320 MW) and

9 ABC, 'Alinta Energy to close power stations at Port Augusta and coal mine at Leigh Cree', Media release, 11 June 2015.
10 Engie, 'Hazelwood power station in Australia to close at the end of March 2017', Media release, 3 November 2016.

Figure 1.4
Scheduled closure profile of coal fired generators



Source: AEMO, *Draft 2020 integrated system plan*, December 2019.

Loy Yang B in Victoria (1000 MW) as the last remaining coal fired power stations outside Queensland.

AGL plans to progressively retire its Liddell power station in NSW from 2022, when it reaches its 50th year of operation. It plans to retire one of the plant's four units in April 2022, but delayed closing the three remaining three units until April 2023 to support system reliability over the 2022–23 summer.[11] The plant suffers from regular failures. During a heatwave in February 2017, for example, three of the plant's four turbines broke down.[12] The plant supplies around 10 per cent of NSW electricity, but declining reliability means it often runs at less than half its current rated capacity. AGL intends to replace the plant with a mix of renewable generation, gas peaking capacity, batteries, and an upgrade of its Bayswater power station.[13]

Two gas plants are also scheduled for retirement—AGL's Torrens Island A plant (480 MW) in South Australia (progressively from 2020 to 2022), and the Mackay plant (34 MW) in Queensland (2021). There is speculation on the future of other plants too. In late 2019 CS Energy announced it may close its Callide B (700 MW) coal generator in Queensland a decade earlier (in 2028) than previously planned, due to technical reasons.[14] EnergyAustralia's Yallourn brown coal generator in Victoria may also close earlier than expected, with the timeframe now described as a phased retirement of the generator's four units from 2029 to 2032.[15] At the time of publication, neither plant had provided notice of closure.

Impacts of solar generation on fossil fuel plant

When rooftop solar PV generation is high in the middle of the day, the demand for electricity from the grid falls significantly (section 1.2.3). This phenomenon drives down prices at these times, challenging the economics of coal fired generators, which are engineered to run continuously.

11 AGL, 'Schedule for the closure of AGL plants in NSW and SA', Media release, 2 August 2019.
12 Angela Macdonald-Smith and Ben Potter, 'The fight about AGL's Liddell power station explained', *Financial Review*, 11 April 2018.
13 AGL, 'AGL announces plans for Liddell Power Station', Media release, 9 December 2017.

14 CS Energy, 'Statement on the future of Callide B Power Station', Media release, 27 October 2019.
15 EnergyAustralia, 'Statement on the Yallourn power station', Media release, 24 June 2019.

Origin and AGL have announced plans to alter the operation of their Eraring and Bayswater plants (NSW) respectively in coming years. Options include shutting some generating units from mid-morning, before firing them back up in the evening. This process—known as two-shifting—represents a significant shift in the operation of coal generators in Australia.

The ability of generators to manage two-shifting will vary depending on plant age and condition. That is, the increased cycling of output compounds stress on equipment, potentially requiring more frequent maintenance (planned outages) or, in an extreme scenario, earlier retirement (if two-shifting proves uneconomic).

Minimum demand remains sufficient to cover the minimum technical operating levels of most coal plant. But, if demand drops below those levels, coal plant operations may be significantly disrupted.

Fuel costs

Fuel costs for black coal and gas powered generators surge from time to time as they compete for fuel supplies on the world market. Export prices for Newcastle black coal rose by 50 per cent between July 2013 and July 2018, for example, exposing black coal generators in eastern Australia to higher fuel costs (to the extent that they were not covered by long term contracts). Black coal prices peaked at around US$120 per tonne in June 2018, but eased sharply in 2019 and sat below US$70 per tonne in February 2020.

A similar story occurred for gas powered generation. Gas fuel prices rose significantly from 2015 to 2018, when Queensland's liquefied natural gas (LNG) plants absorbed gas supplies from the domestic market to meet export obligations. Higher fuel costs made gas powered generation less economically viable during this period. Gas prices then eased from mid-2019, before falling significantly at the end of the year. A plunge in global oil markets led domestic gas prices in early 2020 to return to 2015–16 levels.

When fuel costs are high, fossil fuel generators increase the prices at which they offer capacity into the market. While higher prices cushion the impact of fuel costs, they also incentivise new entry by renewable plant. Then, as renewables take a larger share of the generation mix, coal and gas plant is less able to set high dispatch prices.

1.2 Features of the transition

Features of the energy market transition include an evolving technology mix in the generation sector, including a rapid uptake of distributed energy resources (DER), and significant changes in electricity demand.

1.2.1 A changing generation mix

The mix of electricity generation is changing, both at grid scale and at the individual customer level. Between 2014 and 2020, more than 4000 MW of coal fired generation left the market. No material coal fired or gas powered generation has been added to the market since a 240 MW upgrade to the Eraring power station in NSW was completed in 2013. Over this same period, more than 7000 MW of new renewable supply came online (mainly in the form of wind and large solar) (figures 1.5 and 1.6). Another 3340 MW of renewable capacity is committed for 2020, of which the bulk is wind (56 per cent) and solar (43 per cent) plant. Figure 1.7 illustrates the impact of these shifts on output from different types of plant.

There is also a shift away from the traditional model of having relatively few large power stations congregated close to fossil fuel sources, towards having many small to medium generators spread out across the system. New solar and wind plants are often being constructed in locations with the richest wind and solar resources, but many of these locations are remote areas where the network struggles to cope with more capacity. Sections 1.5 and 1.6 discuss some challenges in managing these issues, and solutions being developed.

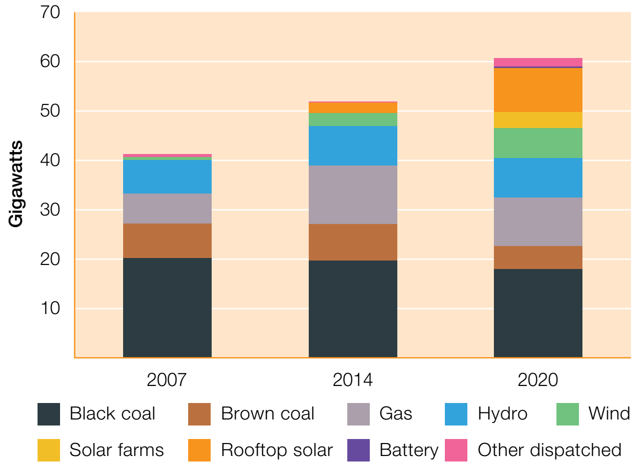
While total capacity in the market has increased, renewable generators have lower utilisation factors compared with conventional plant. For every 1 MW of coal plant retiring, 2–3 MW of new renewable generation capacity is needed, because wind and solar plants can operate only when weather conditions are favourable.[16] For this reason, increased supply from black coal fired stations has been needed to fill much of the supply gap left by the more recent brown coal plant closures in South Australia and Victoria.

Coal fired generation remains the dominant supply source in the NEM, meeting around 68 per cent of energy requirements in 2019.[17] The market at times also uses gas powered generation to manage the variability of renewables' output. As a result, gas plant is being used more often than in the past, at times even when gas fuel costs are high.

Investment in gas powered generation has been negligible, however, with significantly higher gas prices making this plant less economically viable.

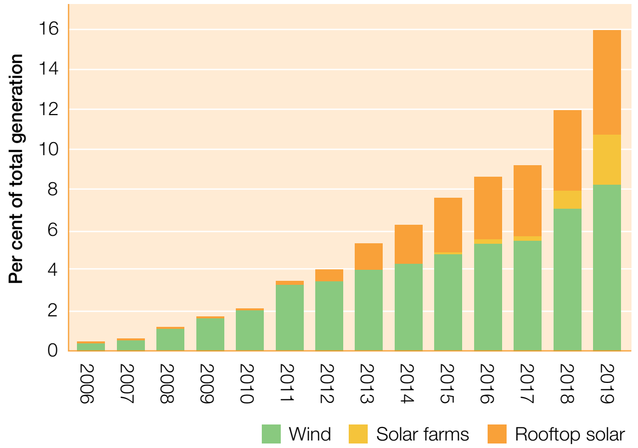
16 AEMO, *Draft 2020 integrated system plan*, December 2019.
17 Based on total generation (including rooftop solar PV) to meet electricity consumption.

Figure 1.5
Generation capacity, by technology



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

Figure 1.6
Renewable generation in the NEM



Source: AER; AEMO (data).

Fewer spot electricity prices above $300 per MWh may also be impairing the profitability of gas plant, whose business model often relies on selling cap contracts to customers that wish to insure against high prices. But the Australian Government announced support for two gas plant proposals in early 2020, to attract more dispatchable plant into the market (section 1.7.1).

Increased variability of supply and demand

Increased wind and solar generation in the NEM is creating more volatile supply and demand conditions. Since wind and solar use weather as a fuel source, their output is both variable and difficult to predict. Solar production depends on the level of light received, so output is lower on cloudy days, and in winter when the days are shorter and the sun is lower in the sky. Wind production varies based on wind speed, which fluctuates continuously. By comparison, coal, gas and large hydroelectric schemes are fuel sources that can stockpile output for continuous use. While those plant technologies are also susceptible to outages or fuel shortages, their output when they are operating is predictable and controllable.

As the lowest marginal cost source of generation, wind and solar typically bid so they can generate when available, with more expensive sources of supply responding to their variability. Apart from variations caused by weather, renewable plant owners can also respond quickly to changes in economic signals (by, for example, switching off a plant if wholesale prices are too low).

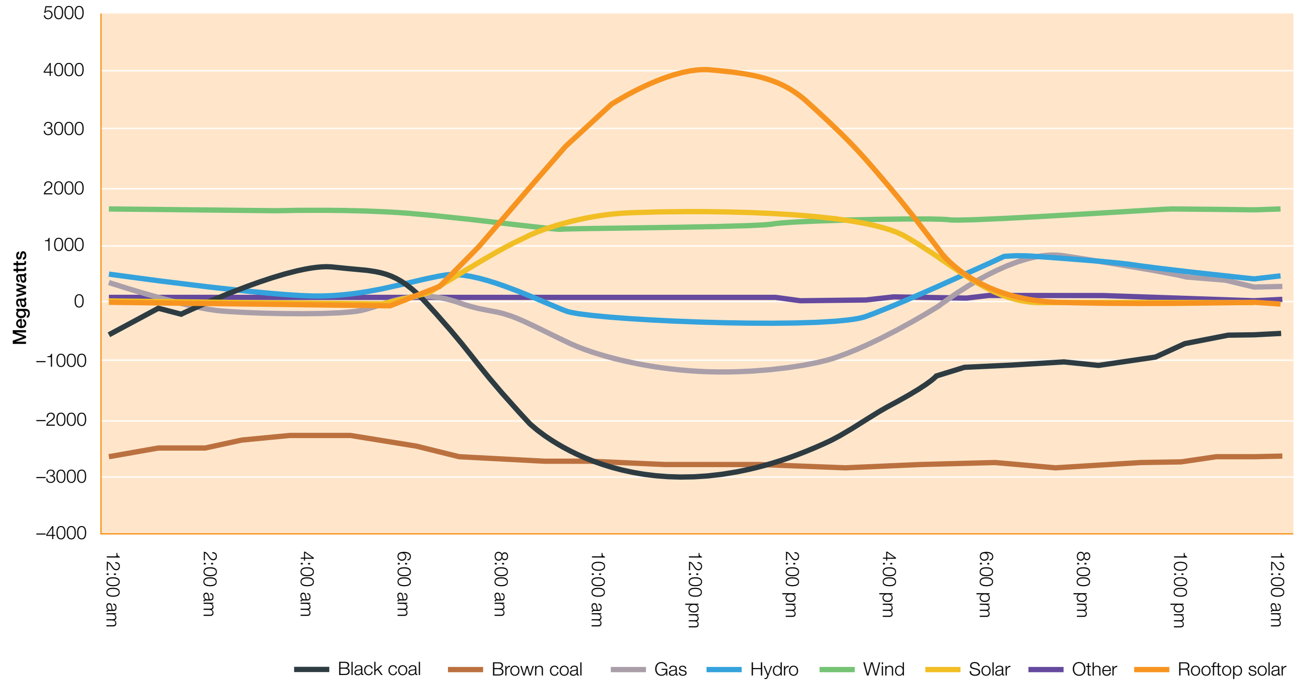
As the market transitions, the power system must increasingly respond to sudden changes in renewable output caused by changes in weather conditions and dispatch decisions by plant operators. Figure 1.8 illustrates the increasing scale of hourly changes in renewable output (ramping) in the NEM since 2015, which must be managed by equivalent changes in dispatchable generation or demand. This trend indicates the increasing need for resources (generation, storage and demand response) that can respond quickly to these changes.

Fast-response alternatives are becoming critical to balance supply and demand in this volatile environment. Gas, hydro and batteries are well able to respond to the variability of wind and solar because they can frequently alter output while still remaining economic. These technologies have been a focus, therefore, of recent policies designed to stabilise the grid. Demand response will also play an important role in responding to sudden shifts in output from renewable generators.

In this environment, accuracy in demand and weather forecasting is critical. Recent work has focused on innovative short term weather forecasting systems for wind and solar generators.[18] The variability of wind and solar farm output is partly offset by a negative correlation between the two: that is, decreasing wind generation is often observed during the morning ramp of rooftop and grid scale solar PV generation, and the opposite is observed in the afternoon. Global-ROAM cited data showing high levels of negative correlation in NSW, but less in other regions.[19]

18 Energy Security Board, *Health of the National Electricity Market 2019*, February 2020, p. 34.
19 Global-ROAM and Greenview Strategic Consulting, *Generator report card*, May 2019.

Figure 1.7
Changing generation profile, by time of day, 2009–19



Note: Comparison of average generation by time of day. The 2009 rooftop PV generation is estimated using the average 2009 daily generation, allocated to intervals using 2019 proportions.
Source: AER; AEMO (data).

Dispersing wind and solar resources over a wide geographic base covering different weather zones can also have a balancing impact.

