Deloitte.
Access Economics

Decarbonising Australia's gas distribution networks

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Contents

Glossary

API 5L	American Petroleum Institute specification API 5L covers seamless and welded steel line pipe.
ARENA	Australian Renewable Energy Agency.
AEMO	Australian Energy Market Operator.
Biogas	Gas fuel composed of mainly methane, produced by the fermentation of organic matter in the absence of oxygen. This process is known as anaerobic digestion.
BECCS	Bioenergy with carbon capture and storage.
Calorific value	The energy (heat) produced by a fuel during complete combustion. Expressed in energy/mole of fuel (kJ/mol); energy/mass of fuel or energy/volume of fuel. Also referred to as energy value or heating value.
CCS	Carbon capture and storage.
CO_2-e	Carbon dioxide equivalent- a standardised unit to measure the impact of different greenhouse gas emissions.
CSIRO	Commonwealth Scientific and Industrial Research Organisation.
Emissions intensity	Level of carbon dioxide (kg) release per unit of energy (joule or kWh).
ENA	Energy Networks Australia.
Energy density	The amount of energy in a given space or volume. Measured as joules/m^3 or equivalent.
FCV	Fuel cell vehicle.
GCCSI	Global Carbon Capture and Storage Institute.
GJ	Gigajoule.
GL	Gigalitre.
IEA	International Energy Agency.

Joule	Standardised unit of energy.
kW	Kilowatt.
kWh	Kilowatt hour.
LCOE	Levelised Cost of Energy/Electricity.
LEL	Lower explosive limit.
ML	Megalitre.
MW	Megawatt.
MWh	Megawatt hour.
NEM	National Electricity Market.
Natural gas	Gas comprised of mainly methane and hydrocarbons used to produce heat for cooking, heating and industrial processes.
NREL	National Renewable Energy Laboratory (United States).
NGER Act	National Greenhouse and Energy Reporting Act 2007.
PE	Polyethylene.
PJ	Petajoule.
SMR	Steam methane reforming.
Town gas	A manufactured gas produced extensively during the 20th century. Composed predominately of hydrogen, methane, carbon monoxide and hydrocarbons. Also referred to as coal gas.
Watt	Standardised unit of power equivalent to 1 joule per second.

Executive summary

Findings

1. Decarbonising electricity while maintaining reliability and affordability is proving to be a major challenge. Gas peak demand is higher than electricity in some states and electrifying gas consumption would substantially increase electricity peak demand.
2. Decarbonisation of gas distribution networks through the use of biogas and hydrogen would utilise the existing and highly reliable networks to deliver zero carbon energy.
3. Our analysis suggests that there are a variety of decarbonised gas options that are likely to be cost competitive with electrification over the long term.
4. Policy that supports a broad range of decarbonisation options, without picking winners, will lower the overall cost to reduce emissions.
5. Additional benefits of decarbonised gas networks include:
   A. Increased consumer choice.
   B. Use of the gas networks and infrastructure to store electricity by coupling of electricity and gas networks through electrolysis, potentially improving the utilisation and integration of variable renewable generation.
   C. Potential to export energy in the form of hydrogen or ammonia.
   D. May provide spill over development benefits for hydrogen fuel cell transport.

Background

Deloitte Access Economics was engaged by Energy Networks Australia (ENA) to identify a practical approach for sustainably decarbonising gas distribution networks to provide low-emissions gas for direct use by Australian households and businesses. This work will contribute to the industry's *Gas Vision 2050* and inform its broader research regarding the potential to decarbonise gas in Australia. The *Gas Vision 2050* presents an illustrative decarbonisation pathway for gas, targeting net-zero emissions by 2050 for gas use in the residential and industrial sectors, via the use of three key transformational technologies:

Biogas production – net zero carbon dioxide emissions, treated as part of the natural carbon cycle under the Australian national greenhouse gas accounting framework.

Hydrogen – emissions neutral when produced from renewable electricity or steam methane reforming and coal gasification paired with carbon capture and storage.

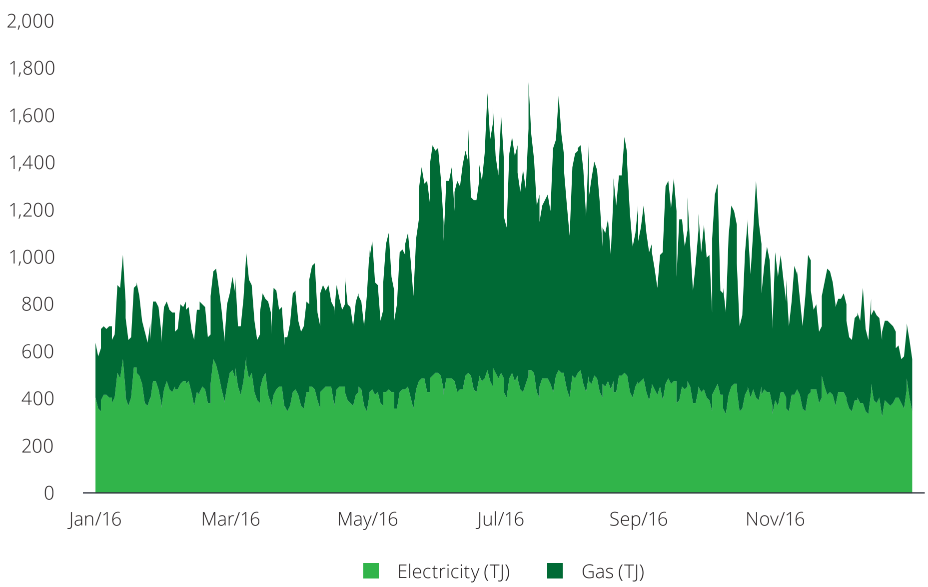
Carbon capture and storage – enables the production of decarbonised hydrogen from natural gas or coal, or can be applied to biogas production to remove carbon dioxide from the carbon cycle.

Role of gas in meeting the decarbonisation challenge

The decarbonisation debate in Australia has been heavily focussed on reducing emissions from the electricity sector. To achieve net-zero emissions, decarbonisation of the entire energy sector and other industries (e.g. agriculture) will be required, enabled by technology, innovation and supportive market and policy settings.

Natural gas usage makes up around one quarter of all energy consumed in Australia. Across the year and averaged across the country, gas provides 44% of total household energy. In Victoria – the state with the most gas connections – gas networks provides 69% of household energy per year.[1] Gas provides a lower emissions option than coal for power generation and also provides a lower emissions option for direct use compared to using electricity powered by coal. Some gas use could potentially be decarbonised by substituting electricity from renewable generation sources. However, shifting energy consumption currently met by gas to electricity (where possible) would be costly and require a large investment in electricity networks and renewable generation. For example, in Victoria, switching from gas to electricity would result in a doubling or tripling of peak electricity demand in winter.

Chart i Victoria's daily gas and electricity consumption, 2016 (TJ per day)



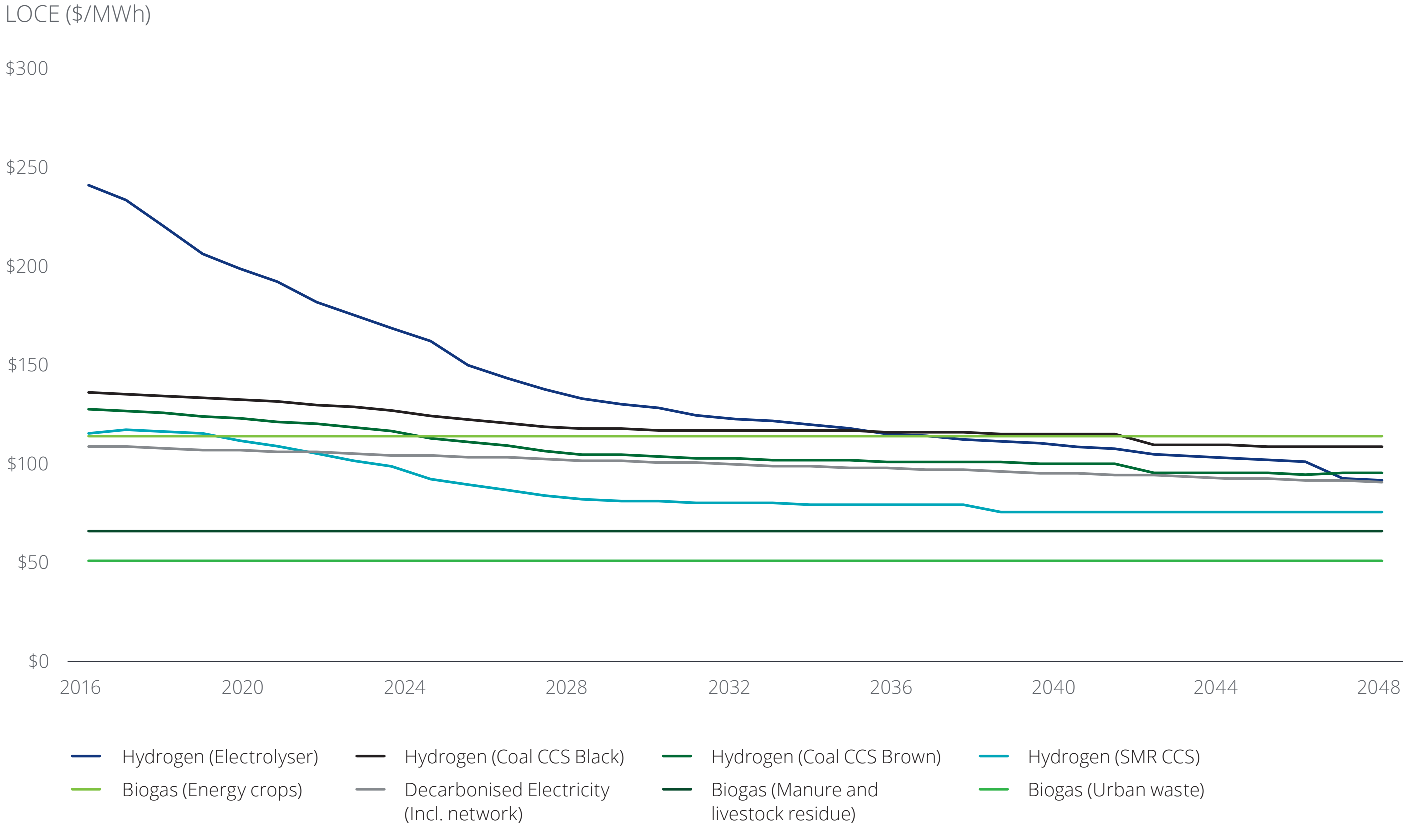
Source: Deloitte Access Economics analysis of AEMO gas and electricity data

Decarbonised gas presents an opportunity to lower the costs of decarbonisation

Achieving net-zero emissions in the energy sector by any means will involve significant challenges and costs. Some of these challenges are already being seen in the debate around decarbonisation of electricity, where concerns about increased costs and reduced reliability have disrupted decarbonisation policy development.

We estimated the cost of producing decarbonised gas from renewable electricity, steam methane reforming and coal gasification - based on national and international cost and technology benchmarks. We also established a high-level 'all electric' decarbonisation scenario to provide a point of comparison. The results of our analysis are shown in Chart ii in the form of a levelised cost of energy (LCOE). These trajectories also reflect potential trends in costs based on benchmarks and analysis from sources such as CSIRO and the IEA.

Chart ii LCOE of decarbonisation approaches to 2050



Source: Deloitte Access Economics analysis

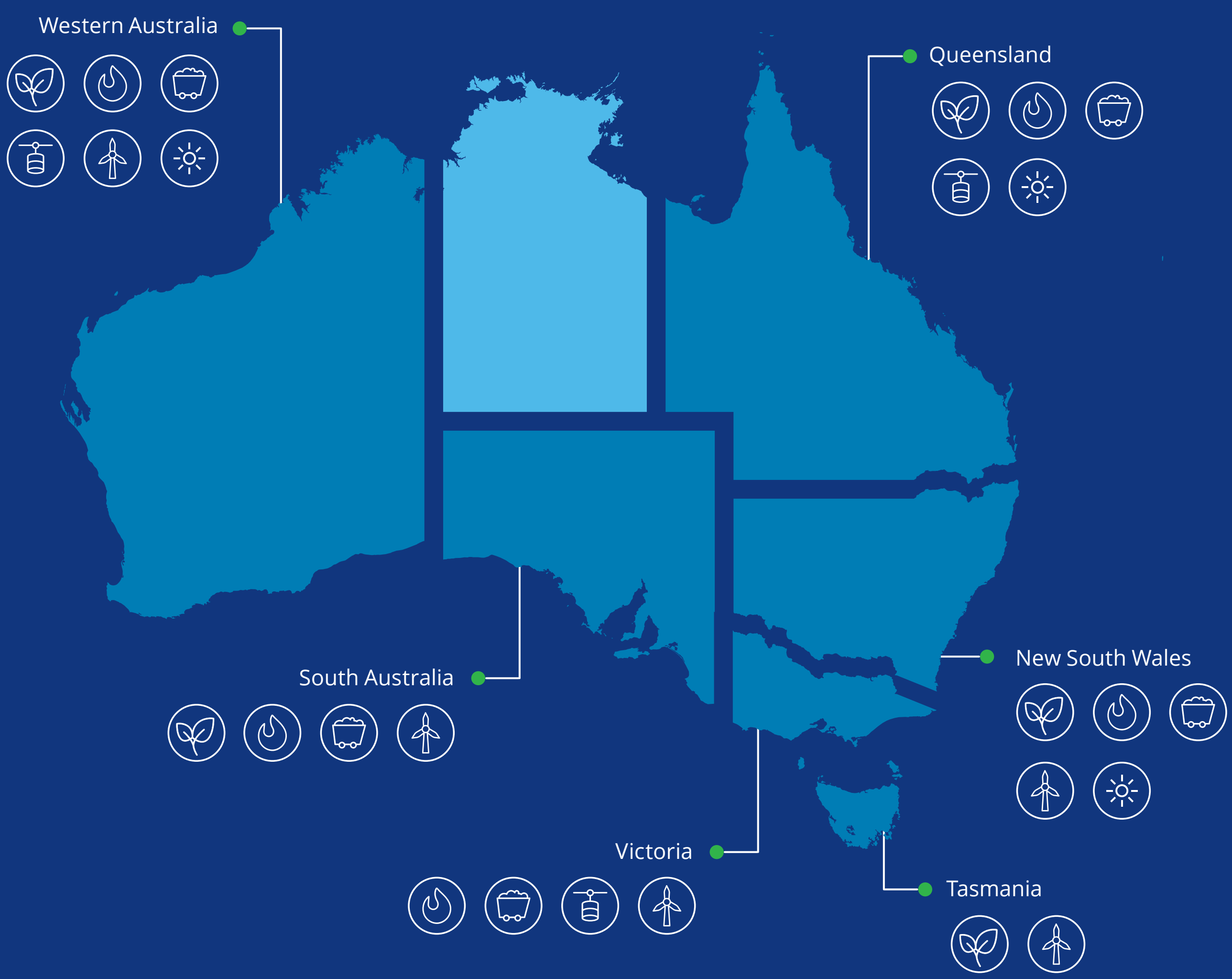
As shown in Chart ii:
Biogas is currently the cheapest option for decarbonisation of energy currently provided by gas networks. Current policies such as the Renewable Energy Target favour the use of biogas for electricity generation rather than injection into the gas network. Enough biogas potential exists to meet all residential and commercial gas demand on the East Coast. The cheapest form of biogas feedstock (urban waste, livestock residue and food waste), is currently sufficient to meet around 14% of energy used from gas.

Hydrogen production costs vary significantly depending on the technology used.

Gasification and steam methane reforming (SMR) are relatively mature, and lower cost, but with less scope for cost reductions. Electrolysis is currently the most expensive technology, but also has the greatest potential for cost reductions given its relatively nascent state. Cost reductions may exceed those shown in the chart given supportive policy settings, similar to what has been seen for the wind and solar electricity generation technologies. Large-scale deployment of hydrogen production would also involve appliance and network conversion costs, however incremental costs compared to a 'business as usual' scenario (or the 'all-electric' alternative) would be relatively minor.

Decarbonised electricity as shown in the chart includes costs such as firming and network augmentation to take on the additional load from energy currently delivered via gas. While electricity is currently the second cheapest form of decarbonisation after biogas, steam methane reforming could be even cheaper by the mid-2020s, and by the end of the analysis period other forms of hydrogen production could also be of comparable cost.

Figure i: Regional advantages for decarbonisation by technology



Biogas potential (excluding agricultural reserves) exceeds 10% of demand

Natural gas reserves

Coal reserves

CCS capability

Strong wind potential for electrolysis

Strong solar potential for electrolysis

Source: Deloitte Access Economics

Regional pathways for decarbonisation of gas networks

The optimal approach to decarbonising gas networks will depend on the regional resources available, existing infrastructure, availability of carbon capture and storage, interdependencies with regional electricity market outcomes and the demand for gas. Figure i summarises the regional resources available which will impact the competitiveness of each decarbonised gas technology.

Based on our current knowledge and resource endowments:

- Queensland and Western Australia have the largest biogas resources relative to gas consumption, followed by South Australia and New South Wales, all of which could technically meet state gas consumption with biogas (including from agricultural crops). Victoria's lower biogas resource and higher gas consumption mean only around a quarter of gas demand could be met with current biogas feedstock resources.
- Victoria, Queensland and Western Australia are the most prospective states for carbon capture and storage (CCS). CarbonNet in Victoria and South West Hub in Western Australia are the most advanced CCS projects (aside from the Gorgon CCS facility), enabling steam methane reforming or coal gasification. Queensland's Surat Basin Carbon Capture and Storage Project is currently at the Feasibility Study/Front End Engineering Design (FEED) Study Stage, but storage assessment is not as advanced as in Victoria and Western Australia. Other states could also take up these options, but would need to either prove up a carbon sequestration site or transport CO_2 to an already established facility (i.e. New South Wales and South Australia have significant coal resources, and could ship CO_2 created from coal gasification to Victoria's CarbonNet storage facility). All mainland states are well-endowed with natural gas and coal, presenting a clear pathway for decarbonisation of gas combined with state-specific CCS projects.
- All states present options for hydrogen production from electrolysis via solar, wind or hydropower. Electrolysis may be particularly effective in South Australia and Tasmania, where the potential for excess supply of renewable generation could bring down input (i.e. renewable electricity) costs substantially.

An efficient policy framework is required to support least-cost solutions

Providing a broad set of decarbonisation options is likely to minimise the cost and disruption to consumers as Australia moves toward lowering emissions. Decarbonisation policy needs to appropriately support a broad range of decarbonisation options, without narrowing the set of options available to consumers. Policy that is targeted toward the objective of emissions reductions (not the means of getting there) will support more efficient outcomes. Policies should provide a level-playing field with other technologies for decarbonising energy use, such as:

- Broad-based mechanisms that identify and price externalities from carbon emissions (e.g. carbon pricing, cap and trade schemes, etc.).
- Direct targets, such as a low carbon gas production target (much like the Renewable Energy Target in the electricity sector).

In competitive markets, we would expect market forces to provide the most efficient allocation of resources towards the uptake of new technologies and decarbonisation of gas. However, markets are imperfect, and there are numerous regulatory and policy constraints operating in Australia's energy market which may mean that the market does not produce an efficient decarbonisation pathway. We note that while biogas is a low-cost solution to reducing emissions from energy use, current policy settings in the Renewable Energy Target mean that the majority of biogas produced is used to generate electricity and tradeable Renewable Energy Certificates.

In general, we see a role for government support for investment in activities such as:

- Early stage research and development, which is likely to have public good characteristics and produce positive externalities that are not fully captured by the party investing in the research, resulting in a lower than optimal level of the activity, from a national perspective.
- Demonstration and early stage commercialisation, where there is a first-mover disadvantage – first movers in the early stage of commercialisation of new technologies are required to take on substantial amounts of risk, with fast-followers able to capitalise on the newly proven market without taking on the same level of risk.

Broader benefits of decarbonising gas

The gas distribution network is an extensive asset that we can leverage to lower the cost of decarbonising the economy. Around 5 million customers[2] (mainly residential) are connected to the gas distribution networks and around half of the gas consumed annually in Australia is from residential and small business customers. Accessing opportunities to decarbonise the gas network could provide these consumers with options that better meet their needs and which lower the overall cost of emissions reduction.

Decarbonised gas options could also produce benefits in adjacent markets in addition to lowering emissions from the gas network. The production of decarbonised gas is complementary to renewable electricity generation, the transport sector and energy export opportunities.

Decarbonising gas distribution networks creates potential opportunities such as:

- Gas distribution networks comprise large, long-lived assets. Repurposing this infrastructure to use decarbonised gas is likely to lower the overall cost of the emissions reduction task.
- There may exist alternative uses of gas distribution infrastructure to serve new markets in addition to the traditional residential and commercial customer base, for example, the network could be used to transport hydrogen for powering vehicles.
- Large-scale energy storage could occur in the network. Hydrogen production can complement renewable electricity generation, in effect turning an intermittent source of energy into a storable source of energy in hydrogen.
- Producing hydrogen from renewable electrolysis could improve the integration of renewable electricity generation into energy markets.
- The production of decarbonised gas through hydrogen presents the opportunity to export energy, in the form of ammonia.
- Capturing the benefit of research and innovation in low emissions technology or systems.
- Continued diversification of energy supply to consumers.

1. Introduction

1.1 Background to the report

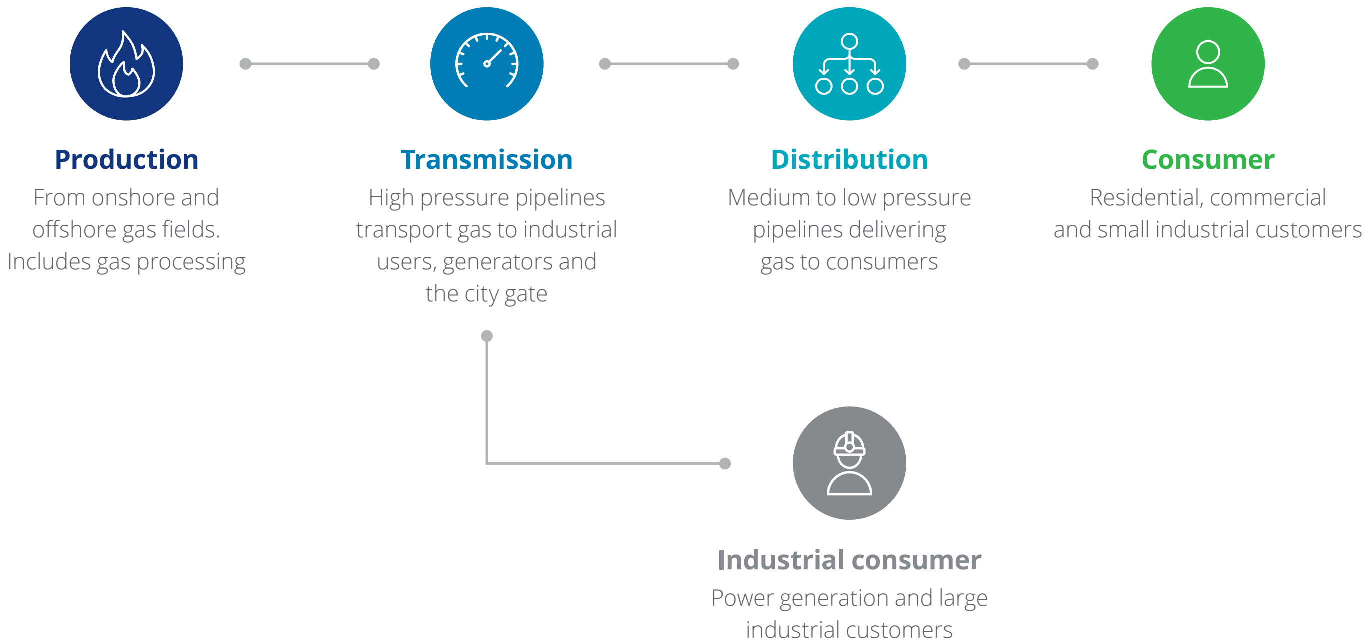
Deloitte Access Economics was engaged by Energy Networks Australia (ENA) to identify a practical approach for sustainably decarbonise gas distribution networks to provide low-emissions gas for direct use by Australian households and businesses. This work will contribute to the ENA's *Gas Vision 2050* and inform the ENA's broader research regarding the potential to decarbonise gas in Australia. The Gas Vision 2050 presents an illustrative decarbonisation pathway for gas, targeting net-zero emissions by 2050 for gas use in the residential and industrial sectors, via the use of three key transformational technologies:

- Biogas production
- Carbon capture and storage
- Hydrogen.

This report presents options to decarbonise the gas transported through Australia's gas distribution networks. These networks supply residential, commercial and industrial customers. The focus of the project is on gas distribution but key considerations and opportunities are also identified for upstream and downstream (i.e. production, transmission and end use) of the network, as well as opportunities within the networks. Figure 1.1 illustrates the gas supply value chain and relationships. While large users take gas from the transmission network, the distribution network mainly supplies retail, small industrial and domestic customers.

The three phases of the project a technical assessment; a commercial assessment; and a strategic plan are presented here in a consolidated report.

Figure 1.1 Gas supply value chain



Source: Deloitte Access Economics

1.2 Benefits of decarbonising gas

Decarbonising any sector of the economy or industry is a substantial, long-term undertaking. Decarbonising distributed networks creates potential opportunities and upsides such as:

- Gas distribution networks are large, long-lived assets. Repurposing this infrastructure to use decarbonised gas may assist to lower the overall cost of the emissions reduction task.
- There may exist alternative uses of gas distribution infrastructure to serve new markets in addition to the traditional residential and commercial customer base, for example, the gas distribution network could be used to transport hydrogen for powering vehicles.
- Large-scale energy storage could occur in the distribution network. Hydrogen production can complement renewable electricity generation, in effect turning an intermittent source of energy into a storable source of energy in hydrogen.
- Producing hydrogen from renewable electrolysis could improve the integration of renewable electricity generation into energy markets.
- The production of decarbonised gas through hydrogen presents the opportunity to export energy, in the form of ammonia.
- Capturing the benefit of research and innovation in low emissions technology or systems.
- Continued diversification of energy supply to consumers.

This report focuses on the decarbonisation of gas distribution networks through the production and transport of zero carbon gas. Decarbonising the energy currently supplied through gas distribution networks by switching to renewable electricity would require a very large increase in electricity generation, transmission and distribution, with customers also incurring costs to make the switch.

The specification and requirements of some industrial equipment means that some large users are unable to switch to electric alternatives from gas. The best, least cost and most suitable solution to decarbonise across Australia is likely to be specific to location conditions and customer needs. So understanding the suite of options available is essential to determining the right solution for each situation. In this report we set out some of the options to decarbonise networks using zero emissions gas and provide a comparison to an electric alternative.

1.3 Approach

In developing this report we consulted with a wide group of stakeholders, conducted desktop research of publicly available sources and performed our own high-level quantitative analysis. Appendix C: lists the stakeholders consulted for this work.

1.3.1 Structure of this report

This report is structured as follows:

- Section 2 sets out the role of gas distribution networks.
- Section 3 covers the three transformational technologies to be deployed and identifies how they can contribute towards the decarbonisation task.
- Section 4 provides a commercial assessment and pathways for converting networks and compares that to alternate all-electric solutions.
- Section 5 illustrates a plausible range of pathway for decarbonising the sector.
- Section 6 sets out research and development options to progress decarbonisation of the gas distribution network.

Decarbonisation of the gas network will require a holistic approach to effectively lower emissions, while maintaining reliable gas supply. The approach should consider the entire supply chain. The supply chain examined in this report includes:

Figure 1.2 Gas supply chain

Production

A secure and reliable supply of decarbonised gas for distribution to customers. Challenges vary between technologies and due to regionally specific conditions. Our analysis considers production of decarbonised gas using:

Biogas

Biogas generated from waste or purpose-grown biofuel crops to create methane, which can be further treated to produce a gas similar to natural gas or converted to hydrogen.

Hydrogen

Steam methane reforming (SMR) (which needs to be paired with carbon capture and storage (CCS)) or electrolysis (which can be effectively emissions free if renewable energy is used).

Carbon capture and storage

CCS is generally viewed as a technology to be adapted to fossil fuel power generation or industry. In the context of distributed gas, CCS will need to be paired with steam methane reforming or gasification to remove emissions.

Networks

A key issue for networks is ensuring that pipelines are suitable for transporting decarbonised fuels. Transmission networks are largely comprised of steel pipes that transport gas at high pressures and these connect to the distribution networks that operate at lower pressure. The distribution networks are already undertaking renewal programs with new materials expected to be capable of carrying hydrogen (e.g. polyethelene).

End users

Ensuring that customer appliances are appropriately designed to operate safely and effectively under different gas composition scenarios. This report will focus primarily on residential users, with consideration being given to commercial and industrial users where possible.

2. Emissions reduction targets and gas distribution networks

2.1 Australia's commitment to emission reduction

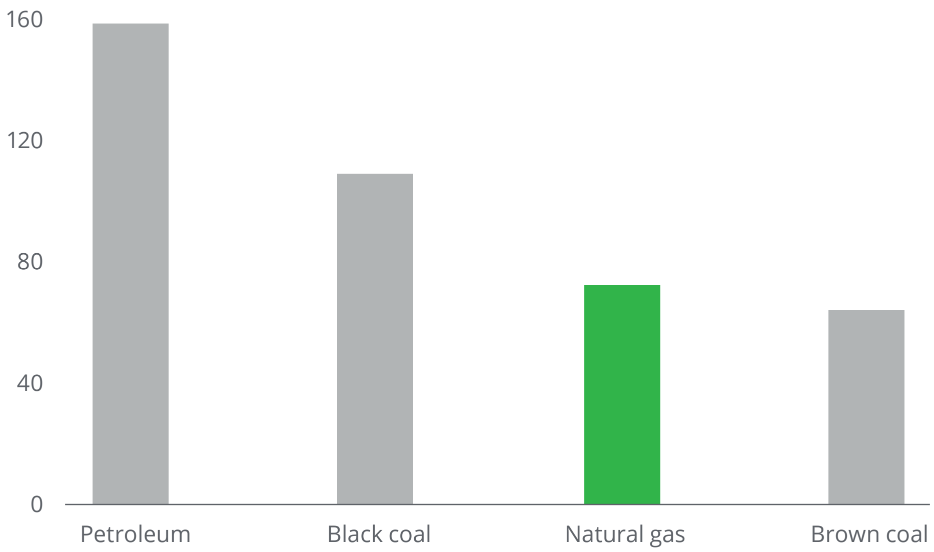
In 2015, the 21st Conference of Parties (COP21) to the United Nations Framework Convention on Climate Change (UNFCCC) was held in Paris with the primary aim of achieving a legally binding and universal agreement on climate change. The Paris Agreement aims to constrain the increase in the global average temperatures to well below 2 °C above pre-industrial levels, with parties also committing to pursue efforts to limit the temperature increase to 1.5 °C.

Achieving the 2 °C target implies that global emissions will need to reach net-zero in the second half of the century, while achieving the 1.5 °C aspiration would require net-zero emissions to be met by sometime around 2050.[3]

The Paris Agreement requires each country to propose an ambitious, nationally determined contribution (NDC) towards achieving the 2 °C target.

The Australian Government has committed under the Paris Agreement to reduce emissions by 26-28% from 2005 levels by 2030, building on its previous commitment to reduce emissions by 5% below 2000 levels by 2020. While there are a range of national and state-based polices and targets in place to deliver emissions reductions in the energy sector[5], a comprehensive pathway for decarbonisation of the Australian energy sector has yet to be agreed upon.

Chart 2.1 Emissions from natural gas and other fossil fuels (2014-15)
Emissions, Mt CO_2-e



Source: Deloitte Access Economics analysis of Department of Environment and Energy data.

