Green Gas Trading

a tool for a zero emissions ACT

ACT Government

Report for the ACT Environment, Planning and Sustainable Development Directorate

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ABOUT ITP

The ITP Energised Group, formed in 1981, is a specialist renewable energy, energy efficiency and carbon markets consulting company. The group has offices and projects throughout the world.

IT Power (Australia) was established in 2003 and has undertaken a wide range of projects, including designing grid-connected renewable power systems, providing advice for government policy, feasibility studies for large, off-grid power systems, developing micro-finance models for community-owned power systems in developing countries and modelling large-scale power systems for industrial use.

ITP Thermal Pty Ltd was established in early 2016 as a new company within the ITP Energised group, with a mandate to lead thermal projects globally. In doing so it accesses staff and resources in the other ITP Energised group companies as appropriate.

ABOUT THIS REPORT

This report was commissioned by the ACT Environment, Planning and Sustainable Development Directorate. It provides an analysis and review of Green Gas trading mechanisms and their applicability in the ACT.

ABBREVIATIONS

ACCU	Australian Carbon Credit Unit
ACT	Australian Capital Territory
AEMC	Australian Energy Market Commission
AGIG	Australian Gas Infrastructure Group
ANU	Australian National University
ARENA	Australian Renewable Energy Agency
ASX	Australian Securities Exchange
AUD	Australian Dollar
CEFC	Clean Energy Finance Corporation
CER	Clean Energy Regulator
CH4	Methane
CHP	Combined Heat and Power
CIE	Centre for International Economics
CNG	Compressed Natural Gas
CO	Carbon monoxide
COAG	Council of Australian Governments
COP	Coefficient of Performance
CSIRO	Commonwealth Scientific and Industrial Research
CTS	Custody Transfer Station
C&D	Construction and Demolition
C&I	Commercial and Industrial
DNSP	Distribution Network Service Provider
EECS	European Energy Certificate System
ENA	Energy Networks Australia
ERF	Emissions Reduction Fund
EU	European Union
EV	Electric Vehicle
FCEV	Fuel Cell Electric Vehicle
FDP	Fossil Depletion Potential
GGCS	Green Gas Certification Scheme
GHG	Greenhouse Gas
GO	Guarantee of Origin
GJ	Gigajoule, unit of energy. 1 GJ = 1,000,000,000 J

GWP	Global Warming Potential
ITP	ITP Thermal Pty Ltd
kPa	Kilopascal, unit of pressure. 1 kPa = 1,000 Pa
MW	Megawatt, unit of power. 1 MW = 1,000,000 W
MWh	Megawatt-hour, unit of power (1 MW generated/used for 1 hour)
LBM	Liquefied Biomethane
LCA	Life Cycle Assessment
LGC	Large-scale Generation Certificate
LMWQCC	Lower Molonglo Water Quality Control Centre
LNG	Liquefied Natural Gas
LULUCF	Land Use, Land-Use Change, and Forestry
Ml	Megalitre, unit of volume. 1 Ml = 1,000,000 l
MRF	Material Recovery Facility
NABERS	National Australian Built Environment Rating System
NCOS	National Carbon Offset Standard
NEM	National Electricity Market
NGER	National Greenhouse and Energy Reporting
NGL	National Gas Law
NPI	National Pollutant Inventory
NSW	New South Wales
NT	Northern Territory
PJ	Petajoule, unit of energy. 1 PJ = 1,000,000 GJ
PPA	Power Purchase Agreement
PV	Photovoltaic
RGGO	Renewable Gas Guarantee of Origin
RET	Renewable Energy Target
RFS	Renewable Fuel Standard
SA	South Australia
SMR	Steam Methane Reforming
TJ	Terajoule, unit of energy. 1 TJ = 1,000 GJ
TRS	Trunk Receiving Station
UAFG	Unaccounted for Gas
WA	Western Australia
WGS	Water Gas Shift
WWTP	Wastewater Treatment Plant

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EXECUTIVE SUMMARY

The Australian Capital Territory has reached its legislated target for 100% net renewable electricity, reducing the ACT's emissions by 40% from 1990 levels. Natural gas demand of 7.1 petajoules (PJ) in 2018-19 represents 20% of the total energy demand in the ACT. It is presently responsible for 21% of the total greenhouse gas emissions.

To continue the transition towards the ACT's target of 100% net zero emissions by 2045, natural gas can be replaced by Green Gas, a zero emissions gaseous combustible fuel alternative.

This report was commissioned by the ACT Environment, Planning and Sustainable Development Directorate to develop an understanding of the potential market mechanisms for the trading of Green Gas and applicability to the ACT.

The following types of Green Gas are most relevant for ACT consideration:

- Biogas, a mixture of gases primarily consisting of methane and carbon dioxide. It is produced from anaerobic digestion of organic material.
- Biomethane, consisting of biogas upgraded to a quality similar to fossil natural gas.
- Green hydrogen, consisting of hydrogen gas, typically produced by the electrolysis of water).

Potential for ACT Green Gas Supply

The potential yearly production of biogas within the ACT is estimated as 0.74 PJ from landfill gas, food and garden waste (currently sent to landfill) and sewerage solids, representing 10% of the natural gas demand in the ACT. If the garden waste currently composted was also converted into biogas, the biogas yearly potential would increase to 1.98 PJ, or 28% of the total ACT natural gas use.

