Image courtesy of Tesla

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 (box 2.1). 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 (figure 2.19).

Around 150 large power stations (comprising around 240 plant units in total) produce electricity for sale into the NEM. A transmission grid carries this electricity along 40 000 kms 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 almost 10 million residential, commercial and industrial energy users. The electricity supply chain is illustrated in infographic 1.

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 1 covers electricity (and gas) retailing.

The generation mix in the energy market continues to evolve as new technologies emerge and the costs of generation from some technologies fall. Wind and solar generation are replacing older coal fired generators as they retire from the market. 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.

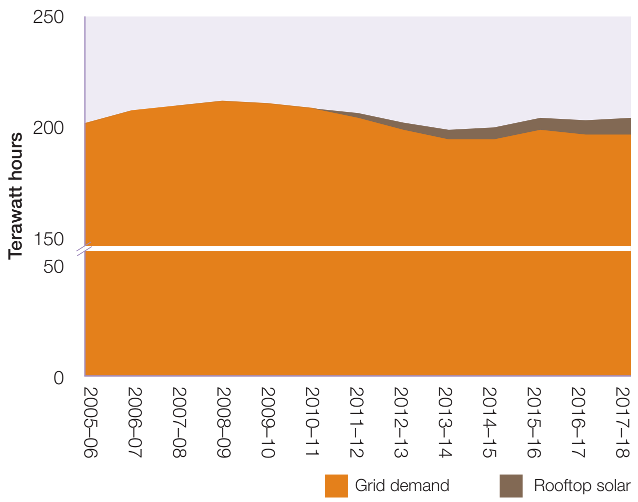
In coming years, customers may increasingly meet their energy needs by drawing on electricity stored in batteries, and be paid by energy suppliers to reduce their energy use or inject stored electricity when the grid is under stress. Technological advances making battery storage more economical will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

2.1 Electricity demand

Almost 10 million residential and business customers consume electricity across the NEM's five regions. Traditionally, all electricity was produced by large scale registered generators, sold through the NEM spot market, and supplied to customers through a transmission and distribution network grid. Consumers produced little of their own electricity until 2010, but by October 2018 almost two million households and businesses had installed solar PV systems to produce electricity. This production met almost 4 per cent of the NEM's total electricity requirements in 2017–18 (figure 2.1).

Figure 2.1

Electricity consumption in the NEM



Note: Grid consumption is native demand (including scheduled and semi-scheduled generation, and intermittent wind and large scale solar generation). Rooftop solar output estimates derived from CER data on installed capacity, and AEMO system output assumptions.

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

2.1.1 Grid consumption

Most electricity consumed in the NEM is produced by registered generators and transported through the NEM transmission grid. Grid consumption peaked in 2008–09 at 210 terawatt hours (TWh). Following several years of declining consumption, demand levelled out from 2013–14. Demand in 2017–18 totalled 196 TWh, similar to levels in the previous five years (figure 2.1).

Electricity consumption from the grid continues to grow in Queensland, mainly due to escalating energy requirements for the state's coal seam gas and liquefied natural gas (LNG) industries. This growth is likely to moderate now the LNG plants are fully operational. Projected demand growth is weakest for South Australia, mainly due to the state's rising rooftop solar PV generation.[1]

Box 2.1 How the NEM 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 needs to match demand in real time.

Table 2.1 **National electricity market at a glance**

Participating jurisdictions	Qld, NSW, Vic, SA, Tas, ACT
NEM regions	Qld, NSW, Vic, SA, Tas
NEM installed capacity (including rooftop solar PV)	55 590 MW
Number of large generating units	240
Number of customers	9.7 million
NEM turnover 2017–18	$17 billion
Total electricity demand 2017–18[1]	203 TWh
National maximum demand 2017–18[2]	32 469 MW

MW, megawatts; PV photovoltaic; TWh, terawatt hours.

1 Includes total energy met by grid connected generation, including rooftop solar PV.

2 The maximum historical summer demand of 35 551 MW occurred in 2009. The maximum historical winter demand of 34 422 MW occurred in 2008.

Around 150 large power stations (comprising around 240 plant units in total) make offers to supply quantities of electricity in different price bands for each five minute *dispatch interval*. Electricity generated by rooftop solar photovoltaic systems is not traded through the NEM, but it does lower the demand needed to be met by market generators.

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. Retailers 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 through demand response contracts with their retail customers.

AEMO, the power system operator, works with constantly varying information to make a continuum of decisions. It uses forecasting and monitoring tools to track electricity demand and generator bidding, allowing it to determine which generators should be dispatched (directed) to produce electricity. It repeats this exercise every five 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 five 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 $14 500 per megawatt hour (MWh). A price floor of –$1000 per MWh also applies.

Figure 2.2 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 3500 megawatts. To meet this, generators 1, 2 and 3 must be fully dispatched and generator 4 is partly dispatched. The dispatch price is $51 per MWh. By 4.25 pm demand has risen to the point where a fifth generator is needed. This generator has a higher offer price of $60 per MWh, which becomes the dispatch price for that five 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 $54 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.

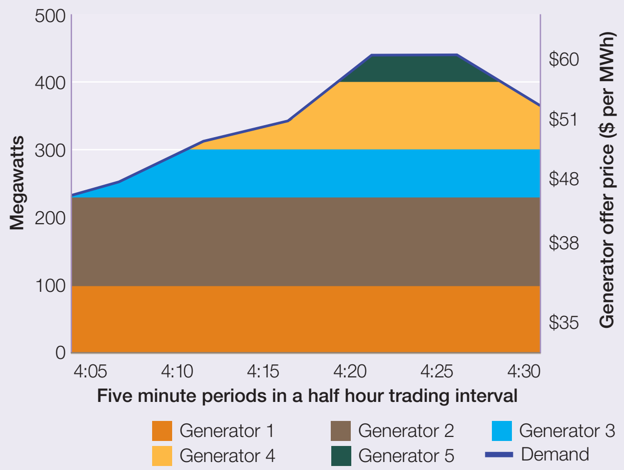
Power system management

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). AEMO may enter contracts with generators or large customers to ensure back-up reserves are available. But, if system issues or an unexpected rise in demand pose a threat of unserved energy, AEMO can direct generators to provide additional supply, or may directly intervene as a last resort.

AEMO also procures *ancillary services* from market participants to keep the power system secure. Frequency control ancillary services maintain system frequency within a safe range. 'Regulation' services correct for minor deviations in load or generation within each five minute dispatch interval. AEMO procures 'contingency' services to maintain safe power flows and voltage levels following a major disturbance such as the loss of a transmission line. These services are offered by generators (including battery storage) that can rapidly adjust output and industrial customers able to rapidly adjust their energy use.

If a serious power system threat 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'—temporarily cut power to some customers. This action is rare. An insecure operating state led AEMO to cut supply to some customers in South Australia on 1 December 2016 and 8 February 2017, and in NSW on 10 February 2017. Extreme weather and infrastructure failures caused the entire state of South Australia to black out for several hours on 28 September 2016, however, this blackout was not at AEMO's direction (section 1.7).

Figure 2.2
Setting the spot price



In other regions (NSW, Victoria and Tasmania), consumption of grid supplied electricity is forecast to remain relatively stable over the next decade. The Australian Energy Market Operator (AEMO) forecast that improvements in energy efficiency and further growth in rooftop PV and non-scheduled generation will largely offset the higher energy use caused by population and economic growth and consumer preferences for energy intensive appliances like home entertainment units and space conditioning. AEMO's demand forecasts factor in how climate change may increase the magnitude and frequency of heatwave conditions that drive peak electricity use.[2]

2.1.2 Maximum grid demand

The demand for electricity varies by time of day, season and ambient temperature (box 2.2). Daily demand typically peaks in early evening, while seasonal peaks occur in winter (driven by heating loads) and summer (for air conditioning). Demand normally reaches its maximum on days of extreme temperature, when air conditioning loads are highest.

Maximum demand for grid sourced electricity rose steadily until 2009, but then flat lined or declined in most regions for several years (figure 2.3). The trend began to reverse in 2015–16, with significantly higher maximum demand in most regions, though it remained well below historical peaks.

Outcomes in 2017–18 varied by region (table 2.2). Queensland continued its almost unbroken trend of rising maximum demand, setting a new record on 14 February 2018 during a prolonged heatwave. Victoria experienced higher maximum demand in 2017–18 than a year earlier, partly due to a warm summer driving air conditioning use and higher industrial demand for power. But the maximum was still 17 per cent below Victoria's demand record, set nine years ago.

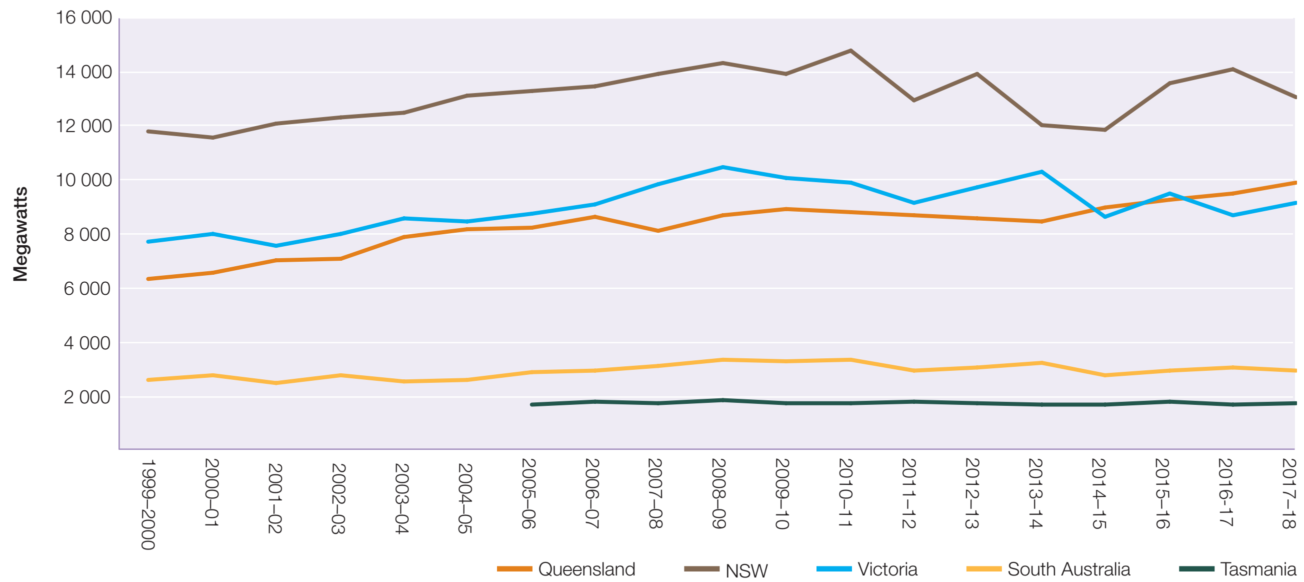
In NSW and South Australia maximum demand was significantly lower in 2017–18 than a year earlier. Demand was steady in Tasmania.

2 AEMO, *2018 electricity statement of opportunities*, August 2018, p. 4–6.

Table 2.2 Maximum grid demand, by region, 2017–18

	QUEENSLAND	NSW	VICTORIA	SOUTH AUSTRALIA	TASMANIA
Change from previous year (%)	4.4	–7.3	4.9	–4.0	0.6
Change from historical maximum (%)	0.0	–11.4	–16.8	–0.1	–0.1
Year of historical maximum	2017–18	2010–11	2008–09	2010–11	2008–09

Figure 2.3
Maximum grid demand, by region



Note (table 2.2 and figure 2.3): Maximum native demand (including scheduled and semi-scheduled generation, and intermittent wind and large scale solar generation) occurring at any time during the year. Excludes consumption from rooftop solar systems.

Source: AER; AEMO.

2.2 Generation technologies in the NEM

The NEM's generation plant uses a mix of technologies to produce electricity. Figure 2.19 maps the locations of generation plant, and the types of technology in use. Table 2.3 lists each plant. Figures 2.5–2.7 compare variations across regions, including movements over time.

Fossil fuel generators produce over 80 per cent of electricity in the NEM. The plants burn coal or gas to power a generator. The combustion process releases carbon emissions as a by-product 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 emissions 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. Coal fired generators have low operating costs, but are slow (and may be expensive) to start. For this reason, coal fired generators tends to operate relatively continuously.

Some gas powered generators can be switched on and off at short notice, but high operating costs tend to constrain their use. Hydroelectric plant has low operating costs, but finite water to draw on, so it cannot operate continuously. Intermittent generation, such as wind and solar, can operate only if weather conditions are favourable, but their operating costs are low.

Box 2.2 Regional demand patterns

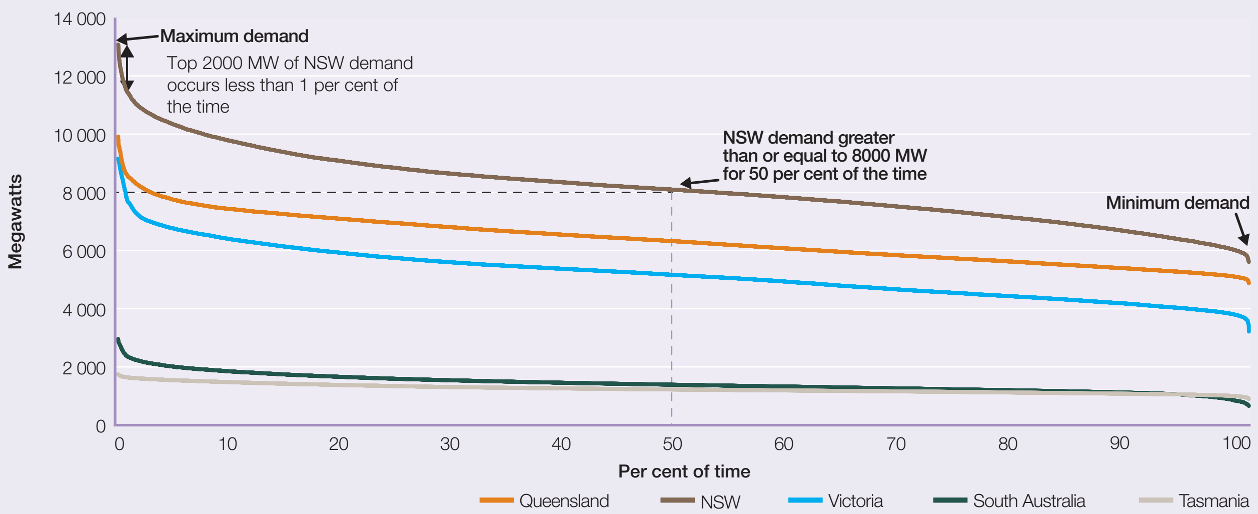
The profile of electricity demand varies across regions. In some regions, grid demand is relatively constant throughout the year, while in others it is more variable. Load duration curves show the frequency of each level of electricity demand over a period of time, and provide an indicator of the variability of this demand. Figure 2.4 illustrates load duration curves for each national electricity market (NEM) region in 2017–18.

The NEM region with the highest *maximum* demand in 2017–18 was NSW (13 080 megawatts (MW)), followed by Queensland (9920 MW), Victoria (9160 MW), South Australia (2960 MW) and Tasmania (1750 MW). *Minimum* demand ranged from 660 MW in South Australia to 5600 MW in NSW. South Australia's lowest minimum demand now typically occurs in the middle of the day during summer (compared with overnight in most regions). This outcome reflects the region's relatively high output from rooftop solar photovoltaic systems.

Taking NSW as an example, grid demand was below 10 000 MW for more than 90 per cent of the year, as shown by the dotted line in the chart. During the very highest demand periods—occurring 1 per cent of the time, or less than four days a year—demand was up to 2000 MW higher than in the remaining 99 per cent of the year. That is, around 15 per cent (2000 MW) of NSW's generation fleet and transmission network capacity was required for just 1 per cent of the year (shown by the steep segment of the curve highlighted by the arrow in figure 2.4).

Regions with 'peaky' demand profiles benefit from generators such as open cycle gas plant that can be drawn on to meet relatively infrequent demand peaks. Demand response by electricity customers can also play a useful role in helping to reduce maximum demand for short periods.

Figure 2.4
Electricity demand duration



Note: Demand is ordered from maximum on the left to minimum on the right. Each point on the curve represents the percentage of time that demand exceeded that level during 2017–18. Native demand (including scheduled and semi-scheduled generation, and intermittent wind and large scale solar generation).
Source: AEMO; AER.

Figure 2.5
Generation in the NEM, by fuel source, 2017–18

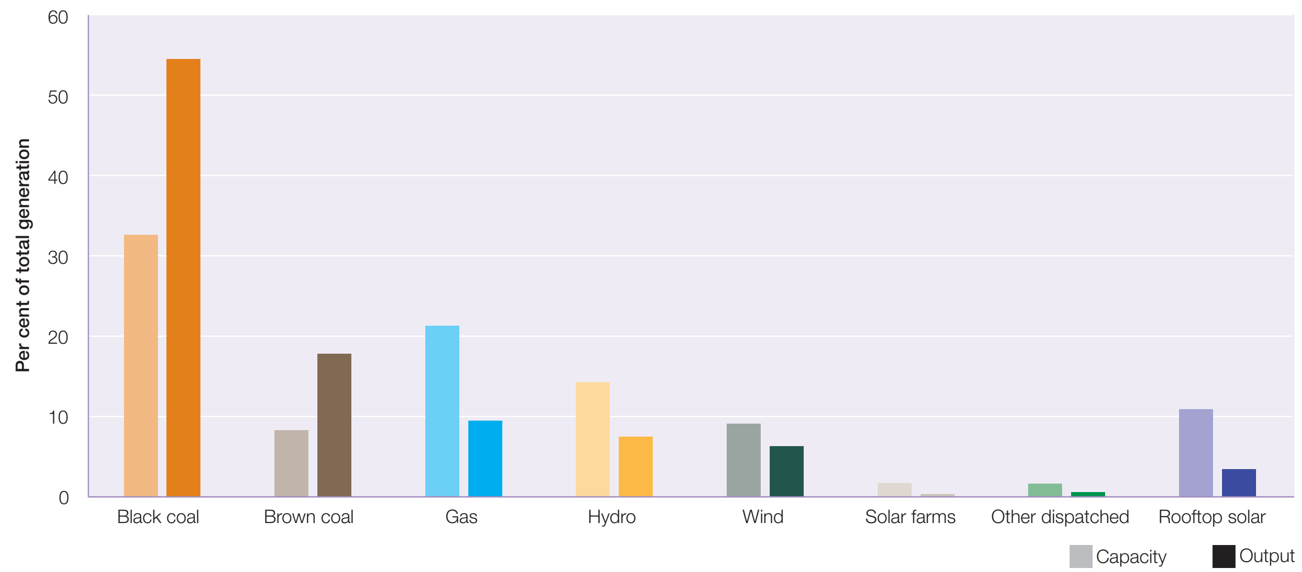
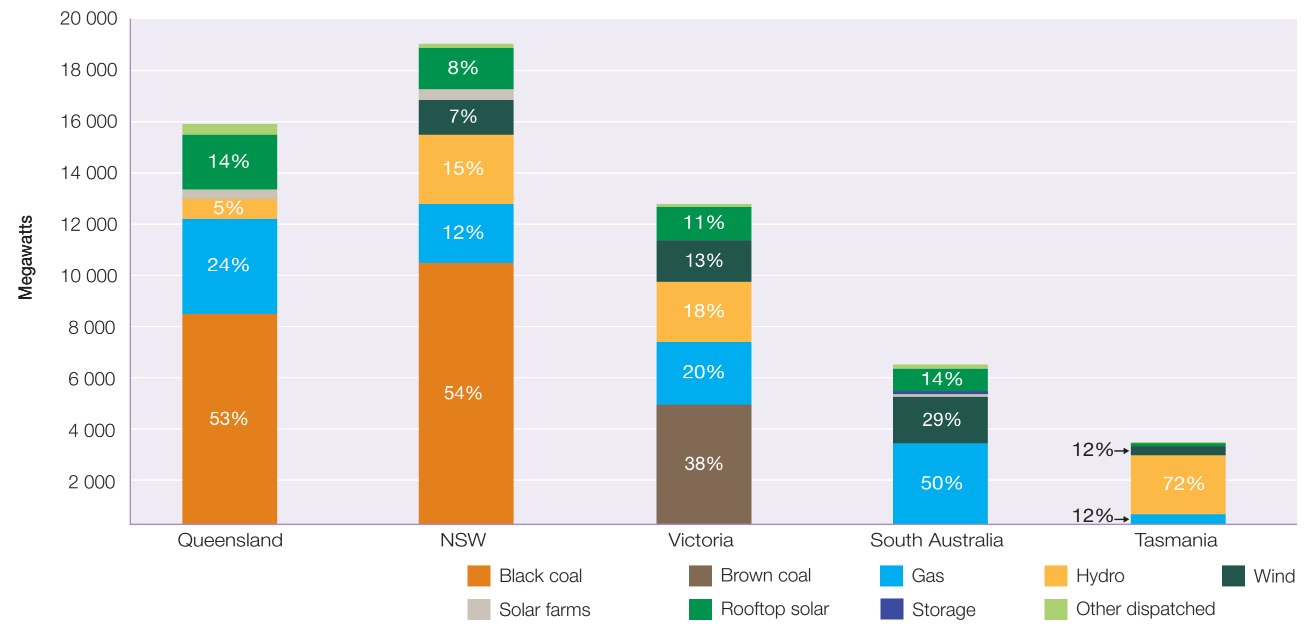
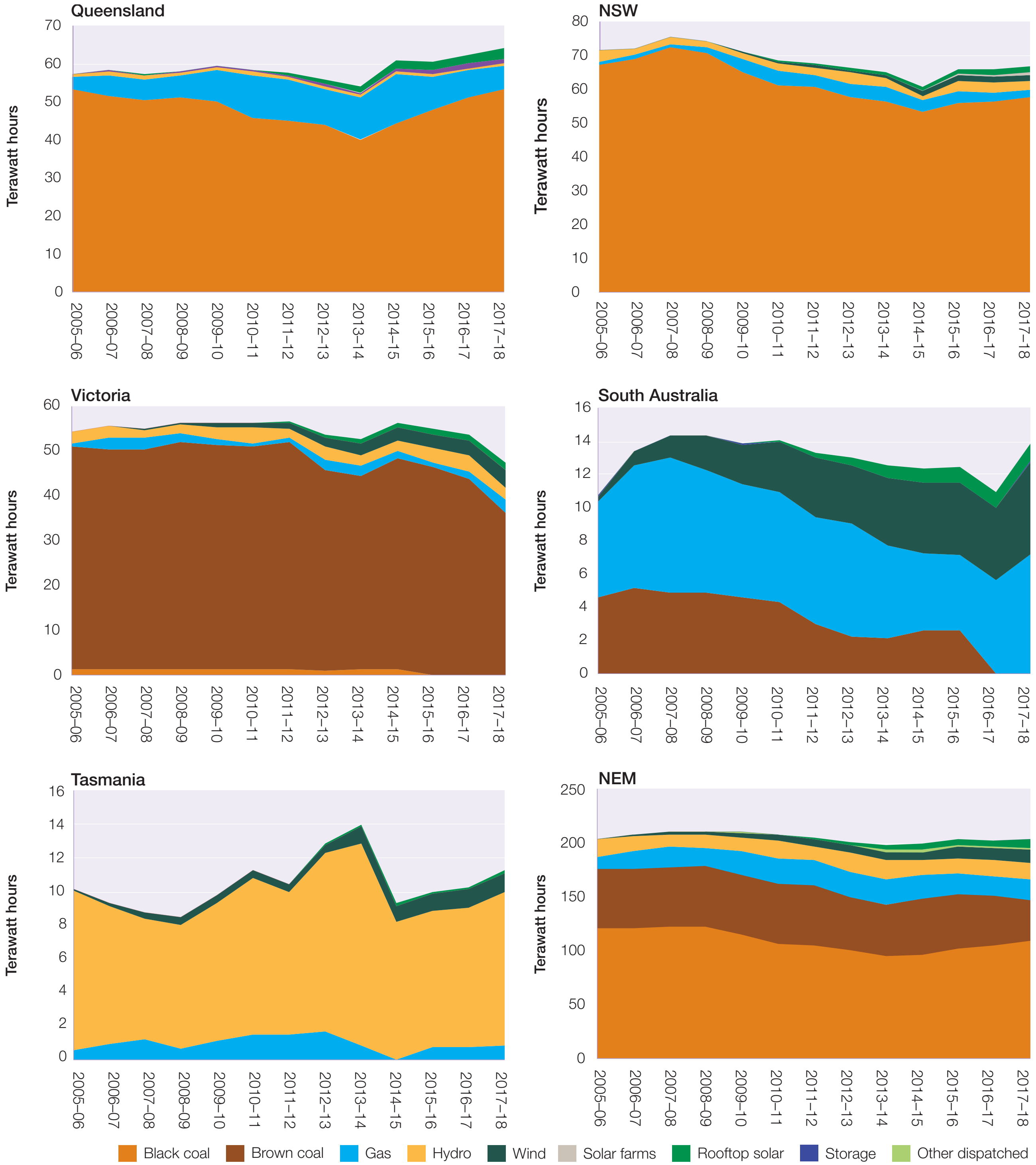


Figure 2.6
Generation capacity in the NEM, by region and fuel source



Note (figures 2.5 and 2.6): Generation capacity at 1 July 2018. Rooftop solar output estimates derived from CER data on installed capacity and AEMO system output assumptions. Other dispatch includes biomass, waste gas and liquid fuels. Storage includes only battery storage.
Source: Grid demand: AER, AEMO; Rooftop solar: AER, CER, AEMO (nemweb.com.au/#rooftop-pv-actual).

