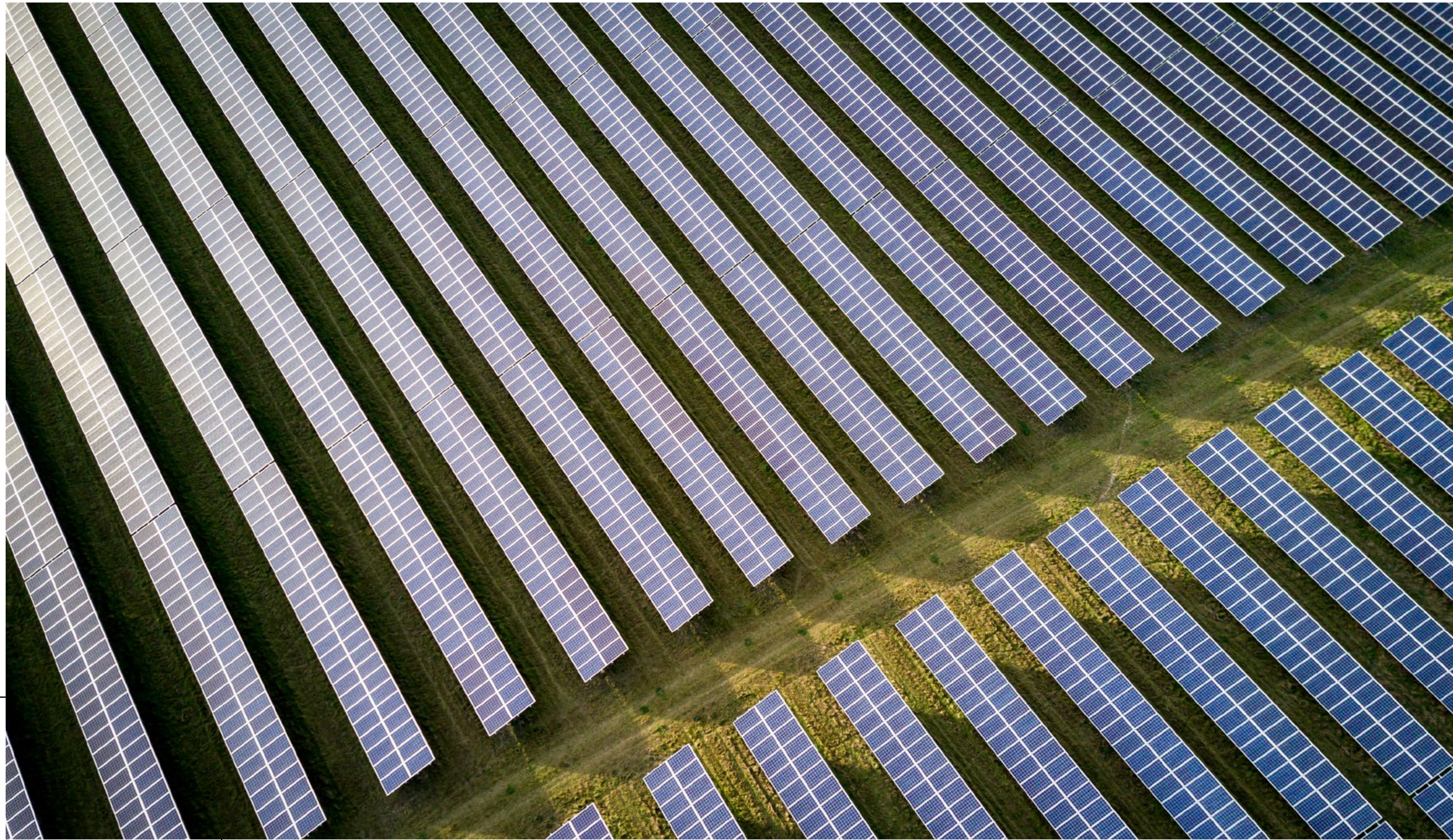

Source: Shutterstock

2 NATIONAL ELECTRICITY MARKET

Electricity generated in eastern and southern Australia is traded through the National Electricity Market (NEM), a wholesale spot market in which changes in supply and demand determine prices in real time. The market covers five regions—Queensland, New South Wales (NSW), Victoria, South Australia and Tasmania. The Australian Capital Territory (ACT) falls within the NSW region. In geographic span, the NEM is one of the world's longest interconnected power systems, stretching from Port Douglas in Queensland to Port Lincoln in South Australia, and across the Bass Strait to Tasmania (box 2.1). The Australian Energy Regulator (AER) plays a number of important roles in the market (box 2.2).

Around 200 large power stations produce electricity for sale into the NEM. A transmission grid carries this electricity along 43 000 kilometres of high voltage power lines and cables to industrial energy users and local distribution networks. Energy retailers complete the supply chain by purchasing electricity from the NEM, and packaging it with transmission and distribution network services for sale to over 10 million residential, commercial and industrial energy users. Infographic 1 shows the electricity supply chain.

This chapter covers the NEM wholesale market and the derivatives (contract) markets that support it. Chapter 3 covers electricity transmission and distribution networks, while chapter 6 covers electricity (and gas) retailing.

The generation mix in the electricity market continues to evolve as new technologies emerge and as the costs of some generation technologies fall. Wind and solar generation are replacing older coal fired generators as they retire from the market, for example. Energy customers are increasingly bypassing the traditional supply chain by producing some or all of their own electricity, using rooftop solar photovoltaic (PV) systems, and selling surplus production back into the grid.

In coming years, households and businesses may increasingly meet their energy needs by drawing on electricity stored in batteries, and be paid by energy suppliers to reduce their energy use or inject stored electricity when the grid is under stress. Technological advances that make battery storage more economical will accelerate this shift.

2.1 Electricity consumption

The market operator defines electricity demand as electricity supplied through the transmission grid, with rooftop solar PV output treated as an offset against demand (because it replaces electricity that would otherwise be supplied through the grid). To avoid confusion, this report refers to that demand as 'grid demand'. Consumption is a wider concept covering the total amount of electricity used, including both grid and rooftop PV generation.

Over 10 million residential and business customers consume electricity across the NEM's five regions. Overall consumption increased steadily from 2014 to almost 206 terawatt hours (TWh) in 2019—its highest level since 2011 (figure 2.2).

The expansion of Queensland's coal seam gas (CSG) and liquefied natural gas (LNG) industries accounts for much of the growth in electricity use since 2014. Elsewhere, consumption moderately increased in NSW, remained flat in South Australia and Tasmania, and fell in Victoria over this period.

Most electricity consumed in the NEM is produced by large generators, sold through a wholesale market, and transported through a network grid to customers. Total grid demand peaked in 2008 at 211 TWh. Following several years of decline, demand levelled out from 2013. Demand in 2019 totalled 195 TWh, similar to levels in the previous six years.

Demand patterns are changing as more electricity customers generate some of their own electricity needs through rooftop solar PV systems. By January 2020 over 2 million households and businesses in the NEM had installed solar PV systems to produce electricity. These systems met around 5 per cent of total energy requirements in the NEM in 2019.

Consumption of grid supplied electricity in the NEM is forecast to decline marginally over the next decade. The Australian Energy Market Operator (AEMO) forecast that rises in consumption associated with population growth and increased mining activity will be more than offset by improvements in energy productivity, growth in rooftop PV and other non-scheduled generation, and a gradual shift away from energy intensive industries.[1]

Section 1.2.3 in chapter 1 further discusses trends in electricity consumption.

2.1.1 Maximum grid demand

The demand for electricity varies by time of day, season and ambient temperature. Daily demand typically peaks in early evening when business and residential use overlap, while seasonal peaks occur in winter (driven by heating loads) and

1 AEMO, *2019 electricity statement of opportunities*, August 2019, p. 8.

Box 2.1 How the National Electricity Market works

The National Electricity Market (NEM) consists of a wholesale spot market for selling electricity and a transmission grid for transporting it to energy customers (table 2.1). Generators make offers to sell power into the market, and the Australian Energy Market Operator (AEMO) schedules the lowest priced generation available to meet demand. The amount of electricity generated (or released from storage) needs to match demand in real time.

Table 2.1 NEM at a glance

Participating jurisdictions	Qld, NSW, Vic, SA, Tas, ACT
NEM regions	Qld, NSW, Vic, SA, Tas
NEM installed capacity (including rooftop solar)[1]	60 824 MW
Number of large generating units	268
Number of customers[2]	10 million
NEM turnover 2019	$18.6 billion
Total electricity consumption 2019[3]	205.5 TWh
National maximum demand 2019[4]	33 941 MW

MW, megawatts; NEM, National Electricity Market; TWh, terawatt hours.

1. At January 2020.
2. Customers are at the second quarter of 2019–20, except for Victoria, which reported customers in 2018–19.
3. Includes energy met by the grid and rooftop PV generation.
4. The maximum historical summer demand of 35 551 MW occurred in 2009. The maximum historical winter demand of 34 422 MW occurred in 2008.

Source: AER; AEMO; Clean Energy Regulator; Energy Made Easy website (energymadeeasy.gov.au); Victorian Essential Services Commission.

Large power stations make offers to supply quantities of electricity in different price bands for each 5 minute *dispatch interval*. Electricity generated by rooftop solar photovoltaic (PV) systems is not traded through the NEM, but it does lower the demand that market generators need to meet.

Only large customers (such as energy retailers and major industrial energy users) deal directly with the wholesale market. Retailers buy power from the market, which they package with network services to sell as a retail product to their customers. They manage the risk of volatile prices in the wholesale market by taking out hedge contracts (derivatives) that lock in a firm price for electricity supplies in the future, by controlling generation plant, or taking out demand response contracts with their retail customers.

As the power system operator, AEMO works with constantly varying information to make a continuum of decisions. It uses forecasting and monitoring tools to track electricity demand, generator bidding and network capability, allowing it to determine which generators should be dispatched (directed) to produce electricity. It repeats this exercise every 5 minutes. It dispatches the cheapest generator bids first, then progressively more expensive offers until enough electricity can be produced to meet demand. The highest priced offer needed to cover demand sets the 5 minute *dispatch price*.

Generators are paid at the *settlement (or spot) price*, which is the average dispatch price over 30 minutes. All dispatched generators are paid at this price. A separate spot price is determined for each of the five NEM regions. Prices are capped at a maximum of $14 700 per megawatt hour (MWh) in 2019–20. A price floor of –$1000 per MWh also applies. The market cap increases in line with the consumer price index (CPI) each year, but the market floor price remains unchanged.

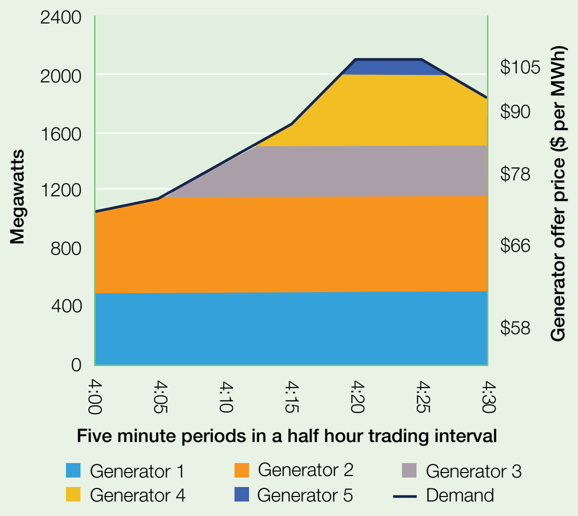
Figure 2.1 illustrates how prices are set. In the example, five generators offer capacity in different price bands between 4.00 pm and 4.30 pm. At 4.15 pm the demand for electricity is 1650 megawatts (MW). To meet this demand, generators 1, 2 and 3 must be fully dispatched, and generator 4 is partly dispatched. The dispatch price is $90 per MWh. By 4.20 pm demand has risen to the point where a fifth generator is needed. This generator has a higher offer price of $105 per MWh, which becomes the dispatch price for that 5 minute interval. The settlement price paid to all dispatched generators for the half hour trading interval is the average of the six dispatch prices over the half hour period—around $89 per MWh.

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

Power system management

AEMO is responsible for managing the NEM spot market and transmission network. The power system needs to be *reliable* (having enough generation and network capacity to meet customer demand, plus a safety margin) and *secure* (being technically stable, even following an unexpected outage of a major transmission line or generator). Security issues, such as frequency and voltage instability, have become more widespread in the NEM in recent years (sections 1.4 and 2.10).

Figure 2.1
Setting the spot price



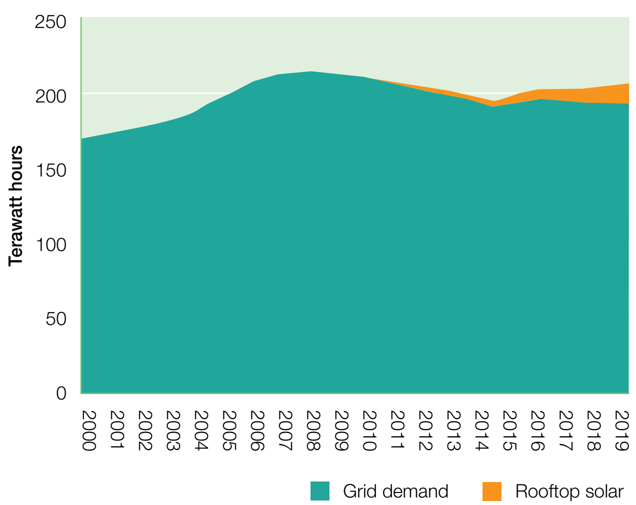
AEMO procures some stability services (such as frequency control) in markets to keep the power system secure. The services are offered by generators and storage facilities that can rapidly adjust output, and demand responders that can rapidly adjust their energy use.

Generators and other participants can offer both energy and stability services into the market. AEMO 'co-optimises' the supply of both services so overall costs are minimised.

Security services such as inertia and system strength are not procured in markets. Instead, AEMO overrides the market's normal operation when issues arise in these areas—for example, it may constrain from operation a generator that contributes to the problem, or direct a generator to operate if it could help alleviate the problem (even if the generator is not the lowest cost available plant). Such interventions are costly, and ultimately consumers pay for them (section 1.4.3).

AEMO can also intervene in the market to manage reliability risks, typically by contracting with back-up generators to ensure reserves are available, or by paying large energy customers to cut their energy use to ease demand (section 2.9.1). If a threat of unserved energy cannot otherwise be avoided, AEMO may direct generators to provide additional supply. If all other avenues have been exhausted, and insufficient generation is available (or cannot be dispatched quickly enough), AEMO may instruct a network business to 'load shed'—that is, temporarily cut power to some customers. This action is rare.

Figure 2.2
Electricity consumption in the NEM



Note: Grid demand is operational demand (including scheduled and semi-scheduled generation, and intermittent wind and large scale solar generation). Rooftop solar consumption is based on generation estimates by AEMO.

Source: Grid production: AER, AEMO; rooftop solar: AER, AEMO (nemweb.com.au/#rooftop-pv-actual).

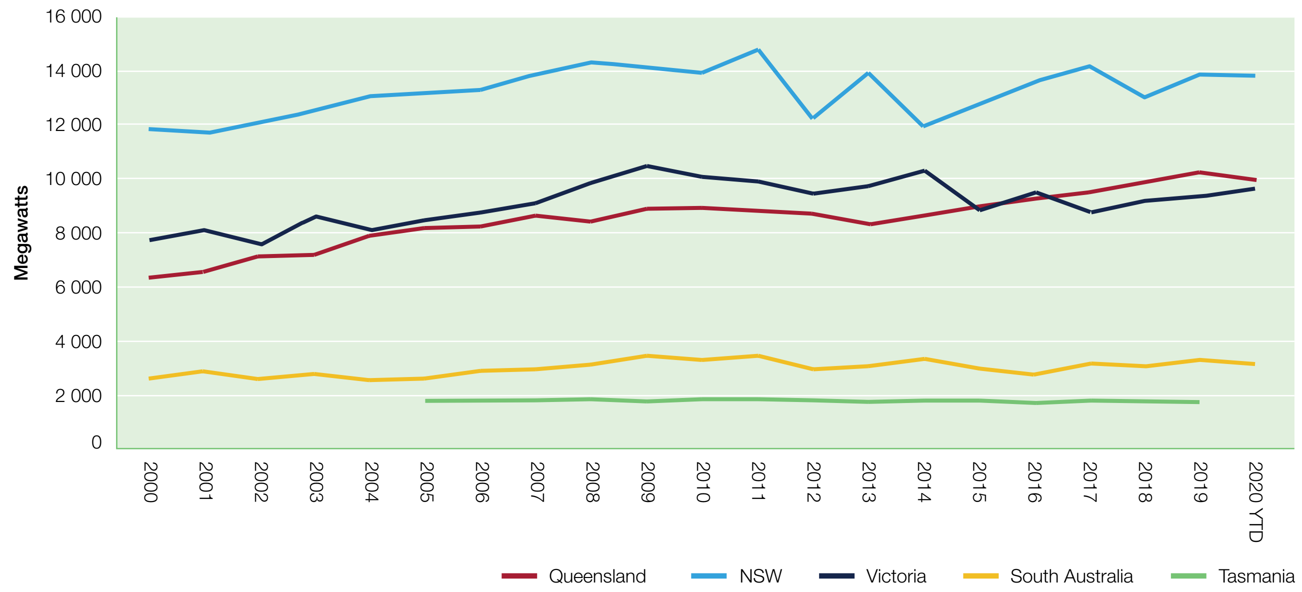
summer (for air conditioning). Demand normally reaches its maximum on days of extreme heat, when air conditioning loads are highest.

Maximum demand for grid sourced electricity rose steadily until 2009, but then flat lined or declined in all regions except Queensland (figure 2.3). Outcomes in 2019 and early 2020 varied by region. Queensland continued its almost unbroken trend of rising maximum demand, setting a new record on 13 February 2019 during a prolonged heatwave. But, in the 2019–20 summer, Queensland's maximum fell for the first time since 2013.

Victoria, NSW and South Australia also experienced higher maximum demand in 2019 than a year earlier, partly due to a warm summer driving air conditioning use and higher industrial demand for power. Maximum demand fell slightly in Tasmania. The maximums in all regions were well below historical peaks. In the 2019–20 summer, Victoria was the only state with a higher maximum demand than a year earlier.

Maximum demand over the next 10 years is forecast to rise steadily in Queensland, remain flat in NSW and South Australia, and to fall in Victoria. Tasmanian

Figure 2.3
Maximum grid demand, by region



YTD, year-to-date.

Note: Maximum operational grid demand (including scheduled and semi-scheduled generation, and intermittent wind and large scale solar generation) is for any time during the year. Data exclude consumption from rooftop solar PV systems. The 2020 year-to-date data include all intervals to 31 March 2020. Tasmania's 2020 maximum is not shown, because Tasmania's maximum demand occurs in winter (from heating loads).

Source: AER analysis of AEMO data.

Box 2.2 The AER's role in the National Electricity Market

The Australian Energy Regulator (AER) has regulatory responsibilities in the National Electricity Market (NEM) across the entire supply chain. At the wholesale level, we monitor and report on spot and contract market activity in all regions of the market (Queensland, NSW, Victoria, South Australia and Tasmania).

Our work in the sector is wide ranging and includes:

- from 1 July 2019, administering and monitoring compliance with the Retailer Reliability Obligation, including participants' activity in electricity contract markets
- reporting on the effectiveness of competition in the NEM. Our second competition report is scheduled for release in late 2020.
- publishing our *Wholesale markets quarterly report,* which launched in November 2019
- publishing the annual *State of the energy market* report, along with interim data updates.

We also monitor the markets to ensure participants comply with the National Electricity Law and Rules, and take enforcement action if necessary. A recent focus is on the provision of accurate and timely information to the Australian Energy Market Operator to help maintain power system security and efficient market outcomes.

We draw on our monitoring work to advise policy bodies and other stakeholders on market trends, policy issues and irregularities. When appropriate, we also propose or participate in reforms to improve the market's operation.

Alongside our wholesale market activity, the AER is the economic regulator for electricity networks in NEM jurisdictions (chapter 3). In retail markets, we hold wide ranging responsibilities in jurisdictions that have passed the National Energy Retail Law—namely, NSW, Queensland, South Australia, Tasmania and the ACT (chapter 6).

maximum demand is forecast rise over the next two years then flatten.[2]

Trends in maximum demand are driven by factors similar to those affecting total demand (population and economic growth, energy efficiency, and technology). But the impact of changes in these drivers can differ for total consumption and maximum demand. As an example, the forecast rise in rooftop solar PV capacity over the next decade will significantly reduce the total generation required from the grid, but will have a more limited impact on maximum demand, which typically occurs in the evening, when solar is generating at limited capacity.

2.1.2 Minimum grid demand

Historically, electricity demand reached its lowest point in the middle of the night, when most people are sleeping. But the growth of rooftop solar PV capacity means households are exporting electricity to the grid in the middle of the day when the sun is at its highest point. This trend is lowering daytime grid demand, to the extent that minimum grid demand increasingly occurs in the middle of the day. This shift is being driven not by low electricity consumption, but by rising 'behind-the-meter' production by solar PV systems.

The shift also reflects in declining levels of minimum demand. While maximum demand was higher in mainland states in 2019, minimum demand fell in every NEM region. The shift was most apparent in South Australia, which beat its previous record low demand on seven separate days, and set a new historic minimum demand of 456 megawatts (MW) on 10 November 2019. South Australia, Victoria and Queensland all recorded their minimum demand in 2019 around the middle of the day.

Over the next five years, minimum demand is forecast to decline in mainland regions and keep shifting towards the middle of the day as rooftop PV capacity increases. The trend is predicted to occur more slowly in Tasmania, which has a comparatively higher proportion of business load, meaning that minimum demand may still occur overnight.[3]

Section 1.2.3 in chapter 1 further discusses trends in minimum demand.

2 AEMO, *2019 electricity statement of opportunities*, August 2019, p. 9.
3 AEMO, *2019 electricity statement of opportunities*, August 2019.

2.2 Generation technologies in the NEM

The NEM's generation plant uses a mix of technologies to produce electricity. Figure 2.17 maps the locations of generation plant, and the types of technology in use. Table 2.2 lists each plant. Figures 2.4–2.6 compare variations across regions, including movements over time.

Fossil fuel generators produce almost 77 per cent of electricity in the NEM. The plants burn coal or gas to power a generator. This combustion process releases carbon emissions as a byproduct into the atmosphere. While large scale, fossil fuel fired synchronous generators still dominate, many older generators are nearing the end of their life, becoming less reliable and closing. Renewable generation is filling much of the gap as Australia transitions to a lower emission economy. Hydroelectric and wind plant use water and wind respectively to drive generators. Solar PV generation does not rely on a turbine; rather, it directly converts sunlight to electricity.

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

Synchronous generators such as coal, gas and hydro plants possess rotational inertia, which regulates frequency in the power system. Wind and solar plant do not possess this inertia, and can pose challenges for power system security. The capability of those technologies to provide inertia and other security services is evolving (section 1.4).