The production of green hydrogen at scale would require the installation of large renewable power generation facilities in high renewable resource areas that would likely be outside the ACT's borders. The electricity generated could then be transmitted to the ACT for the local production of hydrogen if existing transmission lines have capacity. Alternatively, hydrogen

could be produced in the proximity of the renewable power generators and injected into the local natural gas grid or transported to the ACT via purpose-built gas transmission pipelines.

The injection of up to 10% hydrogen into the existing natural gas distribution network is expected to require zero to minimal modifications to the distribution system. The required green hydrogen could be produced with the electricity from a 31 MW wind farm. On the other hand, the complete substitution of all natural gas demand in the ACT with green hydrogen would require the installation of a 1043 MW wind farm, around seven times larger than the Capital Wind Farm near Lake George.

Potential Market Demand for Green Gas

Some level of voluntary demand for Green Gas can be expected even in the absence of mandatory measures to either establish demand for renewable gas or disincentivise the use of natural gas. Early adopters will be most likely to willingly pay a premium on existing energy costs. The experience with the voluntary uptake of GreenPower electricity prior to the mandatory Renewable Energy Target (RET) indicated early movers accepted a 5-10% cost premium for green power.

The largest gas user in the ACT is the ACT Government, principally for its buildings and bus fleet. The ACT Government could play a role in establishing some significant market pull by contracting green gas. The ANU is the second largest user and may also be willing to consider the possibility of contracting for green gas as part of its retail contract.

With reasonable steps to certify and promote Green Gas, near term voluntary demand for Green Gas is expected to comprise of existing landfill gas use of 315 terajoules (TJ)/year, new voluntary demand for lower cost green gas of 70 – 140 TJ/year and demand for hydrogen fuel cell vehicles of around 2.2 TJ/year. However, this is subject to uncertainty and strongly dependant on the various actions of the ACT Government.

To achieve net zero emissions by 2045, all current natural gas and petroleum fuel use (transport sector) must be replaced. This transition will see a competition between Green Gas-based and renewable electrification-based solutions. Green Gas presents some advantages in being better able to match seasonal and daily peaks in demand, presenting opportunities of combined heat and power generation, offering a valid alternative to electric vehicles, and being a natural product of the waste treatment sector.

Based on these considerations, the Green Gas demand by 2045 is approximately estimated to be between 30% and 60% of natural gas demand (2100 – 4200 TJ/year), and between 10% and 50% of the existing transport market (1700 – 8500 TJ/year).

Policy and Industry Advocacy in Australia

There is significant interest and focus on the hydrogen agenda by State Governments and at the national level. This is driving a vast body of work (pilot projects, legal assessment, approach to incentives/market mechanisms, certification etc) that could be leveraged to inform broader considerations for Green Gas. Gas infrastructure owners also have long term interests in their assets, are undertaking pilot projects and are advocating for supportive

policy. In addition, ARENA has already been active in funding projects in the renewable gas sector, both in biomethane and in hydrogen. It is currently conducting a bioenergy roadmap study which is considering mechanisms to support the development of the bioenergy sector and a certificate system for biogas is under active consultation.

The national Clean Energy Regulator (CER), as the administrator of carbon market mechanisms and schemes for measurement of emissions under Federal legislation, appears keen to assist in pilot verification of the production of biomethane for injection into gas pipelines and certification. However, it is currently prevented from performing this role until changes to federal legislation governing its mandate are made.

The NSW Government is active in coordinating a Green Gas pilot demonstration project in NSW that will likely involve private certification of gas purchases in the first instance. The NSW Government has indicated the existing GreenPower voluntary scheme that is available nationally to accredit green electricity suppliers could be adapted to accredit Green Gas suppliers.

Green Gas Certification

In the broadest sense, certification involves creating a paper or electronic certificate for each unit of energy (electricity or gas) to guarantee the origin, assuring buyers that the source is genuine, the environment benefits are real, and the gas has not been sold to someone else.

Private certification approaches can help to apply rigor to guarantee of origin and may have a place in the establishment of pilot projects. However, where justified by the size of the market, certification by a central authority tends to increase market confidence and trust in the environmental/emissions credentials of the energy.

Options for Facilitating Green Gas Uptake

There are several potential incentive mechanisms for Green Gas trading available for consideration. International experience suggests that six main models of policies and laws to create economic incentives for injection of Green Gas are currently in use:

- feed-in tariffs for Green Gas
- market obligation mechanism for Green Gas (similar to the RET)
- grid injection priority (i.e. guaranteed priority of access to gas networks for renewable gas meeting quality standards)
- grants for construction of facilities
- tax or regulatory exemptions for construction of facilities
- emissions caps / carbon pricing.

There are a range of examples of successful incentives for Green Gas overseas. These are in Europe, where Germany and the UK are notable, and in North America, where California and British Columbia are notable.

A staged approach to renewable gas certificates administered at the national level could involve:

1. the creation of a guarantee of origin certificate scheme, which would initially support a voluntary Green Gas scheme, like Green Power
2. the creation of a market obligation mechanism similar to the Renewable Energy Target (RET) but involving tradeable renewable gas certificates.