Figure 2.7
Changes in electricity generation, by region and fuel source



Note: Rooftop solar output estimates derived from CER data on installed capacity, and AEMO system output assumptions. Other dispatch includes biomass, waste gas and liquid fuels. Storage includes only battery storage.

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

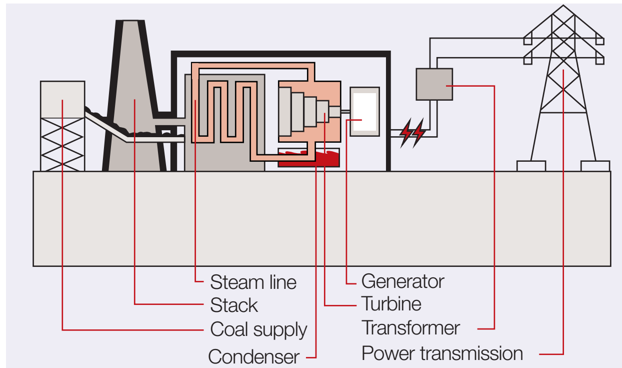
Some intermittent plant can pose challenges for power system security. In particular, the transmission network relies on rotational inertia, system strength, and frequency control mechanisms. But the capability of intermittent generation to provide these services, and the types of services required, are still evolving (section 2.6.3).

Despite challenges in integrating this plant into the grid, the shift to renewable generation continues to gather pace. The technology mix is evolving due to changes in the relative fuel and capital costs or different plant, technological advances making some plant more efficient (such as advances in combined cycle gas plants and thermal solar plants) and government policies to reduce carbon emissions (box 2.3).

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 2.8).

Figure 2.8
Coal fired generation



Coal fired generation remains the dominant supply technology in the NEM, producing 73 per cent of all electricity traded through the market in 2017–18, when it operated at its highest summer output in a decade. But coal plant accounts for only 41 per cent of the market's generation capacity, reflecting that coal generators tend to run fairly continuously.

Coal plant operate in Victoria, NSW and Queensland. Victorian generators run on brown coal, while NSW and Queensland generators use black coal.

Brown coal, also known as lignite, can contain up to 70 per cent water, whereas black (or bituminous) coal has a lower water content and produces more energy than brown coal. Victorian brown coal is cheap to extract as the Gippsland region has abundant reserves in thick seams close to the earth's surface, making Victorian brown coal among the lowest cost coal in the world. But brown coal produces up to 30 per cent more greenhouse gas emissions than black coal when used to generate electricity.

Coal fired generators can require a day or more to start up, so have high start-up and shut-down 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 provide ancillary services that help maintain power system stability.[3]

Significant coal fired capacity has been retired from the market. In May 2016 Alinta retired its Northern power station in South Australia, removing 546 megawatts (MW) of capacity from the market. Then in March 2017 Engie retired its Hazelwood power station in Victoria, removing another 1600 MW of brown coal generation. The plant was over 50 years old, and was Australia's most emissions intensive power station. The closure was especially significant given Hazelwood's size, supplying around five per cent of the NEM's total output.

Following the plant closures, the remaining coal fired generation fleet operated at higher output levels. Over summer 2017–18 it operated at its highest level in a decade.. Black coal generation in particular has played a key role in replacing Hazelwood's generation.[4]

Closures of further ageing coal plant are expected. The most imminent is the planned retirement of AGL Energy's Liddell power station in NSW in 2022, which would remove 1680 MW of black coal capacity from the NEM. Additionally, Engie, Origin Energy and AGL Energy have each signalled they intend to make no further investment in coal plant.

2.2.2 Gas powered generation

Open-cycle gas turbine (OCGT) plant burn gas in a turbine to drive a generator (figure 2.9). 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

3 Synchronous generators—including hydroelectric and thermal plan such as coal, gas and solar thermal generators—can provide these services. The generators' heavy spinning rotors provide synchronous inertia that slows down the rate of change of frequency. They help with voltage control by producing and absorbing reactive power and also provide high fault current that improves system strength.

4 AEMO, *Quarterly Energy Dynamics*, Q1 2018, p. 7.

Figure 2.9
Open cycle gas powered generation

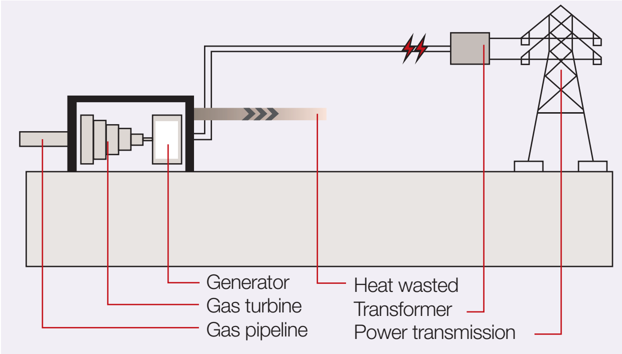
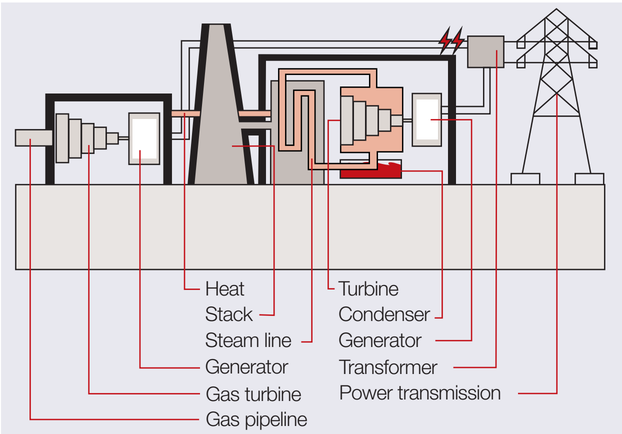


Figure 2.10
Combined cycle gas powered generation



a second turbine (figure 2.10). The capture of waste heat improves the plant's thermal efficiency, making it more suitable for longer operation than open cycle plant.

Gas plant can operate more flexibly than coal, with open cycle plant (and newer CCGT plant) in particular needing as little as five 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 emissions intensive as the most efficient coal fired plant.[5]

Despite these benefits, gas is a relatively expensive fuel for electricity generation, so gas generators more typically operate as 'flexible' or 'peaking' plants. Across the NEM, gas powered plant accounted for 21.3 per cent of plant capacity in the NEM in 2017–18 (up from 19.5 per cent in 2016–17), but supplied only 9.5 per cent of electricity generated (up from 8.8 per cent). The low capacity factor reflects that this plant technology is not widely used to produce baseload power. South Australia relies more on gas powered generation than other regions. In 2017–18, the state produced 56 per cent of its local generation from gas plant.

Gas generation in the NEM tends to be seasonal, peaking in summer (and sometimes winter) when electricity demand and prices are highest (section 4.9.1). It also varies with the amount of intermittent generation and outages affecting coal fired generators.

More recently, sharply higher gas fuel costs linked to Queensland's LNG industry and a lack of new gas supplies slowed demand for gas powered generation from 2015 (figure 2.11). 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 21 per cent of Queensland's electricity output in 2014–15 to just 9 per cent in 2017–18.

A similar squeezing of gas powered generation was apparent for much of 2018 in NSW. Over summer 2017–18 NSW recorded its lowest quarterly level of gas powered generation since 2009—68 per cent below average summer output over the decade.[6] But the retirement of coal generators in Victoria and South Australia has made gas generation critical to meeting electricity demand when renewable generation is low in those regions. This outcome resulted in gas generation in 2017–18 being 270 per cent higher in Victoria than two years earlier, and 160 per cent higher in South Australia.

In 2018 AEMO forecast gas demand for power generation may be 50 per cent lower in 2019 than its year-ahead forecast for 2018. It attributed this reduction to new wind and solar plants coming online and filling more of the supply gap left by the closure of coal plants, reducing the need for gas powered generation.[7]

Hydroelectric generation

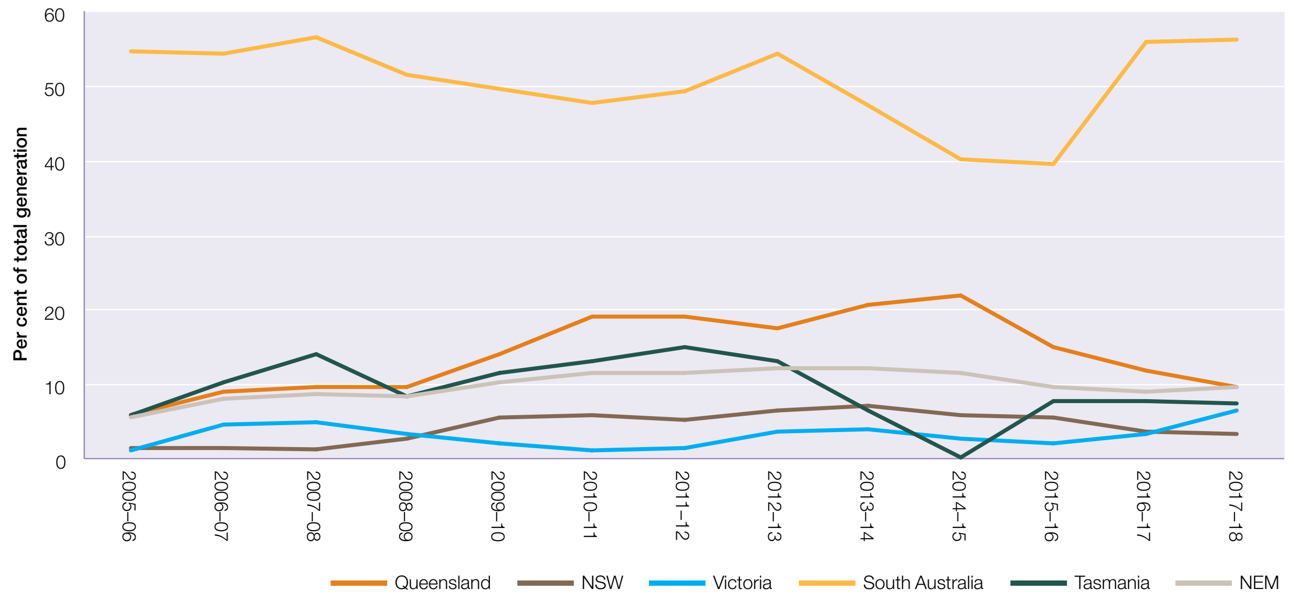
Hydropower uses the force of moving water to generate power. The technology involves channelling falling water through turbines. The pressure of flowing water on the blades rotates a shaft and drives an electrical generator, converting the motion into electrical energy (figure 2.12). Hydroelectric generators are synchronous generators, providing power that can be dispatched when required and other services that support power system security.

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 (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. Some pumped hydroelectric generation already operates in the NEM, but larger scale projects are also being explored (section 2.2.6).

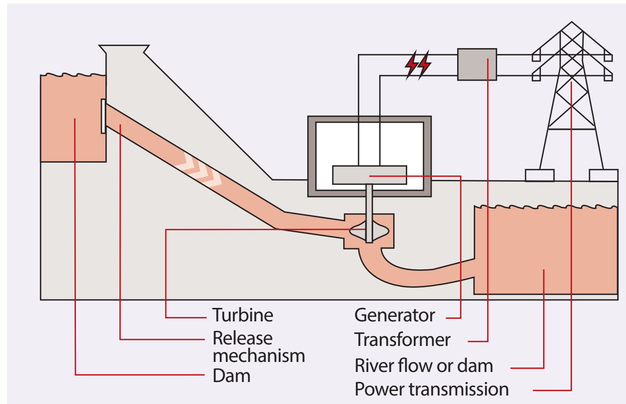
Prevailing conditions in the electricity market affect incentives for hydrogeneration. Subject to environmental water release obligations, hydroelectric generators tend to reduce their output when electricity prices are low and run more heavily when prices are high. Incentives under the Renewable Energy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

Figure 2.11
Gas powered generation



Source: AER; AEMO.

Figure 2.12
Hydroelectric generation



Hydroelectric generators accounted for 14.3 per cent of capacity in the NEM in 2017–18, and supplied 7.4 per cent of electricity generated. Tasmania is the region most reliant on hydrogeneration, with 82 per cent of its 2017–18 grid generation coming from that source. Snowy Hydro is a major generator in the NSW and Victoria regions of the NEM. Queensland also has some hydrogeneration (figure 2.6).

5 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.

6 AEMO, *Quarterly Energy Dynamics*, Q1 2018, p. 9.

7 AEMO in 2018 forecast gas demand for gas powered generation of 88 PJ in 2019. In 2017 it forecast gas demand for gas powered generation of 176 PJ in 2018. AEMO, *Gas statement of opportunities*, June 2018, p. 15.

Hydrogeneration levels in recent years have varied due to weather conditions, market incentives to generate, and subsidy arrangements under the RET scheme. Hydrogeneration tracked higher in 2018— second quarter output set a new record for that quarter and was the fifth highest output for any quarter since the NEM began.[8]

Tasmania's hydrogeneration output in 2017–18 was 10 per cent higher than a year earlier, in part due to a two month Basslink interconnector outage that suspended imports and required the state to be self-sufficient in generation.

2.2.3 Wind generation

Wind turbines directly convert the kinetic energy of the 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 2.13). Wind turbines are typically designed to operate to wind speeds up to 90 km per hour. They shut down automatically in high winds until wind speeds return within the turbine's operations range.

Renewable generation, including wind, have filled much of the supply gap left by thermal plant closures (figure 2.14). Wind generation has risen under the RET scheme, which subsidises renewable generation (box 2.3).

Wind generators accounted for 9.1 per cent of the NEM's capacity and generated 6.3 per cent of grid supplied electricity in 2017–18. Since 2017 an additional 1800 MW of wind capacity was added to the NEM (around 60 per cent of all investment over this period). Overall, wind generation rose by 20 per cent in 2017–18.

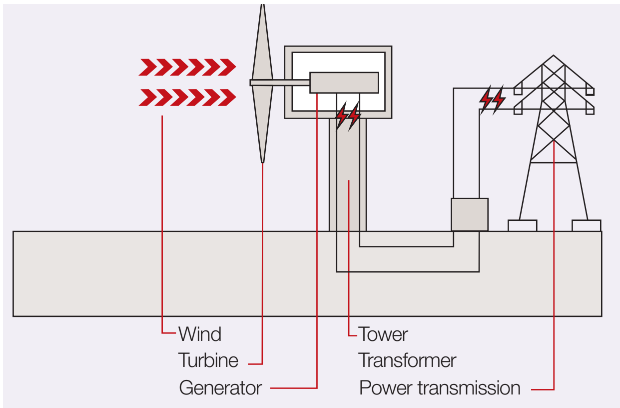
Its penetration is especially strong in South Australia, where it represented 34 per cent of registered capacity and met 40 per cent of the state's electricity requirements in 2017–18. More recently the focus of new wind investment has shifted to NSW and Victoria, with those regions accounting for close to 70 per cent of capacity installed or committed since 2017.

Weather conditions affect wind generation levels. Favourable conditions on 7 July 2018 resulted in record levels of wind output, peaking at 3843 MW. On that day, wind generation accounted for almost 16 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 19 500 MW. Thirteen wind projects, comprising nearly 2500 MW of capacity, are expected to be commissioned by June 2020 (table 2.6).

8 AEMO, *Quarterly Energy Dynamics,* Q1 2018, p. 8.

Figure 2.13
Wind powered generation



2.2.4 Solar generation

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 16 million terawatt hours of solar radiation per year.[9] Most solar investment to date has been in photovoltaic (PV) systems that use layers of semi conducting material to convert sunlight into electricity (figure 2.15).

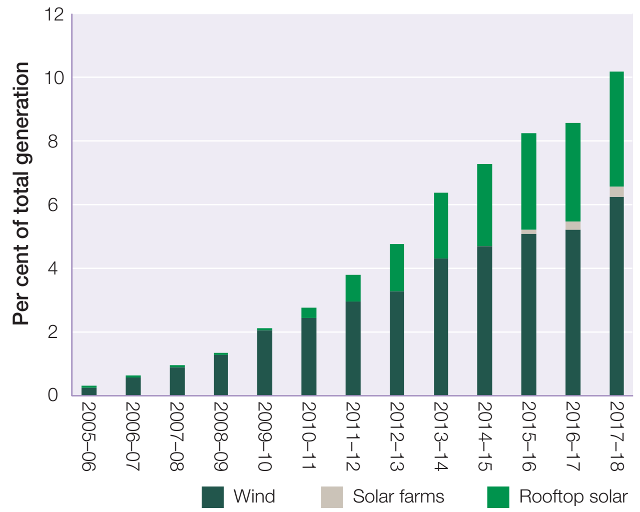
Despite eligibility under the RET scheme, investment in large scale solar farms has been slow to develop in Australia. Commercial solar farms met only 0.3 per cent of the NEM's electricity requirements in 2017–18. But the uptake of rooftop solar PV installations on residential and business premises has been more rapid. These installations met 3.4 per cent of total electricity generation in 2017–18.

Commercial solar farms

Large scale solar generation accounts for less than 1 per cent of total NEM generation. AGL was an early mover, commissioning the Nyngan and Broken Hill solar farms in 2015. The industry continues to grow, supported by funding from the Australian Renewable Energy Agency (ARENA) and the Clean Energy Finance Corporation. At November 2018 large scale solar accounted for around 1850 MW of installed capacity. Sixteen solar farms were commissioned in 2017 and 2018 (totalling 1230 MW), and a further 22 projects (2040 MW) across the NEM were expected to be commissioned by the end of 2019–20.

9 Geoscience Australia, *Solar Energy*, available at: www.ga.gov.au/scientific-topics/energy/resources/other-renewable-energy-resources/solar-energy.

Figure 2.14
Wind and solar generation share of total generation



Note: Rooftop solar output estimates derived from CER data on installed capacity, and AEMO system output assumptions.

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

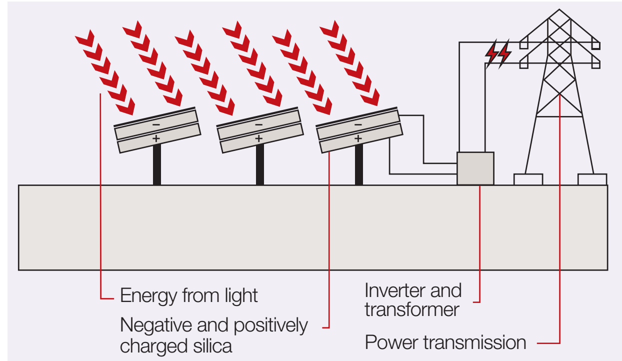
While NSW was the initial focus for solar plant development, the majority of new capacity will be located in Queensland. The largest operating plant at October 2018 is Coleambally solar farm in NSW (180 MW).

Commercial solar farms in Australia produce electricity using arrays of *PV panels*. The conversion of sunlight into electricity takes place in cells of specially fabricated semiconductor crystals. *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.

No solar thermal plant were operating in the NEM in 2018, but two facilities are proposed in South Australia. Construction of the 150 MW Aurora thermal plant was scheduled to begin in 2018, with commissioning expected in 2020 (although the plant was not listed as committed by AEMO at November 2018).[10] Up to 10 hours of storage capacity will enable it to supply dispatchable energy into the grid at any time, including at night.[11] A smaller 60 MW plant has been proposed for Port Augusta, with expected commissioning in 2021.

10 Aurora Solar, *Aurora Solar Energy Project Update,* May 2018.
11 Clean Energy Council, *Clean Energy Australia Report*, 2018, p. 51.

Figure 2.15
Solar photovoltaic power plant



Rooftop solar PV generation

While large scale solar generation has been slow to develop in Australia, consumers are more actively managing their energy supply and consumption by installing rooftop solar PV panels.

Few solar PV systems were installed before 2010, but they account for over 30 per cent of renewable capacity added since that date. In 2018 solar PV systems were meeting 3.4 per cent of the NEM's electricity requirements. Its contribution is highest in South Australia, where it met over 8 per cent of electricity requirements. In South Australia and Queensland, over 30 per cent of households have installed PV systems.[12]

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.

At October 2018 Australians had installed nearly two million solar PV rooftop systems.[13] In the NEM, the total installed capacity of these systems reached 6.6 gigawatt in October 2018, equivalent to 11 per cent of the NEM's total generation capacity.

Australia's 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 the Small-scale Renewable Energy Scheme and premium feed-in tariffs—strengthened incentives to install these systems.

12 AEMO, *2018 electricity statement of opportunities,* August 2018, p. 27.
13 Clean Energy Regulator, *Postcode data for small scale installations*, Small generation units—solar, available at: www.cleanenergyregulator.gov.au/RET/Forms-and-resources/Postcode-data-for-small-scale-installations.

New installations of solar PV systems declined from around 21 000 systems per month in 2011–12 to 13 000 systems per month in 2017–18. But the rate at which capacity is added is rising—1 100 000 MW of solar PV capacity was installed in 2017–18 compared with the previous high of 880 000 MW in 2012–13.

Lower installation costs and uptake of solar PV systems by commercial businesses have seen a shift towards larger systems (figure 1.21 in chapter 1). In the year to 30 June 2018, for example, solar PV installations grew by almost 60 per cent in the business sector, compared with 20 per cent in the residential sector.[14] The average size of systems installed in 2017 more than doubled that in 2011, rising from 2.5 kilowatts (kW) to 5.5 kW.

The uptake of solar PV continues to shift maximum grid demand to later in the day, when the contribution of solar PV is declining. Within the next decade, maximum grid demand in most regions may become so late in the day that adding more PV installations will not materially reduce it further (unless supported by storage).

2.2.5 Storage

Until recently, storing electricity was not commercially viable, but emerging technologies are making storage increasingly attractive. The uptake of battery storage and electric vehicles continues to gather momentum internationally, with declining battery costs and advances in the storage capacity of batteries. The growth in intermittent generation creates business opportunities for storage to offer fast response system security services when solar and wind generation fluctuate.

For smaller customers, storage offers opportunities to store surplus energy from solar PV systems and draw on it when needed, reducing their grid demand. The wider use of cost reflective tariffs may make storage more attractive, by creating incentives to charge batteries during low cost periods and use stored power when prices are high.

Australian households already show significant interest in and awareness of batteries. Nearly three quarters of customers with solar PV systems are interested in using batteries.[15] The Clean Energy Council cited estimates that Australians had installed 28 000 battery systems at January 2018, up from 8000 systems a year earlier. [16] The Clean Energy Regulator's estimates are more conservative at 11 500 battery units installed by November 2018.[17]

On a larger scale, South Australia in December 2017 commissioned the world's largest lithium ion battery at the Hornsdale wind farm (box 2.4). As well as acting operating in the electricity market, the battery provides stability services to the grid.[18]

Other battery projects have since been announced, including at Gannawarra (25 MW) and Ballarat (30 MW) in Victoria. The projects aim to complement and 'firm' solar and wind farm generation.

Aggregation of household battery systems to provide grid scale services is also being explored. Tesla, with support from the South Australian Government, intends to trial a virtual power plant of solar PV and battery systems on 1100 properties to enhance grid security and lower demand. If successful, the trial will be expanded to 50 000 households.[19] ARENA was also supporting trials in South Australia by AGL and Simply Energy of 'virtual power plants' that aggregate the output of household solar and storage systems.

Pumped hydroelectricity

Large scale storage is being explored 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). But advances in technology and the rise of intermittent generation are providing new opportunities for this form of storage to be deployed at a larger scale. In particular, pumped hydroelectricity forms the basis of the proposed 'Snowy 2.0' (2000 MW) and 'Battery of the Nation' (2500 MW) projects in NSW and Tasmania (section 2.7.1).

14 AEMO, *2018 electricity statement of opportunities,* August 2018, p. 5.
15 Energy Consumers Australia, *Energy Consumer Sentiment Survey,* June 2018, p. 36.
16 Clean Energy Council, *Clean Energy Australia Report*, 2018, p. 34.

17 Clean Energy Regulator, *Postcode data for small scale installations*, Solar PV systems with concurrent battery storage capacity by year and state/territory, available at: www.cleanenergyregulator.gov.au/RET/Forms-and-resources/Postcode-data-for-small-scale-installations.
18 AEMO, *Initial operation of the Hornsdale Power Reserve battery energy storage system*, April 2018, p. 4.
19 Government of South Australia, South Australia's Virtual Power Plant: www.virtualpowerplant.sa.gov.au/virtual-power-plant.

Box 2.3 Carbon emissions policies and the electricity sector

Australia has international commitments to reduce its carbon emissions by 26–28 per cent below 2005 levels by 2030. This effort builds on an earlier target of reducing emissions by 5 per cent below 2000 levels by 2020. There is no specific target for the electricity sector.

Australia's carbon emissions have risen continuously since 2015, but the electricity sector's contribution has lowered since the closure of coal fired generators in South Australia (in 2016) and Victoria (in 2017).

Despite this, the electricity sector remains the largest contributor to Australia's carbon emissions, accounting for 35 per cent of all emissions (figure 2.16). Victoria's brown coal plants are the most emissions intensive power stations operating in Australia, followed by black coal plant and gas powered generation. Combined cycle gas plants are less emissions-intensive than open cycle plants. Wind, hydroelectric and solar photovoltaic (PV) power stations generate negligible emissions.