Despite challenges in integrating wind and solar plant into the grid, the shift to renewable generation has been significant. The technology mix is evolving due to changes in the relative fuel and capital costs of different plant, technological advances that make some plant more efficient, and government policies to reduce carbon emissions. Section 1.1 in chapter 1 analyses these drivers.

2.2.1 Coal fired generation

Coal fired generators burn coal to create pressurised steam, which is then forced through a turbine at high pressure to drive a generator (figure 2.7). Coal fired generation remains the dominant supply technology in the NEM, producing 68 per cent of all electricity traded through the market in 2019. But coal plant accounts for only 37 per cent of the market's generation capacity, reflecting that coal generators tend to run fairly continuously.

Figure 2.4
Generation in the NEM, by fuel source, 2019

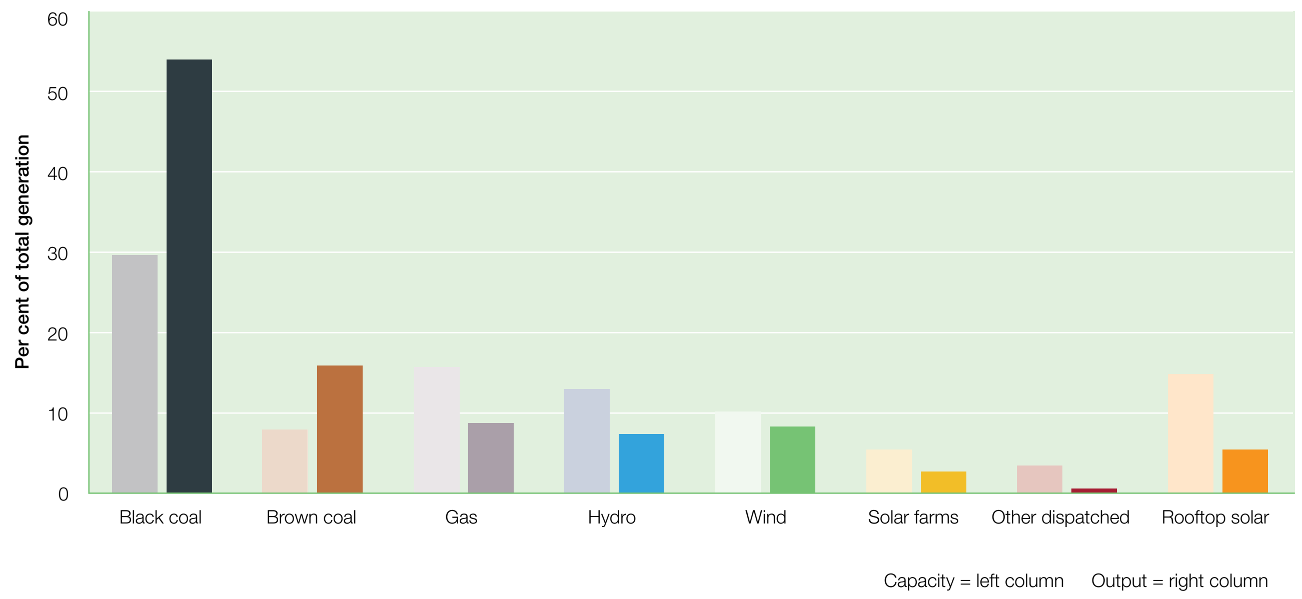
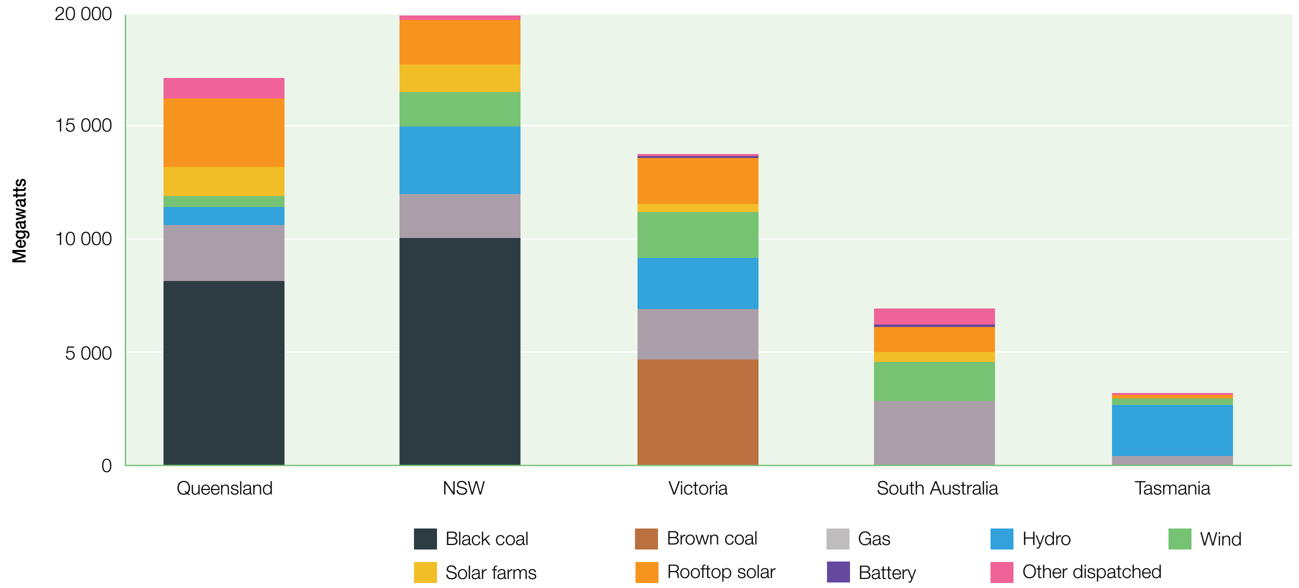
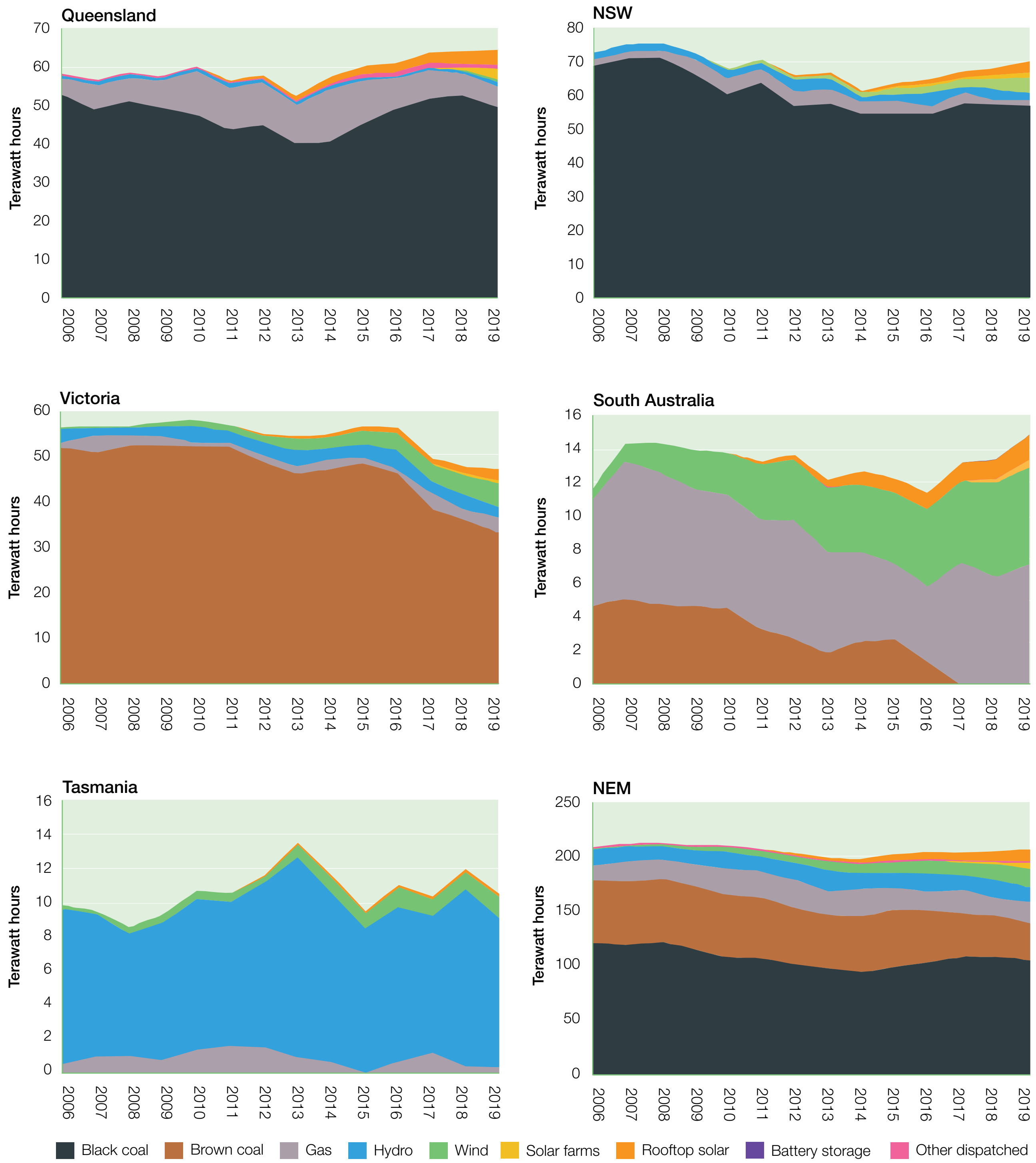


Figure 2.5
Generation capacity in the NEM, by region and fuel source, 2019



Note (figures 2.4 and 2.5): Generation capacity at 1 January 2020. Other dispatch includes biomass, waste gas and liquid fuels. Output is for 2019.
Source: Grid demand: AER, AEMO; rooftop solar: AER, CER, AEMO.

Figure 2.6
Electricity generation over time, by region and fuel source



Note: Other dispatch includes biomass, waste gas and liquid fuels.
Source: AER; AEMO (data).

Figure 2.7
Coal fired generation

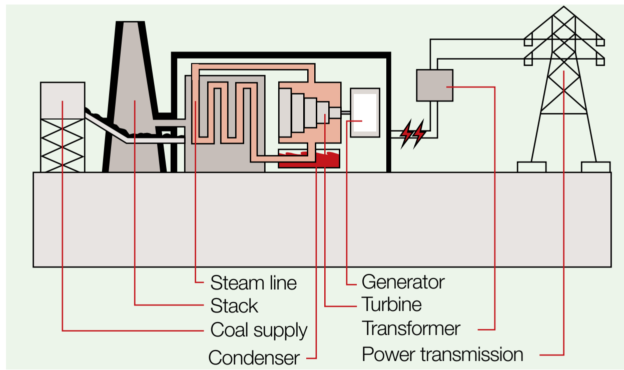
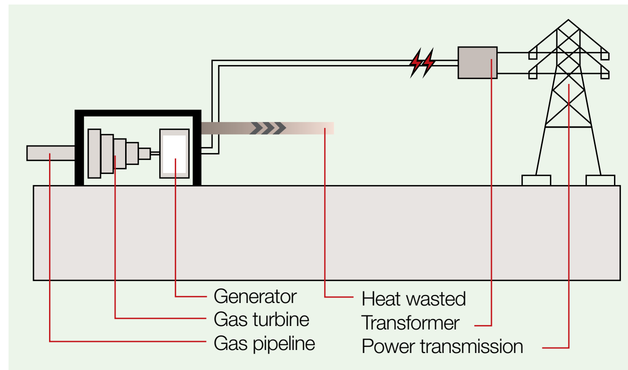


Figure 2.8
Open cycle gas powered generation



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

Coal fired generators can require a day or more to start up, so they have high start-up and shutdown costs. But their operating costs are low. These characteristics make it uneconomical to frequently switch coal plant on and off; once switched on, coal plant tends to operate relatively continuously. For this reason, coal fired generators usually bid a portion of their capacity into the NEM at low prices to guarantee dispatch and keep their plant running. Aside from providing relatively low cost electricity to the market, coal fired generators also help maintain power system stability.[4]

Over 4000 MW of coal fired capacity has been retired from the market since 2014. Most recently, in March 2017 Engie retired its Hazelwood power station in Victoria, removing 1600 MW of brown coal generation. The plant was over 50 years old, and was Australia's most emission intensive power station. The closure was especially significant given Hazelwood supplied around 5 per cent of the NEM's total output.

Following the plant closures, the remaining coal fired generation fleet operated at higher output levels. But significant coal generator outages occurred in the past few years. Brown coal in particular has had an increased rate of forced outages, which rose sevenfold between 2010–11 and 2017–18. In 2019 Loy Yang A unit 2 (530 MW) was offline for almost seven months due to an unplanned outage. This situation raised reliability concerns for Victoria going into summer, particularly given the Mortlake gas plant had a coinciding unplanned outage.[5]

Retirements of further coal plant are expected. The most imminent is the planned retirement of AGL Energy's Liddell power station in NSW in stages over 2022 and 2023, which would remove 2000 MW of black coal capacity from the NEM. No further investment in coal plant is proposed for the NEM, other than a potential recommissioning of the Redbank power station in NSW (151 MW) and minor upgrades to Bayswater (Queensland) and Loy Yang A and B (Victoria) power stations, totalling an additional 125 MW.[6]

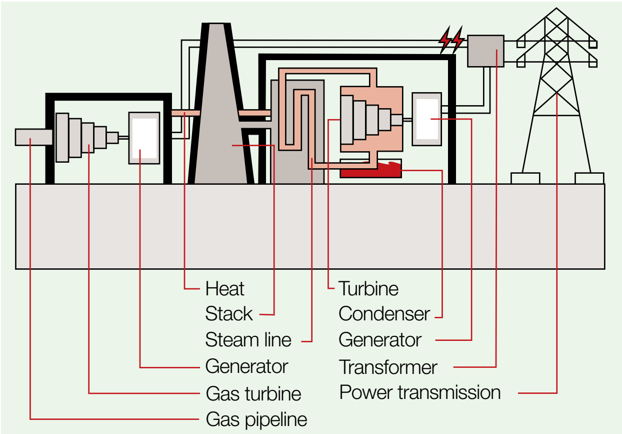
2.2.2 Gas powered generation

A number of gas generation technologies operate in the NEM. *Open cycle gas turbine* (OCGT) plant burn gas to heat compressed air that is then released into a turbine to drive a generator (figure 2.8). In *combined cycle gas turbine* (CCGT) plant, waste heat from the exhaust of the first turbine is used to boil water and create steam to drive a second turbine (figure 2.9). The capture of waste heat improves the plant's thermal efficiency, making it more suitable for longer operation than open cycle plant. More recently, the first *reciprocating engine gas plant* was commissioned in South Australia. This technology uses gas to drive a piston that spins a turbine. These plant operate similarly to OCGTs,

4 Synchronous generators—including hydroelectric and thermal plant such as coal, gas and solar thermal generators—contain heavy spinning rotors that provide synchronous inertia, slowing down the rate of change of frequency. They also help with voltage control by producing and absorbing reactive power, and they provide high fault current that improves system strength.

5 AEMO, *2019 electricity statement of opportunities*, August 2019, p. 72.
6 AEMO, *Generation information April 2020*.

Figure 2.9
Combined cycle gas powered generation



but are more flexible. Some legacy 'steam turbines'—which operate similarly to coal plant—also remain in the market.

Gas plant can operate more flexibly than coal, with open cycle plant (and newer CCGT plant and reciprocating engines) in particular needing as little as 5 minutes to ramp up to full operating capacity. The ability of gas plant to respond quickly to sudden changes in the market makes it a useful complement to wind and solar generation, which can be affected by sudden changes in weather conditions. The most efficient gas powered generation is less than half as emission intensive as the most efficient coal fired plant.[7]

Despite these benefits, gas is a relatively expensive fuel for electricity generation, so gas generators more typically operate as 'flexible' or 'peaking' plant.[8] Across the NEM, gas powered plant accounted for 19.8 per cent of plant capacity in the NEM in 2019, but supplied only 8.7 per cent of electricity generated. South Australia relies more on gas powered generation than do other regions. In 2019 the state produced 48 per cent of its local generation from gas plant, similar to its long term average.

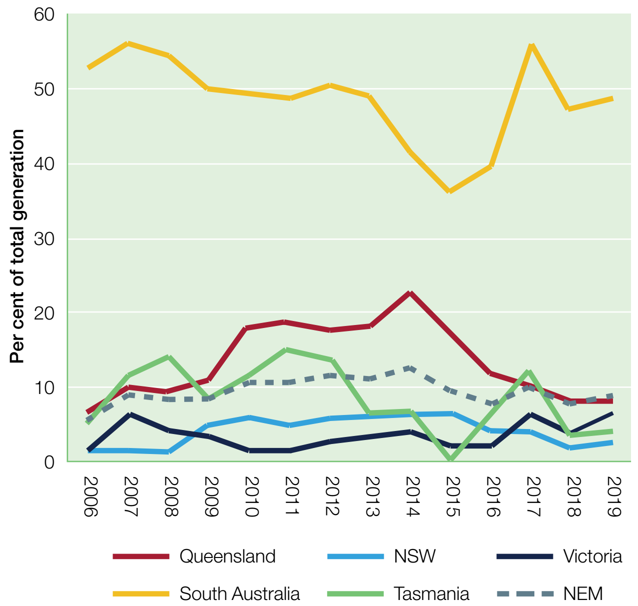
Gas generation in the NEM tends to be seasonal, peaking in summer (and sometimes winter) when electricity demand and prices are highest. It also varies with the amount of intermittent generation and outages affecting coal fired generators.

Higher gas fuel costs linked to Queensland's LNG industry, along with a lack of new gas supplies, slowed demand for

7 Dr Alan Finkel AO, Chief Scientist, Chair of the Expert Panel, *Independent review into the future security of the national electricity market: blueprint for the future*, June 2017, p. 109.

8 Flexible or peaking plant can be turned on at short notice, and is often turned on during high price periods.

Figure 2.10
Gas powered generation



Source: AER; AEMO (data).

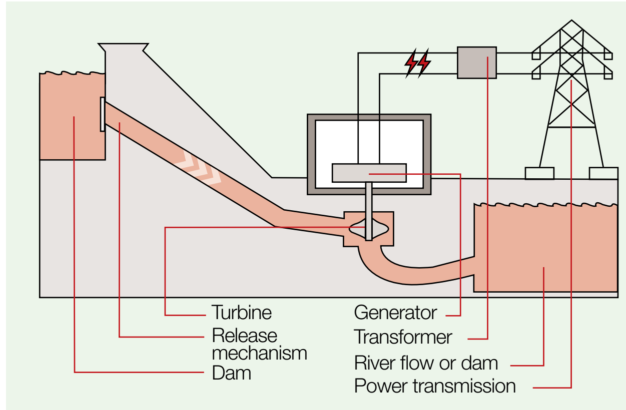
gas powered generation from 2015 (figure 2.10). This shift was reinforced by the Queensland Government in July 2017 directing its major state owned coal generator to lower its offer prices (making gas generation less competitive). These conditions were reflected in gas powered generation slumping from 23 per cent of Queensland's electricity output in 2014 to under 9 per cent in 2018 and 2019.

A similar squeezing of gas powered generation was apparent from 2018 in NSW. The state's gas output in 2018 was 60 per cent below the average output over the previous decade, providing only 2 per cent of total electricity generation. Output was higher in 2019, but remained well below previous years.

In contrast, the retirement of coal generators in Victoria and South Australia made gas generation critical to meeting electricity demand whenever renewable generation is low in those regions. This dependency was reflected in gas generation from 2017 to 2019 being 107 per cent higher in Victoria than in the previous three years, and 46 per cent higher in South Australia.

AGL commissioned new gas plant in South Australia in 2019 at Barker's Inlet (210 MW), replacing the Torrens Island plant that it is retiring. No new gas plant investment had previously occurred in the NEM since Origin commissioned the Mortlake power station (566 MW) in Victoria in 2011. Further new gas plants have been announced for Victoria and Queensland

Figure 2.11
Hydroelectric generation



as part of the Australian Government's Underwriting New Generation Investment (UNGI) program (section 1.7.1).

2.2.3 Hydroelectric generation

Hydropower uses the force of moving water to generate power. The technology involves channelling falling water through turbines. The pressure of flowing water on the blades rotates a shaft and drives an electrical generator, converting the motion into electrical energy (figure 2.11). Similar to coal and gas plant, hydroelectric generators are synchronous, meaning they provide inertia and other services that support power system security. And, because their fuel source is usually available (except in drought conditions), they are 'dispatchable' plants that can switch on as required.

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

While hydroelectric plants have low fuel costs (that is, they do not explicitly pay for the water they use), they are constrained by storage capacity and rainfall levels to replenish storage, unless pumping is used to recycle the water. For this reason, the opportunity cost of fuel is comparatively high. Hydroelectric generators typically operate, therefore, as 'flexible' or 'peaking' plant, similar to gas powered generation. Some pumped hydroelectric generation already operates in NSW and Queensland, but larger scale projects are also being explored (section 1.7.2).

Conditions in the electricity market affect incentives for hydrogeneration. Subject to environmental water release obligations, hydroelectric generators tend to reduce their output when electricity prices are low, and run more heavily when prices are high. Incentives under the renewable energy target (RET) scheme also affect incentives to produce.

Hydroelectric generators accounted for 12.9 per cent of capacity in the NEM in 2019, and supplied 6.7 per cent of electricity generated. Tasmania is the region most reliant on hydrogeneration, with 84 per cent of its 2019 grid generation coming from that source. NSW and Victoria also have significant hydrogeneration plant located in the Snowy Mountains region.

Hydrogeneration levels in recent years varied due to weather conditions, market incentives to generate, and subsidy arrangements under the RET scheme.[9] Hydrogeneration tracked higher in 2018, up 29 per cent over the previous year. This rise stemmed in part from a Basslink interconnector outage that required Tasmania to be self-sufficient in generation.

In 2019 hydrogeneration dropped 18 per cent from 2018 levels, with lower output in all major producing regions—Tasmania, NSW and Victoria. These changes reflected low rainfall in Victoria and NSW, and a return to more typical generation levels in Tasmania. In contrast, Queensland recorded record hydrogeneration output in 2019, following high rainfall in northern Queensland where the region's two main plants are located.

2.2.4 Wind generation

Wind turbines directly convert the kinetic energy of wind into electricity. The wind turns blades that spin a shaft connected (directly or indirectly via a gearbox) to a generator that creates electricity (figure 2.12). Wind turbines are typically designed to operate to wind speeds up to 90 kilometres per hour. They shut down automatically in high winds until speeds return within the turbine's operations range.

Renewable generation, including wind, has filled much of the supply gap left by thermal plant closures (figure 2.13). Government incentives, including the RET scheme, provided impetus for the growth of wind generation in the NEM.

