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Powering out of pandemic: Unleashing the potential of gas

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A Menzies Research Centre Policy Brief

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INTRODUCTION

Australia is fortunate to possess abundant reserves of almost every conceivable energy source. It is home to 14 per cent of the world's proven coal reserves, 30 per cent of known uranium resources and 18 per cent of lithium. In addition, Australia has made the world's largest per capita investment in wind and solar generation.

And then there is natural gas, Australia's third largest energy resource after coal and uranium. For now, Australia is the world's number one supplier of liquid natural gas (LNG) on the international market. It provides a quarter of the nation's energy and is essential to powering industry.

The innovations of hydraulic fracturing, horizontal drilling and the bulk transportation of LNG have broadened its ubiquity and utility this century. International demand for LNG grew more than three times faster than demand for coal between 2009 and 2019. Australian exports quadrupled over this period to 3.6 trillion cubic feet (Tcf). [1]

Yet domestic supply in eastern Australia remains tight, particularly in our two most populous states, where government policy, regulatory inertia and red tape are preventing gas achieving its true potential.

The Menzies Research Centre commissioned one of Australia's most experienced energy and climate economists, Dr Brian Fisher AO PSM, to report on the supply of gas in the Australian domestic market and its potential contribution to Australia's energy mix.

The findings are clear: a competitive and transparent East Coast Gas Market, unburdened by unnecessary restrictions and synchronised to the global commodity market would facilitate manufacturing, increase employment and enable us to reach our environmental goals sooner.

These conclusions are in keeping with the recommendations in the MRC's 2017 report *Power Off Power On: Rebooting the National Energy Market*, in which we sought to map out a pathway from a market corrupted by government failure to one energised by competition and investment opportunity.

While a more competitive energy market would favour consumers, there is no 'pure' free-market solution in a market so grievously distorted by ill-considered government intervention and corporate opportunism. To realise the full potential of gas, governments will be required to make strategic decisions.

The Government's role in facilitating an expansion in the supply of gas will be hotly contested, as indeed it should be. We are not recommending that governments should try to pick winners; quite the opposite in fact. The Government must remain agnostic about the energy sources and technology best suited to delivering an affordable and reliable energy supply.

Government intervention should be motivated by a desire to increase competition, not the concept that governments know best.

This is the measure against which government policy will be judged.

1 BP Statistical Review of World Energy 2020

The post-pandemic energy challenge

Dr Fisher's report was commissioned before the outbreak of the COVID-19 pandemic and the consequent economic downturn. Its findings are all the more pertinent as we anticipate a recovery.

His report highlights the competitive advantages of gas in tackling three post-pandemic energy challenges: the expansion of manufacturing, the replacement of coal generation and maximising the use of renewable energy.

The advent of cheaper and more available gas will help facilitate the expansion of Australia's energy intensive manufacturing base. The price and availability of gas will be a decisive factor in keeping domestic manufacturing competitive, and therefore providing jobs.

Gas is uniquely capable of meeting the tight timetable for replacing retiring coal generators. Approximately a third of Australia's coal-fired generation capacity is scheduled to close over the next 12 years, starting with the retirement of Liddell in NSW in 2023. Gas has the lowest capital costs and the fastest development time.

Peaking and flexible gas generation is the only technology capable of firming intermittent renewable energy at the required scale. Pumped hydro and batteries have a role to play, but their capacity will be constrained by topography and the pace of technology.

In the long-term other technologies are likely to compete, principally next-generation nuclear and hydrogen. Yet it would be irresponsible to bet our future on the hope that these technologies will become scalable, and affordable and stable in the time we have available.

We cannot squander the opportunity to reduce carbon dioxide emissions immediately in the hope there will be a better solution in the future. The immediate challenge requires investment decisions based on the best proven technology.

Why gas?

In hindsight, a transition to gas would have occurred naturally even setting aside concerns about climate change. Transitions from energy-dilute to energy-dense fuels have been occurring for millennia. Technological advances in the extraction and transportation of natural gas in recent decades have made it a strong competitor for coal in many markets.

Natural gas has clear advantages over coal.

- Gas is 50 per cent more energy-dense than coal;
- It emits half as much carbon dioxide;
- 40 times less sulphur dioxide:
- Less nitrous oxide;
- Almost no mercury; and
- Requires 25 to 50 times less water to generate electricity.

The extraction of gas makes less impact on the landscape than wind or solar. It is transported invisibly and cleanly through low-maintenance pipes without noise or other loss of amenity.

No primary energy source has made a greater contribution to the reduction of carbon emissions in the developed world than gas. The transition from coal to gas was one of the main reasons why total carbon dioxide emissions peaked in the 1970s in the largest European economies. Technological advances that facilitated the large-scale extraction of gas from shale was the main reason for the reduction in US carbon emissions of 13 per cent between 2005 and 2018.

Australia faces unique challenges that make a market-driven transition from coal to gas less likely. Australia's comparatively small population mitigates against economies of scale and constrains competition, particularly in the provision of capital-intensive infrastructure such as generators and pipelines.

Compared to the US, the development of natural gas resources in Australia faces greater regulatory hurdles, compounded by stronger professional activism. Indeed, for a period, environmental activists in the US actively supported the development of shale gas as an alternative to nuclear generation.[2]

The transformation from coal to gas has largely been accomplished in South Australia, albeit with a misalignment of timing. Gas drawn from the Cooper Basin in tandem with renewable energy is successfully filling the gap caused by the sudden closure of Northern Power Station.

Partnering renewable energy

Australia is a global leader in the adoption of renewable energy. More than 16 GW of renewable capacity has been added to the National Energy Market (NEM) since 2005. A further 30-47 GW of renewable capacity is expected to be added in the next 20 years.

As we noted in 2017, the implicit and explicit subsidies that stimulated much of this capital investment were poorly judged from an economic as well as a technical perspective. Yet the renewable infrastructure now in place is capable of meeting a significant proportion of energy requirements in partnership with firming technologies.

Quick-start natural gas is currently the most suitable partner for wind and solar in most Australian applications and is likely to remain so beyond the current decade.

It is the only technology capable of firming renewable energy at the scale that is now required on the timetable determined by the retirement of coal generators.

Batteries are playing a part in stabilising the grid but the deployment of batteries for the large part will be necessarily limited to households, light-consumption and remote businesses over the coming decade. We note, for example, that the largest battery system in Australia has the capacity to run a smelter for no more than ten minutes.

Pumped hydro will play an increasing role with the completion of Snowy Hydro 2.0. Geography and topography and the cost of investment place natural limits on the capacity of pumped hydro in Australia. Yet hydro can play an important role as a competitor to gas and other peak-demand sources of supply, helping to reduce prices paid by consumers.

Baseload coal generation will remain the bedrock power source in much of Australia for the next two decades. The replacement of some retiring coal generation plants with new high-efficiency, low-emission coal generators remains an option, particularly on brown-field sites close to coal mines. Decisions should be market-driven taking particular circumstances into account.

2 Bryan Walsh, 'Exclusive: How the Sierra Club Took Millions From the Natural Gas Industry and Why They Stopped,' Time. February 2, 2012

In most circumstances, however, gas has a significant technical and economic advantage over competitor fuels. Open-cycle gas-fired power generators can be ramped up and ramped down more quickly than coal-fired generators which makes them capable of meeting peak demand and augmenting baseload power. They require less land than coal-fired power plants per unit of construction. They need less time for construction and have lower capital costs.

Carbon emissions from gas-fired power generation are about 50 to 60 per cent lower than from conventional coal-fired generators. Average emissions over the cycle are lower still when working in tandem with wind and solar.

South Australia's energy transition

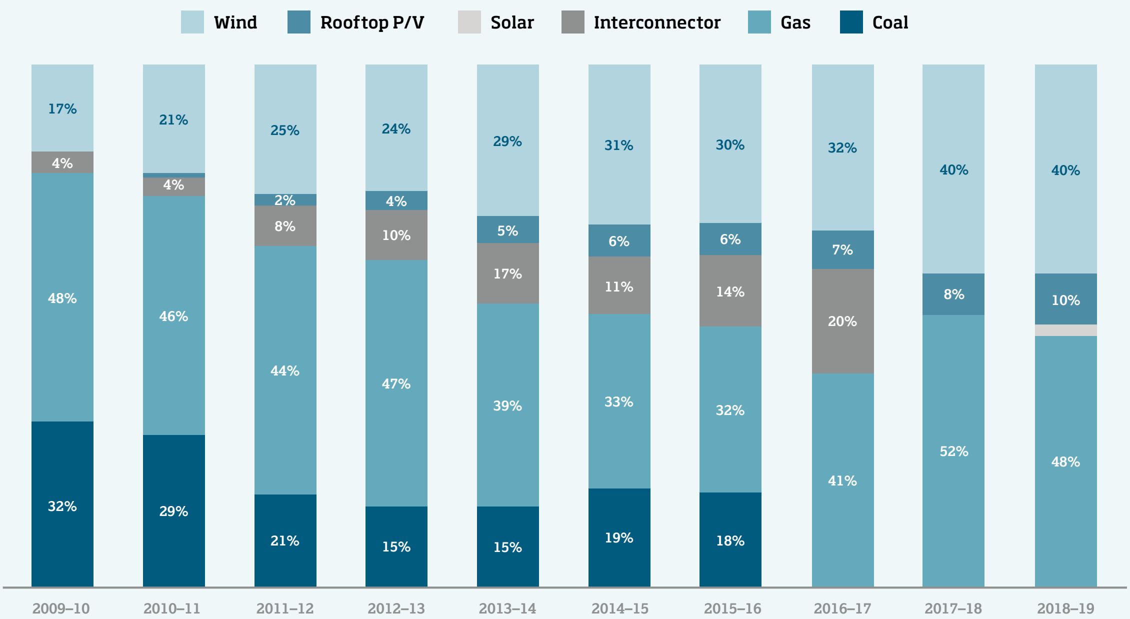
South Australia serves as an experiment in the partnership between gas, wind and solar. The state is second-only to Denmark in the amount of potential wind and solar generation per capita. Unlike Denmark, however, its grid lacks robust interconnection to large neighbouring countries.

The large penetration of domestic rooftop solar has accentuated the gap between peak and non-peak energy requirements, considerably reducing demand on the grid in the middle of the day while driving a steep surge in demand on hot days late in the afternoon.

On January 24, 2019 when the temperature in Adelaide hit 46.6 degrees celcius, operational demand soared to 3140 MW, a level not seen since 2011. On Sunday November 10 2019, on the other hand, SA registered a record low minimum operational demand of 446 MW.

As the gap widens between peak and non-peak demand, the business case for baseload coal generation weakens. Investment in coal generation is attractive when its relatively high fixed costs can be offset over time with relatively low input costs.

Energy transition in South Australia



As demand switches towards dispatchable capacity at times of peak demand, the economics begin to favour gas with its lower fixed costs. The relatively high marginal cost of gas compared to coal is offset by the ability to sell at the top of the market.

Four years on from the blackouts caused by the ill-judged and ill-timed closure of the state's last remaining coal-fired electricity plant, the South Australian grid is supplied by almost equal amounts of variable renewables and gas pumped from the Cooper Basin, assisted at times by the importation of power via Victoria.

Its fortunes, however, are inextricably linked to the prices of gas in southeast Australia which until the start of this year were punitively high. The extent to which natural gas can power us out of the current economic downturn depends heavily on the long-term price and therefore on supply.

Electricity supply in South Australia – 24 hours from 9:00 30 January 2020

The price of gas

Price remains the biggest obstacle to investment and the uptake of gas. The wholesale gas price is an important determinant of the price of electricity, making it a crucial factor in the viability of the broader economy.

There is considerable room for optimism. Two years ago, when the LNG netback price rose above $12 per gigajoule, the price problem seemed insurmountable to some. Yet an increase in international supply with the expansion of production in Australia and the entry of the US as an exporter, combined with the evolution of gas into a global commodity market, engineered a structural change to the gas market that was lowering prices even before the sharp reduction in demand caused by the COVID-19 crisis.