2.2 Australian greenhouse gas emissions

In order to meet our emissions reduction targets under the Paris Agreement, decarbonisation of the energy sector and other industries (e.g. agriculture) will be required, enabled by technology, innovation and supportive market and policy settings. In 2016, energy use (electricity, transport and direct use of fuels such as coal, oil and gas, as well as fugitive emissions from energy) in Australia made up around 78% of total emissions. Out of the 74 Mt of Australia's total emissions from gas use, around 8 Mt of emissions comes from gas transported via gas distribution networks.

The Finkel Review provides a pathway for decarbonisation of the electricity sector, but a pathway to decarbonisation is also required for the direct use of gas. The Finkel Review provided a vision for the National Electricity Market (NEM) outlining a steady trajectory or emissions reductions, such that:

- By 2030, emissions from the electricity sector will be 28% below 2005 levels
- Zero emissions is targeted for the second half of the century.[6]

The Finkel Review proposed a Clean Energy Target for the electricity sector as a mechanism for driving clean energy investments, reducing emissions and supporting reliable supply of electricity.[7] Gas is a large source of fuel for the electricity industry, with gas fired generation making up around 20% of installed capacity in 2017.[8]

But a decarbonisation pathway is also required for the direct use of gas for heating, cooking and for commercial use. Natural gas makes up around one quarter of total energy consumed in Australia. Gas provides a lower emission option than coal for power generation and also provides a lower emission option for direct use compared to using electricity powered by coal.

Meeting Australia's commitment to the Paris agreement will require emissions from natural gas use to reduce over time, and this creates opportunities for low emissions fuels such as hydrogen and biogas.

Reducing transport emissions will ultimately require replacing petroleum as a fuel source. Natural gas is a lower emission fuel than petroleum and other opportunities to make large emission reductions from transport include mixing biogas into the natural gas used as fuel, or electric vehicles powered by renewable electricity or hydrogen. Maintaining a broad suite of options is vital to finding the optimal solution to lower Australia's emissions.

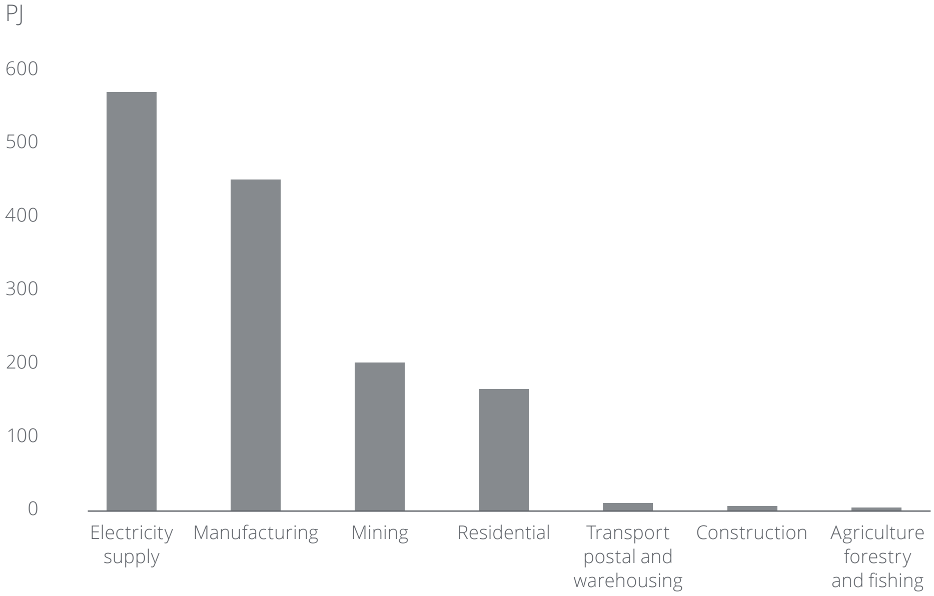
2.3 Gas in Australia

Australia has an abundance of natural gas and this has made it an affordable and reliable source of energy for cooking, heating, generating electricity and use in industrial manufacturing.

2.3.1 Gas consumption by sector

In terms of final energy consumption, Chart 2.2 below shows that gas is primarily used in the manufacturing, mining and residential sectors of the economy. In 2014-15 the manufacturing sector accounted for 19% of energy consumption in Australia. As Australia's economy transitions away from mining led growth and manufacturing toward growth in the health sector and knowledge sectors, changes in energy use will continue. The use of gas in the home is growing modestly with population growth and new housing construction. Over the last decade, gas distribution customer connections have increased by approximately 100,000 per year.[9] Gas is also an important fuel source for electricity generation, accounting for approximately 20% of primary energy input for electricity generation.

Chart 2.2 Energy consumption in Australia for gas, by industry



Source: Office of the Chief Economist, 2016, Australian Energy Statistics, Table F.

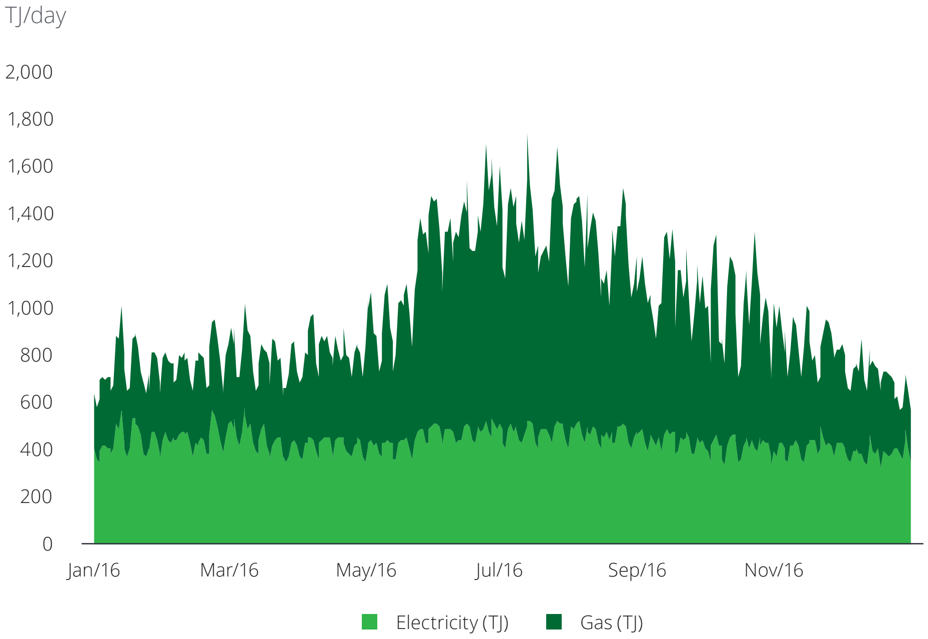
2.3.2 Gas consumption by State

To understand the size of the decarbonisation task it is important to understand how much gas we use each year and where we use it. Gas use in Australia varies by region and by season, with cold regions generally using more gas than warmer regions.

Natural gas usage makes up around one quarter of all energy consumed in Australia. Gas provides a lower emissions option than coal for power generation and also provides a lower emissions option for direct use compared to using electricity powered by coal. Some gas use could potentially be decarbonised by substituting electricity from renewable generation sources.

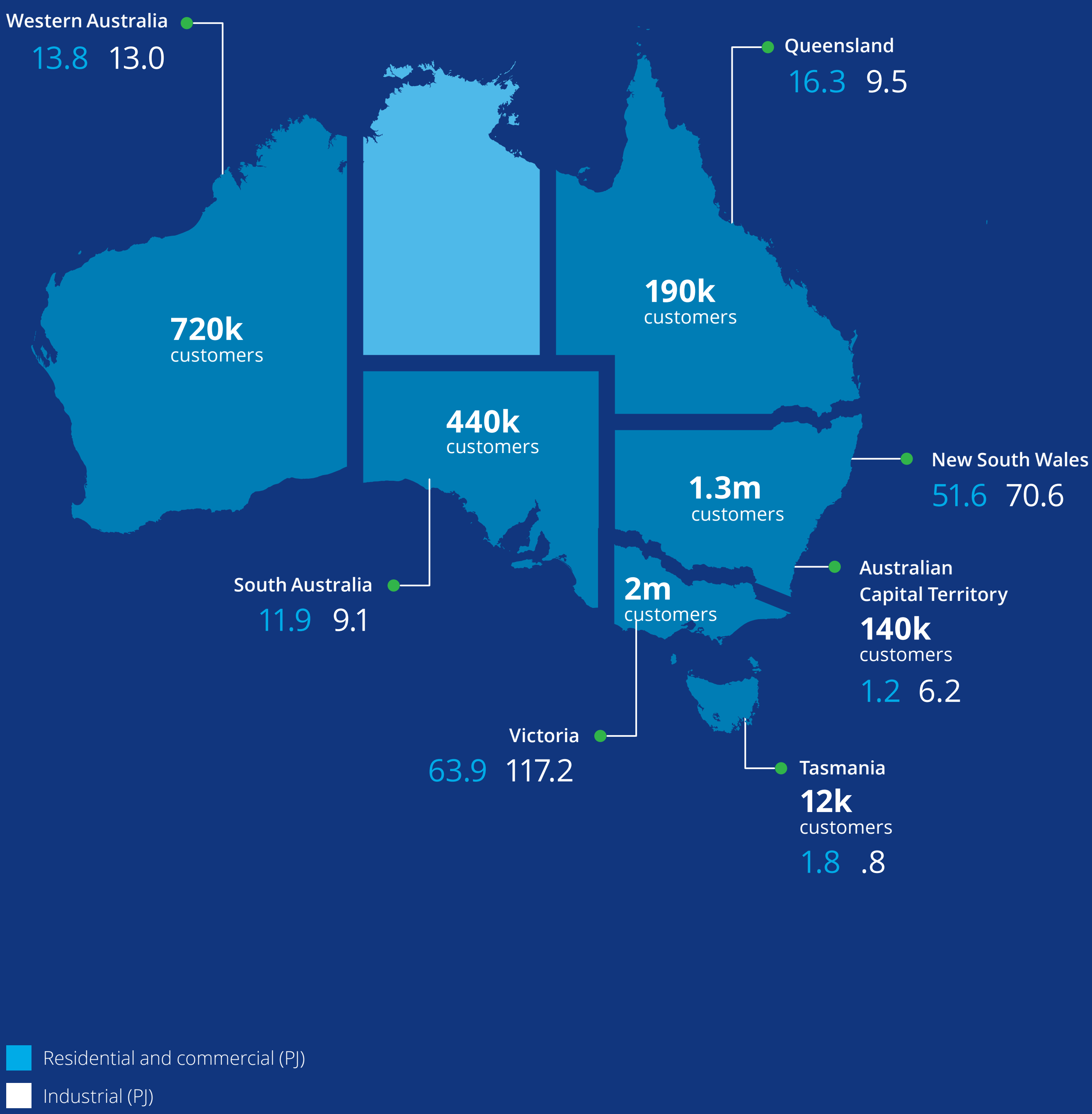
However, shifting energy consumption currently met by gas to electricity (where possible) would be costly and require a large investment in electricity networks and renewable generation. For example, in Victoria, switching from gas to electricity would result in a doubling or tripling of peak electricity demand in winter.

Chart 2.3 Victoria's daily gas and electricity consumption, 2016 (TJ per day)



Source: Deloitte Access Economics analysis of AEMO gas and electricity data

Figure 2.1 Distribution network gas connections and consumption by state



Source: Deloitte Access Economics analysis of Energy Networks Australia and AER data.
Note: The customer estimates refer to the number of connections in each state for residential, commercial and industrial distribution network customers.

Figure 2.1 shows gas use by region in 2016, broken down by residential and commercial, and industrial use. The analysis in this report includes the major distribution regions of Australia. The analysis does not include remote gas networks, networks to transport gas for export, or the Northern Territory. Gas supply in these settings is unique and highly dependent on the industrial users that represent themajority of gas consumed in these regions.

The analysis here focuses on the distribution networks that serve the majority of Australia's gas customers and present the greatest opportunity to decarbonise the gas network

Table 2.1 shows gas consumption per capita by region for residential customers of the distribution network (excluding commercial and industrial customers). Gas consumption varies throughout the year.

In winter, as the temperature cools our use of gas rises due to space heating and additional heating requirements for hot water, with higher consumption of gas on colder days. This seasonal change in the amount of gas needed by consumers varies from region to region. The gas network has been built to cope with these seasonal variations.

Table 2.1 Australian residential gas distribution networks

State	Residential connection (000's)	Residential gas consumption (GJ pa per connection)	Distribution network (km)	Transmission pipelines (km)	Total residential gas consumption (TJ)
ACT	139	35	4,620	–	4,853
NSW	1,332	28	26,290	3,379	36,636
QLD	182	8	5,760	4,732	1,482
SA	427	17	7,950	1,865	7,199
TAS	12	34	710	734	418
VIC	1,958	49	31,090	2,285	96,812
WA	710	15	14,000	6,361	10,506
National	4,762	33	90,420	19,356	156,920

Source: Deloitte Access Economics data collection for *Gas Vision 2050*, Energy Networks Association (2017) *Reliable and clean gas for Australian homes*

3. Transformational technologies

This section describes the technologies used to supply decarbonised gas in Australia's gas distribution networks. Here we set out what the technology does, why it's important and how it can be used in the Australian context. We have investigated the technical and commercial opportunities to decarbonise the gas distribution network using three categories of transformational technologies: biogas; hydrogen gas and carbon capture and storage.

Figure 3.1 Transformational technologies to decarbonise gas in Australia

Biogas
Biogas is methane obtained from organic materials that accumulate carbon as they grow. It can be treated to have the same properties as natural gas.

Hydrogen
Hydrogen is an energy dense gas that can be combusted for heat just like natural gas. When it is powered by renewable energy it is carbon free.

Carbon capture and storage
Carbon capture and storage takes carbon and stores it underground, preventing it from being released into the atmosphere.

3.1 Hydrogen

Hydrogen is a clean burning fuel that can be produced commercially from natural gas or coal, or through electrolysis of water. Hydrogen can also be directly burned to produce energy or heat, and could potentially substitute natural gas in the distribution network. Hydrogen offers fuel flexibility for power generation, transport and direct use with zero greenhouse gas emissions. It can potentially replace or supplement natural gas in Australia's distribution network.

3.1.1 Why hydrogen?

Hydrogen is not a greenhouse gas – it is clean burning, with water the only by-product of combustion. Hydrogen has a lighter density than natural gas which means that it disperses relatively quickly, reducing the risk of accumulation (and consequently reducing the explosion risk or the risk of burning from heat, should it ignite).

Hydrogen can be produced on demand, and stored indefinitely. So unlike some renewable energy sources (such as wind and solar electricity) hydrogen fuel possesses the on-demand property of conventional fuels like coal, natural gas and oil. This means production can be designed to meet demand more efficiently than variable renewable electricity sources of energy. It also means that hydrogen offers a relatively reliable supply of energy.

3.1.2 Current hydrogen uses

Hydrogen has been used globally in a variety of applications for many decades. In 2017 hydrogen is mainly used as a feedstock in industrial processes and to improve the efficiency of industrial processes like oil refining. In the future, hydrogen fuel cell vehicles (FCVs) may become an important part of the decarbonisation path for Australia's transport sector. Hydrogen is also used directly for heat, in the form of town gas in gas networks around the world.

- **Chemical feedstock:** Hydrogen is used as a feedstock for ammonia production and is also used as an input to industrial processes. Hydrogen is a central commodity produced by Australia's specialised industrial gas manufacturing sector. Globally hydrogen is also used in oil refining. Of the more than 50 million tonnes of hydrogen produced worldwide each year, nearly 90% of this is used to produce either ammonia or as part of the oil refining process.[10]
- **Fuel cells:** Hydrogen FCVs are technically feasible and are used in limited applications globally. Hydrogen is used in a reaction which creates electricity to power the vehicle. In Australia in 2017, hydrogen use in vehicles is limited, but there are future opportunities. Six hydrogen-fuelled buses will service Adelaide under a commitment by the South Australian Government. And in Victoria, Moreland City Council has procured 12 garbage trucks that will operate on hydrogen in the council area by 2020.
- **Gas networks:** Hydrogen can also be directly burned to produce energy or heat. It therefore could potentially substitute partially or entirely for natural gas in the distribution network for use in industrial, commercial and residential applications, in the same way in which natural gas is used. Hydrogen gas currently comprises approximately 50% of the gas distributed in networks in Singapore and parts of China, where manufactured town gas is used. Historically, Australia's gas networks comprised similarly large shares of hydrogen. Manufactured town gas was injected into the networks until network conversions to natural gas commenced in 1969 in Adelaide, Brisbane and Melbourne and later in Sydney in 1976.[11]

The Northern Gas Networks H21 Project, underway in the United Kingdom, involves the conversion of the city of Leeds' natural gas network to 100% hydrogen. The project may provide valuable lessons on the feasibility of similar conversions in the Australian context (see Case Study 1 overleaf).

Case Study 1:
H21 Leeds City Gate Hydrogen Network

Source: Northern Gas Networks (2016)

The H21 project commenced in 2017 and aims to deliver findings on the technical and commercial constraints to switching an entire natural gas network to hydrogen.

Leeds is a city of 751,000 with an annual gas demand of 6 TWh (2013) across residential and industrial users. The final conversion area under the project will encompass approximately 660,000 people across 264,000 meter points.[12] Full conversion of the city of Leeds is anticipated to be feasible by 2025 (at the earliest).

The project will see natural gas from the North Sea converted to hydrogen at a nearby steam methane reformer facility (described in 3.1.3.1) in the industrial hub of Teesside. To meet the estimated demand for hydrogen, two reformers will be constructed in addition to the two already in operation at Teesside. These will operate year round.

UK gas use, like much of Australia, is highly seasonal due to its use for heating, with winter peak average daily demand double that in summer. While Leeds' peak average daily demand is 2,067 MW, steam reforming production capacity is being built to serve 1,025 MW, with intra-day and inter-day seasonal variations in demand managed by storing excess production in nearby salt caves in Hull. The salt caves will store approximately 40 days of maximum average daily demand. A hydrogen transmission pipeline will connect the storage facility to Leeds and will be capable of carrying the maximum hourly peak demand of 3,180 MW.

- **Decarbonisation:** steam methane reforming releases CO_2 in the same way that burning methane would. To be carbon neutral, the CO_2 will be transported to and sequestered in depleted oil and gas fields in the North Sea, expected to amount to 1.5 million t CO_2 per year once the entire city is converted to hydrogen.
- **Network conversion:** hydrogen can cause embrittlement of some network materials (particularly steel) (see section 3.1.4). Consistent with the rest of the UK, Leeds' entire distribution network will be converted to polyethylene (PE) by 2032.
- **Appliance conversion:** Northern Gas Networks anticipates that gas stove tops, boilers and heaters can largely be upgraded, rather than replaced, in order to operate using hydrogen. Staged conversions of isolated sections of the city are planned at different points over 3 years to minimise customer disruptions.

3.1.3 Producing hydrogen for use in gas networks

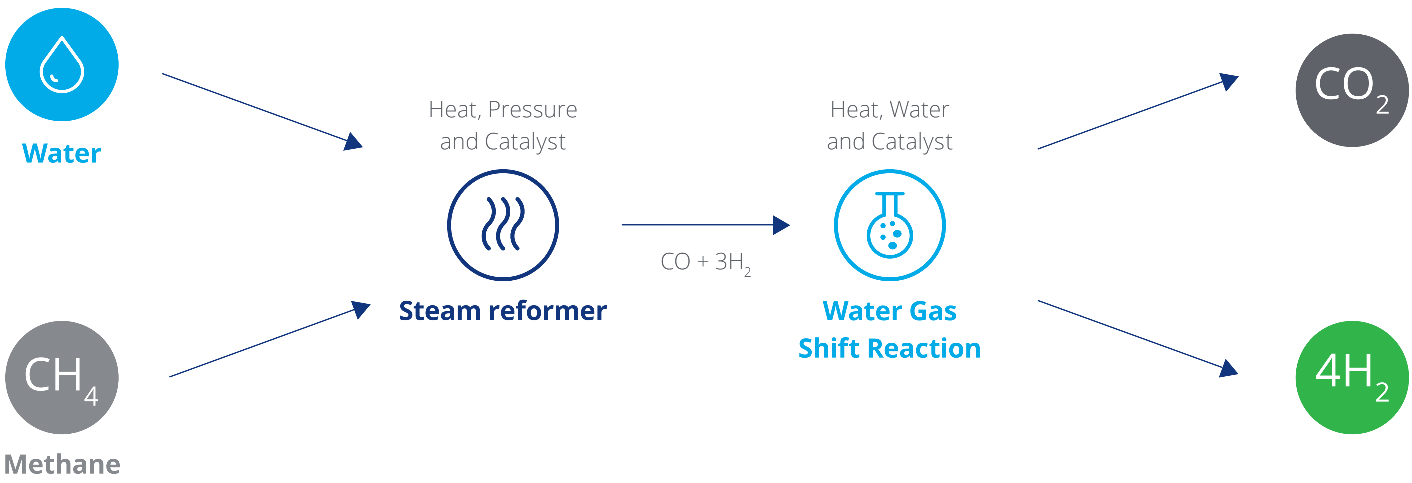
Hydrogen can be produced in a variety of ways, with the three most widely used methods being steam reforming, coal gasification and electrolysis. A range of other processes are available for producing hydrogen, including solar thermochemical, photolytic (direct water splitting) and biological processes. Given the nascent stage of development for these other processes, we have not considered them in detail in this report. Future developments to improve the efficiency or cost of electrolysis may provide additional supply options.

3.1.3.1 Steam reforming

Steam reforming to produce hydrogen is a well-established technology, used extensively throughout the world for hydrogen production. Chemical companies in Australia (e.g. Orica, Incitec Pivot and CSBP) use steam reforming to produce hydrogen gas as part of the ammonia production process (ammonia is a compound of hydrogen and nitrogen).

Reforming involves combining a hydrocarbon feedstock with steam at high temperatures (up to 1,000 ºC) under pressure in the presence of a metal catalyst (such as nickel or an iron oxide). This reaction produces carbon monoxide (CO) and hydrogen (3 H_2). Subsequently, the carbon monoxide can be converted to carbon dioxide¬ and an additional hydrogen can be produced¬ via the 'water-gas shift reaction', by combining water (steam) with the carbon monoxide. Most commonly the hydrocarbon feedstock used is natural gas due to its availability, efficiency and cost. Other hydrocarbon-containing feedstocks can also be used, such as ethanol, propane, petroleum, coal or biomass.

Figure 3.2 Hydrogen production using steam reformation



Source: Deloitte Access Economics, 2017 (Icons: Deloitte and the Noun Project, 2017)

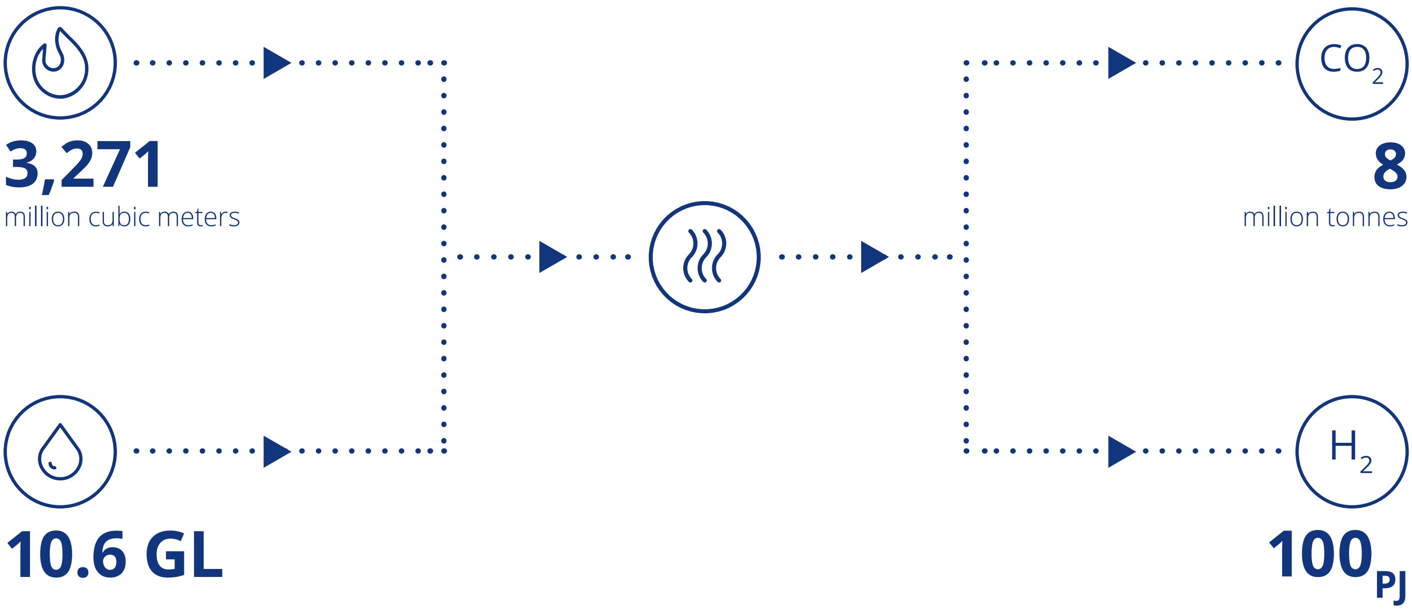
Carbon dioxide is a by-product of the steam methane reforming process. While hydrogen itself is a zero carbon form of energy at the point of combustion, the production process using natural gas still results in the release CO_2 into the atmosphere from the methane feedstock which is used to power the reaction and produce hydrogen.

To create a low, or zero carbon process, approaches include:

- Using biofuels (including biogas) as a feedstock. Limited details are available on the efficiency of alternative fuels in the steam reformation process. We note that more complex compounds are likely to require more processing to separate hydrogen, reducing efficiency and increasing costs.
- The use of CCS technology to sequester carbon emissions from the process. Given the reforming process already separates out the CO_2, to complete the CCS process all that is needed is transport and storage.

Figure 3.3 below shows the required inputs to produce 100PJ of hydrogen from steam methane reforming and carbon capture and storage. If steam methane reforming was used to produce 100 PJ of hydrogen, then 3,271 million cubic metres (130PJ) of natural gas would be required annually to meet gas demand with hydrogen. This is assuming a process efficiency of 77% by 2050 for SMR. Carbon emissions created through the production of hydrogen would need to be captured to produce 100 PJ of hydrogen, around 8 million tonnes of carbon would be captured. The process of steam methane reforming also uses water as an input. To supply 100 PJ of hydrogen requires 10.6ML of water in the process to use as steam.

Figure 3.3 Decarbonising gas by 2050 with hydrogen from natural gas and CCS



Source: Deloitte Access Economics, 2017; (National Renewable Energy Laboratory, 2013)

3.1.3.2 Gasification

Gasification is a mature and widely deployed technology, and can be applied to a range of feedstocks including black coal, brown coal (also known as lignite), and biomass. Victoria has a long history of lignite gasification, having previously used this process to produce town gas in the Latrobe Valley before natural gas from Bass Strait became available in the 1960s.[13]

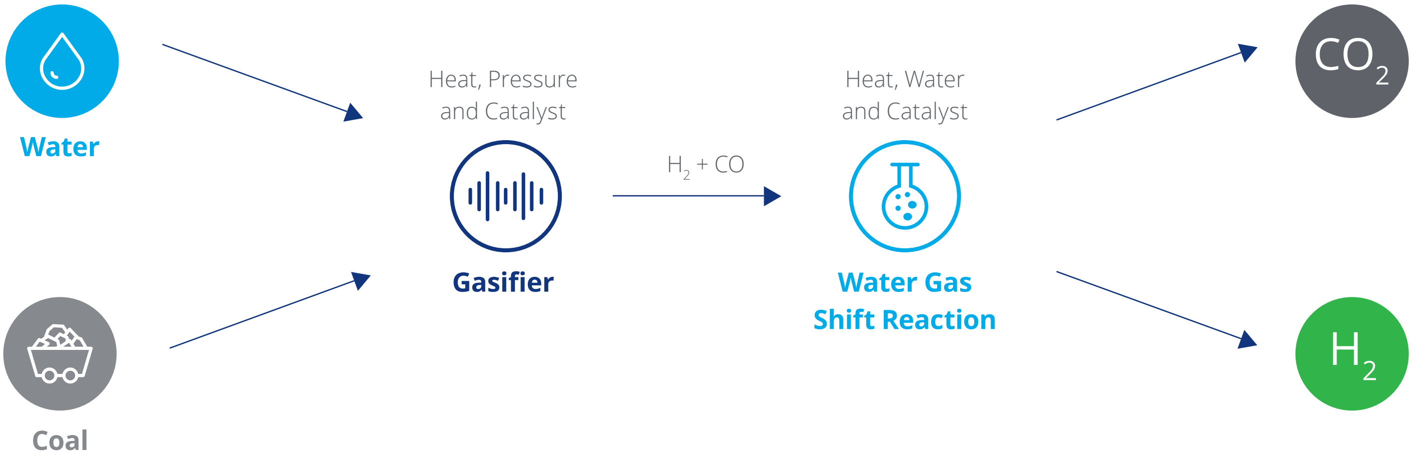
Coal gasification involves a similar process to steam methane reforming. Dehydrated coal, steam and oxygen are combined under heat and pressure (often in the presence of a catalyst to improve efficiency and promote creation of desired compounds[14]) to produce a synthesis gas (also referred to as syngas). The syngas comprises hydrogen gas along with carbon monoxide and carbon dioxide. Similarly, as with steam methane reforming, a secondary water-gas shift process can then separate out the hydrogen and carbon dioxide from the carbon monoxide produced in the gasification process.

Carbon dioxide is a by-product of coal gasification along with hydrogen. Carbon dioxide emissions can be reduced or eliminated by using CCS. Additional carbon dioxide emissions arise from the coal (or other energy source) used to power the gasifier.

Australia has large reserves of black coal, brown coal and natural gas, providing a large potential feedstock for the production of hydrogen. Gasification of lignite to generate hydrogen is currently being trialled in Victoria by Kawasaki Heavy Industries (KHI) (see Case Study 2). In comparison to using natural gas as a feedstock (in steam methane reforming) coal yields less hydrogen for a unit of carbon dioxide emitted.

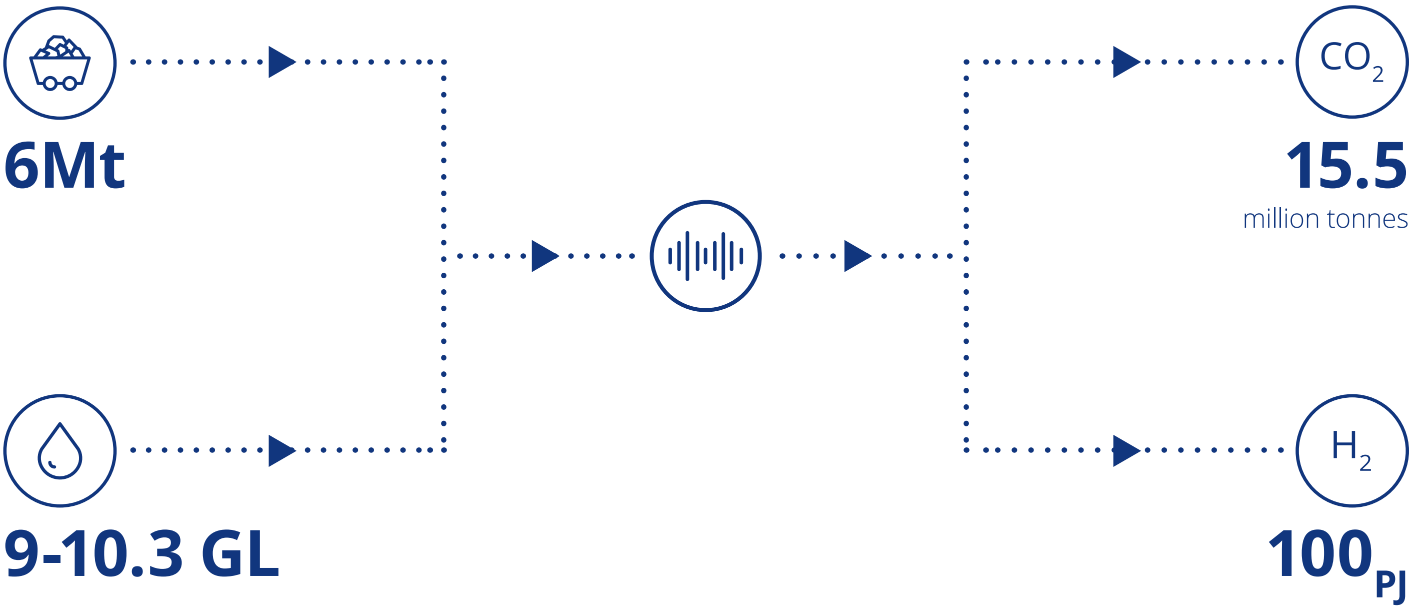
Alternatively, the use of biomass would result in very low or net-zero emissions, and negate the requirement for CCS. While biomass gasification may be a mature technology, there is limited information available on the efficiency of gasification of biomass and the relative efficiency of then creating hydrogen (see pages 37 to 47 for further discussion on biomass).