Australia's policy settings to reduce carbon emissions in the electricity sector have changed direction many times. Policies included the Renewable Energy Target (RET) scheme (launched in 2001 and amended several times), carbon pricing (introduced in 2012 but abolished two years later), funding for schemes that abate carbon emissions (launched in 2014 but with little engagement from the electricity sector) and a proposal to integrate emissions and reliability targets through the National Energy Guarantee (NEG) (abandoned in September 2018).

Alongside these schemes, state and territory governments offered subsidies for rooftop solar PV generation, and in some regions set renewable energy targets that are more ambitious than the national scheme.

Renewable Energy Target

The RET scheme requires electricity retailers to source a proportion of their energy from renewable sources developed since 1997. An expert panel in 2014 found the RET scheme had successfully led to the abatement of more than 20 million tonnes of carbon emissions.[a]

The scheme applies different incentives for large scale renewable supply (such as wind and solar farms) and small scale systems (such as solar water heaters and rooftop solar PV systems installed by households and small businesses). It requires energy retailers to buy renewable energy certificates created for electricity generated by accredited power stations, or from the installation of eligible solar hot water or small generation units. The revenue from these certificates is in addition to earnings through the wholesale market.

Amendments to the RET scheme in June 2015 reduced the 2020 target for energy from large scale renewable projects from 41 000 gigawatt hours (GWh) to 33 000 GWh. On current estimates, this target would result in 23.5 per cent of Australia's electricity generation in 2020 being sourced from renewables. Each year the renewable target rises towards the 2020 target; the annual target for 2018 is just over 28 600 GWh. The Australian Government's policy in late 2018 was to not increase the target beyond the 2020 requirement of 33 000 GWh, and to not extend or replace the target after it expires in 2030.[b]

RET certificate prices fluctuate depending on the availability of RET certificates relative to the prevailing target. Large scale generation certificates (LGCs) traded at around $40 in 2011, eased to $22 in June 2014 when the scheme's future was uncertain, then recovered sharply from late 2014 when it became clear that new renewable investment was not keeping pace with the rising target, creating a shortfall in available LGCs.[c] Prices neared $90 in January 2017 close to the effective penalty that a business must pay for failing to surrender LGCs. Prices remained around this level throughout 2017, before easing over 2018 to around $65 in November.

In February 2018 the Clean Energy Regulator announced it was confident there will be sufficient renewable generation by 2020 to meet the RET.[d] This outcome would result in an oversupply of LGCs through to the end of the scheme in 2030. At November 2018, forward contracts for LGCs from 2020 were trading below $30, reflecting this expectation.

Prices for certificates from small scale projects have been steady at around $40 since 2013. The design of the small scale scheme means prices are largely tied to the accuracy of forecasts on qualifying system installations.

Carbon pricing

A carbon pricing scheme operated in Australia from 1 July 2012 to 1 July 2014. The scheme placed a fixed price on carbon, starting at $23 per tonne of carbon dioxide equivalent emitted. The government intended to replace the fixed price with an emissions trading scheme from July 2014, under which the market would determine a carbon price.

Over the two years of carbon pricing, output from brown coal fired generators declined by 16 per cent (with plant use dropping from 85 per cent to 75 per cent), and output from black coal generators fell by 9 per cent. Coal generation's share of NEM output fell to an historical low of 73.6 per cent in 2013–14, while gas powered, wind and hydroelectric generation shares rose significantly.

Overall, these changes contributed to the emissions intensity of NEM generation falling by 4.7 per cent over the two years that carbon pricing was in place. This drop in emissions intensity, combined with lower NEM demand, contributed to a 10.3 per cent fall in total emissions from electricity generation over those two years.

Emissions Reduction Fund

In 2014 the Australian Government replaced carbon pricing with the Emissions Reduction Fund (ERF), under which the government pays for emissions abatement through auctions run by the Clean Energy Regulator. Seven auctions were held to July 2018, spending $2.3 billion to abate 192 million tonnes of carbon emissions. The reverse auction scheme effectively priced carbon at an average price of $11.97 per tonne of abatement. Purchases have steadily declined over recent auctions, from 50 million tonnes of abatement in the third auction, to under eight million tonnes in the sixth and seventh auctions.[e]

Many ERF projects involve growing native forests or plantations, otherwise known as carbon farming. By the sixth auction in 2018, 12 projects had received funding under the ERF that involved new electricity production or upgrades to existing plant. The total abatement committed under contract for these projects is 3.56 million tonnes CO_2-e. Most of the projects capture and combust waste methane gas from coalmines or landfill for use in electricity generation.[f] The electricity projects represented less than 2 per cent of carbon abatements funded under the scheme.

A safeguard mechanism aims to ensure the reductions purchased through the fund are not offset by increases in emissions elsewhere in the economy. The mechanism requires covered facilities to ensure their net emissions remain below an historical baseline. It currently covers 203 facilities with combined annual emissions of 131.3 million tonnes.[g] In late 2018, less than 10 per cent of the $2.55 billion allocated to the fund remained.[h]

National Energy Guarantee

The Independent Review into the Future Security of the National Electricity Market (the Finkel review) in June 2017 found ongoing uncertainty about Australia's carbon emissions policies had detrimentally affected the electricity sector, particularly relating to investor certainty.[i] The Australian Government rejected the review's recommendation for a clean energy target. Instead, it proposed addressing the market's concerns around reliability and carbon emissions through an integrated policy addressing both issues.

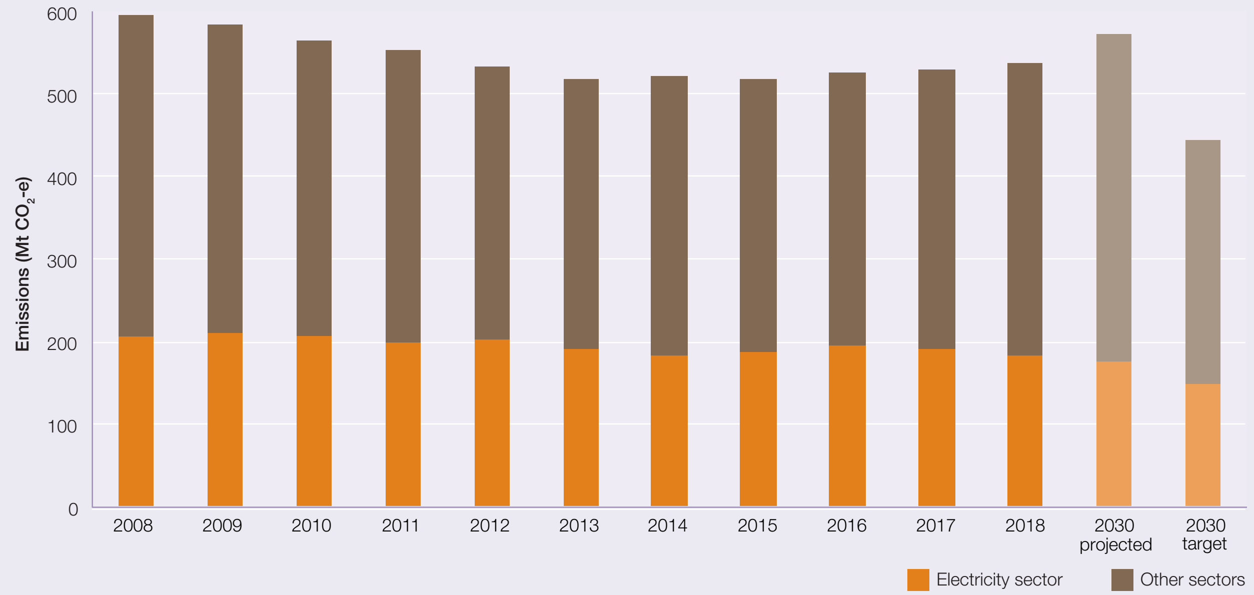
The newly created Energy Security Board developed the National Energy Guarantee (NEG), which comprised:

- a reliability guarantee requiring retailers to produce or contract for sufficient dispatchable[j] energy to meet the maximum energy needs of their customers if the Australian Energy Market Operator (AEMO) identifies (and the AER verifies) a risk that the reliability standard will not be met. AEMO could intervene to ensure sufficient dispatchable energy is available, should the market fail to achieve this. The guarantee included measures to increase liquidity in electricity futures (contract) markets.
- an emissions guarantee requiring retailers to produce or contract for electricity in ways that would meet an average emission level over a specified period. The emissions level would be determined by government and enforced by the Australian Energy Regulator.

The twin guarantees aimed to encourage investment in low emissions technologies while ensuring sufficient dispatchable energy is available to ensure the electricity system remains reliable. The scheme's implementation required all national electricity market jurisdictions to ratify the policy.

Progress on the NEG stalled in August 2018 when the Australian Government removed the policy's emissions component. The government abandoned the NEG as a package, but retained the reliability component as part of a new energy policy.

Figure 2.16
Australia's carbon emissions



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

Note: Electricity sector emissions exclude stationary energy, transport and fugitive emissions. The 2030 target is based on Australia's Paris commitment of a 26 per cent reduction on 2005 emissions levels, and assumes a proportional contribution by the electricity sector. Projected 2030 emissions are as forecast by the Department of Energy and Environment in December 2017 in the absence of policy intervention.

Source: Department of the Environment and Energy, *Quarterly Update of Australia's National Greenhouse Gas Inventory*, December 2017.

a Climate Change Authority, *Renewable Energy Target Review—Report,* December 2014, p. 18.
b Commonwealth, *Parliamentary Debates,* House of Representatives, 18 September 2018, 9325 (Angus Taylor, Minister for Energy).
c A certificate represents 1 MWh of output from qualifying renewable generators (or deemed output from small scale generation).
d Clean Energy Regulator, *Surplus of large-scale generation certificates after final surrender*, media release, 22 February 2018.
e Auction results published by the Clean Energy Regulator: www.cleanenergyregulator.gov.au/ERF/Auctions-results.
f Excludes energy efficiency projects that mostly involve upgrades to devices that consume electricity. Projects do not necessarily connect to the NEM. Clean Energy Regulator, Emissions Reduction Fund project map, available at: www.cleanenergyregulator.gov.au/maps/Pages/erf-projects/index.html.
g Clean Energy Regulator, *2016–17 Safeguard facility reported emissions,* five July 2018.
h Clean Energy Regulator, *Auction June 2018*, 31 October 2018, available at: www.cleanenergyregulator.gov.au/ERF/Auctions-results/june-2018
h 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.
j Dispatchable capacity is capable of being supplied when required. It includes coal fired, gas powered and hydroelectric capacity, and intermittent generation such as wind or solar that is supported by battery storage.

2.3 Trade between NEM regions

Transmission interconnectors (figure 3.1 and table 3.1 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 entire market. It also allows each NEM region to access the cheapest available electricity in the market.

Queensland is a net electricity exporter, given its surplus capacity and (traditionally) low fuel prices. Higher fuel costs for gas and black coal reduced Queensland exports in 2015–16 and 2016–17, but improving cost conditions and the loss of brown coal capacity in other regions led to a rise in exports in 2017–18 (figure 2.17).

Victoria's abundant supplies of low priced brown coal generation also traditionally made it a net exporter of electricity. But Hazelwood's closure eliminated Victoria's trade surplus in 2017–18.

NSW has relatively high fuel costs, typically making it a net importer of electricity. Its trading position tends to be relatively stable, although improved black coal availability for its generation fleet in 2017–18, combined with less availability of cheap brown coal generation in Victoria, reduced its imports.

South Australia was traditionally an electricity importer, due to a lack of low cost local supply. Coal plant withdrawals increased the region's trade dependency, making it proportionally the NEM's highest importer in 2016–17. But surging local wind generation, combined with reduced availability of brown coal generation in Victoria, made it more self-sufficient in 2017–18, resulting in a trade surplus.

Tasmania's trade position varies, depending on local and NEM wide conditions. It 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. By late 2015 Tasmania was importing up to 40 per cent of its energy needs, despite outages on the Basslink interconnector to Victoria.

With Basslink back in service and hydroelectric storage returning to normal levels, Tasmania returned to a net exporting position in 2016–17. Rising Victorian wholesale prices further reduced Tasmania's trade dependence, and in 2017–18, it again became a net exporter to the mainland.

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 rates of price alignment, with the duration of network congestion on interconnectors linking the regions fairly stable. Price alignment between Victoria and South Australia has been less regular, with congestion frequency on the Victoria–South Australia interconnectors more than doubling 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 (which increased its capacity) 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 2017–18, up from 60 per cent in the previous year (figure 2.18).

Interpreting alignment rates as an overall 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.[20]

2.4 Generation businesses

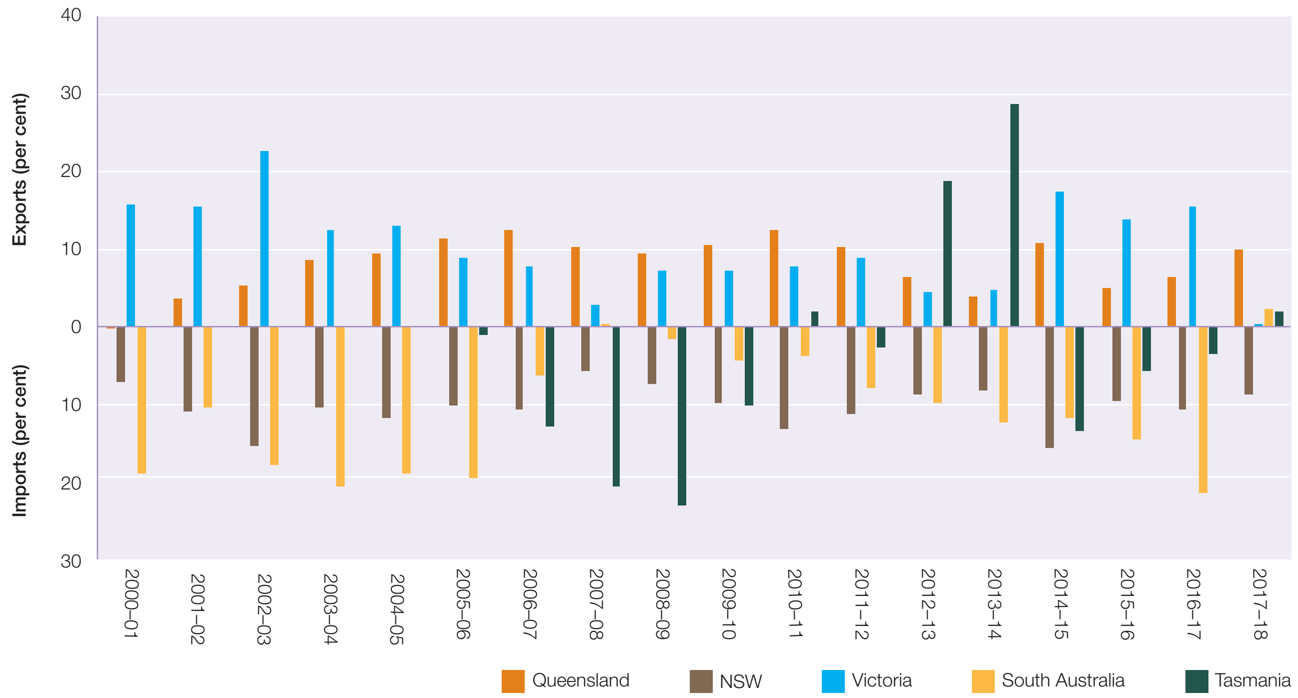
Around 150 registered generators (comprising 240 generation units) sell electricity into the NEM spot market. Table 2.3 lists the major generators, plant technologies and ownership arrangements, and figure 2.19 maps their locations.

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 between regions. Government owned corporations own or control the majority of capacity in Queensland and Tasmania.

Section 2.8 examines the market structure more closely, and section 2.11 considers the market's competitiveness.

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

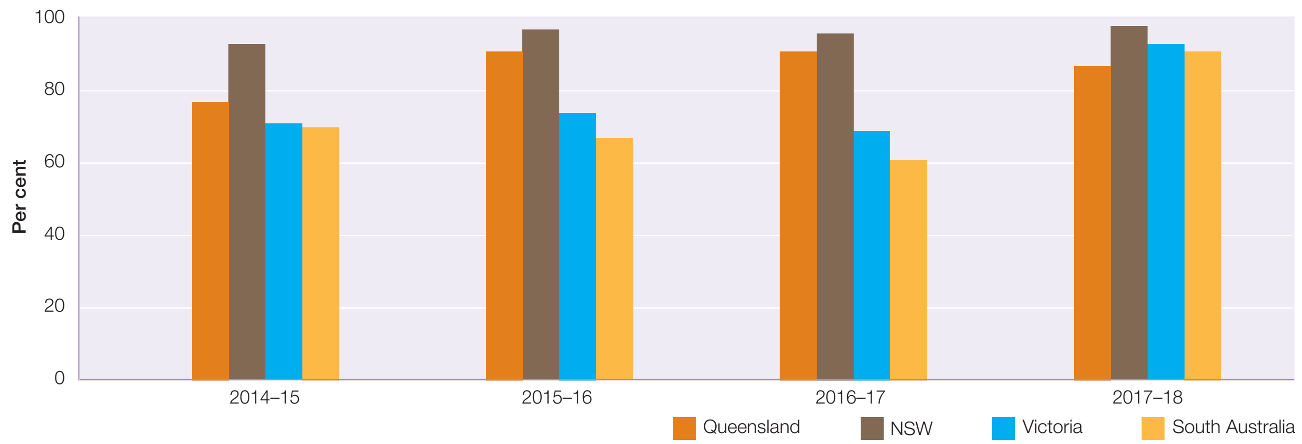
Figure 2.17
Interregional trade as a percentage of demand



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

Source: AER; AEMO.

Figure 2.18
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 at least one neighbouring region, accounting for transmission losses.

Source: AEMO; AER.

CHAPTER 2 NATIONAL ELECTRICITY MARKET

Table 2.3 **Generation plant in the NEM, 2018**

TRADING RIGHTS	CAPACITY (MW)	POWER STATION (MW)	OWNER
Queensland	13 261		
Stanwell Corporation	3 839	Stanwell (1440); Tarong (1400); Tarong North (443); Barron Gorge (60); Kareeya (86); Mackay (34); Swanbank (350)	Stanwell Corporation (Qld Government)
CS Energy	3 583	Callide B (620); Kogan Creek (713); Wivenhoe (570)	CS Energy (Qld Government)
		Gladstone (1680)	Rio Tinto 42%; NRG Energy 38%; others 20%
Origin Energy	1 423	Darling Downs (580); Mt Stuart (400); Roma (54)	Origin Energy
		Daydream (150)	Edify Energy
		Darling Downs (109)	APA Group
		Clare (100)	Fotowatio Renewable Ventures
		Daandine (30)	APT Petroleum Pipeline Holdings
CS Energy 50%; InterGen 50%	840	Callide C (840)	CS Energy (Qld Government) 50%; InterGen 50%
InterGen	612	Millmerran (612)	InterGen/China Huaneng Group 59%; KIAMCO/Daelim 35%; others 6%
Alinta Energy	534	Braemar 1 (491); Collinsville (43)	Alinta Energy (Chow Tai Fook Enterprises)
Arrow Energy	495	Braemar 2 (495)	Arrow Energy (Shell 50%; PetroChina 50%)
ERM Power	340	Oakey (282); Hamilton (58)	ERM Group; Wirsol 95%; Edify Energy 5%
RTA Yarwun	180	Yarwun (180)	Rio Tinto Alcan
Arrow Energy 50%; AGL Energy 50%	155	Townsville (155)	RATCH Australia (Ratchaburi Electricity Generation 80%; Ferrovial 20%)
EnergyAustralia	128	Ross River (128)	Pallisade Investment Partners
Sun Metals Corporation	124	Sun Metals (124)	Sun Metals Corporation
Wilmar International	118	*Pioneer Sugar Mill (68);Invicta Sugar Mill (50)*	Wilmar International
AGL Energy	109	*Moranbah North(64); German Creek(45)*	Energy Developments (DUET Group)
Shell	90	Condamine (90)	Queensland Gas Company
Telstra	72	Emerald (72)	Lighthouse Infrastructure Management Limited
Queensland Government	50	Kidston solar (50)	Genex Power Limited
Mackay Sugar	48	*Racecourse Mill(48)*	Mackay Sugar
Ergon Energy	34	Barcaldine (34)	Ergon Energy (Qld Government)
Other non-scheduled plants of < 30 MW	487	*Misc.*	
NSW	16 975		
AGL Energy	4 703	Bayswater (2520); Liddell (1800); Hunter Valley (30)	AGL Energy
		Broken Hill (53); Nyngan (102); Silverton (198)	Powering Australian Renewables Fund (QIC 80%; AGL Energy 20%)
Origin Energy	3 775	Eraring (2720); Shoalhaven (240); Uranquinty (640); *Eraring (42)*	Origin Energy
		Moree (56)	Fotowatio Renewable Ventures
		Gunning (47)	Acciona Energy
		Cullerin Range (30)	Energy Developments (DUET Group)
Snowy Hydro	3 178	Tumut 3 (1800); Colongra (648); Upper Tumut (616); Blowering (80); Guthega (34)	Snowy Hydro (Australian Government)
EnergyAustralia	2 112	Mt Piper (1300); Tallawarra (378)	EnergyAustralia (CLP Group)
		Gullen Range (166); Gullen Range (10)	Beijing Jingneng Clean Energy 75%; Goldwind Capital 25%
		Taralga (107)	Pacific Hydro (State Power Investment Corporation)
		Boco Rock (104)	Electricity Generating Public Company
		Manildra (47)	First Solar
Delta Electricity	1 320	Vales Point (1320)	Sunset Power International (Waratah Power 50%, Vales Point Invesments 50%)
Infigen Energy	302	*Capital (141)*; Woodlawn (48); Bodangora (113)	Infigen Energy
White Rock Wind Farm Pty Ltd	193	White Rock (173); White Rock (20)	CECEPWP 75%; Goldwind 25%
CWP/Partners Group 67%; ACT Government 37%	187	Sapphire Wind Farm (187)	CWP Renewables and Partners Group
Neoen	180	Coleambally (150), Griffith (30)	Neoen
Visy Power Generation	109	Smithfield Energy Facility (109)	Visy Power Generation
Stanwell Corporation	97	*Appin (56); Tower (41)*	Energy Developments (DUET Group)
ACT Government	91	Crookwell 2 (91)	ACT Government
Capital Dynamics	68	*Broadwater/Condong (68)*	Cape Byron Power
Engie	51	Parkes Solar Farm (51)	Neoen
Essential Energy	50	*Broken Hill (50)*	Essential Energy (NSW Government)
Trustpower	29	Hume (29)	Trustpower (Infratil 51%, Tauranga Energy Consumer Trust 27%, other 22%)
Non-scheduled plant < 30 MW	530	*Misc.*	
Victoria	11 227		
AGL Energy	3 379	Loy Yang A (2144); West Kiewa (68); Somerton (140); Eildon (100); Dartmouth (165); McKay/Bogong (300)	AGL Energy
		Macarthur (420)	Morrison & Co. 50%; Malakoff Corporation Berhad 50%
		Oaklands Hill (42)	Challenger Life (Challenger)
EnergyAustralia	2 405	Yallourn (1420)	EnergyAustralia (CLP Group)
		Jeeralang A (189) and B (216); Newport (475)	Ecogen Energy (IFM Investors)
		Gannawarra (50)	Wirsol 95%; Edify Energy 5%
		Ballarat Energy Storage System (30); Gannawarra Energy Storage System (25)	EnergyAustralia (CLP Group)
Snowy Hydro	2 080	Murray (1510); Laverton North (300); Valley Power (270)	Snowy Hydro (Australian Government)
Alinta Energy	1 175	Loy Yang B (980); Bannerton (88)	Alinta Energy (Chow Tai Fook Enterprises)
		Bald Hills (107)	Energy Infrastructure Trust (Infrastructure Capital Group)
Origin Energy	563	Mortlake (518)	Origin Energy
		Longford (45)	BHP 50%; Exxon Mobil 50%
Acciona Energy	324	*Waubra (192)*; Mount Gellibrand (132)	Acciona Energy

TRADING RIGHTS	CAPACITY (MW)	POWER STATION (MW)	OWNER
Pacific Hydro	235	*Yambuk (30); Challicum Hills (53); Portland (152)*	Pacific Hydro (State Power Investment Corporation)
ACT Government 33%; Ararat Wind Farm 67%	195	Ararat (195)	RES; GE; Partners Group; OPTrust
Meridian Energy	131	Mount Mercer (131)	Meridian Energy
Carlton & United Breweries	90	Karadoc (90)	Carlton & United Breweries
Simec Zen Energy	89	Wemen (89)	Simec Zen Energy
Hydro Tasmania	78	Bairnsdale (78)	Alinta Energy (Chow Tai Fook Enterprises)
Tilt Renewables 50%; Meridian Energy 50%	54	Salt Creek (54)	Tilt Renewables
John Laing Group 72%; Windlab Australia 25%; Local community 3%	31	Kiata (31)	John Laing Group 72%; Windlab Australia 25%; Local community 3%
Trustpower	29	Hume (29)	Trustpower (Infratil 51%, Tauranga Energy Consumer Trust 27%, other 22%)
Non-scheduled plant < 30 MW	369	*Misc.*	
South Australia	5 061		
AGL Energy	1 599	Torrens Island (1260)	AGL Energy
		Hallett 2 (44); *Wattle Point (91)*	Energy Infrastructure Trust (Infrastructure Capital Group)
		North Brown Hill (82)	Energy Infrastructure Trust (Infrastructure Capital Group) 40%; Osaka Gas 40%; APA Group 20%
		Hallett 1 (59)	Palisade Investment Partners
		The Bluff (33)	Eurus Energy (Toyota Tsusho 60%, Tokyo Electric Power Company 40%)
		ESCRI Dalrymple (30MW)	ElectraNet
Engie	913	Pelican Point (458); *Canunda (46)*; Dry Creek (112); Mintaro (68); Port Lincoln (56); Snuggery (54)	Engie 72%; Mitsui 28%
		Willogoleche (119)	
Origin Energy	908	Snowtown (99); Snowtown North (144); Snowtown South (126)	Tilt Renewables
		Quarantine (189); Ladbroke Grove (68)	Origin Energy
		Osborne (172)	ATCO 50%; Origin Energy 50%
		Bungala One (110)	Enel Green Power
ACT Government	309	Hornsdale (309)	Neoen 70%, John Laing 30%
EnergyAustralia	259	Hallet (193)	EnergyAustralia (CLP Group)
		Cathedral Rocks (66)	EnergyAustralia (CLP Group) 50%; Acciona Energy 50%
SA Government	215	Temporary Generation North (119); Temporary Generation South (96)	SA Government
Infigen Energy	198	Lake Bonney 2 (159) and 3 (39)	Infigen Energy
EnergyAustralia 50%; Hydro Tasmania 50%	131	Waterloo (131)	Palisade Investment Partners 74%; Northleaf Capital Partners 26%
Snowy Hydro	129	Port Stanvac (58); Angaston (50); Lonsdale (21)	Snowy Hydro (Australian Government)
SA Government 70%; Neoen 30%	100	HPRG1 (Hornsdale Power Reserve) (100)	Neoen
Essential Energy	81	*Lake Bonney 1 (81)*	Infigen Energy

TRADING RIGHTS	CAPACITY (MW)	POWER STATION (MW)	OWNER
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	57	*Misc.*	
Tasmania	2 723		
Hydro Tasmania	2 601	Gordon (371); Poatina (342); Bell Bay (105); Tamar Valley Peaking (58), others (1475)	Hydro Tasmania (Tas Government)
		Woolnorth(140); Musselroe (168)	Shenhua Clean Energy 75%; Hydro Tasmania 25%
Non-scheduled plant < 30 MW	122	*Misc.*	

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

Note: Capacity as published by AEMO for summer 2017–18, except for non-scheduled plant, where nameplate capacity is used.