Wind generators accounted for 10 per cent of the NEM's capacity in 2019, with over 1000 MW of new capacity added during the year (accounting for almost 40 per cent of all new investment). Wind generation rose 18 per cent on a

9 Box 1.1 in chapter 1 describes the RET scheme.

Figure 2.12
Wind powered generation

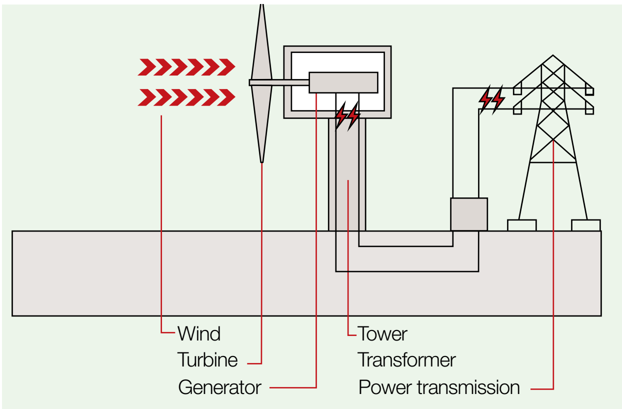
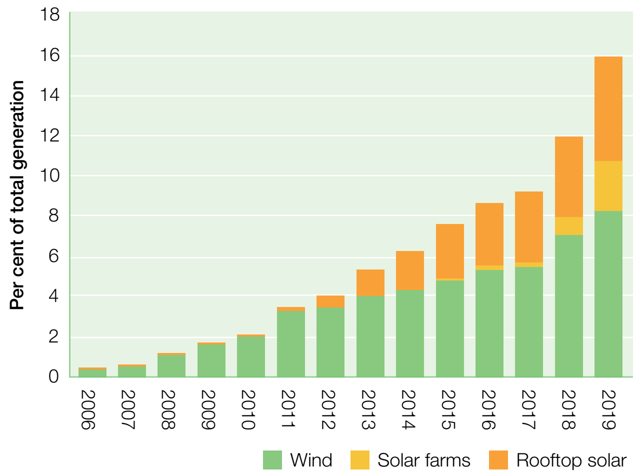


Figure 2.13
Wind and solar generation share of total generation

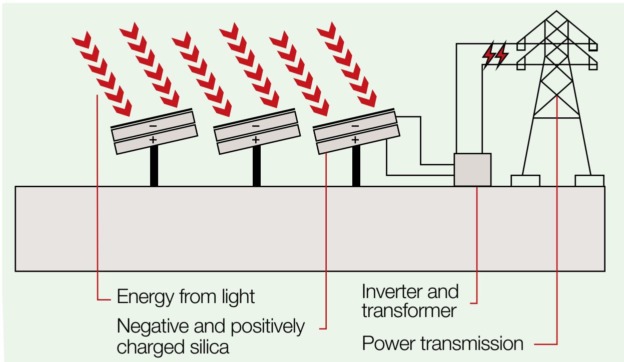


Source: Grid generation: AER, AEMO; rooftop solar: AEMO (nemweb.com.au/#rooftop-pv-actual).

year-on-year basis in 2019, and during the year generated 8.2 per cent of all electricity.

Wind penetration is especially strong in South Australia, where it provided 38 per cent of the state's electricity output in 2019. More recently, the focus of wind investment has shifted to NSW and Victoria, where over 70 per cent of capacity installed or committed since July 2017 has occurred. Queensland had no large scale wind generators until 2018, but now has two in operation, with Cooper's Gap set to be one of the largest in the country (453 MW) when completed. Queensland has significantly less wind generation than other states, however.

Figure 2.14
Solar PV power plant



Weather conditions affect wind generation levels. Favourable conditions on 11 July 2019 resulted in record levels of wind output, peaking at 4624 MW. On that day, wind generation accounted for 17 per cent of all electricity generated in the NEM.

Wind generation accounts for around one third of the NEM's proposed and committed generation projects, at over 20 000 MW. Ten wind projects, comprising over 1500 MW of capacity, are scheduled to be commissioned by the end of 2020 (table 2.4).

2.2.5 Grid scale solar farms

Large scale solar plant is a relatively new entrant in the NEM. Australia has the highest solar radiation per square meter of any continent, receiving an average 58 million petajoules of solar radiation per year.[10] All solar investment to date has been in PV systems that use layers of semi-conducting material to convert sunlight into electricity (figure 2.14). Concentrated solar thermal (CST) is an alternative technology that uses lenses, towers, dishes and reflectors to concentrate sunlight, heating fluid to produce steam that drives a turbine.[11]

Despite eligibility for government incentives under the RET scheme, and funding support from the Australian Renewable Energy Agency (ARENA) and Clean Energy Finance Corporation (CEFC),[12] investment in large scale solar farms in Australia did not occur at a significant scale until 2018. Commercial solar farms accounted for only 0.5 per cent of total NEM generation capacity in 2017, and met only 0.3 per cent of the NEM's electricity requirements in 2017. But by 2019 they made up 5.2 per cent of capacity and 2.5 per cent of output.

Thirty-four solar farms began generating in 2018 and 2019 (totalling 3157 MW),[13] and a further 13 projects (1570 MW) were scheduled to begin output by the end of 2020.

While NSW was the initial focus for solar plant development, the majority of new capacity has been located in Queensland. The largest operating plant at March 2020 is Daydream solar farm in Queensland (168 MW).

10 Geoscience Australia, 'Solar energy', web page, available at: www.ga.gov.au/ scientific-topics/energy/resources/other-renewable-energy-resources/ solar-energy.
11 There are no operating solar thermal plants in the NEM, and only one proposed—a 150 MW plant in South Australia. This project changed ownership in 2019, and an expected commissioning date is unclear.
12 Box 1.1 in chapter 1 outlines the RET scheme's operation, and the role of ARENA and the CEFC.

2.2.6 Grid scale storage

Stored energy can be used to support system reliability by being injected into the grid at times of high demand, and providing stability services to the grid by balancing variability in renewable generation. Storage technologies in the NEM include batteries and pumped hydroelectricity.

Battery storage

Grid scale batteries were not commercially viable until recently in Australia. But lower costs and expanding opportunities for this technology saw a recent uptick in battery investment.

In December 2017 South Australia commissioned the world's largest lithium ion battery at the Hornsdale wind farm, in response to a need for 'firming' capacity to manage variability in wind and solar generation. In 2020 the battery's capacity is being expanded by 50 per cent (to 150 MW). Other battery projects since commissioned include those at Gannawarra (25 MW) and Ballarat (30 MW) in Victoria, and Dalrymple (30 MW) and Lake Bonney (25 MW) in South Australia. The projects complement and 'firm' solar and wind farm generation.

Batteries in the NEM tend to earn a majority of their profits from operating in frequency control markets. The AER estimated South Australia's Hornsdale battery earned around $25 million for frequency services in 2019—five times the battery's earnings from wholesale energy sales.

Trials are underway to aggregate household battery systems to create grid scale 'virtual' power plants (section 1.2.2).

13 The 3157 MW encompasses the new farms' total registered capacity on completion. Some farms are not yet operating at that full capacity, as construction continues.

Pumped hydroelectricity

Large scale storage can be provided through pumped hydroelectric 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 high.

Pumped hydroelectric technology has been available in the NEM for some time, with generation in Queensland (570 MW at Wivenhoe) and NSW (240 MW at Shoalhaven and 1500 MW at Tumut 3). While use of this technology is limited by the availability of appropriate physical sites, advances in technology and the rise of intermittent generation are providing new opportunities for deploying this form of storage at a larger scale. In particular, pumped hydroelectricity is the basis of the proposed Snowy 2.0 (2000 MW) and Battery of the Nation (2500 MW) projects in NSW and Tasmania respectively (section 1.7.2).

2.2.7 Distributed energy resources

Alongside major shifts occurring in the technology mix at grid level, significant changes are occurring in small scale electricity supply with the uptake of *distributed energy resources* (DER). These consumer owned devices can generate or store electricity, or actively manage energy demand. DER include:

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

By far the fastest development has been in rooftop solar PV installations, but interest is also growing in battery systems, electric vehicles and demand response. Small scale battery installations in 2019 were over tenfold those in 2014, although their penetration is much lower than rooftop PV installations.

Rooftop solar PV generation

While large scale solar generation was slow to develop in Australia, consumers began installing rooftop solar PV panels from around 2010. Rooftop systems now account for over one third of renewable capacity in the NEM. In 2019 solar PV systems met 5.2 per cent of the NEM's electricity requirements. Their contribution is highest in South Australia, where they met over 10 per cent of electricity requirements.

Queensland has the highest number of installations and the highest installed capacity (almost 3000 MW).

Rooftop solar PV generation is not traded through the NEM. Instead, installation owners receive reductions in their energy bills for feeding electricity into the grid. AEMO measures the contribution of rooftop PV generation as a reduction in energy demand—because it reduces electricity demand from the grid—rather than as generation output.

By early 2020, NEM customers had installed over 2 million solar PV rooftop systems.[14] The total installed capacity of these systems was 8.8 gigawatts (GW), which was equivalent to over 14 per cent of the NEM's total generation capacity.

The uptake of rooftop solar PV is driven by opportunities for energy customers to reduce their electricity bills and earn income by feeding surplus generation back into the grid. Government incentives—such as rebates through the Small-scale Renewable Energy Scheme and premium feed-in tariffs—strengthened incentives to install the systems.

The rate of installation of solar PV systems has risen each year since 2016. Combined with larger system sizes for newer installations, a record amount of solar PV capacity was installed in 2019—over 2000 MW of capacity, compared with 1400 MW in 2018.

The average size of systems installed in 2019 more than tripled that in 2011, rising from 2.5 kilowatts (kW) to 7.7 kW. This shift to larger systems reflects the lower installation costs and the higher uptake of solar PV systems by commercial businesses (figure 1.9 in chapter 1). In the year to 30 June 2019, for example, solar PV installations grew by almost 35 per cent in the business sector, compared with 20 per cent in the residential sector.[15]

Small scale storage

In coming years, customers will increasingly store surplus energy from solar PV systems in batteries, and draw on it when needed, thus reducing their demand for electricity from the grid. Home battery systems may play an important role in meeting demand peaks in the grid, depending on the extent to which technology improvements can reduce installation costs.

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

Australian households already show significant interest in and awareness of batteries. Nearly half of customers with solar PV systems are interested in using batteries.[16] The Clean Energy Regulator estimates Australians had installed 21 000 battery systems by January 2020.[17]

Individually, distributed storage is largely invisible to the market. But, if aggregated and operated together as a microgrid or virtual power plant, the devices can potentially enhance reliability and power system security.

In May 2019 ARENA 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.

Section 1.2.2 in chapter 1 further discusses distributed storage, including batteries and virtual power plants. Section 1.4.5 discusses the potential role for DER in the future of the market, including as a provider of grid stability services.

2.3 Trade across NEM regions

Transmission interconnectors (mapped and listed in chapter 3) link the NEM's five regions, allowing trade to take place. Trade enhances the reliability and security of the power system by allowing each region to draw on generation plant from across the market, and it allows for more efficient use of the generation fleet.

Queensland has surplus generation capacity, making it a net electricity exporter (figure 2.15). Victoria's abundant supplies of low priced brown coal generation also traditionally made it a net exporter of electricity. But Hazelwood's closure in 2017 eliminated Victoria's trade surplus, with Victoria becoming a net importer for the first time in 2019.

NSW has relatively high fuel costs, typically making it a net importer of electricity. Its trading position tends to be relatively stable, although declining imports from Victoria led to its net imports recording a historic low in 2019.

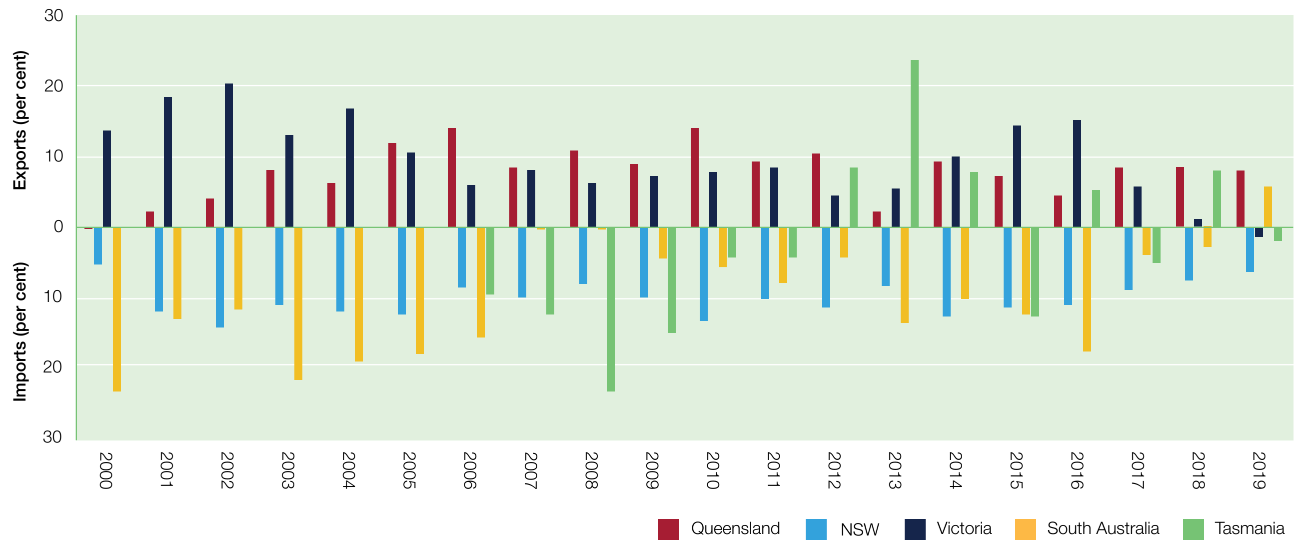
14 Data on small generation units (solar) from: Clean Energy Regulator, 'Postcode data for small scale installations', web page, available at: www.cleanenergyregulator.gov.au/RET/Forms-and-resources/Postcode-data-for-small-scale-installations.

15 AEMO, *2019 electricity statement of opportunities*, August 2019, p. 9.

16 Energy Consumers Australia, *Energy consumer sentiment survey*, December 2019.

17 Data on solar PV systems with concurrent battery storage capacity by year and state/territory from: Clean Energy Regulator, 'Postcode data for small scale installations', web page, available at: www.cleanenergyregulator.gov.au/RET/Forms-and- resources/Postcode-data-for-small-scale-installations.

Figure 2.15
Interregional trade as a percentage of demand



Note: Net interregional trade (exports less imports) divided by regional (native) demand.
Source: AER; AEMO.

South Australia was traditionally an electricity importer, due to its lack of low cost local supply. Coal plant withdrawals increased the region's trade dependency, making it proportionally the NEM's highest importer in 2016. But surging local wind generation, combined with the reduced availability of brown coal generation in Victoria, made it more self-sufficient from 2017. As a result, the state had its first energy trade surplus in 2019.

Tasmania's trade position varies with environmental and market conditions. Key drivers include local rainfall (which affects dam levels for hydrogeneration), Victorian spot prices, and the availability of the Basslink interconnector (which has suffered multiple extended outages in recent years). Tasmania was proportionally the NEM's largest net exporter when carbon pricing made hydroelectric generation more competitive in 2012–14. But the abolition of carbon pricing and drought reversed this position.

2.3.1 Market alignment and network constraints

The market sets a separate spot price for each NEM region. When the interconnectors linking NEM regions are unconstrained, trade brings prices into alignment across all regions (apart from variations caused by physical losses that occur when transporting electricity). At these times, the NEM acts as a single market rather than as a collection of regional markets, and generators within a region are exposed to competition from generators in other regions.

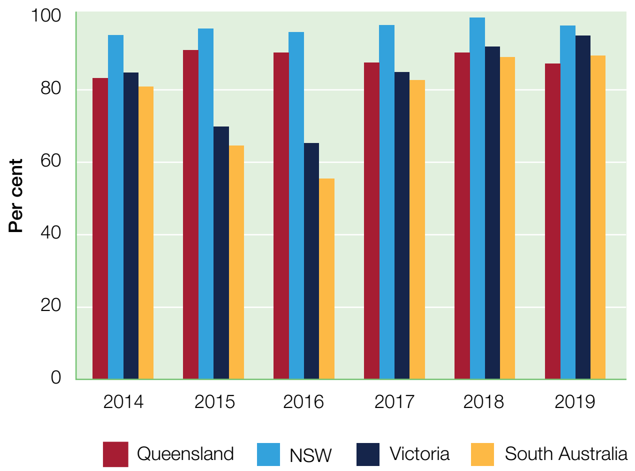
Historically, Queensland and NSW had high alignment rates, with a fairly stable duration of network congestion on interconnectors linking the regions. Price alignment between Victoria and South Australia has been less regular, with congestion on the Victoria–South Australia interconnectors more than doubling in frequency between 2013 and 2017. Heywood was the NEM's most congested interconnector over this period, partly because its capacity was constrained during a major upgrade.

But the completion of the Heywood upgrade and the closure of Victoria's Hazelwood power station in 2017 (which reduced Victorian exports of electricity to South Australia) reduced congestion between the regions. Victoria and South Australian prices aligned over 90 per cent of the time in 2018 and 2019, up from a low of 57 per cent in 2016 (figure 2.16).

But interpreting alignment rates as an indicator of competition between regions requires care. The improved alignment rates between South Australia and Victoria do not necessarily indicate a change in competitive conditions.[18]

18 AER, *Wholesale electricity market performance report*, December 2018, p. 27.

Figure 2.16
Price alignment in mainland NEM regions



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

Source: AER; AEMO.

2.4 Market structure

Around 200 registered generators sell electricity into the NEM spot market. Table 2.2 lists the major generators, plant technologies and ownership arrangements (including the entities that control each plant's dispatch). Figure 2.18 maps each plant's location.

2.4.1 Generation businesses

Private entities own most generation capacity in Victoria, NSW and South Australia. AGL Energy, EnergyAustralia, Origin Energy, Snowy Hydro and Engie are among the leading plant owners, although the scale of each business varies across regions. Government owned corporations own or control the majority of capacity in Queensland and Tasmania.

Section 2.8 examines the market's structure and competitiveness.

2.4.2 Market concentration

A few large participants control a significant proportion of generation in each NEM region. The two largest participants account for over half of total capacity (figure 2.17) and two thirds of output (figure 2.19) in all regions except South Australia.

Queensland, NSW and Victoria account for a higher concentration of output than capacity, given the high utilisation rates of black and brown coal plant, which make up the bulk of capacity held by the major participants. South Australia's largest participants rely on gas powered generation (which operates less often than coal plant).

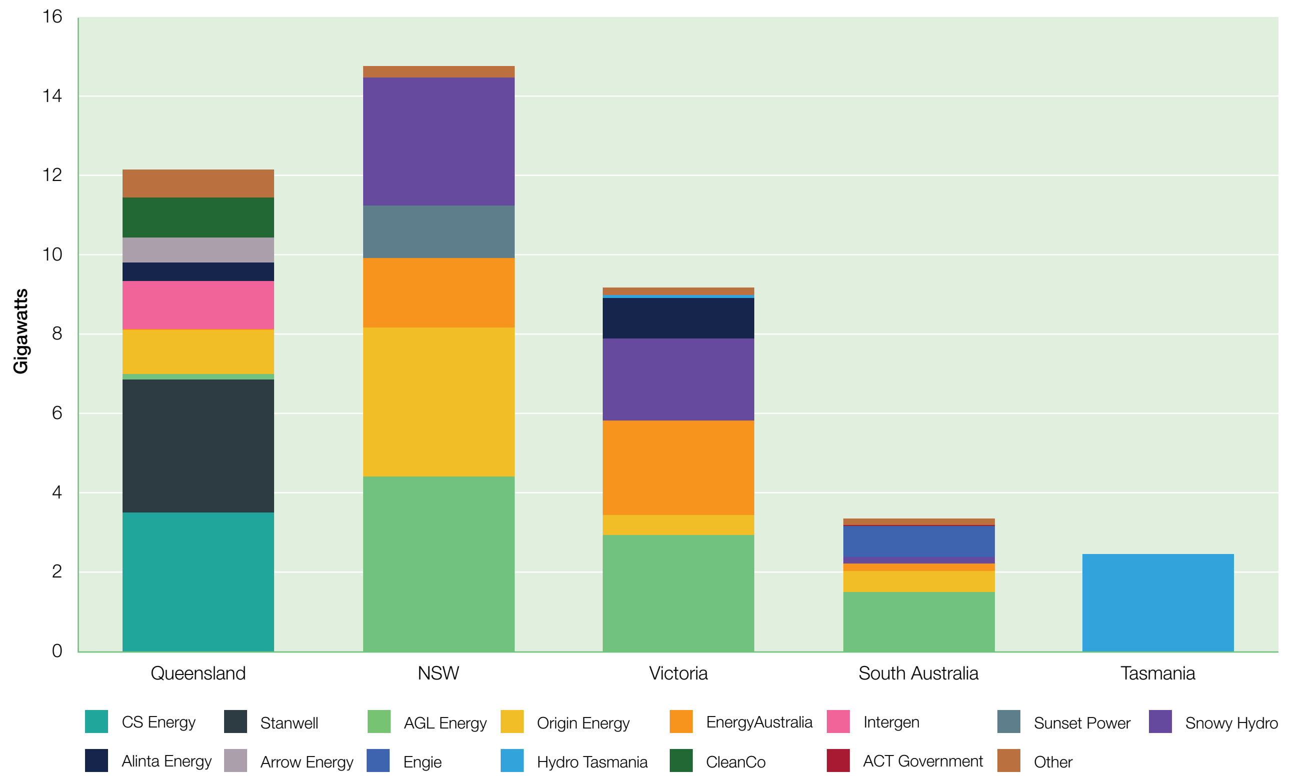
Private entities own most generation capacity in Victoria, NSW and South Australia:

- In Victoria, AGL Energy (32 per cent) and EnergyAustralia (26 per cent) control a majority of capacity. The Australian Government owned Snowy Hydro (23 per cent) is the next largest participant. Engie controlled over 20 per cent of the market until decommissioning its Hazelwood plant in March 2017.
- In South Australia, AGL Energy is the dominant generator, with 45 per cent of capacity. Other significant entities are Engie (23 per cent), Origin Energy (15 per cent) and EnergyAustralia (6 per cent). Before retiring its Playford (2012) and Northern (2016) power stations, Alinta had around 20 per cent market share in South Australia.
- In NSW, AGL Energy (30 per cent) and Origin Energy (26 per cent) became the leading plant owners following the privatisation of state owned generators in 2015. Snowy Hydro (22 per cent), EnergyAustralia (12 per cent) and Sunset Power (9 per cent) are other major players.