Figure 3.4 Production of hydrogen via coal gasification



Source: Deloitte Access Economics, 2017 (Icons: Deloitte and the Noun Project, 2017)

Figure 3.5 Decarbonising gas by 2050 with hydrogen from Bituminous (black coal) and CCS



Source: Deloitte Access Economics, 2017; (National Renewable Energy Laboratory, 2013)

Case Study 2:
KHI's Hydrogen Road

KHI's liquid hydrogen carrier (artist's impression)

Hydrogen plays a significant role in the Japanese Government's energy strategy. With limited domestic endowment of fossil fuels, or land mass required for renewable electricity, Japan is largely reliant on imports for energy security. Hydrogen imports provide a potential source of decarbonised energy supply.

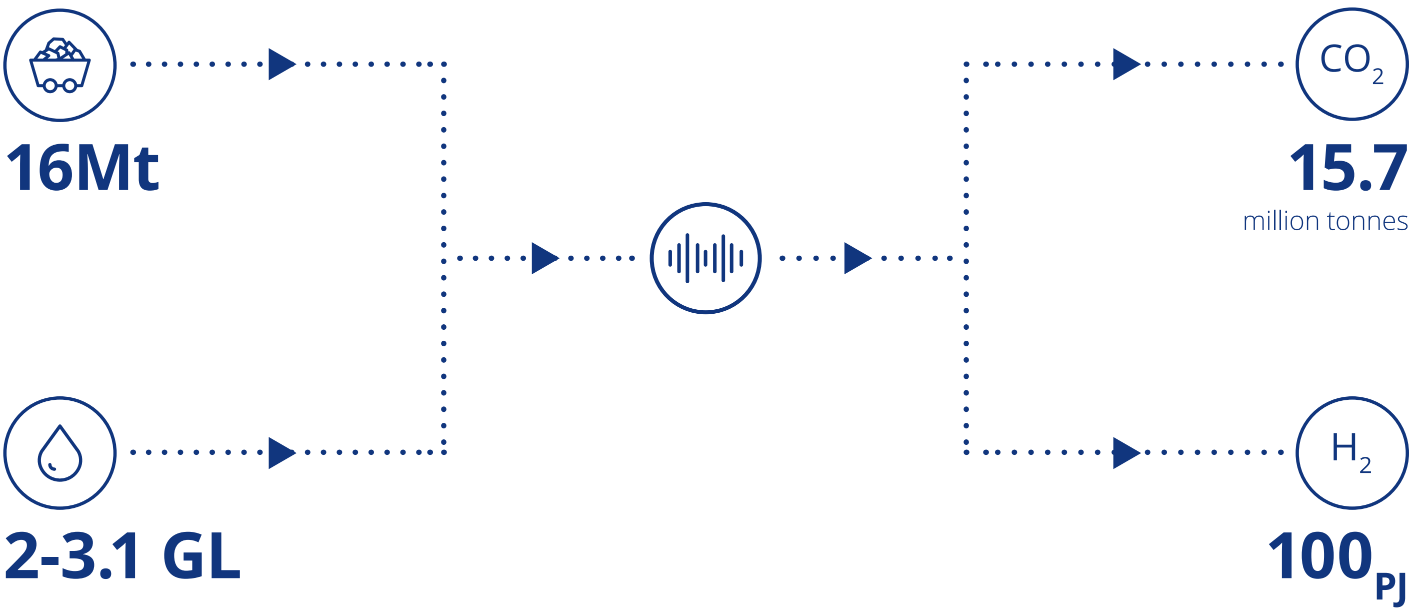
The Hydrogen Road project will see Japan's KHI produce hydrogen in the Latrobe Valley, Victoria through gasification of lignite (combined with CCS). Although currently a pilot project, the Hydrogen Road Project ultimately aims to be an integrated hydrogen energy supply chain covering production through to transport and utilisation of the fuel.

The aim is to transport large quantities of the fuel in liquid form to Japan, and (initially) contribute to fuelling the 2020 Tokyo Olympics using hydrogen.

KHI is working to develop technology across all stages of the hydrogen supply chain, with the prototyping of a small scale liquid hydrogen carrier ship (inset) in November 2014 marking the project's commencement. Hydrogen Road is also connected to the Victorian Government's CarbonNet project, with the CO2 by-product from gasification of lignite to be injected into the CarbonNet CO2 transport network and sequestered in the Gippsland Basin.

Source: Kawasaki Heavy Industries, 2017

Figure 3.6 Decarbonising gas by 2050 with hydrogen from lignite (brown coal) and CCS



Source: Deloitte Access Economics, 2017; (National Renewable Energy Laboratory, 2013)

The use of coal gasification to produce 100 PJ of hydrogen would require around 16 million tonnes of lignite (brown coal), along with 2-3.1 ML of water, as outlined in Figure 3.6 above. Were black coal to be used instead, the production of hydrogen would require 6 million tonnes of black coal, outlined in Figure 3.5. This is equivalent to 167 PJ of coal required, assuming a process efficiency of 60% by 2050 for coal gasification.

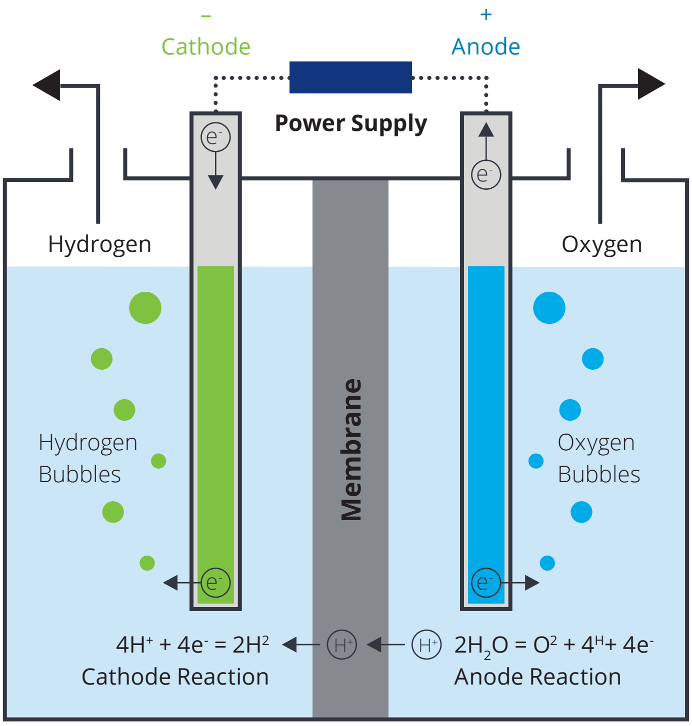
Brown coal has a much lower heating value than black coal, meaning that it produces far less energy per tonne. Brown coal's high moisture content means that little (to no) water is needed to be added in the gasification process. However it means there is less energy per tonne of coal and requires significantly more coal on a weight basis (see Figure 3.6).

3.1.3.3 Electrolysis

Electrolysis involves using an electrical current to split (fresh) water into its two constituent elements: hydrogen and oxygen. There are a range of electrolysis processes, all of which apply generally the same approach and construction (an anode and cathode separated by an electrolyte) but vary in terms of the electrolyte and charge carrier:

- Alkaline electrolysers – a mature technology and currently the cheapest alkaline electrolysers are commercially available in units of up to around 2 MW, but are scalable to much greater capacities. The largest alkaline electrolysers have a capacity of around 135 MW. Alkaline electrolyser efficiency is around 65-82%.[15]
- Polymer Electrolyte Membrane (PEM, also Proton Exchange Membrane) electrolysers – use a solid plastic electrolyte, currently at the early market stage, also scalable to capacities of up to 1 MW, with large capacities able to be built with modular installations, and similar efficiency to alkaline electrolysers.[16]
- Solid oxide (SO) electrolysers – in the research and development phase, laboratory scale which shows efficiency of up to 85-90%.[17]

Figure 3.7 Polymer electrolyte membrane electrolysis process



Summary of PEM electrolysis process:

1. Power is supplied to circuit formed by the anode and cathode.
2. Water reacts at the anode to form oxygen and positively charged hydrogen ions (protons).
3. The electrons flow through the external circuit and the hydrogen ions selectively move across the membrane to the cathode.
4. At the cathode, hydrogen ions combine with electrons from the external circuit to form hydrogen gas.

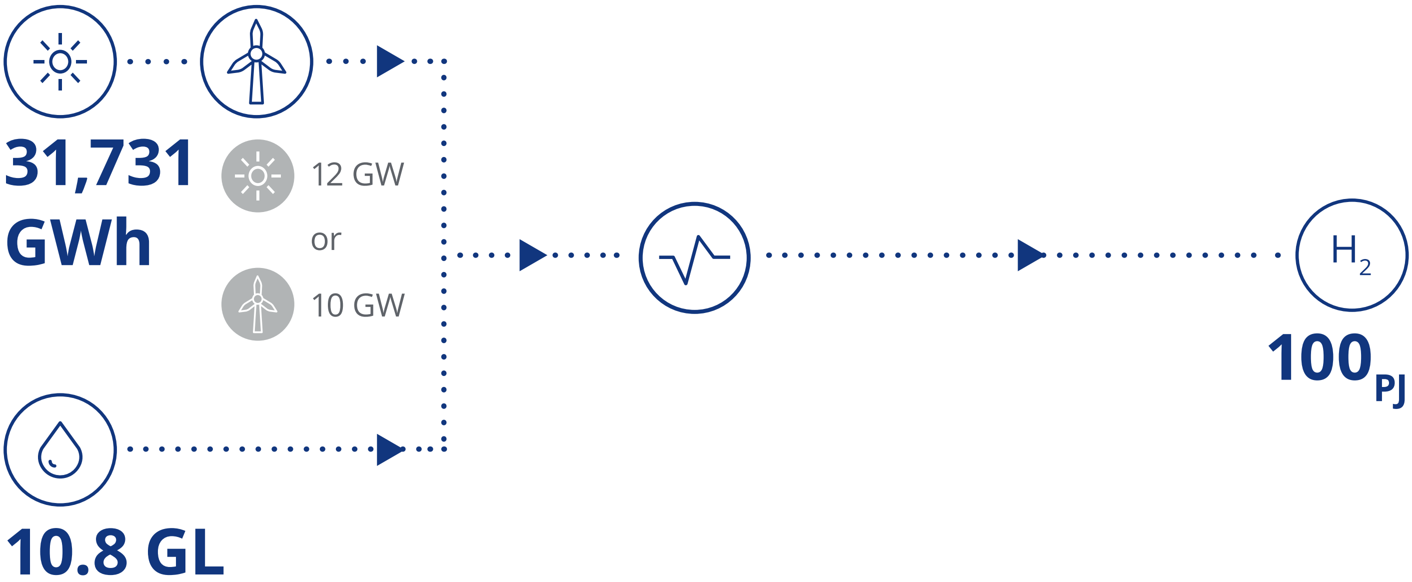
Source: (United States Office of Energy Efficiency & Renewable Energy (EERE), n.d (b))

While electrolysis requires a significant amount of electricity, if powered by renewable electricity the process would be carbon neutral. While this might create some intermittency in the ability to produce hydrogen, the ability to store hydrogen makes it a natural complement to variable renewable electricity.

Figure 3.8 below shows the required energy inputs to produce 100PJ of hydrogen. If electrolysis was used to produce hydrogen and this process was powered with renewable energy, then 31,731GWh of wind or solar power would be required annually to meet 100PJ of gas demand.

By comparison, in 2016, wind and solar generation in the NEM was estimated to be 15,180GWh.[18] This assumes the efficiency of electrolysis reaches 88% by 2050. The process of electrolysis also uses water as an input and to supply 100PJ of gas demand with hydrogen would require 10.8GL of water annually.

Figure 3.8 Decarbonising gas by 2050 with hydrogen from renewable electrolysis



Source: Deloitte Access Economics, 2017

3.1.4 Transporting hydrogen in the gas network

The infrastructure for the natural gas network consists of high pressure transmission pipelines, medium pressure distribution pipelines and low pressure pipes behind the meter that deliver gas to the appliance. The material used to construct each pipeline and the pressure at which the gas is transmitted are specifically configured for natural gas. As such, changes to the nature of the gas carried will not only have an impact upon the pipeline infrastructure, but will also impact upon the gas fired appliances and equipment used by households and businesses.

3.1.4.1 Transmission pipelines

Altering the composition of the gas in the transmission network would have an impact upon the structural integrity of the steel pipelines. Transmission pipelines are typically made from higher strength steels classified under the standard API 5L[19] with the material composition specific to the gas or liquid carried. Hydrogen under high pressure can lead to steel transmission pipelines becoming more brittle, or cracking. In particular, high strength steels – as utilised in modern transmission pipelines – are susceptible to this phenomenon which is known as hydrogen embrittlement.[20]

Studies completed by Meng et.al. have demonstrated in X80 steels (the highest strength grade) that even a 5% hydrogen mixture in natural gas can have a significant effect on hydrogen embrittlement effects with an order of magnitude in fatigue crack growth rates and with significant loss of design fatigue cycles. The authors suggest that a maximum of 20% hydrogen is allowable to maintain a greater than 50 year design life.[21]

The impact of hydrogen embrittlement on high pressure steel transmission pipelines and its effects has been discussed at length in previous reports by Northern Gas Networks[22], and Energy Pipelines CRC.[23]

3.1.4.2 Distribution pipelines

The material structure of the distribution network is critical to whether the gas network can be decarbonised in Australia. Most distribution pipelines will be converted to polyethylene (PE) piping by 2035, allowing the wide-scale transport of hydrogen gas in the medium to lower pressure distribution pipelines.

PE pipelines are not thought to be subject to performance and material durability issues so long as they are underground and protected from UV degradation from the sun.

3.1.4.3 Gas metering

Gas meters are crucial to measuring the total gas used by households and businesses for billing purposes. There are two main meter types: volumetric meters and Coriolis meters. Volumetric meters will likely be capable of measuring hydrogen gas use in the network. Conversely, Coriolis meters measure weight and may not be able to sufficiently measure hydrogen gas. However, Coriolis meters exist across a small minority of consumer sites and the upgrade of Coriolis meters is unlikely to be a significant cost or technology factor to decarbonise the network.

Where the gas composition is 100% natural gas or hydrogen, metering is relatively simple. If the network were to introduce a blended gas, then metering would need to be calibrated and tested to derive an accurate means of estimating the volume of gas passing through the network.

3.1.4.4 Piping downstream of the meter

The piping used to deliver gas from the distribution network to the home can be steel, PE, aluminium, cast iron, a composite material or copper. The delivery pressure of the hydrogen gas in pipes of these materials are such that the technical issues are not significant to the safe delivery of hydrogen gas.[24]

During consultation, some stakeholders expressed concern about losses of hydrogen through joins and other materials in the network. Elastomers and other materials used to seal joins in the pipework are also known to allow hydrogen gas to permeate. The small surface area of elastomers and other join seals which are impacted means the losses are minor compared to the PE pipework itself. Natural gas is also lost at a well understood rate through the pipeline network, so hydrogen does not present a change from measuring losses under existing conditions.

3.1.4.5 Locational issues

Given the existing natural gas steel transmission pipelines may not be suitable for carrying hydrogen gas due to embrittlement, new pipelines would be required to transmit hydrogen over long distances. As such, it may be most efficient to locate hydrogen production relatively close to the distribution network, with major network upgrades reserved for transmission of CO_2, where required as part of a CCS process. Ideally, hydrogen production for use in the gas network would occur close to the distribution pipelines and load centres to minimise transport and pressurisation costs. The use of steam methane reformers requires combination with CCS technology to produce decarbonised hydrogen. As such, to reduce the cost of transporting carbon dioxide (itself a corrosive element to steel pipelines when mixed with water), hydrogen production is typically located close to a CCS location, as seen in the Leeds H21 City Gate project. CCS is dependent on the geological formation of an area. Similarly the production of hydrogen via electrolysis will be more cost efficient if located close to the renewable energy source. Regardless, the location of hydrogen production facilities will be a commercial decision balancing the location of the demand centre, resource availability (gas, water, CCS, etc.) and the costs of CO_2 and hydrogen pipelines.

3.1.5 Residential and commercial use of hydrogen

Hydrogen appliances exist globally, and appliances built to operate on a blend of hydrogen (from town gas) are used throughout the world today. If Australia was to decarbonise using hydrogen, appliance conversion would not be a technical limitation.

3.1.5.1 Maintaining gas supply pressure and velocities

Gas appliances are designed specifically to operate within the bounds of a particular gas specification and operation outside of this can lead to poor performance, appliance damage and ultimately inefficient operation.

Injecting a different gas into the appliance has implications for the gas pressure requirement and the velocity of the gas within the appliance.

As such, changes to the composition and nature of the gas supplied across the network will require modifications to, and in some cases replacements of, the appliances used by households and businesses.

In a standard residential gas fired appliance gas enters the property through to the inlet of the appliance, then to the manifolds, and from here to the supply tubes which have brass injectors that allow the gas to disperse into the burner.

Gas appliances are specifically designed such that the gas will ignite at a point where the velocity of the gas is closest to its flame speed. In a correctly designed appliance, ignition will occur at the burner, but in a poorly designed appliance ignition may occur back at the injector. The challenge of transitioning from natural gas to hydrogen gas is that hydrogen has a very high flame speed, meaning heat from hydrogen dissipates more rapidly than heat from a natural gas flame.

Hence modifications will be required to existing appliances to ensure optimal operation of those appliances. Hydrogen appliances are already used where town gas is in use so these could be modified for 100% hydrogen in networks.

Upgrading natural gas appliances to operate on hydrogen would require physical changes to appliances due to the different velocity and also different pressure requirements. Changes would be required to the appliance regulators, the injector, the ionising flame rod (which detects the flame) and start gas rates (the safe ignition period before the appliance automatically shuts off to prevent it from self-igniting).

Northern Gas Network's Leeds H21 project showed that upgrades, rather than replacement of appliances would suffice. We would also expect this to hold true in Australia. However further research should be undertaken to confirm the costs and effectiveness of an approach which minimises appliance replacement where upgrades of existing appliances are feasible.

3.1.5.2 Industrial appliances

Although fewer in number, industrial users consume a large percentage of the total volume of gas used in Australia. Industrial users predominantly access natural gas from the distribution network, but large users such as electricity generators and chemicals manufacturers are usually directly connected to the transmission network. Both transmission and distribution connected industrial users face challenges operating their appliances and equipment if the gas composition changes. Like residential appliances, industrial users must have their equipment certified by one of the state regulators to ensure that operation complies with Australian Standards (AS 3814).

Industrial users would have the further complication of requiring burner redesign and pressure changes to achieve the right burn conditions. This work would need to be completed by a licensed gas fitter, and could require major review and recalibration of processes. Further discussion is provided in previous reports by Northern Gas Networks[25] and Energy Pipelines CRC.[26]

3.1.5.3 Capability development

Most industrial appliances are unique designs and are similarly built to operate on natural gas. Where existing appliances domestic or industrial could be upgraded the knowledge and engineering capacity to conduct conversions would take time to develop. Australia has stringent safety standards regulating the design, sale, installation and operation of domestic, commercial and industrial gas appliances (AS 45XX Series type A (domestic) appliances; AS3814 type B (industrial) appliances; AS5601 installation).[27] At present, changes to gas mixtures will need to comply with these standards and modifications to the standards will be needed for higher concentrations of hydrogen.

3.1.5.4 Managing the transition

Conversion to a hydrogen network in Australia will undoubtedly create disruption to customers, but technology upgrades are not unprecedented and can be managed to minimise customer inconvenience. Australia converted the natural gas network from town gas in the late 1960s and 1970s. More recently, parallels can be drawn from government managed market wide technological upgrades across television and currently internet. While these upgrades did not face the safety issues that gas network upgrades would face, they are similarly wide scale.

The transition from analog to digital television in Australia began in the 1990s and culminated in the switch off of analogue signals in 2013. Similarly the Government is now managing the rollout of the NBN, with copper telephone wires being replaced by fibre optic cables. Both technological upgrades were government led and coordinated and occurred over a number of years to give manufacturers and customers time to transition, whilst also providing leeway to manage the issues that arose. Given a decarbonised gas network would require the upgrade or replacement of existing natural gas fired appliances, it is likely that any such transition would also require government involvement and would occur over an extended period of time.

3.1.5.5 Safety precautions

Hydrogen has a much wider flammable and detonable range than methane. The lower flammability level (LFL) for hydrogen (4%) is similar to that for methane (5%), however the lower detonability level (LDL) for hydrogen (18%) is much higher than for methane (5.7%).[28] The difference in LDL between the two gases means that a much higher concentration of hydrogen needs to accumulate before an explosive environment is reached. The LFL is typically used in safety devices instead of the LDL for hydrogen, providing an added safety factor. Moreover, hydrogen is four times more diffusive in air than methane, meaning that the concentration of a hydrogen build-up in air will reduce more rapidly than methane. Given this, the EPCRC concluded that the use of hydrogen in networks is of similar risk to natural gas.[29]

Like methane, hydrogen is a colourless and odourless gas. Adding an odorant can assist with the detection of leaks. Odorants do not pose a challenge to the use of hydrogen gas in the network. If the gas distribution network was to also supply fuel cell vehicles with hydrogen, a traditional sulphur or nitrogen based odorant could not be added at production because such odorants contaminate fuel cells.

An alternative odorant has been patented, with tests suggesting this odorant will not contaminate fuel cells.[30] If cost effective, this odorant could allow the two markets to source hydrogen from the same pipeline.

3.1.6 Technical gas network regulation

The technical regulation of natural gas within Australia is governed by each of the States and Territories. The broad requirements have been established by the National Gas Laws and Regulations that are based on *The National Gas Law* originally set out in the schedule to the National Gas (South Australia) Act.

Each jurisdiction has enacted relevant legislation to allow third party gas pipeline access. Within the system, the legislation refers to the various Australian Standards for licensed pipelines (used for transmission), network management and appliances. State Regulations rely on relevant Australian Standards to provide the requirements for each of these systems. Critical work completed on the gas network must be completed by licensed gas fitters. Appliances that use the gas must be approved by State and national regulators, and each State has different processes for this to occur. Although mutual recognition arrangements mean that certification in one State can be recognised by the others.

3.1.6.1 Australian Standards

The Australian Gas Standards establish the requirements for all steps of the natural gas distribution supply chain. This separates the technical and safety issues from the legislation.

The natural gas network infrastructure is comprehensively specified and includes provisions for the pipeline material; pipeline maintenance including monitoring of leaks and pipeline repairs; pipeline pressure; and composition of gas carried.

Residential appliance and industrial equipment are specified under their own Australian Gas Standards. Sale of generic gas fired appliances to consumers occurs following extensive testing by Australian state regulators such as Energy Safe Victoria, with installation of these appliances also covered by the standards. Unique commercial appliances are individually tested, but also need to meet specific standards.

These standards are used by the regulators as the basis for the administration of their regulatory function, with the standards directly called up by the legislation. Further detail on the relevant standards is provided below.

3.1.6.2 AS2885 Pipelines – Gas and liquid petroleum

This standard, which is broken up into five parts, deals with high pressure pipelines used for gas transmission. Two of these parts are directly relevant to the potential use of hydrogen gas in pipelines; namely:

Part 1: Design and Construction

Part 3: Operation and Maintenance.

The standard AS2885, though not specifically designed for hydrogen would be the relevant one for use with hydrogen, subject to a gap analysis on the differences between liquid petroleum and hydrogen and the need to make adjustments to address those differences. The onus is on the operator to undertake this but the safety case for a new pipeline would have to demonstrate to the relevant regulator that it can be operated safely.

Committee ME-038 regularly meets to review and update the standard. There are various industry and regulator representatives on the committee. With such a significant change to the use of gas pipelines, the committee could prepare an appendix to specifically address hydrogen gas use in much the same way as the current CO_2 addendum addresses the needs of pipelines for carbon sequestration.

3.1.6.3 AS4645 Gas distribution networks Part 1: Network Management

This standard has three separate parts:

Part 1: Network Management

Part 2: Steel pipe systems

Part 3: Plastic pipe systems.

Each part excludes the transport of gas including hydrogen either alone or any mixture with hydrogen in significant quantities (Section 1.2 (g)).

3.1.6.4 AS4564-2011 Specification for general purpose natural gas

There is no specific exclusion for hydrogen in the definition of natural gas. As long as conditions can be maintained for the Wobbe Index it would generally be allowed. A non-specific provision that the gas shall not contain contaminants (2.1(a)) that "could cause damage to, or interfere with the proper operation of, pipes, meters, regulators, control systems, equipment or appliances…" does exist.

Therefore, there would be a need to prepare new standards for hydrogen gas to be used in gas networks.

3.1.6.5 Appliances

In Victoria, gas appliances are categorised as either "Type A" or "Type B" appliances. Type A appliances are defined by Section 68 or Section 69 of the Gas Safety Act 1997 (Vic), and typically include light commercial and domestic appliances such as cookers and water heaters. Type B appliances are defined as appliances that consume more than 10MJ/h of gas, but are not classified as Type A. Type A appliances are certified in accordance with AS/NZS 5263, and Type B appliances are approved in accordance with AS 3814. There is also provision in Victoria under Section 69 of the Gas Safety Act for Energy Safe Victoria to accept an appliance or class of appliances at its discretion.

In order for appliances which use hydrogen gas as a fuel source to be approved for sale and use, the acceptance scheme in the standards would need to be updated. The following committees review the relevant standards:

- AG-001 Gas Appliances (AS/NZS 5263)
- AG-006 Gas Installation Committee (AS/NZS 5601)
- AG-011 Industrial and Commercial Gas-Fired Appliances (AS 3814).

The Victorian regulator (Energy Safe Victoria) has significant input to these committees as well as discretional power under Section 69 of the Act. The development of hydrogen gas for use in appliances would therefore be contingent on ESV and other regulators having a large degree of buy-in to the concept from the early stages.

3.1.6.6 Other Regulations: Major Hazard Facilities for hydrogen storage and production

The processing, handling and storage of any hazardous chemical or dangerous good must comply with hazardous chemicals regulation. Hydrogen is no different to natural gas and any hydrogen production or storage facility would be expected to become registered and licensed as a major hazard facility in the relevant state. The threshold quantity of hydrogen for this purpose in Victoria is 50 tonnes.

3.3 Biogas

Biogas is a renewable and carbon neutral form of gas produced from waste products and organic matter. Biogas production technologies are mature and well established, but there has been limited penetration in Australia to date for a range of reasons. There is considerable opportunity to produce biogas and inject it into the distribution network but the resource base needs to be better understood.

3.3.1 What is biogas?

Biogas can refer to a range of gases which are formed from organic materials, rather than sourced from underground natural gas deposits. Biogas producing technologies are part of a broader group of bioenergy technologies, which provide different means of converting biomass into energy. This includes direct combustion (such as burning wood for heat) and conversion to renewable forms of other fuels (such as biogas or biodiesel).

Unlike methane extracted from underground deposits, biogas is produced from organic matter that was recently grown. Under the Australian national greenhouse gas accounting framework, carbon dioxide that is emitted when biogas is burned is treated as part of the natural carbon cycle and not counted towards Australia’s emissions.[31] Any nitrous oxide emissions and other greenhouse gas emissions are counted, however these are small in relation to the carbon dioxide emissions from the combustion of natural gas.

This means that producing and using biogas can reduce emissions in two ways:

1. By capturing methane emissions from the natural breakdown of biomass that would otherwise be released into the atmosphere, for example by producing biogas out of waste material and diverting from landfill.
2. By substituting away from natural gas from underground deposits, therefore avoiding the emissions associated with burning natural gas.

Much like natural gas extracted from underground deposits, biogas is made up of a blend of different gases. The exact composition depends on a number of factors including the source material, size of the digester or landfill, time spent in the digester or landfill, and the temperature.

A typical composition of biogas (from anaerobic digestion) and natural gas is presented in the table below:

Table 3.1 Composition of biogas and natural gas

Component	Biogas (from anaerobic digestion)	Natural gas
Methane	50-85%	90%
Carbon dioxide	15-50%	2.7%
Nitrogen	0-1%	1%
Oxygen	0-1%	N/A
Ammonia	Up to 4,000 ppmv	N/A
Sulfides	Traces	N/A
Other hydrocarbons	N/A	6.3%

Source: (Lambert, 2017), (Australian Pipeline Industry Association, 2009)

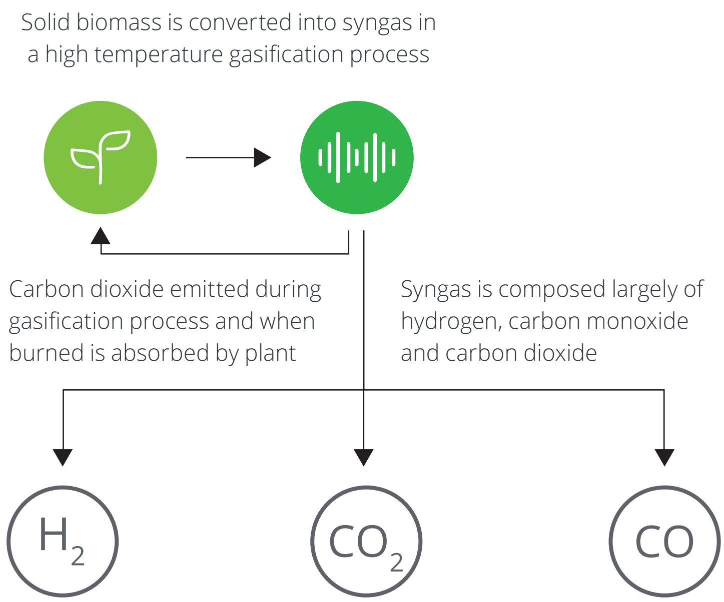
Biogas is primarily comprised of methane, with a significant amount of carbon dioxide and some other gases such as nitrogen. The proportion of methane and carbon dioxide in biogas can be highly variable. It may depend on a range of factors including the type of feedstock used, and the presence of oxygen during the digestion process (which generally results in a higher proportion of carbon dioxide).

The different types of biogas can broadly be broken down into two categories:

- Synthesis gas, also known as syngas, produced from the gasification of biomass
- Biomethane, which is methane produced from biomass or waste and is the focus of this section.

These production processes are outlined in page 39.

Figure 3.9 Gasification of biomass into syngas



Source: Deloitte Access Economics, 2017

3.3.1.1 Gasification of biomass into syngas

Gasification is a thermal process through which a solid fuel stock is converted into a combustible gas which can be used as an energy source. The output is a mixture of hydrogen, carbon monoxide, and carbon dioxide which is known as syngas. Gasification is a multi stage process which occurs at high temperatures. The same general process can be applied to a range of fuel stocks to produce syngas, including coal, and biomass sources such as wood and wood waste.

Syngas has quite different properties from the natural gas currently used in the distribution network, and is more similar to hydrogen gas.