Grid scale storage

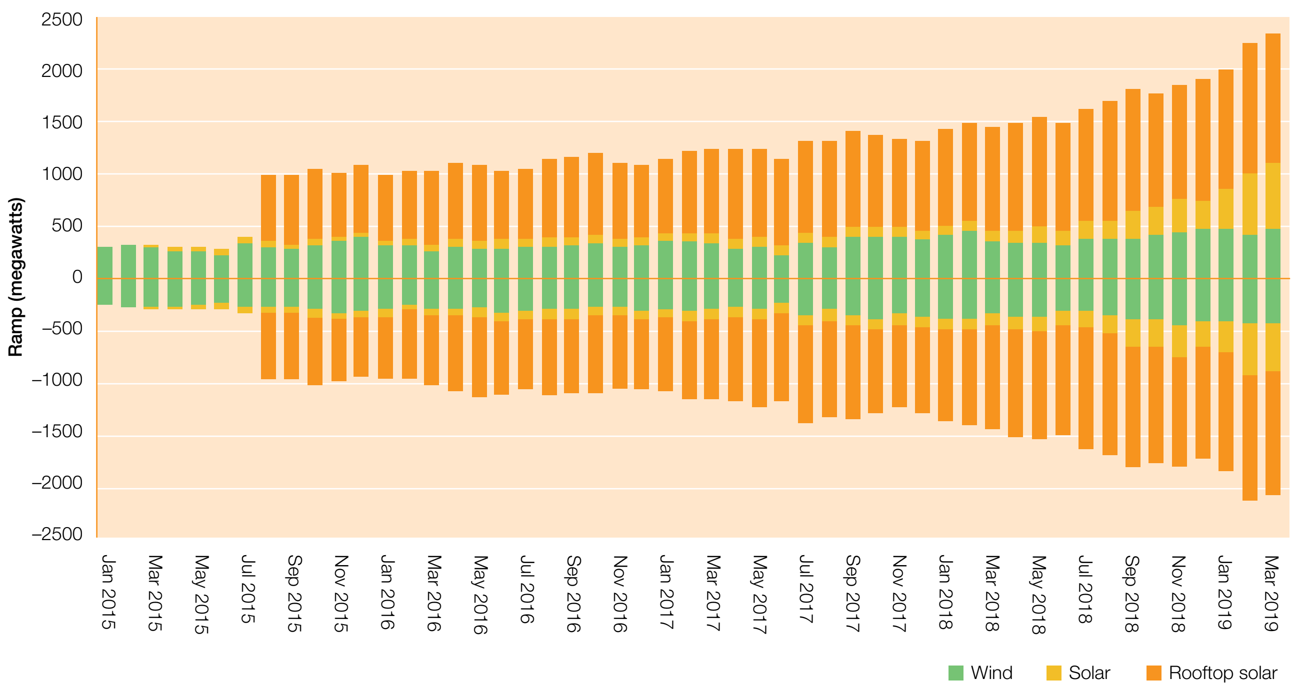
Until recently, storing electricity was not commercially viable, but emerging technologies have changed this. The growth in renewable generation is creating commercial opportunities for storage to offer fast response power system stabilisation services when solar and wind generation fluctuate.

Battery storage is currently best suited to shorter term ‘fast burst’ storage of energy to help stabilise technical issues in the grid (such as in providing frequency control services). South Australia in 2017 commissioned the world’s largest lithium ion battery adjacent to the Hornsdale wind farm. As well as operating in the electricity market, the battery earns significant revenue by supplying stability (frequency) services to the grid. The AER estimated the battery earned around $25 million in 2019 from frequency services—five times its earnings from wholesale energy sales.

A further four battery projects were commissioned in the NEM by January 2020 (table 1.1), including ElectraNet’s Dalrymple Battery Energy Storage System (which ARENA partly funded). Some of these battery storage systems are located adjacent to solar and wind farms, and aim to complement and ‘firm’ generation output from these plants.

Large scale storage is also being pursued through pumped hydroelectricity projects, which allow hydroelectric plant to reuse their limited water reserves. The technology involves pumping water into a raised reservoir when energy is cheap, and releasing it to generate electricity when prices are higher. Pumped hydroelectric technology has operated in the NEM for some time, in Queensland (570 MW at Wivenhoe) and NSW (240 MW at Shoalhaven, 1500 MW at Tumut 3, and 70 MW at Jindabyne). But advances in technology and the rise of intermittent generation are providing opportunities to deploy this form of storage at a larger scale. In particular, pumped hydroelectricity is the basis of the proposed Snowy 2.0 (2000 MW) and Battery of the Nation (2500 MW) projects in NSW and Tasmania respectively (section 1.7.2).

Figure 1.8
Hourly ramping of wind and solar generation



Note: Monthly top 1 per cent of up and down 60 minute ramps in the National Electricity Market.
Source: AEMO, *Renewable integration study, stage 1 report*, April 2020.

1.2.2 Distributed energy resources

Alongside the major shift occurring at grid level, significant changes are occurring in small scale electricity supply. Most significant is the uptake of which are consumer owned devices that can generate or store electricity, or actively manage energy demand. They include:

- rooftop solar PV units
- storage, including batteries and electric vehicles
- demand response, using load control technologies to regulate the use of household appliances such as hot water systems, pool pumps and air conditioners (section 1.5.3).

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

These DER have varying characteristics—for example, rooftop solar systems are passive, and can generate electricity only when the sun is shining, while active resources such as batteries and electric vehicles can both draw electricity from, and inject it into, the electricity grid at any time. With DER, energy customers are changing from passive consumers to active buyers and sellers of energy services.

Rooftop solar PV installations

Government incentives and declining installation costs resulted in Australia having one of the world's highest per person rates of rooftop solar PV installation. Around 20 per cent of all customers in the NEM now partly meet their electricity needs through rooftop solar PV generation, and sell excess electricity back into the grid, compared with less than 0.2 per cent of customers in 2007. This production met over 5 per cent of the NEM's total electricity requirements in 2019.

South Australia has operated for periods when wind and solar (grid level and small scale) output was equivalent to 142 per cent of the state's energy requirements (with excess production exported to Victoria). This trend is creating new challenges for the market around reliability and security (sections 1.4 and 1.5).

Table 1.1 **Grid scale battery storage projects**

STATE	BATTERY NAME	NAMEPLATE CAPACITY (MW)	NAMEPLATE STORAGE (MWh)	STATUS	DATE OF FIRST OUTPUT
South Australia	Hornsdale Power Reserve	100	122	In service	November 2017
South Australia	Dalrymple	30	8	In service	July 2018
Victoria	Gannawarra Energy Storage System	25	50	In service	November 2018
Victoria	Ballarat Energy Storage System	30	30	In service	November 2018
South Australia	Lake Bonney	25	52	In service	October 2019
Queensland	Kennedy Energy Park Phase 1	2	4	Committed	August 2020
Victoria	Bulgana Green Power Hub	20	20	Committed	November 2020

MW, megawatt; MWh, megawatt hour.
Note: Date of commissioning refers to the date of first output to the grid, or the expected full commercial use date for committed projects.
Source: AEMO, *NEM generation information*, January 2020.

Attractive premium feed-in tariffs offered by state governments drove the initial growth in solar PV installations. Despite the closure of those schemes, subsidies through the Australian Government's small scale renewable energy scheme, combined with the falling costs of solar PV systems, has led to sustained strong demand for new installations. In 2019 the average size of a rooftop solar installation in the NEM was 7.6 kilowatts (kW), up from 2.5 kW in 2011 (figure 1.9). The total installed capacity of rooftop PV systems in the NEM reached almost 9000 MW in early 2020.

Batteries and electric vehicles

In coming years, customers will increasingly store surplus energy from solar PV systems in batteries, and draw on it when needed. In this way, they will reduce their demand for electricity from the grid. The owners of DER can thus better control their electricity use and power bills, while taking initiative on environmental concerns. If DER is properly integrated with the power system, they could also help manage demand peaks and security issues in the grid (section 1.5.3).

The charging profiles of electric vehicles will similarly affect power flows. Price incentives that discourage customers from charging during peak demand periods would ease potential strain on the power system. Based on current forecasts, however, AEMO expects the uptake of electric vehicles to be relatively small in the next decade.

It is increasingly plausible for customers to wholly bypass the traditional energy supply model, by going 'off grid' through self-sufficient solar PV generation and battery storage.

Stand-alone systems or microgrids—where a community primarily uses locally sourced generation and does not rely on a connection to the main grid—are also gaining traction in some areas. These arrangements have mainly developed in regional communities that are remote from existing networks. But improvements in energy storage and renewable generation technology may lead more customers to take up this form of energy supply.

Regulatory and pricing frameworks are being implemented to support the growth of off-grid arrangements. The Australian Energy Market Commission (AEMC) in May 2020 proposed rules making it easier for distribution network providers to offer stand-alone power systems (where economically efficient to do so) while maintaining appropriate consumer protections and service standards.[20]

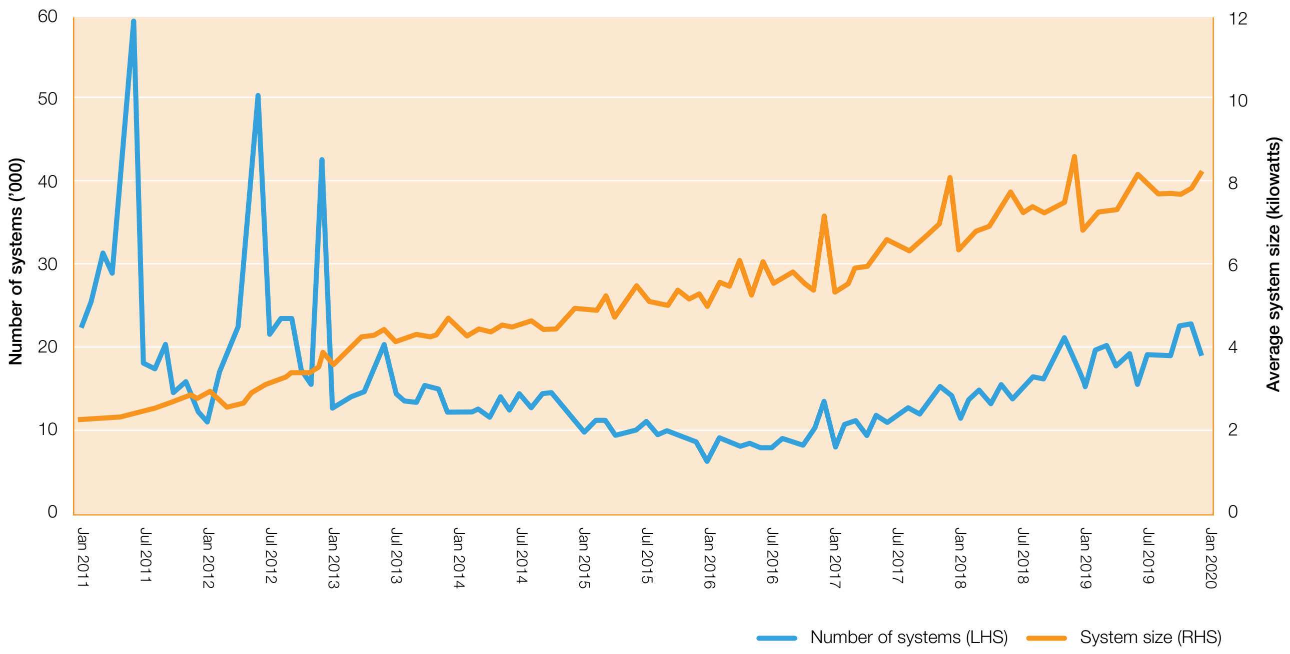
Virtual power plants

Individually, distributed energy resources are largely invisible to the market, and potentially disruptive to the grid. But solar systems combined with batteries can be aggregated to form a microgrid or virtual power plant that, if coordinated, can charge and discharge on a larger scale. Aggregation creates opportunities for small scale resources to participate in markets such as those for demand management and frequency control services.

The Australian Renewable Energy Agency (ARENA) in May 2019 announced $2.5 million in funding for AEMO to run a virtual power plant trial over a 12–18 month period, to demonstrate the technology's capabilities to deliver energy and grid stability services. AEMO invited existing pilot scale projects to participate, including ARENA funded AGL and Simply Energy pilot scale projects in South Australia.

20 AEMC, *Updating the regulatory frameworks for distributor-led stand-alone power systems, Final report*, May 2020.

Figure 1.9
Growth of solar PV installations in the NEM



PV, photovoltaic.

Source: Clean Energy Regulator, *Postcode data for small scale installations, Small generation units—solar*, February 2020.

While virtual power plants are relatively small in scale to date (accounting for round 5–10 MW), AEMO forecast they would contribute up to 700 MW of capacity to the market by 2022.[21]

1.2.3 Changing patterns of electricity demand

As more electricity customers generate some of their own electricity needs through rooftop solar PV systems, the demand for grid supplied electricity is changing. Some consumers with solar panels are self-generating much of their daytime power needs, then using the grid when sunlight and solar generation fall later in the day.[22]

While solar generation is helping to mitigate stress on the power system, timing issues limit the extent of this assistance. In summer, daily energy use peaks in the late afternoon or early evening, when temperatures are high and business use overlaps with households using air conditioning and other appliances. Winter demand peaks at a similar time of day, when households switch on heating appliances. But solar PV generation is falling late in the day when these peaks occur, so it can provide only limited support. For this reason, maximum demand for grid supplied electricity continues to rise in most regions, despite the rapid rise of solar PV systems.

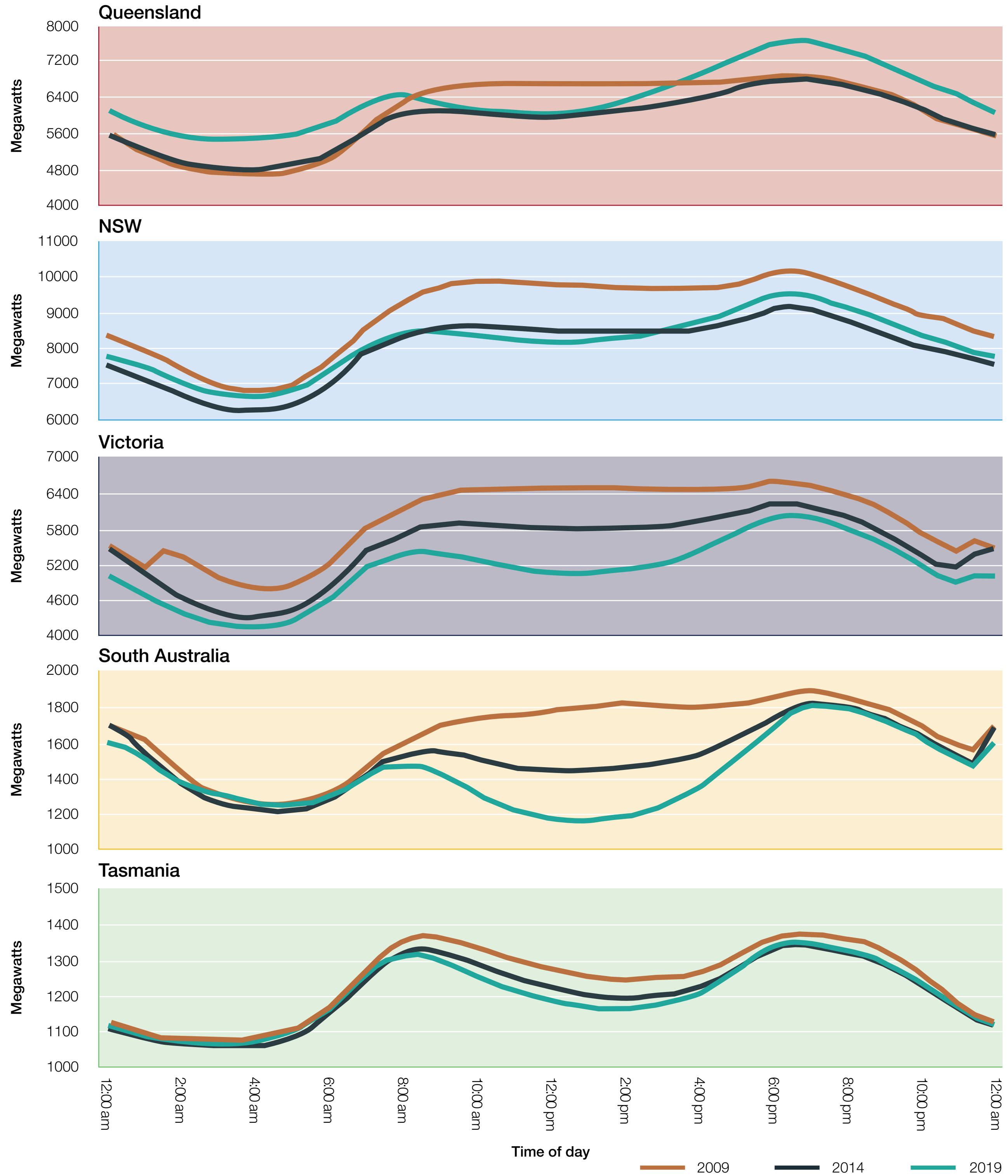
The growth of rooftop solar PV generation is also shifting the level and timing of *minimum* demand for grid supplied electricity. Historically, demand reached its low point in the middle of the night, when most people are sleeping. But the growth in solar PV output in the middle of the day is lowering daytime grid demand, and minimum grid demand increasingly occurs then. Figure 1.10 shows how demand is falling in absolute terms, and how this shift is particularly apparent around midday. Increasing residential rooftop PV uptake is expected to result in all regions experiencing minimum demand in the middle of the day within the next few years.