The average netback price in the second half of 2019 was less than $6 per gigajoule, around half the level forecast by the ACCC a year earlier. While the extraordinary lows seen in the first half of this year are unlikely to continue, expectations that the netback price will remain moderate in the short-term seem reasonable.

As a global commodity market evolves, it becomes all but impossible to quarantine the domestic price of gas from the international price. Nor should we seek to do so. Free commerce in gas, like free trade in any other commodity, will force efficiency into the domestic market and reduce the price for consumers.

Producers, transport operators, buyers and traders are adjusting their operating models as Australia becomes part of the global commodity market. Australia is a price-maker as well as a price-taker. We can expect lower prices, more short-term trades, and demands for contractual flexibility, all of which will ultimately favour growth.

Government initiatives to improve transparency, such as the introduction of the ACCC's spot price index, have illuminated gaps for arbitrage. An equivalent index of forward prices, together with greater transparency of transport costs, would provide more visibility.

The expansion of the local supply hub at Wallumbilla in Queensland would further improve the efficiency and transparency of the market.

A second reason for optimism on the price front is the projected increase in domestic production within the next five years as development proposals mature. The recently approved Santos development at Narrabri, for example, will reduce the East Coast price by up to 12 per cent according to some forecasts.

Based on the principle that the nearest gas is the cheapest gas, governments in NSW and Victoria should offer every encouragement to the development of coal-seam gas resources (CSG) in their states. Currently 10 Tcf of CSG is effectively off limits in NSW together with substantial biogenic CSG in East Gippsland, Victoria.

Strategic investment in pipelines must be as complementary to the development of local resources, rather than a straight alternative. Increasing capacity between north and south and enabling the reversal of flow between Victoria and NSW, will put competitive pressure on prices.

Further, the development of import terminals on the East Coast could have a softening effect on spot prices, by taking advantage of low seasonal demand in the northern hemisphere. LNG from WA would be likely to remain competitive even with the addition of shipping costs. The history of bulk transportation offers a degree of confidence that fixed costs will reduce over time.

Potentially the biggest game changer of all could be the development of shale gas in the Beetaloo Basin in the Northern Territory following the lifting on the ban on hydraulic fracturing by the NT Government in 2018.

Geoscience Australia estimates the capacity of Beetaloo at 250 trillion cubic feet, a reserve that is more than 15 times larger than Browse Basin and 30 times larger than Bass Strait.

The competitiveness of transporting Beetaloo gas to the southern states is as yet unclear. Yet it opens the potential for energy-intensive manufacturing in Darwin and for export. In an international commodity market, an increase in global supply can be expected to put downward pressure on domestic prices once barriers are removed.

The role of government

In our 2017 report, we described the energy system in Australia as a classic case of non-market failure.

The natural barriers to entry for new competitors in the sector, principally capital return, start-up costs and infrastructure constraints, have been confounded by poorly-considered intervention by governments state and federal.

The employment of a Renewable Energy Target (RET) as a carbon abatement mechanism was especially damaging. The misallocation of capital and the transfer of costs to consumers and taxpayers undermined the reliability and affordability of electricity supply. The RET's contribution to reducing emissions was marginal and could have been achieved at a far smaller cost with different policy settings.

Moratoriums on the exploration and development of gas, particularly in NSW and Victoria, further distorted the market, leading to a critical shortage of supply in the East Coast market and a consequent rise in price.

Government must continue on the path we recommended in 2017. First, it must wind back the interventions in the energy market to remove distortions and obstacles to investment.

Second, it must incentivise investment in critical infrastructure, such as pipes and terminals, to encourage a competitive market in gas.

Third, it must use its powers of direct intervention judiciously and strategically to prevent anti-competitive behaviour and override false incentives.

Fourth, government has a role to play in increasing market information. The market would be greatly assisted by the provision of a wholesale gas price index in real time by the ACCC or Australian Energy Regulator.

The effect of past policy mistakes was to restrict competition and distort investment incentives by shackling Adam Smith's invisible hand. The challenge for government now is to provide space for the hand to move.

Nick Cater
Executive Director
Menzies Research Centre
October 2020

Recommendations

1. Increasing supply
    i. Increasing the domestic supply of gas should be made an immediate national priority in the post-pandemic recovery period, recognising its crucial role in viability of local manufacturing and the security of jobs.
    ii. All remaining moratoria on the development of conventional and unconventional onshore gas be lifted immediately.
2. Reducing compliance costs
    i. State, territory and federal governments should conduct a comprehensive audit of compliance costs associated with gas production.
    ii. Regulation should not be unduly prescriptive, recognising that resource extraction is a process of continual innovation.
    iii. Regulatory benchmarks should be measured performance goals rather than fixed methods or procedures.
    iv. Regulation should be clear and concise. It should be communicated effectively and should not be subject to arbitrary change.
    v. Regulation should be consistent with other laws, agreements and Commonwealth jurisdictions.
    vi. Regulation should be administered by accountable bodies and should be subject to appeal.
    vii. Regulation should not be regarded as an opportunity for revenue raising, recognising the long-term benefits of royalties to the state.
    viii. A clear and enforceable timetable should apply to regulatory approvals.
    ix. Indigenous Land Councils should be required to identify traditional owners in a timely manner and facilitate negotiations between developers and traditional owners with appropriate speed.
3. Price transparency
    i. The ACCC's role in guaranteeing transparency of market prices to be strengthened and expanded.
    ii. The ACCC to report netback forward curve prices for long-term gas supply (eg 5-10 years) based on a suitable international gas price marker.
    iii. The ACCC's obligation to ensure transparency be extended to transportation and export costs to facilitate arbitrage.
    iv. An index of wholesale gas contract prices be made available in real time by the ACCC or AER.
4. Infrastructure investment
    i. Gas transport be recognised as vital national infrastructure.

ii. New interconnected proposals be subject to a comprehensive cost-benefit comparison with regional gas-fired generation firming.

iii. The Government to stimulate private sector investment in pipelines, export and import terminals aimed at increasing competition and supply.

iv. The Government should prioritise infrastructure proposals according to their overall contribution to increasing supply and competition, and that priorities be annually reviewed.

v. Infrastructure investment priorities to include a pipeline to connect Narrabri with Newcastle/Sydney, expansion of capacity from Moomba to Adelaide, bi-directional flow on the Eastern Gas Pipeline between Sydney and Melbourne, a connection with the Bowen Basin flowing south, and consideration of connections with the Beetaloo Basin to Darwin and/or Wallumbilla.

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1. Overview

Australia's gas resources are modest by Middle Eastern or Russian standards but Australia is now the largest LNG exporter in the world. Gas markets in Australia are comprised of three key regions: the East Coast incorporating Queensland, NSW, Victoria, South Australia and Tasmania; the Western Australian market; and the Northern Territory. The Northern Gas Pipeline now joins the east coast market to the northern region although the capacity of the connection is quite limited. All regions sell gas to both domestic and international customers.

The increase in natural gas prices in most States over the five years leading up to the COVID-19 outbreak and subsequent severe reduction in economic activity was a direct result of escalating international demand for natural gas exported as LNG and has led to fundamental shifts in the economics of electricity generation.

Historically touted as the transition fuel between coal fired baseload generation and renewable energy, gas has progressively become less economic as a source of generation in the face of higher prices, State-based renewable energy targets and subsidised renewable energy.

As Australia moves to increasingly higher penetration of variable renewable energy (VRE) as well as greater levels of distributed energy (DER), the need to balance or firm these variable sources of power with flexible dispatchable energy becomes more imperative.

In this report, we examine the potential for gas to play a more significant role in the Australian energy market, particularly in view of a scenario where domestic gas prices are lower as a result of decreased energy demand due to COVID-19, there is further downward price pressure linked to oil-related issues, and changing domestic regulations around gas exploration and development lift some barriers to supply.

The report is set out as follows:

Chapter 2 lays out some fundamentals of the natural gas market in Australia including supply and demand, and issues related to regulation of exploration activities;

Chapter 3 looks at the electricity fuel mix and projections for retirement of coal generation, the levelised costs of electricity and firming costs of different technology types;

Chapter 4 reviews the Australian Energy Market Operator's Integrated System Plan including scenarios for a faster or slower transition to renewable energy; and

Chapter 5 explores opportunities for a greater role for natural gas and the factors supporting this scenario.

2. Natural gas markets

Demand

Australia's total energy consumption in 2017-18 was 6172PJ, with an increase in energy productivity of 2 per cent (average 20 per cent over the past 10 years).

In 2017-18 natural gas comprised 25 per cent of Australia's primary energy mix, behind oil (39 per cent) and coal (30 per cent).[1] Renewable energy contributed 6 per cent (Table 2.1). Natural gas consumption increased 4 per cent in 2017-18, primarily due to higher use in LNG export production and electricity generation, even while its use in manufacturing fell.

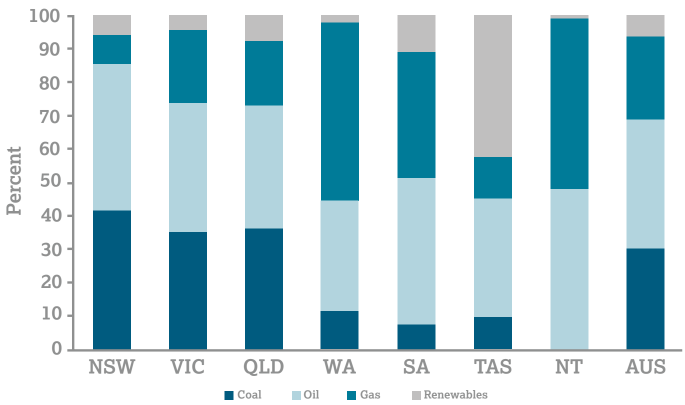
Table 2.1: Australian fuel consumption

	2017-18		Average annual growth	
	PJ	share (per cent)	2017-18 (per cent)	10 years (per cent)
Oil	2,387.8	38.7	3.2	2.0
Coal	1,847.20	29.9	-4.3	-2.6
Gas	1,554.6	25.2	3.8	2.4
Renewables	382.1	6.2	0.9	5.3
Total	**6,171.7**	**100.0**	**0.9**	**0.6**

Source: Department of Environment and Energy (2019)

The share of natural gas in the Australian energy mix varies substantially by State and Territory (Figure 2.1). Western Australia uses the highest amount of gas in its fuel mix, largely in mining and own-use consumption in LNG for export. By contrast, NSW uses the lowest proportion of gas in its fuel mix, relying far more heavily on oil and coal. At present NSW is almost completely reliant for its gas supplies on interstate sources.

Figure 2.1: Australian energy mix by region



Source: Department of Environment and Energy (2019)

1 Primary energy is defined as that energy derived directly from natural sources in contrast to end use energy which includes energy after conversion such as electricity and refined petroleum products.

Sector uses

Natural gas is used in multiple sectors across the Australian economy:

Electricity generation:

- Around 37 per cent of Australia's gas consumption in 2017–18 was used for electricity generation. Gas fired generators provide around 20 per cent of Australia's electricity output, which is primarily used to meet peak demand, however it can also be used for baseload generation (DEE 2019).
- Forecast gas consumption in gas fired power generation plants is expected to decline from around 8 per cent today, as greater interconnection, renewable resources and pumped hydro enter the NEM. As coal generation retires through time, gas powered generation (GPG) is expected to regain 2020 levels (AEMO 2020a).

LNG production:

- Gas is used in liquefaction and to generate electricity. Around 9 per cent of gas flows are consumed by the plant during liquefaction, with the remainder exported as LNG. Around one-fifth of Australian gas consumption in 2017–18 was attributed to LNG production (DEE 2019).
- Consumption of gas by the LNG sector is forecast to remain stable over time (AEMO 2020a).