The advantage of this approach is that it involves the adaptation and amendment of the existing model of renewable electricity incentive legislation.

Conclusions and Recommendations

The ACT's legislated target of net zero greenhouse gas emissions by 2045 implies that there needs to be close to zero use of natural gas or petroleum-based transport fuels by that time. Green Gas has strong technical potential for contributing to this zero emissions outcome.

The ACT Government has many options to choose between on how it moves forward. As one of the biggest natural gas users itself, it could use its own procurement to create some market pull for network injected Green Gas.

It is recommended that the ACT:

1. Consider the introduction of a target for renewable energy gas supply in the ACT under the Climate Change and Greenhouse Gas Emission Reduction Act 2010. A target of 10% from 2025 for both the gas sector and 10% for the transport sector from 2025 could be appropriate.
2. Investigate potential sources of low cost Green Gas from local and interstate sources and consider becoming a first mover in the procurement of Green Gas via competitive processes.
3. Consider mandating the replacement of unaccounted for gas in the network with Green Gas as a short term measure.
4. Move to treat all ACT waste in an international best practice manner that maximises the contribution of Green Gas that it produces.
5. Work to establish mandatory mechanisms that progress the reduction over time in GHG emissions to zero in 2045 in a manner that does not unnecessarily disadvantage Green Gas uptake or lead to higher than necessary costs for ACT citizens.

It is also recommended that the ACT Government continue to work with NSW and the Federal Government to ensure that a national approach to Green Gas verification and certification emerges in the near future.

The ACT Government has indicated an interest in considering broader life cycle assessment (LCA) emissions associated with Green Gas production and use. This is a complex area that warrants further analysis.

1 INTRODUCTION

1.1 Purpose

The ACT Government has a far-reaching plan for renewable energy and has an internationally leading reputation for progressive new policy, programs and initiatives for encouraging uptake leading to associated industry development. All ACT electricity is supplied from renewable sources from 2020, largely due to the success of the large-scale reverse auctions.

Renewable gas can provide a path to decarbonisation beyond renewable electricity. Australia's emerging renewable gas sector presents many economic opportunities, many of which are currently under exploited. The *Finkel Review* identified fuel switching to low-emissions (green) gas as one option that could bring a large volume of emissions reductions[1]. Specifically, biogas and (renewable) hydrogen were identified as low-emissions gas. Given the success with renewable electricity, there is now the opportunity for the ACT to influence the development of an equivalent framework to kick-start the growth of the renewable gas industry leading to similarly catalytic outcomes for emissions reductions and industry development.

This study for the ACT Government is an important step in developing an understanding of the potential market mechanisms for the trading of Green Gas and builds on the concept flagged in the *ACT Sustainable Energy Policy 2020-2025 Discussion Paper* for a potential target for renewable gas consumption in the ACT. It has been completed at a time when there is a significant number of relevant developments on Green Gas at state, federal and international level.

Action 4.5 in the *ACT Climate Change Strategy 2019 – 2025* requires the development of a plan for achieving zero emissions for gas use by 2045. The information provided in this analysis should assist the ACT Government in considering zero emissions natural gas alternatives when developing its plan.

Concurrently to this study, the ACT Government has commissioned a number of other studies to inform the potential future development of the ACT gas sector.[2] These studies are to consider the long term frameworks for hydrogen supply and use in the ACT, providing a strong indication that the ACT is interested in the development of a renewable gas industry which has the potential to have a major impact on the ACT Government's goal of reaching zero net emissions by 2045.

[1] (Finkel, 2017), Independent Review into the Future Security of the National Electricity Market

[2] The review of ACT legal frameworks to determine the applicability to support hydrogen safety, hydrogen supply chain development and impacts on consumers and the community, the review of national and jurisdictional laws in relation to gas including safety of hydrogen use, an assessment of the current state of ACT electricity and gas networks, and advice to support building community knowledge and engagement for hydrogen.

1.2 Green Gas

Green Gas is gaseous combustible fuel alternatives to natural gas from sources that generate net zero emissions. The following types of Green Gas are most relevant to the ACT:

- Biogas, a mixture of gases primarily consisting of methane and carbon dioxide. It is produced from anaerobic digestion of organic material. It can be made from a variety of organic resources, including industrial waste, food waste, agricultural waste, energy crops, sludge from wastewater treatment and biowaste.
- Biomethane, consisting of biogas upgraded to a quality similar to fossil natural gas, to allow its injection in the natural gas network. The upgrading procedure involves separating the methane from carbon dioxide, water and other gaseous contaminants typically present in raw biogas.
- Green hydrogen, consisting of hydrogen gas, typically produced by the electrolysis of water powered with renewable electric power.

In this report, 'hydrogen' is used to indicate 'green hydrogen'.

While the combustion of biogas or biomethane, like natural gas, produces carbon dioxide, a greenhouse gas, the carbon in biogas comes from plant matter that fixed this carbon from atmospheric carbon dioxide. Therefore, biogas production is carbon-neutral and it provides a valid green alternative to natural gas.

Other potential Green Gases more applicable to specific applications encountered elsewhere include renewable ammonia and renewably produced 'syngas' (or synthesis gas, consisting in a mixture of carbon monoxide (CO) and hydrogen).