But government owned corporations own or control the majority of capacity in Queensland and Tasmania:

- In Queensland, state owned corporations Stanwell and CS Energy control 56 per cent of generation capacity, including power purchase agreements over privately owned capacity (such as the Gladstone power station). This market share is lower than in 2018, because some of CS Energy's and Stanwell's assets were transferred to a third state owned corporation, CleanCo, in October 2019. CleanCo was created to increase wholesale market competition and support growth in the state's renewable energy industry. It controls 8 per cent of the state's capacity, including all hydropower plant. The largest private operators are InterGen (10 per cent of capacity) and Origin Energy (9 per cent).
- In Tasmania, the state owned Hydro Tasmania owns all generation capacity. To encourage competition in the retail market, the Office of the Tasmanian Economic Regulator regulates the prices of four safety net contract products offered by Hydro Tasmania, and ensures adequate volumes of these products are available.

Figure 2.17
Market shares in generation capacity



Note: Generation capacity based on 2019–20 summer capacity, except for wind and solar, which are adjusted based on AEMO's 'firm contribution' estimates to account for generation likely to be operational during periods of maximum demand. Capacity is allocated to the business that controls the trading rights for each generator. Import capacity via interconnectors and rooftop solar PV capacity is excluded.

Source: AER; AEMO.

AGL Energy is the largest participant by capacity and output in NSW, Victoria and South Australia. On a NEM-wide basis, it accounts for 21 per cent of capacity and 26 per cent of output.

Snowy Hydro contributed only 3 per cent of output in NSW and Victoria, despite holding over 20 per cent of capacity in each region. This outcome arose because Snowy Hydro's hydroelectric generators have limited water availability, and its gas peaking gas plant operates infrequently.

2.4.3 Vertical integration

While governments structurally separated the energy supply industry in the 1990s, many retailers later re-integrated with generators, forming 'gentailers' with portfolios in both generation and retail. Vertical integration allows generators and retailers to insure internally against price risk in the wholesale market, reducing their need to participate in hedge (contract) markets. But the reduced participation in contract markets reduces liquidity in those markets, posing a potential barrier to entry and expansion for generators and retailers that are not vertically integrated.

Vertical integration has become the primary business structure for large electricity retailers in the NEM. Three retailers—AGL Energy, Origin Energy and EnergyAustralia—supply 63 per cent of small retail electricity customers in the NEM. The same entities expanded their market share in NEM generation capacity from 17 per cent in 2011 to 46 per cent in 2019.

Second tier retailers—Red Energy and Lumo Energy (Snowy Hydro), Simply Energy (Engie) and Alinta—also own major generation assets. These vertically integrated businesses account for another 17 per cent of small residential customers across the NEM, and 18 per cent of generation capacity.

Table 2.2 Generation plant in the NEM, 2020

TRADING RIGHTS	CAPACITY (MW)	POWER STATION (MW)	OWNER
QUEENSLAND	15 345		
Stanwell Corporation	3 333	Stanwell **(1460)**; Tarong **(1400)**; Tarong North **(443)**; Mackay **(30)**	Stanwell Corporation (Qld Government)
CS Energy	3 124	Callide B **(700)**; Kogan Creek **(744)**; Gladstone **(1680)**	CS Energy (Qld Government)
Origin Energy	1 541	Darling Downs **(644)**; Mount Stuart **(419)**; Roma **(80)**	Origin Energy
		Daydream **(167)**	Blackrock 90%; Edify Energy 10%
		Darling Downs **(121)**	APA Group
		Clare **(110)**	Clare Solar Farm
CleanCo	1 106	Swanbank **(385)**; Kareeya **(91)**; Barron Gorge **(60)**; Wivenhoe **(570)**	CleanCo (Qld Government)
InterGen	852	Millmerran **(852)**	China Huaneng Group 71%; InterGen 29%
CS Energy 50%; InterGen 50%	840	Callide C **(840)**	CS Energy (Qld Government) 50%; InterGen 50%
AGL Energy	560	*Moranbah North **(63)***; *German Creek **(45)***	Energy Developments (DUET Group)
		Coopers Gap **(452)**	Powering Australian Renewables Fund
Arrow Energy	552	Braemar 2 **(519)**	Arrow Energy (Shell 50%, PetroChina 50%)
		*Daandine **(33)***	Energy Infrastructure Investments (MMCIF 49.9%, Osaka Gas 30.2%, APA Group 19.9%)
Alinta Energy	546	Braemar 1 **(504)**	Alinta Energy (CTFE)
		Collinsville **(42)**	Braemar Power Project
ERM Power	345	Oakey **(288)**	ERM Power
		Hamilton **(57)**	Wircon 94.9%; Edify Energy 5.1%
Ergon Energy	335	Mount Emerald **(180)**; Barcaldine **(37)**	Ergon Energy (Qld Government)
		Lilyvale **(118)**	Fotowatio Renewable Ventures
Arrow Energy 50%; AGL Energy 50%	242	Townsville **(242)**	RATCH Australia (Ratchaburi Electricity Generation 80%, Ferrovial 20%)
RTA Yarwun	154	*Yarwun **(154)***	Rio Tinto Alcan
ESCO Pacific	149	Susan River **(85)**; Childers **(64)**	Elliott Green Power
Shell	144	Condamine **(144)**	Queensland Gas Company (Shell)
Queensland Government	107	Whitsunday **(57)**	Wircon 94.9%; Edify Energy 5.1%
		Kidston **(50)**	Genex Power
Pacific Hydro	132	Haughton **(132)**	Pacific Hydro (State Power Investment Corporation)
EnergyAustralia 80%; ESCO Pacific 20%	128	Ross River **(128)**	Pallisade Investment Partners
Risen Solar	121	Yarranlea **(121)**	Risen Solar
Sun Metals Corporation	124	Sun Metals **(124)**	Sun Metals Corporation
Wilmar International	118	*Pioneer Sugar Mill **(68)***	Wilmar International
		*Invicta Sugar Mill **(50)***	Stanwell Corporation (Qld Government)
Simec Zen Energy	92	Clermont **(92)**	Wircon
Telstra	88	Emerald **(88)**	Lighthouse Infrastructure Management
Adani Renewables	83	Rugby Run **(83)**	Adani Australia
Foresight	65	Oakey 2 **(65)**	Diamond Energy
Diamond Energy	63	Oakey 1 **(30)**; Maryrorough **(33)**	Diamond Energy
Edify Energy	57	Hayman **(57)**	Edify Energy
Mackay Sugar	48	*Racecourse Mill **(48)***	Mackay Sugar
Renewable Power Australia	30	*Rocky Point Cogeneration Plant **(30)***	Heck Group
Non-scheduled plant < 30MW	266	*Misc.*	

TRADING RIGHTS	CAPACITY (MW)	POWER STATION (MW)	OWNER
NSW	18 046		
AGL Energy	5 043	Bayswater **(2640)**; Liddell **(2000)**; Hunter Valley **(50)**	AGL Energy
		Broken Hill **(53)**; Nyngan **(102)**; Silverton **(198)**	Powering Australian Renewables Fund (QIC 80%, AGL Energy 20%)
Origin Energy	3 960	Eraring **(2880)**; Shoalhaven **(240)**; Uranquinty **(664)**; *Eraring **(42)***	Origin Energy
		Moree **(57)**	Fotowatio Renewable Ventures
		Gunning **(47)**	Acciona Energy
		*Cullerin Range **(30)***	Energy Developments (DUET Group)
Snowy Hydro	2 980	Tumut 3 **(1500)**; Colongra **(724)**; Upper Tumut **(616)**; Blowering **(80)**; Guthega **(60)**	Snowy Hydro (Australian Government)
EnergyAustralia	2 394	Mount Piper **(1400)**; Tallawarra **(440)**	EnergyAustralia (CLP Group)
		Gullen Range **(275)**; Gullen Range **(10)**	Beijing Jingneng Clean Energy 75%; Goldwind 25%
		Taralga **(106)**	Pacific Hydro (State Power Investment Corporation)
		Boco Rock **(113)**	Electricity Generating Public Company
		Manildra **(50)**	New Energy Solar
Delta Electricity	1 320	Vales Point **(1320)**	Sunset Power International (Waratah Power 50%, Vales Point Invesments 50%)
Infigen Energy	373	*Capital **(140)***; Woodlawn **(48)**; Smithfield **(185)**	Infigen Energy
CWP/Partners Group 67%; ACT Government 37%	270	Sapphire **(270)**	CWP Renewables and Partners Group
EnergyAustralia 67%; Neoen 33%	180	Coleambally **(180)**	Neoen
White Rock Wind Farm	175	White Rock **(175)**	CECEPWP 75%; Goldwind 25%
BlueScope Steel 66%; John Laing 34%	162	Finley **(162)**	John Laing Group
Elliott Green Power	132	Nevertire **(132)**	Elliott Green Power
Flow Power 69%; Westpac 26%; Spark Infrastructure 5%	121	Bomen **(121)**	Spark Infrastructure
EnergyAustralia 60%; Infigen Energy 40%	113	Bodangora **(113)**	Infigen Energy
NSW Government 70%; Kelloggs 30%	98	Beryl **(98)**	New Energy Solar
Stanwell Corporation	96	*Appin **(55)**; Tower **(41)***	Energy Developments (DUET Group)
ACT Government	96	Crookwell 2 **(96)**	Global Power Generation Australia (Naturgy 75%, Kuwait Investment Authority 25%)
Capital Dynamics	68	*Broadwater/Condong **(68)***	Cape Byron Power (Cape Byron Infrastructure LP)
Engie	55	Parkes **(55)**	Neoen (Impala 54%, Omnes Capital 23%, Bpifrance 14%, other 9%)
Essential Energy	50	*Broken Hill **(50)***	Essential Energy (NSW Government)
Innogy	38	Limondale **(38)**	Innogy
Meridian Energy	29	Hume **(29)**	Meridian Energy
Goldwind	22	White Rock **(22)**	Goldwind
Non-scheduled plant < 30 MW	271	*Misc.*	

TRADING RIGHTS	CAPACITY (MW)	POWER STATION (MW)	OWNER
VICTORIA	12 467		
AGL Energy	3 539	Loy Yang A (2210) Macarthur (420); Oaklands Hill (67); West Kiewa (62); Somerton (170); Eildon (125); Dartmouth (185); Mackay/Bogong (300)	AGL Energy AGL Hydro Partnership
EnergyAustralia	2 527	Yallourn (1480); Jeeralang A (204) and B (228); Newport (500); Ballarat (30); Gannawarra (30); Gannawarra (55)	EnergyAustralia (CLP Group) Wircon 94.9%; Edify Energy 5.1%
Snowy Hydro	2 112	Murray (1500); Laverton North (312); Valley Power (300)	Snowy Hydro (Australian Government)
Alinta Energy	1 206	Loy Yang B (1000); Bald Hills (106); Bannerton (100)	Alinta Energy
Origin Energy	566	Mortlake (566)	Origin Energy
Snowy Hydro 50%; Victorian Government 37%; Tilt Renewables 13%	335	Dundonnell (335)	Tilt Renewables
Acciona Energy	330	*Waubra (192)*; Mount Gellibrand (138)	Acciona Energy
ACT Government 33%; Ararat Wind Farm 67%	241	Ararat (241)	RES; GE; Partners Group; OPTrust
Telstra	231	Murra Warra (231)	Partners Group
Pacific Hydro	230	*Yambuk (30); Challicum Hills (52); Portland (148)*	Pacific Hydro (State Power Investment Corporation)
Simec Zen Energy	209	Numurkah (112) Wemen (97)	Neoen Wircon
Meridian Energy	160	Mount Mercer (131); Hume (29)	Meridian Energy
Orora	144	Yendon (144)	Northleaf 40%; InfraRed Capital Partners 40%; Macquarie 20%
Carlton & United Breweries	104	Karadoc (104)	BayWa r.e. Renewable Energy
Hydro Tasmania	94	Bairnsdale (94)	Alinta Energy
Pacific Hydro 67%; Melbourne Renewable Energy Project 33%	79	Crowlands (79)	Pacific Hydro (State Power Investment Corporation)
Powershop	54	Salt Creek (54)	Tilt Renewables
Infigen Energy	31	Kiata (31)	John Laing Group 72.3%; Windlab Australia 25%; Local community 2.7%
Non-scheduled plant < 30 MW	275	*Misc.*	
SOUTH AUSTRALIA	6 082		
AGL Energy	1 963	Torrens Island A (480) and B (800) Barker Inlet (211); Hallett 1 (95); Hallett 2 (71); Wattle Point (91); North Brown Hill (132); The Bluff (53) Dalrymple North (30)	AGL Energy ElectraNet
Origin Energy	1 128	Snowtown (99); Snowtown North (144); Snowtown South (126) Quarantine (229); Ladbroke Grove (80); Osborne (180) Bungala One (135) and Two (135)	Tilt Renewables Origin Energy Enel Green Power
Engie	1 025	Pelican Point (478); *Canunda (46)*; Dry Creek (156); Mintaro (90); Port Lincoln (73); Snuggery (63) Willogoleche (119)	Engie 72%; Mitsui 28% Engie
ACT Government	316	Hornsdale 1–3 (316)	Neoen
EnergyAustralia	283	Hallet (217) *Cathedral Rocks (66)*	EnergyAustralia (CLP Group) EnergyAustralia (CLP Group) 50%; Acciona Energy 50%
SA Government	277	*Temporary Generation North (154); Temporary Generation South (123)*	SA Government
Snowy Hydro	237	Port Stanvac (58); Angaston (50); Lonsdale (21) Tailem Bend (108)	Snowy Hydro (Australian Government) Vena Energy
Infigen Energy	223	Lake Bonney 2 (159) and 3 (39); Lake Bonney (25)	Infigen Energy
EnergyAustralia 50%; Hydro Tasmania 50%	130	Waterloo (130)	Palisade Investment Partners 74%; Northleaf Capital Partners 26%
ERM Power	126	Lincoln Gap 1 (126)	Nexif Energy
SA Government 70%; Neoen 30%	100	Hornsdale Power Reserve (100)	Neoen
Essential Energy	81	*Lake Bonney 1 (81)*	Infigen Energy
Meridian Energy	70	*Mount Millar (70)*	Meridian Energy
Pacific Hydro	57	Clements Gap (57)	Pacific Hydro (State Power Investment Corporation)
Hydro Tasmania	35	*Starfish Hill (35)*	RATCH Australia (Ratchaburi Electricity Generation 80%, Ferrovial 20%)
Non-scheduled plant < 30 MW	31	*Misc.*	
TASMANIA	3 154		
Hydro Tasmania	2 906	Gordon (432); Poatina (300); Reece (232); Tamar Valley (208); Catagunya/Liapootah/Wayatinah (173); Mussleroe (168); John Butters (144); *Woolnorth (140)*; Tungatinah (125); Bell Bay (105); Trevallyn (93); Tarraleah (90); Cethana (85); Tribute (83); Lemonthyme/Wilmot (82); Bastyan (80); Mackintosh (80); Devils Gate (60); Fisher (43); Meadowbank (40); Lake Echo (32); Granville Harbour (111)	Hydro Tasmania (Tas Government) Palisade Investment Partners
Goldwind Australia	148	Cattle Hill Wind Farm (148)	Goldwind Australia; Power China Group
Non-scheduled plant < 30 MW	100	*Misc.*	

Misc., miscellaneous; MW, megawatts.

Fuel types: black coal; brown coal; gas; hydro; wind; solar; battery; other (e.g diesel, bagasse).

italics: non-scheduled.

Note: Capacity as published by AEMO for summer 2019–20, except for non-scheduled plant, for which nameplate capacity is used.

Source: AER; AEMO; company announcements.

Figure 2.18
Generators in the NEM

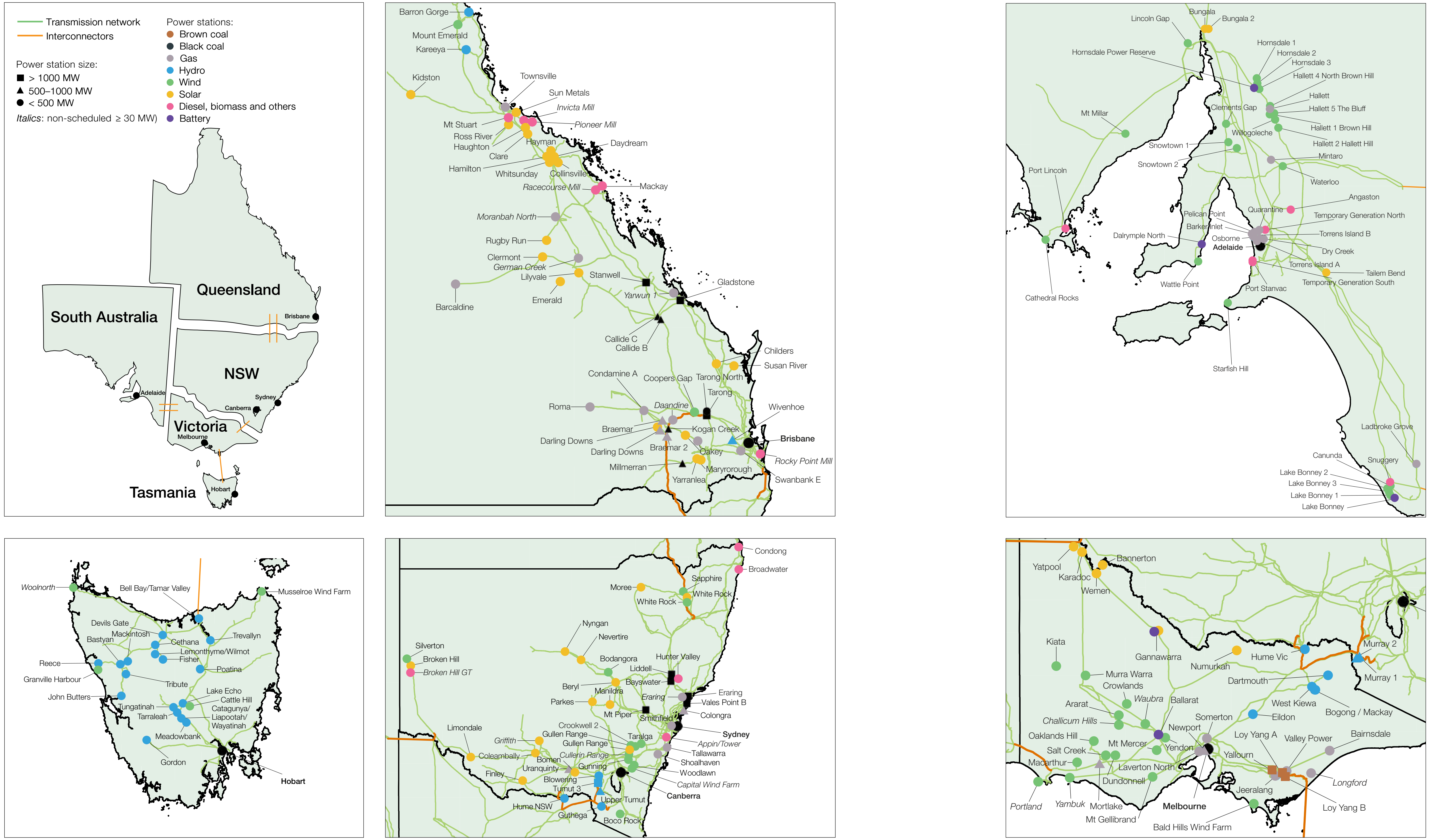
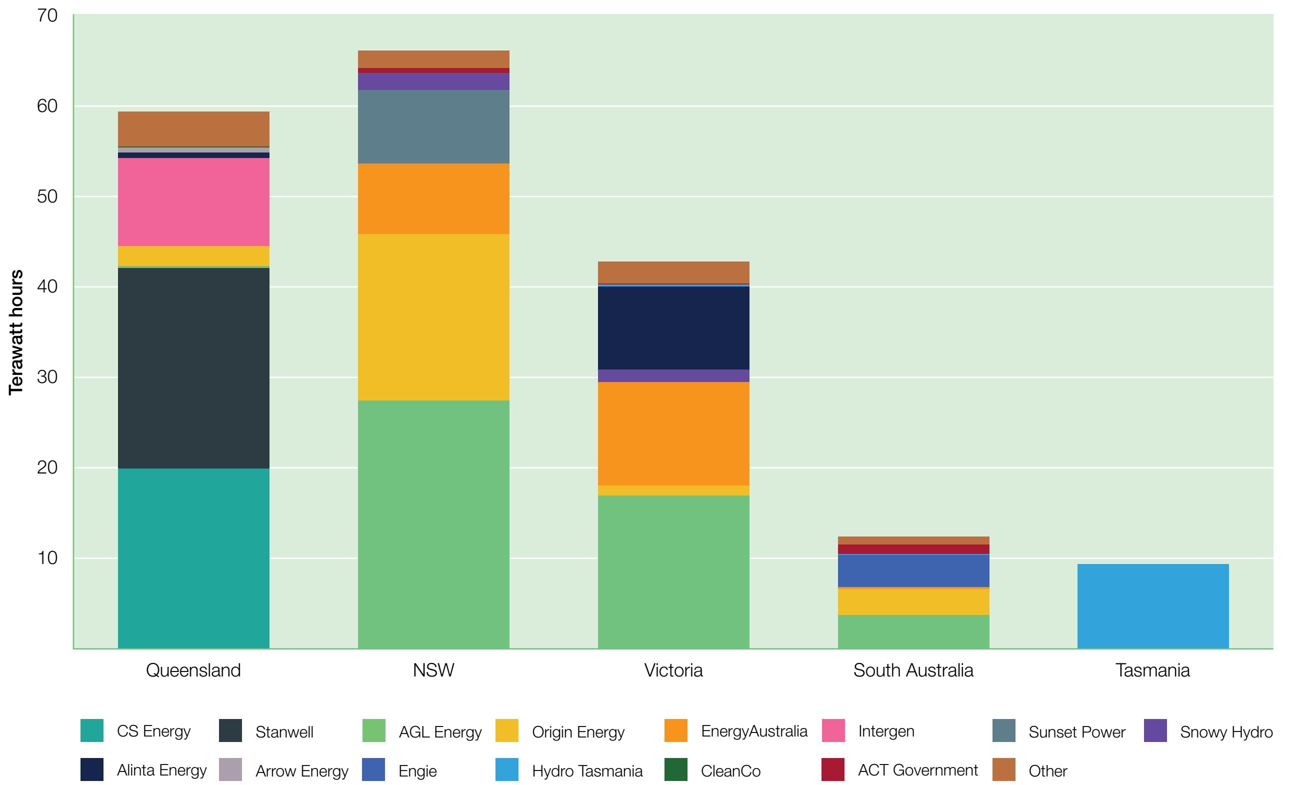


Figure 2.19
Market shares in generation output



Note: Output in 2019. Ownership is attributed by trading rights at the time. Output is split on a pro rata basis if ownership changed in 2019. Data exclude output from rooftop solar PV systems and interconnectors.

Source: AER; AEMO; company announcements.

Across NSW, Victoria and South Australia, these seven retailers jointly own around 90 per cent of generation capacity.