This hollowing out of demand through daylight hours is often called the 'duck curve'. The total energy consumed is represented by the area under the curve, which is falling over time.

21 ARENA, 'AEMO to trial integrating virtual power plants into the NEM', Media release, 5 April 2019.

22 AEMC, *Economic regulatory framework review, Promoting efficient investment in the grid of the future*, July 2018.

Figure 1.10
Electricity duck curves



Note: Average native demand by time of day for 2009, 2014 and 2019.

Source: AER; AEMO (data).

1.2.4 Climate change and the power system

Action on climate change was a key driver of the transition underway in the energy sector. But climatic changes already occurring are impacting electricity demand and the performance of generators and energy networks.

Australia's changing climate is creating more volatile patterns of electricity demand as the frequency of extreme heat events increases. Since maximum summer demand is driven by cooling (air conditioning) load, the warming Australian climate means demand peaks are rising relative to average levels of demand.

Extreme weather also stresses generation plant. Drought affects water storages and hydro generation capacity. Tasmania, for example, experienced a fall in water storage in 2015 and 2016. More recently, many parts of Australia through 2018 and into 2019 experienced low rainfall.

Higher ambient temperatures affect the technical performance of thermal plant (coal, gas and liquid fired plant) by reducing cooling efficiency. This issue affects air cooled plant (such as Kogan Creek and Millmerran) and gas turbines in particular, although high temperatures also affect water cooled plant. The performance of wind and solar plant, and batteries may also degrade at higher temperatures.[23]

These issues are most frequent on very hot days when demand is at its highest. When AEMO notified the market about reliability threats in 2018–19, a number of thermal generators were not available, or running at lower capacity, as a result of technical or safety concerns from extreme weather events.[24] More recently, bushfires caused interruptions to the transmission grid over summer 2019–20 (section 2.6.2). Extreme wind also crippled transmission infrastructure in Victoria in early 2020.

The Energy Security Board's 2020 report on the health of the NEM highlighted the importance of electricity system resilience, given extreme weather events will likely become more frequent and intense.[25] AEMO modeling is also factoring in the increased risk of extreme temperatures impacting peak demand, and of drought affecting water supplies for hydro generation and cooling for thermal generation.[26]

23 Global-ROAM and Greenview Strategic Consulting, *Generator report card*, May 2019.
24 AEMC Reliability Panel, *2019 annual market performance review, Final report*, March 2020.
25 Energy Security Board, *Health of the National Electricity Market 2019*, February 2020.
26 AEMO, *2019 electricity statement of opportunities*, August 2019.

1.3 Reliability issues

Reliability is about the power system being able to supply enough electricity to meet customers' requirements, in terms of available generation and storage capacity, demand response, and transmission network capacity (box 1.2). Cross-border transmission interconnectors support reliability by allowing resource sharing across regions. Reliability concerns tend to peak over summer, when high temperatures spike demand and increase the risk of system faults and outages.

1.3.1 Reliability in a transitioning market

The transition underway in the energy market has increased concerns about reliability. Coal plant closures remove a source of 'dispatchable' capacity that could once be relied on to operate when needed. AEMO raised concerns the market would be at risk of generation shortfalls over each of the past three summers (including 2019–20), especially in Victoria and South Australia where major fossil fuel plant closures occurred.

Additionally, the ageing fossil fuel plants still in the market are becoming more prone to outages, especially in hot weather. AEMO in 2019 reported a trend of rising forced outages among the NEM's ageing thermal generation, due to plant breakdown and more frequent and longer planned outages for maintenance and repair work.

For each of the past four years, brown coal forced outage rates exceeded long term averages (figure 1.11). A particularly significant outage occurred in 2019 at Victoria's Loy Yang A plant.

The surge in wind and solar generation investment over the past few years poses new reliability challenges:

- Because most renewable generation is weather dependent, AEMO cannot depend on it to run unless it is supported by 'firming' capacity such as battery storage.
- The intermittency of renewable generation makes it harder to forecast its output than for other plant types, although forecasting techniques are improving.
- New investment in renewables tends to be financed by long term power purchase agreements, rather than the underwriting of hedge products in contract markets. Over time, this investment approach may drain liquidity from contract markets, potentially posing a barrier to investment in new dispatchable capacity.[27]

27 AEMC Reliability Panel, *2018 annual market performance review, Final report*, April 2019, p. 34.

Box 1.2 How is reliability measured?

Reliability outcomes are measured in terms of unserved energy—that is, the amount of energy required by consumers that cannot be supplied due to a shortage of capacity. An independent panel—the Australian Energy Market Commission's Reliability Panel—sets the current reliability standard for the generation and transmission sectors. The standard requires any shortfall in power supply to not exceed 0.002 per cent of total electricity requirements. It has rarely been breached, but the Australian Energy Market Operator increasingly intervenes in the market to manage forecast supply shortfalls.

The standard excludes outages caused by 'non-credible' threats, such as bushfires and cyclones, because the power system is not engineered to cope with these issues, and the cost of doing so would be prohibitive. It also excludes supply interruptions originating in local distribution networks. Over 95 per cent of a typical customer's power outrages originate in distribution networks, and are caused by local power line and substation issues. While these outages are common, their impact is confined to relatively small cluster of customers in each instance. Section 3.14.3 of this report covers distribution reliability.

In effect, the standard sets a level of unserved energy that balances the cost of providing reliability against the value that customers place on avoiding an unexpected outage. A stricter reliability standard would reduce outages, but then power bills would rise because more generation plant or transmission interconnection would need to be built to ensure peak demand can be met.

1.3.2 Managing reliability risks

AEMO has powers to intervene to manage a forecast lack of supply to meet electricity demand. Over the past three summers (up to and including 2019–20), it used the Reliability and Emergency Reserve Trader (RERT) mechanism to manage reliability risks. Under the scheme, AEMO secures contracts with generators (to provide capacity) and/or large customers (to reduce their consumption) when the power system is under stress.

Before 2017–18, the RERT had been used to procure back-up capacity only three times, and was never activated. AEMO activated the RERT for the first time on 30 November 2017 to manage a forecast lack of reserves in Victoria. It again activated the scheme in Victoria and South Australia in January 2018, January and December 2019, and three times in January 2020, at a cumulative cost of around $110 million (section 2.9.1).

1.3.3 Market reforms on reliability

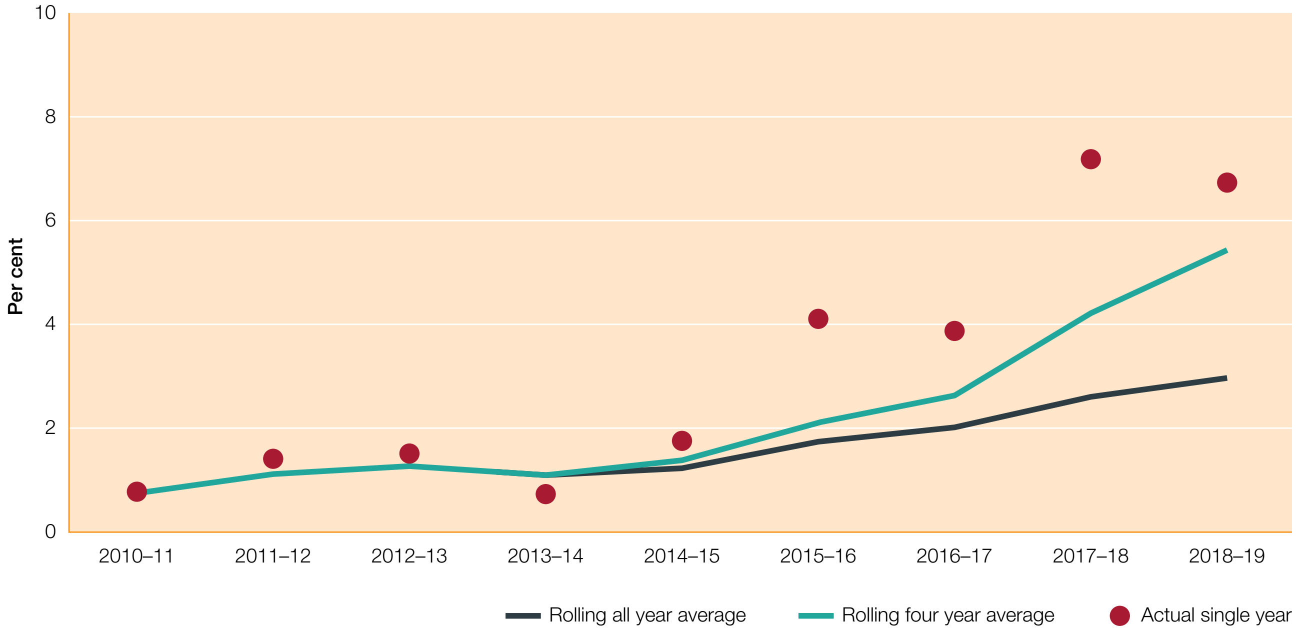
Market bodies are exploring how best to manage reliability risks in an evolving energy market. In doing so, they are looking at investment in resources with flexibility to manage sudden demand or supply fluctuations.

A central reform was the introduction of a Retailer Reliability Obligation (RRO) in July 2019 (box 1.3). The scheme encourages retailers and large energy customers to invest in dispatchable electricity generation in regions where a gap between generation and peak demand is forecast. A longer term focus is on expanding the role of demand response as a cost-effective way of addressing reliability risks (discussed below). Other reliability initiatives include:

- a new rule (from 1 September 2019) that requires generators to provide the market at least 42 months advance notice of their intention to close. The rule aims to improve long term forecasting of plant closures and reduce the reliability risks that closures can impose. When the rule commenced, a number of generators provided formal notice of their impending closure, including AGL Energy's Liddell power station and Torrens Island A power station, and Stanwell's Mackay gas turbine.
- the Energy Security Board's 2020 review of the adequacy of the reliability standard, to account for increased reliability risks from an ageing thermal generation fleet. The Energy Security Board recommended no changes to the reliability standard, but it will explore reforms in the lead-up to a post-2025 NEM design (section 1.6.3). In the short term, it recommended the creation of an out-of-market capacity reserve to be managed by AEMO, at least in part through reverse auctions and offering contract terms of up to three years. It also recommended a lowering of the trigger for activating the RRO.[28]
- From March 2020 AEMO can contract for RERT resources up to 12 months in advance (previously, nine months in advance). And, in Victoria, it can enter multi-year RERT contracts until June 2023, to help address reliability challenges facing that state.

28 CoAG Energy Council, 'Energy Security Board outcomes from 23rd Energy Council Ministerial Meeting', 27 March 2020, web page, available at: www.coagenergycouncil.gov.au/publications/energy-security-board-outcomes-23rd-energy-council-ministerial-meeting.

Figure 1.11
Coal plant outages as a share of capacity



Source: AEMO, *2019 electricity statement of opportunities*, August 2019.

To address reliability risks in the longer term, AEMO proposed substantial investment in transmission networks to integrate new renewable generation into the system as that generation comes online (section 1.7.2).[29]

Expanded role for demand response

Demand response relates to electricity users responding to financial incentives to cut their energy use from the grid temporarily when the power system is under pressure. While demand response can help manage peak demand, it has not been widely used in the NEM. One reason is that only retailers and large industrial customers see the price signals that encourage demand response, and they often prefer to manage this risk through hedge contracts.

The AEMC released rules in 2020 to attract more demand response providers into the market. Under the reform, participants can offer demand reductions through AEMO's central dispatch process, and be paid for any capacity called on. The mechanism will apply from October 2021, but will initially be limited to large customers. The AEMC regards the mechanism as an interim measure in the transition to a two-sided market with participants on both the supply and demand sides participating in dispatch and price setting.[30] The Energy Security Board is developing a two-sided market as part of the NEM framework overhaul that is scheduled to take effect in 2025 (section 1.6.3).

New technologies are also providing opportunities for smaller scale DER to offer demand response in the wholesale market (and in markets for grid stability services). Initiatives include virtual power plant trials (section 1.2.2) and a proposed AEMO operated platform on which participants can contract for electricity in the week leading up to dispatch, to enable more demand response.

1.4 Power system security issues

Power system security relates to keeping the power system within technical operating limits needed to keep it safe and stable. Parameters of system security include frequency and voltage stability, and physical properties such as system strength and inertia (box 1.4). An electricity system that operates outside acceptable limits for these parameters may jeopardise the safety of individuals, damage equipment, and lead to blackouts. A secure system can withstand a disturbance (such as the loss of a major transmission line) by quickly returning to a secure operating state.

29 AEMO, *Draft 2020 integrated system plan*, December 2019.

30 AEMC, *Wholesale demand response mechanism final rule, Information sheet*, June 2020.

Box 1.3 Retailer Reliability Obligation

The Retailer Reliability Obligation (RRO) scheme (launched in July 2019) aims to incentivise retailers and large energy customers to invest in dispatchable electricity generation to meet a forecast reliability risk. The Energy Security Board designed the scheme from an earlier version that formed a limb of the now abandoned National Energy Guarantee.[a] The Australian Energy Retailer (AER) publishes guidelines on the scheme's operation.

The scheme supports reliability by encouraging retailers and large energy users to enter contracts (or own generation capacity) to match their electricity demand in periods when the Australian Energy Market Operator (AEMO) forecasts a reliability gap between generation and peak demand over the coming five years. If a material gap remains three years out, then AEMO will ask the AER to formally trigger the RRO. The trigger level is intended to ensure the electricity system remains reliable during a one-in-10 year summer. The Energy Security Board in March 2020 reduced the trigger for activating the RRO, and introduced more flexibility to initiate the RRO to address forecast reliability gaps at shorter notice.[b]

Once the RRO is triggered, electricity retailers and large energy users are on notice to secure contracts for sufficient generation to cover their expected demand for grid supplied electricity, based on a one-in-two year peak demand forecast. Demand response contracts qualify, if they are 'in market' and have a direct link to the electricity market to manage exposure to high spot prices.