The other type of biogas is the production of methane from biomass or waste sources. This is a closer substitute for the natural gas currently used in networks

3.3.1.2 Methane from biomass

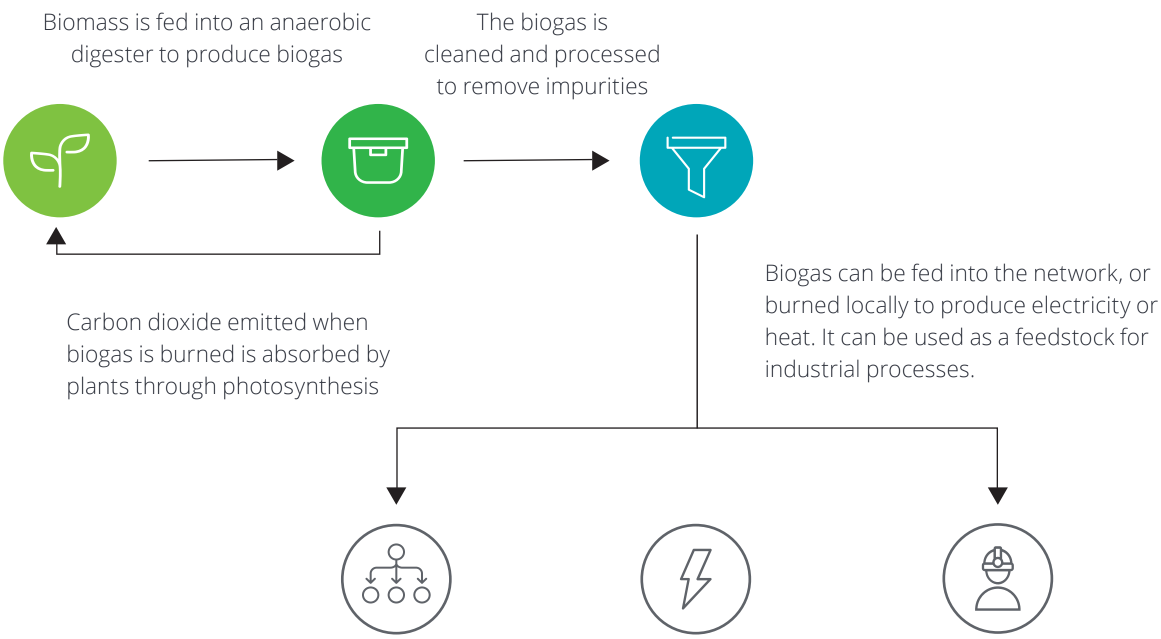
The most common type of biogas is methane produced from organic matter, also known as biomethane. For the remainder of this section 'biogas' will be used to mean biomethane. Once treated to remove carbon dioxide and other impurities, biogas has broadly the same chemical structure as natural gas. It can be used for the same purposes, such as household use, power generation, or as a chemical feedstock for industrial processes.

Producing methane from biomass is typically used as a way to extract energy from materials that would otherwise be a waste product. It involves the breakdown of organic materials in an environment without oxygen, known as anaerobic digestion.

Methane can be formed from a range of organic materials, including:

- Urban organic waste
- Wastewater and sewage
- Agricultural residues
- Livestock residues
- Food waste
- Bioenergy crops.

Figure 3.10 Biogas production process



Source: Deloitte Access Economics, 2017

The process for producing biogas is similar regardless of what is used as the base material. The organic material is formed into a slurry and fed into an airtight anaerobic digester. Bacteria in the digester breaks down the material and methane is formed as a by product of this reaction.

If organic waste is disposed of as landfill, it may experience similar conditions to those in an anaerobic digester. Waste can break down in a similar way to the controlled anaerobic digestion process and produce an output of gas composed of methane, carbon dioxide and other gases. This is known as landfill gas. Anaerobic digestion facilities capture the gases rather than letting them enter the atmosphere. They also tend to more efficiently transform biomass into methane rather than carbon dioxide or other gases in comparison to the uncontrolled decomposition in landfill.

In general, wet wastes and biomass are best suited to anaerobic digestion, as the moisture can facilitate the bacterial processes. Drier forms of biomass can be used for anaerobic digestion, however may be better suited as a feedstock for other types of bioenergy such as direct combustion for heat of electricity generation.

Anaerobic digestion and landfill gas production can provide a steady and reliable stream of biogas, conditional on the reliability of feedstock used for the process. Certain feedstocks, such as agricultural crop residues and livestock residues, may vary in availability through the year. Other feedstocks such as urban waste and food processing waste may be more consistent. If biogas is injected into the network, it may be consumed immediately or could be stored locally or in the distribution network. Where it is possible to store biomass, prior to digestion, such as relatively dry agricultural crop residues, this could provide a means of smoothing biogas production.

3.3.1.3 How much biogas do we generate in Australia?

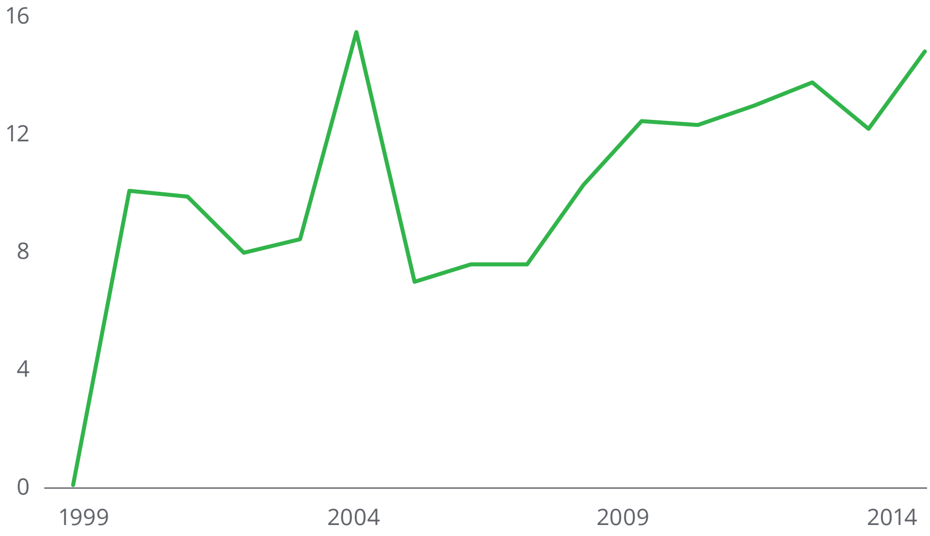
Producing biogas is well established in Australia as a cost effective, renewable, and low emissions source of energy.

But despite this, biogas is not widely deployed. Chart 3.1 shows the expansion in use of biogas for energy since 2000, but total supply remains a minor part of the energy system.

By 2014, biogas produced over 14 PJ of energy, all of which was used for the generation of electricity and heat.[32] There is a significant opportunity for the production and use of biogas to grow and diversity.

In 2016, approximately 8.6% of renewable electricity generation in Australia was from bioenergy sources (including biogas and other forms of energy from biomass), which corresponds to 1.5% of total electricity generation in Australia.[33] Biogas is currently a relatively small component of bioenergy, making up approximately 9% of energy consumption from bioenergy in 2014-15.[34]

Chart 3.1 Energy from biogas used for electricity and heat production, 2000 to 2014
(PJ)



Source: Australian Greenhouse Emissions Information System, Activity table: Stationary energy, 2016

The majority of bioenergy is from the direct combustion of biomass, typically wood and wood waste, and bagasse.[35] The consumption of biogas is growing strongly, increasing by 17% from 2013-14 to 2014-15, and averaging growth of 10% annually for the past ten years.

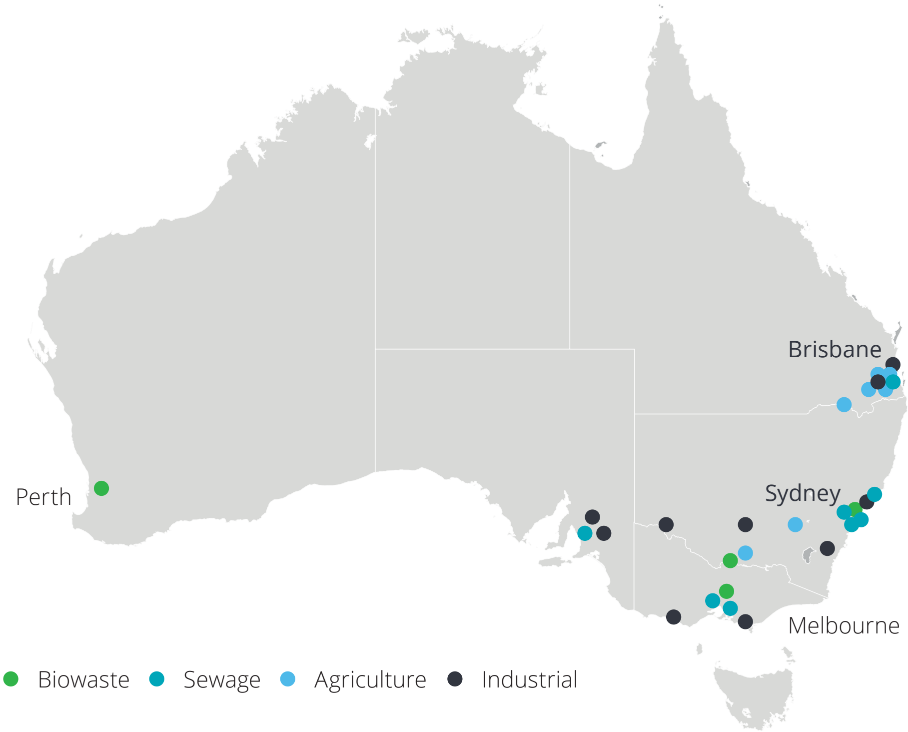
A range of different sources have provided estimates of the number of biogas installations in Australia. The University of Queensland estimates that there are almost 50 biogas facilities operating in Australia in 2017.[36] The Clean Energy Finance Corporation estimates there are over 100 bioenergy and waste energy plants in Australia, with over 800 MW of installed electricity generation capacity.[37] The majority of bioenergy generation capacity uses bagasse[38] or other agricultural waste as the biomass feedstock.

This includes four of the five largest bioenergy projects in the country.[39] A report for the Australian Renewable Energy Agency estimated that 46 wastewater plants used anaerobic digestion to produce biogas and bioenergy, and a further 14 piggeries produced biogas through either anaerobic digestion or covered lagoons.[40]

There are 47 power generators connected to the National Electricity Market that use biogas or energy from waste as the feedstock.[41] The vast majority of these use landfill gas. However these facilities are typically small, with only a small number greater than 10MW capacity. Some other biogas and landfill gas facilities may not be directly connected to the electricity network if they are used primarily for local usage.

The figure presents some of the large biogas production facilities in Australia:

Figure 3.11 Biogas production facilities in Australia



Source: AREMI, n.d.

These projects include a mix of anaerobic digestion, as well as covered anaerobic lagoons for animal manure, which act in a similar manner to anaerobic digesters. Landfill gas projects are not represented in this data. The full list of projects is provided in Appendix D.

Existing biogas facilities are most commonly clustered around large cities, particularly wastewater projects. There are some facilities in more regional areas which use industrial and agricultural waste. The majority of urban and industrial waste and sewage projects are small, and depend on local waste sources. Biogas from urban and industrial waste is concentrated around major population centres which generate the waste feedstock.

In this way, biogas from waste in metropolitan zones is well suited to supplying the distribution network and homes in the same area.Currently, much of the urban waste ends up in landfill, where it forms biogas over time. However, with better waste management processes, some of the waste most suited for biogas production could be captured and processed in anaerobic digestion facilities.

Waste from agricultural products, such as crop or livestock residue, is likely to come from regions that are rural or on the fringe of metropolitan areas. Making the most of agricultural waste to produce biogas will be largely dependent on the agricultural activities of a given region, and the capacity to aggregate appropriate waste close to the distribution network.

A breakdown of biogas and biomass projects by state is presented in Table 3.3. This includes the biogas projects presented in Figure 3.11, and the biomass projects registered with the Australian Government Rural Industries Research and Development Corporation (RIRDC). As noted above, this data does not include landfill gas facilities, or biomass projects which are not registered with RIRDC.

Table 3.3 Biogas and biomass projects and case studies

State	Biogas projects	Biomass projects and case studies
NSW	21	1
VIC	9	11
QLD	10	17
SA	6	0
TAS	0	1
WA	1	8

Source: (AREMI, n.d.)

There are a number of biomass projects and case studies in addition to the biogas facilities. These are largely in Queensland, Victoria and Western Australia. A number of biomass projects are in North Queensland and use bagasse to generate heat and power, making the most of sugar cane waste. Other facilities use animal waste, such as piggery waste and poultry litter, to produce heat and power, crops such as mustard and canola oil to produce biodiesel, or green waste to produce heat.

3.3.2 What is the potential for biogas in Australia?

There is a significant opportunity for biogas production in Australia to grow and diversify, along with bioenergy production more broadly.

A number of independent reports have estimated the potential size of biomass energy resources in Australia as approximately 1000PJ,[42] from a mix of feedstocks. These estimates reflect the overall biomass for bioenergy resource, rather than the biogas resource. Some biomass streams, particularly woody wastes, are generally better suited to other forms of bioenergy such as direct combustion for heat or electricity generation. There is significant uncertainty in the amount of biomass available from each feedstock, and reports often differ significantly in detail even if they find similar overall results. A number of reports estimating the biomass availability are outlined in the table below.

Table 3.4 Existing estimates of biomass availability

Author	Title	Year	Biomass projects and case studies
ClimateWorks	Pathways to Deep Decarbonisation in 2050: Technical Report	2014	ClimateWorks summarised a range of CSIRO modelling which showed over 700 PJ available from energy crops, only 100-200 PJ available from agricultural residues and forest residues, and a very small amount from waste. It estimated the overall biomass availability at 1,000 PJ.[43]
Jacobs	Modelling Bio sequestration to Reduce Greenhouse Gas Emissions	2014	Jacobs modelling estimated the biomass potential from a range of sources, including organic waste, industrial waste, forestry and agricultural residues, and energy crops. It estimated potential of approximately 900 PJ from agricultural residues, and less than 100PJ from energy crops and other sources combined such as other waste streams.[44]
Lang, Kopetz, Stranieri, and Parker	Australia's Under Utilised Bioenergy Resources	2014	Lang et al estimated that Australia produces 50-100 million tonnes of biomass and waste resources, in addition to 20 million m^3 of putrescible wastes (such as sewage, animal manures, food waste and moist green waste) which are particularly suited to biogas production.[45] The authors estimate that the biomass could provide approximately 20% of Australian total primary energy demand, and that the putrescible waste could provide over 19PJ of biogas. If other types of biomass, such as dry municipal solid waste or agricultural crop residues, were used to produce biogas, this value could be higher.
Clean Energy Council	Australian Bioenergy Roadmap	2008	The Australian Bioenergy Roadmap estimated the potential contribution of bioenergy to electricity generation to be approximately 73,000 GWh (263 PJ). This figure included 12.3 PJ from landfill gas, 3.3 from sewage, and 15.5 PJ from urban waste, which are all well suited for capturing and processing into biogas through anaerobic digestion. The majority (182 PJ) of the bioenergy potential was from agricultural waste (including crop and livestock residue), some of which would be well suited to anaerobic digestion.

As these reports demonstrate, there are considerable biomass resources in Australia which are currently underutilised in terms of energy production. There is a lot of uncertainty regarding both the size and composition up of the biomass resources around Australia. For biogas in particular, the opportunity depends not just on the availability of resources, but competition for those resources with other industries.

Wet waste streams, such as food waste, sewage, and livestock residue are particularly suited to anaerobic digestion to produce biogas. Drier biomass streams, such as agricultural crop residue, may be used for anaerobic digestion, but can also be used for direct combustion to produce heat and electricity. The potential for biogas will depend on technological development, but also policy and market development across the energy system.

The Australian Biomass for Bioenergy Assessment (ABBA) project is part way through the process of developing a national database on the type, volume and location of bioenergy feedstocks across Australia. The data is collated and presented through the Australian Renewable Energy Mapping Infrastructure (AREMI) platform. We have used the ABBA data to develop an estimate of the biogas potential in each state. Detailed data on biomass is available for Victoria, South Australia and Queensland. Where data was missing for particular biomass streams in any state, we estimated the availability by benchmarking relevant characteristics such as population, economic activity, and agricultural activity against the states where the data was available.

The results of our analysis are presented in Table 3.5.

Table 3.5 Estimated biogas potential by biomass stream (PJ), and potential biogas supply as a share of regional gas consumption from the distribution network (%)

State	Urban waste	Agricultural crop residue	Livestock residue	Food processing residue	Total biogas (PJ)	Biogas potential (excluding agricultural crop residues)	Total biogas potential
NSW	3.5	75	8.8	0.6	88	15%	103%
VIC	2.4	38	6.8	0.4	48	5%	27%
QLD	8.6	66	8.8	0.6	84	70%	327%
SA	3.3	40	1.9	0.2	46	17%	142%
WA	1.7	100	1.4	0.4	103	13%	384%
TAS	0.2	0.4	0.4	0.0	1	23%	36%
ACT	0.2	0.0	0.0	0.0	0.3	2%	3%
Total	**19.9**	**319.4**	**29.3**	**2.2**	**371**	**14%**	**102%**

Source: Deloitte analysis based on biomass and waste data from (AREMI, n.d.). Benchmark biogas yields from (Sustainable Energy Authority of Ireland)

Biomass and waste resources can be grouped into four broad categories:

1. Urban waste – including the organic component of metropolitan solid waste, commercial and industrial (C&I) waste, construction and demolition (C&D) waste, waste water, and food waste.
2. Agricultural crop residue – the straw and chaff left over from agricultural crop harvest. In Queensland this includes bagasse from sugarcane harvest.
3. Livestock residue – the manure and litter from livestock, such as cattle, sheep, poultry and pigs.
4. Food processing residue – the residue from the processing of foodstuffs including animal processing.

There is also potential to use wood waste from production forestry for bioenergy generation, although it has been noted by the Clean Energy Council that changes to the current legislative and regulatory regime for forestry may be required to encourage the sustainable use of wood waste for bioenergy.[46]

We estimate the total national biogas potential to be approximately 371 PJ. The vast majority is from agricultural crop residue (319 PJ), followed by livestock residue (29 PJ), urban waste (20 PJ) and food processing residue (2 PJ). However, there is considerable uncertainty around this estimate. Estimation of the biogas opportunity could be substantially improved with ongoing development of a consistent and comprehensive national database on biomass. This project remains a work in progress, the difficulty in accurately measuring biomass, and the inherent uncertainty in biogas yields from anaerobic digestion are all challenges to be overcome to better understand the biogas opportunity.

As outlined earlier, wet waste streams tend to be most suited to biogas production through anaerobic digestion. We consider that urban waste, livestock residue and food processing residue are likely to be very well suited to biogas production. Agricultural crop residues can be used for biogas production, but this would compete directly against use for other bioenergy production or other use by agricultural producers (such as using crop residue as soil improver).

Growing bioenergy crops is another opportunity to increase the production of biogas in Australia. A wide range of crops such as grasses, cereals, oilseeds and certain vegetables have been found to be feasible for biogas production through anaerobic digestion.[47] Australia has a large and diverse agricultural sector, and the potential to grow bioenergy crops in Australia is significant. The use of energy crops could potentially be used to supplement other biomass sources and ensure ongoing reliable supply of biomass. It could also help to address any seasonable gaps in availability, particularly for crops that can be stored for long periods of time. Given agriculture is a competitive market, the size of the market for biogas from bioenergy is likely to be determined by the relative price of food and biogas, rather than a technical limitation.

3.3.3 End use of biogas

Biogas is mostly made up of methane, and it can generally be used for the same purposes as natural gas. It can be burned to generate heat or electricity, or used as a chemical feedstock for industrial processes such as fertiliser and methanol production.

Biogas can either be consumed locally at the point of production, or it can be fed into the gas distribution network and blended with natural gas. Currently in Australia, biogas is used on site, either for heat or generation of electricity. This is due to a combination of factors, including the lack of policy support for biogas injection into the network, and the difficulty associated with aggregating feedstock at a large enough scale to make grid injection economically viable. These factors are discussed in further detail in Biogas section, page 37. There is an opportunity to decarbonise the gas network by feeding low emission biogas into the network in place of some, or all, of the natural gas currently being used. However, injecting biogas into the network would be a significant change in the way that biogas is used in Australia. There are a number of challenges associated with using biogas in the network, in terms of technical requirements and market conditions. Some of the technical challenges are explored and addressed below.

3.3.3.1 Biogas and the network

As outlined in page 35, there are regulations that specify the composition of gas fed into the distribution network. Raw biogas generally doesn't satisfy these requirements when it is produced, due to the high proportion of carbon dioxide and the excess amount of other compounds such as nitrogen and sulphides.

For biogas to be introduced into the distribution network, it needs to undergo a number of treatments to satisfy the requirements of network gas. It should be noted that natural gas from underground deposits needs to go through broadly similar treatments to meet regulations before injection into the network.

The composition of biogas varies significantly between production facilities, and the treatment required to inject into the distribution network will similarly vary. In general, the treatment may include:

- Removing excess carbon dioxide using some form of carbon dioxide scrubber
- Removing any water vapour by cooling the gas and causing the moisture to condense
- Removing any hydrogen sulphide if present, which depends largely on the feedstock used
- Adding odour to the gas for safety purposes
- Pressurising to the appropriate level at the network injection point.

In general, these are all conventional chemical processes that make use of well established technologies. There are no particularly unique challenges for integrating biogas into the network different to injecting natural gas. However, this would require an investment in infrastructure at biogas production and injection points, as some of these processes are not required if biogas is consumed locally.

For end users of gas, such as households and businesses, switching to biogas would not mean a significant change. The biogas would have been treated prior to injection to have the same properties as natural gas, so appliances would work in the same way.

3.3.4 Decarbonising the gas network with biogas

Producing biogas is a well established process in Australia, and it is recognised as a relatively low cost and efficient form of renewable energy. Biogas is a versatile product, and can be used in largely the same way as the natural gas currently used in the network. However, the uptake of biogas has been limited, and it is currently used locally for heat and electricity generation rather than fed into the gas distribution network.

Decarbonising the gas network by using biogas would require a significant increase in the production of biogas and a shift in how it is used. There are some technical challenges associated with treating the gas and feeding into the network, however these use relatively common chemical treatments, and would not require a fundamental change in underlying distribution infrastructure or end use appliances.

The real challenge is producing enough biogas, in the right locations. There are significant biomass resources available in each state, from a range of biomass and waste feedstocks. The ultimate amount of biomass that can be used for biogas is uncertain, depending on both the overall amount of biomass and competition from other types of bioenergy.

Supplying a significant proportion of gas demand through biogas is technically achievable. But this would require a significant shift in energy policy to provide long term price signals required to incentivise the production of bioenergy crops to produce sufficient volumes of biogas.

3.5 Carbon capture and storage

Carbon capture and storage prevents greenhouse gas emissions from power generation or industry reaching the atmosphere.

Around 20 projects around the world use this technology at commercial scale and additional take up will be needed to meet global emission reduction targets.

3.5.1 Description of available processes

Carbon capture and storage (CCS) is a three step process that can prevent a large amount of CO_2 from being released into the atmosphere. By lowering emissions released into the atmosphere, CCS can significantly lower emissions from the use of gas and mitigate the risk of climate change. CCS can be applied to industry and power generation and offers opportuntiteis for natural gas by avoiding emisisons from gas fired power generation, gas used in industry such as plactics and fertilisers and also gas used in steam methane reformers to produce hydrogen as described above.

The three steps are:

Separation

CO_2 is separated from other gases, usually produced from power generation or industrial processes. Rather than being released into the atmosphere, it is captured.

Transport

Once separated, the CO_2 is compressed into a liquid-like state and transported via pipelines, trucks or ships to a suitable site for long-term geological storage.

Storage

The CO_2 is injected into deep underground rock formations, often at depths of one kilometre or more, to be permanently stored.

3.5.1.1 Separation

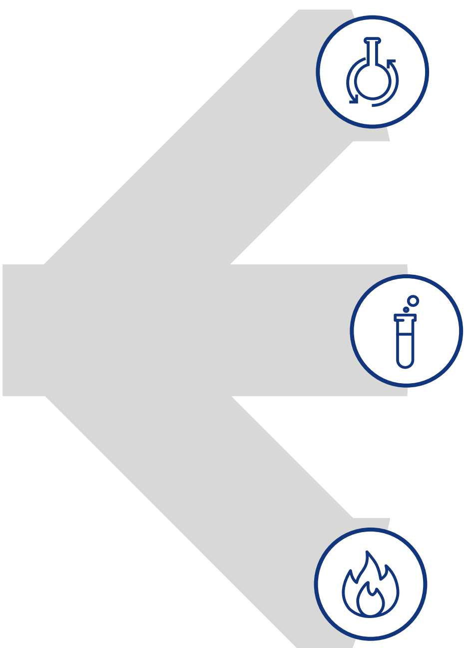
The technology used for separation of CO_2 varies in maturity, and the method used depends on the way that the CO_2 is produced. Approaches to the capture of CO_2 can be categorised according to whether and how the production process needs to be modified to enable CO_2 separation.

There are broadly three types of separation and capture processes:

- Post-process capture or post-combustion capture
- Syngas/hydrogen capture or pre-combustion capture
- Oxy-fuel combustion.

Currently, post-process capture technology is the most developed. However, there are a number of global projects that demonstrate the successful application of pre combustion capture, which separates gas into hydrogen and carbon dioxide, decarbonising it before it enters the gas distribution network. We have discussed some examples in Section 3.3.2.

Figure 3.12 Types of capture technology



Post-process capture
(Post-combustion capture)
CO_2 is separated from a mixture of gassess at the end of the profuction process.

Syngas/Hydrogen capture
(Post-combustion capture)
Syngas, a mixture of hydrogen, carbon monoxide and CO_2 can be generated from fossil fuels or biomass. The CO_2 can be removed, and the syngas can be transformed intro hydrogen if required.

Oxy-fuel combustion
Pure oxygen is used in place of air in the combustion process to yield a flue gas of high-concentration CO_2.

Source: Deloitte Access Economics analysis of GCCSI information and Carbon Storage Taskforce, 2017

3.5.1.2 Transport

Globally, transporting CO_2 is the most technically mature step in the CCS process, with more than 6,000 km of CO_2 pipes in operation across the United States.[48] Although the technical know-how can be transferred to Australia, as reported by the Global Carbon Capture and Storage Institute (GCCSI), currently Australia only has 50km of CO_2 pipelines (purpose and location is not specified).[49] It is estimated that 5,000 km of large-diameter CO_2 pipelines would need to be constructed to meet Australia's emissions reduction goals using CCS.[50] As with the natural gas transmission network, CO_2 gas pipelines are regulated under AS 2885 and are specifically engineered to carry their particular gas.

There is also limited experience with offshore pipelines in Norway from the Snøhvit CO_2 Storage Project. This project involves the capture of CO_2 from a LNG facility, which is transported via a 153 km pipeline to the Snøhvit gas project field development area in the Barents Sea (onshore to offshore). To date, more than 4 Mt CO_2 has been transported.[51] CO_2 can also be transported via trucks and ships, which is the preferred method under the Korea CCS1 project (in evaluation phase).

Although transporting CO_2 through pipelines is well understood technically, to minimise transport costs, projects where CO_2 separation and storage are close together are more efficient.

3.5.1.3 Storage

Geological storage of CO_2 involves the injection of CO_2 into underground rock formations, typically located between one and three kilometres underground (both onshore and offshore). Suitable geologic formations include saline aquifers, depleted oil and gas fields, oil fields with the potential for CO_2-flood enhanced oil recovery, and coal seams that cannot be mined with the potential for enhanced coal-bed methane recovery. Storage in other geological formations, such as basalt, is actively being investigated.[52]

The fundamental science behind storing CO_2 is well researched. However, experience in projects have shown the importance of site selection as all storage reservoirs are different and need extensive dedicated, local characterisation along with on-going monitoring in the initial decades of the project, adding to the costs of CCS.

3.5.2 International CCS application

GCCSI has identified 40 large-scale CCS projects around the world, either in operation, under construction or in development planning. It anticipates that more than 20 will be operational by the end of 2017.[53]

Figure 3.13 illustrates a range of CCS projects (all large scale, except for the Tomakomai project) around the world that involve pre-combustion capture (gasification or natural gas processing), hydrogen production or bioenergy with CCS (BECCS). These projects are either in operation or execution phase (i.e. expected to be in operation by the end of next year).

The concept of CCS was first trialed at an industrial scale by Norwegian oil and gas company Statoil more than 20 years ago, with the project still in operation today.

Case Study 3:
Statoil's Sleipner CCS Project, Norway

Statoil has operated a Carbon Capture and Storage facility in Sleipner, Norway since 1996. The storage facility was “the world’s first industrial scale CCS project for the purpose of carbon emission abatement”.

Carbon Dioxide from natural gas processing is injected into an underground storage facility in the North Sea. The project arose due to a commercial need to purify the natural gas from the field, which contained a much higher level of CO_2 than most of the natural gas used worldwide. As such, the carbon dioxide captured is classed as pre-combustion.

The policy environment in Norway, has supported the economics of this project. For example, a tax on CO_2 emissions made capture of the gases economically viable compared to release.

Sources: (Institution of Civil Engineers, February 2017) and (Global CCS Institute, n.d.)

More CCS project are coming online in the short-term, as a result of the global focus on limiting the global average temperature rise to below 2˚C. CCS plays an integral role in contemporary methods of addressing climate change, particularly in the power and industry sectors. To efficiently lower emissions across all sectors of the economy, CCS will be required to meet the scale of the challenge and mitigate the risk of climate change.

Under the International Energy Agency's (IEA) 2˚C Scenario, there is a quick uptake of CCS after 2025. In particular, the IEA notes that Bio-energy CCS is an opportunity to generate net-negative CO_2 emissions in the energy sector.[54] So for every tonne of carbon captured from the use of biogas, global emissions decrease.

There is currently one Bio-energy CCS project in Illinois (United States) which commenced operations in April 2017. This project involves the capture of CO_2 which is a by-product of the anaerobic fermentation process where corn is processed into fuel-grade ethanol. The findings of these technology applications will play an important role in understanding the applications where CCS provides an efficient means to reduce emissions.

The development of CCS options will likely depend upon the increased application of CCS to coal-fired power generation, as coal-fired generation creates significantly higher emissions than gas-fired generation and is relatively more affected by carbon reduction policy.