Manufacturing:

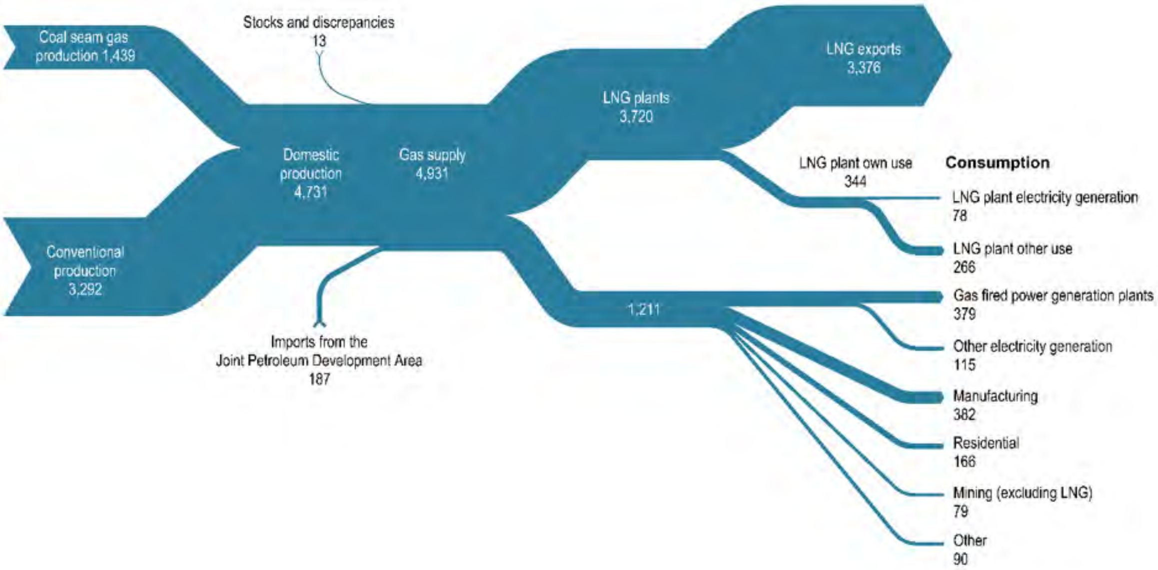
- Uses include non-ferrous metals, non-metallic minerals, chemicals and polymers, plastic packaging for food and beverages, petroleum refining, iron and steel, and pulp, paper and printing (APGA 2020). Manufacturing accounts for roughly 25 per cent of gas consumption nationally.

Households:

- Gas is a major energy source to around 70 per cent of Australian households via either a network connection or bottled gas (ENA 2017). In 2017-18, domestic uses contributed around 11 per cent of total domestic gas consumption.
- Residential growth in gas demand is forecast to grow around 7 per cent by 2040, as energy efficiency, fuel switching and assumed high gas prices offset new connection growth (AEMO 2020a).

Figure 2.2 provides a representation of gas flows in the Australian context, from conventional and coal seam production through to the multiple uses for natural gas and LNG export.

Figure 2.2: Australian gas flows (PJ)



Source: Department of Environment and Energy (2019)

Given the economic, market and political fallout already arising from the COVID-19 pandemic, it is plausible that we will witness a major shift in domestic energy markets over the near to medium term. Possible scenarios include increasing nationalisation of industries in some countries off the back of tightened international movement and trade restrictions, alongside a return to greater local manufacturing to diversify product supplies. Such factors are all likely to contribute to a significant increase in Australian domestic gas consumption. It is therefore also possible that some form of domestic gas reservation to underpin an increase in local manufacturing may occur.

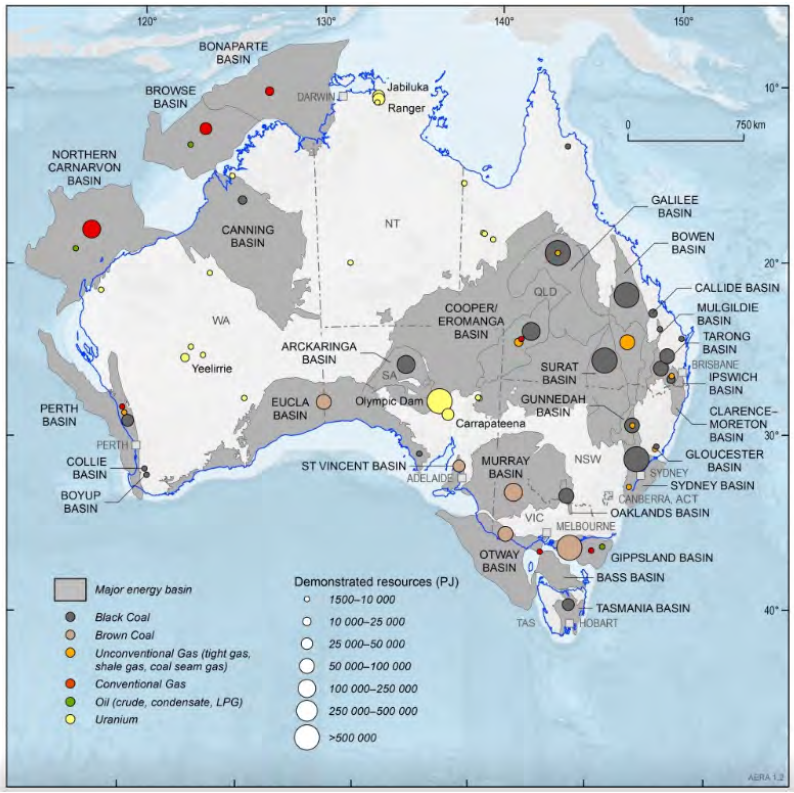
Should second-wave virus implications prove significant, we may see an extension to muted economic activity, which would prolong the reduction in energy demand and result in lower energy prices for an extended period of time.

Supply

Key natural gas producing regions are mapped in Figure 2.3. As at July 2019, Australia had 77,253 PJ of conventional gas economic demonstrated resources (EDR), including reserves. It also had further EDR of 45,895PJ of coal seam gas. Total Demonstrated Resources of all conventional and non-conventional (including coal seam gas, shale gas and tight gas) resources in Australia are 279,685 PJ. These resources equate to around 106 years of gas at current production rates. However, demonstrated resources are expected to grow in line with further exploration, even accounting for increasing production through time (Geoscience Australia 2019).

While conventional gas resources are primarily located off the north-west coast of Western Australia, there are also significant resources of unconventional gas onshore. Coal seam gas basins are primarily on the east coast in Queensland and NSW, while shale and tight gas resources are spread across Australia, with the most prospective being in the Cooper and Perth basins (Geoscience Australia 2019).

Figure 2.3: Distribution of Australia's major non-renewable energy resources



Source: Geoscience Australia

Total energy production in Australia was 18,603PJ in 2017-18, an increment of 4 per cent on the prior year as a result of increased natural gas and black coal production which outweighed a drop in oil and brown coal production. Natural gas production grew by 15 per cent to 4731PJ over the same time period; mostly a result of increased LNG production in Western Australia. It is noteworthy that of the natural gas produced in Australia, 75 per cent is exported as LNG or used in the production of LNG for export. This figure is rising through time as additional LNG capacity comes online. In 2017-18, coal seam gas, developed predominately for export, accounted for one-third of Australian gas production and two-thirds of east coast gas production (DEE 2019). This figure is expected to decline as further LNG capacity comes online; particularly if regulations against further coal seam gas exploration remain in place in some states.

Turning to the east coast and southern gas markets and Northern Territory supply fields, existing gas fields are in decline, with several fields reaching end of life over the next five years. Total east coast gas production in 2024 is expected to be 1,947PJ (AEMO 2020). Some successful exploration and reserve development is continuing in eastern Australia (see for example the recent announcement by Senex[2]).

Two new projects are expected to commence production between 2020 and 2022, and additional new projects in the Otway, Gippsland and Cooper Eromanga basins are expected to come online over the next few years. However, these projects alone will be insufficient to meet forecast demand in 2024 and beyond. Further projects in Queensland will also need to come online to fill the supply-demand gap (AEMO 2020a).

2 Senex ASX Announcement, 14 July 2020, https://www.senexenergy.com.au/wp-content/uploads/2020/07/2085080.pdf?utm_medium=email&utm_campaign=Senex+delivers+major+Surat+Basin+gas+reserves+upgrade+following+delivery+of+transformational+gas+developments&utm_content=senexenergy.com.au%2Fwp-content%2Fuploads%2F2020%2F07%2F2085080.pdf&utm_source=comms.senexenergy.com.au. Accessed 14 July 2020.

Regulation

Victoria is a substantial consumer of natural gas and consumes around 220PJ of gas annually. In March 2020, Victoria lifted its ban on conventional onshore gas exploration from July 2021 partly in response to the Victorian Gas Program investigation finding that there is up to 830PJ of gas in the Otway Basin and Gippsland that could be safely extracted without harming the environment. At the same time, the Victorian Government has also permanently banned CSG exploration and fracking in the State.

While NSW has also had what is effectively a moratorium on coal seam gas exploration, earlier this year it signed a memorandum of understanding with the Federal Government to add 70 PJ/year of gas into the eastern market in return for $0.9 billion in federal contributions to assist the transition to renewables. The most likely project to bridge this production expectation is the Narrabri coal seam gas project, which has been under development since 2014 and has a projected gas output equal to the target. AEMO estimates the well head price for Narrabri gas at $7.40/GJ, which is $2-4/GJ less than importing from Queensland, owing to the additional cost of pipeline transportation. However, the Narrabri project will require the development of some new pipeline infrastructure which would add to the cost of gas from this source.

The Gas Inquiry 2017-2025 (ACCC 2020) highlighted the ongoing need for a greater diversity of supply in the east coast market, as well as the need for transparency and a more efficient transportation and storage network. This finding was underpinned by several observations including:

- LNG producers hold a significant proportion of reserves and may have greater incentive than small or mid-tier domestic-only producers to delay developing or bringing gas to market.
- Such incentives can affect the timing of investment in gas pipeline and storage infrastructure, which will be increasingly necessary if future gas supply is primarily sourced from Queensland as expected.
- This investment could also be affected by shorter contracting periods for gas supply, transportation and storage, given infrastructure owners require certainty of future demand and revenues to undertake significant expenditures.
- To overcome the considerable challenges facing the east coast gas market in the medium to long term, State and Territory governments should adopt policies that consider the risks of individual gas development projects, ensure new gas developments are advanced in a timely manner, and coordinate the development of pipeline and storage infrastructure to avoid unnecessary duplication.

In brief, as moratoria that have prevented onshore gas exploration and development lift, this should enable greater supply to the domestic market and place additional downward pressure on east coast gas prices. Current circumstances may delay these developments, as the near to mid-term gas price forecast appears soft. There remains however a need for government policy coordination to ensure the most efficient development of gas projects and infrastructure.

3. Electricity sector

The Australian electricity sector is a major consumer of natural gas – of the 1200PJ of gas consumed domestically, gas fired and other electricity generation consumes around 500PJ. No other sector of the economy holds such a reliance on gas as a fuel source yet the role of gas in the sector's transition to renewables is at a cross-roads.

Historically, gas was widely viewed as a strong transition fuel for the electricity sector as it moved from a heavy reliance on coal fired baseload generation to variable renewable energy (VRE) sources such as wind and solar. Gas generation was considered a strong candidate given its high dispatchability, lower emissions profile relative to coal, its abundance as a domestic resource, and low capital cost.

More recently, the apparent relevance of gas in the electricity sector transition has been reduced owing to several factors including significant increases in the price of domestically produced natural gas (as it increasingly began competing with LNG exports), subsidised renewable energy under the RET alongside falling underlying wind and solar technology costs, falling costs of battery storage, an increasing interest in pumped hydro and the introduction of virtual power plants (VPPs)/demand aggregators.

As VRE continues to take up an increasingly higher proportion of the electricity generation fuel mix, the retirement of several large baseload coal generators in NSW, Victoria and Queensland will create challenges for system security and reliability in the NEM. AEMO's Integrated System Plan (ISP) is designed to provide a strategy for future NEM investment and ensure these challenges are met in a timely fashion.