One possible approach to Green Gas trading through the gas network is shown in Figure 1.

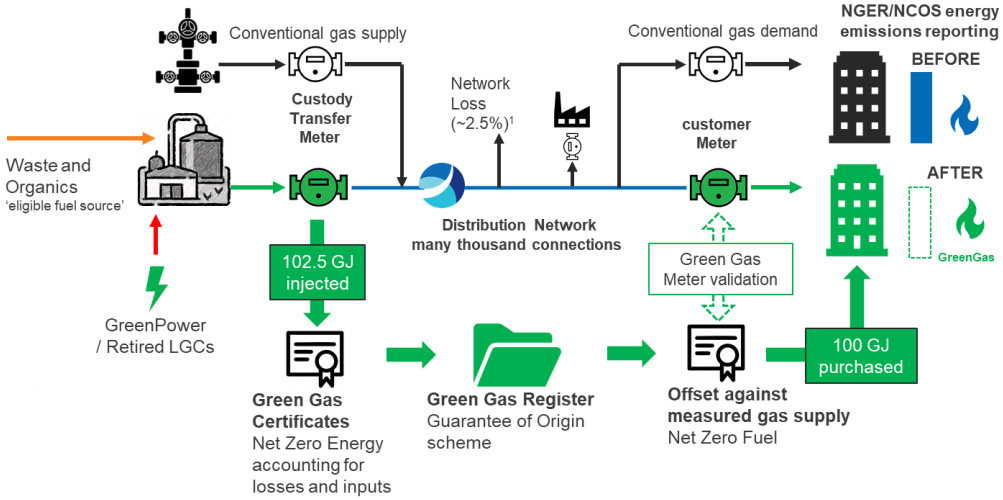

Figure 1: Possible approach to Green Gas trading through gas networks (Source: Jemena).

It suggests a method of certification of the veracity of zero emissions claims and the amount produced, transfer through an existing gas network and operation of a register to track origin. Any validated Green Gas is then offset against the customer's conventional gas

consumption in view of any reporting obligations under the National Greenhouse and Energy Reporting (NGER) or National Carbon Offset Standard (NCOS) frameworks.

1.3 Methodology

ITP Thermal (ITP) was engaged by the ACT Environment, Planning and Sustainable Development Directorate (EPSDD) to analyse and review Green Gas trading mechanisms and their applicability in the ACT. For this study, ITP worked with legal expert Dr James Prest of the ANU College of Law and ANU Energy Change Institute.

To compile this report, ITP consulted a wide range of relevant stakeholders (listed in Appendix A) and analysed information from a range of government and industry sources.

1.4 Report outline

The remainder of this report has the following chapters:

2. **Background and context** on the ACT emissions reductions history and ambitions, technologies to produce Green Gas and sectors that will utilise Green Gas.
3. **Profile of ACT Gas demand**. This outlines current and forecast gas demand in the ACT and seasonal variability in demand.
4. **Potential Green Gas supply**. This discusses resources needed to produce Green Gas, the potential to supply Green Gas in the ACT and Australia, security of supply and risk aspects.
5. **Potential market demand for Green Gas**. This provides a qualitative discussion of the potential demand for Green Gas in the ACT and Australia.
6. **Policy and industry advocacy in Australia**. This provides a high-level review of policy related developments at Federal and State level, and industry advocacy on policy.
7. **Green Gas Certification**. This chapter discusses the options for certification of gas as green and processes for verification of zero emissions claims with reference to national and international best practices and case studies around the world.
8. **Options for facilitating Green Gas uptake**. This canvasses possible incentive mechanisms, policy options, overseas case studies and options for ACT.
9. **Conclusions and recommendations**. This chapter provides the conclusions of this report and recommended actions for the ACT Government to consider.

2 BACKGROUND AND CONTEXT

2.1 ACT Context

Under the ACT Government's large-scale reverse auction feed-in program, the ACT has contracted sufficient capacity from a number of renewable electricity projects to offset forecast annual electricity consumption and meet the 100% net renewable electricity target from 2020. The achievement of this 100% renewable electricity target has enabled the ACT to achieve the first of its staged emission reduction targets, to reduce greenhouse emissions by 40% from 1990 levels by 2020.

The ACT has legislated under the *Climate Change and Greenhouse Gas Reduction Act 2010* to reduce greenhouse gas emissions. In 2018 the ACT Government set new interim emissions reduction targets with the issue of the *Climate Change and Greenhouse Gas Reduction (Interim Targets) Determination 2018*.

The ACT's targets are to reduce greenhouse gas emissions (from 1990 levels) by:

- 40% by 2020
- 50 to 60% by 2025
- 65 to 75% by 2030
- 90 to 95% by 2040 and
- 100% (net zero emissions) by 2045.

These targets align with the emission reductions needed to implement the *Paris Agreement*, and are some of the most ambitious targets in both Australia and the world.

The *Climate Change and Greenhouse Gas Reduction Act 2010* also set the target of 100% net renewable electricity supply from 2020, reached in 2019, enabling the ACT to achieve their first emissions reduction target of 40% by 2020. Current estimates suggest that from 2020 over 20 per cent of ACT greenhouse gas emissions will come from natural gas use.

The *ACT Climate Change Strategy 2019-25* identifies gas as one of the two priority sectors for reducing emissions from 2020, once emissions from electricity are zero[3].