Source: AEMO; AER; company announcements.

Figure 2.19
Generators in the national electricity market

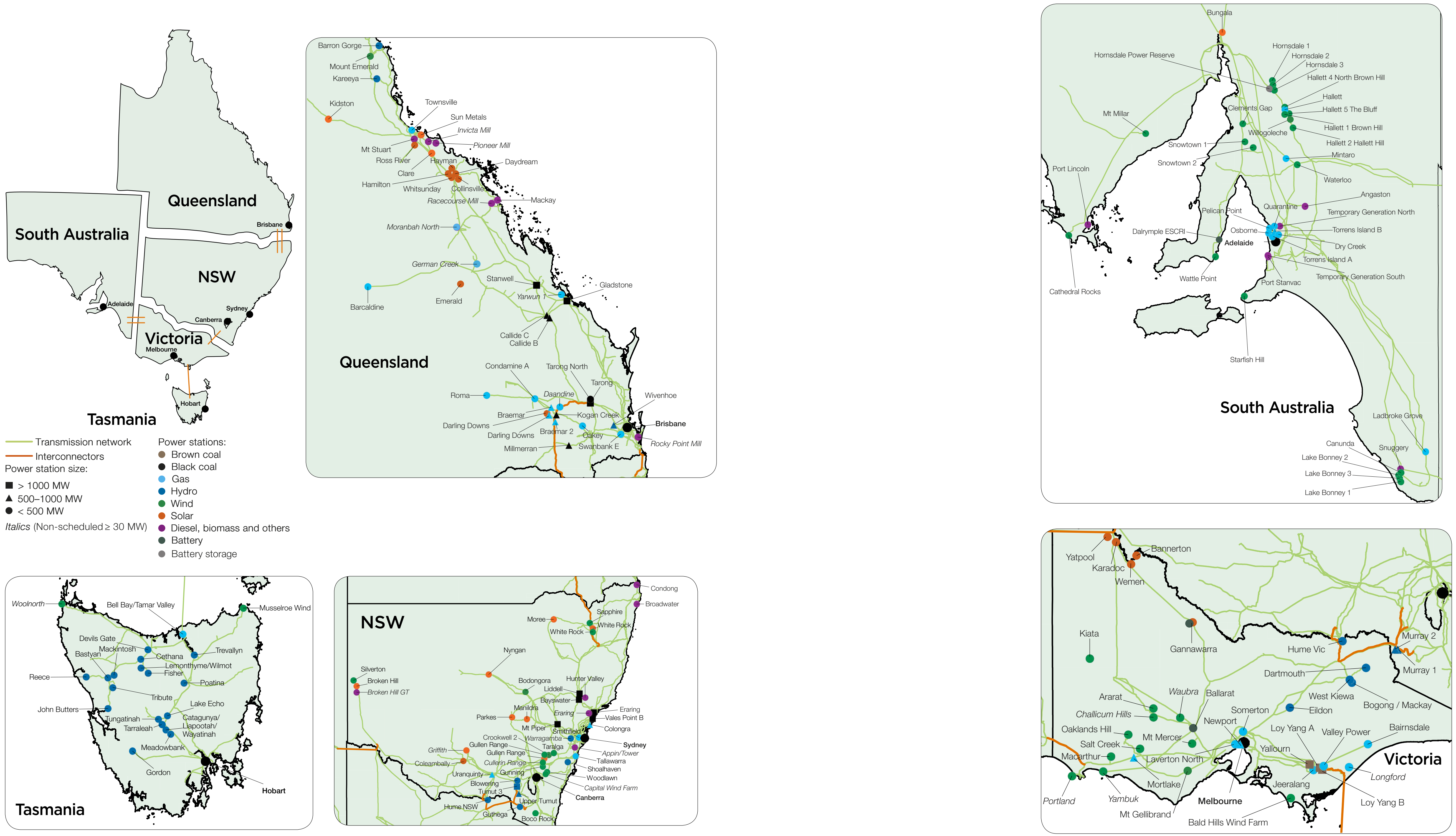


Table 2.4 Generation withdrawals since 2012–13

YEAR	POWER STATION	REGION	TECHNOLOGY	CAPACITY (MW)	STATUS
WITHDRAWN				4174	
2014–15	Wallerawang C	NSW	Coal	1000	Retired
2014–15	Morwell, Brix	Vic	Coal	190	Retired
2014–15	Redbank	NSW	Coal	144	Retired
2014–15	Callide A	NSW	Coal	30	Retired
2015–16	Northern	SA	Coal	530	Retired
2015–16	Playford B	SA	Coal	240	Retired
2015–16	Collinsville	Qld	Coal	190	Retired
2015–16	Anglesea	Vic	Coal	150	Retired
2015–16	Barcaldine	Qld	CCGT	20	Downgraded
2016–17	Hazelwood	Vic	Coal	1600	Retired
2016–17	Mt Piper	NSW	Coal	80	Downgraded
ANNOUNCED WITHDRAWAL				2547	
2021	Torrens Island A	SA	Gas	480	Mothballing of units progressively 2019–21
2021	Mackay	Qld	OCGT	34	Retirement
2022	Daandine	Qld	CCGT	33	Retirement
2022	Liddell	NSW	Coal	2000	Retirement

CCGT, combined cycle gas turbine; OCGT, open cycle gas turbine.

Note: Data at November 2018.

Source: AEMO, Generation information, 2 November 2018, available at: www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

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 2009–15. 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 and table 2.4).

Plant closures were mainly coal fired plant, following commercial decisions by owners to exit the market. The ageing plants had become increasingly unprofitable in part due to rising maintenance costs. The Wallerawang plant in NSW closed after 38 years of operation; the Northern and Playford plant in South Australia after 31 and 55 years of operation respectively; and the Hazelwood power station in Victoria after 53 years.

The plant closures significantly reduced capacity in the NEM and led to AEMO signalling a risk of summer power outages. But the private sector has been slow to respond with new plant investment.

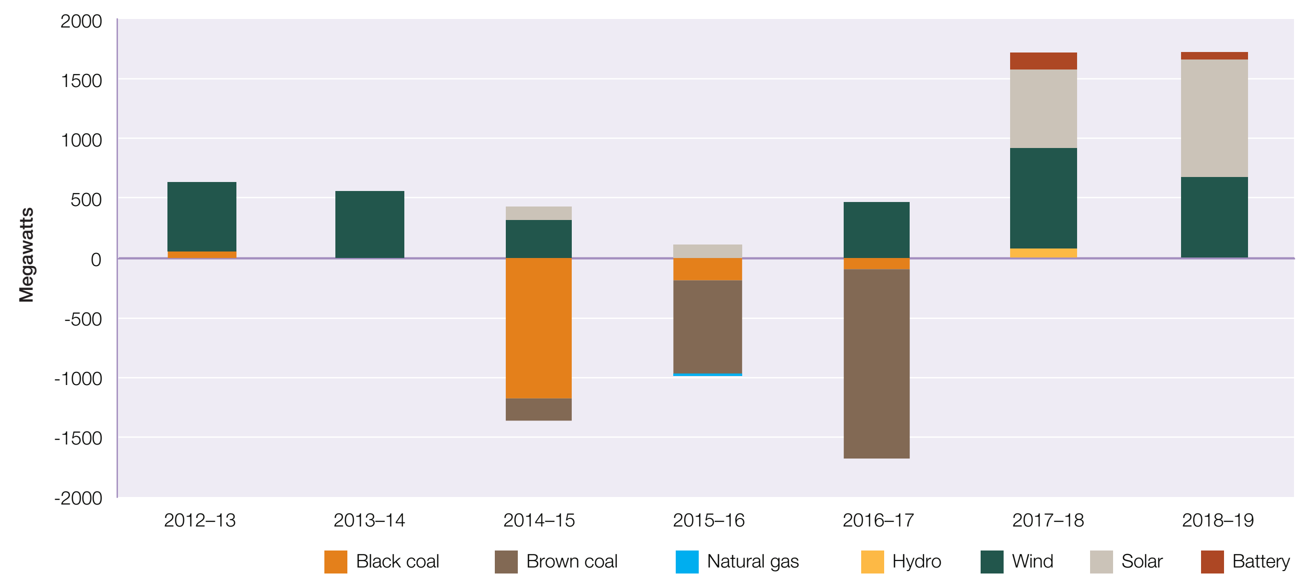
No material coal fired or gas powered generation has been added to the market since a 240 MW upgrade to the Eraring power station in NSW was completed in 2013. Investment in gas powered generation has been negligible, with a threefold rise in gas prices since 2014 making this plant less economically viable.[21] A reduction in the number of spot electricity prices above $300 per megawatt hour (MWh) also affected the revenue potential of gas peaking plant, because these plant rely on selling cap contracts to customers wishing to insure against high prices.[22]

The Independent Review into the Future Security of the National Electricity Market (the Finkel review) argued years

21 The economics depends on prevailing market prices for electricity. See section 2.11.

22 AER, *Wholesale electricity market performance report*, December 2018; AEMO, *Operational and market challenges to reliability and security in the NEM*, March 2018.

Figure 2.20
New generation investment and plant withdrawals



Note: 2018–19 data is to 31 October 2018 only. An additional 2076 MW of committed capacity (1178 MW of wind, 873 MW of solar, 24 MW of biomass and 2 MW of battery storage) is expected to be commissioned in 2018–19.

Source: AEMO, *Generation information,* 2 November 2018, available at: www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

of uncertainty and change in government policies on energy and carbon emissions have affected investment, making financers wary of backing energy assets when policy settings affecting them are volatile.[23]

Similarly, the AER noted participants identified a lack of energy policy stability and predictability as a barrier to entry for new generation.[24] The Australian Competition and Consumer Commission (ACCC) also noted a widespread view among market participants that the failure to implement consistent, enduring environmental policy in the electricity sector has caused significant investment uncertainty.[25]

Over 90 per cent of investment since 2012–13 has been in renewable (wind and solar) capacity, driven in part by subsidies available under the RET scheme and funding by ARENA and the Clean Energy Finance Corporation. Investment in renewables picked up strongly after an Australian Government review into the RET scheme in 2015 confirmed the scheme would continue until 2030.

Despite ongoing uncertainty, investment has gained pace since 2017 (table 2.5). Renewables continue to be the focus, with over 3500 MW of new wind, solar and battery capacity added to the NEM between January 2017 and October 2018. Another 2000 MW of capacity is committed from November 2018 to June 2019, with 6000 MW beyond 2018–19 (table 2.6).

Almost 50 000 MW of additional capacity has been proposed but not formally committed for development (figure 2.21). The bulk of the proposed projects are for solar (44 per cent) and wind (34 per cent) plant.

Against this additional capacity, further plant withdrawals are also likely. In 2022, AGL plans to retire its Liddell coal plant in NSW (1680 MW) to replace it with a mix of renewable gas generation batteries, and an upgrade to the Bayswater power station.[26]

Two gas plants are listed for retirement—AGL's Torrens Island A plant (480 MW) in South Australia (progressively from 2019–21), and the Mackay plant (34 MW) In Queensland (2021) and in Tasmania, the Tamar Valley plant (208 MW) was unavailable for much of 2018, although can be returned to service with less than three months' notice.[27]

23 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.

24 AER, *Wholesale electricity market performance report*, December 2018.

25 ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final Report*, June 2018, p. 100.

26 AGL, *NSW generation plan*, media release, December 2017.

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

Table 2.5 New generation investment in 2017 and 2018

OWNER	POWER STATION	TECHNOLOGY	CAPACITY (MW)	DATE COMMISSIONED
NSW			1040	
CECEPWP (75%), Goldwind (25%)	White Rock	Wind	173	July 2017
EnergyAustralia	Gullen Range	Solar	10	September 2017
CWP Renewables (63%), ACT Government (37%)	Sapphire	Wind	187	December 2017
Engie	Parkes	Solar	51	December 2017
AGL Energy	Silverton	Wind	198	February 2018
EnergyAustralia	Manildra	Solar	47	April 2018
Infigen	Bodangora	Wind	113	August 2018
CECEPWP (75%), Goldwind (25%)	White Rock	Solar	20	August 2018
ACT Government	Crookwell 2	Wind	91	August 2018
Neoen	Coleambally	Solar	150	September 2018
QUEENSLAND			1060	
Queensland Government	Kidston	Solar	49	November 2017
Origin Energy	Clare	Solar	100	February 2018
ERM Power	Hamilton	Solar	58	May 2018
Queensland Government	Whitsunday	Solar	58	May 2018
EnergyAustralia	Ross River	Solar	116	June 2018
Origin Energy	Darling Downs	Solar	109	June 2018
Sun Metals	Sun Metals	Solar	124	July 2018
Alinta Holdings	Collinsville	Solar	43	July 2018
Ergon Energy	Mount Emerald	Wind	181	August 2018
Telstra	Emerald	Solar	72	September 2018
Origin Energy	Daydream	Solar	150	October 2018
SOUTH AUSTRALIA			568	
ACT Government	Horsndale Stage 2	Wind	100	February 2017
ACT Government	Horsndale Stage 3	Wind	109	August 2017
South Australian Government (70%), Neoen International SAS (30%)	Hornsdale Power Reserve	Battery	100	November 2017
Origin Energy	Bungala One	Solar	110	May 2018
AGL Energy	Dalrymple North	Battery	30	June 2018
Engie	Willogoleche	Wind	119	July 2018
VICTORIA			832	
Ararat Wind Farm (67%), ACT Government (37%)	Ararat	Wind	240	June 2017
John Laing Group (72%), Windlab (25%), Kiata local community (3%)	Kiata	Wind	31	November 2017
EnergyAustralia	Gannawarra	Solar	50	March 2018
Powershop Australia	Salt Creek	Wind	54	May 2018
Acciona Energy	Mt Gellibrand	Wind	132	June 2018
Alinta Holdings	Bannerton	Solar	88	July 2018
Carlton & United Breweries	Karadoc	Solar	90	October 2018
EnergyAustralia	Ballarat	Battery	30	November 2018
EnergyAustralia	Gannawarra	Battery	29	November 2018
Simec Zen Energy	Wemen	Solar	88	November 2018

Table 2.6 Committed investment projects in the NEM

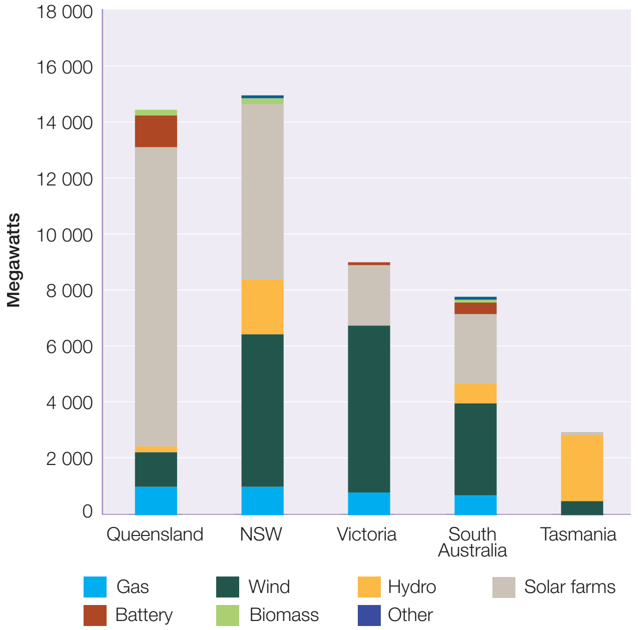
OWNER	POWER STATION	TECHNOLOGY	CAPACITY (MW)	PLANNED COMMISSIONING
NSW			787	
Innogy	Limondale 2	Solar	29	2018–19
FS NSW Project No 1 AT	Beryl	Solar	98	2019–20
CRWF Nominees	Crudine Ridge	Wind	135	2019–20
Elliott Nevertire Solar	Nevertire	Solar	105	2019–20
John Laing, Maoneng Group	Sunraysia	Solar	200	2019–20
Innogy	Limondale 1	Solar	220	2019–20
QUEENSLAND			1208	
Childers Solar	Childers	Solar	56	2018–19
Clermont Asset	Clermont	Solar	93	2018–19
PARF Company 6	Coopers Gap	Wind	350	2018–19
Pacific Hydro	Haughton	Solar	100	2018–19
Edify Energy	Hayman	Solar	50	2018–19
Windlab / Eurus	Kennedy Energy Park	Solar	15	2018–19
Windlab / Eurus	Kennedy Energy Park	Battery	2	2018–19
Windlab / Eurus	Kennedy Energy Park	Wind	43	2018–19
Lilyvale Asset Co	Lilyvale	Solar	100	2018–19
RE Oakey	Oakey 2	Solar	55	2018–19
Canadian Solar	Oakey	Solar	25	2018–19
Adani	Rugby Run	Solar	65	2018–19
Esco Pacific	Susan River	Solar	75	2018–19
MSF Sugar	Tableland Mill	Bagasse (expansion)	24	2018–19
Teebar Clean Energy	Teebar One	Solar	52	2019–20
Risen Energy	Yarranlea	Solar	103	2019–20
SOUTH AUSTRALIA			554	
Enel Green Power	Bungala Two	Solar	110	2018–19
Lincoln Gap Wind Farm	Lincoln Gap—stage 1	Wind	126	2018–19
AGL	Barker Inlet	Gas	210	2019–20
Vena Energy	Tailem Bend	Solar	108	2019–20
TASMANIA			256	

OWNER	POWER STATION	TECHNOLOGY	CAPACITY (MW)	PLANNED COMMISSIONING
Granville Harbour Operations	Granville Harbour	Wind	112	2019–20
Wild Cattle Hill	Wild Cattle Hill	Wind	144	2019–20
VICTORIA			1981	
Bulgana Wind Farm	Bulgana	Wind	194	2018–19
Goldwind	Moorabool	Wind	320	2018–19
Westwind Energy	Lal Lal—Yendon end	Wind	144	2018–19
Neoen	Numurkah	Solar	100	2018–19
Bulgana Wind Farm	Bulgana	Battery	20	2019–20
Pacific Hydro	Crowlands	Wind	80	2019–20
Northleaf, InfraRed, Macquarie Capital	Lal Lal—Elaine end	Wind	84	2019–20
RES Australia	Murra Warra—stage 1	Wind	226	2019–20
Goldwind	Stockyard Hill	Wind	532	2019–20
BayWa r.e Australia	Yatpool	Solar	81	2019–20
Total Eren S.A.	Kiamal—stage 1	Solar	200	2019–20

Note (tables 2.5–2.6): Data at November 2018.

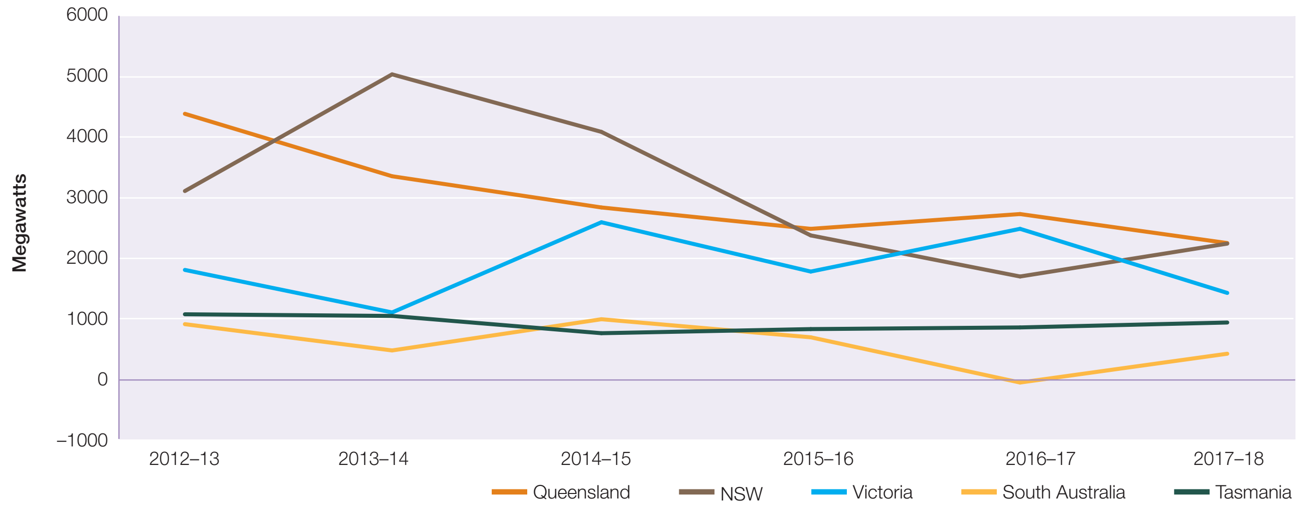
Source: AEMO, Generation information, 2 November 2018, available at: www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

Figure 2.21
Announced generation proposals at July 2018



Source: AEMO, *Generation information,* 2 November 2018, available at: www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

Figure 2.22
Surplus generation capacity, by region



Note: Maximum demand in financial year minus summer capacity (nameplate capacity for non-scheduled plant) at 31 January in each region. Summer capacity for 2016–17 in Victoria includes Hazelwood, with closure of the plant reflected in 2017–18 data. Wind and solar summer capacity is de-rated based on AEMO's 'firm contribution' estimates to account for generation likely to be operational during periods of maximum demand.

Source: AEMO, *Generation information*, 31 July 2018, available at: www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

2.6 Power system reliability and security

The Finkel review found the closure of coal fired plants may pose risks to power system reliability and security, in part because the intermittent (weather dependent) wind and solar plant replacing them has not been well integrated into the system.[28]

The concepts of reliability and security should not be confused. Power system *reliability* relates to having sufficient generation capacity to meet demand. *Security* refers to the system's technical capability in terms of frequency, voltage, inertia and similar characteristics.

2.6.1 Reliability in the NEM

The Reliability Panel sets a *reliability standard* for the generation and transmission sectors, which requires any shortfall in power supply not exceed 0.002 per cent of total electricity requirements. The standard factors in generation required to meet forecast electricity demand on peak days, allowing for a 'safety margin'. The standard has rarely been breached, although AEMO sometimes intervenes in the market to manage forecast supply shortfalls. Consumers do experience supply interruptions, but over 95 per cent of these originate in local distribution networks, and relate to local power line issues.

An over-supply of generation capacity built up for several years in the NEM. But plant retirements, including the closure of major coal fired generators, began to reduce this surplus in Queensland (from 2012–13) and NSW (2013–14), followed by South Australia and Victoria (from 2014–15). The shift was exacerbated from 2013–15 by investment in renewables tailing off due to uncertainty over government policy on the future of the RET scheme.

The retirement of South Australia's Northern power station in 2016 made the state more reliant on imports from other regions to meet peak demand (figure 2.22). The closure of the Hazelwood power station had a similar tightening impact on Victoria in 2017.