Fuel mix in Australia

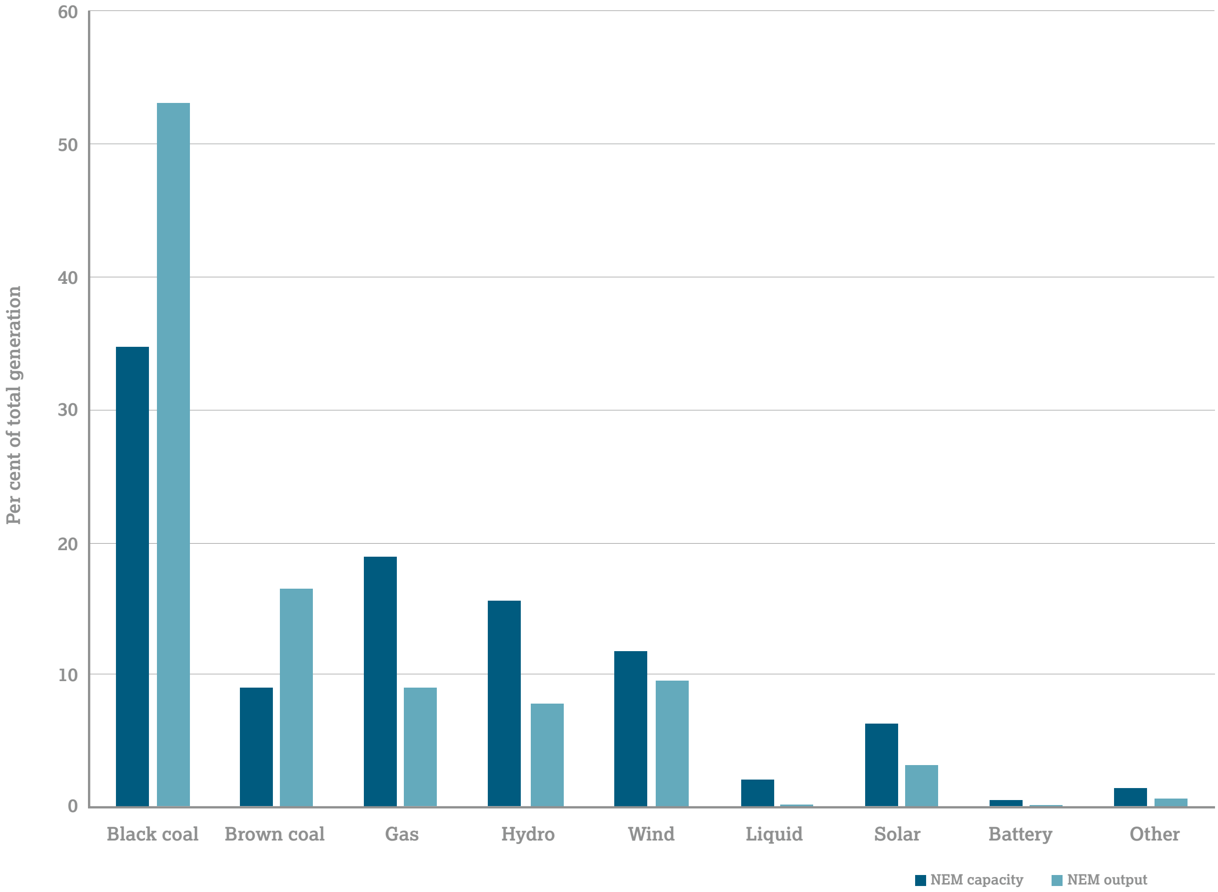
In 2017–18 total electricity generation in Australia including industrial, rooftop solar PV and off-grid generation was 261 TWh (940PJ). Over the decade 2008-09 to 2017-18, average annual electricity consumption grew by 0.9 per cent, and in 2017-18 electricity consumption accounted for around 19 per cent of total final energy consumption in Australia (DEE 2019).

In 2018, fossil fuels contributed 81 per cent of total generation, including coal (60 per cent), gas (19 per cent) and oil (2 per cent). Renewables contributed around 19 per cent of total electricity generation, comprised of hydro (8 per cent), wind (6 per cent) and solar (5 per cent) (DEE 2019).

There are many projections of the Australian electricity fuel mix into the future, however this will depend on several factors including economic growth, industry mix, fuel prices, solar PV uptake and developments brought about through the Integrated System Plan. It is plausible that lower economic growth may result in slower uptake of DER and a delay in high-value investments in hydro and transmission. It may also result in existing coal fired generators being retained past their intended retirement dates. Furthermore, it is likely that ongoing downward pressure on oil prices will have a moderating effect on gas prices, thereby changing the relative economics of gas fired generation.

Figure 3.1 shows the percentage contribution by each fuel source to total NEM capacity and NEM output during the second half of 2019. While black and brown coal together account for around 43 per cent of capacity, they contributed almost 70 per cent of output. Gas is typically operated in the NEM to meet loads during peak and intermediate demand for electricity.

Figure 3.1: Generation capacity and output by fuel source - NEM



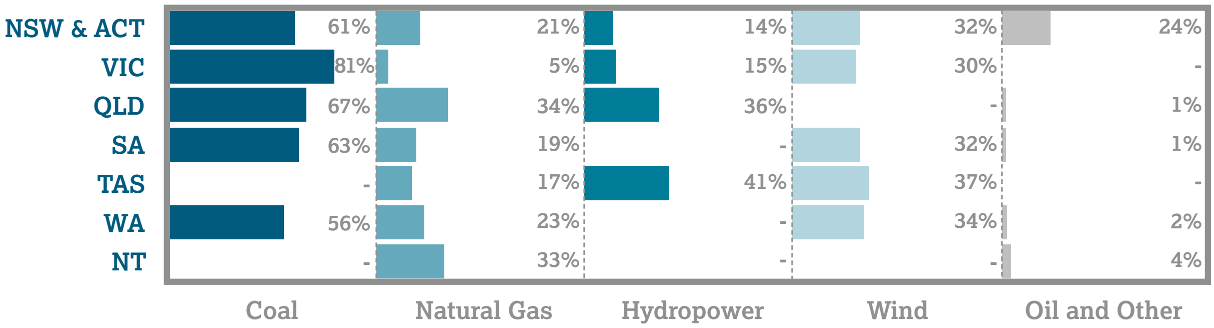
Source: AER (2020)

Note: Data as of January 1, 2020

The term 'capacity factor' describes the ratio of actual electricity output over a given period of time relative to the maximum possible electricity output over the same timeframe. The maximum possible energy output would be achieved if the generation unit operated at its nameplate capacity for the entire period under consideration. The actual energy output of the unit depends on a whole range of factors including type of electricity being produced and its price, its location, overall fuel mix in the power system, maintenance issues, transmission constraints and regulatory barriers. Hence what is often described as a capacity factor in the literature is often more accurately reflective of a 'utilisation rate'.

The utilisation factors of coal and gas generators vary by technology and fuel type, different load patterns by State, and power system fuel mix (Figure 3.2). Depending on turbine and generator size, location and transmission line capacity, wind farms in southeast Australia operate at utilisation factors of between 30 and 35 per cent. Hydropower in Australia operates across a wide band of utilisation depending on size, water supply, and load characteristics.

Figure 3.2: Generation utilisation factors



Source: Australian Energy Council (2017)

Coal generation is retiring

Almost two thirds of Australia's coal fleet will retire by 2040, taking 15GW of baseload capacity out of the NEM. The remaining baseload coal fleet will be retired by 2060 (Table 3.1). Looking ahead, there is a pressing need to understand the optimal mix of generation, transmission and storage that will fill this gap whilst ensuring the reliability, sustainability and cost-efficiency of the NEM.

AEMO's 2020 Integrated System Plan (ISP) is designed to meet this challenge. It envisages a primary role for intermittent renewable generation including wind and solar, supported by hydro, battery storage and transmission development, alongside demand management, GPG and a rapid increase in DER. It is expected that this suite of options will provide the optimal development path to ensuring grid reliability and security in the future.

Whichever bundle of generation options are adopted as coal generators retire from the NEM, they will need to be sufficiently flexible to proactively match capacity reductions through time and to also ensure system reliability and security.

System reliability means ensuring consumer demand is met under normal operating conditions. It does not mean all customer demand is met at all times. However, there must be enough generation, demand response and network capacity in the system to meet consumers' energy needs to the defined reliability standard. Lack of reliability may lead to involuntary load shedding at levels that reduce public confidence and value and create health and safety risks (AEMO 2019).

Table 3.1: Retirement dates: coal fired generators

Generation unit	Installed capacity (MW)	Expected closure	Emissions (MtCO2e/yr)	Location
Liddell 4	500	2022	7.8	Vic
Liddell 1-3	1500	2023		
Callide B	700	2028	5.1	Qld
Vales Point B	1320	2029	7.0	NSW
Yallourn W 1	360	2029	13.9	Vic
Yallourn W 2	360	2030		
Yallourn W 3	360	2031		
Yallourn W 4	360	2032		
Eraring	2880	2032	14.9	NSW
Gladstone	1680	2035	8.5	Qld
Bayswater	2640	2035	13.7	NSW
Tarong 1&2	700	2036	10.5	Qld
Tarong 3&4	700	2037		
Tarong North	443	2037		
Loy Yang B	1050	2047	10.1	Vic
Loy Yang A	2200	2048	20.1	
Mt Piper	1400	2043?	6.8	NSW
Stanwell	1445	2043?	7.6	Qld
Callide C	810	2051?	5.3	Qld
Kogan Creek	750	2057?	4.4	Qld
Millmerran	852	2052?	5.8	Qld
TOTAL	**23010**		**141.5**	

Source: AEMO

System security means ensuring that critical power system services such as frequency and voltage control, and system strength stay within safe limits. This is critical to avoid widespread interruption of electricity supply and to lower the risk of physical damage to power system and customer assets through large voltage or frequency variations. System security also relates to the capacity of the power system to recover from unexpected events without relying on emergency supplies or other high cost alternatives (AEMO 2019).

As part of identifying system requirements, AEMO nominated key areas in current need of improved system strength in South Australia, Tasmania and northwest Victoria. It is noted that these areas could expand significantly as coal generation retires and additional VRE enters the NEM. Currently proposed grid augmentations are outlined in Table 3.2. Together, the first tranche of capital investments proposed by AEMO total $3.1 - 5.2 billion, with further substantial transmission and interconnection expenditures required through time. The net market benefits of these augmentations are above 1.0 in all except the Slow Change scenario.

Table 3.2: Proposed transmission and interconnector investments

Investment description	Augmentations	Estimated cost
Project EnergyConnect	New interconnector between SA and NSW 750MW	$1.5 billion[3]
HumeLink	Reinforce NSW Southern Shared Network and increase capacity between Snowy Hydro and NSW demand centres	$900 million -$1.6billion[4]
Western Victoria TNP	Add transmission to unlock REZ in west and NW Victoria	$370 million[5]
VNI Minor	Upgrade capacity Victoria - NSW by 170MW	$87 million[6]
QNI Minor	Upgrade Qld - NSW by 190MW, and NSW - Qld by 460MW	$65 million - $1.6billion[7]

Additional proposed grid augmentation works costing well in excess of $7 billion[8] are recommended for future years, including:

- Marinus Link cables 1 and 2[9]
- VNI West[10]
- QNI medium[11] or large[12] interconnector upgrade
- Queensland grid reinforcements
- NSW grid reinforcements
- Augmentation of northern NSW grid to support Renewable Energy Zones (REZs).

Generation costs and firming

There are a variety of approaches that can be used to compare the competitiveness of different electricity generation technologies. Any investment in generation is composed of both capital costs and operating costs; the proportionality of these costs varies by technology type.