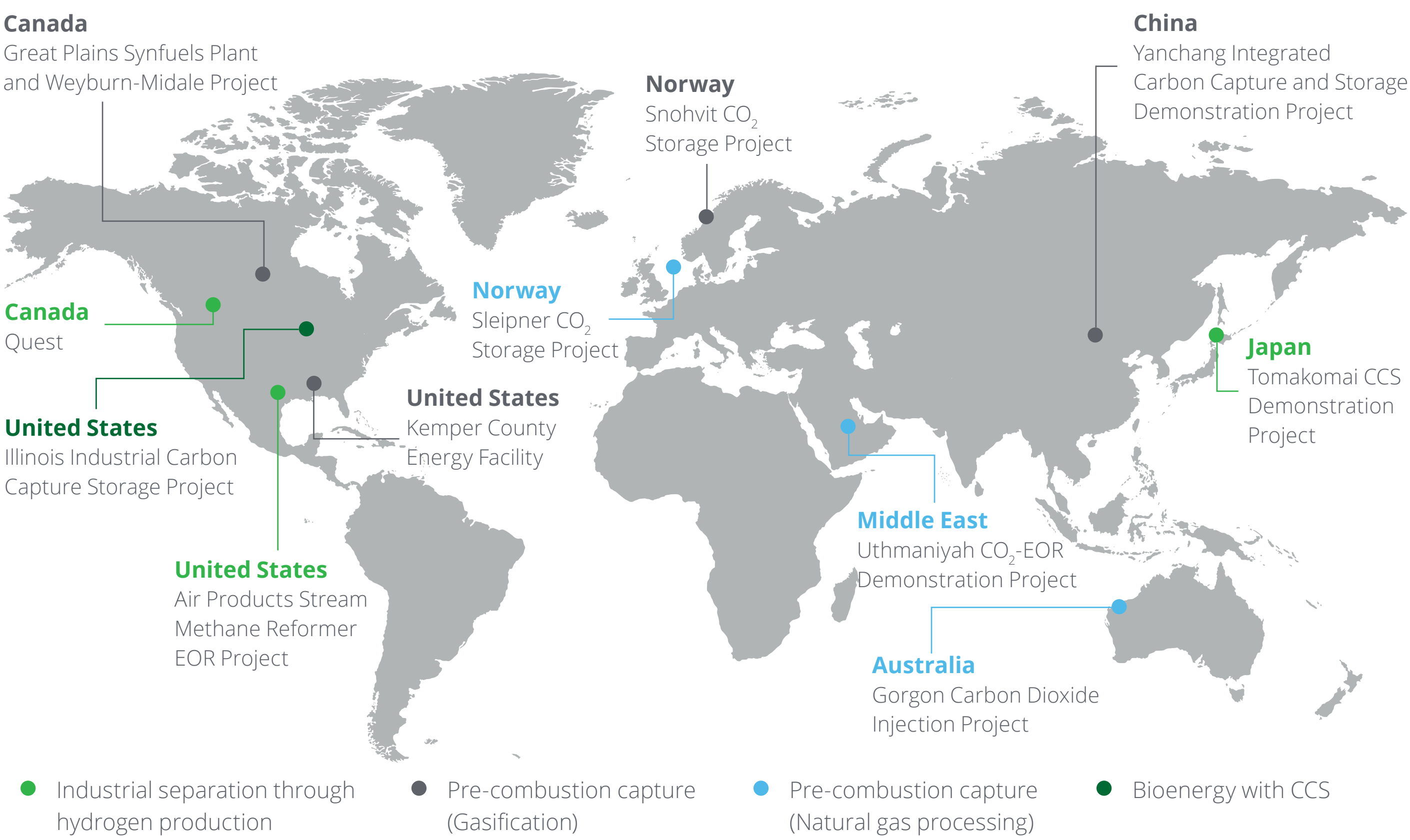
Developments in CCS will advance current technology associated with separating CO_2 from the source, and improve the data and feasibility of potential CO_2 storage sites.

3.5.3 CCS in Australia

There are multiple commercial-scale CCS projects under development in Australia, notably the Gorgon Carbon Dioxide Injection Project, South West Hub, CarbonNet and the Surat Basin Carbon Capture and Storage Project.

There is a significant opportunity for Australia to benefit from the application of CCS in the domestic gas market or international exports. We would expect to see increasing investment in CCS technology given recent changes in Government policy.[55]

Figure 3.13 Example CCS projects around the world



We have provided an illustrative view of a selection of global CCS projects, simply to demonstrate the diverse capability of CCS and its applications on different continents

Source: Deloitte Access Economics analysis of GCCSI, 2017

Existing research has shown that there are a number of highly suitable sedimentary basins in Australia for CO_2 storage. The sites are shown in Figure 3.14. In particular, the offshore Gippsland Basin (location of the CarbonNet project), is a very favourable site due to its geological suitability for deep storage of gas (technically feasible) and ideal location next to Latrobe Valley (commercially advantageous).

The CarbonNet Project is exploring the potential to capture and store up to 5 million tonnes of CO_2 per year (Mtpa).[56] This would represent around 6.3% of the stationary energy greenhouse gas emissions in Victoria.[57] CarbonNet is also using scalable infrastructure to develop a commercial scale CCS network that may be able to store up to 20 Mtpa after 25 years.[58] This expansion may be possible as production ceases on depleted oil and gas fields, which can be used as storage locations.

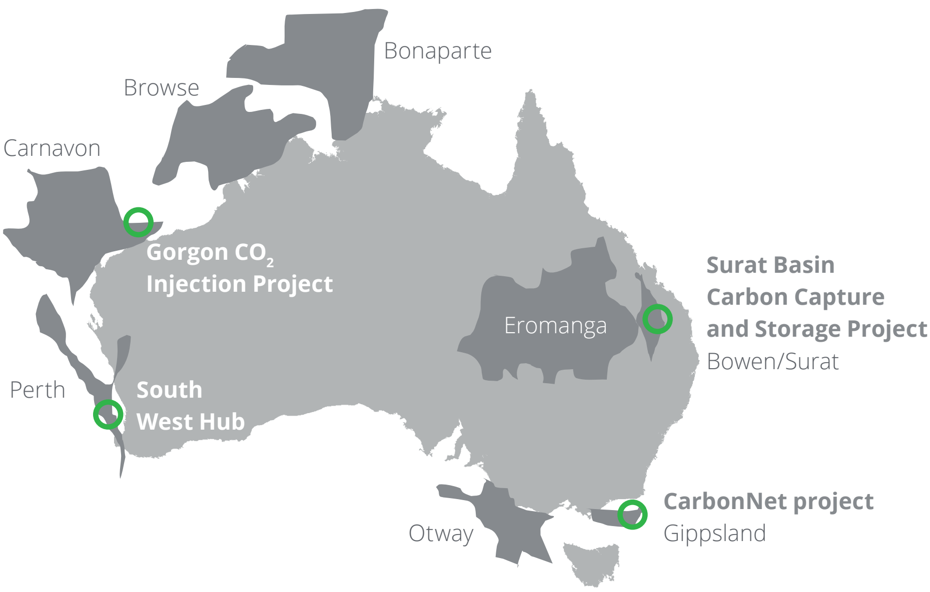
The volume of hydrogen required for Australia's gas distribution networks depends on the market demand for gas from the distribution network.

Similarly, the amount of reserves required for CCS also depends on this (among other factors, such as the fuel source for hydrogen production).

In Victoria, annual gas consumption is around 30 GJ per capita. This equates to approximately 187 PJ total annual gas consumption.[59] Should this consumption be supplied with hydrogen produced from steam methane reforming, around 17 Mt of carbon would need to be captured.[60] Although not likely in the short-term, this is possible in the longer-term for the CarbonNet project.

The future of CCS in Australia will heavily depend on government policy to lower emissions. The uncertainty around emissions policy in Australia, including the Renewable Energy Target and the possibility of a change in emissions policy, investors are unlikely to pursue CCS projects without a credible commitment from governments on emissions policy.[61] The investments required for energy assets and CCS assets involve significant investments over long time horizons of 20 years or more, and policy uncertainty makes accurately assessing the viability of these projects unfeasible.

Figure 3.14 Potential carbon storage locations in Australia



Source: Deloitte Access Economics analysis of GCCSI information and Carbon Storage Taskforce, 2009

3.5.3.1 Projects in Australia

There are a number of notable CCS projects in Australia: the Gorgon Carbon Dioxide Injection Project; South West Hub; CarbonNet; and the Surat Basin Carbon Capture and Storage Project. These are shown in Figure 3.14 along with a selection of potential storage locations around Australia. These locations have been ranked as highly suitable basins by the Carbon Storage Taskforce, and were also agreed by GCCSI in recent discussions.

Gorgon Carbon Dioxide Injection Project

This is part of the LNG Gorgon gas development project which is a joint venture between various major gas businesses for the development of the Gorgon and Jansz-Io gas fields in the Carnarvon Basin, Western Australia.[62]

Although the Gorgon Project began producing LNG in 2016, it has only drawn from the Jansz-Io gas field, which contains less than 1% reservoir CO_2.

Once gas from the Gorgon field (which contains on average 14% reservoir CO_2) is flowing to the Barrow Island gas processing plant in sufficient volumes, the operation of carbon dioxide compressors will commence. GCCSI anticipates that this will occur in 2017.

Figure 3.15 Gorgon CCS Project Overview

Separation

Gas is collected from Gorgon and Jansz-Io, and transported to Barrow Island for processing (including removal of carbon dioxide, dehydration, mercury removal etc) through pre-combustion capture.

Transport

7km pipeline from natural gas processing facilities to injection wells on Barrow island (onshore to onshore).

Storage

The CO_2 will be injected into the Dupuy formation (sandstone), approximately 2.3km below Barrow Island. It is expected that 3.4 – 4 Mtpa will be injected.

Source: (Global CCS Institute, n.d.)

Figure 3.15 CarbonNet CCS Project Overview

Separation
The sources of CO_2 captured will depend on industry sector partners, but will likely be from high emissions industries in the Latrobe Valley. The intension is for multiple sources of CO_2 will be transported and injected into the Gippsland Basin.

Transport
Pipeline expected to be approximately 130km (onshore to offshore).

Storage
Several sites in the Gippsland Basin have been shortlisted. CarbonNet expects that up to 5 Mtpa of CO_2 will be injected, with the possibility for increased capacity over time.

Source: (Global CCS Institute, n.d.)

CarbonNet Project

The CarbonNet Project involves investigating the potential for CCS in the Victorian Gippsland region. This region was considered to be highly suitable for CCS by the Carbon Storage Taskforce in 2009, and continues to be considered a world-class location.[63] The Taskforce ranked the Gippsland Basin as having the highest technical ranking of 25 major basins across Australia, taking into consideration factors such as size, depth, faulting intensity, reservoir, seel and data availability.[64]

Not only is the Gippsland Basin favourable as it has large empty (or depleting) oil fields that have the potential to hold significant volumes of CO_2, but also it is near a significant brown coal deposit and associated industries in Latrobe Valley, with significant existing gas distribution pipeline infrastructure.

To date, the project completed extensive feasibility studies and modelled potential CCS sites. CarbonNet has shortlisted three prospective storage sites and finalised a business case outlining the strategic direction of the project.

Over the period to 2020, as part of the Project Development Stage, the CarbonNet project intends to:

- Gain storage site appraisal (including a 3D marine seismic survey)
- Progress industry collaboration
- Transition CarbonNet to the private sector (around 2020).

CarbonNet is managed by the Victorian Government but is jointly funded by the both the Victorian and Commonwealth Government.

Figure 3.16 South West Hub CCS Project Overview

Separation

This project expects to capture CO_2 from fertiliser production and a sub-bituminous coal power station in the Collie and Kwinana regions.

Transport

Pipeline expected to be approximately 80km from Collie and approximately 110km from Kwinana (onshore to onshore).

Storage

The Harvey region of Western Australia is currently being modelled and analysed for CO_2 injection. The capacity is expected to be at least 2.5 Mtpa with the possibility to growth to 5 – 6 Mtpa.

Source: (Global CCS Institute, n.d.)

South West Hub

The South West Hub is a CCS initiative led by the Western Australian Government, which is currently undertaking data acquisition of possible storage sites. The geology has been previously examined through a 2D seismic survey, a 3D seismic survey and well drilling at four sites.

This project is currently in evaluation and feasibility stage, with core analysis and modelling being undertaken.[65]

There are currently plans to trial injection of CO_2 in 2018, which will provide the basis for the application of regulatory approvals and support advanced engineering studies on the transport and injection infrastructure.

Surat Basin Carbon Capture and Storage Project

Queensland's Surat Basin Carbon Capture and Storage Project, has been established by the Carbon Transport and Storage Company (CTSCo) a wholly owned, 'non-profit' subsidiary of Glencore, to demonstrate the technical viability, integration and safe operation of CCS in the Surat Basin. The project is currently at the Feasibility Study/Front End Engineering Design (FEED) Study Stage but limited work has been carried out and the project has not yet progressed to CO_2 injection testing.[66]

3.5.4 Next steps for CCS

Although there are a number of currently functioning CCS projects around the world, investment is well short of planned projects. In the longer term, it is likely that more stringent carbon policy (i.e. a high cost of carbon) will improve uptake and investment in CCS. However, current carbon policy settings, and lack of public support and poor understanding of CCS appear to be hindering uptake.[67]

For example, one of the main challenges is the public's concern around the long-term safety and potential leakage of storing large volumes of CO_2 deep underground, particularly where storages are located near urban areas.[68, 69] Over the past decade, experience in monitoring both naturally occurring deposits of CO_2 and CCS projects shows the risk of adverse and harmful outcomes from CCS is minimal.[70] One of the recommendations of the Energy Security and Prosperity in Australia: A Roadmap for CCS report prepared for the CO_2 CRC suggested that as part of the Stakeholder and Engagement and Communications Program, there should be a wide-ranging energy education campaign with a particular focus on secondary school students.[71]

The technical challenges for CCS are associated with locating and demonstrating the suitability of carbon stores, as the technologies associated with the capture (or separation) and transport of CO_2 is relatively mature.

Long development timeframes for storage site preparation and the large upfront capital cost of CCS plants are hindering investment, which is slowing the ability to progressively reduce costs through knowledge spill-over and long-term coordination benefits. For our analysis and commercial assessment we have assumed a cost of $30 per tonne for the CCS process. This cost is based on our expertise and understanding of the industry, and consistent with costs in an analysis of CCS for the Latrobe Valley.[72] These costs would include the cost of operations and management capital recovery of the retrofit, transportation and storage. We have not conducted a detailed analysis into cost curve reductions and possible efficiency improvements of the technologies associated with CCS. We have taken a conservative estimate where we maintain costs at their current level, given that the technologies involved are relatively mature.

4. Commercial assessment

Decarbonisation of the gas distribution network is an important part of reducing Australia's greenhouse gas emissions in line with its obligations under the Paris Agreement, while maintaining secure and affordable access to energy. This report has identified a set of transformational technologies that could contribute to decarbonising the gas network.
These include:

- Production of hydrogen from electrolysis using renewable electricity
- Production of hydrogen from steam methane reforming (SMR) of natural gas, or coal gasification combined with carbon capture and storage (CCS)
- Production of biogas from anaerobic digestion of waste or other biomass.

This section outlines our estimate of the cost of producing decarbonised gas using each of the processes above. It also describes some of the other costs associated with large scale decarbonisation, such as network augmentation and modification, and behind the meter costs such as appliance modifications.

4.1 Costs of decarbonising the gas network

Decarbonising the gas distribution network will require a significant investment across the supply chain, from production of decarbonised gas through to network modifications and final consumers of gas. Given the significant role that gas plays in the Australian energy system, a business as usual path is unlikely to deliver the scale of decarbonisation required to meet Australia's international obligations.

4.1.1 Overview of methodology

The potential pathway to decarbonisation uses technologies and processes which are generally well understood, or have been deployed internationally, but the technologies have not been deployed at scale in Australia. Currently, no hydrogen (from electrolysis, steam methane reforming, or coal gasification), or biogas is injected into the gas distribution network. There are no currently operating CCS plants in Australia, although Gorgon is expected to commence injection shortly.

We estimated the cost of production of each technology using assumptions and drawing on international benchmarks to estimate the cost of large scale decarbonisation. Our assessment builds on the analysis throughout Section 3, uses cost data published by internationally recognised organisations such as the International Energy Agency (IEA), U.S. Energy Information Administration (EIA), International Renewable Energy Agency (IRENA) and Australian organisations such as the Australian Energy Market Operator (AEMO), and draws on advice obtained through consultation with industry experts.

We have estimated the cost of producing decarbonised gas, or alternatively decarbonised electricity, by calculating a levelised cost of energy (LCOE, \$/MWh or \$/GJ) for each of the technologies. The LCOE spreads the total cost of producing energy over the energy output, presented in net present value terms.

As outlined above, large-scale decarbonisation of the gas network involves costs in addition to the production of decarbonised gas, such as network modifications or upgrades and appliance modifications. These costs are an inevitable consequence of decarbonisation, regardless of which technology or process is used to generate the gas. However, the nature and degree of costs may vary significantly depending on whether decarbonisation is achieved through hydrogen, biogas, electrification or a mixture of these. These costs are discussed following the production cost of decarbonised gas.

4.1.1.1 LCWOE of producing decarbonised gas

For each method of producing decarbonised gas for the network, the LCOE (\$/GJ) is the cost of production spread over the total energy output of the assets. Broadly, it includes the capital cost of building the necessary assets to produce decarbonised gas, fuel costs (where relevant), operating and maintenance (O&M) costs and financing costs. It reflects efficiency and usage rate assumptions for each production process. For each technology, our estimates assume that the production assets built are sufficient to supply the winter peak of gas demand, maintaining the reliability expected of gas supply. A detailed discussion of the LCOE of hydrogen and biogas is presented in page 60 of the Commercial Assessment section.

4.1.1.2 Cost of decarbonised electricity

As an alternative to decarbonising the gas distribution network, some (but not all) energy currently consumed in the gas network could be shifted to the electricity network, to meet this demand with renewable electricity generation. We estimate the LCOE of renewable electricity based on a study of renewable electricity in Australia by Blakers et al.[73] The Blakers study estimated the cost of producing electricity using entirely renewable sources, with approximately 90% of generation from wind and solar, and the remainder from bioenergy and pumped hydro. The study found the LCOE of electricity to be approximately $93/MWh, composed of $65/MWh to generate electricity, and $28/MWh to balance supply and demand (with no network costs included). Using a simple energy conversion, this corresponds to an LCOE of approximately $26/GJ.

The network costs to accommodate the energy currently served by gas to electricity would be substantial. If all gas demand was transferred to the electricity network, this would significantly increase the demand placed on the network, primarily at peak times, requiring significant augmentation.

In each state, we have estimated the new peak demand based on AEMO forecasts of daily peak gas demand and peak summer and winter electricity demand from the AEMO National Gas Forecasting Report and National Electricity Forecasting Report.

We estimate that, cumulatively across the NEM, peak demand would be approximately 21,000 MW higher in 2050 if all of gas demand was shifted to the electricity network. Based on a benchmark electricity network augmentation cost of $1.5m/MW, this could require investment of greater than $30 billion.

Although most gas customers also have an electricity connection, a comprehensive transition away from the gas network would require disconnecting gas appliances and installing electric appliances. A transition to electric appliances would require some appliances to be replaced before the end of their useful life and therefore impose costs on customers. Furthermore, such a transition will need to ensure secure and cost effective supply of gas as the electricity network is strengthened to cope with the additional demands. Industrial users in particular may not have a suitable electric fired alternative to the gas fired equipment currently used. Finding a decarbonised solution for both gas and electricity will maintain the choice available to current customers.

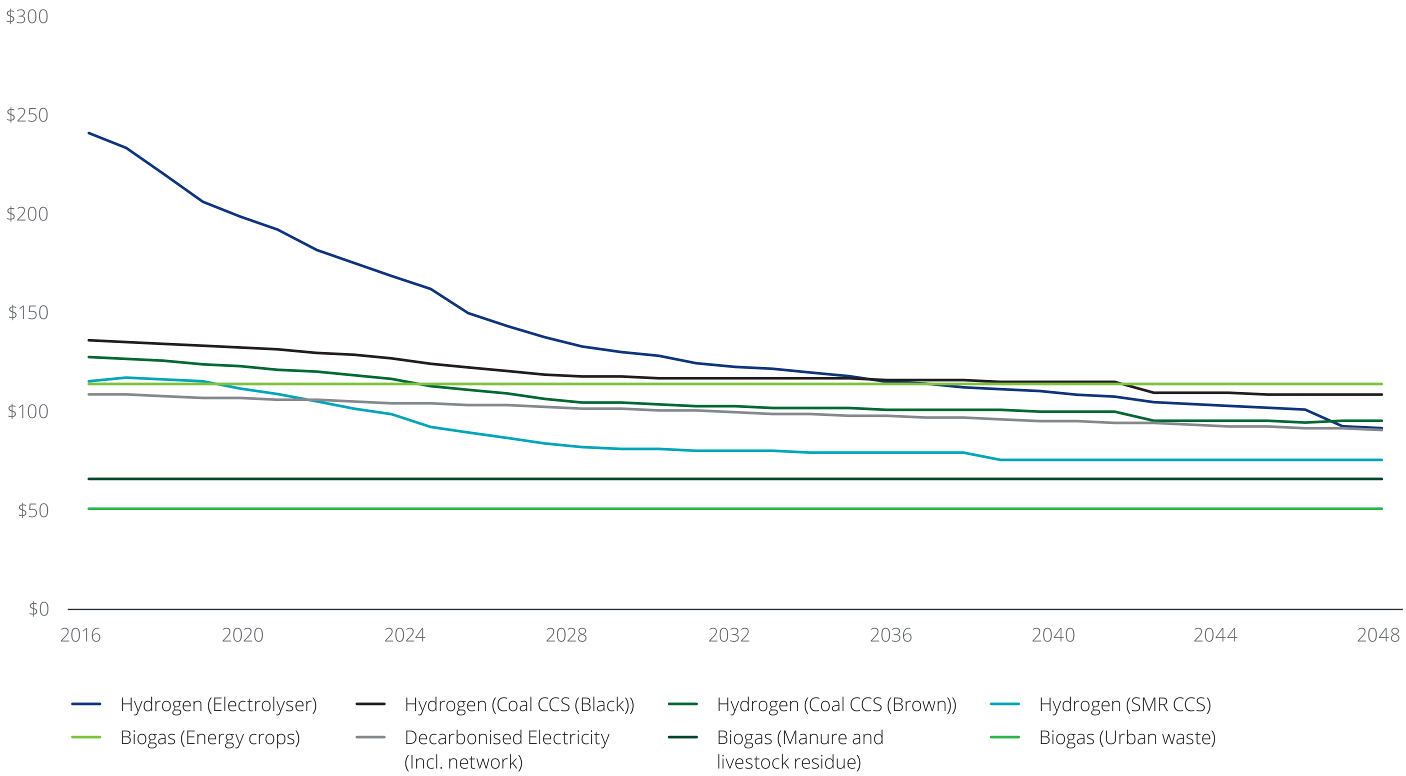
Due to the wide availability of electric appliances, and potential for a longer transition away from gas appliances, it is reasonable to assume that the cost of switching to electric appliances would be somewhat lower than switching to hydrogen or town gas appliances. Switching electricity appliances does impose a cost on consumers, and is not a costless alternative to decarbonising gas.

4.1.2 Production cost of decarbonised gas

Based on the methodology described above we estimate the LCOE of producing decarbonised gas through a number of processes. These include the three hydrogen technologies (coal gasification with CCS, SMR with CCS and electrolysis using renewable electricity), biogas from anaerobic digestion of different feedstocks, and the alternative of renewable electricity.

The results of the analysis over the period to 2050 are presented in the figure below.

Figure 4.1 LCOE of decarbonisation approaches to 2050
LOCE ($/MWh)



Source: Deloitte Access Economics analysis

We estimate that the LCOE of producing hydrogen using electrolysis is currently above $60/GJ (see table 4-1). However, this is forecast to decrease significantly over time. Over the period to 2050, we expect the capital cost of electrolyser units to decrease as penetration and scale increase and economies of scale are achieved. We also expect the cost of renewable electricity used to power the units to decrease. By 2050, we expect the combined cost reductions to result in a cost decrease to below $30/GJ.

A large proportion of the cost for steam methane reforming is the input fuel, natural gas so we conducted sensitivity analysis to test the results for changes to the gas price. With a 20% increase in the price of natural gas the cost of producing hydrogen from SMR rises only 6.8%. This means if natural gas prices were to rise by $1.60/GJ in 2017, the price of hydrogen production would increase from $32.76/GJ to $34.99/GJ in 2017. This does not change our assessment of the relative competitiveness of each technology over the long term.

Producing hydrogen from black and brown coal gasification, combined with CCS, currently has an LCOE above $35/GJ. We estimate that gasification using brown coal has a lower cost than gasification using black coal, due largely to lower fuel costs. This is forecast to decrease steadily to approximately $30/GJ by 2050 as learning and economies of scale reduce costs. We estimate that SMR combined with CCS is currently the lowest cost method for producing hydrogen. The cost is currently approximately $30/GJ, however this is forecast to decrease to approximately $20/GJ.

Table 4.1 LCOE by technology, 2016 and 2050

LCOE ($/GJ)	Hydrogen (Electrolyser)	Hydrogen (SMR CCS)	Hydrogen (Black coal CCS)	Hydrogen (Brown coal CCS)
2016	$67.04	$32.19	$37.91	$35.60
2050	$25.43	$20.94	$30.13	$26.32
% Change	-62%	-35%	-21%	-26%

Source: Deloitte Access Economics, 2017

We estimate that biogas produced from urban waste streams (such as household, industrial, and food processing waste) using an anaerobic digester provides the lowest cost decarbonised gas, at approximately $14/GJ. The LCOE for biogas includes the cost of producing raw biogas (including the cost of building and operating the digester, as well as feedstock costs), treating and upgrading the biogas, and injection into the distribution network. This estimate relies on aggregating appropriate waste feedstocks at scale at low or negative costs, as there are considerable economies of scale associated with producing biogas for the network. Biogas from manure and livestock residue tends to cost more than biogas from urban waste streams, with $18/GJ a reasonable benchmark. This is typically due to the higher cost to collect and transport the feedstock to an appropriate location. For biogas produced by energy crops or agricultural crop residue, the cost is significantly higher, approximately $30/GJ.

As outlined in Section 3.2, there is potential to produce biogas from low cost sources such as urban waste and livestock residue but decarbonisation of the entire network with biogas would likely require agricultural residues or energy crops. We consider that biogas from those sources may find it difficult to compete economically with alternative uses for crops such as food consumption, export, and other bioenergy. However, biogas can play a significant role in decarbonisation alongside the hydrogen production technologies.

The cost of producing hydrogen and biogas are discussed in detail in the following sections.

4.1.3 Network costs to decarbonise the gas network

The gas distribution network in Australia is a large piece of infrastructure, with a long expected useful life. It reflects over $8 billion of regulated asset value.[74] As gas production decarbonises, the gas network infrastructure will need to undergo a transition to ensure it can continue to safely transport decarbonised gas from producers to consumers. The transition to decarbonisation is not costless but, the alternative to switch energy consumed through the gas network to renewable electricity would require significant augmentation of the electricity transmission and distribution networks. The actual costs incurred may vary substantially depending on the exact configuration of the network.

4.2 Hydrogen

The use of hydrogen in the gas distribution network is an opportunity to decarbonise gas networks but may require upgrades of networks and appliances.

4.2.1 Overview of cost estimates by production technology

The final production cost estimate of hydrogen varies for each production technology. The following table provides our price estimates benchmarked against estimates from other sources. Although other estimates exist, comparison with these is cautioned as the assumptions and cost components included in each estimate vary widely and depend on assumptions that may not reflect realities in Australia.

Table 4.2 Cost estimates of the production technologies of hydrogen

Production Technology	Cost Estimate (~2030[a])		Source
	$/kg H_2	$/GJ H_2[b]	
SMR (with CCS)	$2.72	$22.63	DAE
	$2.70-$3.30	$22.50-$27.50	CSIRO
	$2.95	$24.58	Northern Gas Networks
Coal Gasification (with CCS)	$3.45-$3.91	$28.77-$32.63	DAE
	$2.40-$2.90	$20.00-$24.17	CSIRO
	$2.70[c]	$22.50	NREL
Electrolysis	$4.34	$36.19	DAE
	$4.30-$5.20	$35.83-$43.33	CSIRO

Source: Deloitte Access Economics analysis of (CSIRO, 2017); (National Renewable Energy Laboratory, 2013); (Northern Gas Networks, July 2016, p. 261)

Notes: [a] *All DAE estimates present the cost of hydrogen in 2050 except for this table which presents the costs in 2030 to allow for comparison with other sources.*

[b] *Conversion factor GJ H_2: kg H_2= 0.122*

[c] *In $AUD 2005*

To decarbonise the gas network with hydrogen gas, it is necessary to build sufficient capacity to meet peak daily demand as well as total annual demand. As such, some of the hydrogen production infrastructure would not be fully utilised throughout the year. We have estimated the cost of production by including the full capital cost of these underutilised assets in the estimation. In practice, these assets may be used to produce hydrogen for other purposes, such as to produce hydrogen fuel cells for vehicles or to export in the form of ammonia.

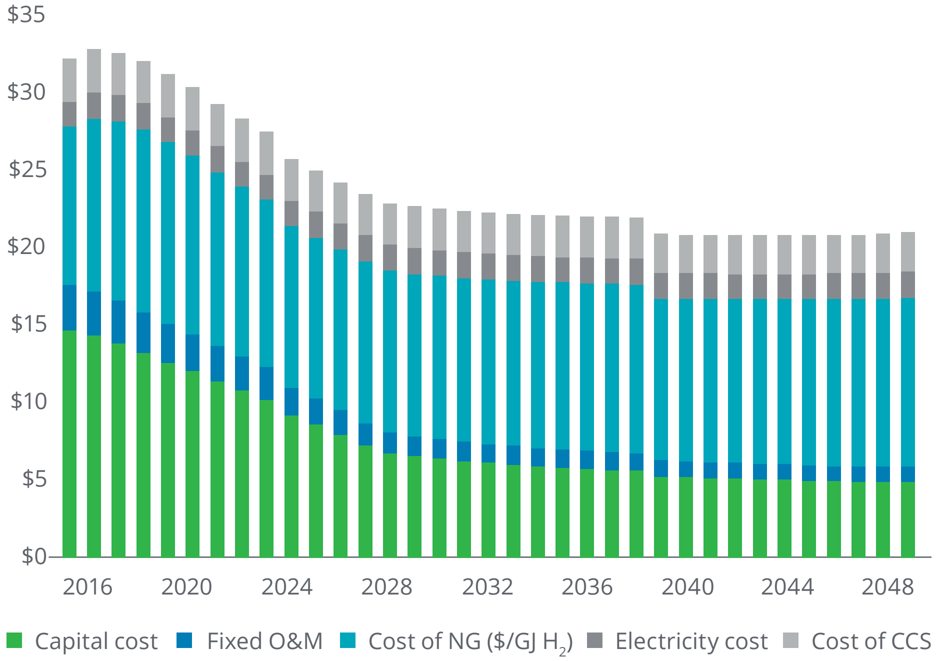
Alternatively, there may also be storage options that can be utilised to reduce the production capacity required. This could reduce the LCOE of hydrogen production for the network.

4.2.2 Cost profile over time

The production cost of hydrogen is influenced by the production technology, the input fuel, the need to capture emissions (CCS) and the projected reduction in each cost component over time. The cost profile of the three technologies considered is presented in the following figures, and we have provided additional modelling for the LCOE of coal gasification from black coal versus brown coal.

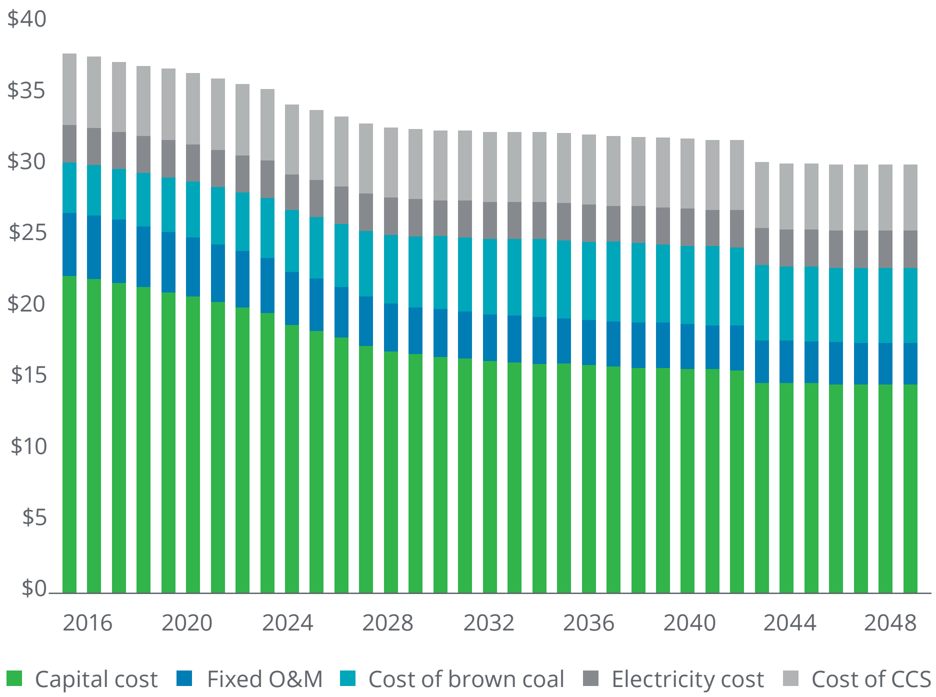
The levelised cost captures the average cost of production ($/GJ) including capital costs, fuel costs, fixed and variable operating and maintenance (O&M) costs and financing costs. The fixed O&M costs are incurred on an annual basis and are assumed to be proportional to the capital costs for each technology. Each LCOE captures the cost of producing hydrogen efficiently under each technology. An LCOE is representative way of expressing a cost across different technologies. It does not capture the full cost to supply the gas network.