AEMO in September 2017 raised concerns the market would be at risk of generation shortfalls over summer 2017–18, especially in Victoria and South Australia where plant closures had occurred.[29] It raised similar concerns

28 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.

29 AEMO, *Electricity statement of opportunities for the national electricity market*, September 2017.

for power outages over summer 2018–19 (section 2.9.8). AEMO took action to manage reliability risks over both summers (sections 2.6.2 and 2.9.8).

2.6.2 Managing reliability risks

AEMO can use the Reliability and Emergency Reserve Trader (RERT) mechanism to manage short term reliability risks in the NEM. The scheme involves AEMO securing contracts with generators (to provide capacity) or large loads (to reduce their consumption) when the power system is under stress. This capacity normally operates outside the NEM. AEMO in 2018 recommended expanding its capacity to secure reserves under the RERT mechanism, arguing it would enhance reliability management.[30]

If a serious reliability threat cannot otherwise be avoided, AEMO may direct generators to provide additional supply or large energy customers to reduce demand. 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'—temporarily cut power to some customers. This action is rare. An insecure operating state led AEMO to cut supply to some customers in South Australia on 1 December 2016 and 8 February 2017, and in NSW on 10 February 2017.

Transmission solutions

AEMO in 2018 proposed major investment in transmission networks that it argued will be necessary to meet the reliability standard as new generation comes online. Its inaugural integrated system plan (ISP) recommended $450–650 million of immediate investment in transmission networks—including upgrading cross-border interconnectors between Victoria, NSW and Queensland—to manage reliability risks. It recommended further major investment by the mid-2020s (including the Riverlink interconnector between NSW and South Australia) and later (including Snowylink between NSW and Victoria).[31]

Market bodies are reviewing the role of the ISP in driving transmission investment, including the use of cost–benefit testing to assess the efficiency of new investment proposals. This work also explores broader coordination issues between transmission and generation investment.

Investment in expensive, long lived assets is risky—especially when a market is in transition, and where more flexible and potentially cheaper alternatives are available.

30 AEMO, *AEMO observations: Operational and market challenges to reliability and security in the NEM*, March 2018, p. 26.
31 AEMO, *Integrated System Plan for the National Electricity Market*, July 2018.

The cost–benefit focus of the AER's regulatory investment test provides a robust and transparent model for analysing whether network upgrades provide value for money to energy consumers.

2.6.3 Challenges of an evolving market

The surge in intermittent generation investment over the past few years has added capacity to the market. But it can create challenges for managing the power system. In particular, intermittent generation may not be available at a given time due to the uncertain nature of weather conditions. AEMO accounts for this uncertainty by factoring in a plant's region and technology when assessing its contribution to peak demand.

Solar generation raises particular challenges for coal plant. When solar generation is high in the middle of the day, the demand for dispatchable generation can significantly fall. This phenomenon challenges the economics of coal fired generators, which are engineered to run fairly continuously at or near full capacity to be profitable.

While the effects of intermittent wind and solar generation on *reliability* are complex, higher levels of this generation may increase the risk of power system *security* issues. The older fossil fuel power plants that are retiring helped maintain power system security by providing frequency, voltage, inertia and system strength services that kept the system in a secure technical state.[32]

The capability of intermittent generation plants to provide these services, and the types of services required, are still evolving. AEMO noted the rising proportion of wind plant in the NEM's generation portfolio is resulting in more periods with low inertia and low available fault levels, reducing market resilience to extreme events.

The most serious security event to date occurred on 28 September 2016, when a combination of severe weather, catastrophic failure of transmission infrastructure and the performance of a number of generators caused much of South Australia to be blacked out for several hours. The AER published a comprehensive report on this event in December 2018.[33]

A similar event occurred in March 2017, when network faults caused a large and sudden reduction in local

32 Synchronous generators—including hydroelectric and thermal plan such as coal, gas and solar thermal generators—can provide these services. The generators' heavy spinning rotors provide synchronous inertia that slows down the rate of change of frequency. They help with voltage control by producing and absorbing reactive power and also provide high fault current that improves system strength.
33 AER, *The black system event*, Compliance report, December 2018.

generation, resulting in voltage instability on the Heywood interconnector. A major blackout was avoided, but South Australia's power system operated in an insecure state for 40 minutes.

AEMO is intervening in the market more often to ensure a minimum level of system security services is maintained. It imposes constraints on generation and uses its directions powers to maintain a balance between synchronous and non-synchronous generation.[34] AEMO issued directions to generators on 25 occasions in 2017, double the number of interventions in the previous seven years combined.[35] In the first five months of 2018 a further 62 directions were issued.[36]

Factors such as wind speed and cloud cover pose challenges for demand and supply forecasting. While solar PV systems reduce strain on the electricity grid when the sun is present, the market can lose 200–300 MW of power if cloud covers a major city, for example.[37] AEMO in 2018 reported multiple instances where rooftop generation caused deep voltage dips in the middle of the day, leading to hundreds of megawatts of nearby loads being removed from the power system for several minutes, before slowly returning.[38]

The uptake of small scale supply, collectively known as *distributed energy resources* pose additional challenges. Distributed energy resources are located within a distribution network but usually operate behind customers' energy meters. They include generation (solar PV systems being the most common form), storage (including batteries and electric vehicles) and demand response. These resources create two-way flows on an energy network (power is both injected in and withdrawn at customer connection points), raising challenges for network design and system security.

Policy responses

The Finkel review in 2017 explored how to better integrate intermittent generators and distributed energy resources into the market to capitalise on its benefits—including its advantages as low cost and low emissions generation.

Many of the review's proposals relate to promoting investment in resources with flexibility to manage sudden demand or supply fluctuations.[39] In the future, resources such as batteries or pumped hydroelectric storage and demand response may become a significant part of the solution to these issues by becoming suppliers of services that maintain power system security. Options may include intelligent wind turbine controllers, batteries and synchronous condensers that could better integrate intermittent plant into the grid.

The Australian Government endorsed most of the review's recommendations. Reforms to ancillary service markets and technical frameworks arising from the recommendations are now being implemented to encourage a more efficient integration of intermittent and distributed generation into the market.

The Australian Energy Market Commission (AEMC) in 2017 introduced reforms to allow batteries and demand response aggregators to provide frequency control services. It is also exploring reforms to allow wider use of demand response and aggregation of small scale generation in the wholesale market. Another reform requires generators to provide three years' notice prior to closing a plant to allow time for the market to adjust to the change. New standards are also being applied to ensure the technical standards of new generators match local power system needs.[40]

2.7 Government intervention in the market

The lack of a clear, agreed national energy policy has led governments at all levels to intervene in the market in a less coordinated way. The interventions include investments in state owned generation projects, financial incentives for private generation, and directions to the market on how it should operate. In late 2018 over 20 such measures were operating, had been committed or announced as policy in the wholesale electricity sector (Appendix 1). The initiatives include:

- major investments in publicly owned generation and storage
- a pricing direction to state owned generators
- a threat of compulsory divestment of private generation assets
- national and state level renewable energy targets

34 AEMO, *AEMO observations: Operational and market challenges to reliability and security in the NEM*, March 2018, pp. 8, 25.
35 AEMO, *AEMO observations: Operational and market challenges to reliability and security in the NEM*, March 2018, p. 26.
36 AEMO, *NEM event—direction* reports, available at: www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Market-notices-and-events/Market-event-reports.
37 Australian Energy Council, *Solar Report, Quarter 1, 2018*, p. 6.
38 AEMO, *Power system requirements*, March 2018, p. 8.

39 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.
40 AEMC, *AEMC system security and reliability action plan*, updated 5 July 2018.

- programs offering financial assistance for grid scale renewable projects or residential solar and battery systems
- a market wide reliability guarantee.

Other interventions are occurring in the electricity retail and transmission sectors.

While government intervention can help manage an identified market issue, its wider market impacts are complex. In particular, intervention can distort market signals, affecting private sector investment decisions. The AER in December 2018 reported the views of energy market participants that a lack of stability and predictability in government energy policy is a barrier to entry for new generation. Emissions policy instability, interventions to address energy policy objectives such as reliability and affordability, and government ownership in the industry were cited as key impediments to investment in the NEM.[41]

2.7.1 Public investment in generation and storage

The Australian Government and some state governments have announced new energy infrastructure projects in generation, storage and transmission.

Among major initiatives, the Australian Government in 2018 undertook a feasibility study into expanding Snowy Hydro (which it owns) using pumped hydroelectric technology. The proposal would increase Snowy Hydro's hydroelectric generation capacity by around 2000 MW—a 50 per cent rise on current capacity. A final investment decision on the project was scheduled for late 2018, with generation from the project commencing in late 2024 if it proceeds.

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

The Queensland Government in 2019 will launch CleanCo, a new state owned generation corporation with a commercial mandate to increase competition in the wholesale market. It will focus on low and no emissions technology. Initially, 1000 MW of hydroelectric and gas power stations will transfer to CleanCo from other state owned generators. The Queensland Government will provide funding for CleanCo to invest in a further 1000 MW of renewable capacity by 2025. Earlier, the Queensland Government invested in recommissioning the state owned Swanbank E generator in December 2017.

On a smaller scale, the South Australian Government developed diesel (convertible to gas) generation and battery storage, including the 100 MW Hornsdale Power Reserve—the first scheduled battery in the NEM. The battery has helped lower the cost of frequency control services needed to keep the power system secure.

2.7.2 Market directions

In June 2017 the Queensland Government directed the state owned Stanwell generation business to 'alter its bidding strategies to help put as much downward pressure on wholesale electricity prices as possible'.[42] Stanwell indicated it subsequently adjusted its bidding behaviour in line with the direction, resulting in a significant lowering of Queensland wholesale prices in 2017–18 (section 2.9.1).

In late 2018 the Australian Government drafted legislation to insert a power into the *Competition and Consumer Act 2010* enabling the Courts, on the advice of the Treasurer and ACCC, to order divestiture of an asset by energy companies, or order electricity companies to enter into contracts to supply at specified prices and for specified volumes. The draft legislation listed grounds to force asset divestment, including a retailer's failure to pass on lower wholesale prices to energy customers, or attempts by energy companies to manipulate spot or contract markets.[43]

2.7.3 Renewable energy targets

The Australian, Queensland, Victorian and ACT governments operate renewable energy targets:

- The Australian Government launched a national RET scheme in 2001 and has since revised it several times (box 2.3). The scheme applies different incentives for large (such as wind) and small (such as rooftop solar PV) scale energy supply. The RET scheme targets 33 000 GWh of electricity sourced from large scale renewable projects by 2020, equivalent to 23.5 per cent of Australia's forecast generation at that time.
- The Queensland scheme targets 50 per cent of Queensland's electricity being produced from renewable resources by 2030. It is not a legislated target.
- The Victorian scheme targets 25 per cent of the state's electricity being sourced from renewable resources by 2020, and 40 per cent by 2025. The targets are legislated.
- The ACT Government applies a range of measures to pursue a target of 100 per cent of Canberra's demand being sourced from renewable resources by 2020.

The Victorian, ACT and Queensland governments have (or intend to) run reverse auctions to acquire new private investment in renewable generation to support the targets (section 2.7.4). The Queensland Government's CleanCo generation company will also directly invest in new renewable capacity (section 2.7.1).

2.7.4 Financial incentives for private investment

Governments have introduced a range of programs and schemes offering financial incentives for private investment in generation capacity (appendix 1). Most incentives target investment in renewable energy, but a recent Australian Government initiative focuses on 'dispatchable' capacity.

Some schemes offer direct subsidies or grants. Others underwrite investment through debt or equity support, or through measures such as selling 'contracts for difference' that provide financial certainty for investors. Some schemes use a mix of approaches.

The Australian Government operates three major schemes offering financial support for renewables investment:

- The Australian Renewable Energy Agency (ARENA) was established in 2012 to fund research, development and commercialisation of clean energy technologies. Much of its funding is provided as grants. Its mandate is to advance clean energy technology, rather than generate profit. At 30 June 2018 ARENA had allocated $1 billion in grant funding to 320 projects since 2012, totaling 263 MW of capacity. These projects included 12 large scale solar plants, many with Clean Energy Finance Corporation (CEFC) involvement. Its development pipeline included $2.5 billion worth of additional projects.
- The CEFC launched in 2012 as a government owned green bank to promote investment in clean energy. The fund provides debt and equity financing for projects that will deliver a positive return, rather than grants. The CEFC invested in almost $20 billion of clean energy projects from 2012–18—including 5500 small scale clean energy projects, 20 large scale solar projects, and 10 wind farms.
- The Emissions Reduction Fund launched in 2014 to fund carbons emissions abatement through 'reverse' auctions run by the Clean Energy Regulator. Seven auctions were held to July 2018, spending $2.3 billion to abate 192 million tonnes of carbon emissions. Less than 2 per cent of funding under the scheme was made to the electricity sector. The participating electricity projects mostly capture and combust waste methane gas from coal mines or landfill for electricity generation (box 2.3).

Following an ACCC recommendation, the Australian Government in 2018 proposed underwriting new investment in 'firm' or 'firmed' generation capacity.[44] The support may take the form of a floor price, contracts for difference, collar contracts, government loans, or alternative mechanisms. Expressions of interest are expected to open by January 2019 and proposals will be due by March 2019. Financial support is expected to commence from 1 July 2019.[45]

State governments also operate schemes to support grid scale renewable projects:

- The Queensland Government operates its Renewables 400 and Solar 150 schemes that provide 'contracts for difference' to support the development of renewable and large scale solar generation. Projects are selected through reverse auctions. The Solar 150 scheme has supported 300 MW of new capacity.
- The Victorian Government operates a renewable energy auction scheme, grid scale battery project, and renewable certificate purchasing initiative. The auction scheme has provided support for six projects totaling 928 MW of generation, and the certificate process has supported a further four projects totaling 210 MW. The battery project has supported two batteries totaling 55 MW.
- In 2017 the South Australian Government contracted to source 100 per cent of the government's electricity requirements from the Aurora solar project, a 150 MW solar thermal plant at Port Augusta, due for completion in 2020. The Government's Renewable Technology Fund is also offering $150 million in support for renewables as grants and loans. At November 2018, it had provided funding to three grid scale battery projects.
- The ACT Government introduced a large scale feed in tariff to fund new renewable generation. Projects funded under the scheme are selected through reverse

41 AER, *Wholesale electricity market performance report*, December 2018.

42 Queensland Government, *Stabilising electricity prices for Queensland consumers*, media release, 2017.

43 Treasury Laws Amendment (Electricity Price Monitoring) Bill 2018, exposure draft.

44 Department of the Environment and Energy, *Underwriting New Generation Investments, Public Consultation Paper*, October 2018. 'Firm' capacity is generation that can be available when needed—for example, coal or gas powered generation or wind generation with onsite storage such as batteries. 'Firmed' capacity encompasses intermittent generation such as wind or solar that is contracted with a certain proportion of firm capacity across the grid.

45 Department of the Environment and Energy, *Underwriting New Generation Investments, Public Consultation Paper*, October 2018.

auction processes. At November 2018 640 MW of new generation had been funded under the scheme.

The Victorian, South Australian, Queensland and ACT governments also operate schemes that provide grants, rebates or loans to support small scale solar PV and battery systems. All state governments have previously operated feed-in tariff schemes to support installation of residential solar PV systems. These schemes are all closed to new entrants.

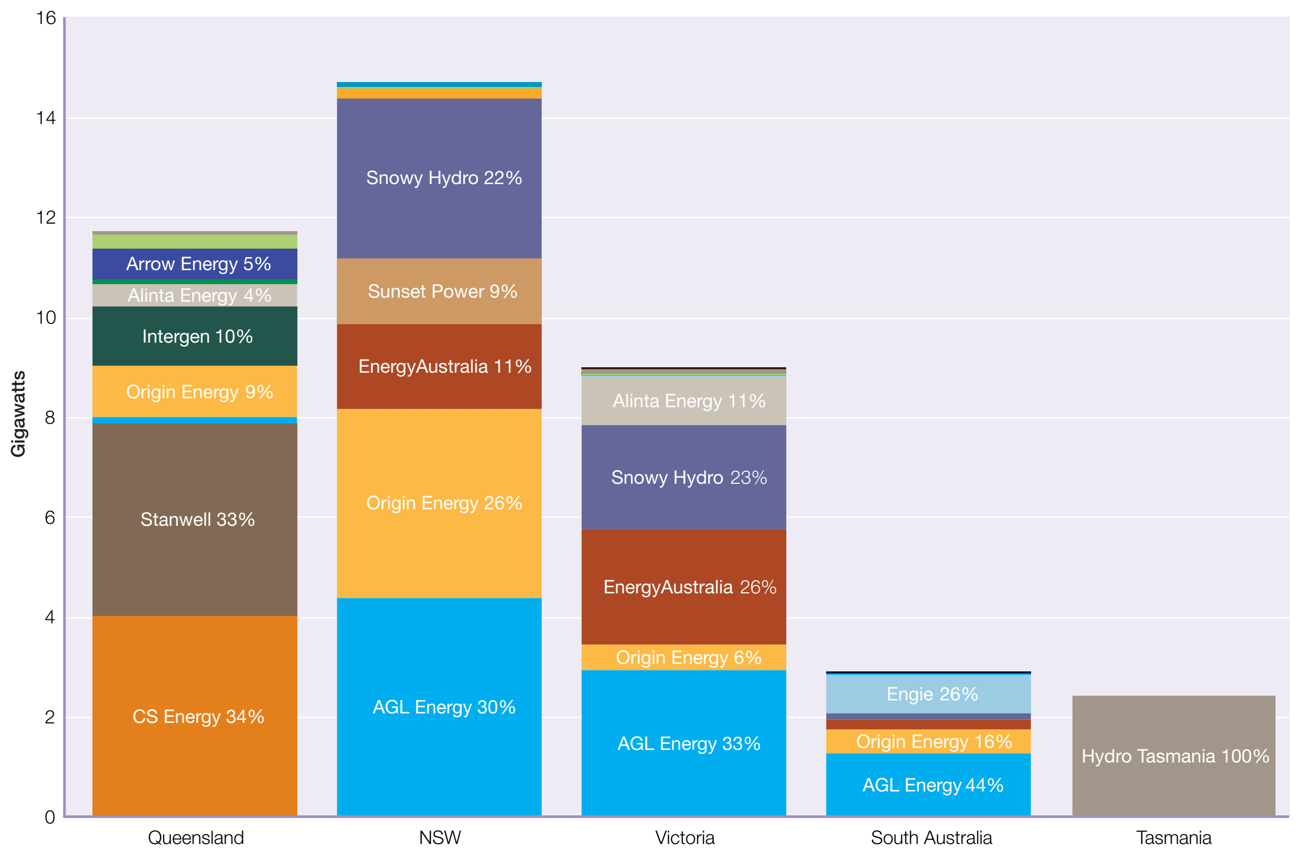
2.8 Market structure

Around 150 registered generation businesses sell electricity into the NEM spot market. Table 2.3 lists the major generators, plant technologies and ownership arrangements (including the entities that control each plant's dispatch).

A few large participants control a significant proportion of generation in each NEM region. The two largest participants in each region account for over half of total capacity (figure 2.23) and two thirds of output (figure 2.24), except in South Australia which is slightly less concentrated.

Higher concentration in output compared to capacity in Queensland, NSW and Victoria reflects the high utilisation rates of black and brown coal plant that make up the bulk of the generation fleet of the largest participants. South Australian outcomes are more even across capacity and output measures, because its largest participants all rely on gas powered generation (which operates less often than coal plant, for example).

Figure 2.23
Market shares in generation capacity



Note: Generation capacity based on 2017–18 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 allocated to the business that controls the trading rights for each generator. Import capacity via interconnectors, and rooftop solar PV capacity are excluded.

Source: AER; AEMO.

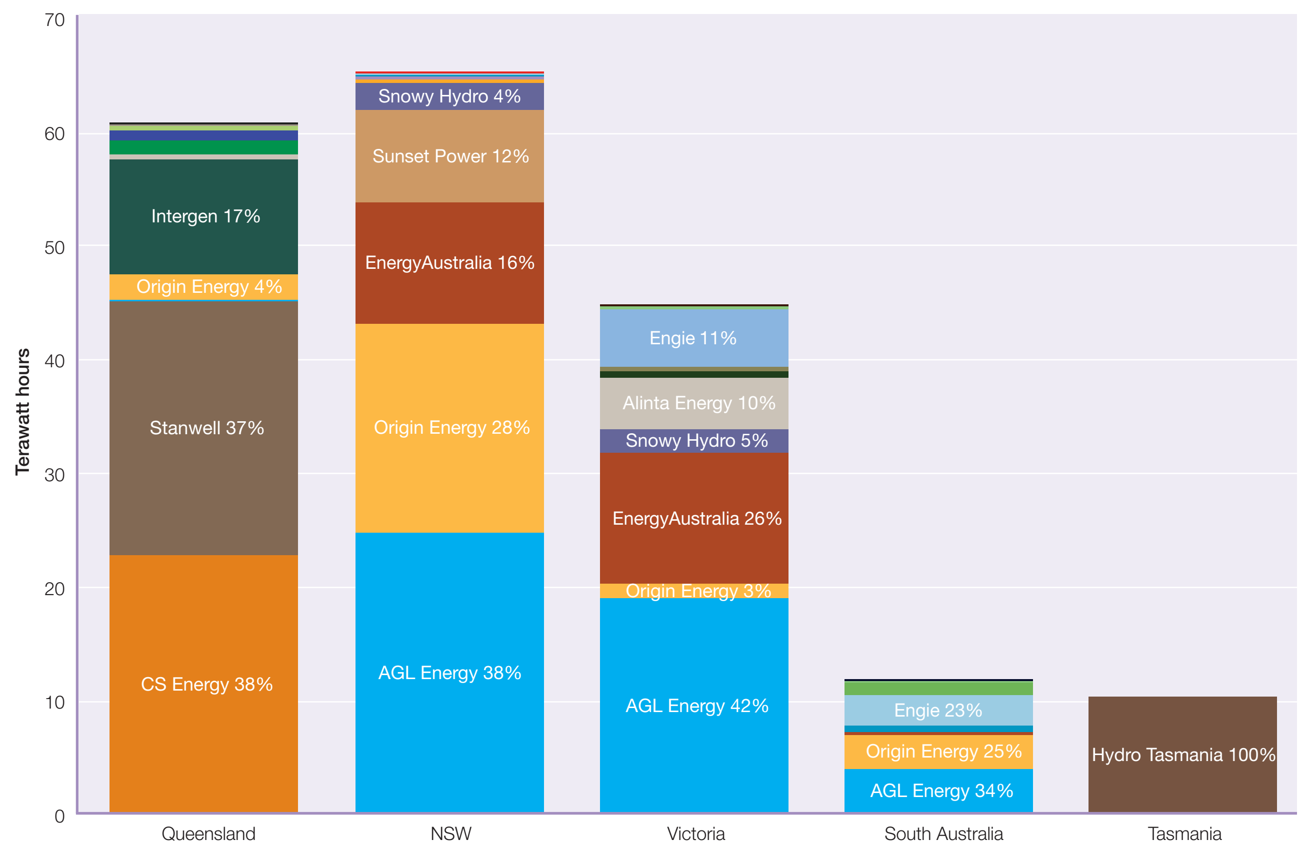
Private entities own most generation capacity in Victoria, NSW and South Australia (figure 2.23):

- In Victoria, AGL Energy (33 per cent), EnergyAustralia (26 per cent) and Snowy Hydro (23 per cent) control a majority of capacity. 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 44 per cent of capacity. Other significant entities are Engie (26 per cent), Origin Energy (16 per cent) and EnergyAustralia (7 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, the privatisation of state owned generation businesses was completed in 2015. AGL Energy (30 per cent), Origin Energy (26 per cent) and Snowy Hydro (22 per cent) emerged as the state's leading generators following the sale process. EnergyAustralia (11 per cent) and Sunset Power (9 per cent) also acquired significant generation capacity.

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 67 per cent of generation capacity, including power purchase agreements over privately owned capacity (such as the Gladstone power station). The most significant 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 it ensures adequate volumes of these products are available.

Figure 2.24
Market shares in generation output



Note: Output in 2017–18. Ownership is attributed by trading rights at the time. Output split on a pro-rata basis where ownership changed during 2017–18. Excludes output from rooftop solar PV systems.

Source: AEMO; AER; company announcements.

AGL Energy is the largest participant by capacity and output in NSW, Victoria and South Australia. On a NEM-wide basis, it accounts for 20 per cent of capacity and 25 per cent of output.

Snowy Hydro contributed only 4 per cent of output in NSW and five per cent in Victoria, despite holding over 20 per cent of capacity in each region. This outcome is because its fleet comprises hydroelectric generators with limited water availability and peaking gas plant, which typically operate less frequently.

2.8.1 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 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 (section 2.10).

Vertical integration has become the primary business structure for large electricity retailers in the NEM. Three retailers—AGL Energy, Origin Energy and EnergyAustralia—supply 66 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 2018.

Red Energy and Lumo Energy (Snowy Hydro), Simply Energy (Engie) and Alinta also own major generation assets. These vertically integrated businesses account for another 15 per cent of small residential customers across the NEM and 19 per cent of generation capacity.

In NSW, Victoria and South Australia, those six businesses jointly own at least 90 per cent of generation capacity.