A number of smaller retailers are also vertically integrated:

- Powershop and Tango Energy each have a portfolio of wind and hydroelectric generation operated by their respective parent companies, Meridian Energy and Pacific Hydro.
- Momentum Energy is backed by Hydro Tasmania, which owns the vast majority of generation capacity in Tasmania.

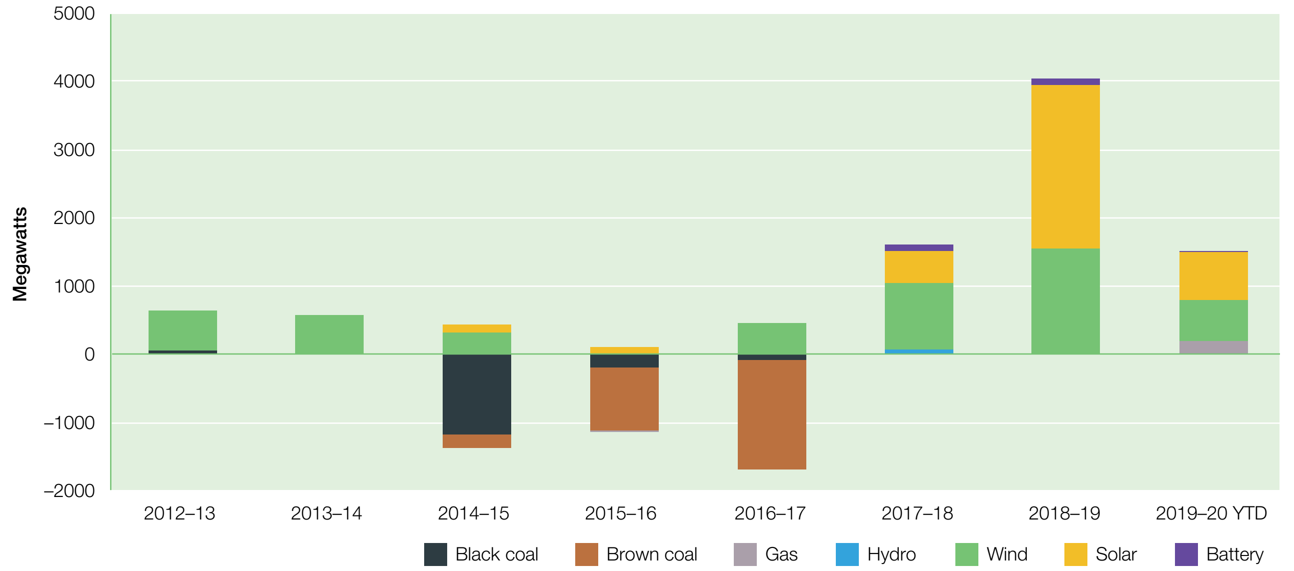
2.5 Generation investment and plant closures

Investment in generation plant outpaced the growth in electricity demand for several years, resulting in significant surplus capacity from around 2009 to 2015. In response, new investment slowed and some generators permanently or temporarily removed capacity from the market. While 2200 MW of new generation investment was added to the NEM over the five years to June 2017, over 4000 MW of capacity was withdrawn over the same period (figure 2.20).

Plant closures were mainly coal fired plant, following commercial decisions by owners to exit the market (section 1.1.3 in chapter 1). These ageing plants had become increasingly unprofitable, partly as a result of rising maintenance costs. The Wallerawang plant in NSW closed after 38 years of operation; the Northern and Playford plants in South Australia after 31 and 55 years of operation respectively; and the Hazelwood power station in Victoria after 53 years.

Two gas plants are also listed for retirement—AGL's Torrens Island A (480 MW) in South Australia (retiring progressively in 2020–21) and Mackay (34 MW) in Queensland (retiring in 2022). In Tasmania, the Tamar Valley plant (208 MW) is unavailable for much of the time, but can be returned to service with less than three months notice.[19]

Figure 2.20
New generation investment and plant withdrawals

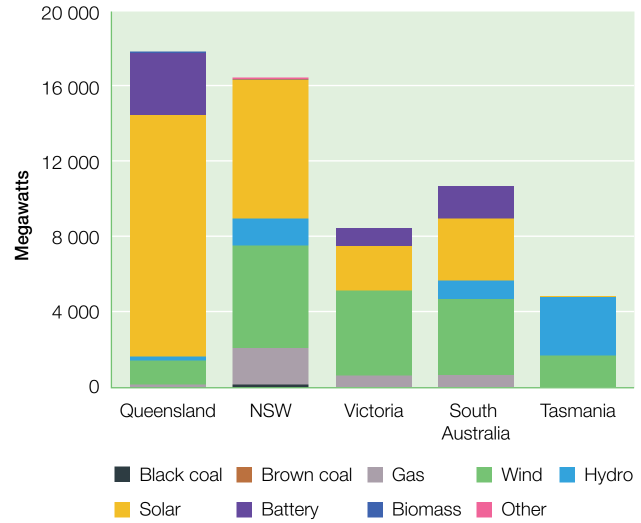


YTD, year to date.

Note: 2019–20 data are to 31 March 2020. An additional 2817 MW of committed capacity (1461 MW of wind, 1334 MW of solar and 22 MW of battery storage) is expected to be commissioned in 2020.

Source: AER; AEMO (data)

Figure 2.21
Announced generation proposals at March 2020



Source: AEMO, *Generation information April 2020*.

The plant closures significantly reduced capacity in the NEM and led to AEMO signalling risks of summer power outages. The private sector responded with significant investment in renewable generation, but investment in other technologies has been limited. High gas fuel costs, less frequent high electricity spot prices, and policy uncertainty have been cited as reasons for the lull in gas plant investment.[20] Barker Inlet (South Australia, 210 MW) is the NEM's first material addition of fossil fuel capacity since an upgrade to Eraring in 2012. The gas plant was commissioned to replace capacity lost by the retirement of Torrens Island A.

Over 93 per cent of generation investment since 2012–13 has been in renewable (wind and solar) capacity, partly driven by RET scheme subsidies, and ARENA and CEFC funding. Investment in renewables picked up strongly after the Australian Government confirmed in 2015 the RET scheme would continue until 2030. Over 5900 MW of new wind, solar and battery capacity was added to the NEM between June 2017 and December 2019 (table 2.3). Another 3000 MW of capacity is committed to come online by 2021 (table 2.4).

19 AEMO, *2018 electricity statement of opportunities*, August 2018, p. 55.

20 AER, *Wholesale electricity market performance report*, December 2018; ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—final report*, June 2018, p. 100.

Table 2.3 New generation investment, January 2018 – March 2020

TRADING RIGHTS	POWER STATION	TECHNOLOGY	CAPACITY (MW)	FIRST DISPATCH DATE
QUEENSLAND			2406	
Origin Energy	Clare	Solar	110	April 2018
Origin Energy	Darling Downs	Solar	121	July 2018
ERM Power	Hamilton	Solar	57	July 2018
Sun Metals	Sun Metals	Solar	124	July 2018
Queensland Government	Whitsunday	Solar	57	July 2018
Alinta Holdings	Collinsville	Solar	42	August 2018
Ergon Energy	Mount Emerald	Wind	180	August 2018
Telstra	Emerald	Solar	88	September 2018
EnergyAustralia	Ross River	Solar	128	September 2018
Origin Energy	Daydream	Solar	167	October 2018
ESCO Pacific	Susan River	Solar	85	December 2018
Edify Energy	Hayman	Solar	57	January 2019
ESCO Pacific	Childers	Solar	64	February 2019
Ergon Energy	Lilyvale	Solar	118	March 2019
Diamond Energy	Oakey	Solar	30	March 2019
Pacific Hydro	Haughton	Solar	132	May 2019
Adani Renewables	Rugby Run	Solar	83	May 2019
AGL Energy	Coopers Gap	Wind	452	June 2019
Simec Zen	Clermont	Solar	92	June 2019
Foresight	Oakey 2	Solar	65	September 2019
Risen Solar	Yarranlea	Solar	121	January 2020
Diamond Energy	Maryrorough	Solar	33	March 2020
NSW			1535	
Engie	Parkes	Solar	55	February 2018
CWP/Partners Group 67%; ACT Government 37%	Sapphire	Wind	270	February 2018
EnergyAustralia	Manildra	Solar	50	May 2018
AGL Energy	Silverton	Wind	198	May 2018
EnergyAustralia 60%; Infigen Energy 40%	Bodangora	Wind	113	August 2018
ACT Government	Crookwell 2	Wind	96	August 2018
EnergyAustralia 67%; Neoen 33%	Coleambally	Solar	180	September 2018
Goldwind	White Rock	Solar	22	October 2018
NSW Government 70%; Kelloggs 30%	Beryl	Solar	98	April 2019
BlueScope Steel 66%; John Laing 34%	Finley	Solar	162	August 2019
Elliott Green Power	Nevertire	Solar	132	December 2019
Innogy	Limondale 2	Solar	38	December 2019
Flow Power 69%; Westpac 26%; Spark Infrastructure 5%	Bomen	Solar	121	March 2020
VICTORIA			1509	
EnergyAustralia	Gannawarra	Solar	55	April 2018
Acciona Energy	Mount Gellibrand	Wind	138	June 2018
Powershop	Salt Creek	Wind	54	June 2018
Alinta Holdings	Bannerton	Solar	100	July 2018
Carlton & United Breweries	Karadoc	Solar	104	October 2018
EnergyAustralia	Ballarat	Battery	30	November 2018
Simec Zen	Wemen	Solar	97	November 2018
EnergyAustralia	Gannawarra	Battery	30	November 2018
Pacific Hydro 67%; Melbourne Renewable Energy Project 33%	Crowlands	Wind	79	December 2018
Telstra, in consortium	Murra Warra stage 1	Wind	231	April 2019
Simec Zen	Numurkah	Solar	112	May 2019
Orora	Yendon	Wind	144	June 2019
Snowy Hydro 50%; Victorian Government 37%; Tilt Renewables 13%	Dundonnell	Wind	335	March 2020
SOUTH AUSTRALIA			889	
Origin Energy	Bungala One	Solar	135	May 2018
AGL Energy	Dalrymple North	Battery	30	July 2018
Engie	Willogoleche	Wind	119	August 2018
Origin Energy	Bungala Two	Solar	135	October 2018
Snowy Hydro	Tailem Bend	Solar	108	February 2019
ERM Power	Lincoln Gap stage 1	Wind	126	May 2019
AGL Energy	Barker Inlet	Gas	211	October 2019
Infigen Energy	Lake Bonney	Battery	25	October 2019
TASMANIA			256	
Goldwind	Cattle Hill	Wind	144	January 2020
Hydro Tasmania	Granville Harbour	Wind	112	February 2020

MW, megawatts.

Source: AER; AEMO, *Generation information April 2020*.

Almost 60 000 MW of additional capacity is proposed but not formally committed (figure 2.21). The bulk of proposed projects are in solar (43 per cent) and wind (31 per cent) plant.

Offsetting new capacity, further fossil fuel plant withdrawals are expected (figure 1.4 in chapter 1). Among these withdrawals, AGL plans to retire its Liddell coal plant in NSW (2000 MW) in stages over 2022 and 2023, and replace it with a mix of renewable gas generation, batteries, and an upgrade to the Bayswater power station.

2.6 Wholesale prices and activity

Wholesale electricity prices tend move in seasonal cycles linked to the weather. Prices tend to rise in the fourth calendar quarter (October–December) as the weather warms up, then peak in the first quarter when summer demand for air conditioning is highest, before easing in the cooler second and third quarters.

Alongside this seasonal pattern, longer term trends show an upward movement in wholesale prices after the closure of

Table 2.4 Committed investment projects in the NEM at March 2020

OWNER	POWER STATION	TECHNOLOGY	CAPACITY (MW)	PLANNED COMMISSIONING
QUEENSLAND			244	
Windlab/Eurus	Kennedy Energy Park	Solar	15	2020
Windlab/Eurus	Kennedy Energy Park	Battery	2	2020
Windlab/Eurus	Kennedy Energy Park	Wind	43	2020
University of Queensland	Warwick	Solar	64	2020
Shell	Gangarri	Solar	120	2021
NSW			3340	
Fotowatio Renewable Ventures	Goonumbla	Solar	70	2020
Edify Energy; Octopus Investments	Darlington Point	Solar	275	2020
Innogy	Limondale 1	Solar	220	2020
John Laing/Maoneng Group	Sunraysia	Solar	229	2020
Beijing Jingneng Clean Energy	Biala	Wind	111	2020
RATCH Australia	Collector	Wind	227	2020
TEC-C Investments	Molong	Solar	30	2020
CWP Renewables	Crudine Ridge	Wind	138	2021
Snowy Hydro	Snowy 2.0	Pumped hydro	2040	2025
VICTORIA			1734	
Northleaf 40%; InfraRed Capital Partners 40%; Macquarie 20%	Elaine	Wind	84	2020
John Laing Group	Cherry Tree	Wind	58	2020
Total Eren	Kiamal stage 1	Solar	200	2020
BayWa r.e.	Yatpool	Solar	94	2020
Neoen	Bulgana Green Power Hub	Battery	20	2020
Goldwind	Stockyard Hill	Wind	532	2020
Goldwind	Moorabool	Wind	320	2020
Wirtgen Invest	Glenrowan West	Solar	106	2020
Neoen	Bulgana Green Power Hub	Wind	204	2021
Fotowatio Renewable Ventures	Winton	Solar	85	2021
Enel Green Power	Cohuna	Solar	31	2020
SOUTH AUSTRALIA			86	
Nexif Energy	Lincoln Gap stage 2	Wind	86	2020

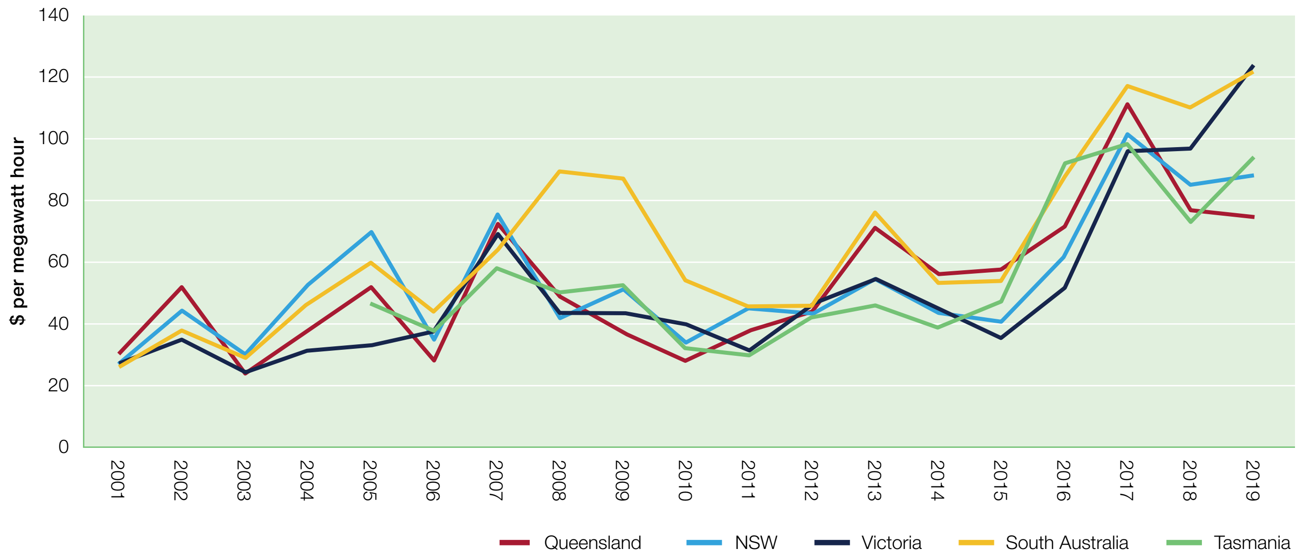
MW, megawatts.

Source: AER; AEMO, *Generation information April 2020*.

two brown coal power stations—Northern (South Australia) in May 2016 and Hazelwood (Victoria) in March 2017. The Hazelwood closure withdrew around 5 per cent of the NEM's total capacity, much of it usually offered at low prices. From that point, more expensive black coal and gas plant began to set spot prices more often. Between July 2015 and July 2017, the average offer price for the cheapest 20 000 MW of capacity in the NEM increased from $50 per megawatt hour (MWh) to almost $100 per MWh. Prices generally remained elevated in 2017 and 2018.

Queensland prices followed a different trend. In June 2017 the Queensland Government directed the state owned generation business, Stanwell, to put downward pressure

Figure 2.22
Wholesale electricity prices



Note: Volume weighted annual averages.

Source: AER; AEMO (data).

on wholesale electricity prices.[21] The state has since moved from having some of the highest average prices in the NEM to generally having the lowest average price. The government direction remained in place until 30 June 2019.

2.6.1 The market from 2019

The following is a high level summary of market conditions from 2019. The AER's *Wholesale markets quarterly*, launched in 2019, analyses price trends and underlying causes in more detail.

In 2019 wholesale prices across the NEM (on a volume weighted average basis) averaged close to $100 per MWh, up from $90 per MWh in 2018, but slightly lower than the 2017 average of $106 per MWh (figures 2.22 and 2.23):

- Victoria ($126 per MWh) edged out South Australia ($125 per MWh) as the NEM's highest price region. The state more than doubled its 2016 average ($52 per MWh) before the closure of Hazelwood.
- South Australia recorded its third consecutive year of triple digit average prices, and more than doubled its 2015 average before the closure of the region's last brown coal generator, Northern.
- Queensland ($75 per MWh) and NSW ($89 per MWh) were the lowest price regions.
- Tasmania recorded a 30 per cent year-on-year rise in spot prices—the largest for any region, with prices averaging $95 per MWh.

These calendar year averages mask a distinct shift in market outcomes over 2019. Prices were elevated in the first quarter (setting records in some regions), then eased in the second quarter, before moving lower in the second half of the year. This downward shift continued into 2020.

In the first quarter of 2019, weather events combined with plant failures led to Victoria ($216 per MWh) and South Australia ($223 per MWh) setting record prices. Temperatures on some days neared 50°C in parts of South Australia. During the quarter, Victoria and South Australia experienced 16 and 15 trading intervals respectively of prices exceeding $5000 per MWh. The number for South Australia was a quarterly record.

Eleven of the high price events occurred on 24 January 2019. Record temperatures in South Australia (48°C) following three days of temperature above 35°C, and high temperatures in Victoria, caused a surge in demand. This surge coincided with unexpected equipment failures, causing forecast demand to exceed available supply in both regions. Prices reached the market cap ($14 500 per MWh at the time) in both regions.[22]

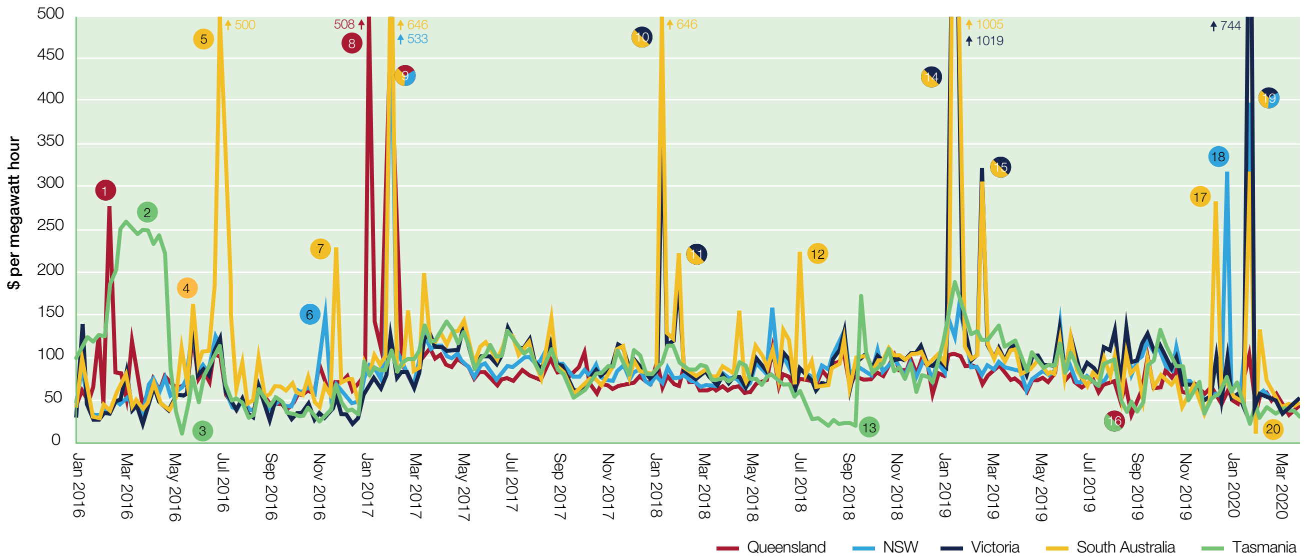
On 25 January, continued high temperatures in Victoria drove high demand. Prices reached the cap in Victoria,

21 Queensland Government, *Stabilising electricity prices for Queensland consumers*, June 2017.

22 AER, *Electricity spot prices above $5000/MWh, Victoria and South Australia, 24 January 2019*, March 2019.

Figure 2.23

Wholesale electricity prices—volume weighted weekly averages



Price events

1 Record high demand and rebidding
2 Basslink outage and record low rainfall and dam levels
3 High rainfall increased hydro output
4 Coal plant closures and extensive coal outages reduced supply. Coincided with high gas prices
5 Heywood interconnector outage due to planned maintenance. Coincided with low wind and plant closures
6 Rebidding behaviour and network constraints on the Victoria-NSW interconnector
7 Rebidding behaviour and an unplanned outage of the Heywood interconnector
8 High temperatures led to record Queensland demand, plant restrictions, rebidding and limited imports
9 Extremely high temperatures led to high demand across the NEM. Extensive coal generator outages in Queensland and NSW. Load shedding in SA because demand exceeded forecasts and wind output was low
10 High temperatures led to high demand in Victoria and South Australia, coincided with a plant outage in Victoria
11 High temperatures led to high demand
12 Planned outages on the Heywood interconnector. Coincided with low wind output
13 High rainfall increased hydro output
14 High temperatures led to high demand in Victoria and South Australia, and load shedding in Victoria coincided with a plant outage in Victoria
15 High temperatures led to high demand in Vic and SA at a time of low wind output
16 Record low demand and an increase in solar output drove negative prices in Queensland during the middle of the day. High hydro output in Tasmania
17 High temperatures drove demand close to record levels. Coincided with limited import capacity on the Murraylink interconnector and low wind output
18 Bushfires led to Victoria-NSW interconnection being disrupted. Coincided with high demand
19 Extreme storm conditions led to South Australia being isolated from the NEM. Tight supply conditions and high demand driven by high temperatures in Victoria and NSW. Another price event in South Australia and Victoria due to high demand, low wind generation and a plant outage
20 South Australia unable to export energy due to interconnector disruptions, resulting in excess supply

Note: Volume weighted weekly averages.