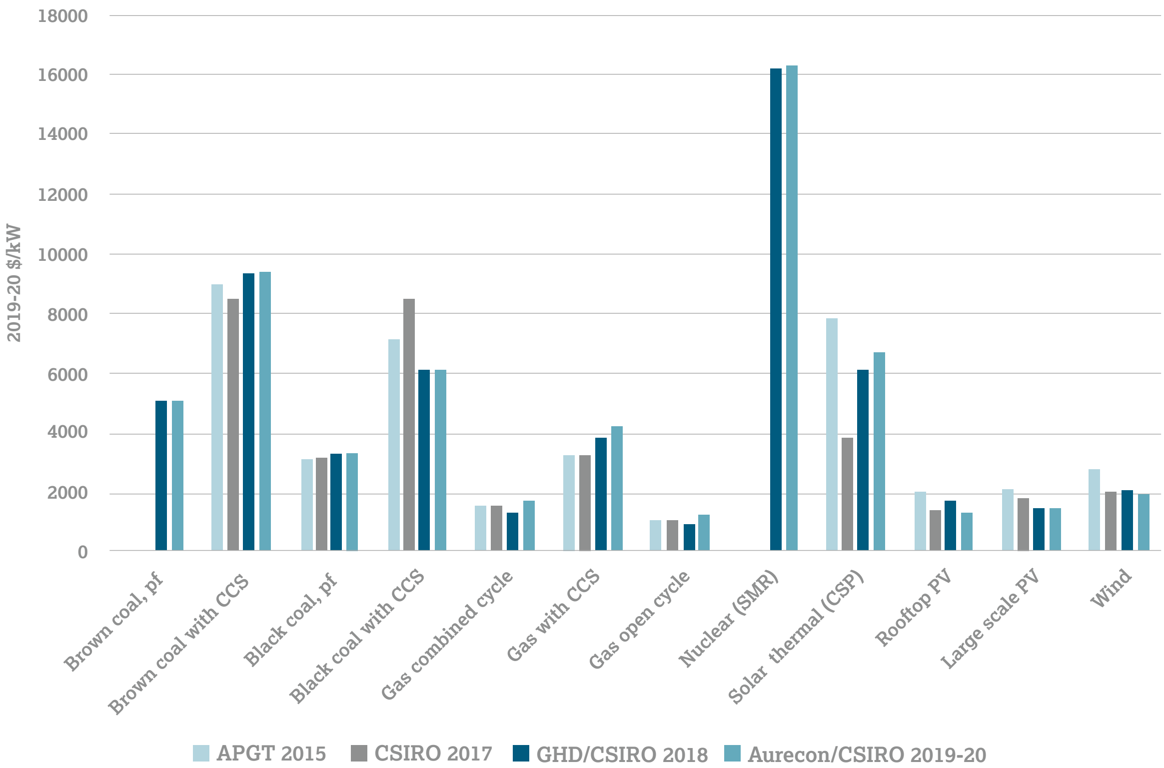
A review of capital cost estimates for generation types in Australia was undertaken by CSIRO and Aurecon as part of the GenCost project (CSIRO 2019). Current (2019-20) generation capital cost estimates are compared against three other recent sources, namely GenCost 2018 (GHD/CSIRO 2018), CSIRO 2017 and the Australian

3 ISP 2020 draft assumption
4 NTNDP 2018
5 AEMO 2019b
6 NTNDP 2018
7 NTNDP 2018
8 This does not include the cost of grid reinforcements in Queensland and NSW or augmentation of the northern NSW grid
9 Cost estimate $1.9-3.1 billion
10 $815million-$1.9billion
11 Cost estimate $560 million
12 Cost estimate $560 million

Power Generation Technology (APGT) report (CO2CRC 2015). This publication is regularly updated and it is noted that the most significant changes in the latest work include an increment to gas capital costs owing to an assumption about falling economies of scale with smaller plant sizes, a cost increment in major solar thermal plant due to reduced local learning benefits resulting from locational changes, and a reduction in wind capital costs.

Figure 3.3 indicates that gas open cycle currently has the lowest of all generation capital costs, with large scale solar PV and gas combined cycle ahead of wind with respect to capital costs alone. Scenario based projections of capital costs reveal that gas combined cycle and gas open cycle are considered mature technologies, and as such, their assumed cost reductions through time are relatively small compared to less mature technologies such as large-scale solar PV or solar thermal with storage (CSIRO 2019).

Figure 3.3: Generation technology capital costs



Note: Overnight costs in real 2019-20 Australian dollars.
Source: CSIRO 2019

A broader and perhaps more common approach to comparing electricity generation costs is the levelised cost of electricity (LCOE) method. This approach allows the competitiveness of different types of electricity generation to be assessed on a consistent basis by calculating the minimum price of electricity required for the project to break even over its lifetime. LCOE is measured in units of currency per MWh and relies on assumptions about fixed and variable costs, including fuel. The calculation also requires assumptions to be made about investment expenditure, discount rate, expected lifetime, and capacity factor. It is particularly useful when comparing generation technologies whose capital and fuel cost profiles differ substantially.

However, critics of LCOE raise important issues with the approach, namely that it ignores dispatchability and profile-matching of generation to market demand. That is, it does not account for the balancing costs required to integrate VRE generation technologies into the power system. As such, there is general acknowledgement that LCOE needs to be evolved given the significant expected changes in Australia's electricity fuel mix and particularly the increasing penetration of VRE in the power system.

When a generation technology is added to the power system, other generation and network components of that system are affected, and total system costs may increase or decrease. Integration cost refers to the effect that deploying that technology has on costs elsewhere in the power system. Specifically, VRE technologies interact differently with the power system than is the case for conventional plant that can be dispatched, and are far more difficult to integrate, particularly at high levels of penetration.

The integration costs of wind and solar PV technologies derive from the fact that these technologies operate in a manner that is fundamentally different from conventional generation technologies. The electricity output from these technologies is 'intermittent'; that is, they are not continuously available to generate electricity because of external factors that cannot be controlled, such as the strength (or sometimes the complete lack) of wind or the amount of sunlight. As a result, there are significant limitations in the extent to which intermittent technologies can be dispatched, and therefore the extent to which they can usefully be deployed to meet demand at any given time. Beyond a certain point, intermittent production of electricity poses a threat to the security of a power system because supply and demand cannot be matched using intermittent resources alone. The deployment of VRE resources means that specific actions need to be taken – and corresponding costs incurred – in the non-intermittent part of the power system. In this context, integration costs are defined as all additional costs in the residual part of the power system when VRE resources are deployed.

The integration costs of VRE technologies consist of three key components:

- Balancing costs which occur because the supply from VREs is uncertain until realisation and therefore forecasting errors ensue. Costs arise due to adjustments to the least-cost dispatch schedule, and the need to hold additional short-term reserves.
- Profile costs are caused by the variability and intertemporal generation profile of VRE technologies, which is often not well correlated with demand. They reflect back-up costs arising from the need to maintain conventional generation capacity, and overproduction costs when VRE technologies need to be constrained down or off because they produce electricity in excess of demand.
- Grid costs arise if additional network investment is necessary to accommodate VRE resources due to their location, for instance if high quality VRE sites are located far from demand centres. Where distance is involved there will also be additional transmission losses to consider. Furthermore, congestion costs can occur where the additional output from renewable generators constrains existing transmission infrastructure.

Conventional generators have inherent characteristics that contribute to the security of the power system, such as inertia which contributes to the ability of the power system to remain stable through fault events and limit system frequency excursions. As conventional generators are displaced by non-synchronous generation technologies, the overall reduction in inertia tends to increase the frequency and magnitude of power system disturbances, so that the power system becomes more vulnerable to fault events.

Integration costs depend on the characteristics of VRE technologies, but also on the flexibility of the particular power system into which they are being integrated. Hence integration costs tend to be higher in power systems dominated by less flexible thermal generation resources (as is the case in Australia) than in predominantly hydroelectric systems. These costs also tend to be less in larger interconnected power systems than in smaller systems with weak interconnections. Integration costs are therefore system specific. The components that constitute the integration costs of VRE resources – balancing, profile and grid costs – are not constant parameters, but are a function of many system properties.

Integration costs increase with the penetration of VRE resources. At low levels of penetration, the integration costs of intermittent renewables may be low or even negative. In these circumstances, the additional balancing and profile costs are outweighed by fuel cost savings from wind and solar PV resources. Overall, integration costs are considered to be relatively small at penetration levels of up to 10 per cent. Even allowing for adaptation in the generation mix to account for the uncertainty and variability of intermittent renewables, however, the integration costs of VRE technologies can become very high at high penetration rates (Schnittger and Fisher 2017).

There are a wide range of integration costs quoted in the literature, no doubt reflective of the specific nature of different power systems into which they are being integrated. An international literature review by Fisher and Schnittger (2016) revealed overall integration costs as high as AU$ 37 to AU$ 53 per MWh when wind penetration reaches 30 to 40 per cent. Schnittger and Fisher's (2017) more recent trend estimate across wind integration studies in thermal power systems suggested that wind integration costs increase from a base of around $2.7/MWh by $1.08/MWh for each percentage point increase in the share of wind generation.

CSIRO (2019) have attempted to 'extend' traditional LCOE analysis to take account of some of the integration costs attached to VRE generation, as well as higher risk premia attached to fossil technologies (on account of possible climate policies), and the different roles played by various generation types in the power system (Table 3.3). Assuming no carbon price or technology risk premia, in 2020 the scenario delivers peaking gas at between $120-137/MWh, flexible gas at $67/MWh, variable wind firmed by 2hr battery storage and 6hr pumped hydro at $109 and $88/MWh respectively. Solar PV firmed by 2hr battery or pumped hydro is lower at $98 and $75/MWh respectively. By 2050, when storage is added to solar and wind, the costs are similar to fossil fuels without a carbon price or risk premium.

CSIRO (2019) report that whether there is climate policy risk or not, the relative competitiveness of flexible load fossil fuel generation is largely a function of the fuel price that can be secured[13]. This is partly because as mature technologies, the capital costs are assumed stable through time.

For a scenario involving climate policy risk, solar thermal with eight hours storage is the least cost in the low emission flexible generation category by 2050. However, gas with carbon capture and storage (CCS) is least cost to 2030. While gas CCS has a lower capital cost than coal CCS, the relative prices of the fuels and future carbon pricing will ultimately determine the overall competitiveness of these two technologies.

13 CSIRO assumes long-term prices of $5.80/GJ for gas, $2.60-$2.70/GJ for black coal and $0.60-$0.70/GJ for brown coal.

Table 3.3: LCOE projections 2019-20 $/MWh

Category	Assumption	Technology	2020		2030		2040		2050	
			Low	High	Low	High	Low	High	Low	High
Peaking 20% load	Carbon price	Gas turbine	137	203	142	221	150	244	157	284
		Gas reciprocating	120	167	123	180	129	196	134	224
Flexible 40-80% load, high emission	No carbon price or risk premium	Black coal	83	112	83	109	82	107	82	107
		Brown coal	95	123	94	122	94	121	94	121
		Gas	67	114	67	117	67	117	67	117
	No carbon price, 5% risk premium	Black coal	125	168	124	164	122	162	121	160
		Brown coal	160	209	158	206	156	204	154	201
		Gas	81	132	80	135	79	134	79	133
	Carbon price	Black coal	96	135	104	148	117	175	129	222
		Brown coal	111	151	121	170	137	203	150	260
		Gas	73	127	77	141	83	157	88	184
Flexible 40-80% load, low emission	Carbon price	Black coal with CCS	148	200	140	199	136	204	137	202
		Brown coal with CCS	181	233	170	233	166	235	165	225
		Gas with CCS	125	197	114	205	109	211	109	206
		Solar thermal 8hrs	129	173	129	157	103	132	91	119
		Nuclear (SMR)	254	333	254	333	124	333	124	333
		Biomass (small scale)	256	402	256	402	251	402	250	402
Variable	Standalone	Wind	53	66	49	63	45	60	41	58
		Solar photovoltaic	35	56	22	41	17	33	15	28
Variable	2hrs battery storage	Wind	109	144	78	119	72	114	67	109
		Solar photovoltaic	98	160	57	126	50	117	47	106
Variable	6hrs PHES	Wind	88	112	82	108	76	104	71	102
		Solar photovoltaic	75	118	61	112	55	102	52	95

Source: CSIRO 2019

The breadth of inclusion of integration costs by CSIRO in this analysis is limited and somewhat unclear. It appears that costs decline according to learning rates unique to each technology, and that any increasing need for system balancing as the share of VRE generation in the system increases has not been incorporated. As such, the extended LCOE estimates shown in Table 3.3 underestimate the integration costs attached to changes in the technology mix in the NEM. This is particularly the case considering that the costs of transmission and interconnection projects are not part of CSIRO's analysis. Other factors that hide the underlying costs of VRE integration are renewable subsidies, discounted finance and direct grants.