A number of smaller retailers are also vertically integrated:

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

2.9 Market activity

Price pressure in the NEM intensified following the closure of coal fired plant in South Australia (in May 2016) and Victoria (in March 2017). These retirements followed years of stagnant investment in dispatchable generation.

The closure of the Hazelwood power station withdrew around five per cent of the NEM's capacity. This low cost supply was initially replaced more expensive gas and hydroelectric generation output. But wind and solar generation took more of this share in 2018, and this share will further rise in 2019.[46]

Brown coal generators—traditionally the cheapest thermal supply source—now rarely set electricity prices because the market rarely has enough brown coal capacity to meet demand.[47] More expensive black coal and gas plant now more often set prices. Between July 2015 and July 2017, the offer price for the cheapest 20 000 MW of capacity in the NEM increased from $50 per MWh to almost $100 per MWh.[48]

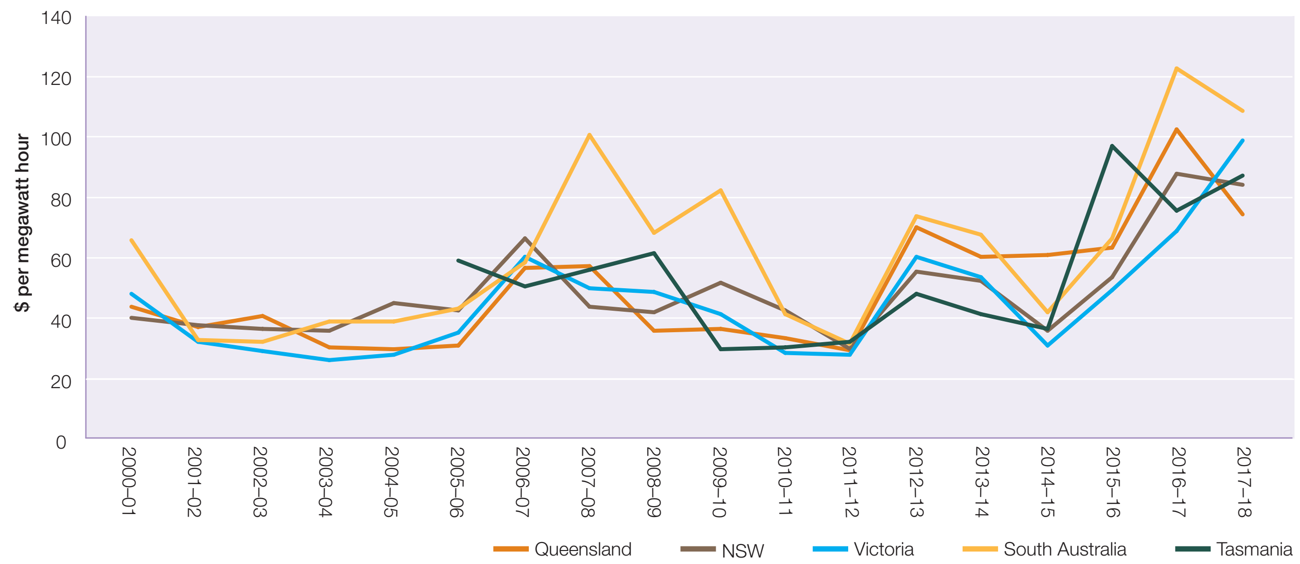
A significant factor in this shift was NSW and Queensland black coal generators raising their offer prices. This change in bidding behaviour partly reflected a rise in black coal costs and issues around coal supply availability. A large increase in gas fuel costs also reduced competitive restraints on black coal plant, allowing them to periodically price closer to gas plant prices. The AER found average offers from some black coal generators in NSW and Queensland increased more than underlying costs.[49]

Market volatility was exacerbated by outages affecting coal and gas generators, and interconnector constraints limiting trade between Victoria and other regions. These conditions resulted in spot prices setting records or near-records in most NEM regions in 2016–17 (figures 2.25 and 2.26).

Prices eased in Queensland, NSW and South Australia in 2017–18. Market intervention by the Queensland Government contributed to that region's prices being 28 per cent lower in 2017–18 than a year earlier. Improved gas and black coal supply conditions and increased renewable plant coming online improved outcomes in some regions.

46 AER, *Electricity wholesale performance monitoring, Hazelwood advice*, March 2018; AEMO, *2018 electricity statement of opportunities*, August 2018.
47 AER, *Electricity wholesale performance monitoring, Hazelwood advice*, March 2018, p. 16.
48 ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final Report*, June 2018, p. 55.
49 AER, *Electricity wholesale performance monitoring, NSW electricity market advice*, December 2017.

Figure 2.25
Annual NEM electricity prices



Note: Volume weighted averages of spot prices.
Source: AER; AEMO.

But prices rose 43 per cent to a new record in Victoria, averaging almost $100 per MWh.

Several years of high wholesale prices have boosted profits for many generators.[50] Large generation businesses in most regions were earning profit margins of around 20–22 per cent in 2014–15, but by the end of 2017, several generators had margins above 30 per cent. Even the least profitable of seven businesses assessed by the ACCC was earning at least a 14 per cent margin in the first half of 2017–18.[51]

2.9.1 Queensland

Queensland prices averaged $75 per MWh in 2017–18, the lowest for any NEM region. Prices were 27 per cent lower than a year earlier, the largest reduction for any region. Market intervention by the Queensland Government played a key role in this outcome.

The government in July 2017 directed the state owned Stanwell generation business to 'alter its bidding strategies to help put as much downward pressure on wholesale electricity prices as possible'.[52] This intervention contributed to generators shifting capacity previously bid at over $5000 per MWh to lower prices, typically below $300 per MWh. The volume of capacity offered at low prices (below $50 per MWh) has remained relatively stable (figure 2.27).

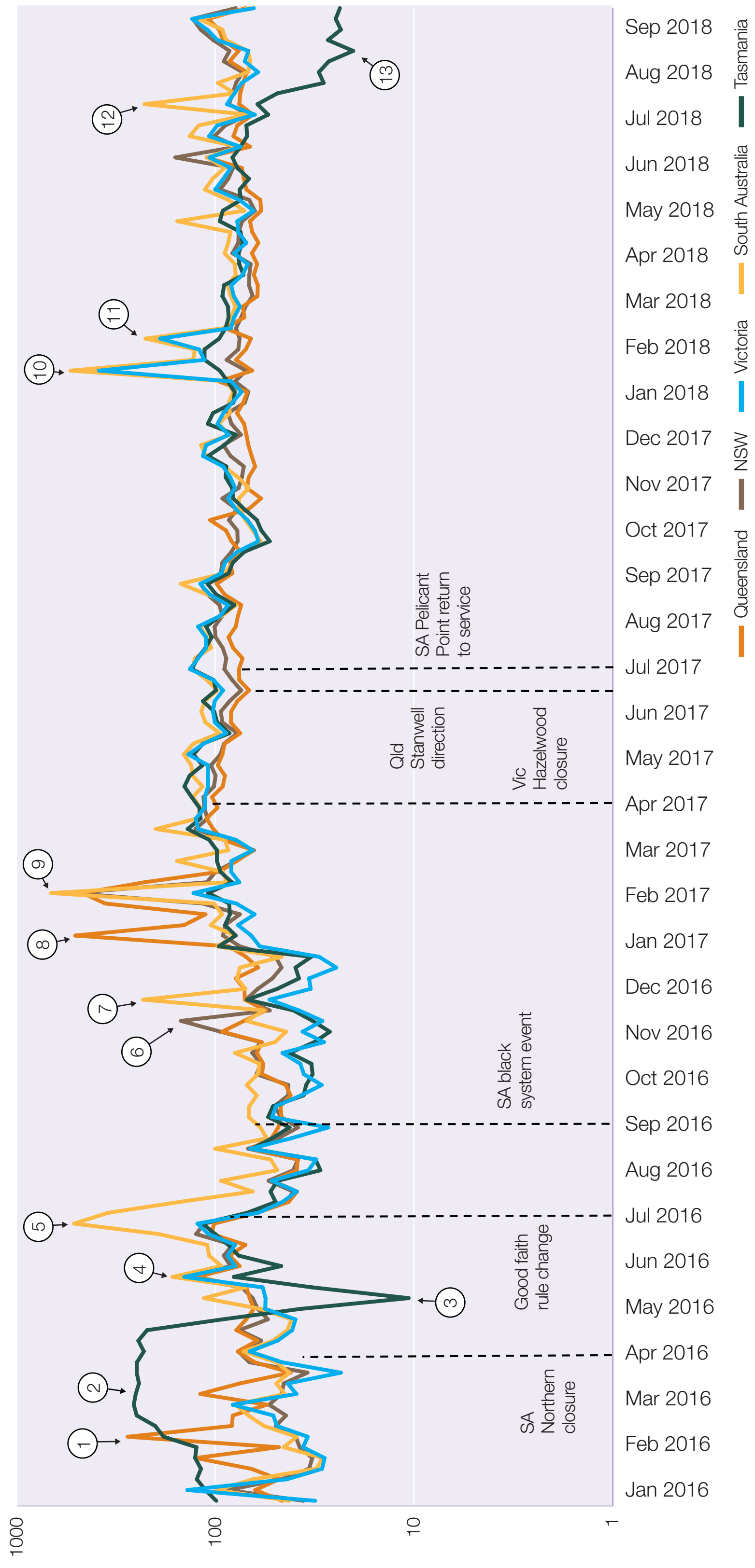
Despite maximum demand setting a new record during a heatwave in February 2018, summer conditions were generally relatively mild, contributing to lower prices. Other contributing factors included the return to service of the mothballed Swanbank E generator.

The Queensland Government intervention took place after a year of extremely high prices. Queensland prices averaged over $100 per MWh in 2016–17, a record high for the region. In that year, higher fuel costs for gas and supply issues affecting black coal put pressure on market prices. These changes coincided with Queensland's black coal generators in 2017 shifting significant capacity from $20–50 per MWh price bands to $50–100 per MWh bands.[53]

But the AER found some black coal generators raised their average supply offers more than can be explained

50 ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final Report*, June 2018, p. 50.
51 Earnings before interest in tax as a share of revenue, based on information from seven large mainland generators.
52 Queensland Government, *Stabilising electricity prices for Queensland consumers*, media release, 2017.
53 ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final Report*, June 2018, p. 55

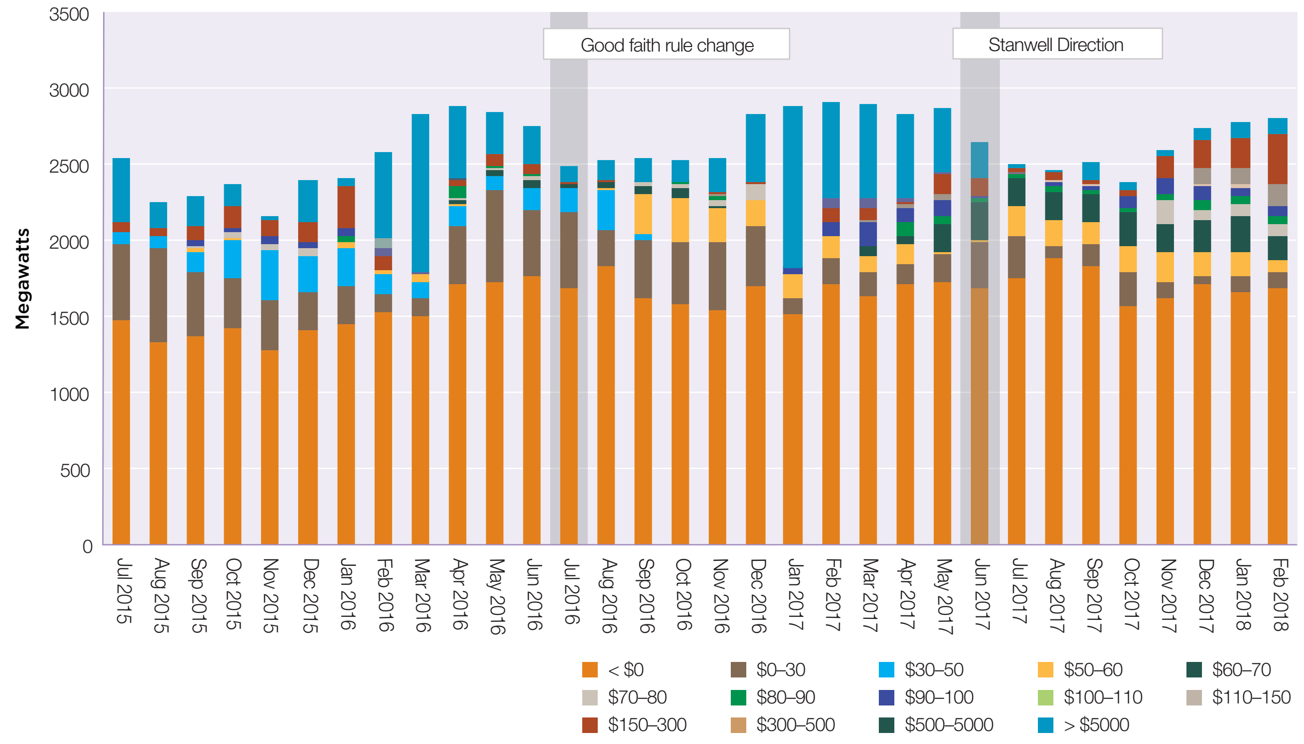
Figure 2.26
Weekly spot prices



1 Record high demand and rebidding.
2 Basslink outage and record low rainfall and dam levels.
3 High rainfall increased hyrdo output.
4 Coal plant closures and extensive coal outages reduce 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 Vic–NSW interconnector.
7 Rebidding behaviour and an unplanned outage of the Heywood interconnector .
8 High temperatures led to record Qld demand, plant restrictions, rebidding and limited imports.
9 Extremely high temperatures led to high demand across the NEM. Extensive coal generator outages in Qld and NSW. Load-shedding in SA as demand exceeded forecasts and wind output was low.
10 High temperatures led to high demand in Vic and SA. Exacerbated by a plant outage in Vic.
11 High temperatures drove high demand. No significant generator or network outages.
12 Planned outages on the Heywood interconnector coincided with low wind output.
13 High rainfall increased hyrdo output.

Source: AER.

Figure 2.27
Stanwell Corporation's monthly offered capacity by price band—Stanwell and Tarong power stations



Note: Monthly average capacity offered by price band.
Source: AER; AEMO.

by higher costs alone.[54] The ACCC found Queensland's highly concentrated market structure and a reduction in competitive constraints on Queensland generators since the closure of the Hazelwood power station contributed to record prices in the region.[55]

2.9.2 NSW

NSW prices averaged $85 per MWh in 2017–18, the second lowest for any NEM region, and 3 per cent lower than a year earlier.

NSW is a relatively import-dependent region, and its electricity prices are affected by events across the NEM. The region recorded a 62 per cent rise in prices in 2016–17, partly due to higher fuel costs for gas powered generators and fuel availability issues affecting black plant. In these conditions, NSW generators shifted some of their capacity offers to higher prices (figure 2.28).

But as in Queensland, the AER found the average offers from some black coal generators in NSW increased more than underlying costs. Electricity imports from Victoria were also more expensive following the closure of Victoria's Hazelwood plant in March 2017. The closure lessened competitive pressures on NSW generators, allowing them to bid into the market at higher prices.

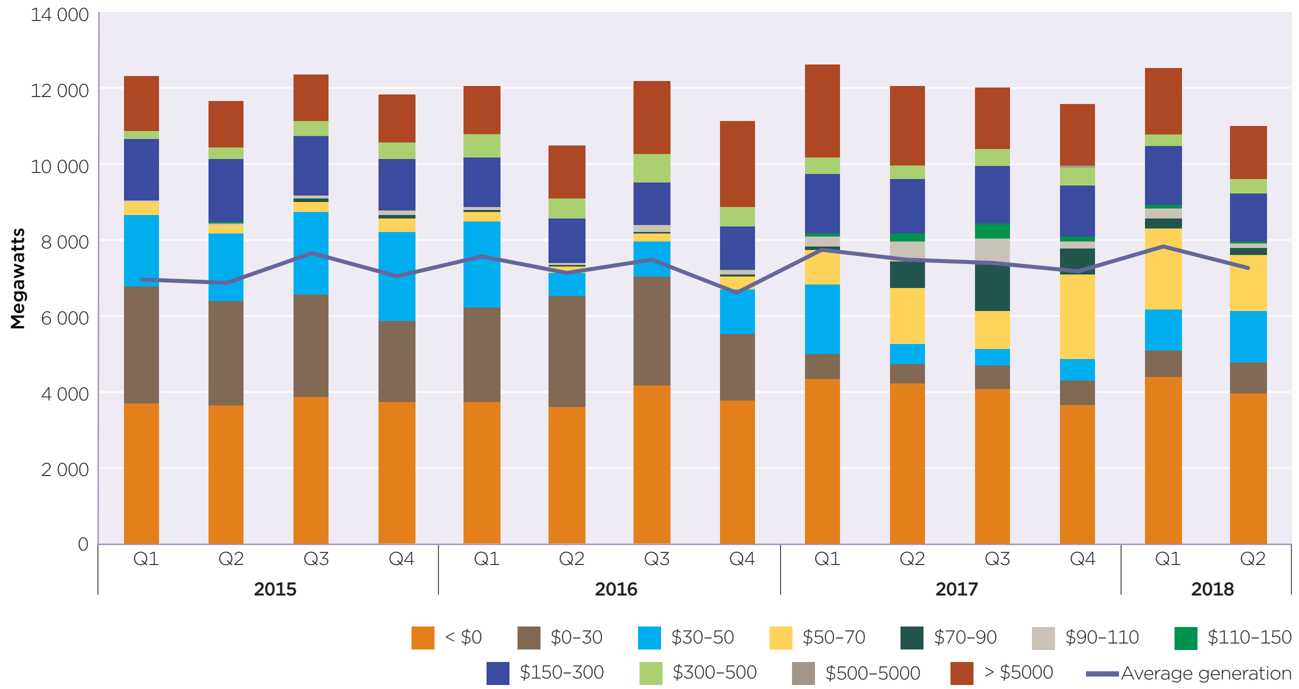
Market intervention by the Queensland Government in July 2017 to lower prices in that region also increased competitive pressure on NSW generators. Improved access to black coal and gas fuel availability also took some pressure off NSW prices.

Hydroelectric plant played a significant role in setting prices during the year. Similar to black coal generators a year earlier, Snowy Hydro from early 2017 shifted capacity from prices under $50 per MWh into higher price bands. This behaviour persisted for much of the year.[56] But an increase in hydrogeneration over summer 2017–18 and a relatively mild summer helped to stabilise prices. By autumn 2018

54 AER, *Electricity wholesale performance monitoring, NSW electricity market advice*, December 2017.
55 ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final Report*, June 2018, pp. 66–70.

56 AEMO, *Quarterly Energy Dynamics,Q1 2018*.

Figure 2.28
NSW generators' average quarterly offered capacity by price band



Note: Quarterly average capacity offered by price band.

Source: AER, Electricity wholesale performance monitoring—NSW advice, December 2017.

lower priced hydroelectricity offers (from Snowy and Hydro Tasmania) helped to ease wholesale prices.[57]

2.9.3 Victoria

Victorian prices averaged $100 per MWh in 2017–18, a record high for the state. Prices were 43 per cent higher than a year earlier and 30 per cent higher than in any year since the NEM began. Victoria was traditionally a relatively low cost electricity producer, but in 2017–18 was second only to South Australia as the NEM's most expensive region.

Victorian prices moved sharply higher following the closure of its low cost Hazelwood generator in March 2017, which diminished the role of brown coal in price setting in the region. Over summer 2017–18, brown coal set the dispatch price less than 2 per cent of the time, compared with 24 per cent in the previous summer (figure 2.29).

Outages at Loy Yang A and Yallourn in late 2017, and at Loy Yang B in January 2018, contributed to supply and price volatility. Adding to market pressures, Victoria was the only mainland region to record higher average summer demand in 2018 than a year earlier. Warm summer conditions and increased industrial load drove this demand.[58]

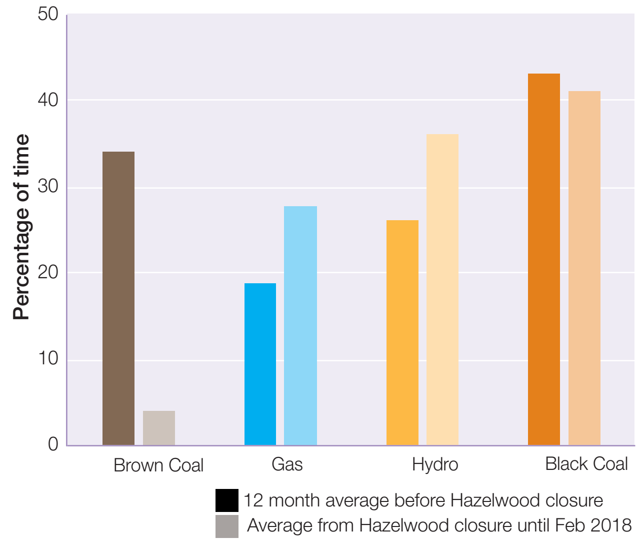
With the closure of Hazelwood, only 28 per cent of Victorian spot prices in 2017–18 were set by generators located in Victoria, compared with over 36 per cent of prices three years earlier. AGL's Bayswater black coal station (NSW), Torrens Island gas power station (South Australia) and Origin's Eraring black coal station (NSW) were among frequent price setters for Victoria during the year.

Despite Victoria's increased reliance on electricity imports, interconnector issues constrained imports from NSW 30 per cent of the time over summer 2017–18, pushing the region's average wholesale prices 43 per higher than NSW prices.[59]

57 AEMO, *Quarterly Energy Dynamics Q2 2018*.

58 AEMO, *Quarterly Energy Dynamics, Q1 2018*, p. 3.
59 AEMO, *Quarterly Energy Dynamics, Q1 2018*, p. 10.

Figure 2.29
Price setting in Victoria by fuel type since Hazelwood closure



Note: Hazelwood closure in March 2017. Data is for the periods March 2016 to February 2017 and March 2017 to February 2018. Victorian prices can be set by generation located outside Victoria.

Source: AER, Electricity wholesale performance monitoring—Hazelwood advice, March 2018.

2.9.4 South Australia

South Australian prices averaged $111 per MWh in 2017–18, the highest for any NEM region. Despite prices easing by 12 per cent from a year earlier, South Australia recorded triple digit prices for a second consecutive year.

The closure of Alinta's Northern power station in May 2016 removed significant capacity from the South Australian market. Gas powered generators now represent about two thirds of dispatched generation in South Australia, and often sets prices, despite gas fuel costs being at historically high levels. South Australia is more sensitive to gas price shifts than other regions.

Supply conditions improved in 2017–18 with the return to service of a previously mothballed unit of the Pelican Point plant, and the launch of the Hornsdale Power Reserve (section 2.9.8). A slight easing in gas fuel costs also cushioned prices somewhat.

Intermittent generation plays an increasingly significant role in setting South Australian prices. Periods of low wind generation contributed to the state's record prices in 2016–17, but its contribution increased in 2017–18 and helped ease prices. The increasing contribution of solar PV generation was apparent when South Australia recorded its lowest ever summer grid demand on 1 January 2018.

2.9.5 Tasmania

Tasmania prices averaged $88 per MWh in 2017–18—the state's third highest average since joining the NEM in 2005. Tasmania was one of only two NEM regions to record higher prices in 2017–18 than a year earlier (the other region being Victoria). Tasmanian prices rose on average by 14 per cent.

Tasmanian prices fluctuate depending on conditions for hydrogeneration and electricity market conditions on the mainland. Issues with the Basslink interconnector also affect prices.

Tasmania's higher prices in 2017–18 partly reflect the closure of the Hazelwood power station reducing the availability of cheap electricity imports from the mainland. Dry conditions also affected hydrogeneration for some of the year, but good rainfall in 2018 reversed this trend.