Figure 4.2 LCOE for a GJ of hydrogen produced from steam methane reforming (with CCS)
LCOE $/GJ



Source: Deloitte Access Economics analysis

Figure 4.3 LCOE for a GJ of hydrogen produced from black coal gasification (with CCS)
LCOE $/GJ



Source: Deloitte Access Economics analysis

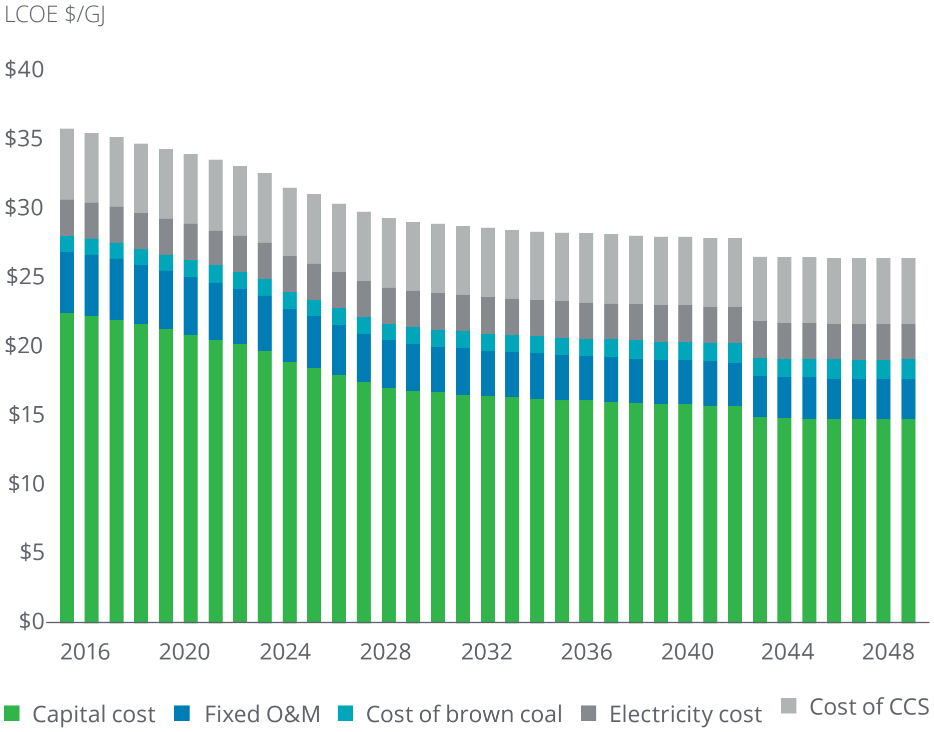
The LCOE of producing hydrogen from SMR is estimated at around $20/GJ in 2050, with a large proportion of costs associated with the input fuel (natural gas). Capital costs (and in turn fixed O&M) are expected to decrease over time as it is anticipated reformer technology will follow a learning curve, derived from Schoots et al.[75] Electricity costs are assumed to remain constant over the outlook due to substantial uncertainty around the cost of grid electricity over the long term. However, we note that new investments in generation in each jurisdiction or the retirement of large generation capacity could substantially alter the future cost of electricity. Similarly, the introduction of state or national carbon policies would have material impacts on the cost of electricity. We assumed a neutral price of electricity to 2050, in line with modest demand growth expectations.

The LCOE of producing hydrogen from coal gasification of black coal is estimated at around $30/GJ in 2050, with a large proportion of costs associated with the construction of gasification plants. Learning efficiencies over the next decade similar to those expected for SMR could see the cost of producing hydrogen from gasification of both brown and black coal decline further.

The LCOE of producing hydrogen from coal gasification of brown coal is estimated at around $26/GJ in 2050, lower than black coal gasification. The difference between the two LCOEs is primarily associated with the cost of the input: brown coal is cheaper than black coal.

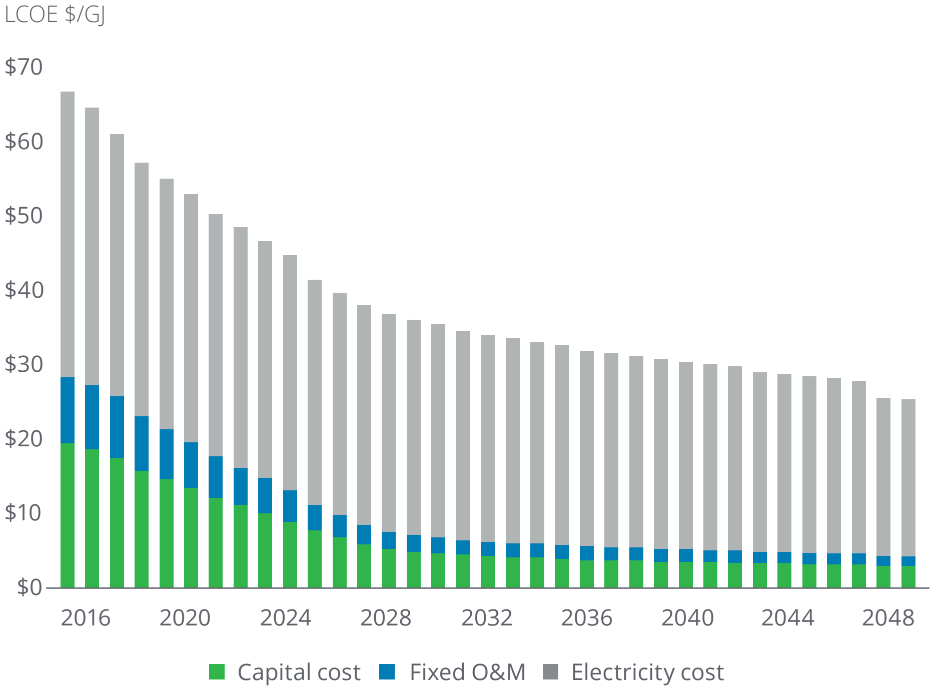
In 2050, the LCOE of producing hydrogen from electrolysis is estimated at around $25/GJ. In 2017 the LCOE is estimated at nearly $67/GJ. Significant cost efficiencies are expected to be realised through learning rates of large scale electrolysers and construction of renewable energy capacity over the outlook.

Figure 4.4 LCOE for a GJ of hydrogen produced from brown coal gasification (with CCS)



Source: Deloitte Access Economics analysis

Figure 4.5 LCOE for a GJ of hydrogen produced from electrolysis



Source: Deloitte Access Economics analysis

The network upgrade and appliance costs will add further expense to the final customer bill (for both Australian households and businesses). Detail on each of these cost components is provided in the sub-sections below.

4.2.2.1 Processing costs

Each of the three production technologies we considered has its own capital investment and operating costs. The plant investment makes up a substantial portion of the price when amortised over a 40 year asset life[76] for reformers and gasifiers. The cost breakdown is similar for electrolysers, however the plant life is assumed to be a shorter 25 years based on supplier specifications. The ongoing operating costs include the energy required to power the process and in turn the price of electricity, along with any other inputs required.

Within each technology type – coal gasifiers, steam reformers and electrolysers – there is a variety of different plant specifications that will further vary costs. However, for the purposes of simplifying our analysis and focussing on the development of a possible pathway towards decarbonisation, we have based our estimates on the lowest cost plant specification and thus broadly reflect the processing cost.

Currently, coal gasification and steam methane reforming are more competitive processes than electrolysis as they are more mature technologies and also have a longer plant life over which to amortise capital costs. Reformers are relatively low cost to operate due to their scale of operation in modern chemical production and a simpler technical process that makes them more efficient than gasifiers. However, as electrolysers are deployed to levels of decarbonising gas networks through to 2050 the capital cost of electrolysers is anticipated to follow a learning curve and decrease substantially, based on analysis by the IEA,[77] bringing the total cost within a competitive band of the other technologies. It is possible that the cost of electrolysers may reduce further and faster, similar to solar PV panels, with the correct policy settings to drive take up of electrolysers.

4.2.2.2 Input fuel

Each of the production technologies require different inputs. Greater detail on these can be found in the technical report. The input costs for each technology are provided in the following table, alongside the input price assumption and its contribution to the final cost:

Table 4.3 Cost contribution of input fuel to the price of hydrogen, 2050

Production Technology	Input Fuel	Price assumption	Cost contribution	
			($/kg H_2)	($/GJ H_2)
SMR	Natural gas	$8.37/GJ	$1.30	$10.87
Coal gasification	Black Coal	$0.09/kg	$0.63	$5.26
	Brown Coal	$0.01/kg	$0.17	$1.40
Electrolysis	Renewable electricity	$0.07/kwh	$2.54	$21.14

Source: *Price Assumptions* Natural Gas (Climate Change Authority Modelling: Jacobs, 2017; CIE, 2017); Black Coal (ACIL Allen, 2014); Brown Coal (ACIL Allen, 2014); Renewable Electricity (Finkel et al., June 2017);

Cost Contribution Deloitte Access Economics analysis of above sources

4.2.2.3 Cost of carbon neutral hydrogen

The attraction of injecting hydrogen into the gas network instead of natural gas is the ability to deliver a decarbonised solution, while using existing infrastructure which reduces the total cost of the decarbonisation task. Electrolysis produces carbon-free hydrogen when powered by renewables, whilst SMR and coal gasification can be combined with CCS to significantly reduce the carbon emissions produced.

Manufacturing pure hydrogen from natural gas and coal requires other gases, including carbon dioxide (CO_2), to be separated out during the production process. As such, there is very little additional cost associated with extracting the carbon from the production process. Rather, much of the cost of CCS is in the transportation, injection and sequestration of the CO_2 into storage. The cost associated with the transportation of carbon dioxide varies greatly depending on the method (through pipelines, trucks or ships) and distance between the 'production' of CO_2 and the injection point. There is also a significant variability in costs between different geological storage sites (offshore storage is typically more expensive). We estimate that the cost associated with injecting and storing carbon is \$0.30/kg H_2 (\$2.51/GJ H_2) of the total cost for SMR, \$0.56/kg H_2 (\$4.70/GJ H_2) for brown coal gasification and \$0.55/kg H_2 (\$4.65/GJ H_2) for black coal gasification in 2050.

As outlined in Chapter 3, specific geological requirements must be met to establish a carbon store (to ensure that the carbon can be contained safely over the long-term), thereby limiting the potential storage locations. We would expect investors to construct gasifiers and steam reformers close to carbon storage locations to minimise CO_2 transportation costs. However, hydrogen production points also need to be located close to load centres to minimise investment in the hydrogen gas transmission network.

4.2.3 Injecting hydrogen into the network

The injection of decarbonised gas into the distribution network is not expected to add substantially to existing costs. The additional costs may arise with the requirement to pressurise hydrogen in order to inject it into the existing distribution network and subsequently depressurise the gas before injecting into low pressure pipes to users (households and businesses). A more complex pressure system may incur higher maintenance costs than the existing system.

The main network costs associated with decarbonised gas relate to the transition and may include:

- Management costs incurred in managing the transition from a natural gas network to a decarbonised alternative, including:
  - Identifying the types of appliances that currently exist in the network and whether these will require upgrade or replacement
  - The nature of industrial gas connections and whether users use natural gas as a feedstock or energy source.
- Operational costs associated with running a dual gas network during the transition. By 2035, the majority of the distribution network is expected to consist largely of polyethylene (PE) pipes that will be capable of carrying hydrogen. As such, the distribution costs are likely to largely resemble current costs for distributing natural gas, assumed to be \$0.02/kwh or (\$5.55/GJ).[78]

Outside of the pipeline renewal cost, the transition process to a hydrogen network would be staged over a significant period of time, adding to the cost of managing the transition. The H21 Leeds City Gate report outlined a potential process, for a staged transition. It involves sequentially isolating small zones of the network (approximately 2500 homes), and converting to hydrogen during low demand periods. Any house would be disconnected from the network for 1-5 days, and the overall process would take a few years. The planning, communication and labour force costs for such a transition could be significant, although it is difficult to quantify without detailed considerations of the structure of each network.

Hydrogen produced through SMR or coal gasification combined with CCS would likely involve some additional transmission costs. Gas demand centres are typically positioned away from CCS locations, and it will be necessary to transport hydrogen from production to demand, and/or carbon dioxide from production to the CCS reserve. For example, if hydrogen was produced at Longford in Victoria using SMR, the hydrogen would need to be transmitted to Melbourne, and the carbon dioxide to the Gippsland Basin for sequestration. The long distance transmission of hydrogen could not occur efficiently in the existing natural gas transmission network. New pipelines that meet the technical specifications required for hydrogen gas would need to be constructed.

Establishing additional injection sites and controlling pressure, flow and gas composition would require additional metering and testing facilities. The requirement for investment in these facilities would depend on the number of injection sites (with more disaggregated supply sources requiring more sites) and the gas mix (as set out in section 3, a least cost decarbonisation pathway is likely to involve a blend of hydrogen and biogas). The costs of such facilities have been estimated at \$200,000 per TJ/day.

4.2.4 End-user costs for hydrogen

Most household appliances can safely process hydrogen blends of anywhere between 10-30%, however the exact proportion varies internationally.[79] A significant contribution towards the decarbonisation of the gas network could therefore be achieved through a hydrogen blend without requiring appliance upgrades. However, larger scale decarbonisation using a higher proportion of hydrogen gas would require appliance modifications or upgrades.

Based on estimates by Northern Gas Networks for the H21 Leeds City Gate project, the cost to upgrade heaters and stovetops could be approximately $700 per household, including meter upgrades. Replacing appliances is likely to be more expensive than upgrading, and could cost approximately $1,250 per customer. Gas water heating units are estimated to cost approximately $1,000 per household.[80] To the extent that these upgrades occur in line with planned appliance upgrades and replacements, the additional costs would be minimised. Replacing newer appliances would impose greater costs by cutting short the benefits from appliance investments.

Safely and comprehensively upgrading appliances alongside the transition to a hydrogen network would likely require external coordination. We estimate the cost to manage this process could be approximately 20% on top of the appliance costs as per the estimates from the H21 Leeds Project.[81]

The piping used to deliver gas from the distribution network to the home can be steel, PE, aluminium, cast iron, a composite material or copper. The delivery pressure of the hydrogen gas in pipes of these materials is such that the technical issues are not significant to the safe delivery of hydrogen gas.[82] Any required piping upgrades will likely occur during the installation of new hydrogen appliances. The H21 Leeds Project estimates these costs in the UK to be approximately AU$80, however the cost in the Australian context will require further research.[83]

The colder, southern states of Australia tend to rely more on gas appliances because of the cold winters and abundance of cost effective natural gas. A recent report by the Grattan Institute notes that more than 90% of Melbourne households have multiple gas appliances, whilst in Brisbane 60% of households have just one gas appliance, typically a stovetop or hot water unit.[84] State-wide, approximately 82% of Victorian households, 75% of households in the ACT, 70% of West Australian households and 60% of South Australian households are connected to the gas network, compared to 39% in NSW and 11% in Queensland.[85] Given this, we would expect the state-wide cost of upgrading the southern states to be higher than the cost incurred by their northern neighbours or in Western Australia. This is due both to higher per household costs and a greater number of gas users state-wide.

4.2.5 Policy settings and hydrogen

Global action to tackle climate change is driving a need to look at alternate fuel sources. Commercial interest in hydrogen worldwide will aid the rollout of a hydrogen gas network in Australia as economies of scale develop and bring the costs of production down. This pattern of global investment leading to local cost reductions is observed in the supply of solar PV units. The current policy setting in Europe is supportive of innovative decarbonised fuel and energy sources. This is aiding projects such as the H21 Leeds Pilot, which will see the UK city of Leeds' natural gas network converted to hydrogen gas, and the H_2 Mobility Europe project, which is constructing a network of hydrogen refuelling stations across Europe to power fuel cell vehicles. The lessons from these projects will assist the rollout of any hydrogen project in Australia.

Australia's policymakers have begun investigating hydrogen as a viable alternate fuel and energy source. The CSIRO's low energy roadmap considers the future of a hydrogen economy in Australia. This research is being used to inform the federal government's Climate Change Policy review, which is due for release late in 2017. At the state level, policy interest in hydrogen has been expressed by the Victorian government in the recent Edwards's Review. Findings 7 and 8 of the review note that hydrogen for export is a potentially viable alternative use of brown coal in the near to medium term and may contribute substantially to the state's economic output.[86]

Other State governments are investigating the potential of hydrogen, including South Australia which is developing a hydrogen roadmap.[87] The Australian Capital Territory is funding research into hydrogen as a form of energy storage through their Next Generation Renewables program[88] and federally the Australian Renewable Energy Agency (ARENA) is providing funding for a Power-to-Gas trial.[89]

Policies supporting hydrogen research and development will assist the rollout of a decarbonised gas network. The greater the deployment of hydrogen producing technology the faster costs will reduce. This phenomenon has been observed with many technologies historically, such as solar PV which has fallen from $10,000/kW[90] in 1998 to around $2,000/kW in 2017. An effective carbon policy, which encourages the least cost method of reducing emissions support hydrogen projects to gain access to finance.

4.2.6 State by state analysis

The profile of hydrogen production in each state will depend on the interplay between the above factors and how they influence the final cost of each technology. Broadly, the key cost differentials are the price of the input fuel and the total cost of CCS. Coal Gasification and SMR are the least cost production methods and will be the most competitive production options if CCS is available in the state. In states without geological CCS storage capacity, carbon captured would need to be transported to a storage site. This would substantially add to the total cost of the production technology and electrolysis may be the preferred option.

Currently there has been limited research into carbon storage in New South Wales, Tasmania and South Australia, meaning decarbonised hydrogen in these states is likely to come from electrolysis and biogas.

Victoria, Queensland and Western Australia have proven or feasible CCS sites, meaning that the production of decarbonised hydrogen gas through SMR or coal gasification is possible. The choice between these two production technologies depends on the cost and access to the input fuel. All these states have access to coal and gas and the choice of process used will depend on potential other uses of those fuels (eg exports).

Currently Australia has an integrated east coast gas market which permits the long distance transmission of natural gas to interstate markets. Any transition to a hydrogen network will likely be staged, and as such, management of inter-seasonal and interstate demand variations will be crucial to its success to ensure the stability of gas prices across the country. The transmission of gas was outside the scope of this report, and would require additional analysis should hydrogen become a substantial part of the energy market.

4.3 Biogas

Biogas from anaerobic digestion is a renewable and carbon neutral alternative to natural gas. Injecting biogas into the network has three broad stages, with distinct costs: producing raw biogas, cleaning and upgrading, and injection. The commercial viability of biogas injection depends the capacity to aggregate large scales of appropriate feedstock at low cost.

4.3.1 Producing biogas for the distribution network

The production of biogas is a well-established process in Australia. However, it is not deployed at large scale and is used for local electricity and heat generation, rather than injection into the gas distribution network. This outcome is due to a combination of policies and market factors including the design of the Renewable Energy Target.

Production of biogas for use in the distribution network broadly involves three stages, each with distinct costs. These stages are different to those required for producing biogas for local electricity or heat generation, and as such, the costs of producing biogas in the network may differ significantly, even though both start with the same underlying process (of producing raw biogas).

The three stages for feeding biogas into the network include:

- **Producing raw biogas**
  Production of raw biogas through anaerobic digestion. The costs include the capital and operating cost of the digester, feedstock costs including transportation of cost, and auxiliary power requirements.
- **Treating and upgrading the biogas**
  Removal of impurities such as water vapour, hydrogen sulphide, and carbon dioxide, to ensure similar properties as natural gas.
- **Injection into the network** –
  Compression to appropriate pressure, and transport from the digester into the distribution network.

The overall cost of injecting biogas into the network builds from these stages. The cost of producing and injecting biogas is uncertain, highly variable, and depends on site-specific factors.

Characteristics which significantly influence the overall cost include the size of facility, type of feedstock used, location relative to the existing gas distribution network and other variables. A summary of our estimates of the overall cost of injecting biogas into the network in Australia is presented below, with a breakdown of costs associated with the three primary stages.

4.3.2 Total cost of producing biogas for the network

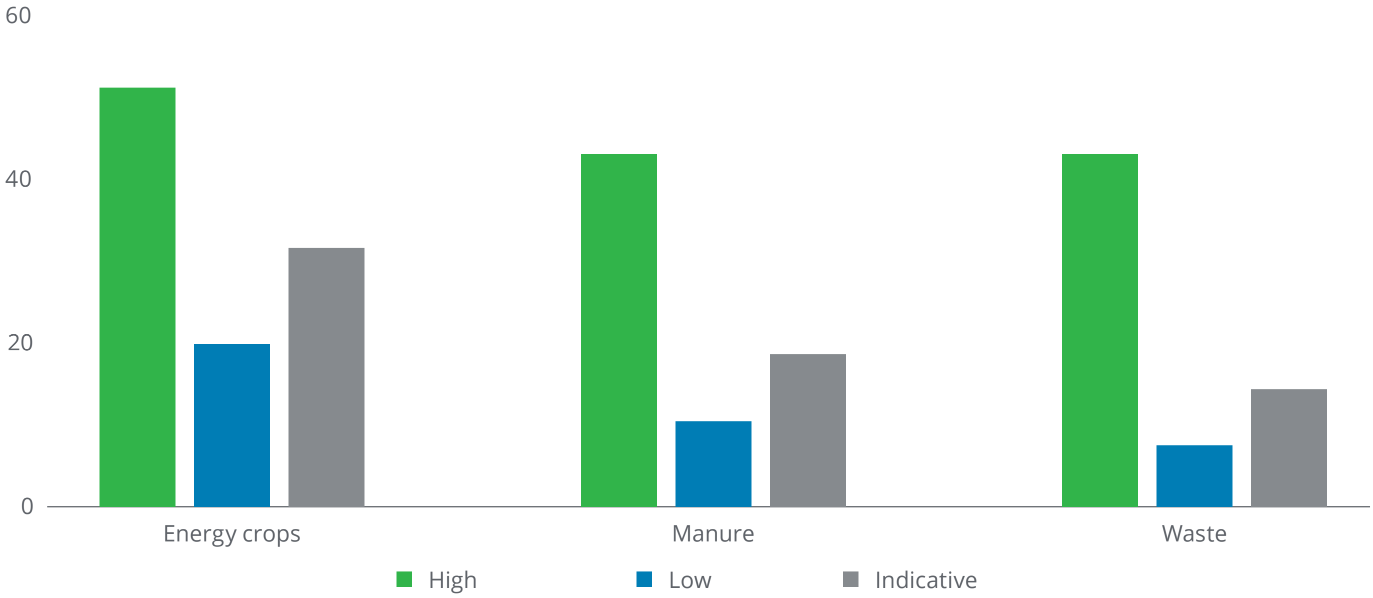
Biogas is not currently used in the network in Australia, so there are no local cost estimates available. We have therefore based our cost estimate on international benchmarks. Germany is a leading producer of biogas in the world, both in terms of producing raw biogas and injecting it into the network.[91] In 2016, approximately 33 PJ of biogas was injected into the network.[92] Other European countries which inject biogas into the network include the United Kingdom (7 PJ), the Netherlands (3 PJ), and Finland, Sweden, Austria, Switzerland, France, and Spain at smaller scales.

We estimate the costs of producing, treating, and injecting biogas using a report by the International Renewable Energy Agency (IRENA), which is based largely on costs from Germany.[93]

The costs of producing biogas for injection into the network vary significantly, with a range from:

- $7.4/GJ, for a large scale project using waste as a feedstock and injecting to a low pressure network, up to
- $51.1/GJ, for a small scale project using energy crops.

Figure 4.6 Cost of producing biogas and injecting into the network by feedstock
($/GJ)



Source: Deloitte Access Economics analysis based on (Scholwin et al., 2017)

The cost of biogas production and injection depends on a few important factors, which drive a significant amount of the difference in cost between the feedstocks, and the variation within each feedstock. These include the following:

- **The cost of feedstock**. In general, biogas production from urban and industrial waste is relatively cheap, as the feedstock can be obtained by the biogas producer at low or even negative cost. Projects that use energy crops or agricultural residues generally need to purchase feedstock and pay for the delivery costs. This can contribute significantly to overall costs.
- **The size of the biogas processing facility.** The cost of cleaning, upgrading and injecting biogas into the network depend significantly on project scale, and the cost falls substantially for larger project.
- **Location of the biogas production facility**. Injecting biogas into the network has its own costs. These are lowest where the production facility is close to a low pressure network, and increase if the biogas needs to be compressed to higher pressures or requires additional infrastructure to connect to the existing network.

There may be a tension between these factors, which individual projects need to navigate. For example, feedstock costs are generally lowest where waste can be used locally, such as manure from a livestock feeding lot. However, local use typically implies low scale, which increases the cost of cleaning, processing and upgrading. Sources of low cost and appropriate waste may also not be located in close proximity to the existing gas distribution infrastructure. Aggregating waste or other biomass from a number of sources may provide economies of scale for the cleaning and injection process, however it introduces the need to collect and transport feedstock which pushes up the cost of raw production.

In Australia, we consider that a reasonable benchmark for producing and injecting biogas from urban waste streams is approximately $14/GJ. This includes the capital cost of the anaerobic digester, assumes a negative or zero feedstock cost (due to avoided waste disposal costs), and includes treatment and injection into a low pressure network from a medium scale production facility, of approximately 500 m^3/hour peak capacity (150,000 GJ/annum assuming 90% capacity factor). However, as discussed above this depends on a range of factors including capacity to secure a reliable stream of appropriate waste, and appropriate location relative to the existing gas distribution network. In certain cases, it may be possible to produce biogas at cheaper rates than $14/GJ, depending on whether it is possible to aggregate a large enough amount of suitable waste in an appropriate location. However, this should not be assumed to occur widely.

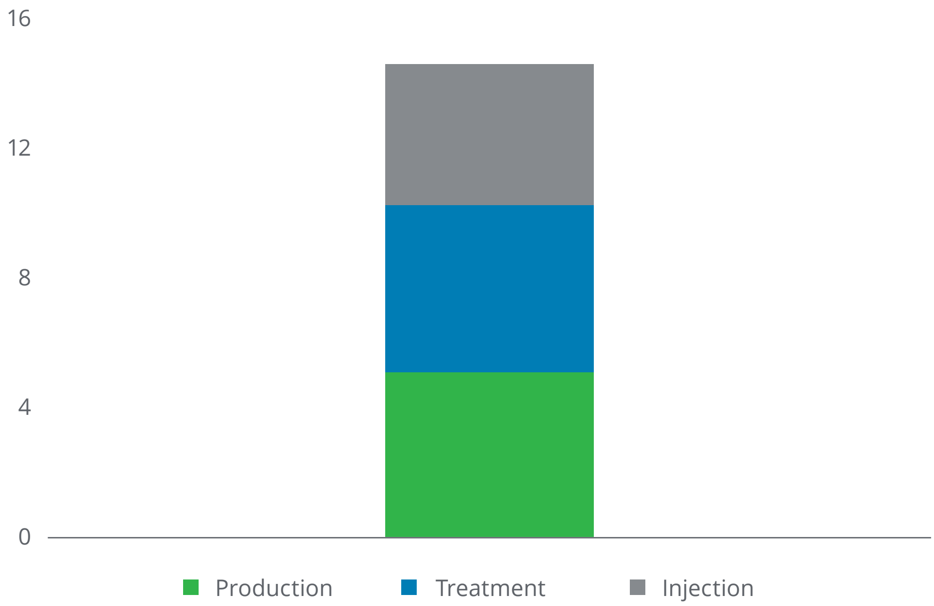
Where biogas is formed from livestock residues such as manure, the feedstock typically comes at low or negative costs, depending largely on whether it is processed locally or aggregated and transported. Depending on the proximity of livestock residue to the gas distribution network, these costs can vary substantially. We estimate a reasonable benchmark cost to be $18/GJ, however this could be as low as $11/GJ in appropriate circumstances.

Where energy crops are used as the feedstock for anaerobic digestion, the majority of the overall cost of producing and injecting biogas comes from the raw production of biogas.

We expect projects that use agricultural residue projects would have a similar cost breakdown to energy crop costs. A report by Bioenergy Australia estimated the delivered cost of crop residues to be similar to the delivered cost of short cycle energy crops.[94]

An indicative breakdown of costs between the three stages of production, treatment, and injection for biogas produced from urban waste is presented below.

Figure 4.7 Breakdown of biogas (urban waste) cost by stage
($/GJ)



Source: Deloitte Access Economics analysis based on (Scholwin et al., 2017)

For biogas produced from urban waste, each of the cost components contribute significantly. Although urban waste may have a low or negative feedstock cost, the raw biogas production reflects the capital and operating costs of the digester. Where feedstock costs are higher, for example for energy crops, the raw production component makes up a larger share of costs. For small scale facilities, the treatment and injection costs tend to be a larger share. Further discussion of these cost components is presented below.

Production of raw biogas
The costs to produce raw biogas are based on anaerobic digestion, and include the capital and operating costs of the digester, as well as feedstock costs. The cost of producing raw biogas depends largely on the type and cost of the feedstock used for anaerobic digestion. Where energy crops are used, the cost of the feedstock make up a significant proportion of total production costs, which range from $15/GJ to $21/GJ, without considering the additional cost to process and inject biogas into the network. These costs mean that using energy crops for large scale biogas production is unlikely to be cost competitive with natural gas, or alternative uses for crops such as food production and export. Agricultural crop residues may have similar delivered costs as bioenergy crops, and have competing uses for other forms of bioenergy such as direct combustion. Where transport makes up a significant proportion of costs, the economics may favour local use over aggregation and grid injection.

If manure or waste products are used, the feedstock costs may be low or negative, depending on the transport costs to aggregate waste, and avoided disposal costs, and the cost of production may be as low as $3/GJ. The capital and operating costs of the digester are relatively similar across feedstocks.

Treating and upgrading the biogas
Treating and upgrading biogas is a capital intensive process, and there are significant economies of scale. For small scale facilities, the cost of treating biogas to network standard can be over $10/GJ, which may not be competitive relative to using onsite in processes which do not require as much processing. For larger scale facilities, this decreases significantly, to approximately $3/GJ for facilities with capacity of 2,000 m^3 of biogas.

Injection into the network
Injection is similarly capital intensive, and the cost depends on the size of the facility, the amount of compression required based on the network pressure, and the distance from the anaerobic digester to the network. The cost varies significantly, from approximately $18/GJ for a small scale injection into a high pressure system, to as low as $2/GJ for a large scale injection in to a low pressure system.

As the cost to treat and inject biogas depends so much on the size of facility, biogas injection into the network is most feasible where large quantities of waste can be aggregated at low or zero cost. For small scale facilities, biogas production could still be feasible, but it may be more economic to use locally.

4.3.3 Network and end-user costs for biogas

Biogas can be used throughout the distribution network once treated and upgraded to meet the same specifications with natural gas currently used in the network. End-users, such as residential customers in the home and commercial businesses also do not need to change their appliances to accommodate biogas. As such, we consider that any additional network or end-user costs to facilitate the injection of biogas into the network will be relatively immaterial in comparison to business-as-usual.

Biogas needs to be treated and upgraded before injection into the gas network, so it has the same properties as natural gas. Biogas producers would need to build the equipment required to pressurise and inject biogas into the network, although this is reflected in the LCOE for biogas presented above.

If biogas is blended with hydrogen, there would be additional challenges associated with metering and maintaining a stable and efficient composition of gas. The blending and testing of a biogas and hydrogen mixture in a network is expected to require a one off capital investment of $200,000 for each TJ of gas handled per day. The exact specification of the metering system will vary depending on the gas mixture. A station handling 50 TJ of gas per day could expect a capital cost of approximately $10 million. The final cost will vary based on the station's exact specification including required pressure control, flow control and emergency response, with further detail provided in the EPCRC report.