If a forecast gap persists one year out, then liable entities must submit their contract position to the AER for a compliance assessment. AEMO may also start procuring emergency reserves through the Reliability and Emergency Reserve Trader mechanism to address any remaining supply gap.

The RRO's design relies on retailers having access to hedge products. To support contract market liquidity, a market liquidity obligation (MLO) also applies if the RRO is triggered: it requires large generators to perform a 'market maker' role by offering to buy and sell hedge contracts on the Australian Securities Exchange (ASX) within a limited price spread. The obligation aims to ensure smaller participants can access enough contracts to meet their RRO obligations. The AER monitors relevant generators' compliance with the MLO.

AEMO in 2019 identified a supply shortfall in 2019–20 in Victoria, but did not highlight any shortfall three years out (that is, in 2022–23) for any NEM region. So, the RRO was not triggered.

South Australia

The operation of the RRO differs in South Australia compared with other regions, in that the state energy minister can trigger the obligation in South Australia.

In January 2020 the minister triggered the RRO in South Australia for periods in the first quarters of 2022 and 2023. Large generation businesses in South Australia—Origin, AGL and Engie—must now offer contracts for those periods on the ASX.

a Energy Security Board, *National Energy Guarantee, Final detailed design*, 1 August 2018.

b CoAG Energy Council, 'Energy Security Board outcomes from 23rd Energy Council Ministerial Meeting', 27 March 2020, web page, available at: www.coagenergycouncil.gov.au/publications/energy-security-board-outcomes-23rd-energy-council-ministerial-meeting.

System security differs from reliability, but the distinction can sometimes blur. If, for example, electricity demand is forecast to exceed available supply (a reliability issue), then the imbalance may also affect the power system's frequency (a security issue). There is also a temporal distinction. Reliability is typically a longer term consideration, while security issues tend to occur closer to real time.

1.4.1 Security in a transitioning market

The energy market transition impacts system security on many levels. Historically, the normal operation of the NEM's synchronous coal, gas and hydro generators produced inertia and system strength as a byproduct of producing energy, which helped maintain a stable and secure power system. But as older synchronous plants retire, important sources of inertia and system strength are removed from

Box 1.4 Power system security parameters

The power system's *frequency* refers to the rate of oscillations as electricity transmits through the system. Generators require a narrow band of system frequency to operate safely and efficiently. In the National Electricity Market (NEM), the frequency target is 50 cycles per second, or 50 Hertz. Sudden shifts in supply or demand can push frequency away from this level. In the NEM, 49.85–50.15 Hertz is considered an acceptable range. Wider deviations, or rapid changes of frequency, can lead to system failures.

Synchronous generators (such as hydro, coal and gas plants) produce *inertia*, which is a physical property that helps the power system ride through disturbances. The large rotating mass of a plant's turbine and alternator create this inertia as they rotate in synch with system frequency, which helps resist disturbances caused by a shift in supply or demand. A system with low inertia has a higher risk that frequency deviations will cause generators to disconnect from the power system.

Voltage is the electrical force or potential between two points that 'pushes' an electric charge through a wire. Voltage stability is necessary for a healthy power system, whereas large fluctuations in voltage can make it difficult for generators to remain connected to the system. In a healthy power system, the injection and absorption of reactive power manages these fluctuations. Synchronous generators create and absorb reactive power as a byproduct of producing energy, which helps manage voltage instability.

System strength is an umbrella term referring to the power system's sensitivity to disturbances such as voltage changes caused by a fault. A strong system can better cope with faults caused by electrical plant malfunctions, or by threats such as lightning and bushfires. With low strength, protection systems in the transmission network are less able to locate and clear faults. Failing to clear faults in a timely manner risks equipment damage, and makes it difficult for generators to remain connected during a disturbance. While inertia can be shared across regions, system strength is a more local phenomenon that requires local solutions.

Frequency, inertia, voltage and system strength interrelate and affect each other. Weak inertia, for example, can lead to frequency instability and weak system strength. In turn, weak system strength intensifies the effects of voltage instability (resulting in deeper, more widespread voltage dips).

the system. Falling inertia makes it harder to keep frequency within an acceptable band, while falling system strength makes it harder to keep voltage stable. The retirement of synchronous generation is also causing situations where too much reactive power is injected (particularly at times of high renewable output), causing overvoltage.

Wind and solar (non-synchronous) generators are not electro-mechanically coupled to the frequency of the power system. To connect with the system, they use a synthetic power device called an inverter, which simulates an alternating current (AC). Wind and solar generators are limited in their ability to dampen rapid changes in frequency, and have provided little or no fault current to support system strength.

So far, the rising proportion of renewables in the generation mix has meant more periods of low inertia, weak system strength, volatile frequency and voltage instability. It also raises challenges to the generation fleet's ability to ramp (adjust) quickly to sudden changes in renewable output. To help manage this ramping issue, the settlement period for the electricity spot price will change from 30 minutes to 5 minutes. While this change was planned for July 2021, the AEMC in May 2020 was consulting on a delay to July 2022.[31]

Since the closure of South Australia's Northern power station in 2016, and new entry of wind and solar plant, inertia shortfalls have caused more volatile frequency disturbances in the state. AEMO in 2018 declared an inertia shortfall in South Australia. Inertia levels have also fallen in Victoria since the closure of its Hazelwood power station in March 2017, falling at times below acceptable thresholds.

System strength has become an issue on the fringes of the grid, particularly in South Australia, north Queensland, south west NSW, north west Victoria and Tasmania. Weak system strength can lead to overvoltage in parts of the transmission system. AEMO has declared shortfalls in important security services in these regions (section 1.4.4). The uptake of DER is also creating voltage issues in distribution networks (section 1.5.3).

31 AEMO in April 2020 proposed the delay in response to the potential impact of COVID-19 on the energy industry, to free up human and financial resources that would be under strain during the pandemic.

Declining system strength also makes it harder for generating units to meet their performance standards. The operation of inverters—such as those used by wind farms, transmission interconnectors, solar PV systems and battery storage—requires sufficient system strength to ride through faults.

As the generation mix changes, new approaches are required to provide the stability services that we previously took for granted. The capability of wind and solar plants to provide these services is evolving, as are the types of service required. The first wave of wind farms in particular were not well engineered to provide security services. However, some modern inverter based generation has the capability to respond rapidly to sudden changes in electricity supply or demand, and to make a limited contribution to system strength (at the expense of producing energy).

Other technology solutions include synchronous condensers—that is, large spinning machines similar to those used in synchronous generators, but with shafts that spin freely. The motion of the machines creates inertia. They can also supply and absorb fault current to support system strength and maintain voltage stability (section 1.4.3).

The AEMC noted international experience suggests it is not yet possible to operate a large power system without some synchronous inertia, and 'synthetic' inertia from non-synchronous generators does not currently provide a direct replacement.[32]

Power system security was previously achieved as a byproduct of the power system's normal operation. But it increasingly needs careful management. AEMO is responsible for managing power system security in the NEM. It uses market based methods where possible, but it can override the market's normal operation if market measures are inadequate. Further, AEMO and other stakeholders can propose rule changes to address systemic issues (section 1.4.4). At a higher level, market, policy and regulatory bodies are developing reforms of the market's architecture to keep it fit for managing security issues in the longer term (section 1.4.5).

32 AEMC Reliability Panel, *System security market frameworks review, Final report*, June 2017.

1.4.2 Market procurement of security services

Some of the services needed to maintain power system stability can be procured through markets. In particular, AEMO operates markets to procure different types of frequency control services.

Frequency control services

AEMO operates spot markets to procure frequency control ancillary services (FCAS) needed to maintain stable system frequency. Participants make offers to provide these services in a similar way to how they provide energy offers. AEMO determines which generators will be dispatched to provide *both* energy and FCAS at the lowest cost (which is known as co-optimisation). The costs are recovered from generators and consumers, partly through a 'causer pays' mechanism.

Eight different markets operate, each providing a different type of service. *Regulation services* are procured to manage frequency deviations within the normal operating frequency band, while *contingency services* are procured to arrest any major variations caused by events such as the loss of a generating unit or a significant electricity transmission line. Contingency services are available over a range of response speeds (from 6 seconds to 5 minutes). Separate markets operate to *raise* and *lower* frequency for each type of service.

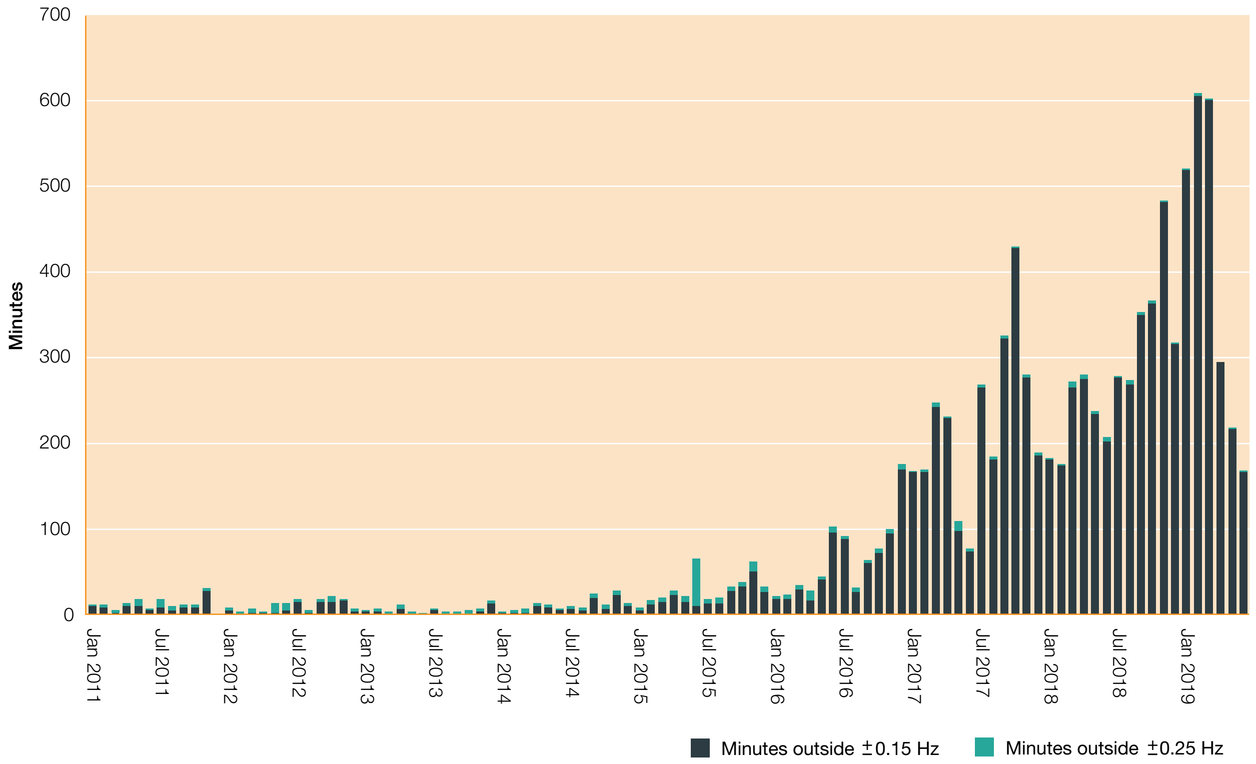
System frequency is deviating from its normal operating range more often than in the past (figure 1.12). Policy reforms—including mandatory primary frequency response—target this issue (section 1.4.4).

Historically, FCAS costs were comparatively low in relation to energy costs. In 2015 FCAS costs totalled $63 million, which represented around 0.7 per cent of NEM energy costs. However, they steadily increased over the past few years (figure 1.13), and they totalled around $223 million in 2019, which was almost four times their total in 2015.[33] For the first quarter of 2020, FCAS costs were higher (at $227 million) than they were over the whole of 2019. The first quarter peak was partly driven by high local costs in South Australia when it was isolated from the rest of the NEM for several weeks. Chapter 2 further describes recent FCAS costs (section 2.10.2).

The increase in FCAS prices over the past five years, coupled with technological developments, has driven new types of FCAS provider to enter the market. These new entrants include demand response, virtual power plants,

33 AER, *Wholesale markets quarterly—Q4 2019*, February 2020.

Figure 1.12
NEM mainland frequency excursions



Hz, hertz.

Source: AEMC Reliability Panel, *2019 annual market performance review, Final report,* March 2020.

wind farms and utility scale batteries. They demonstrate new technologies and business models will have an increasingly important role in maintaining system security. To strengthen transparency around FCAS markets and encourage participation, the AER in 2019 launched quarterly reporting on each market, including an analysis of outcomes.[34]

Procurement of other security services

Alongside the spot markets for frequency control services, AEMO enters long term contracts to procure two other types of security service:

- network support and control ancillary services, for controlling voltage at different points of the network, controlling power flow on network elements, and maintaining transient and oscillatory stability after major power system events
- system restart ancillary services, for restarting the electrical system after a complete or part system blackout.

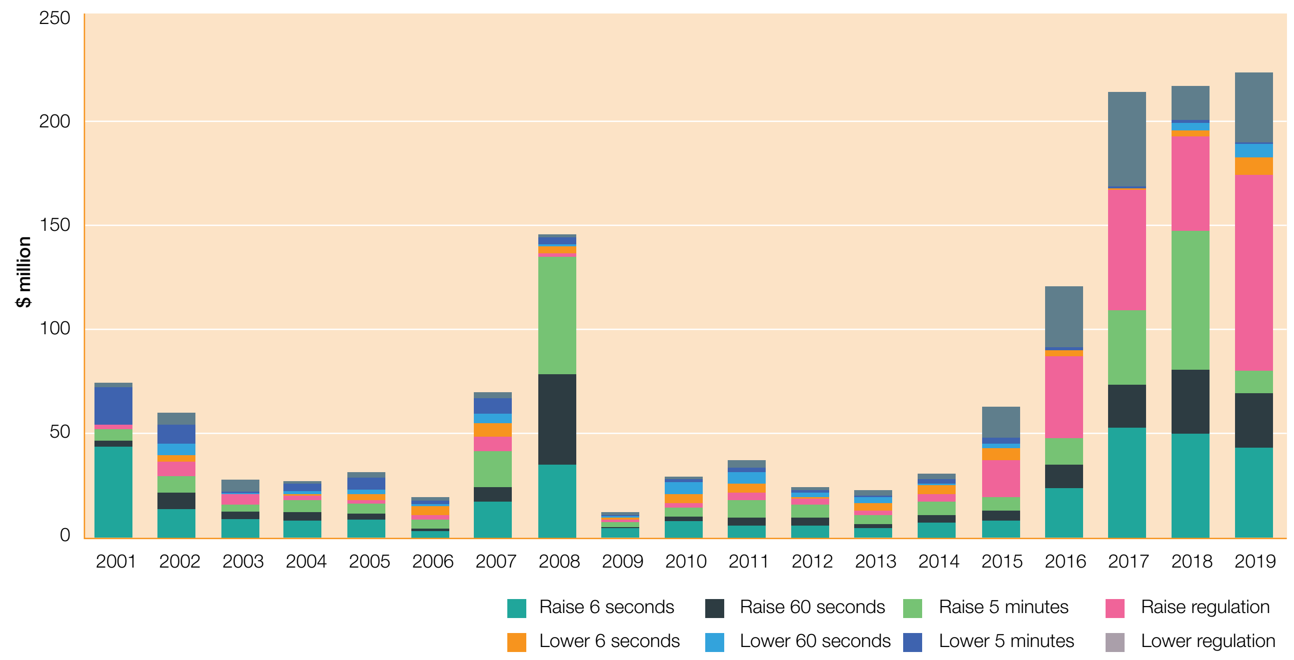
No market yet exists to procure other system services such as inertia and system strength. In the past, these properties were so plentiful that no value was ever placed on them, and no mechanism to procure them was required. But the AEMC is exploring new mechanisms to obtain and pay for these services.