It is important to note that none of the integration costs required to 'firm' variable renewable generation are currently borne by the market participants that cause such costs to be incurred. This results in a type of market failure, whereby over-investment in renewable generation is likely to occur, with costs ultimately borne by consumers.

4. Integrated System Plan

Around two-thirds of coal generation is projected to retire from the NEM by 2040, with the remainder exiting by 2060. Given the high capacity factors of coal generators, AEMO (2020b) estimates that the 15 GW of retiring coal generation over the next two decades will necessitate about 26 GW of renewable energy generation to replace it, along with up to 19 GW of new dispatchable resources to firm the renewables. AEMO envisages these dispatchable resources will be comprised of utility-scale pumped hydro or battery storage, distributed batteries participating as VPP and demand side participation (DSP). In addition, substantial upgrades to the transmission system are required to support new VRE, given the existing network has connection capacity for only 13 GW in areas with desirable renewable resources. AEMO (2020b) acknowledges the important role for gas in providing dispatchable capacity, inertia and system security services but under its central scenario forecasts that no new gas fired capacity will be required in the coming decade.

AEMO (2020) states that strategically placed interconnectors and renewable energy zones (REZs), coupled with energy storage and DSP, will be the most cost-effective way to add capacity and balance variable resources across the NEM. This is considered the case in light of the economics of different generation technologies, the system services and reliability they provide, and also the public policy requirements of existing state and federal policies on emission reduction, including state-based renewable energy targets (RETs).

To assist its planning processes, AEMO has devised several scenarios based on degrees of decentralisation and decarbonisation, utilising varying assumptions around electricity demand growth, uptake of DER and uptake of VRE.

In the Central Scenario, market forces determine the pace of transition under existing state and federal policies. Specifically, it incorporates:

- The NEM's share of the Federal Government objective of reducing emissions by at least 26% by 2030;
- Renewable Energy Targets in Victoria (VRET, 50% by 2030) and Queensland (QRET, 50% by 2030); and the New South Wales Electricity Strategy;
- Annual generation in the NEM increases by over 25 per cent but much of this growth is taken up by DER;
- 6.5GW of already committed renewable generation comes into the system, including the Snowy 2.0 pumped hydro project;
- The Marinus Link is commissioned by 2036;
- 31GW of new grid-scale wind and solar are added by 2040, comprised of 56 per cent solar and 44 per cent wind;
- Black and brown coal fired generators retire on schedule; and
- New transmission and interconnection investment is made to enable integration of higher VRE, given the existing transmission network has an estimated connection capacity of only 13GW in areas with favourable renewable resources.

This set of assumptions results in a 6 per cent gas installed capacity share in 2040, reflecting roughly 6.9GW of installed peaking gas (4.9GW) and CCGT (2GW) generation capacity. In the Central scenario, 5,900GWh of electricity are generated, representing a 2.5 per cent gas generation share in 2040.

While the ISP and its recommendations are built around the Central scenario, it is likely that recent global events position Australia in the Slow Change scenario over the short term and possibly longer. The combined reduction in economic activity associated with COVID-19 and price shocks linked to oil oversupply will result in falling energy prices and less electricity consumption in Australia for an uncertain period of time, and a substantial timeframe to recovery.

In the Slow Change scenario, energy demand, DER and VRE uptake are all lower than previously forecast. This means that energy decarbonisation in the stationary energy sector could be slower and may result in life extensions for existing baseload generators. This scenario requires the addition of only 4GW of grid-scale renewables by 2040. Coal generators are expected to continue to operate past their planned retirement dates. It may also be expected that firming requirements are significantly lower in this scenario, and hence less transmission and interconnector development, hydropower and batteries will be needed. It is also likely that there will be slower changes in technology costs alongside lower political, commercial and consumer motivation for significant emissions reductions.

The Slow Change scenario embeds the following key assumptions out to 2040:

- B rown coal fired generators retire on schedule, as do black coal fired generators with the exception that an additional 8GW of black coal remains in the NEM over and above the Central scenario;
- NEM generation (GWh) remains static between now and 2040;
- 6.5GW already committed of renewable generation comes into the system, including Snowy 2.0; and
- 4GW of new grid-scale renewables is added by 2040.

This set of assumptions results in a 12 per cent gas fuel share in 2040, reflecting around 8GW of installed peaking gas (1.5GW) and CCGT (6.5GW) generation capacity in the NEM. However, in this scenario, only 3,900GWh of electricity is generated by GPG, representing a 2 per cent gas generation share in 2040 (Table 4.1).

These results indicate that the Central scenario represents a far higher utilisation rate of gas fired generation assets than in the Slow Change case. The detail of why generation from gas fired plant varies substantially between 2039-40 and 2040-41 is not made clear, although it likely reflects assumptions by AEMO regarding increased GPG utilisation during drought and adverse weather forecast years. AEMO (2020b) notes that demand for GPG can vary as much as +/- 15 per cent based on the range of weather conditions observed in the past five years. For the purposes of this paper we assume the higher of the two data points (see Table 4.1).

Table 4.1: Installed capacity and generation from gas fired generators by selected year

Scenario/ year	Central			Slow Change		
	2020	2039-40	2040-41	2020	2039-40	2040-41
Installed capacity (GW)	11.1	7	6.9	11	8.2	8.1
Capacity share (%)	16		6.0	16.5		11.5
'As generated' generation (GWh)	4,700	2,150	5,900	4,600	650	3,900
Generation share (%)	2.3		2.5	2.4		2.0

Note: Gas fired generators refers to CCGT and Peaking Gas + Liquids generators
Source: AEMO 2019 Appendix 3; BAEconomics calculations.

Note these figures in Table 4.1 contrast quite significantly with January 2020 data from AER (refer Figure 3.1) which indicated a 19 per cent gas generation capacity share and 9 per cent gas share on a NEM output basis in 2020. This discrepancy arises because the ISP forecasts are based on least cost modelling results.

AEMO has forecast the system costs under each scenario, with Central case being higher than the Slow Change case. Annual system costs under the Central scenario are expected to be around $10 billion in 2039-40 (Figure 4.1), compared to around $6 billion under the Slow Change scenario (Figure 4.2). This is primarily a result of much lower capex, interconnector and REZ costs under the Slow change scenario.

Figure 4.1: Forecast total system costs, Central scenario

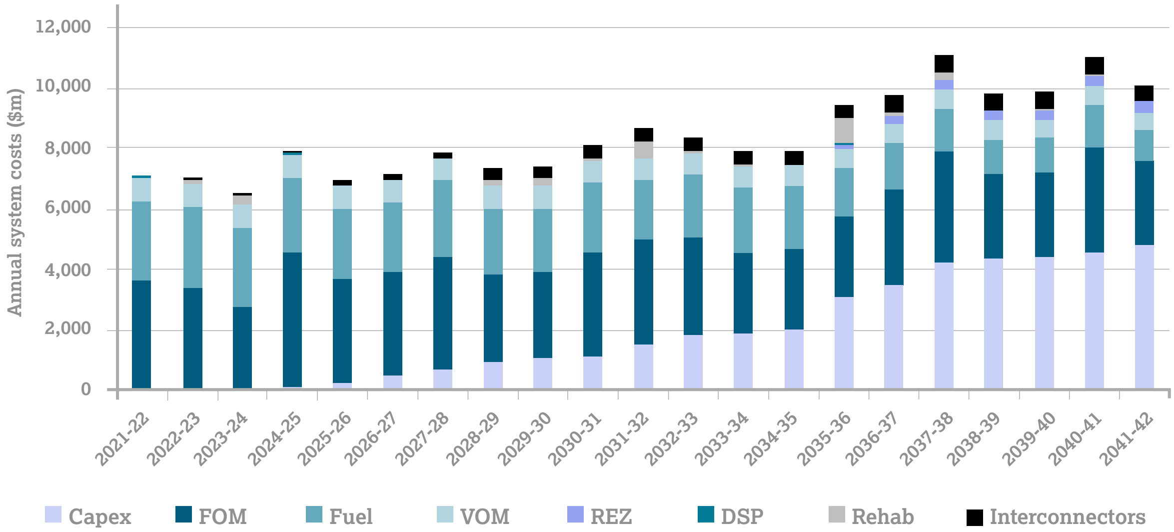
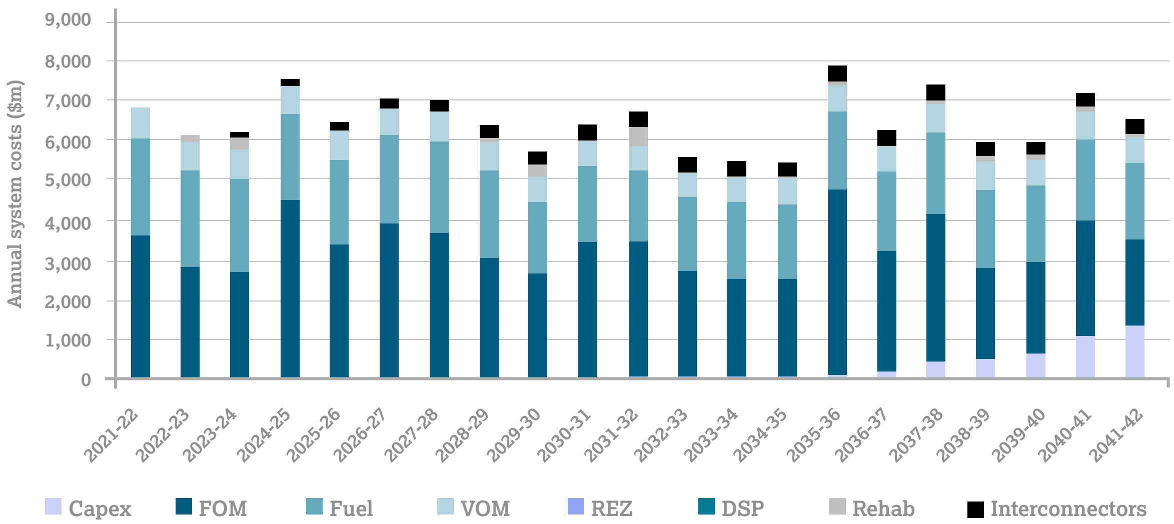
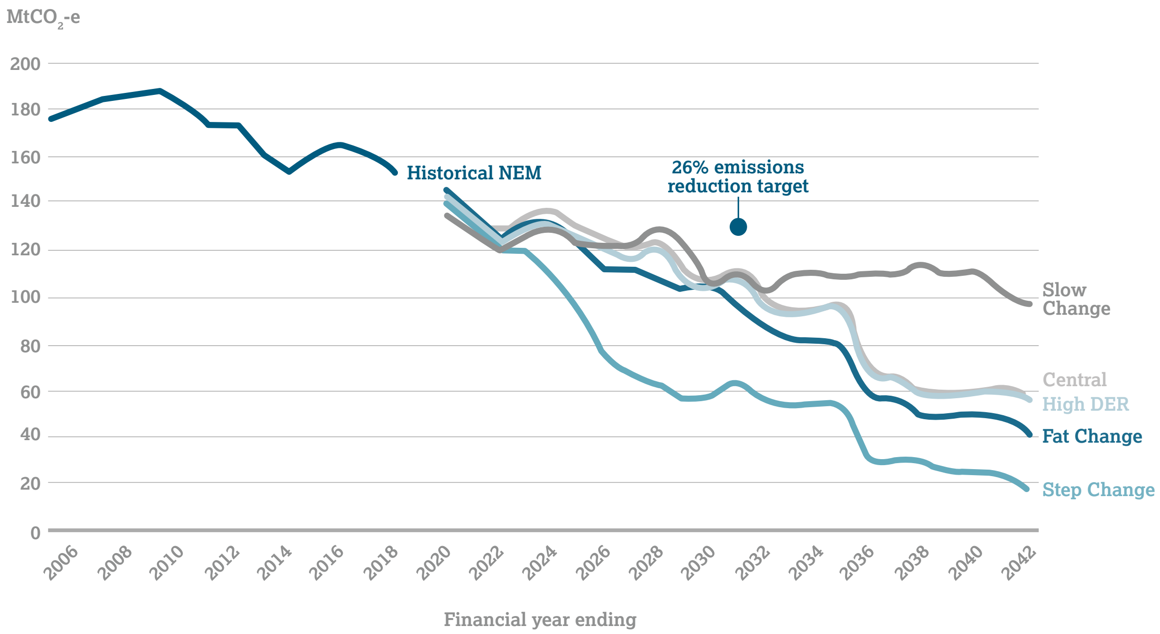


Figure 4.2: Forecast total system costs, Slow Change scenario



Annual electricity sector emissions are projected under the Central scenario to fall from around 150 Mt CO_2e in 2020 to around 60 MtCO2e by 2040. Under the Slow Change scenario, emissions fall to around 105 Mt CO_2e by 2040. Under both scenarios, emissions exceed the electricity sector's nominal share of the Paris target of 26 per cent emissions reduction by 2030 compared to 2005 levels.