4.3.4 Costs of using biogas and biomass for electricity generation

In Australia, facilities that produce biogas for the gas distribution will compete directly or indirectly with other biogas and bioenergy facilities that produce heat or electricity. There are a number of bioenergy electricity generation projects, some of which use biogas. These project can provide a useful benchmark to determine the costs of using biomass and biogas for purposes other than injection into the gas network. The Clean Energy Finance Corporation recently published the levelised cost of electricity (LCOE) from landfill gas as approximately $75/MWh, below most other renewable electricity generation in Australia.[95] It stated the cost of electricity from biomass sources more generally ranged from approximately $150 to $250/MWh.

The CSIRO estimated the LCOE of electricity from landfill gas as $130 to $160/MWh, and direct firing of biomass as $110 to $140/MWh.[96] These estimates demonstrate the variability of costs from bioenergy, and particularly biogas, which can depend largely on local factors and the availability of low cost feedstock.

Injecting gas into the distribution network involves different processes and costs than burning biogas for electricity generation. For example, generating electricity avoids the cost of injection into the network, however producers face a different set of connection costs if they sell into the electricity network. Local consumption avoids these network costs entirely, but does not allow producers to sell their output to the market, and limits the scale of production. For biogas injection to be economically viable relative to alternative uses of biogas, further consideration should be given to these cost structures and potential financial incentives for injection.

4.3.5 Policy settings and biogas

The quantity of biogas produced, and the way that it is consumed, depends largely on the policy frameworks in place in each country. In Australia, there are limited incentives to place to invest in the infrastructure required to produce biogas at scale and inject into the network. The absence of a broad based carbon price, or specific policies targeting decarbonisation of the gas sector, limit the injection of biogas. The large scale renewable energy target (LRET) provides incentives for renewable electricity generation, including electricity from biogas. Although the LRET has increased the overall size of the bioenergy market in Australia, it discourages the injection of biogas into the gas network, even where it may be more efficient than burning locally. This is an unintended consequence of the design of the LRET.

There are some state based schemes which provide support and incentives for bioenergy and energy from waste. The Victorian Waste to Energy Infrastructure Fund, provides some investment support to install or upgrade waste to energy facilities in Victoria.[97] In New South Wales, the Energy from Waste policy provides a regulatory framework for facilities which produce energy from waste materials.[98] The economics of injecting biogas into the network depend largely on aggregating appropriate waste material at significant scale, so broader waste management policies, such as the Victorian Metropolitan Waste and Resource Recovery plan which includes aims to increase organic waste recovery, also support the development of the biogas market.[99]

The United Kingdom provides a valuable case study in how energy policy can create a market for biogas. In 2011, there was only a single biogas upgrading facility, however the introduction of carbon pricing in 2013, and a feed in tariff for biogas under the Renewable Heat Incentive resulted in rapid increase in the number of biogas upgrading facilities, up to 37 in 2014.[100]

A broad based carbon price, or other policies targeting the use of low carbon gas, could improve the commercial attractiveness of injecting biogas into the network. Using the greenhouse gas emissions factors for natural gas and biogas from the Australian National Greenhouse Accounts Factors, a broad based carbon price of $50/tonne would reduce the relative cost of biogas by approximately $2.3/GJ.[101] It would also help to address the current imbalance in the incentives for gas injection and electricity generation.

4.4 Summary of commercial assessment

The following table summarises the key commercial issues for each technology considered above.

Table 4.4 Summary of commercial issues by technology

	Biogas	Hydrogen from renewable electrolysis	Hydrogen from SMR or coal gasification	All electric
Production costs (current)	Current wholesale costs range from around \$7/GJ (LCOE, for a large-scale urban waste project), to \$51/GJ for a small-scale project using energy crops.	Current costs (LCOE) are estimated at around \$67/GJ. However as a relatively immature technology there is significant potential for cost reductions.	Current costs are estimated at \$32/GJ (LCOE) for SMR, based on a gas price of around \$8/GJ. \$36/GJ for black coal gasification. \$38/GJ for brown coal gasification.	\$26/GJ, including firming costs to balance supply and demand, but excluding network costs.
Transmission network cost implications	Nil, biogas is similar to natural gas (costs of treatment to remove impurities are accounted for in the above).	Transmission networks are generally unsuited to hydrogen – requirements for new infrastructure (which may be electricity or hydrogen transmission) will depend on the location of renewable electricity production, electrolysers, and demand.	As for electrolysis, plus potential transmission costs for CO_2 storage – these will need to be compared to hydrogen transmission costs.	Substantial transmission upgrades required.
Distribution network cost implications	Nil, biogas is similar to natural gas.	Distribution network upgrades (to PE or similar) expected to be largely completed as part of normal renewals programs by mid 2030s.	As for electrolysis.	Substantial distribution upgrades required, around mil\$1.5/MW.
Appliance modifications	Nil, biogas is similar to natural gas.	Households must switch appliances to operate at high hydrogen composition. Costs per customer could range from \$700-\$1,250 – note that these costs would not necessarily significantly exceed the costs of an alternative, all electric approach.	As for electrolysis.	Households will need to switch from gas to electric appliances, with costs likely to be of a similar range as for hydrogen switching.
Other	CCS can be applied to the CO_2 produced in the biogas process which could provide an additional commercial incentive.	Hydrogen Storage or production for secondary markets including ammonia and fuel cells could reduce production costs.	Reduced use of coal for power generation could reduce input costs going forward.	Implications for peak demand may drive up costs with gas use shifting to electricity intensifying peak.

5. Pathway to decarbonisation

5.1 Overview

In this section we provide a high-level pathway of all the steps and likely timing required for decarbonisation of Australia's gas distribution network.

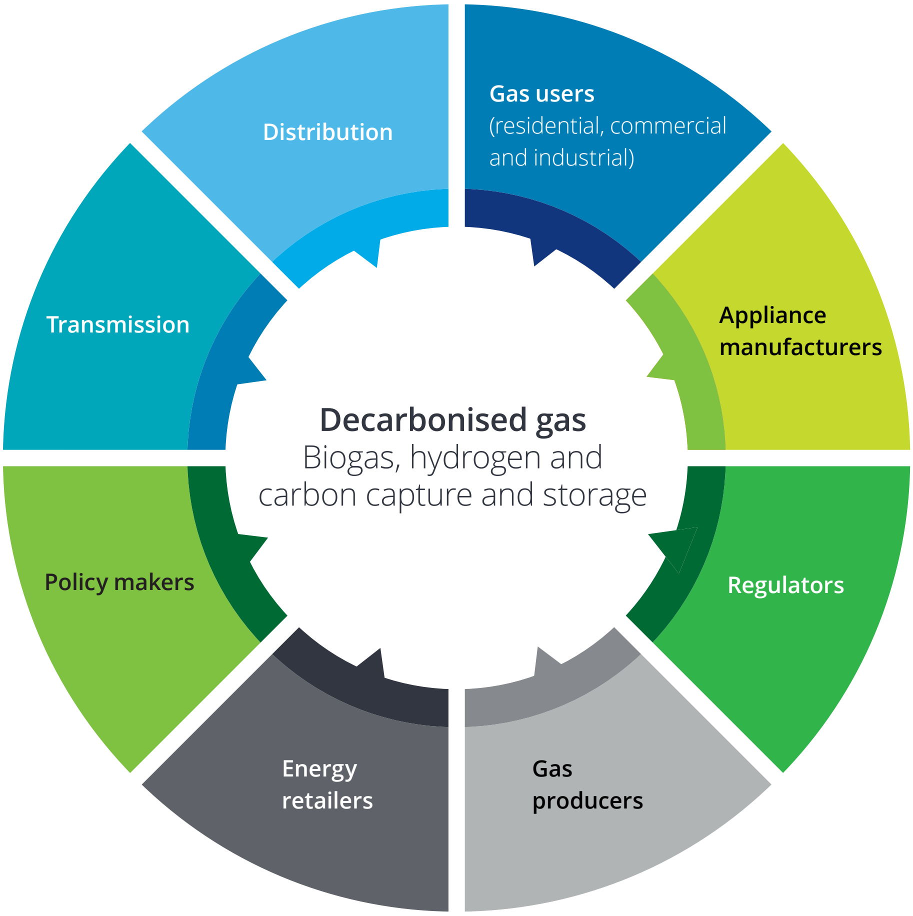
The pathways draw on the technical and commercial analysis in this report to describe a feasible pathway to decarbonisation of the gas distribution network. Each state may follow a regional-specific pathway depending on the available resources, the presence of CCS capacity, network characteristics and the timeline of upgrades for distribution networks. The state pathways to decarbonisation are discussed in further detail below.

The pathways to a decarbonised gas future described here are considered the most likely given the current status of technologies. Over time, with changes to the policy and commercial environment, the pathway to decarbonise may evolve. The factors that will influence the final direction include the projected cost of each production method; technological advances; the cost of inputs; policy and regulations; customer preferences and other uncertainties including:

- Carbon policy at the commonwealth and state levels
- Production technology cost learning rates
- Co-ordinating across the value chain
- The price of input costs including the price of natural gas, biomass from waste, coal and renewable electricity.

Using decarbonised gas will require coordination along the supply chain because of the advanced, interconnected gas network infrastructure. The ENA and network businesses may lead this transition. However, in the absence of a national carbon policy to deliver a commercially led decarbonisation pathway, government coordination will play a role. Regardless of whether the decarbonisation of gas is policy or commercially led, the successful rollout of a decarbonised network will require a coordinated effort (Figure 5.1).

Figure 5.1 The coordinated effort required for a credible pathway to decarbonise gas



5.1.1 Key actions in the decarbonisation pathway

To produce decarbonised gas at the scale required by consumers in the distribution network, technical and commercial milestones need to be achieved. Figure 5.2 highlights milestones on the pathway to a decarbonised future. These actions are based on current projections for the development of the various technologies, but may well change in future with changes to energy and carbon policy, technological progress or competing uses for fuels. The following sections provide greater detail on the role that each segment Wof the value chain will play.

Decarbonisation of gas across the whole supply chain is likely to require significant investments and policy support. While most of the required technologies are relatively mature and well-understood, large scale deployment and coordination across the supply chain is required to facilitate an orderly transition and minimise costs. Numerous pathways for decarbonisation are possible, and the optimal pathway may differ between jurisdictions, depending on market conditions and resources.

The figure below outlines a number of possible actions required for a decarbonised gas pathway, with each element briefly discussed in the following sections.

Figure 5.2 Possible milestones on the pathway to decarbonisation

Production

Biogas – further mapping of the resource and improved bio-digester technologies (including increased scale).

Hydrogen electrolysis – R&D into early stage technologies and pilot/demonstration of early market technologies. Opportunity for interaction with wholesale electricity markets (e.g. hydrogen storage capability).

SMR and gasification technologies – large scale demonstration and commercialisation.

CCS – further proving of storage sites in each jurisdiction.

Distribution networks

Networks are already suited to biogas, and replacement plans should ensure that network materials are also suitable for hydrogen by mid 2030s.

Where converting to high proportions of hydrogen in the gas mix, network conversions will need to be planned and coordinated with appliances.

Transmission

Transmission requirements will be determined by the types of decarbonised gas resources and location relative to major demand centres.

Further work will be required to understand the trade-off between transmission of hydrogen compared to CO_2 where CCS is required.

Retail and appliances

Households will be required to switch appliances to operate at high hydrogen composition – understanding of tipping points and coordinated response.

Collaboration between retailers, appliance manufacturers and networks to support customers transitioning between energy sources.

Policy and regulation

Equivalent policy support for decarbonised gas.

Policy support for large scale pilot and demonstration projects for production technologies (including CCS) should also be pursued.

Regulatory frameworks need to facilitate the transition and balance risks.

5.1.1 Production

The final gas mix chosen and the production technologies used will be determined by the total cost of production and the availability of resources. Biogas is generally the lowest cost form of decarbonised gas, but this relies on the availability of suitable, low cost biomass (i.e. 'wet' biomass from food waste, sewage, and livestock residue). Once readily accessible biomass becomes scarce and other biomass sources need, the cost of the fuel source increases. Biomass with competing uses, such as crop residue being used as soil improver for agricultural land will increase the cost of the fuel for biogas.

Under these circumstances biogas becomes relatively less competitive with hydrogen production methods (see page 68 for discussion of the costs of biogas).

Hydrogen can be produced using three methods: steam methane reforming (SMR); coal gasification; and electrolysis (see page 58), with SMR generally the lowest cost (see page 60). The economic case for SMR relies on availability of storage sites for CCS. Gasification of coal may be attractive under high gas prices. Like SMR gasification also requires CCS storage sites to produce a decarbonised gas, but the total captured CO_2 is higher than under SMR.

Consequently, hydrogen production from coal gasification will be limited by carbon storage capacity before SMR production is constrained by available carbon stores. Additionally, as a more mature technology, coal gasifier technology is not expected to benefit from same amount of technological learning and therefore cost reductions as SMR over the outlook.

By 2050 hydrogen production using electrolysis powered by renewable energy is anticipated to be cost competitive with the other hydrogen production methods. This is due to significant cost reductions from technological learnings.

Availability of low cost renewable electricity (such as wind generation) to power the process is also expected to reduce the cost of electrolysis. Despite these costs reductions, SMR is projected to remain relatively more competitive over the long term.

5.1.1.2 Distribution networks

Biogas is assumed to be processed to a standard suitable for injection into the network without upgrades and may be injected as an early stage decarbonised gas prior to the finalisation of the network upgrades. Although biogas may comprise some of the final gas mix, current projections of biomass in Australia indicate that insufficient quantities will be produced to meet the scale required to entirely replace natural gas at costs that are competitive with other forms of decarbonised gas.

Therefore, a decarbonised gas network in 2050 will likely involve a transition to hydrogen, which would require the distribution network to be upgraded to polyethylene pipes or equivalent to protect against issues such as embrittlement when hydrogen is transported through steel pipes. Scheduled network upgrades in each region are expected to be complete by 2035, with the distribution network suited to carrying hydrogen at this point. Network businesses may need to manage the transition to ensure it is done effectively and systematically if it is not managed by government.

5.1.1.3 Transmission

A final hydrogen gas mix would require network upgrades to transmission pipelines if production points are not directly connected to the distribution network. The current transmission system in Australia is an integrated network that spans the East Coast gas market, with a separate transmission system supplying the West Coast. Although localised production of hydrogen would mitigate the need to construct additional hydrogen transmission pipelines, it may alter the existing market dynamic and also reduce line pack storage potential (although we note that transmission of natural gas may still be appropriate with hydrogen production occurring at the point that the gas enters the distribution network).

5.1.1.4 Retailers

Gas retailers are a valuable contact point for gas producers and network businesses to engage with customers and direct information to them, and vice versa. Retail businesses are experienced and familiar to gas users, so under a government managed transition, communication between retailers and upstream businesses will be essential to transitioning the existing network effectively. This communication will be particularly relevant under a staged transition where different parts of the network are operating on different gas mixes.

5.1.1.5 Consumers, appliance manufacturers & gas fitters

Existing domestic, commercial and industrial gas appliances, boilers and burners are constructed to operate efficiently and safely on natural gas. Any changes to the gas supplied may impact their safe operation. Based on international studies, domestic and commercial appliances have been found to operate safely and effectively with a hydrogen proportion of anywhere between 10-30%, however the exact proportion varies across jurisdictions.[102] The thresholds under which appliances in Australia can operate safely will require further research and testing.

Before networks transition to a new gas mix involving hydrogen levels in excess of the technical thresholds, all users connected to the network would require new appliances or changes to existing appliances. Appliance manufacturers would need to develop and scale up production of appliances suited to operating on the gas mix specified by networks. Gas fitters and those who work with gas infrastructure will need to acquire capabilities to effectively and safely manage installation and operation of the new gas connections.

Communication with residential and commercial gas users will be critical to minimising the disruption of a transition to the decarbonised gas pathway. A staged transition that gradually isolates and upgrades manageable sections of the network (both appliances and piping downstream of the meter) to the final pathway is recommended to minimise the length of disruptions for individual customers. This process would most likely need to be managed by government, although a market led transition could occur if appliance manufacturers, retailers and network businesses coordinate to facilitate and manage the installation or upgrade of customer's appliances and associated pipework.

Industrial equipment such as gas turbine burners have a much lower tolerance to changes in the gas specification and will likely operate safely with 1-2% hydrogen, but not beyond.[103] Other industrial equipment such as boilers and kilns will likely cope with a similar gas mix to domestic and commercial appliances.[104] Communication with industrial operators will be essential to ensuring these parts of the network have equipment that suits their operating needs and can operate safely on the supplied gas.

Some industrial users of natural gas use the resource as a feedstock, rather than a source of energy. These operators will need to be provided with an alternative natural gas supply. The existing natural gas transmission lines are unsuitable for carrying hydrogen, so large industrial users connected to these pipelines may still be able to receive their gas supply in this way. Smaller users, which represent the majority of industrial users, are connected to the distribution network, which will transition to carrying the final decarbonised gas mix. As such, these customers will require an alternative supply solution.

5.1.1.6 Policy and regulation

Policy and regulatory changes will be an essential part of the transition to decarbonise the gas network and support the commercial viability of decarbonised gas. This includes:

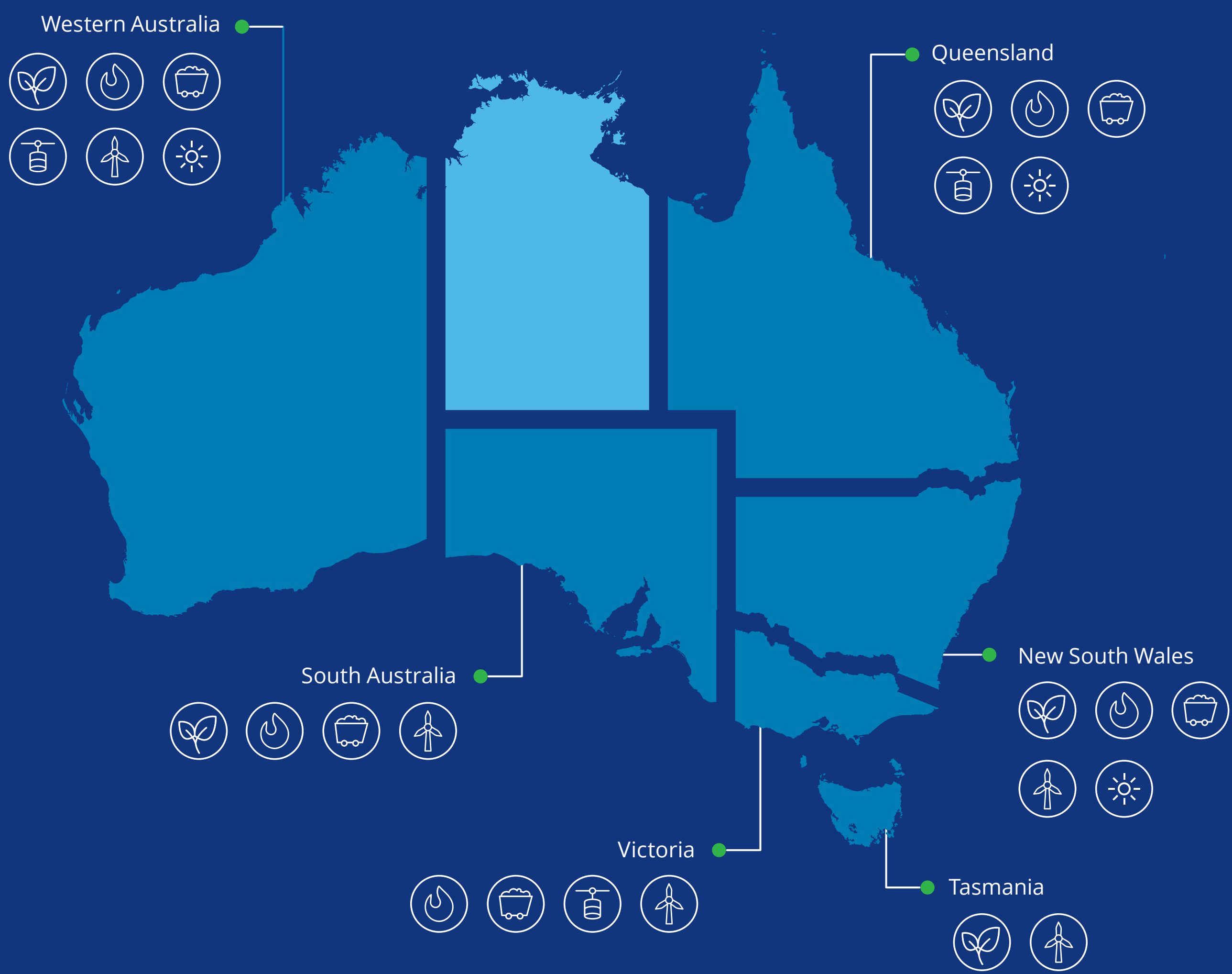
- Support for, and potential coordination of, a staged conversion process to align the changes required to production, transport and consumption of gas.
- Carbon policy that provides equivalent support and incentives for both decarbonised gas and decarbonised electricity.
- Support for CCS (direct or through a broad carbon policy)
- Pipeline regulations will require changes to allow more than 15% hydrogen
- Customer safety concerns and building the case for lower emissions through the gas network will need to be addressed
- Appliance testing and approval for effective and safe operation of decarbonised gas appliances.

5.2 Regional pathways

Australia has large diversity in natural resources and infrastructure across each state and territory. The comparative advantage of each region in terms of its potential to produce biogas, natural gas and coal reserves, infrastructure required to sequester carbon dioxide, and potential to produce wind and solar electricity for electrolysis will all determine the most efficient pathway to decarbonisation.

The figure below summarises the resources and comparative advantages of each region for decarbonising the gas network.

Figure 5.3 Regional advantages for decarbonisation by technology



- Biogas potential (excluding agricultural reserves) exceeds 10% of demand
- Natural gas reserves
- Coal reserves
- CCS capability
- Strong wind potential for electrolysis
- Strong solar potential for electrolysis

The **figure** summarises the resources and comparative advantages of each region for decarbonising the gas network.

Source: Deloitte Access Economics analysis

New South Wales is characterised by:

Large coal resource that may be available for coal gasification as coal-fired generators retire

Strong renewable resource and increasing uptake of renewable energy. Hydrogen produced by electrolysis will have to compete with alternative uses of renewable energy.

Gas demand of 85 PJ per annum

88 PJ
biogas

3,540-17,420 PJ
2P + prospective gas reserves

>500,000 PJ
coal reserves

CCS: Surat
(possible, untested)

Small portion of state with **>7m/s** wind speed

Solar radiation **>20MJ/m^2/day** in central and northern parts

New South Wales has the second largest gas demand of the states. A climate policy is currently being prepared to place the State on a pathway to zero carbon emissions by 2050. There is significant potential for New South Wales to expand its renewable energy industry in central, northern and western regions of New South Wales. These regions have low population densities, large open spaces and high average global solar exposure providing some of the best solar resources in the world. NSW also boasts a strong wind resource on the east coast along the Great Dividing Range.[109]

Electrolysis - New South Wales is a well interconnected state in the electricity market with the largest and most consistent load throughout the year. This means that any renewable energy in this market is likely to be dispatched in the wholesale market (as opposed to being lost or stored as surplus). Any hydrogen production from electrolysis within New South Wales would have to compete with the opportunity cost of selling electricity in the wholesale market.

Steam methane reforming - Steam methane reforming for hydrogen production is unlikely to be feasible in New South Wales in the short-to medium term.

While previous studies have found that NSW potentially has a large undeveloped gas resource, low 2P reserves coupled with no proven CCS resources will make the process more costly than other states.

Coal Gasification - New South Wales has a heavy economic reliance on coal, which is NSW's largest export earner and the fuel source for about 80% of electricity generation. NSW has more than 15 billion tonnes of recoverable coal reserves contained within 40 operating mines, and over 20 new major development proposals.[110] As the state transitions to decarbonisation the use of coal in electricity will begin to reduce, with Liddell coal-fired power station slated for closure. With its large reserves of black coal, New South Wales may have a comparative advantage in producing hydrogen from black coal gasification.

CCS - Producing hydrogen from coal gasification will require CCS. With limited potential for CCS in NSW there may be additional costs in transporting CO_2 to the Gippsland Basin for storage.

Biogas - The potential for biogas in the state excluding agricultural waste, based on data collected for the Australian Biomass for Bioenergy Project is estimated at 12.4 PJ, equivalent to almost 15% of New South Wales' current gas demand.

Victoria is characterised by:

A rich endowment in natural gas and brown coal, which if repurposed could produce hydrogen from steam methane reforming and coal gasification.

A biogas resource which is only a small fraction of overall gas demand and is therefore unlikely to contribute significantly to decarbonised gas.

48 PJ
biogas

10,750-10,990 PJ
2P + prospective gas reserves

>500,000 PJ
brown coal reserves

CCS: Gippsland, Bass, and Eastern Otway (Strong)

Average wind spends **>7m/s**
Strong resource offshore **>9m/s**

Solar radiation reaching up to **>18MJ/m²/day**

Victoria has the largest residential natural gas demand in Australia, with approximately 181 PJ consumed in the gas distribution network in 2016. Natural gas is a core aspect of the energy mix, and producing sufficient amounts of hydrogen or biogas to decarbonise the network represents a significant transformation of the energy system in the state. Using existing resources and infrastructure could reduce the costs of decarbonisation.

Electrolysis – Victoria has a strong wind resource with average wind speed of >7m/s in southern and western parts of the state. The Victorian Government has introduced a state based Renewable Energy Target (VRET) of 40% by 2025, which will grow the renewable energy industry in Victoria over the next seven years. Electrolysis is likely to play a small role in Victoria, producing from cheap wind generation.

Steam Methane Reforming and Coal Gasification - There are a range of natural gas and coal reserves in Victoria, which are currently used to feed into the gas distribution network or for power generation. These resources could be repurposed and used to produce hydrogen through steam methane reforming or coal gasification.

In particular Victoria has significant deposits of low cost brown coal, and the infrastructure to extract it, which are currently used to power generators in the Latrobe Valley. Using existing brown coal or natural gas deposits to produce hydrogen may best utilise Victoria's comparative advantages in natural resources. It also has strong potential for carbon capture and storage through the CarbonNet project, which facilitates both of those technologies.

Biogas - We estimate that Victoria has approximately 10 PJ of biogas production potential, excluding agricultural crop residues, based on detailed data collected for the Australian Biomass for Bioenergy Project. The Metropolitan Waste and Resource Recovery Plan, part of the broader Victorian Waste and Resource Recovery Infrastructure Plan, sets out objectives including to increase the amount of organic waste recovered which would support efficient biogas production.[111] This could allow biogas to make a useful contribution to decarbonising the Victorian gas network alongside hydrogen.

Queensland is characterised by:

Queensland is rich in resources, possessing strong biogas, renewable energy, coal, and gas resources. Electrolysis and biogas have strong potential to provide decarbonised gas in Queensland.

84 PJ
biogas

18,650-90,540 PJ
2P + prospective gas reserves

>500,000 PJ
coal reserves

CCS: Bowen, Eromanga
(Strong but untested)

Majority of state solar rediation **>20MJ/m²/day** Large portion **>23MJ/m²/day** and with parts accessed by network

Electrolysis - Queensland has a considerable opportunity to produce renewable electricity, particularly from solar, which could be used to produce hydrogen gas through electrolysis. The renewable electricity sector in Queensland is relatively underdeveloped and in 2016 only 5% of electricity generation came from renewables, including hydro and small scale solar PV. However, the Queensland Government has introduced a target to obtain 50% of electricity from renewables by 2030, and the sector will need to grow substantially to meet this target.[112] The increasing penetration of renewable capacity, combined with the natural advantage in solar generation, could allow for relatively low cost electrolysis in Queensland by utilising surplus renewable energy.

Steam Methane Reforming - Queensland has some of the largest natural gas reserves in Australia, including approximately 44,300 PJ of 2P reserves in the Surat Bowen basin.[113] This provides opportunities for steam methane reforming to produce hydrogen (although we note that the LNG projects compete for this resource). There are a number of basins that are potentially appropriate for carbon capture and storage in Queensland to support steam methane reforming, however they are relatively untested and undeveloped, and require further research into their feasibility.

CCS - CCS is undeveloped in Queensland and lack of suitable storage locations historically have meant that CCS projects have not progressed in the state.[114] It is currently unlikely that Queensland would pursue steam methane reforming and coal gasification over electrolysis and biogas without certainty on CCS.

Biogas - Based on data collected by the Queensland Government for the Australian Biomass for Bioenergy Project, we estimate that biogas could provide approximately 70% of Queensland's current gas distribution demand using urban waste, livestock residue and food processing waste as feedstocks. The potential from agricultural crop residues, including bagasse, could exceed total gas demand in the State, however biogas would face considerable competition for these resources with other forms of bioenergy. We also note that estimates of biomass resources are subject to considerable uncertainty, however it is likely that biogas could play a significant role in the decarbonisation of the gas network in Queensland.

South Australia is characterised by:

South Australia has strong opportunities and advantages for decarbonising the gas network. It has strong potential for renewable electricity generation, particularly wind generation.

In 2016, approximately 48% of South Australian electricity generation was from renewable sources, including small scale solar PV.[115]

46 PJ
biogas

10-82,250 PJ
2P + prospective gas reserves

250,000-500,000 PJ
of coal reserves

CCS: Western Otway
(Untested)

Large share of state **>7m/s**
average wind speeds
Off shore resource **>9m/s**

North of state **>20MJ/m^2/day**
Although not near
transmission lines

The South Australian Government has a target to generate 50% of its electricity from renewables, however does not currently provide financial support on top of the national LRET. Much of the South Australian coast has average wind speeds greater than 7 meters per second. There are some challenges associated with integrating intermittent renewables such as wind at levels significantly above the current penetration in South Australia, while maintaining a reliable and secure network.

Electrolysis - The integration of high wind generation in the network provides an opportunity to produce hydrogen for the gas network through electrolysis, with excess generation able to be used to bring down input costs. Building additional renewable capacity, particularly wind generation, and using it to produce hydrogen in South Australia may result in some of the lowest cost electrolysis available. It could also allow South Australia to make the most of its renewable electricity potential, which may significantly exceed the amount that can be fed into the electricity network.

Steam methane reforming and coal gasification - South Australia also has considerable coal resources, including the Leigh Creek coal mine which was closed in 2015. After the closure of Northern Power Station, there are no coal electricity generators in South Australia, and no operational coal mines. So producing hydrogen from coal gasification could provide an opportunity to utilise those resources. South Australia has prospective gas resources in the Otway Basin area and the Cooper basin. However, there are currently limited opportunities for carbon capture and storage in South Australia, so carbon dioxide may need to be transported to Victoria for sequestration, which could increase costs relative to other means of producing hydrogen.

Biogas - South Australia is relatively progressed in mapping the availability of biomass and waste for bioenergy through the Australian Biomass for Bioenergy Program, which is an important precursor to producing biogas at scale. We estimate that urban waste, food processing waste, and livestock residues could provide over 5 PJ of biogas, approximately 17% of current natural gas demand, at low cost. The South Australian Government is currently providing significant support for bioenergy, through the Bioenergy Roadmap for South Australia run by Renewables SA,[116] with funding available for bioenergy trials.

Western Australia is characterised by:

Large natural gas resource that could be used to produce hydrogen by steam methane reforming.

Strong potential for CCS with the South West Hub site near Perth.

Significant renewable resources that could be taken advantage of to foster hydrogen production from electrolysis.