2.9.6 Price volatility

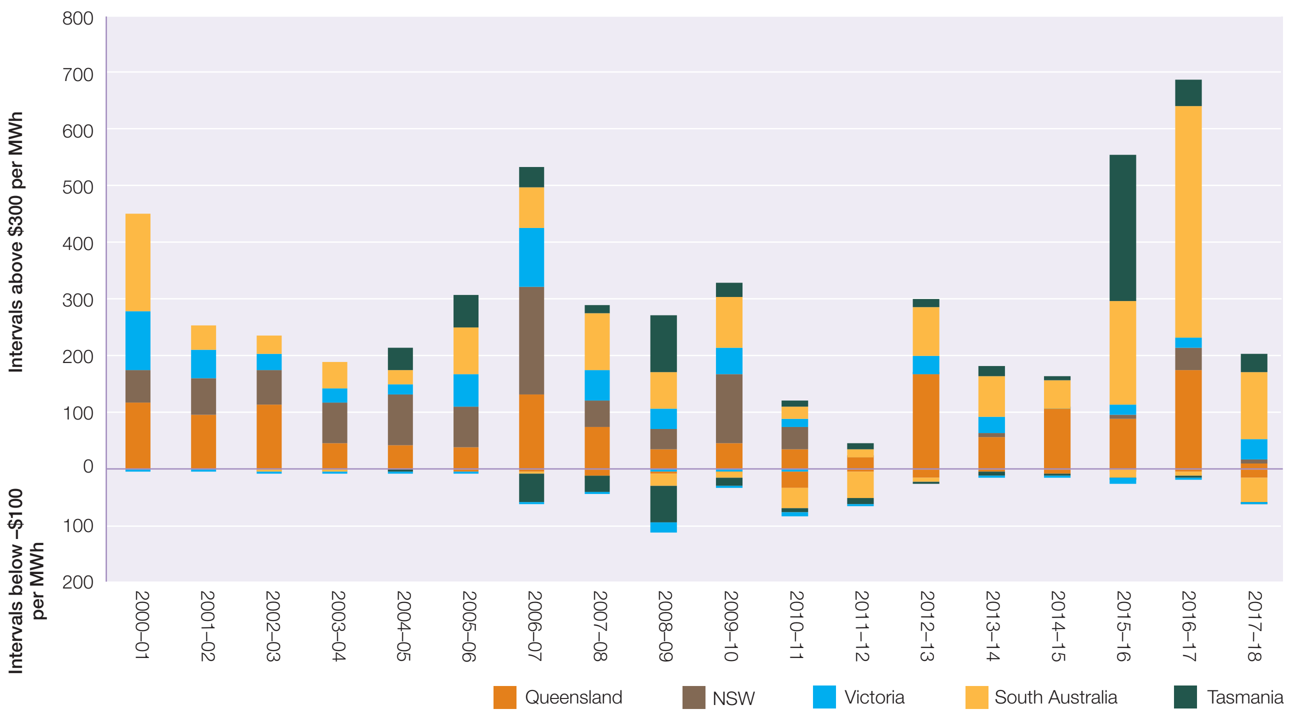
After two years of record volatility, NEM prices were generally more stable in 2017–18 (figure 2.30). Queensland and NSW experienced negligible price volatility despite record high demand in Queensland on 14 February 2018. Queensland recorded only nine prices above $300 per MWh in 2017–18, compared with 176 events the year before. In NSW, the number fell from 39 events in 2016–17 to eight in 2017–18. Directions by the Queensland Government to its generators to lower prices contributed to these outcomes. Queensland and NSW also benefited in 2017–18 from more stable fuel prices, the return to service of mothballed capacity at Swanbank E, increased hydroelectric generation in NSW, and a generally mild summer.[60]

South Australia recorded a majority of the NEM's prices above $300 per MWh in 2017–18 (116 out of a total 205 events). Victoria recorded 38 events, its highest count in a decade. Tasmania recorded 34 events. The high prices in Victoria and South Australia mostly occurred on three days of coincident hot weather, high demand and low wind output—18 and 19 January and 7 February 2018. A plant outage at Loy Yang B on 18 January contributed to this volatility.

Despite a reduction in the number of extremely high prices, the NEM in 2017–18 recorded its highest incidence of extreme negative prices (below –$100 per MWh) since 2011–12. A majority of the events (44 out of 61 events) occurred in South Australia, and usually coincided with high wind and solar PV generation.

60 AEMO, *Quarterly Energy Dynamics, Q1 2018*, p. 3.

Figure 2.30
Market volatility



Note: Total number of intervals where spot prices exceeded $300 per MWh or fell below –$100 per MWh.

Source: AER; AEMO.

2.9.7 FCAS prices

Frequency control ancillary services (FCAS) are required to maintain the frequency of the power system within safe operating standards. Regulation FCAS continuously adjust to balance small changes in frequency during normal operation of the power system, while contingency services manage larger frequency changes associated with sudden unexpected shifts in supply or demand.

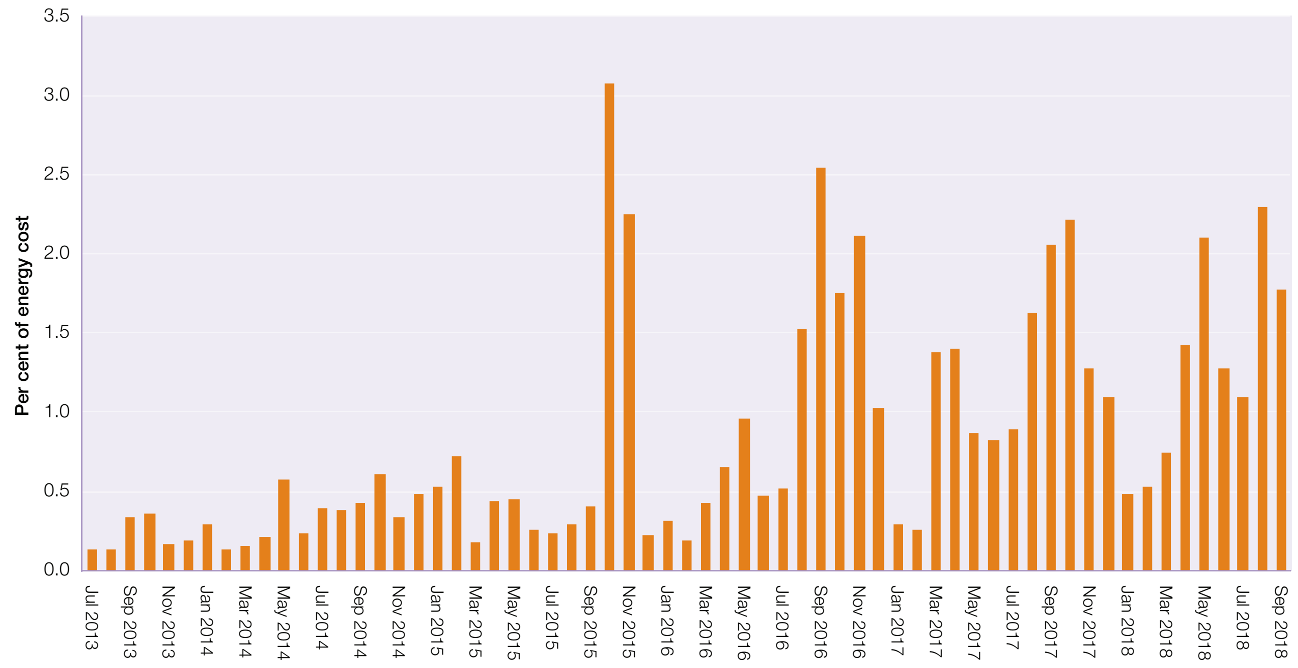
AEMO acquires FCAS through a market that is co-optimised with the wholesale energy market (offers from generators and other participants are coordinated in both markets to minimise overall costs), and consumers ultimately pay the costs. Historically, FCAS costs were small compared with energy costs—before September 2015, FCAS costs averaged less than 0.5 per cent of NEM energy costs. But more recently FCAS costs have often accounted for 1–2 per cent of costs (figure 2.31)

Costs rose for both regulation and contingency services. South Australia in particular experienced significantly higher FCAS costs following stricter requirements for localised sourcing of those services in 2015. This change coincided with a reduction in the number of local suppliers of FCAS. The requirement for additional local FCAS was later removed. New sources of FCAS have also begun operating in South Australia, including the Hornsdale Power Reserve and a provider of demand response services (box 2.4).

The NEM's changing generation mix has contributed to rising FCAS costs. Some thermal generators that traditionally provided FCAS (such as the Northern power station in South Australia) have exited the market. Many older renewable generators (wind and solar) were not engineered to provide these services, but newer plant is required to have this capability.

A reduction in FCAS offered by Tasmania also contributed to higher FCAS costs. Unplanned outages on the Basslink interconnector between Tasmania and the mainland (from December 2015 to June 2016 and again from March to June 2018) reduced FCAS supply. AEMO also imposed limits on the amount of FCAS regulation services Tasmania may provide to the mainland.

Figure 2.31
FCAS costs as a percentage of energy cost,



Note: Based on total wholesale and FCAS market costs each month.

Source: AEMO; AER.

2.9.8 Power system reliability and security

Power system reliability refers to having sufficient generation capacity to meet demand, while security refers to the system's technical capability in terms of frequency, voltage, inertia and similar characteristics (section 2.6). Reliability concerns tend to peak over summer, when high temperatures spike electricity demand and increase risks of system faults.

AEMO in September 2017 raised concerns the market was at risk of power outages over summer 2017–18, especially in Victoria and South Australia where plant closures had occurred.[61] Its concerns were exacerbated by an increasing number of outages affecting fossil fuel generators.

While AEMO issued 31 low reserve warnings over summer 2017–18, none led to load shedding. Outages were averted, partly because maximum demand was significantly lower than a year earlier in NSW and South Australia.

The market had also increased supply by returning mothballed gas powered generators to service in South Australia, Queensland, Tasmania and NSW.[62] In South Australia, the government also invested in nine hybrid diesel–gas generators (276 MW) and in a 100 MW grid connected battery at Hornsdale (box 2.4).

Other factors that helped avert reliability issues were high levels of hydroelectric and other renewable generation over summer 2017–18. Rooftop solar PV generation also contributed, operating at its highest quarterly output on record.[63] Coal plant also operated at relatively high capacity, partly due to increased plant availability in Victoria and an easing of black coal supply concerns in NSW.[64]

61 AEMO, *Electricity statement of opportunities for the national electricity market*, September 2017.

62 In Queensland, Swanbank E returned to service in Q1 2018 after having been mothballed in October 2014. In South Australia, Pelican Point returned to full station capacity on 1 July 2017 after operating at half capacity since March 2013. Additionally, the planned mothballing of Torrens A was deferred from June 2016 until July 2019 In Tasmania, Hydro Tasmania recommissioned the Tamar Valley Power Station in 2016 following its announced in August 2015 to decommission and sell the plant. In NSW, Smithfield returned to service in summer 2017–18 after being originally scheduled for retirement in July 2017.

63 AEMO, *Quarterly Energy Dynamics, Q1 2018*, p. 8.

64 AEMO, *Quarterly Energy Dynamics, Q1 2018*, p. 7.

AEMO also took advance action to manage forecast supply risks over summer 2017–18 by securing over 1100 MW of back-up reserves through the Reliability and Emergency Reserve Trader (RERT) mechanism at a cost of over $51 million. The reserves included generation and storage capacity as well as demand response whereby large energy customers are paid to reduce their load when the power system is under stress.

Low reserve forecasts led AEMO to activate the RERT mechanism by calling on reserves twice over summer 2017–18, but those reserves were ultimately not required. AEMO put reserves on standby on 30 November 2017 in Victoria, a day of unseasonably warm weather and generator unavailability that coincided with a major gas facility outage.[65] It also activated the mechanism in South Australia and Victoria on 19 January 2018, a day of high temperatures coupled with a Victorian generator outage and bushfire risks.[66]

A series of planned and unplanned generation outages led AEMO to issue 'lack of reserve' notices in NSW in June 2018, although no involuntary load shedding occurred. Grid demand was unusually high for June for several days, due to thick cloud cover and rain limiting rooftop solar output.[67] AEMO also issued several directions to keep the power system in a secure operating state, including the curtailment of some wind generation.

On 25 August 2018 a fault due to a suspected lightning strike on the NSW–Queensland interconnector separated Queensland from the rest of the NEM. To maintain frequency levels across the NEM, South Australia was also separated from the rest of the NEM, and load shedding occurred in NSW, Victoria, and Tasmania.

Reliability outlook

AEMO in August 2018 again raised reliability concerns for summer 2018–19, forecasting a higher risk of power outages than for the previous summer. It forecast a 1-in-3 chance of some power outages for Victoria if temperatures reach 40 degrees Celsius—particularly if high temperatures occur towards the end of the day, when business demand is relatively high, residential demand is increasing, and rooftop PV's contribution is declining.

Under these conditions, AEMO forecast around 380 MW of additional resources would be needed across Victoria and South Australia to avoid outages, which it proposed to tender for under the RERT scheme. The reserves may include a combination of additional supply capacity, energy storage, and demand response.[68]

AEMO's modelling of the risk of power outages over summer 2018–19 accounted for the market's ageing coal and gas powered plants becoming less reliable. It also factored in drought risks affecting water availability for hydroelectric generation and cooling for thermal generation in NSW.[69]

Beyond summer 2018–19, AEMO forecast an improved reliability outlook, based on expectations of committed new generation and storage capacity coming online and existing plants being upgraded.[70]

2.10 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 settlement prices reducing their earnings, while retailers risk having to pay high prices they cannot pass on to their customers. A retailer may sign up new customers at a particular price but then incur higher than expected prices in the wholesale market, for example, leaving the retailer substantially out of pocket.

Market participants need to manage their exposure to these risks to ensure their financial solvency. Three energy retailers went into administration in recent years—GoEnergy in 2016, Urth Energy in 2017 and COZero in 2018—due to exposure to high wholesale prices.

Generators and retailers can manage their market exposure by locking in prices they will trade electricity for in the future. An alternative strategy adopted by some participants is to internally manage risk through vertical integration—operating both generation and retail arms to balance out the risks in each market. When the retail arm of the business pays high prices for wholesale energy, for example, the generation arm benefits from high prices.

Typically, vertically integrated 'gentailers' are imperfectly hedged—their position in generation may be 'short' or 'long' relative to their position in retail. For this reason, gentailers participate in contract markets to manage outstanding exposures, but usually to a lesser extent than stand-alone generators and retailers.

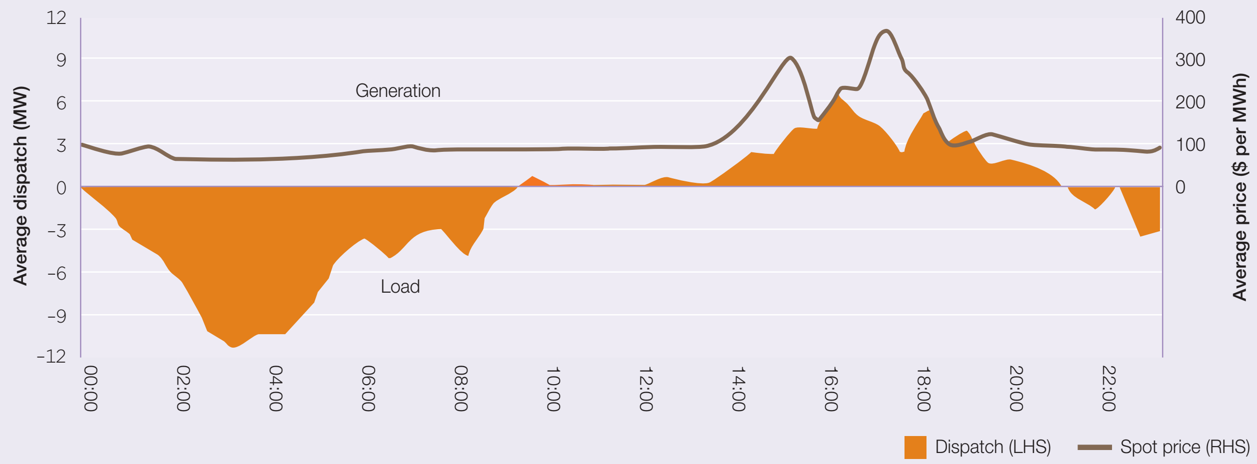
65 AEMO, *Summer 2017–18 operations review*, May 2018.
66 AEMO, *Activation of unscheduled reserves for Victoria and South Australia—19 January 2018*, May 2018.
67 AEMO, *New South Wales 7 June*, media release, 10 June 2018.
68 AEMO, *2018 electricity statement of opportunities*, August 2018, p. 8.
69 AEMO, *2018 electricity statement of opportunities*, August 2018, p. 3.
70 AEMO, *2018 electricity statement of opportunities*, August 2018, p. 3.

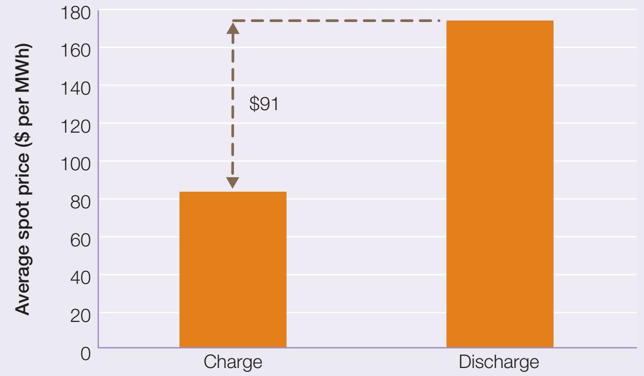
Box 2.4 Hornsdale Power Reserve

The Hornsdale Power Reserve—the NEM's first scheduled battery—played a significant role in the wholesale market over summer 2017–18. It consumed energy (for charging) during 38 per cent of trading intervals in January–March 2018, and was dispatched as a generator in 32 per cent of intervals. The battery was typically charged in the early hours of the morning, when energy prices are low, and power discharged (sold into the grid) in the late afternoon, when prices are higher (figure 2.32).

The difference between the average charge and discharge prices earned the battery an average price arbitrage of over $90 per MWh over this period. Three days of price volatility in South Australia (18 and 19 January, and 7 February 2018) largely accounted for this spread. South Australia prices settled at above $5 000 per MWh in nine trading intervals on these days.

Figure 2.32
Performance of Hornsdale Power Reserve





Source: AEMO, *Quarterly energy dynamics*, Q1 2018, p. 14.

Hornsdale also played an important role over summer 2017–18 in providing frequency control ancillary services (FCAS). EnerNOC, a demand response provider, also provided FCAS over the summer, marking the first time distributed demand-side resources had provided grid balancing services in the NEM.

During the first quarter of 2018 these technologies captured a large share of the South Australian FCAS market, displacing higher priced supply from coal fired and hydrogeneration plant. Competition from the new providers also lowered offer prices from traditional providers such as CS Energy and Hydro Tasmania.[a] FCAS costs in quarter one 2018 averaged 57 per cent lower than in the previous quarter, despite similar volumes of FCAS being required.

Following the success of Hornsdale, other grid scale battery installations have been announced across the NEM to complement and 'firm' solar and wind farm generation.

a AEMO, *Quarterly energy dynamics*, Q1 2018, p. 14.

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 also include financial intermediaries and speculators such as hedge funds. 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 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 Victoria, NSW, Queensland and South Australia.

While ASX trades are publicly reported, activity in OTC markets is confidential and not disclosed publicly, which impairs market information on prices and liquidity. The Australian Financial Markets Association (AFMA) reports data on OTC markets through voluntary surveys of market participants. The AEMC and ACCC both recommended data on OTC electricity contracts be made available to the market in a form that enhances transparency.[71] The ACCC considered this outcome could be achieved through a repository of trades that is disclosed publicly in a de-identified format.

Various products are traded in electricity contract markets. Similar types of 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 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. In OTC markets, futures are known as *swaps* or *contracts for difference*.
- *Options* are a type of contract giving 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.
- *Caps* are contracts setting an upper limit on the price a holder will pay for electricity in the future (typically set at $300 per MWh, while floors are contracts setting a lower price limit. Caps can be traded either as futures or options.

71 AEMC, *2018 Retail energy competition review*, June 2018; ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final Report*, June 2018, p. 122.

Box 2.5 Contracting and the reliability guarantee

The reliability guarantee originally proposed as part of the NEG (box 2.3) included an important role for contract (hedge) markets.

If implemented, the reliability guarantee would require AEMO to forecast the supply-demand balance out 10 years ahead. The guarantee would be activated if AEMO identifies (and the AER verifies) a shortfall in supply that risks the NEM not achieving the reliability standard. Retailers (and other liable entities) would then need to demonstrate they have hedge contracts in place to encourage sufficient generation to meet their expected demand. Hedge contracts with a direct link to the electricity market— including futures (swaps) and caps— would qualify

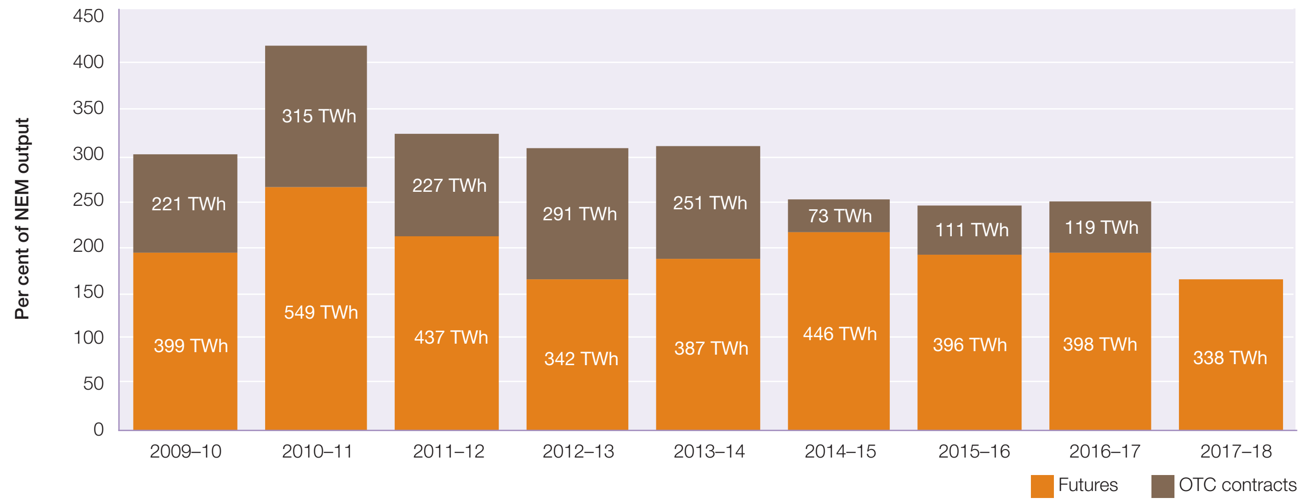
The guarantee's design relies on retailers having access to hedge products. To support contract market liquidity, the reliability guarantee design requires that if a supply shortfall is identified, large vertically integrated retailers must perform a 'market-maker' role by offering to buy and sell hedge products within a limited price spread.

In December 2018 the Australian and state governments were progressing work on the reliability guarantee through the COAG Energy Council.

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. Increasingly, OTC negotiated contracts are cleared and registered through block trading on the ASX.

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.

Figure 2.33
Traded volumes in electricity futures contracts



Note: Data for 2017–18 OTC contracts were not available at the time of publication.
Source: AER; AFMA; ASX Energy.

2.10.1 Contract market activity

As noted, comprehensive data on electricity futures is not publicly available. While ASX trades are publicly reported, activity in OTC markets is confidential and only disclosed publicly via participant surveys in aggregated form.

In ASX markets, regular trade occurs in Queensland, NSW and Victoria, but liquidity is poor in South Australia. Traded volumes also appear to be declining across the market generally (figure 2.33).

In 2017–18 contracts covering 338 TWh of electricity were traded on the ASX, equivalent to 172 per cent of underlying NEM demand. Volumes were down by 15 per cent from 2016–17 levels, when concerns about the impacts of the Hazelwood closure prompted a rise in trading. The 2017–18 data continues a longer term trend of declining activity in the ASX electricity futures market, and was 38 per cent below the peak trading year of 2010–11.

AFMA data based on voluntary reporting suggests OTC trading has increased since 2014–15, but remains well below previous levels. Activity switched from ASX to OTC markets during the period of carbon pricing (2012–14), when participants sought greater contract flexibility, but OTC trading has since weakened. The number of intermediaries (financial market participants without a position in the underlying electricity market) in the market also appears to have reduced.

Declining volumes in electricity futures trades may be partly due to higher levels of intermittent generation, which is not suitable for contracting because its output is weather dependent. But 'firming' of this generation through storage or gas may support contract market participation. A number of market participants with flexible generation capacity are already offering firming products targeted at renewable generation. In April 2018, ERM launched a solar firming product and AGL launched a similar wind firming product.[72]

Flat electricity demand and less price volatility in the wholesale market may also have contributed to lower volumes in contract markets, particularly for cap contracts. As discussed previously, vertical integration—which allows businesses to internally manage risk by operating both generation and retail arms—also limits businesses' need to contract with third parties.

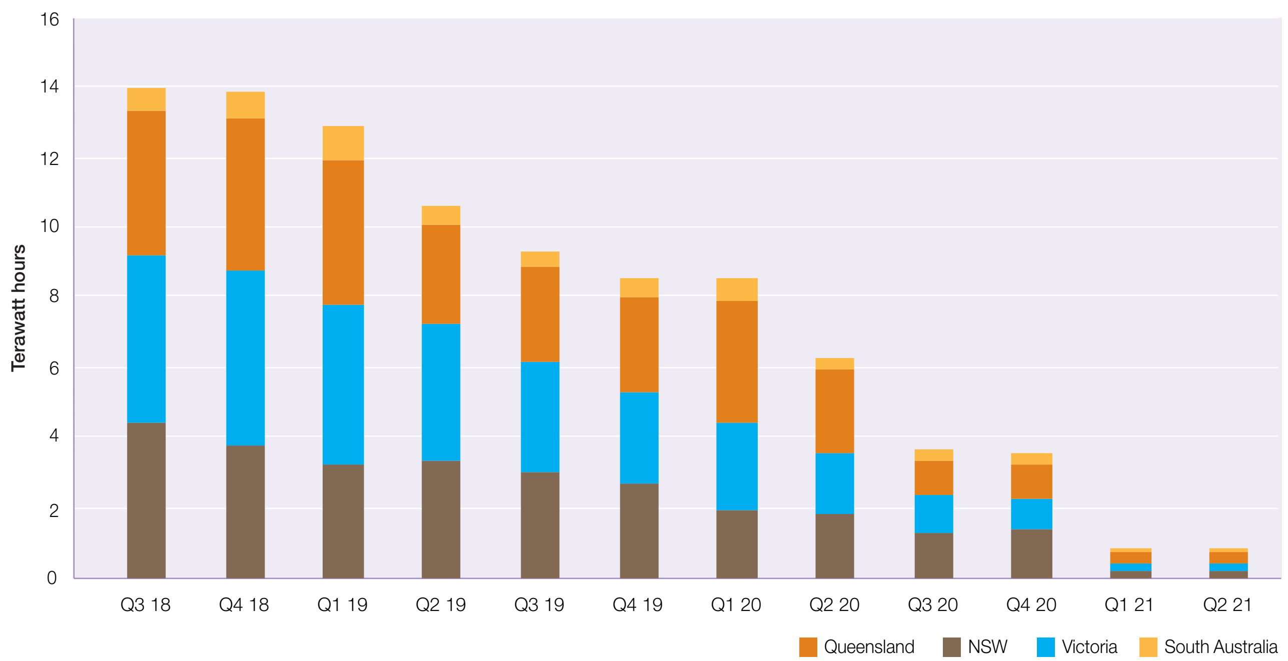
Composition of trade

Victoria, NSW and Queensland each accounted for 30–33 per cent of open ASX electricity futures in November 2018. Liquidity was much lower in South Australia, with 6 per cent of open contracts.