1.4.3 Market intervention to manage security

Where no market exists to manage a security issue, AEMO may intervene. The extent of such intervention has risen markedly in recent years. While necessary as a short term measure, this intervention is costly for energy consumers.

34 AEMC, *Monitoring and reporting on frequency control framework, Fact sheet*, July 2019.

Figure 1.13
Frequency control ancillary service costs



Note: South Australia's local frequency control ancillary service (FCAS) costs rose from late 2015 through to 2017 as a result of stricter requirements for localised sourcing of those services in that period, and fewer participants offering FCAS.

Source: AER.

AEMO uses a blend of interventions methods, which include:

- directing generators to operate even if it is not economic for them to do so
- preventing some low priced generation plants from operating
- de-energising transmission lines
- as a last resort, instructing load shedding.

Some mechanisms can be applied jointly. In South Australia, for example, AEMO has managed inertia and system strength issues by constraining wind and solar generators, while also directing synchronous (gas) generators to operate. In Victoria, it has managed voltage and system strength by constraining transmission lines and directing gas powered plants to operate.

While AEMO targeted these mechanisms in recent years mainly at security threats, they can also target reliability issues. AEMO's principal mechanism for managing short term reliability risks in the past few years, however, was the RERT mechanism (section 1.3.2).

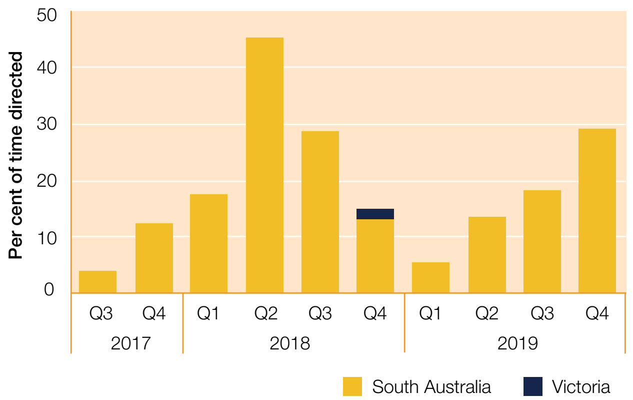
Between 2014 and 2016 AEMO intervened in the market only once each year, for a cumulative total of less than 4 hours. Market interventions to maintain security rose sharply from 2017. South Australia and, more recently, Victoria have been the focus of these interventions.

Directions

AEMO normally dispatches the lowest cost generators to meet demand, but this dispatch can cause security issues. If, for example, a lack of online synchronous generators causes a lack of system strength, then AEMO may direct one or more synchronous generators to operate, even if this direction overrides the market's normal efficient operation.

The use of AEMO directions has increased markedly in recent years, with most targeting system strength issues in South Australia (figure 1.14). The duration of these directions peaked in 2018, when they were in place for 26 per cent of the time. While this ratio eased to 16 per cent in 2019, AEMO intervened regularly late in the year, and intervention costs in October–December 2019 hit a record $13 million.

Figure 1.14
System security directions



Source: AEMO.

Constraints

In recent years, AEMO periodically constrained renewable generation to maintain inertia and system strength. Figure 1.15 shows a significant increase in the volume of renewable generation curtailed by constraints and operator decisions in 2019.

Much of this curtailment applied to wind generation in South Australia, particularly in the third quarter each year (July–September), when electricity demand is lowest. Since September 2019 the focus of AEMO's intervention shifted to north west Victoria and south west NSW, where it constrained substantial volumes of solar generation to manage voltage issues (box 1.5).

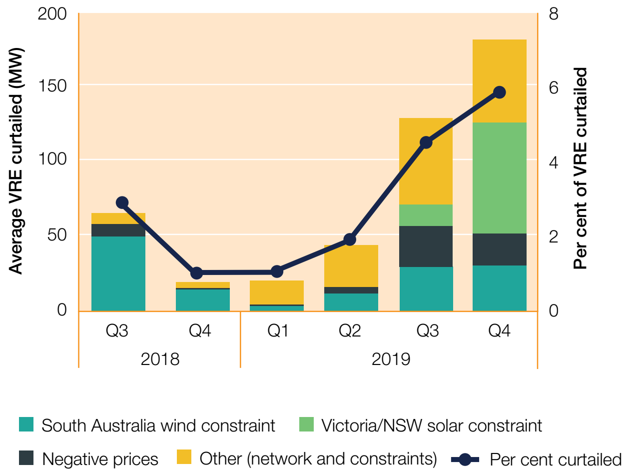
In March 2020 AEMO raised system strength concerns in north Queensland that occur when insufficient coal or hydro plant is operating. It introduced new constraints preventing three renewable generators in the region from operating when coal and hydro output falls below a set threshold.[35]

Transmission network intervention

While power system intervention often targets the generation sector, some instances target transmission networks. The closure of Victoria's Hazelwood power station in March 2017 removed a generator that historically played an important role in supporting voltage control. Following the closure, AEMO began managing overvoltages at times of minimum demand by de-energising (switching off) high voltage lines (and sometimes also directing a gas powered generator to operate).

35 AEMO, 'Revised system strength limits in north Queensland', Market notice 74987, 19 March 2020.

Figure 1.15
Curtailment of renewable generation



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

In November 2018 a significant voltage incident led to AEMO switching off three separate 500 kilovolt (kV) transmission lines in Victoria for the first time in the history of the NEM. AEMO in December 2018 declared a gap for voltage control in Victoria, and entered contracts with synchronous generators for voltage support.

Load shedding

The most extreme form of intervention occurs when AEMO instructs a network business to load shed (that is, temporarily cut power to some customers). This action is rare and occurs only if all other avenues have been exhausted. In recent years, insecure operating states led AEMO to cut supply to some customers in South Australia (December 2016 and February 2017), NSW (February 2017) and Victoria (twice in January 2019).

Intervention costs

Until recently, generators subject to a direction were entitled to claim compensation. The cost of AEMO directions—that is, the compensation recovery amount—was around $15.7 million in 2018–19, and $18.2 million the year before.[36] There are no compensation provisions for generators affected by constraints. Given the scale of these costs, the AEMC in December 2019 abolished compensation payments associated with system security directions.

36 Energy Security Board, *Health of the National Electricity Market 2019*, February 2020.

Box 1.5 Curtailment of solar farms in Victoria and NSW

In September 2019 the Australian Energy Market Operator (AEMO) began overriding the power system's normal operation to manage system strength and voltage issues in north west Victoria and south west NSW. Many solar farms have been commissioned in the region over a short period.

The area is too remote from synchronous generators for AEMO to manage the issue through directions to gas or coal fired generators. Instead, AEMO intervened by constraining the output of five solar farms (four in Victoria and one in NSW) by 50 per cent of their maximum output at all times. The constraints equated to a loss of up to 170 megawatts of output. The intervention aimed to manage the risk of voltage instability following a contingency such as the loss of a nearby transmission line.[a] Following changes to inverter settings for the affected plants, AEMO lifted the constraints in April 2020.

Limited transmission capacity may still impede the connection of new plant in the region. Another five generators ready to connect to the grid had been placed on hold until a solution to the issue was found. In early 2020 a further 15 generators had committed to connect in the region, and another 25 generators were at the point of applying for connection.

In December 2019 AEMO began a cost–benefit analysis of building new transmission capacity to unlock renewable capacity in the region. It estimated a lead time for this investment of six to seven years. A shorter term option to manage system strength and voltage issues would be to install synchronous condensers.

In December 2019 AEMO declared a 'fault level shortfall' in north west Victoria relating to this issue. AEMO (as the network planner for Victoria) is assessing combinations of synchronous condensers to supply additional fault current, and is looking to have a solution in place by 1 January 2021.

a AEMO, *Notice of Victorian fault level shortfall at Red Cliffs*, December 2019.

Aside from formal compensation, the use of constraints or directions penalises consumers by driving up wholesale electricity prices. By, for example, restricting wind or solar output that might have zero marginal costs, AEMO directions may lead to dispatch from synchronous generators with higher costs. ElectraNet estimated the cumulative effect of system strength directions in South Australia on wholesale market prices exceeded $270 million at September 2018.[37]

1.4.4 Rule changes and regulatory reform

While AEMO intervenes in the market to manage short term security issues, AEMO and other stakeholders can propose changes to the Electricity Rules to address more systemic issues. The AEMC considers these proposals, which (if accepted) are then written into the rules. A number of recent rule changes target security issues.

37 ElectraNet, *Addressing the system strength gap in SA, Economic evaluation report*, February 2019.

System strength and inertia

New rules addressing the issue of declining system strength commenced in 2017 in South Australia, and in July 2018 elsewhere.[38] Under the framework:

- if AEMO identifies a system strength shortfall in a region, transmission network businesses must maintain minimum levels of system strength for generators connected to the network
- new connecting generators must 'do no harm' to the level of system strength needed to maintain the security of the power system. This rule applies to all new connecting generators in the NEM. In effect, new plant must be able to operate to specific system strength levels before it can connect to the system.

A separate rule change imposed similar requirements on transmission businesses to maintain minimum levels of inertia (or provide alternative services to meet these levels) if a shortfall is identified.

AEMO declared a system strength gap in South Australia in October 2017, and an inertia shortfall in December 2018. The issue typically arises when low to moderate demand combines with high levels of renewable generation to

38 AEMC, *Managing power system fault levels, Information sheet*, September 2017.

cause low spot electricity prices. If prices are too low for gas powered generators to cover their short run costs, the generators may bid to avoid dispatch. When fewer synchronous generators operate, unacceptably low fault current and weak system strength may occur.

South Australia's transmission business, ElectraNet, plans to partly address the issue by installing four high inertia synchronous condensers (by the end of 2020) to cover the system strength gap. It was exploring options such as contracting with generators or battery providers to cover the remaining inertia shortfall. In the meantime, AEMO will continue to direct synchronous generation to remain online to maintain system strength.

More recently, other regions of the market have experienced shortfalls in important security services. AEMO declared inertia and fault level shortfalls in Tasmania (November 2019), and fault level shortfalls in north west Victoria (December 2019) and north Queensland (April 2020).[39]

The AEMC noted the 'do no harm' rule may be causing issues for the connection of new generators. It is exploring options to value additional system strength and inertia, and to develop a mechanism to pay for these services.[40]

Mandatory frequency response

In March 2020 the AEMC ruled all capable generators and batteries must provide primary frequency response support whenever the system needs to respond to a supply–demand imbalance.[41] The response needs to be automatic and almost instantaneous, in the form of either a change in generation or a demand response.

In effect, generators must be engineered to vary from their preferred energy dispatch whenever frequency goes outside a specified range. The aim is to ensure an immediate response is available to address an imbalance, so FCAS markets have enough time to deliver frequency services.

The rule commenced in June 2020 and will sunset after three years. During this period, the AEMC will explore the development of payment mechanisms to encourage businesses such as utility scale batteries to provide fast frequency response. Further, it is considering a proposal from AEMO to address perceived regulatory disincentives to generators operating their plant in a frequency response mode during normal operation. The AEMC expects to make a draft decision on the proposal in September 2020.[42]

1.4.5 Market architecture reform

Policy makers are exploring reforms to the energy market's design so, in the longer term, it can efficiently deliver services to maintain system security. Work is underway, although many reforms will take time to be implemented.

Market bodies are exploring the development of new markets for services such as inertia, system strength and voltage control, which were traditionally viewed as cost-free byproducts of synchronous generation. The AEMC in 2017 introduced reforms to allow batteries and demand response aggregators to offer services in FCAS markets (section 1.5.3). The rule potentially widens the pool of FCAS suppliers and may stimulate competition between providers.

Technologies such as virtual power plants are increasing opportunities for smaller scale DER to participate in FCAS markets (and the wholesale market), and could widen scope for emerging markets such as voltage control, ramping and demand response. Pilot programs are exploring a new market design for a two-way energy system and marketplace in which DER can participate via aggregators to provide wholesale energy and/or ancillary services to the electricity grid and market.

AEMO is analysing the generation fleet's ability to ramp (adjust) quickly to sudden changes in wind and solar generation. To help manage this ramping, the settlement period for the electricity spot price will change from 30 minutes to 5 minutes.[43] This reform aims to stimulate investment in technologies that are particularly suited to providing a fast ramping response, such as batteries, gas peaking plants and demand response.

1.5 Efficiency challenges

Aside from reliability and security challenges, Australia's energy market transition poses risks to the efficient investment and use of energy infrastructure.

Small and geographically dispersed generators are being commissioned each year, often in sunny or windy areas at the edges of the grid, where the transmission network is weak. Connecting new generation to weaker parts of the grid is causing network congestion and security risks to the electricity grid. Yet, current frameworks do not provide accurate signals to connecting generators on the costs and risks of connecting in these locations.

The current regime for connecting new generation plant to the transmission grid raises a number of issues. One issue is that generators connecting to the grid do not pay for their use of the transmission networks, beyond a basic charge to connect to the nearest point on the network. The cost of other work to augment the network to accommodate a new generator with a poor network connection is charged to all energy users.

1.5.1 Efficient locating of new renewables plant

Generators consider a number of factors when determining where to locate a new plant. They consider the cost and availability of fuel resources, whether they can connect to the network to sell electricity, the costs of connecting to the grid, and energy losses that will scale down their future earnings. Regulatory frameworks have not encouraged efficient choices in some of these areas.

Transmission losses

As a result of the NEM's generation fleet becoming more geographically dispersed, and new plants locating further from the existing grid, energy losses from the system are rising. When electricity is transported across a network of poles and wires, some of it is lost as heat. These losses increase as more generators locate far from demand centres, because power has to travel further to reach customers. Across the NEM, transmission losses equate to around 10 per cent of all electricity transported between power stations and customers.[44]

A generator's earnings from selling electricity are scaled down to reflect this loss of energy. Generators that locate near the end of the line, where transmission is weak, have a relatively higher loss factor. As a result, their earnings can be significantly scaled down. This outcome appropriately signals to developers that locating new plant in a weak network area poses risks to future earnings. In this way, loss factors provide a price signal that discourages investment in inefficient locations.[45]

In the NEM, this signal is applied through marginal loss factors (MLFs), which estimate the percentage of the next (marginal) unit of electricity sent into the grid that is likely to reach customers rather than being lost. AEMO forecasts the MLF for each generator annually, based on forecast losses between a generator and the regional reference node (the place in a region where wholesale electricity prices are set).