The successful transition to 100% net renewable electricity was achieved by awarding Contracts for Difference (CfD) following reverse auctions for wind farms to feed electricity into the National Electricity Market (NEM) grid to match Canberra consumption. The sites, in New South Wales, Victoria and South Australia, are shown in Figure 2. This contractual mechanism is based on the exchange of Large-scale Generation Certificates (LGCs), which are created by the renewable generators, transferred to the ACT, and are then voluntarily surrendered to the Clean Energy Regulator (CER).

[3] (ACT Government, 2019), ACT Climate Change Strategy 2019-25.

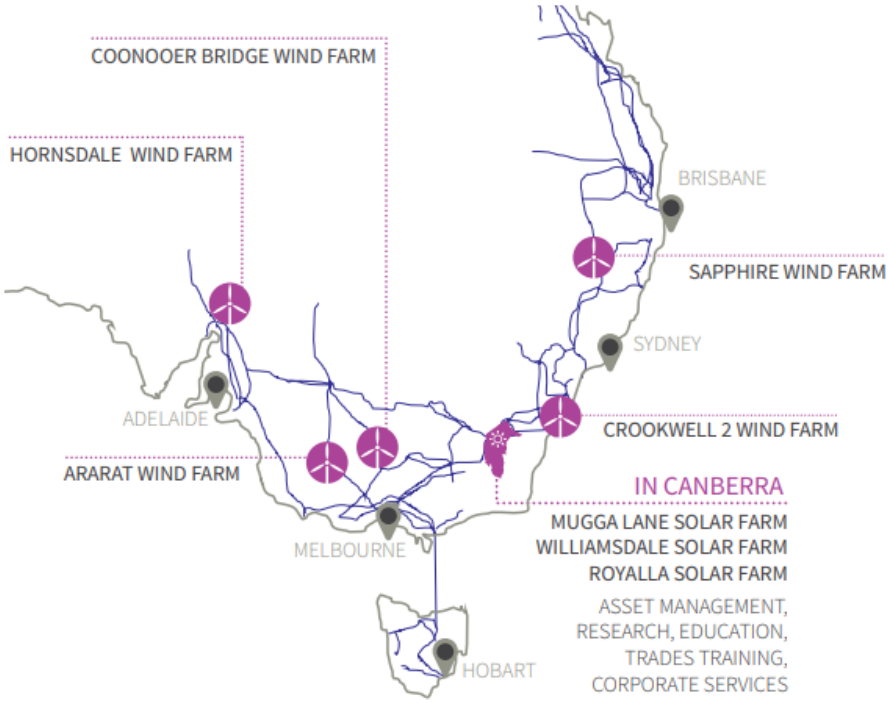

Figure 2: Location of Canberra's wind and solar farms within the NEM (Source: ACT Government).

Until recently, the electricity sector was the largest contributor to the ACT's greenhouse gas (GHG) emissions, accounting for more than 40% the total emissions in 2017-2018.[4]

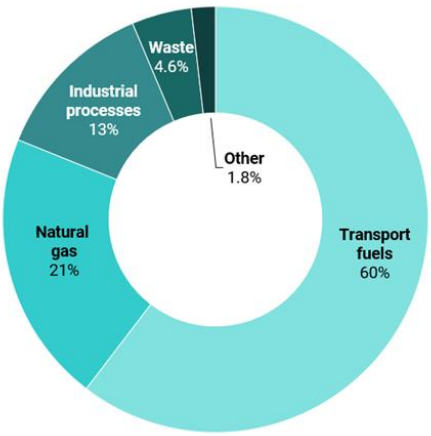

Figure 3: ACT 2018-19 greenhouse emissions shares by source, excluding electricty and LULUCF[5], (Strategy. Policy. Research., 2019).

Given that with the achievement of the 100% renewable electricity target these emissions are expected to be zero, other GHG sources now need to be addressed to further reduce emissions in the ACT.

[4] (Saddler, 2018), ACT Greenhouse Gas Inventory for 2017-2018.
[5] The emissions related to Land Use, Land-Use Change and Forestry (LULUCF) were excluded from the graph as they were negative in 2018-2019

In 2020, around 21% of the ACT's total carbon emissions is estimated to come from natural gas, making it the second biggest source after transport emissions. Figure 3 shows the breakdown by source of the ACT greenhouse emissions for 2019-2020 if considering the emissions from electricity to be zero and if maintaining the same 2018-2019 values for the other sources.

It is important to note that policy options for the ACT are impacted by the national context of law and policy making for energy. Some of the barriers to development of Green Gas arise from national laws. For example, the ring-fencing arrangements in National competition law that restrict the ability of gas distribution companies to produce or sell renewable gas are administered and enforced by the Australian Energy Regulator and made by the Australian Energy Market Commission AEMC and COAG Energy Council (and its successor).

2.2 Producing Green Gas

There are a range of Green Gas production technologies depending on the form of Green Gas to be produced and on the type of renewable resource used as input. In addition, technologies are available for the conversion of green hydrogen to methane and vice versa. Below is a summary of these technologies.

2.2.1 Electrolysis

Water electrolysis is the process of electrically dissociating the water molecule (H_2O) into its constituents, hydrogen and oxygen, by applying electrical power (as illustrated in Figure 4).