103 PJ
biogas

72,540 PJ
2P + prospective gas reserves

25,000-45,000 PJ
coal reserves

CCS: South West Hub (Strong)

Southern part of state average wind spends **>7m/s**
Off shore average wind speeds **>10m/s**

Majority of state
>20MJ/m^2/day

Steam Methane Reforming - Western Australia has a large share Australia's natural gas reserves, estimated at approximately 72,540 PJ 2P reserves largely in the Carnarvon basin.[117] This alongside Western Australia's strong potential for CCS, with the South West Hub site around 100km South of Perth a promising storage facility. There is also some potential for offshore sites in Carnarvon, Bonaparte and Browse Basins, and onshore the Canning Basin.[118] However these sites are a significant distance from Perth and would require significant investments in transmission of either hydrogen or CO_2 to function. The natural gas resource and potential CCS provide Western Australia with a strong case for steam methane reforming.

Electrolysis - Western Australia has access to a myriad of renewable energy resources, with large geothermal, solar, wind, wave and tidal resources. These technologies could provide a significant supply of renewable energy for electrolysis, with a more diversified power generating portfolio increasing the capacity factor for producing hydrogen gas. Whilst the State has a large renewable resource the distance of this resource from population centres may impose additional transmission costs (either electricity or hydrogen) for the production of hydrogen from electrolysis.

Biogas - Based on data from Australian Biomass for Bioenergy Project the biogas potential in Western Australia, excluding agricultural waste, is approximately 3.4 PJ. This would service 12.6% of Western Australia's current domestic gas demand.

Tasmania is characterised by:

Tasmania is currently powered by almost 100% renewable energy.

Strong wind resource and firm capacity from hydro provide strong prospects for hydrogen from electrolysis in Tasmania.

1 PJ
biogas

240 PJ
2P + prospective gas reserves

10,000-25,000 PJ
coal reserves

Majority of state has average wind speed **>7m/s**

Weak solar resources

Tasmania has a clear path to produce decarbonised gas. Its large renewable energy resource supports the production of hydrogen from electrolysis, and furthermore, Tasmania has very limited gas and coal resources, with no known CCS capability.

Electrolysis - Tasmania currently has 98% renewable electricity generation with more wind generation able to developed in the State. The benefit of Tasmania's electricity generation mix is the ability to balance wind with hydro power for storage. Tasmania is therefore best suited to using electrolysis to produce decarbonised gas, with electrolysis potentially having a higher capacity factor in Tasmania than in other states.

Steam methane reforming and coal gasification - Tasmania has coal resources, including the Leigh Creek coal mine which was closed in 2015. Tasmania also has prospective offshore gas resources in the Otway Basin area. Producing hydrogen from coal gasification could provide an opportunity to use the potential resources. There are currently limited opportunities for carbon capture and storage in Tasmania, so carbon dioxide may need to be transported to Victoria for sequestration, which would increase costs relative to other means of producing hydrogen.

Biogas - The biogas resource (excluding crop residue and forestry waste) is Tasmania is approximately 0.6PJ which would service 20% of Tasmania's current gas demand.

The previous sections provide a more detailed discussion of the resources and infrastructure available in each region, and outline how this could influence the most efficient pathway to decarbonising gas in that region.

Table 5.1 State-specific decarbonised gas resources, as at 2017

State	Natural gas reserves (2P prospective resources, PJ)* [105]	Coal reserves[106] (PJ)	Biogas potential (including crop residue) (PJ/year)	Renewable electricity generation advantages[107]	CCS[108]
Victoria	10,750 – 10,990 The higher value includes 240 PJ Otway Gas Project which spans Victoria and Tasmanian	>500,000 (brown coal)	48	Average wind speeds >7m/s Strong wind resource off shore >9m/s Solar radiation reaching 18MJ/m²/day, less than this for most of state	Gippsland, Bass, and eastern Otway (strong)
New South Wales	3,540-17,420 The higher value includes 13,880 PJ for Clarence Morton which spans Queensland and New South Wales	>500,000	88	Small portion of state with >7m/s wind speed Solar radiation >20MJ/m²/day in central and northern parts	Surat (possible, untested)
Queensland	18,650 – 90,540 The higher value includes 82,240 for Cooper Eromuga Basin which spans part of South Australia and 13,880 for Clarence Morton which spans part of New South Wales	>500,000	84	Majority of state solar radiation >20MJ/m²/day Large portion >23MJ/m²/day and with parts accessed by network	Bowen, Eromanga (strong but untested)
South Australia	10 – 82,250 The higher value includes 82,240 PJ for Cooper Eromuga Basin which spans part of South Australia A more detailed breakdown by state is not available	~ 250,000-500,000	46	Large portion of southern state >7m/s average wind speeds off-shore resource >9m/s Top of state solar radiation >20MJ/m²/day although not near transmission line.	Western Otway (untested)
Western Australia**	~72,540	~25,000-45,000	103	Southern part of state average wind spends >7m/s Off shore average wind speeds >10m/s Majority of state >20MJ/m²/day	South West Hub (strong), Carnarvon, Bonaparte Browse and Canning (untested)
Tasmania	~240 Includes the Otway Gas Project 240 PJ which spans Victoria and Tasmania	~10,000-25,000	1	Majority of state has average wind speeds >7m/s Little solar resource	–

Source: Deloitte Access Economics analysis based on data from referenced sources

* Gas reserve data taken from AEMO 2017 Gas Statement of Opportunities and 2016 WA Gas Statement of Opportunities which relies on gas reserve information from 2015 from EnergyQuest data. Estimates are 2P and prospective resources.

** Western Australia is 2P reserves only and includes some NT reserves. A more detailed breakdown is not available.

5.3 Financing the transition

There are a range of options to assist in financing the conversion of Australia's gas networks, from market mechanisms, policy support, and regulatory solutions. A mix of approaches is likely to be required, with different components of the supply chain requiring different solutions.

In competitive markets, we would expect market forces to provide the most efficient allocation of investment capital towards the uptake of new technologies and decarbonisation of gas. However, markets are imperfect, and there are numerous regulatory and policy constraints operating in Australia's energy market which may mean that the market does not provide an efficient allocation of capital to finance the transition. In general, we see a role for government support for investment in activities such as:

- Early stage research and development, which is likely to have public good characteristics and produce positive externalities that are not fully captured by the party investing in the research (resulting in a lower than optimal level of the activity, from a national perspective).
- Demonstration and early stage commercialisation, where there is a first-mover disadvantage – first movers in the early stage of commercialisation of new technologies are required to take on substantial amounts of risk, with fast-followers able to capitalise on the newly proven market without taking on the same level of risk.

The following table highlights the financing issues to be addressed at the production, network and customer level and comments on options for financing.

Table 5.2 Options for financing the conversion

Component of supply chain	Financing issues	Options to support financing
Production		
Transformational production technologies	Given energy production and wholesale energy markets are competitive, options for financing the production of decarbonised gas should be targeted at attracting private sector capital to the task with policy support and market-based approaches to address market failures (i.e., lack of recognition of externalities), but generally allowing investment to follow competitive market principles.	Policies should provide a level-playing field with other technologies for decarbonising energy use. This might include: • Direct targets, such as a low carbon gas production target (much like the Renewable Energy Target in the electricity sector). • Broad-based mechanisms that identify and price externalities from carbon emissions (e.g. carbon pricing, cap and credit schemes, etc.). Where technologies are in the early stages of R&D or demonstration, direct government support for these phases of development may be necessary to push these technologies towards commercialisation and eventual market take-up. For example, this might include support from existing funding bodies such as ARENA and the CEFC, or a specifically convened agency with a targeted objective to provide funding support to decarbonisation of gas.

Table 5.2 Options for financing the conversion

Component of supply chain	Financing issues	Options to support financing
Networks		
Distribution networks	Gas distribution is, for the most part, a regulated service. As such, network businesses need to operate within a specific set of rules for investments to be rolled into their regulated asset bases such that an appropriate rate of return can be made on those investments.	For regulated networks, the efficient costs of converting the networks should be recoverable through regulated prices. This might include: • Incentives and cost recovery for investments in innovative technologies. The AER's Demand Management Innovation Allowance (DMIA), which provides a fixed allowance to electricity distributors each year, and the Network Innovation Allowance (NIA) administered by Ofgem in the UK, provide examples. • Ensuring coordinated investments in the conversion of networks, production capacity and customer appliances to provide continuity of service are appropriately timed and recoverable. Note that in general, regulated cost recovery would require direct (i.e. decarbonised gas targets and/or investment mandates) or indirect (e.g. carbon pricing) support to meet regulatory hurdles for prudency and efficiency.
Transmission and storage	Transmission and storage facilities operate under both regulated and unregulated regimes, depending on the nature and use of the facility.	The function of transmission and storage is essentially one of arbitrage – locational in the case of transmission, and temporal in the case of storage. As such we would expect the market to adequately invest in transmission and storage infrastructure in competitive markets, to capture the value from geographical and temporal price differences. Where operating in regulated settings, the same principles as outlined above for distribution networks apply.
Customers		
Appliance conversions	Like the wholesale market, retail energy markets are, for the most part, unregulated, making the most efficient financing approaches those that provide market signals for customers to invest in new appliances, and manufacturers to invest in their development.	A broad-based policy that provided price signals reflecting externalities from carbon emissions would be the most efficient approach to attracting investment in hydrogen capable appliances. However, we also note that a timely and coordinated transition may require additional financing support to ensure the total costs of the conversion are minimised, such as: • Subsidy schemes for hydrogen appliances. The Victorian Energy Efficiency Target (VEET), which provides subsidies for energy saving appliances, is an example of such a scheme that could be applied to hydrogen ready appliances. • Targets for retailers to transitioning customers away from natural gas and onto hydrogen. There may also be a role for government in providing financing support for pre-commercial R&D and demonstration of appliances capable of operating with high concentrations of hydrogen.

6. Research and development

Injecting hydrogen into the gas network presents a number of opportunities for further research. In this section we present some R&D requirements and recommendations for the short term, and longer term. R&D items have been rated as being of high, medium or low priority:

- High priority refers to R&D that is deemed crucial to the successful transition to a decarbonised gas mix
- Medium priority items are those that would assist the rollout, but are not crucial
- Low priority items refer to those that will likely be addressed during the rollout, but early knowledge may help the transition.

The main areas of research cover appliance modifications and safe operation; network modifications; low emissions gas technologies including biogas production methods; and further research into the dual uses of hydrogen across gas networks and fuel cell vehicles.

Area	R&D priorities	Priority	Timing
Appliances	Further research and testing as to the maximum level of hydrogen that can be safely injected into the Australian network without jeopardising the safe operation of existing appliances (domestic, commercial and industrial). Consideration of the network and fuel characteristics, and existing appliances in Australia is essential to determine what percentage of hydrogen will maintain the current Wobbe index specifications for Australian appliances. This is a research priority should the decarbonised pathway incorporate the injection of a low emission gas into the existing network before transitioning to the final mix.	High	Very short term (1-2 years)
Biogas injection	Biogas may be injected into the existing gas network as part of a low emissions fuel before the network transitions to its final decarbonised mix. Greater knowledge of potential biogas injection sites (based on proximity to waste sources and gas distribution network) is recommended.	High	Very short term (1-2 years)
Appliances	Further research into the development and manufacture of hydrogen appliances (domestic and commercial). The development requirements to reach commercial scale manufacture may guide the timing of the final gas mix, so early research is advised. Moreover, the short term timeline of this R&D item is reasonable given international markets including Singapore and China operate on town gas and have commercially manufactured appliances specified to operate on up to 65% hydrogen. Understanding the potential to mix methane (biogas) with high amounts of hydrogen would also contribute to the decision making on decarbonised gas. Similarly this research is required for industrial gas fired equipment. Similarly, research into the approaches to maintain natural gas supply to industrial customers using it as a feedstock may be required.	High	Short term (5 years)

Area	R&D priorities	Priority	Timing
Meters & associated pipework	Some joints and seals may be susceptible to hydrogen leaks and will require replacement during a transition to a hydrogen gas network, however the extent of the required replacement is currently unknown. Consequently further research into the materials used in pipework joints and seals downstream of the meter and the distribution of each across the existing gas network is recommended, although not essential and could be treated as a variable cost of the upgrade process (i.e. if the piping is deemed unsuitable during the transition to the final mix then it can be upgraded then).	Low	Short term (5 years)
Transmission network	Further research into the required upgrades or replacement of the existing transmission infrastructure to safely carry hydrogen at higher pressures. This research item should also consider the suitability of the transmission network for line pack storage of hydrogen.	High	Medium term (5-10 years)
Biogas resource mapping	The commercial viability of biogas depends on aggregating low cost feedstock. Understanding the biomass and waste supply chain is a necessary part of this. Mapping and understanding biomass resources is underway through the ABBA project and AREMI map, however further work is required to make the database consistent and comprehensive. Engagement along the supply chain of waste, including with agricultural producers, large industrial producers, and metropolitan councils may facilitate a more coordinated and efficient approach to waste management.	Medium	Medium term (5-10 years)
Hydrogen storage	The commercial viability of hydrogen storage is a key area for future research. Current storage options include cryogenic storage facilities or geological rock formations, each with its own benefits and costs. Whilst cryogenic storage is applicable to most sites, the need to cool hydrogen below its critical point of 33K (or 20.28 K if it is not pressurised) is a costly process. The alternative storage option is in geological rock formations, but this limits the storage sites and total storage capacity. Research into chemical catalysts that may assist in the storage and transport of hydrogen is an ongoing field, and is recommended to continue.	Medium	Medium term (5-10 years)
Review of gas legislative framework	National and state-based legislation and regulation specify what types of gases can be injected into, and distributed by, networks. A review of these frameworks is essential to better understand the regulatory implications of injecting biogas or hydrogen in networks.	High	Short term (1-2 years)

In addition to Deloitte Access Economics' recommendations, a previous report by Energy Pipelines CRC[119] has noted the following areas of research:

- More comprehensive study of leakage rates of hydrogen from all types of plastic pipes in a range of pressures and geographic locations.
- The full extent of changes required to the network materials, instrumentation, customer appliances and plant equipment need to be understood for renewable gas and in particular hydrogen-methane mixtures.
- The changes required to industrial and domestic burners and control systems has only partially been addressed in previous work and needs to be more comprehensively addressed on a case by case basis.
- Improved gas composition, flow metering, as well as leak detection instruments may need to be developed.
- Assessment of distribution networks for physical bottlenecks and bottlenecks in the approval processes for hydrogen injection.
- Detailed studies of the effect of injection locations and variability of injection rates on gas composition in specific networks will need to be performed to gain a fuller appreciation of the costs of transport, metering and extra storage.
- Safety considerations need to be reviewed for hydrogen generation, transport and injection.
- Uncertainties regarding the lifecycle costs for hydrogen production, transmission, storage and injection need to be reduced.
- Research into the long term performance of materials transporting and storing natural renewable gas and development of new materials with improved performance characteristics and degradation resistance.
- Impurities or contaminants in hydrogen, SNG, biogas or renewable/natural gas blends may affect network materials and customer equipment and require further study.

Analysis by CO2CRC, the CSIRO, the Global Carbon Capture Institute and others have proposed the following R&D items for Carbon Capture and Storage.[120]

The majority of the recommended research objectives relate to global cooperation on R&D and increasing the rate of CCS uptake to develop economies of scale and reduce costs.

- Continued research and development into next generation capture technologies to further reduce costs.
- Enhance international cooperation to facilitate access to clean energy research and technology.
- Assist regional neighbours implement CCS to develop economies of scale.
- Reduce the costs associated with geological surveys to prove sites.
- Identifying alternate storage formations to lower the cost of CO_2 capture and utilisation.
- Demonstrate CCS projects to encourage community understanding and acceptance of CCS projects.
- Consider the required legal and regulatory frameworks that will support the use of CCS sites once technically proven to assist in the commercialised rollout of CCS capability.


Vacuum
Stickstoff

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Appendix A: Gas regions

The analysis in this report is based on our understanding of the major Australian gas distribution networks. The analysis here does not consider gas transmission or remote gas grid applications. The gas distribution regions are presented in table A.1 below:

Table A.1: Regions of the decarbonised gas network examined for this report

State	Region	Network operator
NSW	Sydney greater metropolitan region	Jemena
NSW	Southern NSW	Australian Gas Network
VIC	Melbourne North East	Multinet Gas
VIC	Victoria Outer North	Australian Gas Network
VIC	Victoria West	AusNet Services
QLD	Brisbane and surrounds	Australian Gas Networks
QLD	Brisbane south	Allgas
SA	Adelaide greater region	Australian Gas Networks
WA	Perth greater region	ATCO Gas
TAS	Tasmania	TasGas
ACT	Canberra	Actew AGL

Appendix B: Measurements

B.1 Energy values used in this report

Natural gas can be measured in several units: either according to energy content (also referred to as heat) or volume. Within each of these measurements, several units are used in the natural gas industry.

Throughout this analysis the energy values set out in the National Greenhouse and Energy Reporting (Measurement) Determination 2008.

Table B.1: Energy content and emissions factors, Australia

Fuel combusted	Energy content factor (GJ/m^3 unless otherwise indicated)	Emission factor kg CO_2 e/GJ (relevant oxidation factors incorporated)		
		CO_2	CH4	N2O
Natural gas distributed in a pipeline	39.3 × 10-3	51.4	0.1	0.03
Coal seam methane that is captured for combustion	37.7 × 10-3	51.4	0.2	0.03
Coal mine waste gas that is captured for combustion	37.7 × 10-3	51.9	4.1	0.03
Compressed natural gas that has reverted to standard conditions	39.3 × 10-3	51.4	0.1	0.03
Unprocessed natural gas	39.3 × 10-3	51.4	0.1	0.03
Ethane	62.9 × 10-3	56.5	0.03	0.03
Coke oven gas	18.1 × 10-3	37	0.03	0.05
Blast furnace gas	4.0 × 10-3	234	0	0.03
Town gas	39.0 × 10-3	60.2	0	0.03
Other gaseous fossil fuels	39.3 × 10-3	51.4	0.1	0.03
Landfill biogas that is captured for combustion (methane only)	37.7 × 10-3	0	4.8	0.03

B.2 Carbon content factors

Australia's National Greenhouse and Energy Reporting scheme sets out the reporting requirements for all emitters covered under the legislation. The National Greenhouse and Energy Reporting (Measurement) Determination 2008 provides methods and criteria for calculating Australia's greenhouse gas emissions and energy data under the National Greenhouse and Energy Reporting Act 2007 (NGER Act). Throughout this analysis, carbon content factors set out in the national framework for emissions reporting have been used.

Appendix C: Stakeholder consultations

The following stakeholders were consulted over the course of this project, however the views in the report are those of Deloitte Access Economics.

Stakeholder
APA Group
ATCO Gas
Ausnet Services
Australian Gas Networks
Bioenergy Australia
CarbonNet
CO_2 CRC
CSIRO
Energy Networks Australia
Energy Pipelines CRC
Energy Safe Victoria
Global Carbon Capture and Storage Institute
Jemena
Multinet gas
Northern Gas Networks – Leeds H21 Project team

Appendix D: Biogas facilities in Australia

Table D:1 Biogas facilities in Australia

Name	State/Territory	Feedstock	Category
Biogass Richgro Food Waste AD facility	WA	Food waste	Biowaste
Bolivar Wastewater Treatment Plant	SA	Sewage sludge	Sewage
Bondi WWTP	NSW	Wastewater	Sewage
Casella Wines	NSW	Winery and brewery waste water	Industrial
Castlemaine Perkins Water Recycling Plant	QLD	Brewery waste water	Industrial
Cessnock WWTP Cogeneration Plant	NSW	Primary– sludge – sewage treatment	Sewage
Christies Beach Wastewater Treatment Plant	SA	Sewage sludge	Sewage
Cronulla WWTP	NSW	Wastewater	Sewage
EarthPower	NSW	Food waste and grease trap	Biowaste
Eastern Treatment Plant	VIC	Sewage solids	Sewage
Elanora STP	QLD	Sewage sludge	Sewage
Glenelg Wastewater Treatment Plant	SA	Sewage sludge, liquid industrial waste	Sewage
Glenfield WWTP	NSW	Wastewater	Sewage
Liverpool WWTP	NSW	Wastewater	Sewage
Luggage Point WWTP	QLD	Wastewater	Sewage
Malabar WWTP	NSW	Wastewater	Sewage
Mars Food Australia Berkeley Vale	NSW	Food processing waste water	Industrial
Mooroopna Wastewater Management Facility	VIC	Screened raw municipal wastewater	Sewage
North Head WWTP	NSW	Wastewater	Sewag–e
NPEC-Hi BOD	SA	Winery residuals processing	Industri–l
NPEC-Lo BOD	SA	Winery and distillery waste water	Industrial
Oakey Beef Exports Pty Ltd Biogas Plant	QLD	Meat processing waste	Industrial

Name	State/Territory	Feedstock	Category
Oxley Creek WWTP	QLD	Wastewater	Sewage
Quant – m Power – AJ Bush beaudesert	QLD	Process water from rendering plant	Industrial
Quant – m Power – NSW Food Processing 1	NSW	Process water from red meat abattoir	Industrial
Quant – m Power – NSW Piggery 1	NSW	Pig manure	Agriculture
Quant – m Power – NSW Piggery 2	NSW	Pig manure	Agriculture
Quant – m Power – Qld Piggery 1	QLD	Pig manure	Agriculture
Quant – m Power – Qld Piggery 2	QLD	Pig manure	Agriculture
Quant – m Power – Qld Piggery 3	QLD	Pig manure	Agriculture
Quant – m Power – Qld Poultry 1	QLD	Chicken manure & spent hens	Agriculture
Quant – m Power – Vic Food Processing 1	VIC	Process water from dairy factory	Industrial
ReWaste	VIC	Commercial and industrial waste streams from food manufacturing, processing and retailing	Biowaste
Rivale Bungowannah 5 biogas project	NSW	Piggery manure	Agriculture
Rivale Corowa module 5 biogas project	NSW	Piggery manure	Agriculture
Rivalea Biogas	NSW	Piggery waste	Agriculture
Rivalea Corowa Module 5	NSW	Piggery manure	Agriculture
Shellharbour WWTP	NSW	Wastewater	Sewage
Shepparton Wastewater Management Facility	VIC	Municipal wastewater (high concentration of industrial waste from food processing)	Sewage
Tatura Wastewater Management Facility	VIC	Raw municipal sewage	Sewage
Thomas Foods International Murray bridge	SA	Abattoir effluent	Industrial
Treasury Wine Estates	VIC	Winery waste water	Industrial
Warriewood WWTP	NSW	Wastewater	Sewage
Warrnambool Cheese & Butter	VIC	Dairy manufacture waste	Industrial
Werribee Western Treatment Plant	VIC	Sewage solids	Sewage
West Camden WWTP	NSW	Wastewater	Sewage
Wollongong WWTP	NSW	Wastewater	Sewage

Source: (AREMI, n.d.)

Appendix E: Modelling inputs and assumptions

The following assumptions were made in our modelling. They are based on best available information and rely on aggregating datasets from other organisations, including the Australian Energy Market Operator (AEMO), International Energy Agency (IEA), National Renewable Energy Lab (NREL), Commonwealth Scientific and Industrial Research Organisation (CSIRO) and Climate Change Authority (CCA).

E.1 Gas demand in the distribution networks

Gas demand has been collected from distribution networks and collated into states. The source for the demand is ENA gas data and supplemented from network access agreements.

Table E.1: Gas demand by state

State	Unit	Consumption	Share (%)
Victoria	PJ	181	50
NSW	PJ	85	23
QLD	PJ	26	7
SA	PJ	32	9
WA	PJ	27	7
TAS	PJ	3	1
ACT	PJ	10	3
Total demand	PJ	363	100

Source: ENA gas data, Deloitte Access Economics Analysis

E.2 Renewable energy generator assumptions and inputs

The assumptions around renewable energy generators affect the results from electrolysis and decarbonised electricity scenarios. The main assumption used in the modelling is a variable energy generator, wind and solar, is used to generate renewable energy. The implications of this assumption is reduced electricity cost and low capacity factor.

Table E.2: Solar inputs

Input	Unit	Assumption (2016)	Assumption (2050)
Winter Capacity Factor	%	25	
Summer Capacity Factor	%	34	
Yearly Capacity Factor	%	31	
Capital cost	$/kW	$2,300	$1,376
Annual Capital Cost decline	%	2	
Life of Plant	Years	25	

Source: AEMO Solar trace, AEMO Jacobs forecasting

Table E.3: Wind inputs

Input	Unit	Assumption (2016)	Assumption (2050)
Yearly Capacity Factor	%	35	
Capital cost	$/kW	$2,500	$1,495
Annual Capital Cost decline	%	2	
Life of Plant	Years	25	

Source: AEMO CO_2 CRC

E.3 Electrolyser

The electrolyser is assumed to run only from renewable energy, and is therefore limited by the capacity factor of the renewable generator. Wind has the highest capacity factor of current renewable generators and is used as the electrolysers "best case" capacity factor. This assumption can change with co-location of wind and solar, or dispatchable higher capacity factor renewable generator, or a 100% renewable energy grid. Although as capacity factor increases there is an assumption that the electricity cost per MWh would increase to pay for the extra capacity, newer technology or network costs respectively.

Table E.4: Electrolyser inputs

Input	Unit	Assumption (2016)	Assumption (2050)
Efficiency	%	72	88
Capacity factor	%	35	35
Water requirement	L/kg of H_2	13	13
Life of Plant	Years	25	
Capital cost	$/kW	$2,288	$418
Fixed O&M	% of capital cost	5	5
Cost of electricity (LCOE of renewable generator wind)	$/kWh	0.10	0.07

Source: CSIRO, IEA and Deloitte Access Economics Analysis

E.4 Steam Methane Reforming

Steam methane reforming is assumed to improve over time with increased production. There is an assumed increase in efficiency and decrease in capital costs over time. The capacity factor is assumed from building capacity to meet winter demand and then utilising this capital to produce average annual production. The electricity input for SMR is assumed to be $0.18/kWh. This cost is built from a large electricity user with network costs and GreenPower premium included, it however neglects fixed and capacity charges and is not escalated over the analysis period.

Table E.5: Steam Methane inputs

Input	Unit	Assumption (2016)	Assumption (2050)
Efficiency	%	70	77
Water requirement	L/kg of H_2	12.7	12.7
Capacity factor	%	56	56
Life of Plant	Years	40	
Capital cost	$/daily kg H_2	$2,511	$926
Fixed O&M	% of capital cost	2	2
Electricity use	kWh/kg H_2	1.11	1.11
Cost of electricity (LCOE of renewable generator wind)	$/kWh	0.18	0.18
Cost of Natural Gas	$/GJ	7.12	8.37

Source: IEA, NREL and Deloitte Access Economics

E.5 Coal Gasification

The capacity factor results from the assumption that capacity must meet winter demand, and using this capital investment to produce average annual production. The electricity input for coal gasification is assumed to be $0.18/kWh. This cost is built from a large electricity user with network costs and GreenPower premium included, it however neglects fixed and capacity charges and is not escalated over the analysis period.

Table E.6: Coal Gasification inputs

Input	Unit	Assumption (2016)	Assumption (2050)
Efficiency	%	56	60
Water requirement	L/kg of H_2	11.2	11.2
Capacity factor	%	56	56
Life of Plant	Years	40	
Capital cost	$/daily kg H_2	$3,061	$2,158
Fixed O&M	% of capital cost	2	2
Electricity use	kWh/kg H_2	1.72	1.72
Cost of electricity (LCOE of renewable generator wind)	$/kWh	0.18	0.18
Cost of Black coal	$/kg	0.053	0.085
Cost of Brown coal	$/kg	0.007	0.009

Source: IEA, NREL and Deloitte Access Economics

E.6 Emissions

Emission factors are those from Nation Greenhouse Accounts (2016). They are the equivalent CO_2 emissions per unit of fossil fuel. A carbon capture and storage cost is assumed to be $30/tonne.

Table E.7: Emissions

Input	Unit	Scope	Assumption
Natural Gas	kg-CO_2e/GJ	1	51.3
		3	12.8
Bituminous Coal	kg-CO_2e/GJ	1	90
		3	3
Brown Coal	kg-CO_2e/GJ	1	93.50
		3	0.40

Source: National Greenhouse Accounts Factors 2016

Table E.8: Carbon capture and storage cost

Input	Unit	Assumption
CCS	$/tonne	30

Source: CarbonNet

E.7 WDecarbonised Electricity

A decarbonised electricity grid will require renewable energy sufficient to meet the gas demand added to the electricity grid. Additional network build will be required to meet gas peak demand as it exceeds forecast peak demand.

Table E.9: Decarbonised electricity

Input	Unit	Assumption
Yearly gas demand	PJ	419
Yearly gas demand on electricity network	TWh	116
Marginal loss factor	%	10
Capacity factor of renewable generation	%	35
Capital cost of wind	$/kW	$1,495
Change in forecast peak demand aggregated for all states	MW	21,848
Cost of building new network	$/MW	$1.5million

Source: Deloitte Access Economics analysis

Footnotes

1. (ENA, 2017)
2. (ENA, 2017)
3. (Shell, 2016)
4. For example, the national Emissions Reduction Fund and Safeguard Mechanism, the Renewable Energy Target, the National Energy Productivity Plan, and support for investment in low emissions energy via bodies such as the Australian Renewable Energy Agency (ARENA) and the Clean Energy Finance Corporation (CEFC). A range of renewable energy and emissions reduction targets also apply at state level, such as Victoria's 2050 net zero emissions target.
5. (Australian Government, 2017)
6. (Finkel, Moses, Munro, Effeney, & O'Kane, June 2017)
7. (Finkel, Moses, Munro, Effeney, & O'Kane, June 2017)
8. (Australian Energy Regulator, 2017)
9. (ENA, 2017)
10. (US Department of Energy, 2014)
11. (Energy Networks Australia, 2017)
12. (Northern Gas Networks, July 2016, p. 24)
13. (Department of Economic Development, Jobs, Transport and Resources, 2016)
14. (National Energy Technology Laboratory, n.d)
15. (IEA, 2015); (United States Office of Energy Efficiency & Renewable Energy (EERE), n.d (b)); and (NEL Hydrogen, 2014)
16. (IEA, 2015); (United States Office of Energy Efficiency & Renewable Energy (EERE), n.d (b))
17. (IEA, 2015); (United States Office of Energy Efficiency & Renewable Energy (EERE), n.d (b))
18. (Note: AEMO metered demand of wind and solar generation in the National Electricity Market, of 11,180GWh and 492 GWh respectively. Plus 3,500 GWh of estimated smaller non-scheduled renewables that are not included in the metered demand data. (Green Energy Markets, 2017)
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21. (Meng, Gu, Zhang, Zhou, & Zhao, n.d)
22. (Northern Gas Networks, July 2016)
23. (Energy Pipelines CRC, 2017)
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27. (Government of South Australia, 2017)
28. (Rigas & Amyotte, 2012, p. 100)
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31. (Australian Government, 2017)
32. Australian Greenhouse Emissions Information System, 2016
33. (Clean Energy Council, 2016)
34. (Australian Government, 2016)
35. Note: Bagasse is the fibrous residue that is left over after the extraction of juice from sugarcane
36. AREMI, 2017, biogas facilities, University of Queensland data
37. (Clean Energy Finance Corporation, 2015)
38. Note: Bagasse is the fibrous residue that is left over after the extraction of juice from sugarcane
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40. (Beca Consulting, 2015)
41. (Australian Energy Regulator, 2017)
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57. (Australian Government, 2017)
58. Department of Economic Development, 2015
59. Population from (ABS, 2017)
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62. (Global CCS Institute, n.d.)
63. (Department of Economic Development, Jobs, Transport and Resources, 2016)
64. (Carbon Storage Taskforce, 2009)
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70. Innovation, 2007
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73. (Blakers, Bin, & Matthew, 2017)
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120. Taken (and in some cases adapted) from assorted reports including: (CSIRO, 2017); (EPRI, 2015); (Greig, Bongers, Stott, & Byrom, 2016); (Global Carbon Capture and Storage Institute, 2017)

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Contact us

Deloitte Access Economics
ACN: 149 633 116
8 Brindabella Circuit
Brindabella Business Park
Canberra Airport ACT 2609
Tel: +61 2 6263 7000
Fax: +61 2 6263 7004

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