The increase in renewable generation in weaker (often remote) parts of the grid is causing large changes in loss factors in parts of the power system. The planned connection of substantial solar generation in north and central Queensland led to MLFs in the region being scaled back in each of the three years to 2020–21. Loss factors were also scaled back in 2020–21 for some other regions where network limitations constrain generation output, including areas of north west Victoria, south west NSW, the south east and Riverland areas of South Australia, and several parts of Tasmania.[46]

Declining MLFs increase risks for investors in new generation plant (figure 1.16). To help decision making, the AEMC in February 2020 amended the calculation process to increase transparency and improve predictability for investors.[47]

Under rules made in 2018, stricter technical standards applying to connecting generators help mitigate these risks.[48] Transmission networks may impose such technical requirements (generator performance standards) as they see fit. As networks become more constrained in areas with high quality renewable energy resources, requirements placed on connecting generators are becoming increasingly stringent. But the new arrangements have raised concerns among developers, with some reporting that network businesses are delaying the processing of connection applications or altering required standards during negotiations.

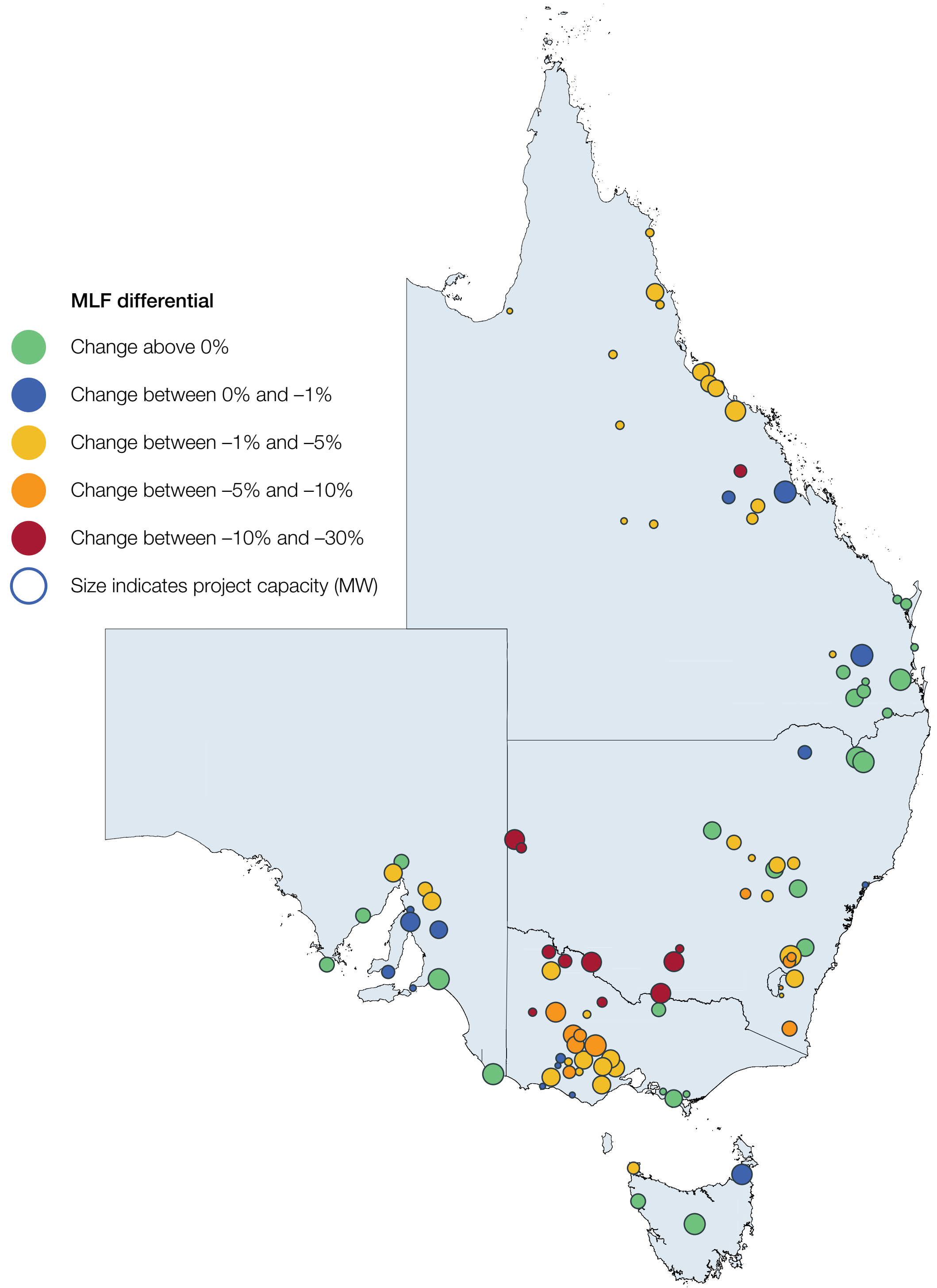
Congestion costs

Under current frameworks, a new connecting generator is not penalised for causing network congestion that degrades the quality of access for other generators. Existing generators cannot gain firm network access to avoid this risk. Further, current frameworks do not allocate congestion costs among generators. The MLFs account for transmission losses, but not for congestion caused by a generator connecting in a weak network area.

Rising generation in weaker parts of the grid is causing congestion that weakens network security for all participants. The lack of certainty also poses risks to

39 AEMO, *Notice of inertia and fault level shortfalls in Tasmania*, November 2019; AEMO, *Notice of Victorian fault level shortfall at Red Cliffs*, December 2019; AEMO, 'Revised system strength limits in north Queensland', Market notice 74987, 19 March 2020.
40 AEMC, *Investigation into intervention mechanisms and system strength in the NEM, Consultation paper*, April 2019.
41 AEMC, 'Final rule to better control power system frequency', Media release, 26 March 2020.
42 AEMC, *Primary frequency response rule changes, Fact sheet*, September 2019.
43 While the change was planned for July 2021, the AEMC in May 2020 was consulting on a delay to July 2022.
44 AEMO, 'Loss factors and regional boundaries', web page, available at: https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/market-operations/loss-factors-and-regional-boundaries, viewed 21 May 2020.
45 AEMC, *Transmission loss factors*, Fact sheet, November 2019.
46 AEMO, *Regions and marginal loss factors: FY 2020–21*, April 2020.
47 AEMC, *Transmission loss factors, Final determination*, 27 February 2020.
48 AEMC, *Generator technical performance standards rule determination*, Information sheet, September 2018.

Figure 1.16
Two year change in marginal loss factors, 2018–19 to 2020–21



MLF, marginal loss factor; MW, megawatt.

Source: KPMG for the Australian Energy Council, *Marginal loss factors: the state of play in Australia*, May 2020.

prospective generators that their assets may become unprofitable if subsequent parties connect to the network and create congestion. New rules introduced in 2018 help to some extent by requiring new connections to 'do no harm' to local system strength in the network (section 1.4.4).

Pricing reforms

The AEMC in 2019 proposed pricing reform to address congestion issues.[49] Every generator and customer in a region receives or pays the same price (adjusted for loss factors), which is determined at a single point in the region called the reference node. Under the proposed reform, generators would instead receive a local price based on the marginal cost of supplying electricity in their specific network area. This localised price would account for congestion and losses in that area. Retailers would continue to pay a single regional price. Customers could elect to pay either the local price or a load weighted regional price.

Financial transmission rights would be available for parties to hedge against price differences caused by network congestion and transmission losses. The hedges would effectively pay a generator the difference between the local and regional price. The AEMC argues the combination of local pricing and financial transmission rights would improve incentives for generators to connect to efficient areas of the network, thereby lowering costs to customers. The Council of Australian Governments' (CoAG) Energy Council will consider the AEMC's proposed pricing model as part of the NEM 2025 reform package at the end of 2020.

Coordinating generation projects

Transmission network providers are receiving an unprecedented volume of generation connection enquiries from renewable projects in various stages of development. While significant information is available about a generator once it connects to the grid, these projects have limited transparency before the generator signs a connection agreement with a network. This lack of transparency can lead to inefficient outcomes. As an example, multiple generators seeking to connect to a network may each invest in separate connection assets, when a shared asset may be more efficient.

Reforms are underway to improve transparency and coordination. AEMO's *Integrated system plan* (first published in 2018 and updated in 2020) provides information to the market on future generation and network requirements over a 20 year horizon. It also identifies efficient hubs for renewables investment. Called renewable energy zones, these hubs are based on assessments of fuel resources, network connections and proposed network upgrades (section 1.6.2). The Energy Security Board in 2020 was progressing reforms to better coordinate decisions on locating new renewable plant, and support efficient network planning to move energy from renewable energy zones to markets.

More generally, new rules effective from December 2019 require network businesses to share connection information about generation proposals with AEMO, which then publishes this information. The rule provides better and more up-to-date information about what generation projects are in the pipeline, to help developers make better investment decisions on where to locate new generators and to assess project viability.[50]

1.5.2 Efficient network investment

Current regulatory arrangements for transmission networks raise a number of efficiency issues, including whether cost allocation is efficient, and whether new investment to support the energy market transition is timely.

Cost allocation

Under current arrangements, transmission investment is paid for mainly by energy customers in the region where new assets locate. But, in cases such as investment in cross-border interconnectors, customers in other regions may benefit most from this investment.

In November 2019 the CoAG Energy Council tasked the Energy Security Board with considering a fair method for allocating transmission costs to better align the costs and benefits of network investment. The AER in 2020 led an Energy Security Board working group looking into this issue. The board will report back to the CoAG Energy Council in mid-2020, with a final report due in September.[51]

Timeliness of transmission investment

Transmission investment tends to lag behind generation investment, often resulting in delays between the completion of a generation project and the network being ready for the plant to connect. These lags create uncertainty for generation proponents, and may delay efficient investment.

49 AEMC, *Coordination of generation and transmission investment proposed access model*, Discussion paper 14, October 2019.

50 AEMC, *Transparency of new projects, Fact sheet*, December 2019.

51 CoAG Energy Council, 'Energy Security Board outcomes from 23rd Energy Council Ministerial Meeting', 27 March 2020, web page, available at: www.coagenergycouncil.gov.au/publications/energy-security-board-outcomes-23rd-energy-council-ministerial-meeting.

Some delays stem from regulatory processes for transmission investment, which can be lengthy.

The CoAG Energy Council in March 2020 agreed to streamline some regulatory processes (such as the AER's regulatory investment test) to fast track strategic transmission projects. This decision followed an earlier change to streamline processes for priority projects identified in AEMO's first integrated system plan. The changes (scheduled to commence in July 2020) would allow some parts of the regulatory process to run concurrently, and avoid duplicating processes such as modeling in cost–benefit assessments (section 1.6.2).[52]

1.5.3 Efficient integration of distributed energy resources

Investment in DER by energy customers poses challenges to the power system, in terms of DER's lack of visibility, and variations in controllability and level of performance. If integrated efficiently, DER has a flexible nature that can help delay the need for large scale generation and network investments, and provide new sources of network support and energy management capabilities. The ability to take advantage of these opportunities depends on how well DER—for example, rooftop solar PV systems, household battery systems, and demand response such as home energy management systems—interact with the system. The CSIRO estimated household bills could lower by as much as $400 per year if these resources are optimised.[53]

Technical issues for distribution networks

Distribution networks were historically engineered to transport electricity one way—that is, from large generators to energy customers. But, with the continued uptake of rooftop solar PV systems and other types of DER, the networks now support multidirectional energy flows. Customers can generate electricity, store it, and export it to their local distribution network.

While grid scale wind and solar generation raise security issues for transmission networks, distribution networks face similar issues as consumers adopt DER and export electricity into the grid. Some networks are experiencing congestion issues as areas of their networks reach capacity limits on the amount of DER that they can host. Those networks with high penetration of rooftop solar PV systems (such as SA Power Networks and Energy Queensland) are experiencing the greatest impacts.[54]

The export of power from solar generation into distribution networks is causing security issues:

- *voltage* issues may arise when electrical pressure reaches its upper threshold as more and more rooftop solar PV units inject power into the grid
- *thermal limits* are reached when wires and other equipment are unable to carry any more power because the equipment has reached its upper temperature limit.

Voltage control can be a major issue for distribution networks in those cities where rooftop solar penetration exceeds 20 per cent of homes (currently Brisbane and Adelaide). The level of demand for grid power in some feeders, or even in whole suburbs, can drop close to zero in the middle of the day when demand is met by rooftop solar PV generation. In 2018 AEMO reported multiple instances of rooftop generation causing deep voltage dips in the middle of the day, requiring it to remove hundreds of megawatts of nearby load from the power system for several minutes at a time.[55]

AEMO published in 2020 a survey on how DER are impacting distribution networks in the NEM, illustrating the range and complexity of these issues.[56] Distribution businesses identified over- and under-voltage issues; problems with inverter setting at customers' premises; and voltage, phase balancing and thermal capacity issues on feeders and at substations. The extent of integration challenges varies by the size and location of PV clusters in each network, relative to physical network characteristics and load. AEMO's survey findings confirmed South Australia and Queensland experience the most significant challenges due to their high uptake of solar PV systems, exacerbated by some cluster areas in these states having generally weaker network capacity.

To mitigate the risk of DER breaching technical limits, the networks set circuit breakers that interrupt supply if those limits are exceeded. But the performance of inverters connecting DER devices to the network has posed challenges in some regions. AEMO estimated around 15 per cent of rooftop systems in Queensland and 30 per cent in South Australia did not meet the Australian standard for inverters. Work is being undertaken to improve performance standards for newly installed inverters.[57]

52 CoAG Energy Council, Energy Security Board, 'Actionable ISP final rule recommendation', 27 March 2020, web page, available at: www.coagenergycouncil.gov.au/publications/actionable-isp-final-rule-recommendation.

53 CSIRO/AEC, *Electricity network transformation roadmap, Final report*, April 2017.

54 AEMC, *Economic regulatory framework review, Integrating distributed energy resources for the grid of the future*, September 2019.

55 AEMO *Power system requirements*, March 2018.

56 AEMO, *Renewable integration study*, *Stage 1*, Appendix A, April 2020.

57 AEMC, *Economic regulatory framework review, Integrating distributed energy resources for the grid of the future*, September 2019.