The most heavily traded ASX products in 2017–18 were baseload quarterly futures (55 per cent of traded

72 AER, *Wholesale electricity market performance report* December 2018.

Figure 2.34
Open interest in ASX electricity derivatives



Note: Data at November 2018.
Source: AER; ASX Energy.

volume), followed by options (31 per cent) and cap futures (13 per cent). In the OTC market, the vast majority of transactions are for flat swap products.

Liquidity is highest in products traded 12–24 months out. Open interest (the number of contracts) in the market at November 2018 mostly related to contracts out to the first quarter of 2020, with liquidity rapidly tailing off beyond then (figure 2.34).

2.10.2 Contract market liquidity

Contract volumes traded in Victoria and Queensland (across ASX and OTC markets jointly) generally exceed demand for electricity, while NSW trade volumes and electricity demand are generally balanced. 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. Several retailers indicated to the ACCC they consider liquidity in contract markets in Victoria, Queensland and NSW is adequate.

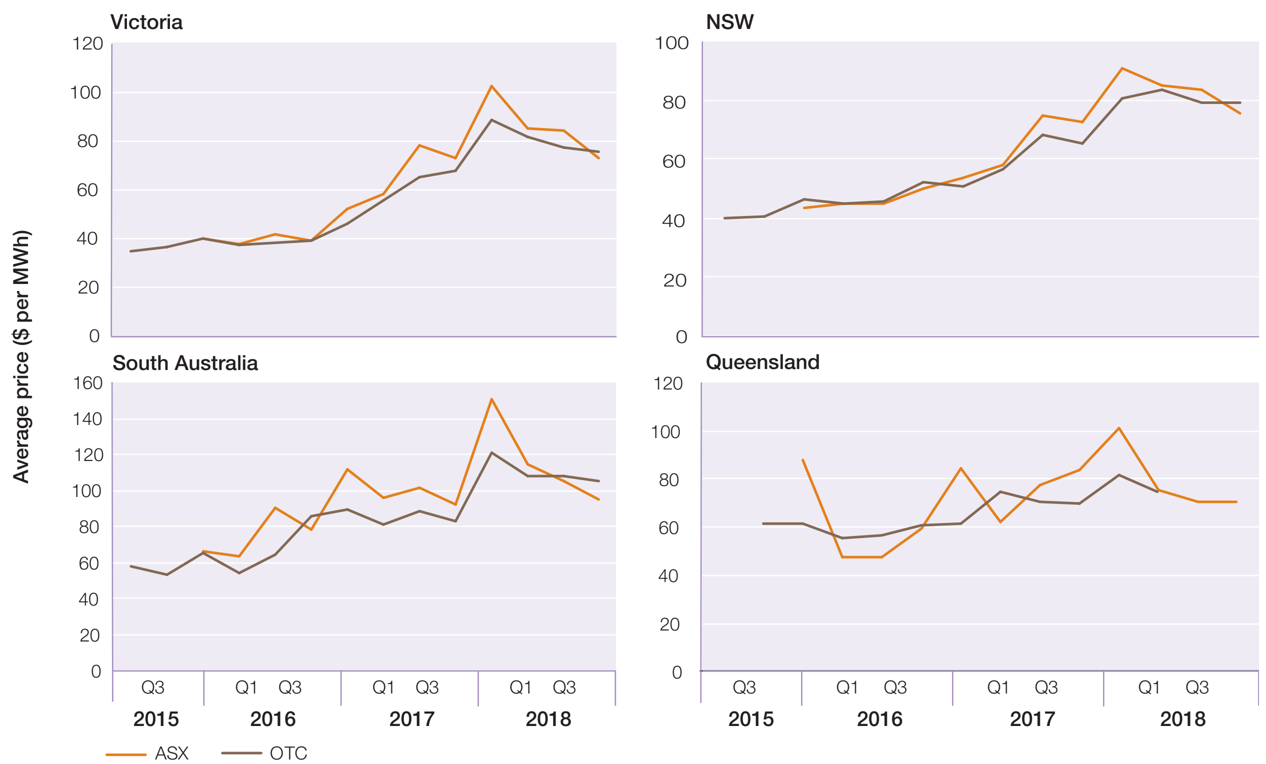
South Australia, by contrast, has trading levels well below regional demand for electricity, which is consistent with claims by retailers that the region's contracting market is highly illiquid. The region's high proportion of renewable generation and relatively concentrated ownership of dispatchable generation likely contributes to this illiquidity. The ACCC also found South Australia is the only region where traded volumes are higher in the OTC than ASX market.[73]

Given South Australia's liquidity issues, the ACCC recommended a 'market-maker' obligation be imposed in South Australia.[74] Similar to the proposed obligation under the reliability guarantee, this obligation would require large vertically integrated retailers to make offers to buy and sell hedge products, with a capped price spread.

The ACCC also noted retailers' concerns about a reduction in offerings of 'load following' contracts in the OTC market generally. These contracts remove volume risk, and are particularly sought by smaller or new retailers without extensive wholesale market capacity.

73 ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final Report*, June 2018, p. 119.
74 ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final Report*, June 2018, p. 130.

Figure 2.35
ASX and OTC average contract prices for base swaps



Note: Average prices by maturity dates ranging from Q3 2015 to Q3 2018.
Source: ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final Report*, June 2018.

While comparisons of price outcomes in OTC and ASX markets are not generally available, the ACCC conducted a comparative study for trading over several quarters. It found prices of OTC contracts were generally lower than for comparable products traded on the ASX, regularly trading at $10–20 per MWh less. This differential was most evident in Victoria, NSW and South Australia. No clear trend was evident for Queensland (figure 2.35).

2.10.3 Recent contract prices

Price movements for electricity base futures for calendar years 2018, 2019 and 2020 are presented in figure 2.36.

Base futures prices rose steadily prior to the closure of Victoria's Hazelwood power station in March 2017, reflecting expectations of how the closure would affect wholesale prices.

Futures prices for supply in 2019 and beyond tended to ease over 2017 and through the first half of 2018. This easing reflected expectations that a large influx of renewable generation planned to come online in 2018–19 would exert downward pressure on wholesale prices. However, futures prices remained well above historical levels, and began trending higher from mid-2018.

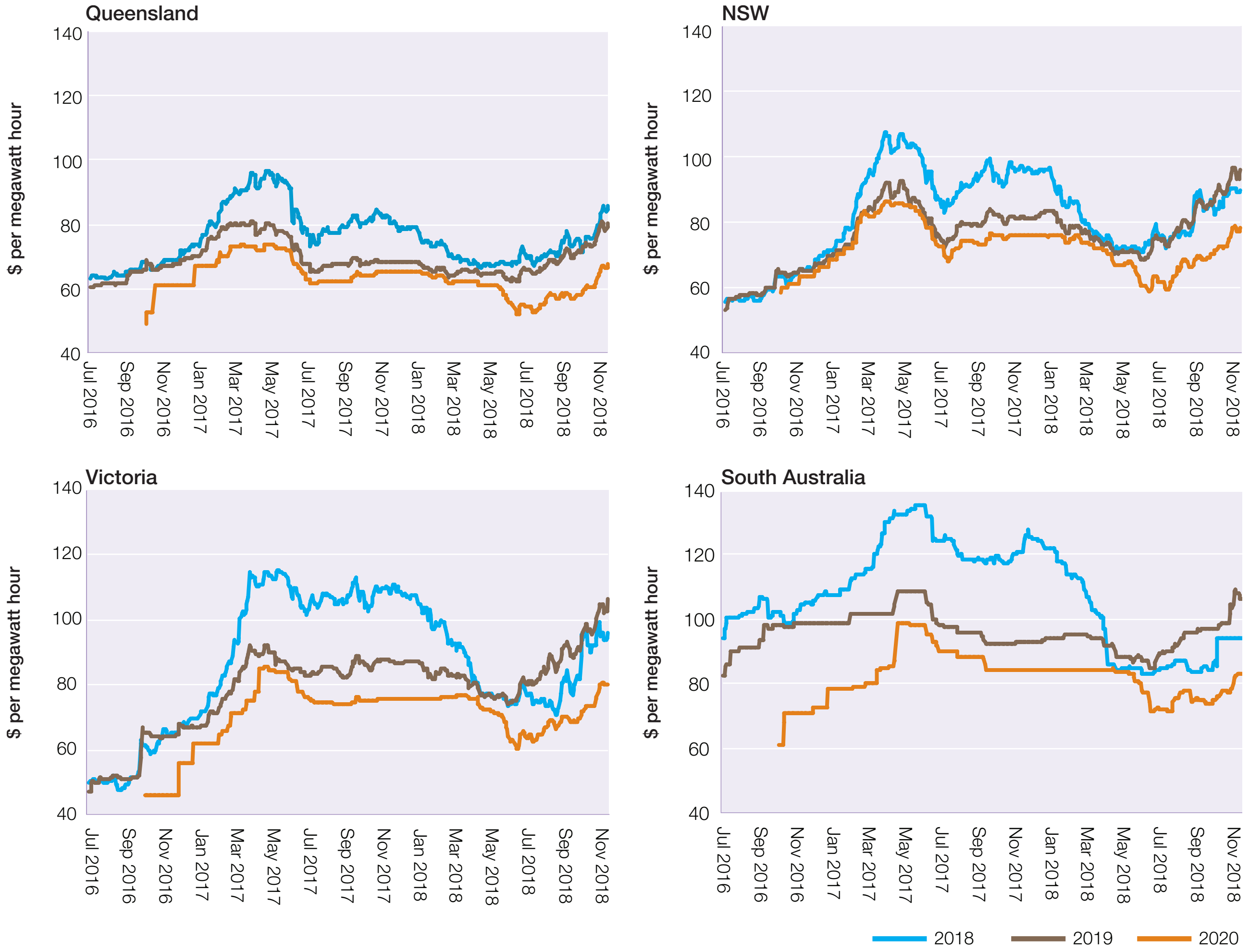
Concerns about electricity market conditions over summer 2018–19 saw futures prices trend higher from mid-2018. Between May and November 2018, futures prices for summer (quarter one) 2019 supply rose by 35–40 per cent in NSW and Victoria, and 25 per cent in Queensland and South Australia. These rises likely relate to market concerns about drought impacting coal and hydroelectric plant availability over summer, and expectations gas fuel costs will likely remain high.

2.10.4 Small retailers' access to contract markets

Lack of effective access to hedging products can pose a barrier to new generators and retailers entering or expanding their presence in the electricity market. The risk is particularly

Figure 2.36

Prices for 2018, 2019 and 2020 base futures



Note: Data at November 2018. Prices for calendar strips, calculated as the average of prices for quarterly base futures for each quarter of the calendar year.

Source: AER; ASX Energy.

high for electricity retailers not vertically integrated with a generator. The ACCC identified potential barriers to small or new retailers accessing hedge products in ASX and OTC markets, with significantly fewer trade options available.[75]

In the ASX market, the credit requirements of clearing houses, and daily margining of contract positions, impose significant costs on retailers. The use of standardised products with a minimum trade size of 1 MW may be too high to meet the contracting requirements of smaller retailers.

Credit risk is also a barrier to smaller retailers in the OTC market, with counterparties likely to impose more stringent credit support requirements on them. Bilateral trade agreements underpinning OTC trades can also be costly to set up.

Major retailers were found to pay less on average for OTC contracts than smaller retailers. To some extent, this outcome may reflect the higher risk of dealing with smaller retailers. But a lack of transparency in the OTC market, combined with smaller retailers having access to fewer potential trading partners, creates a risk of price discrimination against smaller retailers. Reforms to enhance market transparency would improve outcomes in this area.

75 ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final Report*, June 2018, p. 111.

2.11 Market competition

The AER monitors the performance of the wholesale electricity market, including whether it is effectively competitive. Prices in an effectively competitive energy market should reflect demand and underlying cost conditions, at least in the longer term.

In an effectively competitive energy only market, 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 tighten supply and demand conditions allow 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.

In previous editions of *State of the energy market,* the AER highlighted periodic evidence of opportunistic bidding in several NEM regions, including by AGL Energy in South Australia, Hydro Tasmania in Tasmania and most recently by state owned generators in Queensland. Our reporting on these issues supported reforms to generator bidding rules, that the AEMC implemented. The reforms, relating to bidding in good faith, require generators to have genuine intent to honour their bids.

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 five minute dispatch prices. This timing difference allows generators to rebid capacity late in a trading interval to capture high prices, while giving competing generators little time to respond.

The AEMC approved a rule change in 2017 to align the timeframes for dispatch and settlement prices to five minutes. It considered removing the time discrepancy would encourage more efficient bidding and operational decisions. The reform will take effect in 2021.

More recently, the AER reported on the effectiveness of competition in NSW in 2016–17[76], impacts of the Hazelwood closure in Victoria in 2017[77], and a NEM wide review over the past five years.[78] The ACCC in 2018 also analysed competition in the NEM.[79]

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.

A key driver of higher electricity prices has been the exit of low cost coal generation plant. With less capacity available at low prices, higher cost black coal, gas and hydroelectric generators are more frequently setting electricity prices. The increased reliance on gas also comes at a time of high gas costs.

These issues may be transitional. But certain features of the market make it vulnerable to the exercise of market power, and may have driven prices higher than recent changes in the generation mix and underlying supply costs can explain. A few large vertically integrated participants control significant generation capacity and output in most NEM regions. This output is needed to meet demand in most regions a significant proportion of the time, which creates opportunities to exercise market power (box 2.6).

Generator bidding

The AER did not identify opportunistic generator bidding behaviour (such as rebidding, withholding capacity or manipulating ramp rates) as significant contributors to recent energy price rises. Some participants periodically used these methods to exercise market power over the past five years, but this behaviour was not apparent recently. Previously observed rebidding behaviour by Queensland generators declined, for example, after a Queensland Government directive to Stanwell in July 2017 (section 2.9.1).

But the AER did identify longer term market trends that warrant surveillance. In particular, average offers from some black coal generators in NSW and Queensland have increased more than underlying costs. The AER also identified participants exercising market power in South Australia's FCAS markets. However, new entrants have since entered that market and regulatory requirements contributing to the problem have been changed (section 2.9.7).

More generally, wholesale electricity prices have risen to a level that should signal new entry for lower cost technologies. Consistent with these findings, significant

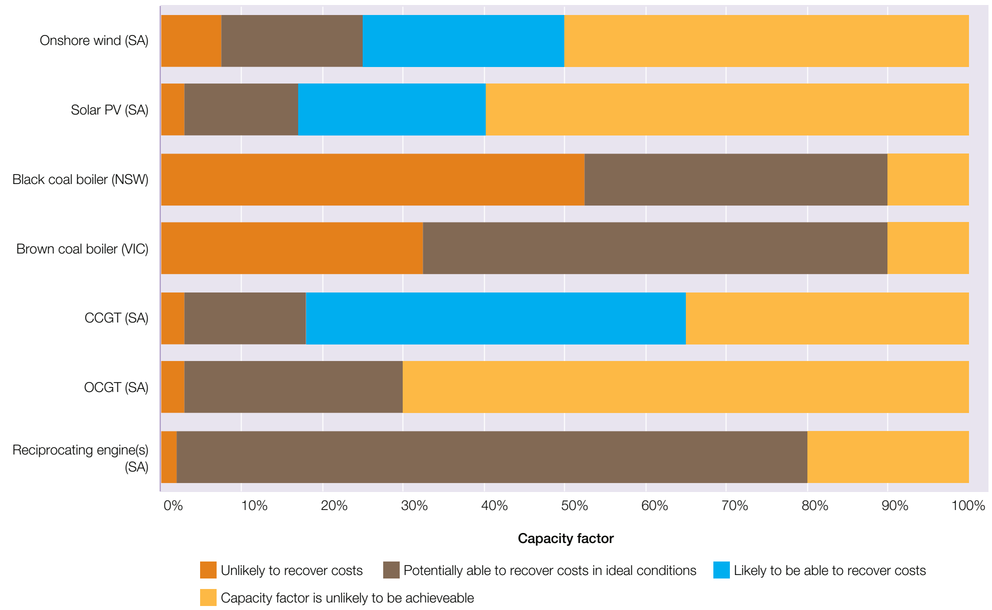
76 AER, *Electricity wholesale performance monitoring, NSW electricity market advice*, December 2017.

77 AER. *Electricity wholesale performance monitoring. Hazelwood advice*, March 2018.

78 AER, *Wholesale electricity market performance report*, December 2018.

79 ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final Report*, June 2018.

Figure 2.37
Likelihood for new entrant cost recovery by technology type



CCGT, combined cycle gas turbine; OCGT, open cycle gas turbine.

Note: Based on spot market outcomes for 2017–18. Cost estimates for new entrants based on publicly available information on generic costs and include both high and low cost scenarios. Cost estimates are levelised, meaning a new entrant generator's lifetime costs are allocated across each megawatt-hour of energy produces over the plant's expected life. New entrants would also consider more site-specific, detailed modelling of costs, risk and production not captured in this analysis.

Source: AER, *LCOE Modelling approach limitations and assumptions*, 2018.

investment in renewable generation is on the horizon (section 2.5). This wind and solar plant investment will create an increasing need for flexible generators or storage able to match variations in intermittent supply.

AER analysis suggested price signals for flexible and firming technologies (such as open cycle gas turbines) are improving. But they remain weaker than for other technologies, because the price spikes these generators need to recover their costs are not occurring frequently enough.

Despite a significant train of recent and planned investment, market participants identified continued barriers to entry for new generation—particularly for flexible capacity. The AER reported views that a lack of stability and predictability in government energy policy is a barrier to entry for new generation. Emissions policy instability, interventions to address energy policy objectives such as reliability and affordability, and government ownership in the industry, were cited as key impediments to generation investment.[80]

In addition, there may be barriers to non-vertically integrated or new entrant generation participants to obtaining finance and managing market exposure. These barriers include the need to contract with gentailers with which they would compete, and poor liquidity in contract markets (section 2.10.4).

Signals for new investment

The Australian Energy Regulator assessed the viability of new entrant plant in the NEM based on spot price outcomes in 2017–18 and estimated production costs.

Figure 2.37 summarises results for the regions with the highest potential spot revenue for each technology. The colour indicates the likelihood of cost recovery for a new entrant at different capacity factors.

Based on spot revenues in 2017–18, the results indicate strong price signals to invest in large scale solar and wind plant—even without support from the Renewable Energy Target scheme. Closed cycle gas turbine technologies would also likely recover their costs based on 2017–18 prices, particularly if operating at higher capacity factors. The results indicate improving investment signals for new coal technologies but, based on current prices and cost estimates, those signals are weaker than for other technologies.

Flexible, firming technologies such as open cycle gas turbines could possibly recover their costs in a best case scenario. But investment signals are again weaker than for other technologies, because the price spikes needed to support the low capacity factors of technologies such as open cycle gas turbines are not occurring frequently enough, despite a general uplift in wholesale prices.

80 AER, *Wholesale electricity market performance report*, December 2018.

Box 2.6 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. Markets with a high proportion of capacity controlled by one or two generators are more likely to be susceptible to the exercise of market power. Figures 2.23 and 2.24 illustrate generation market shares in 2018, based on capacity and output criteria.

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. The higher the HHI, the more concentrated is the market.

Figure 2.38 compares market concentration over time in mainland NEM regions. The average HHI is over 2000 for each region, and has not varied significantly in recent years. But significant variation from the average occurs in some dispatch intervals, due to plant outages, fuel availability and bidding behaviour in response to different levels of demand and prices. South Australia had the highest and lowest single HHI value each year.

Figure 2.38
Herfindahl–Hirschman Index

Note: Based on bid availability or the capacity each generator offered, every five 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 does not account for imports and so overstates 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, *Wholesale electricity market performance report*, December 2018.

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

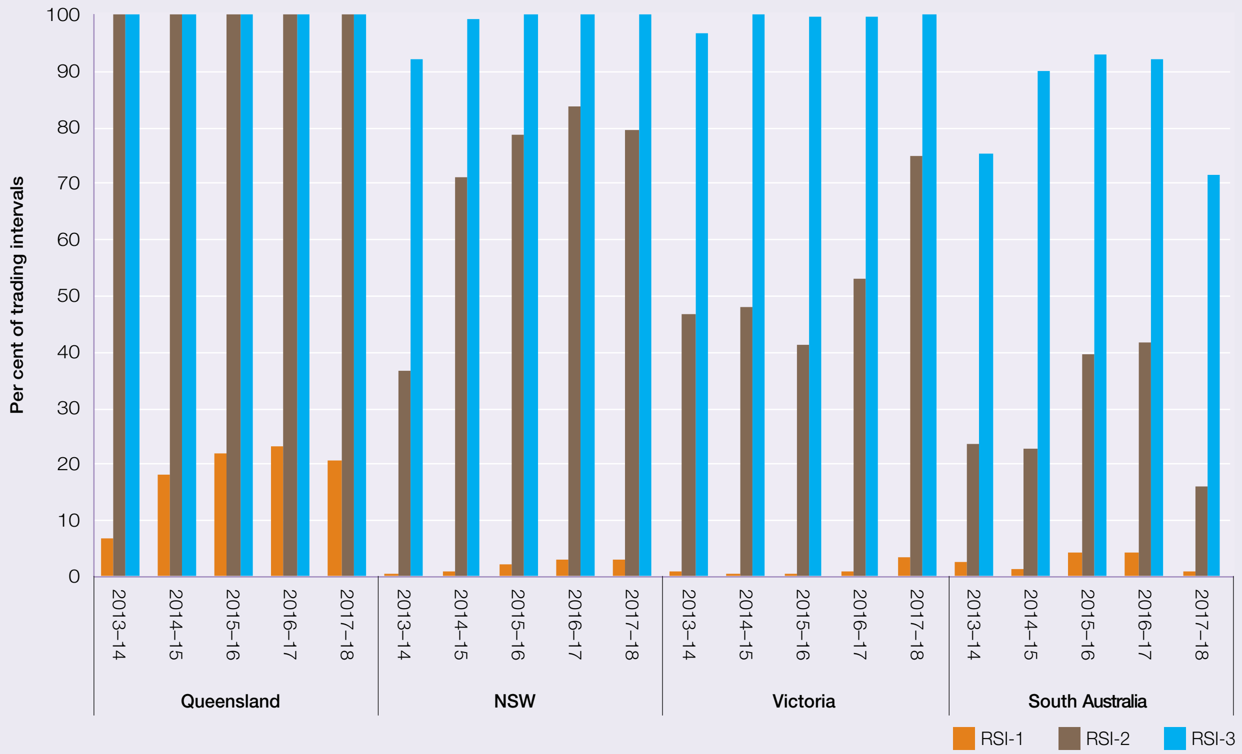
An RSI-1 greater than one means demand can be fully met without dispatching the largest participant. Similarly, RSI-2 and RSI-3 measure the ratio of demand that can be met by all but the two or three largest participants. Various factors may cause the RSI index to deteriorate, including a rise in demand, a decrease in available generation capacity, or an increase in the proportion of available capacity supplied 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 potential risk of multiple participants coordinating behaviour to influence market outcomes.

A limitation of RSI analysis is its focus on whether a participant *can* raise prices rather than 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 2.39 shows the percentage of trading intervals in each the past five years where RSI values were below one—that is, where at least some generation from the one, two or three pivotal participants was needed to meet demand.

Figure 2.39
Pivotality of largest generators



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

Source: AER, *Wholesale electricity market performance report*, December 2018.

In Queensland the largest participant (whether Stanwell or CS Energy) is pivotal— that is, needed to meet demand—more often than the largest generator is pivotal in any other region. In Queensland, the largest generator is pivotal 20 per cent of the time. When Stanwell and CS Energy are jointly considered (RSI-2), some of their combined capacity is needed to meet demand 100 per cent of the time.

In NSW and Victoria, the largest participant is needed to meet demand 3 per cent of the time (around 10 days per year). The two largest participants are needed to meet demand 75–80 per cent of the time. Some output from one of the three largest participants is always needed to meet demand.

South Australian generators are pivotal less often than those in other regions. Output from the largest South Australian generator was rarely required to meet demand in 2017–18. The largest participant(s) was also less pivotal in 2017–18 than previously, in part because a previously mothballed plant at Pelican Point returned to service.

Outcomes for Tasmania are straightforward. In that region, Hydro Tasmania is needed to meet demand 100 per cent of the time.