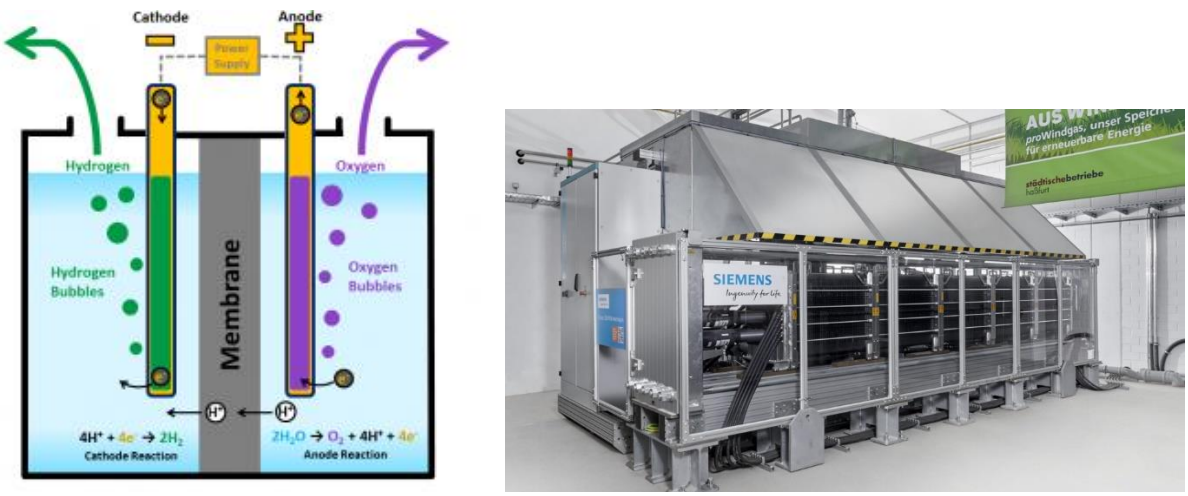

Figure 4: Left: example of the electrolysis process, reproduced from (Deloitte Access Economics, 2017)*. Right: 1.25 MW Siemens electrolyser.*

In its simplest form, electrolysis is achieved by applying an electrical current between two conductive electrodes (metal rods) immersed in water. Hydrogen forms at one electrode,

while oxygen will form at the other. The two gases can then be separately extracted and stored.

Hydrogen production via electrolysis requires water as one of the major inputs. For every one kg of hydrogen produced, nine litres of water are required.

Depending on the efficiency of the electrolyser, a certain amount of electrical energy will produce a fixed amount of hydrogen gas. Typically, around 54 kWh are required to produce one kg of hydrogen, while the theoretical minimum is 39.7 kWh.

If renewable electricity is used to drive the electrolyser, the hydrogen produced is considered to be ‘zero emissions’ and can be called ‘green hydrogen’.

2.2.2 Anaerobic digestion

Anaerobic digestion is the process in which microorganisms break down biodegradable material in the absence of oxygen and convert it into biogas. A large variety of organic resources can be used as feedstock, including industrial waste, agricultural waste, energy crops, sludge from wastewater treatment and urban organic waste.

This process is carried out in large covered vessels as illustrated in Figure 5. This example installed in Jandakot, WA, can process up to 50,000 tonnes of biowaste each year producing around 140 TJ of biogas and has an installed capacity of 2 MW electrical and 2.2 MW thermal[6]. These vessels typically have flexible membrane covers that allow the gas volume to rise and fall at a constant pressure.

Figure 5: Biogas plant installed in Jandakot, WA by Biogass Renewables.

In addition to energy production, anaerobic digestion also produces digestate – the material remaining after anaerobic digestion of biodegradable feedstocks. Digestate is a nutrient-rich

[6] (ARENA, 2019), Renewable energy options for industrial process heat.

material that can be used as a fertiliser and applied on agricultural land instead of chemical fertilisers.

The complete feedstock decomposition process is comprised of four different phases; hydrolysis, acidogenesis, acetogenesis, methanogenesis. These take place simultaneously with each phase facilitated by a specific type of microorganism.

Biogas can be directly used on-site to generate heat or electricity or both together in a combined heat and power (CHP) plant. Alternatively, it can be upgraded to biomethane for direct replacement of natural gas.

Whilst anaerobic digestion typically involves wet waste, there is a version of ‘’dry’’ anaerobic digestion that is suitable for material such as wood chips and prunings.

2.2.3 Gasification or Pyrolysis

Another approach available to produce renewable combustible gas is gasification or pyrolysis. This involves the heating of biomass feedstock at high temperatures ranging from 400 to 600°C with restricted supply of air either with or without the addition of steam. These conditions cause the separation of the biomass volatile organic components from the carbon-rich char. The product of such a process, synthesis gas (or syngas), is a mixture of carbon monoxide (CO), hydrogen (H_2), and other components such as methane (CH_4). The syngas can be combusted on site to generate heat and/or electricity, or it can be converted into hydrogen or biomethane in additional process stages.