In the longer term, distribution networks require more visibility over DER to manage frequency and voltage stability. Technical standards for DER devices and smart software can help. In addition, AEMO needs to be able to support better load shaping and localised storage requirements.[58]

Pricing reforms

Pricing is one mechanism that can be used to optimise the benefits of DER. Reforms introduced in 2017 require electricity distribution businesses to progressively move customers onto network tariffs more closely aligned to the costs of providing the services that they use. The reforms reduce network 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. Retailers are expected to offer a range of products to suit different customer needs and preferences. Some customers may prefer basic 'insurance' style products that charge the customer one price for energy regardless of when it is used. But, for customers with some flexibility in their energy use, retailers may offer incentives for those customers to switch their energy use to times of low demand, and operate DER such as rooftop solar PV systems and batteries in ways that minimise network stress.

Pricing reform is progressing slowly, with most networks initially adopting 'opt in' models for transferring customers to cost-reflective network tariffs. More recently, distributors are starting to require customers to 'opt out' of cost reflective network tariffs. The AER estimates this shift will result in up to half of all residential customers in NSW, Tasmania, the ACT and Northern Territory being on cost-reflective network tariffs by 2024 (figure 1.17).[59]

The limited penetration of smart meters for residential and small business customers is also limiting tariff uptake. Smart meters (or manually read interval meters) are required to measure customers' electricity use across the day. While around 98 per cent of Victorian customers had access to a smart meter, penetration is much lower in other regions. Outside Victoria, Ausgrid (NSW) had the highest penetration of smart or interval meters at February 2020, at 34 per cent of small customers. In other networks, 10–15 per cent of small customers had a smart or interval meter.

58 Energy Security Board, *Health of the National Electricity Market 2019*, February 2020.

59 AER estimate. Outcomes will depend on the rate at which smart meters are installed for new connections. Source: AER, 'Network tariff reform', web page, available at: www.aer.gov.au/networks-pipelines/network-tariff-reform, viewed 1 April 2020.

The AER supports network pricing reform through its demand management incentive scheme and demand management innovation allowance (section 3.10.7).

Pricing of DER exports to the grid

Pricing reforms to date mainly focus on network charges for the use of poles and wires to transport electricity from the grid *to* the consumer. At present, distribution networks cannot charge DER owners for exporting electricity back into the network, beyond a basic charge to connect to the network.

Forward and reverse power flows through a distribution network fluctuate widely during the day. This fluctuation can impact the quality and reliability of power supplies at certain times, especially during periods of very high or low demand, when voltage instability is more likely. These costs affect all customers but are not charged to DER owners, so are not factored into DER investment decisions.

As solar penetration increases to levels that cause network constraints, distributors have the option of expanding the network, and recovering the costs from all consumers through higher charges. But network augmentation is costly. Some consumer groups argue the approach is also inequitable, with the cost of DER integration being borne by all consumers regardless of whether they own DER.[60] Nevertheless, customer research conducted by AusNet Services' found support for sensible investment to allow solar exports, with the cost to be shared among all customers and with government.[61]

Some distributors are managing network constraints by restricting DER exports in constrained parts of their network, with some customers facing very low or zero export limits in areas with high levels of solar penetration.

While scope exists for technical solutions in the short term, the AEMC found flexible export limits offer an alternative. Instead of applying a low static export limit to all consumers (as occurs now), this approach recognises technical issues caused by DER exports to the grid occur infrequently, so blanket restrictions are inefficient. Distributors with a high level of DER penetration, such as SA Power Networks, have already proposed flexible export limits.

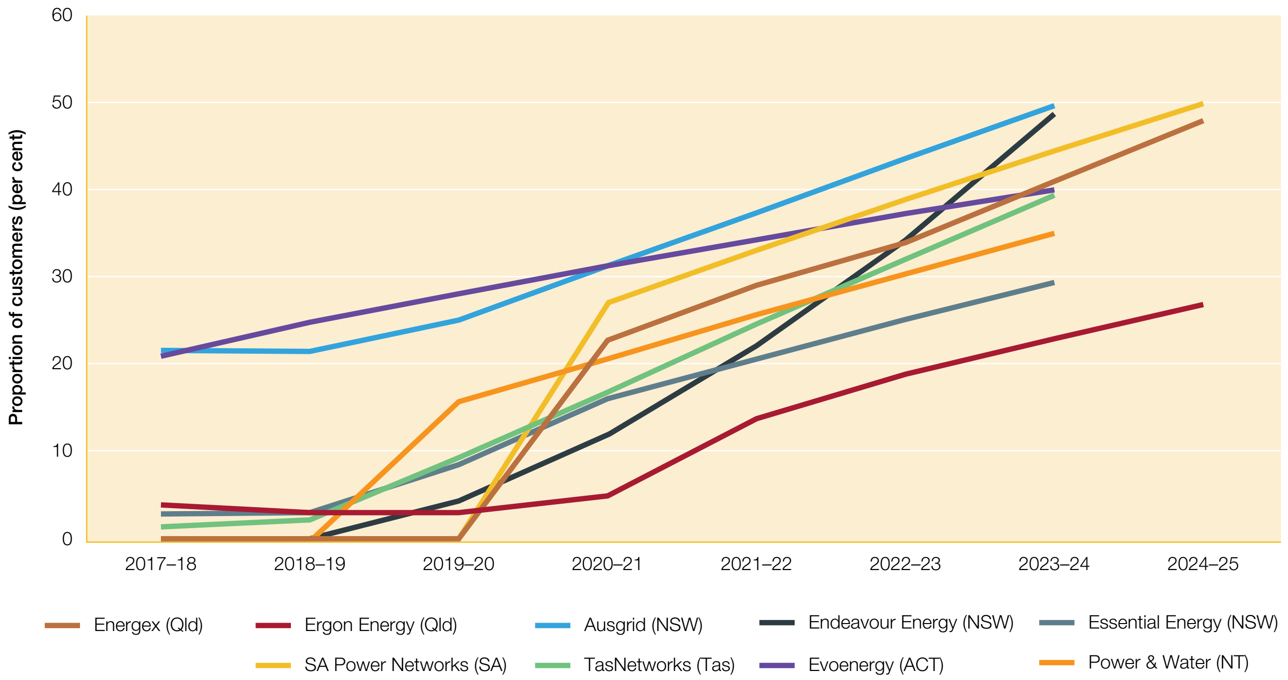
In the longer term, the AEMC proposed a 'use of system charge' for DER exports as part of an efficient solution. Network charges for the use of poles and wires to transport electricity could apply to exports to the grid, and to energy taken from it. The reforms could accompany options for

60 AEMC, *Economic regulatory framework review, Integrating distributed energy resources for the grid of the future*, September 2019.

61 AusNet Services, *2021–2025 Electricity distribution price review, Customer forum final engagement report*, 2020, p. 14.

Figure 1.17

Projected assignment of cost-reflective tariffs for residential customers



Source: AER estimates based on distribution network business data.

customers to choose a level of 'firmness'—such as rewards for their solar panels being constrained from exporting to the grid when the network is under pressure.[62]

DER visibility

More issues arise from DER's inherent lack of visibility, which compromises the market operator's ability to understand DER behaviour and manage the power system. AEMO and Australian distributors have little real time visibility of PV systems less than 5 MW.

As synchronous generators retire, the NEM increasingly relies on emergency control schemes to manage fluctuations in system frequency. Such schemes rely on the visibility of loads and generation to work effectively. But residential rooftop solar PV systems can blur this visibility. Activation of a scheme to disconnect load may unintentionally disconnect distributed generation as well, which could further destabilise frequency and disconnect more loads than intended.

More generally, as passive DER (rooftop solar PV generation) increases, the controllability of the power system reduces.

62 AEMC, *Economic regulatory framework review, Integrating distributed energy resources for the grid of the future*, September 2019.

The NEM currently has no means to actively control residential DER, even in emergency situations.[63]

In response to these issues:

- new arrangements announced in September 2018 require AEMO to establish a register of DER in the NEM. The register will give network businesses and AEMO visibility of where DER are connected, to help plan and operate the power system as it transforms.
- demand response and virtual power plant trials are exploring how DER behaves during disturbances, and developing a database of DER installations
- the CoAG Energy Council in March 2020 agreed to incorporate DER technical standards into the National Electricity Rules, and make them nationally consistent through complementary measures across the jurisdictions.[64] The new technical standards will aim to improve DER performance to support energy system security.

63 AEMC Reliability Panel, *2019 annual market performance review, Final report*, March 2020.

64 CoAG Energy Council, 'Energy Security Board outcomes from 23rd Energy Council Ministerial Meeting', 27 March 2020, web page, available at: www.coagenergycouncil.gov.au/publications/energy-security-board-outcomes-23rd-energy-council-ministerial-meeting.

Demand response technologies

DER can help manage power system disturbances by, for example, aggregating resources into virtual power plants. Automated technologies could help consumers respond to dynamic pricing signals, shifting their use away from high demand periods to when power is available at a lower cost.

As an example, affordable automated home energy management systems with 'set it, forget it' technologies could allow consumers or their service providers to pre-program use parameters that limit adverse effects on their lifestyles. Equipment, appliances and software are already available that use emerging smart grid technologies to save energy and seek the lowest energy rates. Specific loads such as electric hot water, pool pumps and air conditioners can be controlled remotely to reduce costs without significantly impacting consumers' amenity.

These trends will be accelerated by the entrance of new service providers marketing home energy management services. To optimise benefits to consumers, smart home energy management systems need to have access to real time information on network constraints and dynamic operating envelopes, and to price signals at the wholesale level.

The AER supports distribution networks in undertaking innovative projects in this area, through its demand management innovation allowance and demand management innovation scheme (section 3.10.7).

1.6 Coordinated reforms

Generation investment equivalent to the current size of the NEM (50 GW) is expected to occur over the next two decades.[65] Coupled with a significant proportion of conventional generation in the NEM retiring over this period, strategic planning is increasingly being used to coordinate the market's requirements to ensure efficient investment in generation plant and network capacity.

Two related processes focusing on the issues at a high level are:

- the AEMC's Coordination of Generation and Transmission Investment (CoGaTI) review, which examines how best to coordinate incentives for investment across both the generation and transmission sectors
- AEMO's integrated system plan, which is a long term plan of the NEM's transmission requirements to support and accommodate the transformation of the energy sector.

65 AEMO, *Draft 2020 integrated system plan*, December 2019.

A longer term reform initiative is the Energy Security Board's work to develop a new market framework (NEM 2025) to apply from the mid-2020s. This work is at an early stage.

Other high level policy workstreams with implications for electricity markets are gas reform and initiatives to develop a hydrogen industry in Australia.

1.6.1 Coordination of generation and transmission investment

Policy bodies are progressing reforms to better coordinate planning and investment in transmission and generation, to ensure new assets are built in the right place, at the right time, to serve the long term interests of consumers. The reforms (many of which are discussed in section 1.5) include:

- introducing transmission access reforms to strengthen price signals for generators to more efficiently locate and operate new plant
- facilitating renewable energy zones so clusters of generators can share the costs of connecting to the shared transmission network, or contribute to wider network improvements
- more closely allocating transmission costs to the parties that benefit from it
- simplifying the process for large scale storage systems to connect to the grid
- streamlining regulatory approvals for strategic transmission projects.

The AEMC is developing a model for transmission access reforms. It proposes that generators would receive a local price that reflects generation costs and congestion at their location. Generators would also have access to new products (financial transmission rights) to manage the risks of congestion and transmission losses (section 1.5.1). The CoAG Energy Council will consider the AEMC model as part of the NEM 2025 reform package at the end of 2020.

In 2020 the Energy Security Board was progressing rule changes to support the development of renewable energy zones. The process will include a staged development plan for each priority zone and trial rules for the connection of generators within the zones.

1.6.2 Integrated system plan

The integrated system plan (ISP) is a roadmap for the efficient future development of the NEM over a 20 year horizon. The first plan—published by AEMO in 2018 and updated in 2020—arose from recommendations in the Finkel review, following a statewide blackout of South Australia in September 2016.[66]

The ISP forecasts where and when network investment is likely to be needed to accommodate the large amount of new generation likely to connect to the grid in coming years. The 2018 plan focused on upgrading transmission interconnection in targeted locations to promote efficient sharing of energy, storage, and backup supply generation across regions, to reduce energy costs and enhance reliability and security. The draft 2020 plan updates and reclassifies some projects, but its direction is largely unchanged.

The draft 2020 plan forecast by 2040:

- small scale rooftop solar PV generation capacity will likely double or triple
- over 30 GW of new grid scale renewables will likely be needed to replace coal fired generation as it retires, supported by up to 20 GW of flexible, dispatchable resources such as pumped hydro and battery storage. If gas prices materially reduce, then new gas generators may also form part of the mix.
- innovative power system services will be needed to manage security issues such as voltage control, system strength, frequency control and power system inertia
- the transmission grid will require targeted augmentation (including new interconnectors and energy storage) to balance resources and unlock renewable energy zones.

The 2020 draft ISP identified over 15 projects for augmenting the transmissions network in eastern and southern Australia. The projects fall into three groups, by priority. Projects identified for immediate development (if not already underway) include:

- a new interconnector between NSW and South Australia (EnergyConnect) aimed at unlocking stranded renewable investments
- a new interconnector between NSW and Victoria, aimed at accessing planned new capacity at Snowy Hydro and unlocking renewable energy resources in western and north west Victoria
- minor upgrades to the Queensland–NSW and Victoria–NSW interconnectors
- reinforcements to the network in southern NSW to increase transfer capacity from Snowy Hydro to NSW demand centres.

AEMO recommended assessing and planning other major (but less time critical) projects, including a new Tasmania–Victoria interconnector (Marinus Link), upgrades to the Queensland–NSW interconnector supported by grid reinforcements, and infrastructure to support renewable energy zones.

The CoAG Energy Council in March 2020 agreed on an action plan developed by the Energy Security Board to action the ISP and integrate it with existing planning processes. The plan covers, for example, a streamlined process for the AER's regulatory investment test (a cost–benefit test for assessing the efficiency of network investment proposals) for ISP projects.[67]

1.6.3 NEM 2025

The CoAG Energy Council has tasked the Energy Security Board with advising on a long term, fit-for-purpose market framework that could apply from the mid-2020s, to support energy reliability and security, and emission reductions. The plan (NEM 2025) will consider opportunities and challenges, including:

- incentivising timely and efficient generation investment (including the right level and mix of technologies), and coordinating it with transmission investment to integrate renewable energy into the grid in a way that maintains system security and reliability
- optimising the contribution of DER to efficiency, security and reliability outcomes
- identifying additional security services such as frequency, inertia and system strength that may be needed in future, and how best to source and pay for those services.

In April 2020 the Energy Security Board identified market frameworks that could meet the project objectives of NEM 2025:

- *Two sided markets*, where consumers signal the value that they place on energy and are active in responding to wholesale prices. Consumer behaviour under this model is transparent, with real time information used to keep the power system operating securely and reliably.[68] This model would build on the wholesale demand response mechanism to be launched in October 2021.
- *'Ahead' markets*, where electricity supply and demand are scheduled (sold) ahead of the real time market. This model provides AEMO with greater visibility of energy market needs and, and it also allows the time to plan accordingly.
- *System services markets*, for products that are not currently valued. They include markets for operating reserves, frequency management (through synchronous inertia and fast frequency response) and system strength.[69]

The Energy Security Board will release a detailed analysis by the end of 2020 on a package of measures to adapt the existing market design.