Figure 4.3: Emissions projections under all scenarios



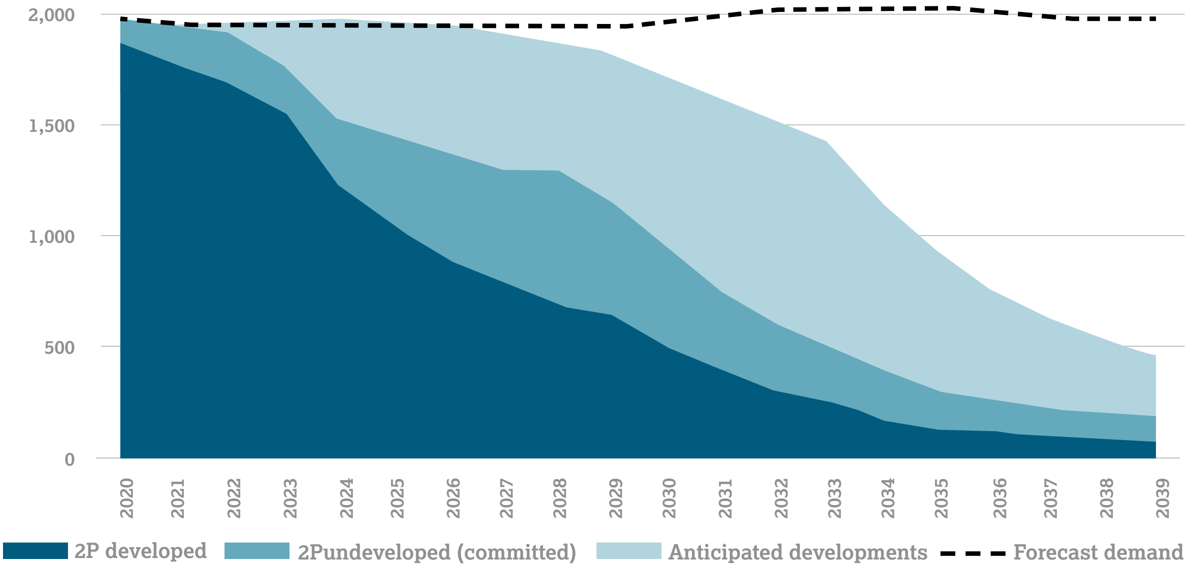
5. What role for gas?

The ACCC (2020) reported that projected natural gas supply for the year ahead on the east coast is 2025 PJ, while demand is forecast at 1831 PJ, not including LNG producers' excess gas of 209 PJ. Given the longer term economic impact of COVID-19, supply may exceed demand by a larger amount than anticipated, and the supply-demand imbalance may continue for some time depending on the speed and timing of the return to more normal economic activity.

Aside from this interruption to the typical functioning of the market, the concern about whether the established southern gas reserves will meet longer term east coast demand given their declining levels of production is being exacerbated by an ongoing write-down of LNG reserves and resources in Queensland and an expected increasing reliance on coal seam gas (CSG). Future CSG supplies are in question owing to the current moratorium on gas exploration in NSW, although the recent lifting of onshore gas exploration restrictions in Victoria may assist (refer section 2.3).

Without further investment in new supply, both ACCC (2020) and AEMO (2020a) project a shortfall in domestic supply commencing from around 2026-27. ACCC (2020) expects this to reach 600PJ by 2030 on an Australia-wide basis, while AEMO (2020a) foresees a shortfall of around 1600PJ in the eastern and southeastern gas market (for export and domestic use) by 2040 under the Central scenario (Figure 5.1). It is noted that daily supply-demand balances may also be affected earlier, particularly in terms of peak demand in Victoria and taking into consideration capacity limits on the Victorian southwest gas peipeline.

Figure 5.1: Potential shortfall in eastern and southeastern gas production



Source: AEMO (2020a)

Recent oversupply in global LNG markets has reduced prices, which in turn has put downward pressure on east coast gas prices. However, the ACCC observed that domestic producer price offers had not fallen as much as LNG netback prices[14] (at around $7.50/GJ), with some offers including a fixed price component in addition to the LNG spot price linkage, resulting in retail offers in the $8-12/GJ range.

14 Netback prices refer to the LNG spot price in Asia minus shipping and pipeline costs ex Wallumbilla.

By contrast, the AER reported that spot gas prices in the final quarter of last year had fallen below $5.35/GJ. Domestic delivered natural gas prices for large industrial consumers were trading in average real terms at between $5 – 12/GJ. This equates to average annual volume weighted spot prices in 2019-20 (YTD) of between $65 and $93/MWh depending on location – Queensland being the cheapest and Victoria the most expensive. It is noteworthy that for NSW, SA and Tasmania, these prices are roughly twice their 2014-15 levels, while for Victoria spot prices have tripled over the same period. Queensland's spot prices by contrast have been far more stable over the past five years (AER 2020).

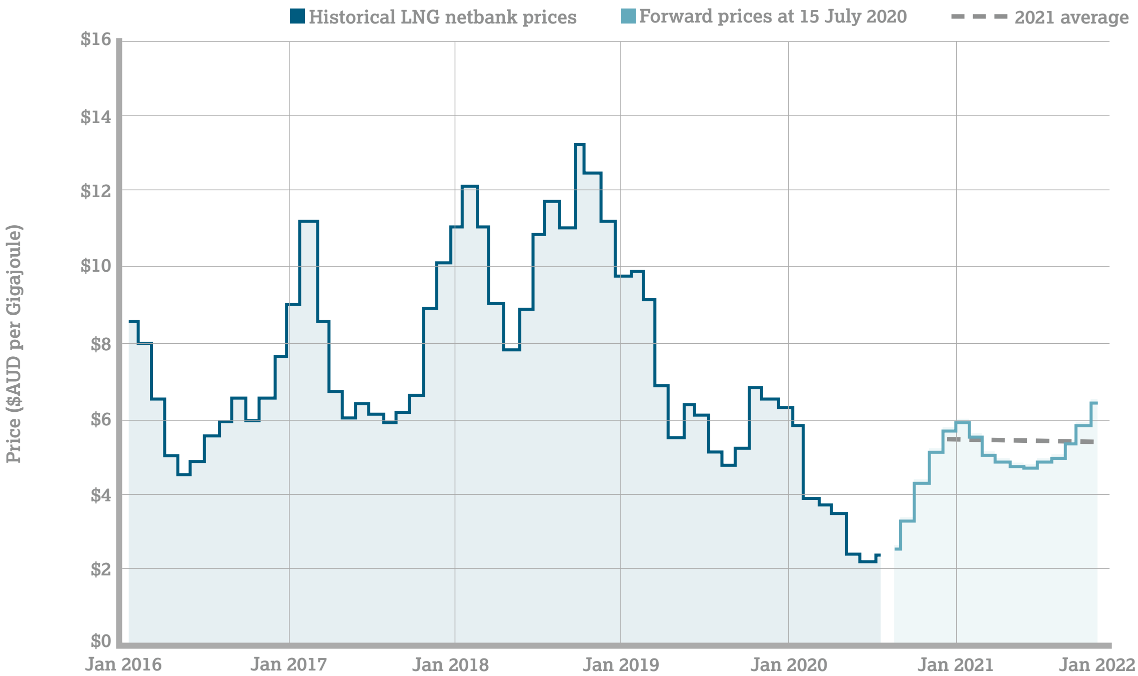
Figure 5.2 outlines the LNG netback price series including:

- Historical monthly LNG netback prices at Wallumbilla based on historical Asian LNG spot prices; and
- Forward monthly LNG netback prices at Wallumbilla based on expectation of future Asian LNG spot prices as at 2 April.

This series indicates that as of July 2020, forecast LNG netback prices are expected to remain below $4/GJ for much of the year and under $6/GJ in the near term. Given that domestic prices are closely linked to LNG netback, and LNG oversupply is likely to be greater than forecast, and, subject to the annual delivery programs, excess LNG can be expected to enter the domestic market, thereby generating further downward pressure on domestic gas prices.

The longer-term outlook for domestic gas prices will depend on many factors, including geopolitical and market tensions around oil. The lower the oil price, the lower LNG-linked domestic gas prices will be. Depending on how future OPEC negotiations regarding production cuts play out, the volume of distressed oil cargoes as global storage facilities reach tank tops, and the interlinked magnitude and duration of COVID-19 impacts on energy demand, it seems probable that wholesale gas prices in the east coast market will hit historic lows in the near term, and trade significantly below historic floor prices in the medium term.

Figure 5.2: LNG netbank prices



Source: ACCC, 16 July 2020

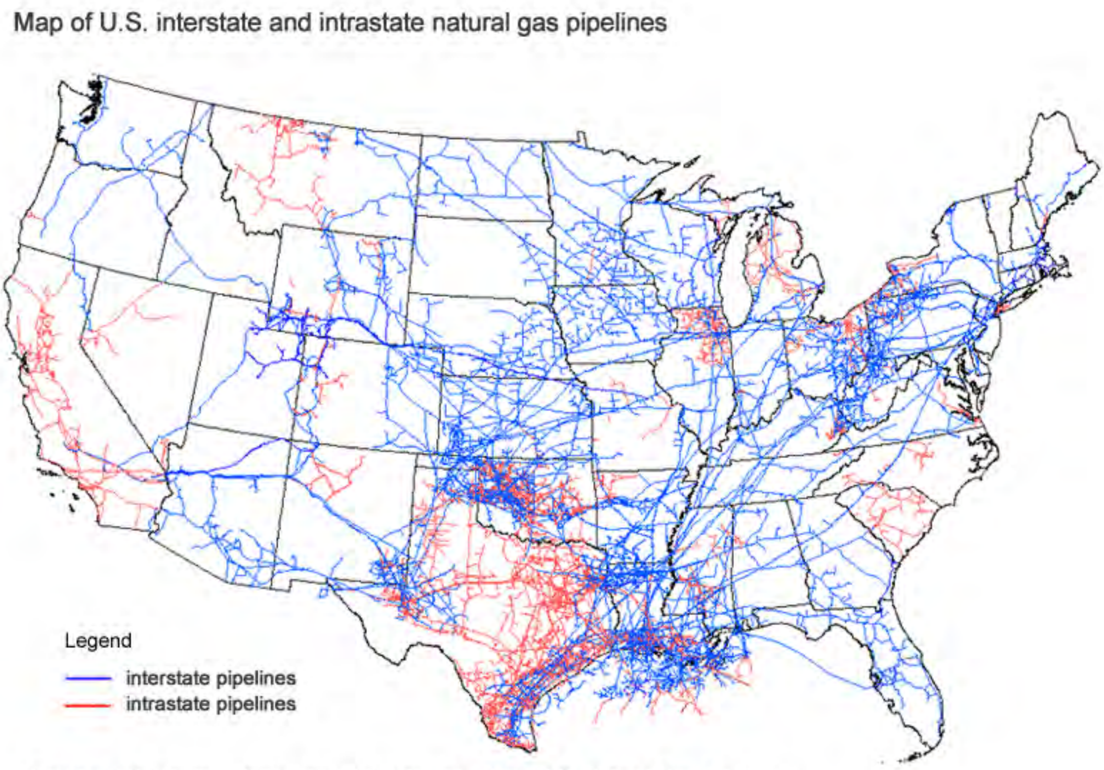
If domestic gas prices remain low for a significant period of time, and if trade delays and disruptions affect the sourcing of materials for renewable energy generators, there may be a shift in the economics of generation. As currently seen under the Slow Change scenario, coal generation remains in place for a longer period of time, yet GPG does not come into the mix in a meaningful way. With potential moves toward greater local manufacturing and increased volumes in the east coast gas markets, the economics underpinning the ISP scenarios must be revisited.