2.2.4 Steam Methane Reforming

Steam methane reforming (SMR) is the process of converting methane into a gas primarily composed of hydrogen and carbon monoxide. The carbon monoxide component can then be separately processed in a Water Gas Shift (WGS) reactor, where it reacts with water to produce more hydrogen and carbon dioxide. Currently, these processes are the preferred technologies for the production of hydrogen for industrial purposes from natural gas (e.g. production of ammonia).

The same processes can be applied to the production of a high hydrogen content gas from biomethane or gasification products.

2.2.5 Methane cracking

An innovative technology to produce hydrogen from methane is the methane cracking process. It consists in separating the carbon (C) and hydrogen components of the methane molecule in a high temperature environment and in the presence of a catalyst. While this technology is not as commercially mature as SMR and WGS, it has two key advantages. Firstly, it avoids the production of carbon monoxide altogether, avoiding the requirement of additional equipment for the purification of the hydrogen produced. Secondly, the carbon is separated in the form of solid (graphite) instead of gas. As long as the solid carbon is never combusted, this is a genuinely zero GHG emissions process. If the methane used as

feedstock comes from renewable sources, this process can effectively provide ‘negative GHG emissions’.

2.2.6 Methanation

Methanation is the reaction by which carbon dioxide and hydrogen are converted to methane and water. If green hydrogen is used as feedstock, the methane produced is considered a zero-emission fuel and can be used as a direct substitute of natural gas in any application. However, it does also require a source of CO_2, which is likely to be produced from the combustion of another fuel. Methanation reactions can be applied directly to biogas mixtures that contain CO_2 as an advanced method of upgrading to biomethane.

2.2.7 Biogas upgrading

In order to use biogas in natural gas applications (e.g. injection in the natural gas distribution network or use as fuel in the transport sector), its composition needs to be such as to satisfy the quality requirements set in the Australian Standard 4564-2011 “Specification for General Purpose Natural Gas”. The upgraded biogas is referred to as biomethane.

Raw biogas does not satisfy these requirements when it is produced, due to the large proportion of undesired compounds. There are different technologies available for the separation of these components from the methane, selected case by case depending on the scale, capital costs, and operational costs of the different technologies. Figure 6 illustrates a membrane filtration method.

Figure 6: Biogas upgrading system, based on membrane technology. Reproduced from HZI BioMethan.

Regardless of the technology used, the upgrading of biogas involves the following processes:

- Removal of the carbon dioxide, that typically represents 30% to 50% of the volume in raw biogas;
- Removal of water vapour, that could otherwise condense in the natural gas infrastructure and cause corrosion problems;
- Removal of hydrogen sulphide (H_2S), that can give corrosion issues and that would generate pollutants if combusted; and

- Addition of odorants typically used in natural gas.

The resulting biomethane is a clean gas with a content of methane typically higher than 97%.

2.3 Pathways for the utilisation of Green Gas

In contemplating the uptake of Green Gas, the potential is not just a one for one replacement of existing natural gas use, but also an opportunity to contribute to the transport sector and provide demand management and dispatchable generation in the electricity sector.

At the same time, improved environmental outcomes for waste management can be expected. A conceptual circular economy based around Green Gas is illustrated in Figure 7.

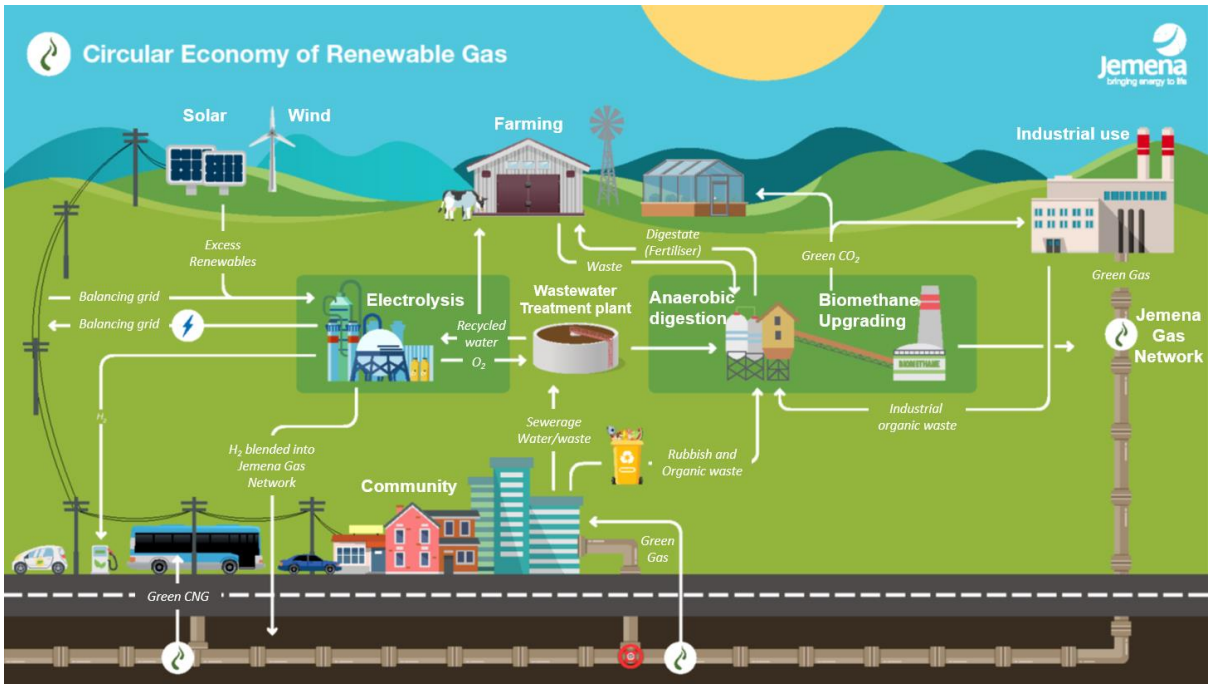

Figure 7: Circular integration of Green Gas and electricity sectors. Reproduced from Jemena.