1.6.4 Gas market reform

The launch of Australia's LNG industry, combined with structural issues in the domestic gas market, put significant pressure on domestic gas prices. This price pressure posed challenges for gas powered generation, which had been widely viewed as a key transition technology as coal fired plants close and more renewable generation comes online.

Government initiatives in Australia, including the Australian Domestic Gas Security Mechanism, increased domestic gas supply and eased price pressures, but structural issues in the market remain.[70] Legacy gas fields in southern Australia continue to deplete, and the status of new gas resources is unclear. In some states and territories, community concerns about environmental risks associated with fracking have led to legislative moratoria and regulatory restrictions on onshore gas exploration and development (section 4.10.1).

Gas pipeline access has been another structural issue in the market. Access to transmission pipelines on key north–south transport routes is critical to moving gas to demand centres. But gaining access to pipeline capacity has proved difficult for some customers.

In response to this issue:

- the AER in 2018 began publishing new data on prices and liquidity in gas markets to make wholesale gas markets more transparent for customers
- reforms to the Gas Bulletin Board widened reporting coverage of gas production, pipelines and storage options
- reforms making it easier for gas customers to gain access to underused capacity on transmission pipelines took effect in 2019. The AER monitors and enforces compliance with the reforms, which include a voluntary trading platform, backed by the mandatory day-ahead auction of all contracted capacity that is not in use. Early indications are that the reforms have improved transparency and flexibility in the domestic gas market (section 4.10.4).

1.6.5 Hydrogen

Hydrogen is derived primarily by splitting water or by reacting fossil fuels with steam or controlled amounts of oxygen. It can be stored as a gas or liquid, and retains roughly 80 per cent of the energy value of electricity used to produce it, giving it potential as a form of large scale electricity storage.

Hydrogen's storage potential gives it scope to offer electricity reliability and stability services. Grid connected electrolysers (which are energy intensive electrical loads) can be used to quickly ramp up or down the production of hydrogen, to manage fluctuations in renewable generation.

Hydrogen can also be stored in gaseous form in pipelines at concentrations of up to 10 per cent. Potentially, gas distribution networks could blend hydrogen with gas, and eventually transition to hydrogen as a fuel for heating and other industrial feedstock. The CSIRO outlined opportunities for hydrogen to compete favourably on a cost basis by 2025 in Australian applications such as transport and remote area power systems.[71]

In November 2019 the CoAG Energy Council released the National Hydrogen Strategy, with a focus on removing market barriers and efficiently building supply and demand. State governments have also announced initiatives. In 2019 the South Australian and Tasmanian governments established hydrogen plans to explore opportunities for using or exporting hydrogen, provide funding for pilot projects, and establish frameworks and infrastructure.

66 Dr Alan Finkel AO, Karen Moses, Chloe Munro, Terry Effeney and Professor Mary O'Kane, *Independent review into the future security of the National Electricity Market: blueprint for the future* (Finkel review), 2017.

67 CoAG Energy Council, 'Energy Security Board outcomes from 23rd Energy Council Ministerial Meeting', 27 March 2020, web page, available at: www.coagenergycouncil.gov.au/publications/energy-security-board-outcomes-23rd-energy-council-ministerial-meeting.

68 AEMC, 'What next for a two sided market? The implications of venturing behind the meter', Media release, 20 April 2020.

69 Energy Security Board, *System services and ahead markets*, April 2020, available at: https://prod-energycouncil.energy.slicedtech.com.au/sites/prod.energycouncil/files/System%20services%20and%20ahead%20markets%20paper%20-%20COAG%20April%202020.pdf.

70 Department of Industry, Science, Energy and Resources, 'Australian Domestic Gas Security Mechanism', web page, available at: www.industry.gov.au/regulations-and-standards/australian-domestic-gas-security-mechanism.

71 CSIRO, *National hydrogen roadmap*, August 2018.

ARENA is supporting a number of demonstration scale renewable hydrogen projects, and 16 research projects. This support includes funding for a Jemena project to produce hydrogen from renewable energy, for injection into the Sydney gas network.[72] The trial will inject a majority of the hydrogen for domestic use, with a portion used for gas powered electricity generation. Some hydrogen will be stored to refuel hydrogen vehicles.

On an international scale, a pilot project in Victoria's Latrobe Valley is demonstrating the full hydrogen supply chain, from production through to export to Japan. The four year project uses a world first purpose-built liquefied hydrogen carrier, and is the world's largest hydrogen demonstration project.[73]

The largest commercial green hydrogen project currently proposed for Australia is a 15 GW wind and solar project in the Pilbara in Western Australia. Up to 3 GW would be dedicated to large energy users in the region, such as mines and mineral processing facilities, while 12 GW would be used to produce green hydrogen for domestic and export markets. Construction is forecast to commence in 2023–24, with first generation in 2025–26.

1.7 Government initiatives

Governments at all levels are undertaking unilateral (or bilateral) policy initiatives to manage aspects of the energy market transition. The initiatives include major investments in publicly owned generation and storage, programs offering financial assistance for private grid scale projects, and regulatory interventions to streamline investment approvals.

While government intervention can help manage an identified market issue, its wider market impacts are complex. In particular, intervention can distort market signals, affecting private sector investment decisions. The Energy Security Board argued, for example, government intervention intended to improve reliable supply may also distort the market and lower investor confidence.[74]

The AER in December 2018 reported views of energy market participants that a lack of stability and predictability in government energy policy is a barrier to entry for new generation. Emission policy instability, interventions to address energy policy objectives such as reliability and affordability, and government ownership in the industry were cited as key impediments to investment in the NEM.[75]

72 ARENA, 'Hydrogen to be trialled in NSW gas networks', Media release, 22 October 2018.
73 CoAG Energy Council, *Australia's National Hydrogen Strategy*, November 2019.
74 Energy Security Board, *Health of the National Electricity Market 2019*, February 2020.
75 AER, *Wholesale electricity market performance report*, December 2018.

1.7.1 Incentivising private capacity investment

Australian governments offer a range of financial incentives for private investment in generation and storage capacity. Some schemes offer direct subsidies or grants. Others underwrite investment through debt or equity support, or through measures such as selling 'contracts for difference' that provide financial certainty for investors. Some schemes use a mix of approaches.

Underwriting new generation investment

Alongside ongoing funding schemes run by ARENA and the Clean Energy Finance Corporation (CEFC) (box 1.1), the Australian Government launched the Underwriting New Generation Investments program (UNGI) in 2019. The program offers incentives for 'firm' and 'firmed' capacity targeted at lowering prices, increasing competition and increasing reliability. It is stated to be technology neutral, and may include upgrades or life extensions to existing generators. The multi-phased program runs over four years to June 2023.

UNGI support may take various forms. It may include, for example, a guaranteed floor price, contracts for difference, collar contracts, government loans, and other mechanisms. Shortlisted projects may be eligible for support from the Grid Reliability Fund, which the CEFC administers.[76]

The first registrations of interest led to a shortlist of 12 projects, including six pumped hydro projects, five gas projects, and a proposed upgrade of the Vales Point black coal fired generator. From the shortlist, the Australian Government announced two successful projects in January 2020:

- APA Group's proposed 220 MW gas generator in Victoria to provide fast start generation to balance the increase in intermittent renewables in that state
- Quinbrook Infrastructure Partners' 132 MW gas generator in Queensland to help meet peak demand in Queensland and NSW, increase competition, and complement an upgrade to the Queensland–NSW interconnector.[77]

The government previously announced a commitment to develop an underwriting mechanism through the UNGI program for the Battery of the Nation scheme (section 1.7.2).

76 The government will refer UNGI projects to the Grid Reliability Fund only if the referral reflects the CEFC's legislative mandate. The CEFC will not invest in coal projects.
77 The Hon. Angus Taylor MP (Minister for Energy and Emissions Reduction), 'Initial support terms for two new generation projects agreed', Media release, 23 December 2019.

Queensland generation feasibility studies

In February 2020 the Australian Government committed funding for a feasibility study into new generation projects in central and northern Queensland. It allocated:

- $4 million to Shine Energy to conduct a feasibility study for a 1 GW 'high efficiency low emissions' coal plant at Collinsville. Shine Energy is seeking government indemnity against a future carbon price.
- $2 million to a pre-feasibility study for a 1.5 GW pumped hydroelectric plant located between Collinsville, Proserpine and Mackay.

The two projects are partly targeted at adding new synchronous generation to address system strength issues in the region (section 1.4.3). If found to be viable, they may be eligible for underwriting through the Australian Government's UNGI program.

1.7.2 Public investment in generation capacity

Despite strong investment in renewable capacity, private sector investment in 'firming' or 'dispatchable' capacity in recent years has been negligible. To fill the gap, the Australian Government and some state governments have announced new public sector investment in electricity generation, storage and transmission projects.

Snowy 2.0

Among major initiatives, the Australian Government undertook a feasibility study in 2017 for expanding Snowy Hydro (which it owns) by using pumped hydroelectric technology (figure 1.18). The proposal would increase Snowy Hydro's pumped hydroelectric generation capacity by around 2000 MW—a rise of 50 per cent. A final investment decision was made in late 2018, and a contractor was appointed in 2019.

Snowy Hydro's sole shareholder is the Australian Government, after the government purchased the NSW and Victorian governments' shares in March 2018.

The Snowy 2.0 project will construct an underground power station and about 27 kilometres of power waterway tunnels to link the existing Tantangara and Talbingo reservoirs. The underground power station will pump water from the Talbingo reservoir to the Tantangara reservoir when electricity prices are low. When prices are high, it will generate electricity by releasing water from the Tantangara reservoir to flow down through the underground power station back to the Talbingo reservoir.

The proposal adds 2000 MW of energy generation and 175 hours of storage to the NEM. The $5 billion project is forecast to start producing power from the first of six new generators by late 2024.

Battery of the Nation

The Australian and Tasmanian governments in April 2017 announced a feasibility study into expanding the Tasmanian hydroelectric system. The expansion would deliver up to 2500 MW of additional capacity through pumped storage and possible expansions of the Tarraleah and Gordon power stations.

CleanCo

The Queensland Government in December 2018 launched CleanCo, a state owned corporation focused on meeting Queensland's 50 per cent renewable energy target by 2030, supporting secure and reliable electricity generation, and creating investment and jobs in regional Queensland. CleanCo has a particular focus on low and zero emission technology. Initially, 1000 MW of capacity from hydroelectric and gas power stations transferred to CleanCo from other state owned generators. The Queensland Government will fund CleanCo's investment in a further 1000 MW of renewable capacity by 2025. That investment will involve a mix of building, owning and operating its own assets, and investing in private sector projects.

Hornsdale

The South Australian Government developed diesel (convertible to gas) generation and battery storage, including the 100 MW Hornsdale Power Reserve—the first scheduled battery in the NEM. The battery has helped lower the cost of frequency control services in the region. Its capacity was expanded to 170 MW in 2020.

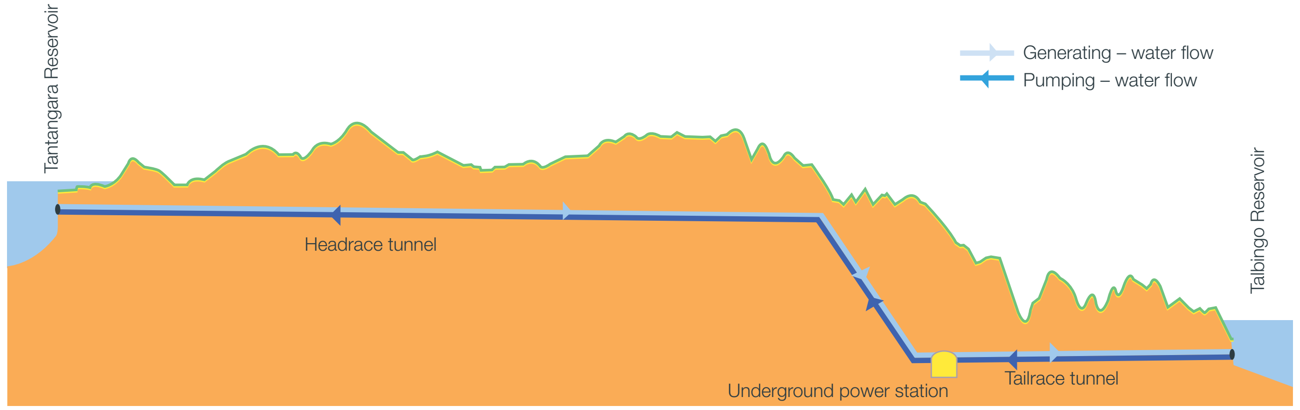
NSW electricity strategy

The NSW Government launched a new electricity strategy in November 2019.[78] The strategy has three key elements:

- grants to support grid scale electricity generation and storage projects, to diversify the NSW electricity mix and drive competition in the wholesale market
- support for renewable energy zones, which includes (where appropriate) changing regulatory settings to incentivise generators to cover part of the cost of building new transmission assets. The initial focus will be on a 3000 MW pilot zone in the state's central west.

78 Prime Minister of Australia and Premier of New South Wales, 'NSW energy deal to reduce power prices and emissions', Media release, 31 January 2020.

Figure 1.18
Snowy 2.0



Note: Illustration not to scale.
Source: Snowy Hydro.

- a NSW-specific reliability target, accompanied if necessary by additional support (through grants or contracts for output) for new generation, and by fast tracking of priority transmission projects. The NSW Government may also use its emergency response powers and processes.

The strategy follows an earlier NSW Transmission Infrastructure Strategy that looked to accelerate four transmission projects to improve interconnection with Queensland, Victoria, South Australia and the Snowy region.

The Australian governments will support elements of the strategy, along with initiatives to:

- ensure reliability following the planned exit of the Liddell power station, and ensure long term access to coal for the Mount Piper power station
- inject another 70 petajoules (PJ) of gas per year into the NSW market
- ensure access to the $1 billion federal Grid Reliability Fund
- guarantee support for three NSW generation projects under the federal UNGI program.[79]

Victoria

The Victorian Government in February 2020 introduced legislation to fast track priority projects such as grid scale batteries and transmission upgrades. Amendments to the *National Electricity (Victoria) Act 2005* will allow the government to override the national framework on transmission approvals—the government argues that the framework excessively delays the delivery of transmission projects and fails to account for the full benefits of investments. The changes will focus on projects that increase the state's capacity to import electricity during periods of peak demand.

The Victorian Government will work in consultation with AEMO to implement the changes, with an initial focus on expanding the capacity of the Victoria–NSW Interconnector.

The government linked its intervention to the grid's increasing vulnerability to extreme heat, which is causing unprecedented demand for electricity. That demand is putting pressure on the state's ageing coal fired generators, and making the transmission network more vulnerable to bushfires and severe weather events.[80]

79 The Hon. Angus Taylor MP (Minister for Energy and Emissions Reduction), 'Backing reliable energy for commercial and industrial users', Media release, 8 February 2020.

80 Minister for Energy, Environment and Climate Change (Victoria), 'Victoria acts to secure a more reliable energy system', Media release, 18 February 2020.