Source: AER; AEMO (data).

and exceeded $11 000 per MWh in South Australia.[23] The high price events over the two days contributed around $40 to the quarterly price in Victoria and South Australia. Coincident high temperatures in Victoria and South Australia again drove prices above $5000 per MWh on 1 March in both regions.

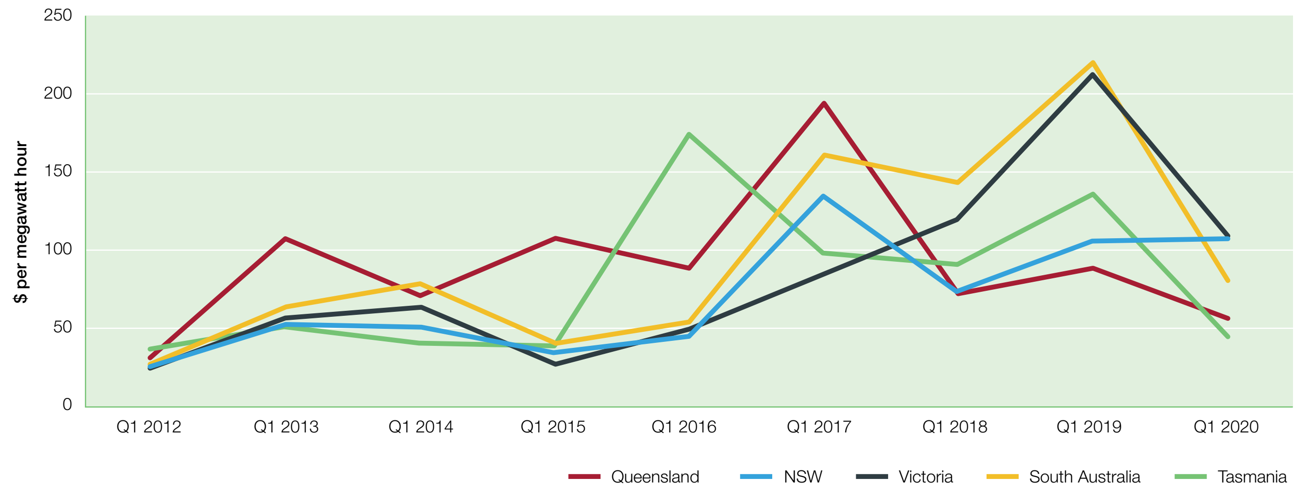
Tasmania also recorded high prices during the quarter, driven by high demand and below average rainfall affecting offers from hydro generators. Overall, hydro generation was around 15 per cent lower in 2019 than a year earlier.

Wholesale prices remained elevated in some regions during the second quarter of 2019, compared with the same quarter in 2018. Prices were higher in Victoria than elsewhere, partly due to planned and unplanned outages reducing brown coal generation. An unplanned outage at Loy Yang A ran from May to December 2019, removing 11 per cent of low cost generation from the region. Loy Yang B unit 2 was also unavailable, due to a planned upgrade. Outages at the Yallourn and Mortlake power stations compounded the situation, resulting in Victoria setting record prices of over $100 per MWh in the second and third quarters of 2019.

23 AER, *Electricity spot prices above $5000/MWh, Victoria and South Australia, 25 January 2019*, March 2019.

Figure 2.24

First quarter wholesale electricity prices



Note: Volume weighted quarterly averages.

Source: AER; AEMO (data).

Prices generally eased in the second half of 2019 as new renewable generation came online, and fuel costs for coal and gas generators fell (see below). South Australia and Queensland recorded their lowest third quarter averages since 2016. A fault on the Basslink interconnector between Tasmania and Victoria meant the connection was unavailable for around six weeks in August–September 2019, contributing to Tasmania having higher third quarter prices than a year earlier.

By the fourth quarter, prices across the market had entered a discernible downward trend, averaging below $90 per MWh in every region for the first time in two years. Queensland and Victorian prices in the fourth quarter recorded their lowest quarterly averages since 2016 (figure 2.24). The easing of Victorian prices was assisted by the return to service of Yallourn and Loy Yang A.

2.6.2 The market in early 2020

Prices continued to ease in 2020, when first quarter prices fell to their lowest average since 2012 in Queensland, 2015 in Tasmania, 2016 in South Australia, and 2017 in Victoria. Notably, first quarter prices were below $110 per MWh in all regions for the first time since 2015.[24]

This outcome appeared unlikely in January 2020, when most regions experienced bushfires and periods of extreme weather that caused bursts of high prices in NSW, Victoria and South Australia. On 4 January high demand and network outages due to bushfires resulted in NSW spot prices rising above $5000 per MWh between 4 pm and 6 pm.[25] On 30 January higher than forecast demand, lower than forecast wind generation and generator outages meant evening prices in Victoria and South Australia rose above $10 000 per MWh.

On 31 January the Heywood interconnector connecting Victoria to South Australia failed when a localised storm collapsed six transmission towers. As a result, South Australia was isolated from the rest of the NEM until 17 February, when a temporary 500 kilovolt (kV) line was installed (the interconnector returned to full operation on 3 March). Prices exceeded $5000 per MWh in NSW, Victoria and South Australia immediately following the interconnector failure as a result of constraints invoked by AEMO, tight supply and demand conditions driven by hot weather, and technical plant issues.[26]

While mainland regions recorded their highest weekly prices for the quarter in the week commencing 26 January, Tasmania recorded its lowest weekly average in the same week. It appears Tasmania's generation capacity was being offered in a way to ensure it was dispatched to take advantage of high prices on the mainland.[27]

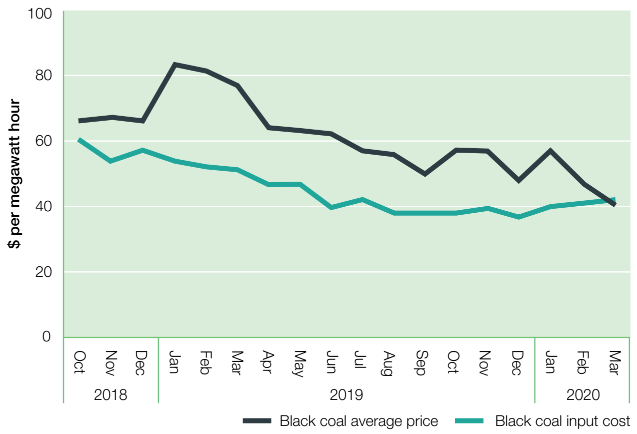
24 All prices are volume weighted averages.

25 AER, *Electricity spot prices above $5000/MWh, New South Wales, 4 January 2020*, February 2020.

26 AER, *Electricity spot prices above $5000/MWh, South Australia, Victoria and New South Wales, 31 January 2020*, March 2020.

27 AER, *Wholesale markets quarterly—Q1 2020*, May 2020.

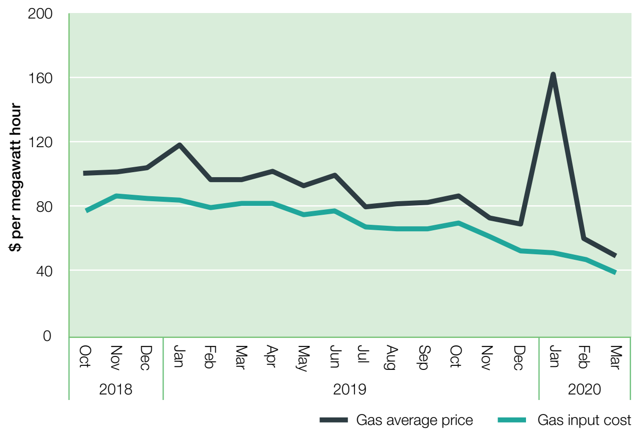
Figure 2.25
Black coal fuel costs, NSW



Note: The international reference price for Newcastle spot thermal coal and the average monthly price when black coal generators set the price in NSW. The black coal input cost is derived from the Newcastle coal index (US$ per tonne), converted to A$ per MWh with the Reserve Bank of Australia exchange rate, and the average heat rate for coal generators.

Source: AER analysis using globalCOAL data.

Figure 2.26
Gas fuel costs, Sydney



Note: The Sydney gas market price and the average monthly price when gas generators set the price in NSW. The gas input cost is derived from the Sydney short term trading market (STTM) price (A$ per GJ), converted to A$ per MWh, and the average heat rate for gas generators.

Source: AER analysis using NEM and gas price data.

From the week beginning 16 February, generally milder weather reflected in relatively low summer demand. Prices in all regions progressively converged and remained below $74 per MWh for the remainder of the quarter. Subdued demand also reflected in average generation in the NEM being 4 per cent lower in the first quarter of 2020 than in the same quarter of 2019, with the largest reductions being for black coal and gas generation.

But longer term factors that began around mid-2019 also contributed to benign market conditions. Two key factors were a downward shift in generator fuel costs, and rising levels of renewable generation.

2.6.3 Generator fuel costs

Fuel costs for black coal and gas generators eased significantly after the first quarter of 2019. In NSW, for example, fuel costs for black coal generators hovered around $60 per MWh in January 2019, but then steadily declined to $40 per MWh by June 2019, where they have since stabilised (figure 2.25). Prices set by black coal plants generally tracked falling international coal prices over this period. In March 2020 the average price set by black coal generators in NSW ($47 per MWh) was at its lowest level since late 2016. This shift occurred despite coal supply and plant availability issues at Bayswater and Mount Piper that constrained black coal generation. Over a period of several months in 2019, coal supply issues cut Mount Piper's output to less than half of what the plant generated in the same period in 2018.

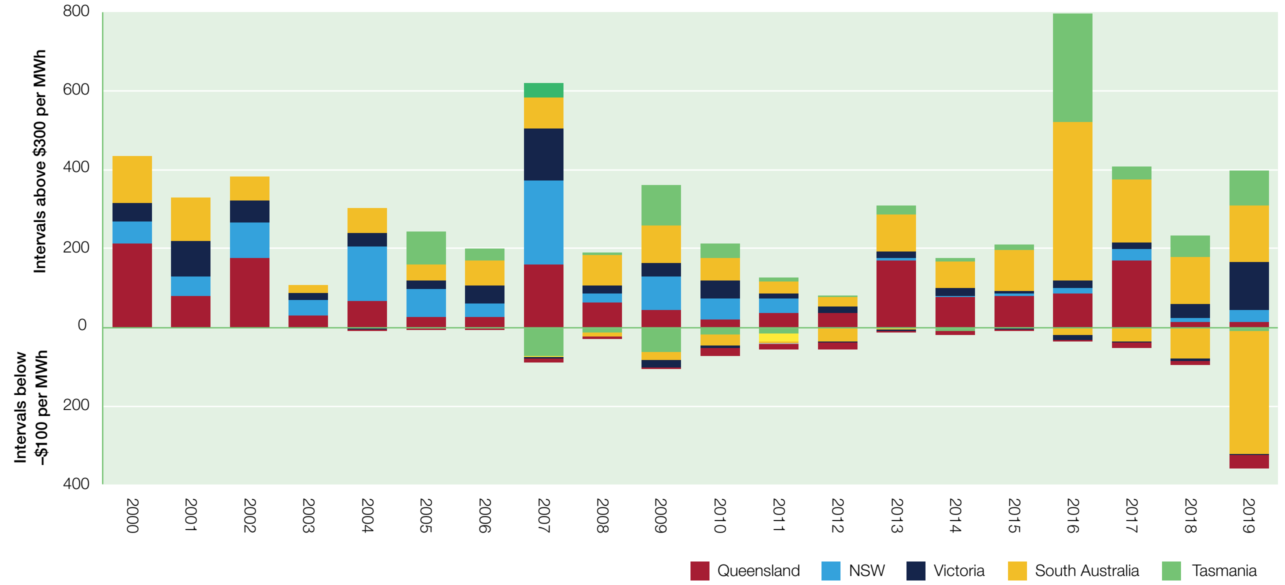
Fuel costs for gas plant also lowered in 2019. Again taking NSW as an example, fuel costs for gas plant eased from around $80 per MWh in January 2019 to around $60 late in the year (figure 2.26). The trend continued into 2020, with fuel costs falling to around $40 per MWh by March 2020. This decline generally reflected in wholesale electricity prices set by gas generators trending downwards since early 2019. January 2020 was an exception, when bushfires and high temperatures in NSW allowed generators to set some prices above $5000 per MWh.

More generally, coal and gas generation set lower wholesale electricity prices in the first quarter of 2020 than in the same quarter of 2019 in all regions except South Australia. Notably, black coal generators in NSW offered nearly all their capacity at less than $50 per MWh. This reduction in offer price is significant because black coal sets the price in NSW, Queensland and Victoria around 70, 60 and 40 per cent of the time respectively.

2.6.4 Renewable output

Another factor driving lower prices from the second half of 2019 was the increased renewable output from the recent influx of new wind and solar plant in the market. Over the 12 months to 31 March 2020, around 1550 MW of wind

Figure 2.27
Prices above $300 per MWh and below –$100 per MWh



Source: AER; AEMO (data).

capacity entered the market, of which almost half was installed in Victoria. Over the same period, almost 1200 MW of grid scale solar capacity entered the market, mostly in Queensland and NSW. A substantial rise in solar capacity contributed to Queensland being the only region with a lower year-on-year average price in 2019, despite electricity demand in the region continuing to grow.[28]

Wind generation in the first quarter of 2020 was 18 per cent higher than in the same quarter of 2019, and in South Australia it periodically displaced gas generation. Over the same period, solar generation was 54 per cent higher. Hydro generation was also higher (by 17 per cent), with the increase occurring mostly in Tasmania and NSW. This growth of renewable output is easing price pressures in the market, and contributed to a record number of negative prices during the third quarter of 2019. The number of negative prices in the first quarter of 2020 was also a first quarter record (section 2.6.2).

2.6.5 Price volatility

Spot price volatility is a natural feature of energy markets, and can signal to the market a need for investment in new generation (figure 2.27). Following record volatility in 2016 and 2017, the NEM recorded a marked reduction in the number of trading intervals with spot prices over $300 per MWh in 2018, with 232 instances (down from 409 the previous year).

Volatility returned in 2019, with 397 trading intervals exceeding $300 per MWh. Much of this volatility occurred in Victoria, South Australia and Tasmania, and was associated with extreme weather and high system demand early in the year, as well as generator outages in Victoria in mid-2019. Significant volatility was also observed in early 2020, again linked to extreme summer weather.

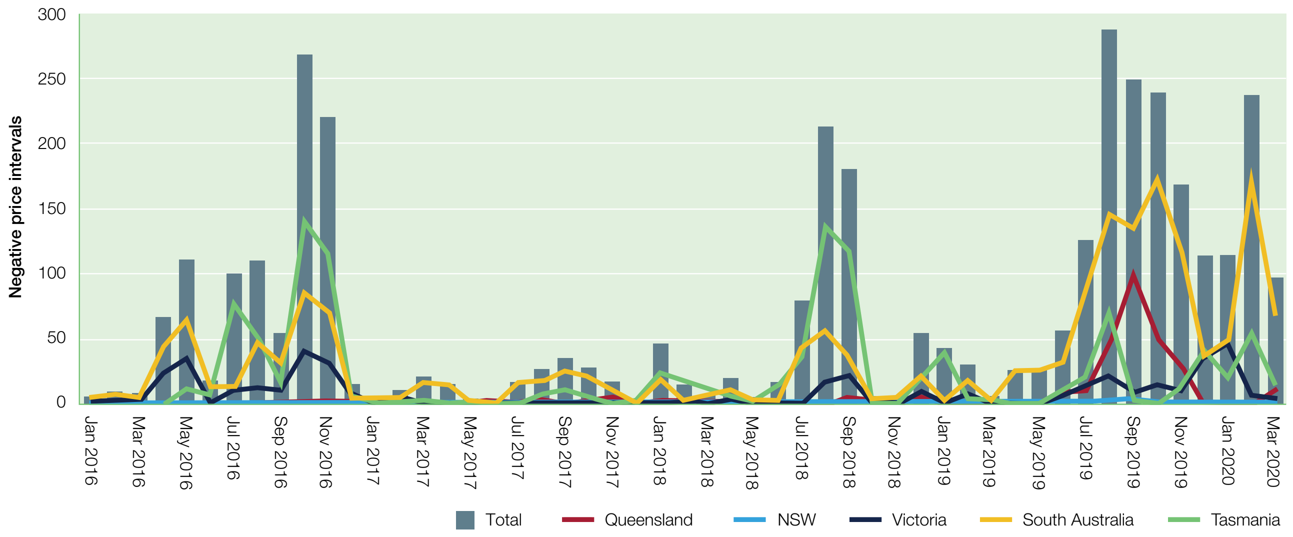
Bushfires and storms also impacted the market, causing transmission lines to trip and suddenly cut off available generation. At times, these events led to market separation between regions, as occurred between NSW and Victoria on 4 January 2020, and between Victoria and South Australia from 31 January to 17 February 2020. Spot prices hit the cap of $14 700 per MWh on multiple days during the bushfire period.

Negative prices

A relatively recent aspect of market volatility is a rising incidence of negative prices. Generators in the NEM can offer capacity as low as the market floor price of –$1000 per MWh. Negative bids essentially signal a generator's willingness to pay to produce electricity rather than switch

28 On 13 February 2019, Queensland set a new record for the region's maximum demand, at 10 179 MW.

Figure 2.28
Negative spot price count



Source: AER; AEMO (data).

off. AEMO typically dispatches generators by using the lowest priced offers first, then working its way through the merit order until demand is met. Allowing generators to offer capacity at negative prices increases the chances of the generator being dispatched into the market.[29]

Generators may have various motivations to offer capacity at negative prices. As an example, it may be cost-effective for large baseload coal generators to offer large amounts of capacity at negative prices to ensure continuous operation and avoid the high costs of shutting down and then restarting a few hours later. Once generating, baseload plants generally have low operating costs.

A generator's hedge position in contract markets may also affect its bidding strategies. If a generator has a contract ahead of time that ensures a fixed price for electricity sold into the market, its exposure to negative prices may be minimal.

The ability of wind and solar generators to operate varies with prevailing weather conditions. These generators do not incur high start-up or shutdown costs, and have running costs close to zero. If generating conditions are optimal, they may bid capacity at negative prices to guarantee dispatch.

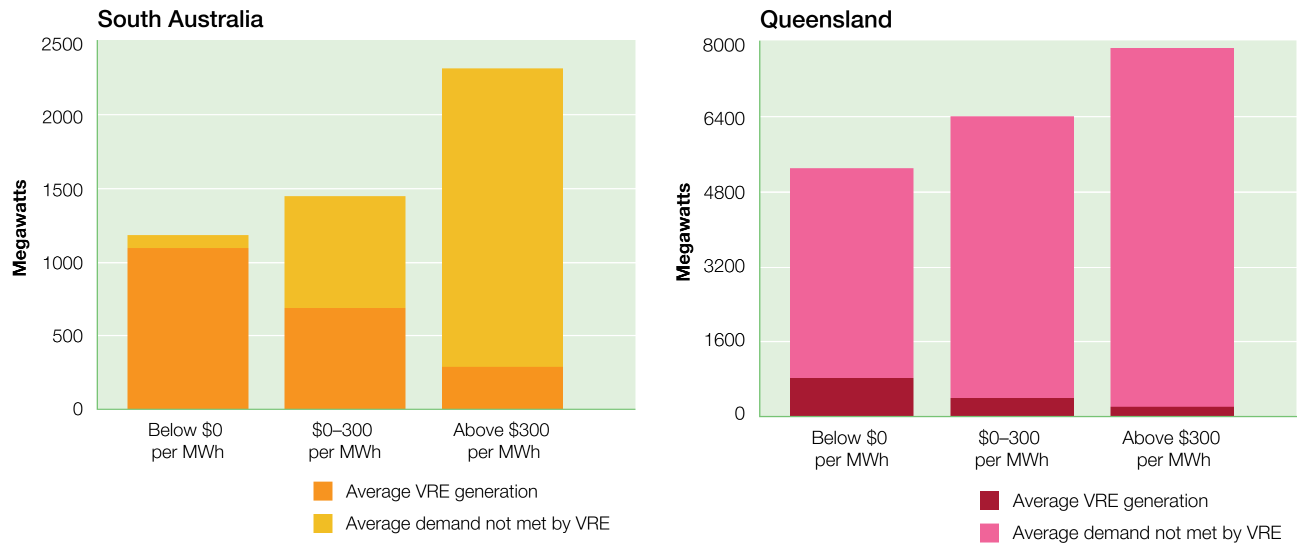
29 While a generator may offer capacity at negative prices, it does not necessarily mean the spot price will settle at a negative price. The dispatch price is determined by the marginal generator required to meet demand every 5 minutes. The spot price is determined every 30 minutes as the average of the six dispatch prices within that half hour.

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

While some renewable generators are insulated from negative spot prices through power purchase agreements, other generators may adjust their bidding and shift capacity to higher prices to avoid being dispatched at a negative price. Some wind and solar generators also source revenue from the sale of renewable energy certificates, so they may operate profitably even when wholesale prices are negative.

The instances of negative spot prices increased markedly in the second half of 2019, compared with the same period in 2018 and 2017 (figure 2.28). The third quarter of 2019 exceeded the previous record of the number of negative spot prices, with over 650 negative price intervals across the five regions. Negative prices tended to occur when electricity demand was low and weather conditions were optimal for renewable generation. While historically occurring overnight, they are now more common during the day when solar resources are producing maximum output. The phenomenon was particularly apparent for South Australia and Queensland—regions with a high penetration of wind and solar (grid scale and rooftop) generation (figure 2.29).

Figure 2.29
Renewable generation and negative prices, 2019



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

The first quarter of 2020 had over four times as many negative prices (450) as the previous first quarter record in 2014. In that quarter, South Australia accounted for almost two thirds of all negative prices, and over 80 per cent of prices under –$100. Over 40 per cent of its negative prices occurred while South Australia was separated from the rest of the NEM, and coincided with mild temperature and high wind generation. The high incidence of negative prices reduced the average spot price in South Australia by around $5 per MWh during the quarter.

2.7 Electricity contract markets

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

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

Typically, vertically integrated 'gentailers' are imperfectly hedged—their position in generation may be 'short' (not enough generation) or 'long' (too much generation) relative to their retail position. For this reason, gentailers participate in contract markets to manage outstanding exposures, although usually to a lesser extent than stand-alone generators and retailers do. Vertically integrated gentailers in the NEM include AGL Energy, Origin Energy, EnergyAustralia, Snowy Hydro (with retail brands Red Energy and Lumo Energy), Engie (Simply Energy), Alinta, Hydro Tasmania (Momentum), Meridian Energy (Powershop) and Pacific Hydro (Tango).