Whether gas can maintain or increase its share as an energy source in the manufacturing sector will crucially depend on both the expected long-term local gas price and the reliability of domestic supply.

On the domestic supply side, Australian producers face a number of challenges. Regulatory impediments to exploration and production have already been raised in section 2.3 and in many cases these issues remain to be fully resolved. In addition, there are a number of other impediments to gas development. Perhaps the most important of these is what might be labelled as the 'tyranny of distance' and the size of the domestic market. As an illustration, New York State in the United States is about 2 per cent of Australia's land area but has a population approaching 20 million people and an annual gas consumption around that of the whole of Australia. As a result of the large US population and the extent of concentrated high gas demand areas, the historical development of the gas pipe network in the United States has been extensive as can be seen from Figure 5.3. This has meant that pipeline capacity has not been an impediment to the development of new gas supply sources over the past few decades.

In contrast, Australia's existing pipeline network is shown in Figure 5.4 and Figure 5.5 shows greater detail for the east coast. Gas from the Cooper Basin destined for the Sydney market needs to be piped over 2000 km. To supply gas from the Beetaloo field (in the early stages of development) in the Northern Territory to Sydney would require transport over a distance of about 3600 km.

Figure 5.3: US gas pipeline network



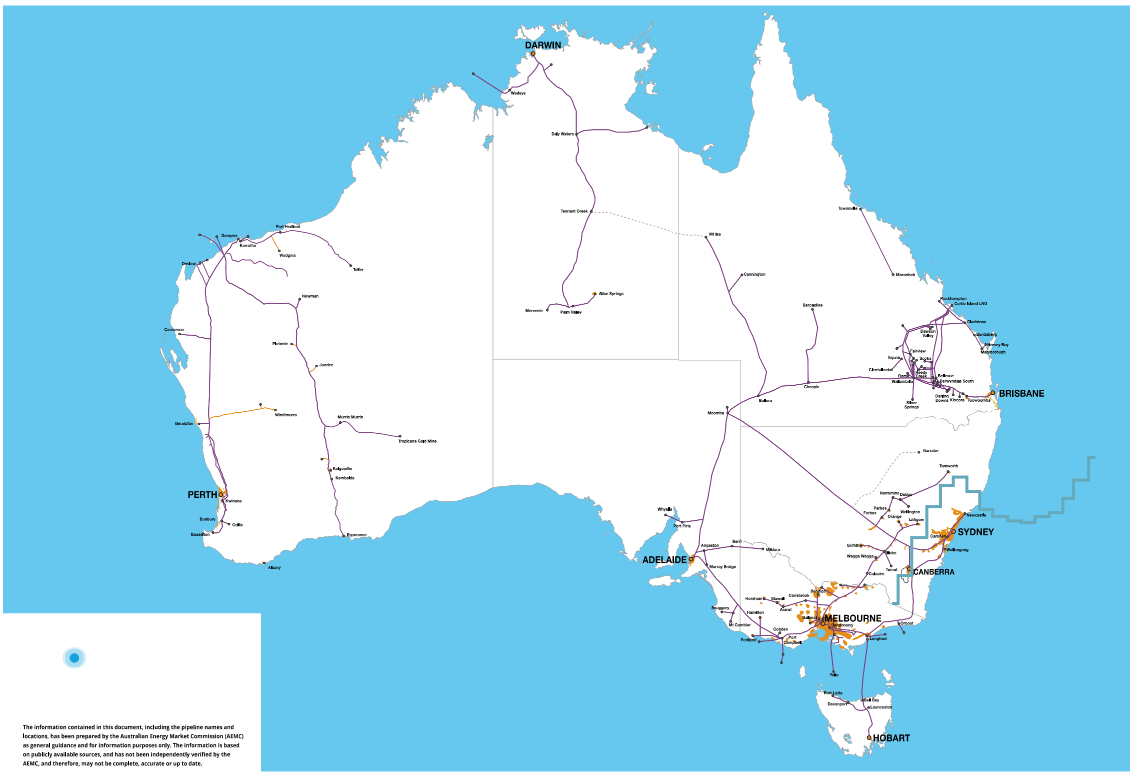
Source: https://www.eia.gov/energyexplained/natural-gas/natural-gas-pipelines.php

In Australia even today, large-scale new gas supply development usually has to go hand-in-hand with the development of new pipeline capacity. This then raises a problem of potential market failure and coordination in the sense that gas explorers and developers are unlikely to develop remote gas fields unless they can deliver the gas to market, and a pipeline builder is unlikely to construct a new pipeline unless there is a very high probability that gas is available to be shipped and there is a buyer(s) available that is willing to make a long-term commitment to purchase gas. Given the market and regulatory uncertainty and the very long-term nature of such developments there is therefore a potential case for government intervention to ensure that there is appropriate coordination between pipeline infrastructure construction and the development of new gas fields. Of course, any such intervention should be justified on a case-by-case basis by a properly conducted social benefit cost analysis.

The development of new domestic gas fields has the economic advantage of generating local employment as well as enhancing Australia's energy security – both important objectives particularly during the COVID-19 recovery phase. However, at least for some markets a strong economic case can be made at the present time for the import of gas in the form of LNG. Among other advantages the liquefaction process reduces gas volume by about 600 times, meaning that LNG is an efficient form in which to transport gas over very long distances. Very long-distance pipelines are expensive to build, require the use of significant amounts of gas for compression and often face significant land access challenges.

As mentioned previously, the current world spot price of LNG is low in historical terms and the capital costs of LNG import terminals appear modest compared to that required to develop new domestic supply and pipeline capacity. Various competing proposals have been collated by AEMO (2019) and are shown in Table 5.1. The development timelines for many of these projects have slipped since the data were compiled but the general conclusions remain the same.

Figure 5.4: Australian gas pipeline network



Source: https://www.aemc.gov.au/sites/default/files/content/f017d30c-d7bb-4e80-a8af-c05c7bf1baf3/Australia-with-gas-pipelines-A3-with-scheme-register-links.pdf

Figure 5.5: Australian east coast gas pipeline network

Source: AEMO

For example, the proposed Port Kembla LNG import terminal has a reported capital cost of around $250m compared with $3-4b for the extension of the Northern Gas Pipeline, would be located in close proximity to the large Sydney gas market and require the construction of only about 6 km of new pipeline to connect to the existing pipeline infrastructure. In addition the project proponent plans to use a floating storage and regasification unit (FSRU), that is a vessel similar to a standard LNG carrier with regasification equipment to warm the imported LNG and return it to its gaseous state onboard, rather a fixed on-shore gas storage and regasification plant.[15] This approach has the advantage that if market conditions either in Australia or globally change resulting in reduced demand for imported gas the FSRU can be deployed elsewhere at little cost. In the case of Victoria, the Crib Point LNG import project has the advantage of being located adjacent to the Longford to Melbourne gas pipeline that services not only Melbourne but feeds into the east coast network.

The introduction of new suppliers into the market, whether they be domestic producers or LNG importers would increase the level of competition and reduce the uncertainty around long-term gas supply currently facing local manufacturers and retail gas users. In the case of LNG imports even one import terminal would substantially increase liquidity in the east coast gas market, at least in the coming few years, given that the domestic market is relatively small.

15 See https://ausindenergy.com/wp-content/uploads/2019/04/Project-Overview-AIE.pdf, accessed 20 July 2020.

Table 5.1: Gas expansion candidates

	Project	Available	Build cost (A$)
LNG import terminal	Crib Point LNG terminal	2023	$250m
LNG import terminal	Port Kembla LNG import terminal	2021	$200-250m
LNG import terminal	Port Newcastle LNG import terminal	2021?	$600m
LNG import terminal	Port Adelaide LNG import terminal	2022	$180m
Pipeline	Northern Gas Pipeline extension Wallumbilla	2022	$3-4b
Gas field development	Galilee gas basin	2022	$1.5b
Gas field development	Narrabri gas field	2021	$3.6b
Pipeline	Qld-NSW interconnection	2022	$900m

Source: AEMO 2019, delivery dates uncertain, https://veniceenergy.com/media/, 'Twiggy set to fast-track LNG import terminal', Australian Financial Review, 21 October 2020,p.16.

6. Conclusions

Australia's energy system is facing a major transformation over the coming decades as ageing coal fired power stations are retired and the economy reduces its greenhouse gas emissions in line with the Paris Agreement. The exact nature of the technology mix in the energy sector in the long term remains uncertain but the overall direction is clear. The key challenge is to minimise the cost of the transition in the face of uncertainty about the direction of future technology development while at the same time ensuring that domestic energy users have access to reliable power at world competitive prices.

Gas has a significant role to play in the energy transition at least in the medium term. The technology for using gas as a source of heat in the manufacturing sector or to generate electricity is mature and reliable. It is also the case that on the basis of energy units delivered to the end-user, gas is less carbon intensive than coal. Questions remain about the impact of fugitive emissions in some gas production and pipeline networks but that problem is capable of being solved using the price mechanism or appropriate regulation.

The rapid penetration of intermittent renewables such as wind and solar into the electricity generation sector has given rise to the question of what is the most economically efficient way of maintaining the reliability of the system. A number of technical options including pumped hydro, batteries and additional gas generation for firming the system currently exist and the least-cost mix of firming technologies is likely to include those listed in the medium term. However, gas generation has a number of short-term advantages. First, its capital cost is relatively low, it is readily scalable and, if required, a gas generator can produce dispatchable power for very long periods of time. Second, the lead time to establish a gas generation plant is short compared to the typical type of engineering project required to establish a new pumped hydro facility. And finally, the footprint of a gas generation plant is small. It follows that gas generation will play an important role in maintaining the reliability of the electricity grid at least in the medium term.

The total capacity of new gas generation required to firm the electricity grid in the coming decade will depend on a number of factors. First, a highly interconnected and well spatially diversified grid with a high penetration of intermittent renewables will require less firming capacity than the same grid with weak interconnection. Therefore, to some extent, investment in transmission infrastructure is a partial substitute for investment in back-up generation and thus the amount of new gas capacity required will depend on decisions about how much is invested in transmission infrastructure.

Second, the requirement for firming capacity will depend heavily on how rapidly the share of intermittent generation rises in the electricity grid. The extent of the rise in the renewable share in electricity generation is policy dependent but key states in the NEM have already committed to a 50 per cent share by 2030 so it seems reasonable to assume that the intermittent share in the NEM will be at least 50 per cent by the end of this decade.

Third, the contribution of gas to meet the needed additional firming capacity will depend largely on the cost of alternatives such as batteries, the practicality of building new pumped hydro capacity and its delivery date and the domestic price of gas.

The delivered price of gas on the east coast has risen substantially over the past several years. This is attributable to a number of factors including the closer linking of the east coast domestic gas price to global markets as a result of the development of LNG export projects in Queensland and various regulatory impediments that were put in place by some state and territory governments to limit the development of new onshore gas fields. Although some of these impediments have now been lifted and there recently has been some new gas resources proved up, there remain long lags in the planning process for new developments.

The trend to higher domestic gas prices, until the impact of the COVID-19 pandemic reduced economic activity, led to a reduction in the competitiveness of domestic manufacturers who were dependent on gas as an input. Economic recovery from the effects of the pandemic would be enhanced by an increase in domestic supplies of gas and increased competition in the domestic gas market. This can be achieved by a combination of actions including reducing the regulatory impediments to new domestic onshore gas development, government intervention to facilitate the joint development of new pipeline infrastructure and new gas fields in cases where the social benefit cost ratio exceeds unity and measures to enhance competition in the gas market. LNG imports offer the potential to increase competition in the market by offering retailers the opportunity to buy both domestic and imported gas and to ramp up imports when international markets are weak.

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