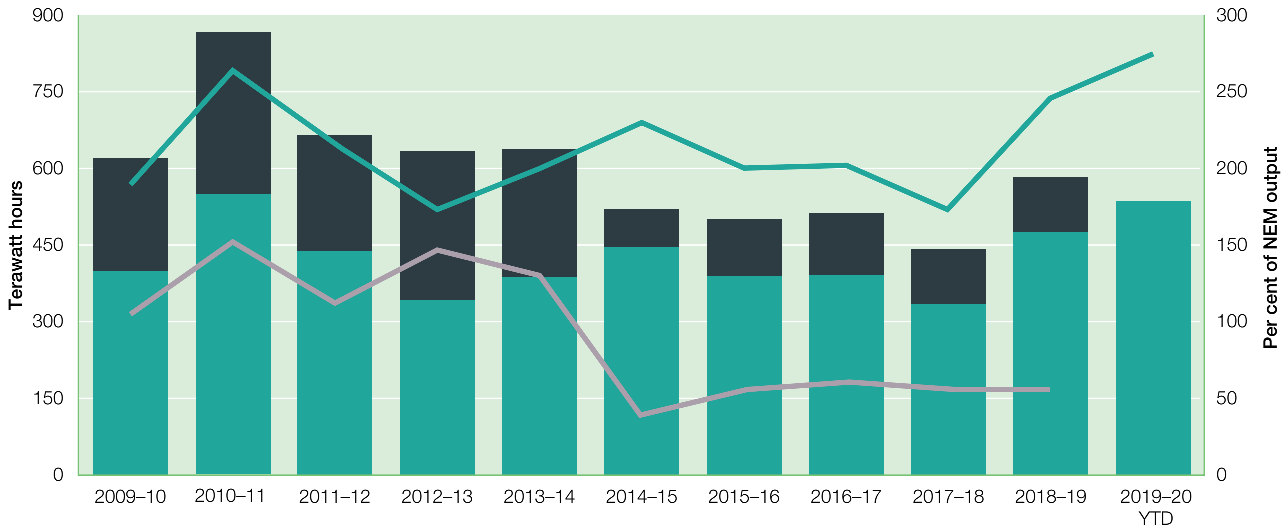
Alongside generators and retailers, participants in electricity contract markets include financial intermediaries and speculators, such as investment banks. Brokers often facilitate contracts between parties in these markets.

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

- Over-the-counter (OTC) markets, in which two parties contract with each other directly (often assisted by a broker). The terms of OTC trades are usually set out in International Swaps and Derivatives Association (ISDA) agreements.

Figure 2.30

Traded volumes in electricity futures contracts



NEM, National Electricity Market; OTC, over-the-counter; TWh, terawatt hours; YTD, year-to-date.

Note: Data for the full 2019–20 financial year trading of OTC contracts were not available at the time of publication. ASX data for 2019–20 are year to date at 31 March 2020.

Source: AER; AFMA; ASX Energy.

- The exchange traded market, in which electricity futures products are traded on the Australian Securities Exchange (ASX). Participants include generators, retailers, speculators, banks and other financial intermediaries. Electricity futures products are available for Queensland, NSW, Victoria and South Australia.

Various products are traded in electricity contract markets. Similar products are available in each market, but the names of the instruments differ. And while ASX products are standardised to encourage liquidity, OTC products can be uniquely sculpted to suit the requirements of the counterparties:

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

While prices are publicly reported for ASX trades, activity in OTC markets is confidential and not disclosed publicly. The Australian Financial Markets Association (AFMA) reports data on OTC markets through voluntary surveys of market participants, providing some information on the trade of standard (or vanilla) OTC products such as swaps, caps and options.

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

Electricity derivatives markets are regulated under the *Corporations Act 2001* (Cth) and the *Financial Services Reform Act 2001* (Cth). The Australian Securities and Investments Commission is the principal regulatory agency.

2.7.1 Contract market activity

As noted, ASX trades are publicly reported, while activity in OTC markets is confidential and disclosed publicly only via participant surveys in aggregated form. The OTC data are published on a financial year basis. To allow some comparability across OTC and ASX data, this section refers to financial years for both markets.

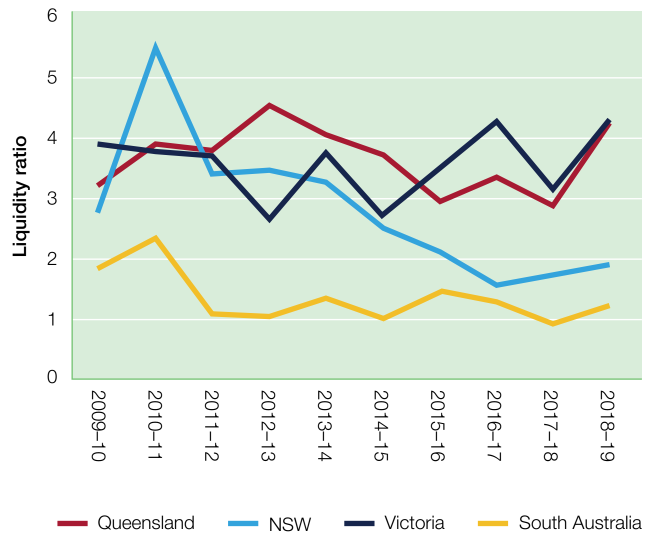
Regular ASX trades occur for the Queensland, NSW and Victorian regions of the NEM, but liquidity is poor in South Australia. A decline in trade volumes across the market from 2014 to 2017 may link to flat electricity demand and an oversupply of generation creating less price volatility in the wholesale market, which likely weakened demand for cap contracts. But volumes increased after hitting a low point in 2017–18 (figure 2.30).

In 2018–19 there were trades of 476 TWh of electricity contracts on the ASX, up 43 per cent on the previous financial year and the highest volume traded since 2010–11. These trades represented 243 per cent of underlying NEM demand. Trading levels rose again in 2019–20, with volumes traded in the nine months to 31 March 2020 already exceeding the 2018–19 total.

The recent growth in trading of ASX futures occurred despite the rising share of wind and solar generation in the market. This intermittent renewables generation is not well suited to contracting because its output is weather dependent. But 'firming' this generation by backing it with storage or gas powered plant can support contract market participation. A number of market participants with flexible generation capacity are offering firming products targeted at renewable generation.

Figure 2.31

Liquidity ratio in NEM regions



Source: AER; AFMA; ASX Energy.

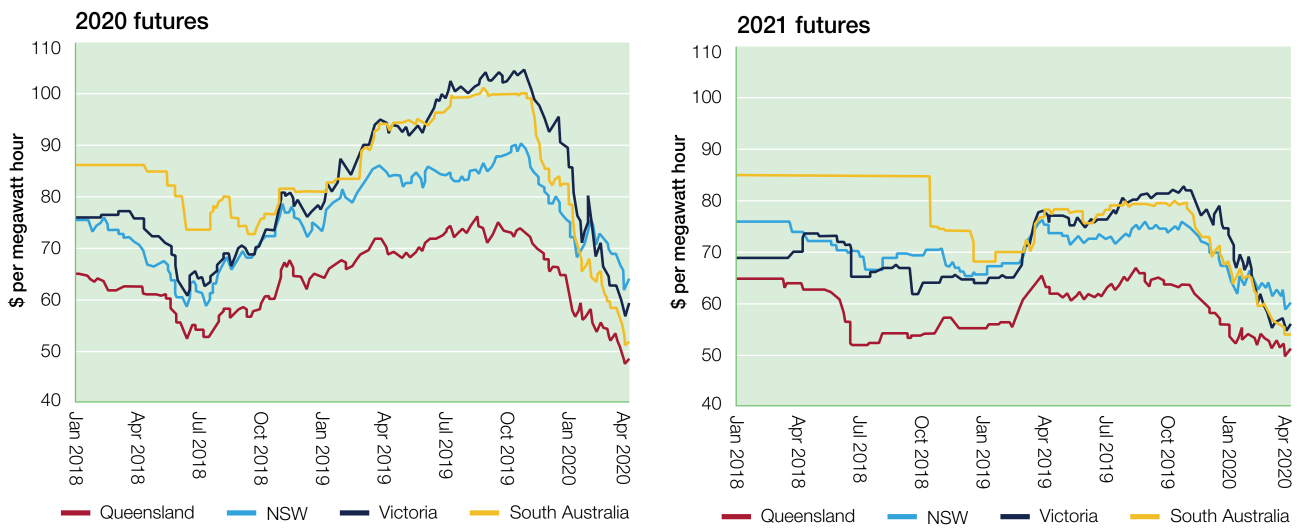
More recently, ARENA in February 2020 provided funding support to Renewable Energy Hub to establish a firming market platform that offers new hedge products designed for clean energy technologies. The project aims to fill a gap in risk management products and overcome a market barrier for clean energy technologies.[30] In April 2020 Renewable Energy Hub introduced a new 'super peak' electricity contract for electricity supply during the high demand hours of the morning, afternoon and evening periods.[31] Snowy Hydro became the first participant to offer this product.

OTC trade volumes have reduced substantially from levels of a few years ago, making up less than 25 per cent of contract volumes since 2013–14. Leading up to and during the period of carbon pricing from 2012 to 2014, participants sought greater contract flexibility to manage risk through wider participation in the OTC market, and OTC trade volume peaked at 46 per cent of total trade in 2012–13.

30 ARENA, 'Renewable Energy Hub marketplace', web page, available at: https://arena.gov.au/projects/renewable-energy-hub-marketplace/, viewed 1 May 2020.

31 Renewable Energy Hub, 'New era for renewables as first new super peak firming contract signed', Media release, 14 April 2020.

Figure 2.32
Prices for calendar year base futures



Source: AER; ASX Energy.

Contract market liquidity

Overall, contract liquidity has improved across the NEM in recent years as participants seek additional price protection. The liquidity ratio (contract trading relative to underlying demand) across the NEM rose from around 230 per cent in 2017–18 to 300 per cent in 2018–19 (figure 2.30), with all regions showing improvement (figure 2.31).

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

Liquidity is poorer in South Australia, where trading volumes tend to roughly match underlying electricity demand. The region's high proportion of renewable generation and relatively concentrated ownership of dispatchable generation likely contribute to this weaker liquidity. Given South Australia's liquidity issues, the Australian Competition and Consumer Commission (ACCC) recommended the imposition of a 'market maker' obligation, under which large vertically integrated retailers must make offers to buy and sell hedge products within a capped price spread. Reforms to similar effect were introduced in 2019 under the Retailer Reliability Obligation (RRO) (section 2.7.3 and box 1.3 in chapter 1).

Composition of trade

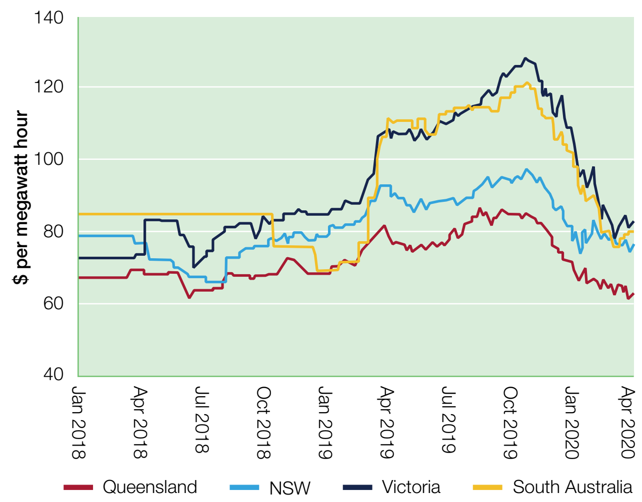
Victoria, NSW and Queensland each accounted for 25–37 per cent of ASX contracts traded in 2018–19. Trading in South Australia accounted for only 2 per cent of contract volumes. In the OTC market, the majority of reported OTC trading (63 per cent) occurred in Queensland. NSW and Victoria each accounted for 17 per cent of trading, with South Australia accounting for 4 per cent.

Quarterly futures made up the majority (67 per cent) of ASX trading in 2018–19, with 98 per cent of those futures being baseload products. Peak products accounted for only 2 per cent. The next most commonly traded products were ASX options (21 per cent) and caps (11 per cent). In the OTC market, swap products (83 per cent) and caps (13 per cent) accounted for most of the reported trading.

2.7.2 Contract prices

Base futures prices for 2020 ASX contracts began rising in the second half of 2018 in the lead up to the summer period, before easing during the summer (figure 2.32). Prices again moved upwards in early 2019 and continued for much of the year. In November 2019 prices began what would become a significant decline across all NEM regions, with falls of almost 50 per cent for Victorian and South Australian futures. The falls coincided with weakening wholesale market prices, linked to falling generator fuel costs and rising renewable generation (section 2.6).

Figure 2.33
Prices for first quarter 2021 base futures



Source: AER; ASX Energy.

The outlook for 2021 prices is relatively stable, with prices following a downward trajectory since November 2019, although the decline has been more gradual than for 2020 base futures.

Futures prices for the first quarter 2021 contracts have been more volatile (figure 2.33). Prices in Victoria and South Australia rose sharply in March 2019, following record high quarterly wholesale prices in each region over the summer. They continued to rise through to October 2019, peaking at $121 and $128 respectively. Prices for Queensland and NSW first quarter 2021 contracts rose to a lesser extent, peaking at $86 and $97 respectively in 2019.

Prices declined for all regions late in the year, and by April 2020 had eased 30 per cent off their 2019 peaks in Queensland, Victoria and South Australia, and 20 per cent in NSW. These movements mirrored spot market outcomes, where prices generally eased in the fourth quarter of 2019, and remained subdued over the first quarter of 2020. As noted, lower generator fuel costs and rising renewable generation contributed to this shift in the market. The market appears to expect these changes in market dynamics to continue through to the summer of 2020–21.

2.7.3 Access to contract markets

Access to contract markets, either on the ASX or in OTC markets, can pose a significant barrier to retailers and generators looking to enter or expand their presence in the electricity market. This barrier is a risk because contracts offer a degree of control over costs (for retailers) and revenue (for generators). The ACCC identified potential barriers to small or new retailers accessing hedge products in ASX and OTC markets, with significantly fewer trade options available to these retailers.[32]

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

The RRO scheme introduced in July 2019 includes features aimed at improving access to contract markets. It includes a market liquidity obligation (MLO) on specified generators to post bids and offers in contract markets in the period leading up to a forecast reliability gap, to help smaller retailers meet their requirements. Box 1.3 in chapter 1 outlines the scheme's operation.

AEMO's assessment in 2019 did not identify a shortfall in any NEM region over the relevant period, so the RRO was not triggered. The operation of the RRO differs in South Australia, where the local energy minister can trigger the obligation. In January 2020 the minister triggered the RRO in South Australia for specific 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. By May 2020 there had been trade during the MLO trading windows of 32 MW of contracts covering those reliability gap periods. These contracts represented 55 per cent of all trades relating to the reliability gap periods.

2.8 Market competition

The AER monitors the performance of the wholesale electricity market, and assesses whether it is effectively competitive. It is required to report on the performance of

32 ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—final report*, June 2018.

the wholesale electricity market every two years. The AER published its first *Wholesale electricity market performance report* in December 2018, and expects to publish its second report by the end of 2020.

In an effectively competitive energy market, prices should reflect demand and underlying cost conditions, at least in the longer term. Barriers to entry and exit must be sufficiently low so investors can respond efficiently to price signals. Relatively short periods of high prices driven by tighter supply and demand conditions may occur, allowing generators to recover their fixed costs and earn a return on their investment. But a sustained period of high prices provides clear signals for new generation to enter the market. Likewise, a fall in demand relative to supply should put downward pressure on prices, and prompt higher cost generators to exit the market.

The AER has highlighted periodic evidence of opportunistic bidding in NEM regions. Its reporting on these issues supported reforms to generator bidding rules, which the Australian Energy Market Commission (AEMC) implemented. The reforms require market participants to ensure offers, bids and rebids are not false or misleading.

Opportunistic bidding by large generators can be profitable because dispatch and settlement prices are determined over different time frames—that is, the 30 minute settlement price is the average of six of the 5 minute dispatch prices. This timing allows generators to rebid capacity late in a trading interval to capture high prices, while giving competing generators little time to respond. To help manage this risk, the settlement period for the electricity spot price will change from 30 minutes to 5 minutes to align the timeframes for dispatch and settlement prices. The reform was expected to take effect in July 2021, but the AEMC in early 2020 was consulting on a delayed introduction to July 2022.[33]

Assessing whether the energy market is operating efficiently as it transitions to a lower emissions generation mix is difficult. The market will take time to adjust to the changing role of fast response 'flexible' generators, demand management and storage, for example.

The exit of low cost coal generation plant in 2016 and 2017 contributed to higher electricity prices. With less capacity available at low prices, higher cost black coal, gas and hydroelectric generators were more frequently setting electricity prices. This period also coincided with high gas costs.

33 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.

But certain features of the market make it vulnerable to the exercise of market power, and at times may drive prices higher than recent changes in the generation mix and underlying supply costs can explain. A few large participants control significant generation capacity and output in most NEM regions. Their output is typically needed at times of high demand, creating opportunities to exercise market power at these times (box 2.3).

2.9 Power system reliability

Reliability is about the power system being able to supply enough electricity to meet customers' requirements, drawing on available generation and storage, demand response, and transmission network capacity to transport power to customers.[34] Cross-border transmission interconnectors support reliability by allowing power sharing across regions. Reliability concerns tend to peak over summer, when high temperatures spike demand and increase the risks of system faults and outages.

Chapter 1 looks at how the current energy market transition is affecting reliability. This section focuses mainly on recent outcomes. It refers to the reliability of wholesale electricity supply through the transmission system. The current reliability standard for these sectors requires any shortfall in power supply to not exceed 0.002 per cent of total electricity requirements.

2.9.1 Managing reliability

The reliability standard has rarely been breached, although AEMO intervenes in the market to manage any forecast shortfalls. Around 94 per cent of supply interruptions experienced by consumers originate in distribution networks, and relate to local power line issues. Section 3.14.3 in chapter 3 discusses distribution reliability.

AEMO raised concerns that the NEM's wholesale electricity supply would face reliability risks over each of the past three summers (including 2019–20), especially in Victoria and South Australia where major coal (and gas) plant closures have occurred. The closures removed significant 'dispatchable' capacity from the generation fleet that previously could be relied on when needed. Exacerbating the risk, the remaining coal plants have become more prone to outages, especially in hot weather (section 1.3.1).

34 Reliability should be distinguished from security, which refers to the power system's technical stability in terms of frequency, voltage, inertia and other characteristics (section 2.10).

Box 2.3 Competition metrics

The market structure of the generation sector affects opportunities and incentives for generators to exercise market power. In particular, a market structure dominated by a handful of generators—especially in a region with limited in-flow interconnector capacity—is likely to be less competitive than a market with diluted ownership. Market shares are a simple illustrator of the degree of concentration in a market. Figures 2.18 and 2.19 illustrate generation market shares in 2019.

The Herfindahl–Hirschman Index (HHI) accounts for the relative size of firms when analysing market structure, by tallying the sum of squared market shares in a market. The index can range from zero (in a market with many small firms) to 10 000 (that is, 100 squared) for a monopoly. By squaring market shares, the HHI emphasises the impact of large firms.

Figure 2.34 compares market concentration over time in mainland National Electricity Market (NEM) regions. The average HHI is over 2000 for each region, and did not vary significantly in recent years. But significant variation from the average occurs in some dispatch intervals, reflecting plant outages, fuel availability and bidding behaviour in response to demand and prices.

South Australia had the largest range of HHI values in 2019, similar to previous years. This outcome reflects the significant variability in renewable output in that state. Victoria, NSW and Queensland recorded their lowest minimum HHI values over the assessed period, indicating the market is more competitive at certain times. Queensland recorded the largest improvement, following the introduction of a third state owned generation business in that state—CleanCo. More generally, the 2019 results coincided with higher levels of wind and solar generation across the NEM, as well as a more frequent occurrence of negative spot prices in Queensland and South Australia.

While NSW, Victoria and South Australia recorded their lowest minimum HHI values, the maximum HHI value in those regions rose from 2018 levels. NSW recorded a significant rise, with outages in the third quarter of 2019 leading to greater market concentration at that time.

In most regions, the output of a few large participants is necessary to meet demand at times of high demand, even allowing for import capacity from other regions. At these times, those participants are 'pivotal' to meeting demand and may be able to exercise market power. The residual supply index (RSI) quantifies when the largest participants are pivotal to meeting demand in a region.

An RSI-1 greater than 1 means demand can be fully met without dispatching the largest participant. Similarly, RSI-2 and RSI-3 measure the ratio of demand that can be met by all but the two or three largest participants. Various factors may cause the RSI to deteriorate, including a rise in demand, a decrease in generation, or an increase in the share of generation controlled by the largest participants.

It is easier for one pivotal participant to exercise market power than for two or three participants to do so. But RSI-2 and RSI-3 can indicate the risk of participants coordinating behaviour to influence market outcomes.

A limitation of RSI analysis is its focus on whether a participant can raise prices, rather than on its incentives to do so. Many factors can influence a participant's incentives, including the extent to which it is vertically integrated, and its contract position. RSI analysis also fails to account for market intricacies such as transmission constraints and ramp rate limitations.

Figure 2.35 shows the percentage of trading intervals in each the past five years when RSI values were below 1—that is, when at least some generation from the one, two or three pivotal participants was needed to meet demand.

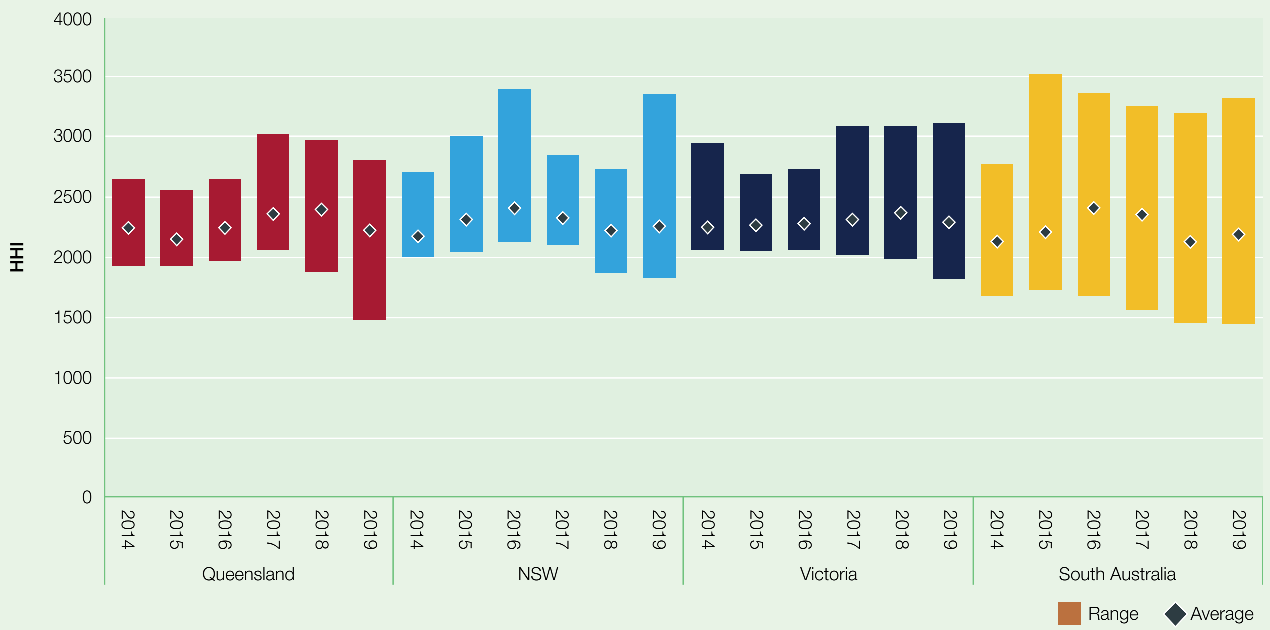
In 2019 the largest participant in Queensland (whether Stanwell or CS Energy) was pivotal 14 per cent of the time—more often than the largest participant in any other region. But this outcome significantly improved on 2018, when Queensland's largest participant was pivotal 22 per cent of the time. For the first time since 2014, Queensland also had periods in 2019 when neither of its two largest generation participants was pivotal. This situation occurred 3 per cent of the time.

In NSW and Victoria, the largest participant was needed to meet demand around 4 per cent of the time (around 15 days per year). The two largest participants were needed to meet demand 74–80 per cent of the time. Some output from one of the three largest participants is always needed to meet demand.

South Australian generators were pivotal less often than were those elsewhere. Output from the region's largest generator was rarely required to meet demand in 2019. The high penetration of rooftop solar PV installations in South Australia in recent years also meets much of the region's demand during daylight hours.

Outcomes for Tasmania are straightforward: Hydro Tasmania is always needed to meet demand.

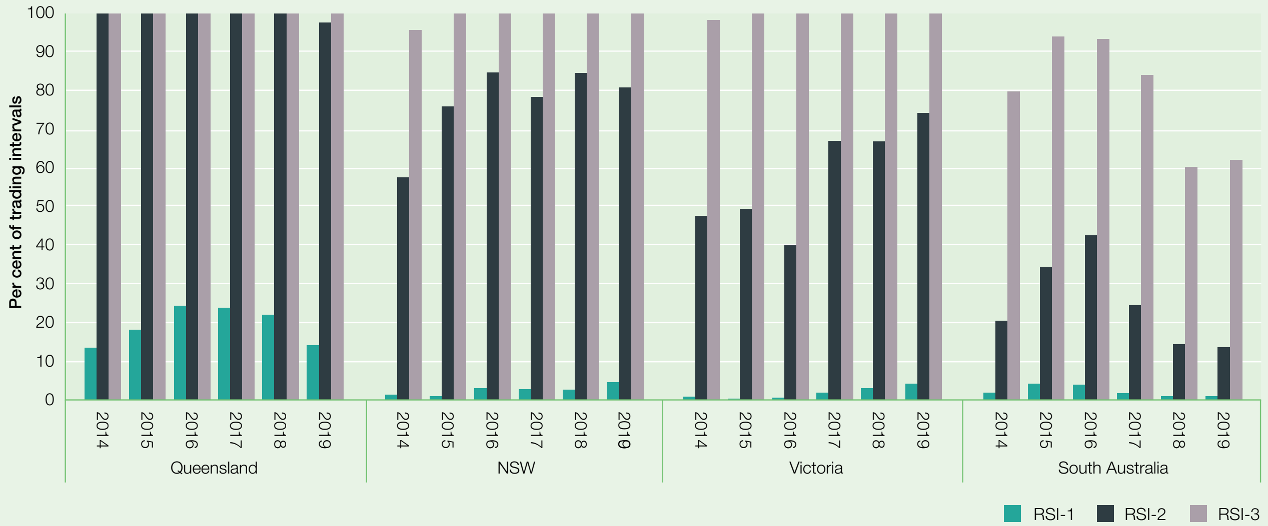
Figure 2.34
Herfindahl–Hirschman Index



Note: Based on bid availability or the capacity that each generator offered, every 5 minutes. Bid availability accounts for outages, fuel availability and bidding behaviour, and provides a dynamic assessment of the levels of concentration in the market based on changing market conditions. The data do not account for imports, so overstate the risks of uncompetitive outcomes. South Australian results for 2016–17 are adjusted to remove outcomes when the market was suspended following the black system event in September 2016.

Source: AER.

Figure 2.35
Pivotality of largest generators



RSI, residual supply index.

Note: The percentage of trading intervals when the one, two and three largest generators are pivotal. Allocations are based on the control of trading rights. Data are based on real time (half hourly) bid availability, and include maximum possible imports as available capacity. If an interconnector is forced to export, then it is treated as additional demand in the region.

Source: AER.

Reliability and Emergency Reserve Trader

Over the past three summers (up to and including 2019–20), AEMO intervened in the market to manage forecast risks of available generation not being sufficient to meet demand. In each year, it activated the Reliability and Emergency Reserve Trader (RERT) mechanism, which acts as a safety net to maintain reliability when electricity demand is forecast to exceed supply. The mechanism allows AEMO to procure (via competitive tender) additional supply from generators and/or demand management from customers (to reduce their consumption) at times of system stress, to reduce the risk of load shedding.

Reserves procured under the RERT must be 'out of market.' This feature seeks to preserve economic signals for new investment or demand response by market participants. Procuring reserves from existing market generators could perversely incentivise participants to withhold supply from the market in an attempt to obtain a better price through a RERT procurement. This feature was underlined by a rule change in 2019 that specifies any scheduled generator or load that participated in the wholesale market in the previous 12 months may not provide emergency reserves through the RERT.[35] It ensures the wholesale market remains the primary mechanism for delivering reliability.

The RERT scheme is expensive to operate, and consumers ultimately bear these costs. The costs include availability costs (capacity payments to secure the service over a specified timeframe), pre-activation payments (because some services incur costs to be on standby), and activation costs (for the actual use of the reserves). Other costs include administration costs and compensation payments to participants.[36]

Changes introduced in 2019 and 2020 provide more flexibility and transparency in the use of the RERT. A key change was to increase AEMO's lead time to purchase reserves from nine to 12 months. In Victoria, AEMO can enter multi-year contracts of up to three years under the long notice RERT mechanism. This arrangement helps address short term reliability challenges facing that state, and applies until June 2023.

Before 2017 AEMO entered contracts with RERT providers on only three occasions, but RERT capacity was never dispatched. The RERT was activated for the first time in November 2017 in Victoria. It was activated twice in January 2018 in Victoria and South Australia, and twice again in those states in January 2019. On two occasions, back-up reserves activated under the RERT were insufficient, and load shedding was required.

AEMO issued 31 low reserve warnings over the summer of 2019–20, and activated RERT reserves on five occasions. The RERT was activated in NSW for the first time in January 2020. No load shedding occurred over the summer of 2019-20. The RERT has never been used in Queensland or Tasmania. Table 2.5 sets out instances of reserves being activated under the RERT.

The total cost of the RERT was over $30 million in each of the past two summers, and around $50 million in the 2017–18 summer (figure 2.36).

2.9.2 Reliability outlook

AEMO in August 2019 forecast relatively low reliability risks over the 2020–21 and 2021–22 summers, based on its expectations of nearly 5 GW of new generation and upgrades to existing generators coming online by that time.[37] But it noted 'uncontrollable, but increasingly likely' high impact events (such as prolonged or coincident generator outages) could threaten reliability over the next 10 years, given forecast continued reliability risks over the next decade unless new investment replaces ongoing fossil fuel plant retirements.

AEMO forecast a higher reliability risk for NSW than for other regions over the medium term, particularly in the window between the closure of the Liddell power station in 2023–24 and the expected commissioning of Snowy 2.0 in 2025. Even with increased import capacity from proposed upgrades to the Queensland–NSW and Victoria–NSW interconnectors, AEMO forecast NSW could be exposed—if high summer demand coincided with unplanned generator outages—to significant supply gaps and involuntary load shedding if no mitigation action is taken.

Market bodies are exploring how best to manage reliability risks in the context of an evolving energy market. Focus areas include encouraging investment in resources with flexibility to manage sudden demand or supply fluctuations. Section 1.3.3 discusses recent reform initiatives.

2.10 Power system security

Power system security refers to the power system's technical stability in terms of frequency, voltage, inertia and similar characteristics.[38] Historically, the NEM's synchronous coal, gas and hydro generators helped maintain a stable

35 AEMC, *Rule determination: National Electricity Amendment (Enhancement to the Reliability and Emergency Reserve Trader) Rule 2019*, May 2019.
36 AEMC, *Rule determination: National Electricity Amendment (Enhancement to the Reliability and Emergency Reserve Trader) Rule 2019*, May 2019.
37 AEMO, *2019 electricity statement of opportunities*, August 2020.
38 Box 1.4 in chapter 1 defines these terms.

Table 2.5 RERT activation and costs

DATE	REGION	QUANTITY PRE-ACTIVATED (MW)	QUANTITY ACTIVATED (MW)	RERT COSTS ($ MILLION)[1]	CAUSE OF EVENT
SUMMER 2019–20					
31 January 2020	NSW Victoria	390 110	134 185	10.9 7.5	In NSW, high temperatures and humidity saw forecast demand reach 13 025 MW. Coupled with this demand, 2800 MW of scheduled generation was unavailable due to unplanned outages and temperature driven limitations. In Victoria, severe winds caused the collapse of several transmission towers, resulting in the region seperating from South Australia, and 1100 MW of generation being unavailable to Victoria.
23 January 2020	NSW	406	152	7.5	Significant capacity was not available at Mount Piper and Bayswater, and an additional 700 MW unavailable due to temperature-driven limitations.
4 January 2020	NSW	368	68	8.4	Bushfires caused the loss of several transmission lines in southern NSW and islanded part of NSW and Queensland from the rest of the NEM. This outcome led to an disconnection of a generator and loss of customer load in NSW, and reduced available generation capacity by over 2200 MW.
30 December 2019	Victoria	80	92	4.9	A transmission outage reduced import capacity to Victoria from NSW by over 1000 MW.
SUMMER 2018–19					
25 January 2019	Victoria	na[2]	396	24.5	Unplanned outages and temperature driven generation capacity limitations reduced Victorian supply by 1600 MW. AEMO activated the RERT and also requested AusNet Services to shed 100 MW of customer load at 11:00 am, and a further 150 MW at 11:30 am.
24 January 2019	Victoria South Australia	na[2]	625	9.9	Unplanned outages and generation capacity limitations reduced supply at a time of high temperature driven demand. AEMO also instructed AusNet Services to shed 75 MW of customer load in Victoria.
SUMMER 2017–18					
19 January 2018	Victoria South Australia	500 na[2]	130 6.5	24.1	Elevated temperatures coincided with plant outages. These conditions were compounded by extended recall times of some generation, capacity reductions on the Basslink interconnector, and bushfires near the Heywood interconnector.
30 November 2017	Victoria	na[2]	32	0.9	Unseasonably warm weather spiked demand and coincided with significant generation capacity being unavailable.

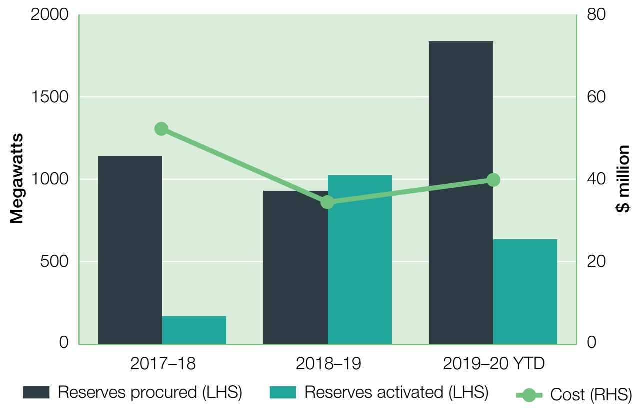
AEMO, Australian Energy Market Operator; MW, megawatts; na, not available; NEM, National Electricity Market; RERT, Reliability and Emergency Reserve Trader.

1 2017–18 and 2018–19 RERT costs include costs for pre-activation, and activation, and other costs (including compensation costs). 2019–20 costs also include ongoing availability costs, which do not apply to any one specific event.

2 AEMO reporting for RERT activation did not itemise pre-activation quantities for this event.

Source: AER analysis of AEMO's RERT reporting.

Figure 2.36
RERT reserves and costs



RERT, Reliability and Emergency Reserve Trader; YTD, year-to-date.

Note: Calculations for the 2020 component of the 2019-20 data are based on AEMO's initial estimates of RERT costs in January 2020. Includes costs for availability, pre-activation, activation and other costs (including compensation costs). 2019–20 YTD is data to 31 March 2020.

Source: AER analysis of AEMO's RERT reporting.

and secure system through inertia and system strength services provided as a byproduct of producing energy. But, as older synchronous plants retire, these sources of inertia and system strength are being removed from the system. Falling inertia makes it harder to keep frequency within an acceptable band, while falling system strength makes it harder to keep voltages stable.

The wind and solar generators entering the market are less able to support system security. For this reason, the rising proportion of renewable plant in the NEM's generation portfolio reflects in more periods of low inertia, weak system strength, more 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 these challenges, the settlement period for the electricity spot price will change from 30 minutes to 5 minutes. The reform was expected to take effect in July 2021, but the AEMC in early 2020 was consulting on a delay to July 2022.[39]

AEMO uses market based methods when possible to manage system security in the NEM. If market measures are unavailable or insufficient for some services, AEMO may intervene in the operating decisions of generation businesses. Intervention of this sort has risen sharply in recent years, particularly in South Australia and, more recently, Victoria (section 1.4.3).

39 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 this pandemic.

In the longer term, energy rule reforms aim to widen the pool of providers (such as batteries and demand response) of security services. At a higher level, market policy and regulatory bodies are developing reforms of the energy market's architecture, to manage security risks in the context of an evolving energy market. Sections 1.4.4 and 1.4.5 discuss recent reform initiatives.

2.10.1 Security performance in the NEM

Section 1.4 discusses security issues in the NEM, including intervention mechanisms and reform initiatives. This section is a summary of recent performance.

Power system security has degraded in recent years, and this trend continues. In 2019 the market experienced:

- 28 instances on the mainland when the system frequency did not meet the operating standard requirements. Another 180 events were recorded in Tasmania over the same period.
- A continuing system strength shortfall in South Australia, as well as emerging shortfalls in Victoria, Queensland and Tasmania.

The NEM experienced a major security event on 31 January 2020, islanding South Australia from the national market (box 2.4). Security issues persisted during the 18 day separation, and elevated reliability risks in Victoria and NSW.

2.10.2 Frequency control markets

AEMO procures some of the services needed to maintain power system stability through markets (section 1.4.2 in chapter 1). In particular, it operates markets to procure various types of frequency control services.

Frequency control ancillary services (FCAS) are used to maintain the frequency of the power system close to 50 Hertz. The NEM has eight FCAS markets that fall into two categories: regulation services and contingency services. *Regulation services* operate continuously to balance minor variations in frequency caused by small changes in demand or supply, during normal operation of the power system. *Contingency services* manage large frequency changes from sudden and unexpected shifts in supply or demand, and they are used less often.

Costs for regulation services are recovered from participants that contribute to frequency deviations (causer pays); costs for raise contingency services are recovered from generators; and costs for lower services are recovered from market customers (usually retailers). AEMO acquires FCAS

Box 2.4 Islanding of South Australia on 31 January 2020

On 31 January 2020 storms damaged six transmission towers connected to the Heywood interconnector. Heywood connects the Victorian and South Australian power grids, and the outage separated South Australia from the rest of the National Electricity Market (NEM) for 18 days.[a] The Australian Energy Market Operator (AEMO) constrained a second interconnector linking the regions, Murraylink, to avoid the risk of catastrophic system failures. A second outage occurred on 2 March, but with a shorter duration.

Electricity supply was sufficient to meet demand during the 18 day separation. But, with South Australia unable to trade electricity with Victoria, the system at times faced security risks due to the high level of renewable generation in South Australia. The separation caused system frequency in South Australia to rise above acceptable limits, causing several generators and batteries to trip or reduce output. Demand for grid supplied electricity was high at the time of the separation, and rose further when output from rooftop solar photovoltaic (PV) generation fell as a result of the high frequency.

AEMO was required to manage South Australia as an extended island (South Australia and elements of Victoria), which called for significant intervention. Between 1 February and 17 February 2020, AEMO intervened in the market 100 per cent of the time to maintain system strength in the region.

South Australia was required to provide its own frequency control ancillary services (FCAS) during the separation, resulting in record FCAS costs for the quarter (section 2.10.2). The separation also raised reliability threats in Victoria and NSW, resulting in AEMO dispatching Reliability and Emergency Reserve Trader (RERT) reserves in those regions (section 2.9.1).

Wind generators offered less capacity during the weeks of separation. AEMO constrained wind output to maintain system security, but some plants repriced their offers in the market to avoid the double penalty of being dispatched at negative prices and having to pay high FCAS costs. Before the separation, wind generators offered nearly all their capacity below \$0 per megawatt hour (MWh). But, during the separation event, they shifted significant capacity into higher price bands, including over \$5000 per MWh.

South Australia's battery storage units also offered significantly less capacity during the separation, following AEMO directions that they hold a constant state of charge and not dispatch. During the separation weeks, batteries shifted nearly all capacity offers to over \$5000 per MWh.

a AEMO, *Preliminary report—Victoria and South Australia separation event, 31 January 2020*, April 2020.

through a co-optimised market that coordinates offers from generators and other participants in both energy and FCAS markets to minimise overall costs.

Fewer participants operate in FCAS markets than in the wholesale electricity market. In early 2020 there were seven major FCAS providers in NSW, nine in Queensland, eight in South Australia, seven in Victoria, and one in Tasmania. A number of new participants emerged in recent years (table 2.6). Demand response aggregators now offer FCAS across all mainland regions; virtual power plants offer services in NSW and South Australia; and battery storage offers services in South Australia and Victoria. But these new entrants account for only a small proportion of FCAS trades. To strengthen transparency around FCAS markets and encourage participation, the AER in 2019 launched quarterly reporting on market activity.[40]

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

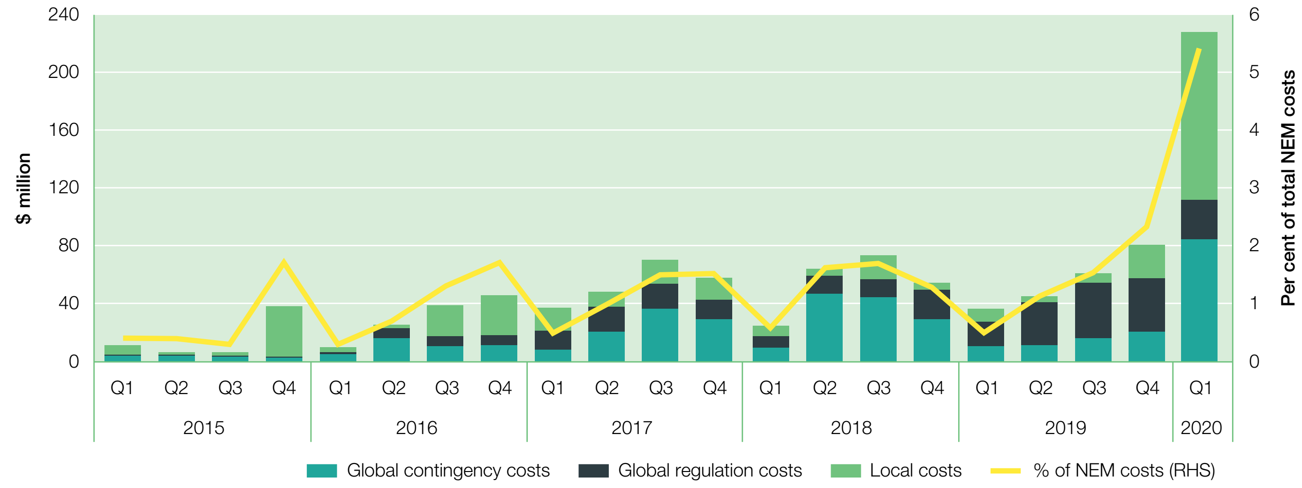
Historically, FCAS costs were comparatively low in relation to energy costs—in 2015 FCAS costs totalled \$63 million, which represented around 0.7 per cent of NEM energy costs. However, these costs rose steadily over the past few years. In 2019 FCAS costs totalled around \$223 million, almost four times their level in 2015 (figure 2.37).

Following deteriorating frequency performance, AEMO in 2019 increased sourcing requirements for base regulation services on the mainland by 70–75 per cent.[41] AEMO also introduced a stricter approach to assessing sourcing requirements for contingency service.[42] The amount of time that frequency remained within the normal operating

41 AEMO, *Frequency and time error monitoring 2nd quarter 2019*, November 2019.

42 The change in AEMO's approach to enabling FCAS contingency services resulted in an increase of over 300 MW compared with the same period in 2018.

Figure 2.37
FCAS costs



FCAS, frequency control ancillary services; NEM, National Electricity Market.
Source: AER; AEMO (data).

Table 2.6 Number of providers of FCAS in each market

	LOWER				RAISE				TYPE OF PROVIDER
	5 min	60 sec	6 sec	Reg	5 min	60 sec	6 sec	Reg	
Queensland	4	6	5	8	6	7	7	8	Gas, black coal, hydro, pump, demand aggregator, liquid
NSW	6	6	6	5	6	6	6	5	Black coal, demand aggregator, virtual power plant, hydro
Victoria	5	5	5	5	6	6	6	5	Brown coal, hydro, gas, battery, demand aggregator, load (smelter), pump
South Australia	5	6	6	5	6	7	7	5	Gas, demand aggregator, virtual power plant, battery, wind, liquid
Tasmania	1	1	1	1	1	1	1	1	Hydro, pump, gas

min, minutes; reg, regulation; sec, seconds.
Source: AER; AEMO (data).

band subsequently improved, but regulation FCAS costs rose to record levels. Costs also increased in Tasmania when an outage on the Basslink interconnector in August–September 2019 reduced the availability of services. Once the interconnector was restored, frequency performance improved, but it remained below the standard.

Costs for both regulation and contingency services reached record levels in the first quarter of 2020, at over \$220 million (equivalent to 5.4 per cent of energy costs). First quarter FCAS costs were higher than total costs for the whole of 2019. Local regulation services in South Australia accounted for almost half of these costs, mainly due to the region being islanded for several weeks following the loss of the Heywood interconnector. Also, in January 2020 the impact of bushfires on transmission networks drove record prices for contingency services across the NEM. FCAS prices exceeded \$5000 per MW several times over the quarter.

AEMO's concerns about the sourcing of frequency services led the AEMC in March 2020 to introduce a mandatory requirement for generators to provide primary frequency response. The new requirement commences in June 2020 (section 1.4.4).