The Green Gas industry can develop down a range of different pathways. These investment options and their attractiveness will depend on the type of Green Gas, the location of the proposed plant, the scale of the proposed facility and, for biogas specifically, on the feedstock source. Different project configurations will have different economic and regulatory requirements.

Green Gas development is user- and demand-specific. Table 1 lists a range of possible usage pathways specific to the different Green Gas types. For biogas, when there is no market demand, flaring is the only feasible option, as it can at least reduce the environmental and greenhouse impact of CH_4 emissions.[7] Next is the scenario when there is

[7] Methane has a global warming potential 25 times higher than carbon dioxide.

on-site or nearby demand for thermal or electrical energy. Green Gas can be combusted for thermal energy utilisation (e.g. in industries where process heat is needed) or electricity generation to be used locally or supplied to a nearby microgrid system. When the Green Gas quantity exceeds local demand and there is a potential market demand and regulations framework for the use of renewable gas, the Green Gas can be injected into the gas distribution network either as biomethane or hydrogen.

If pipeline injection is infeasible, there are alternatives. Green Gas can be used in vehicles fuelled at, or near, the Green Gas production facility. It can be sold to companies operating any compressed natural gas (CNG) or compressed hydrogen (CH_2) fuelling station. Or it can be trucked to the point of consumption, in cylinders traditionally used to haul compressed gases over long distances.

In the context of striving for zero emissions, Green Gas use should become more sophisticated than natural gas use has in the past. A key example of this is the potential for combined heat and power fuel cell systems that are already available in Europe. These can be sized for commercial buildings or even households and simultaneously provide space-heating and electricity generation at times when solar or wind electricity are not available.

In Europe, strategies in which electricity and gas sectors are deliberately more integrated and operate in order support each other are referred to as 'sector coupling' or 'power to gas'.[8] An explicit objective of the power-to-gas strategy is to capture the energy value of excess renewable electricity production which would otherwise be curtailed at times where supply exceeds demand (for example, late on a windy night). The energy value of this otherwise wasted electrical energy can be stored chemically as renewable gas (after electrolysis, for example) and in this way the gas network can be utilised as a giant battery or energy storage device.

Table 1: Green Gas use pathways – observations and considerations.

Green Gas use pathway	Observations and considerations
BIOGAS	
Flaring	Converts CH_4 to CO_2 and thereby reduces greenhouse gas emissions
Direct use in facility for heating	Viable for agricultural, wastewater treatment or food processing generation of biogas where facilities may benefit from heating
Direct use in facility for CHP (Combined Heat and Power)	Behind the meter, with no need to arrange a power purchase agreement (PPA) or feed-in tariff
Electricity generation for export	Produces renewable electricity (that may be eligible for renewable electricity incentives depending on location

[8] (Boudellal, 2018), Power to Gas: Renewable Hydrogen Economy for the Energy Transition.

	and commissioning date). CHP configuration possible, with direct use in facility of heat.
BIOMETHANE or HYDROGEN	
Utilisation as fuel for transport	If used in own company vehicles (e.g. waste management company that owns landfill), can reduce transport fuel expenses. Depends on the availability of alternative transport fuel incentives, and market development of EV and hydrogen alternatives, especially as applicable to heavy transport.
Injection into the gas network	Biomethane, when meeting pipeline gas quality specifications, can be supplied to the market in various forms, such as injection to gas distribution network. Hydrogen can also potentially be injected, although gas metering upgrades might be required for high concentrations of hydrogen. All natural gas end uses can be supplied including heat, power generation, CHP and for transport.
Utilisation in a regional microgrid	Raises various threshold questions of applicability of utility law and regulation. Also must consider the liability of gas distributor OR microgrid operator and compliance obligations of utilities.
HYDROGEN ONLY	
Hydrogen for electricity storage	Hydrogen can be generated using excess cheap renewable energy and then be compressed and stored in gas storage facilities. In case of low supply of renewable power, the stored hydrogen can then be converted back to electricity by means of fuel cells.

3 PROFILE OF ACT GAS DEMAND

This chapter describes the current trends in daily and seasonal fluctuations in gas demand and contribution to greenhouse gas emissions in the ACT. It also briefly considers likely future changes in these patterns.

3.1 Current Demand

According to the ACT Greenhouse Gas Inventory[9], in 2018-2019 the Territory's natural gas energy demand was 7.1 PJ[10], representing 20% of the total energy demand in the ACT. Separately, Evoenergy reports that total gas handled by the distribution network was 8.2 PJ[11]. This figure is larger because the Evoenergy network also provides gas to the greater Queanbeyan region in NSW.

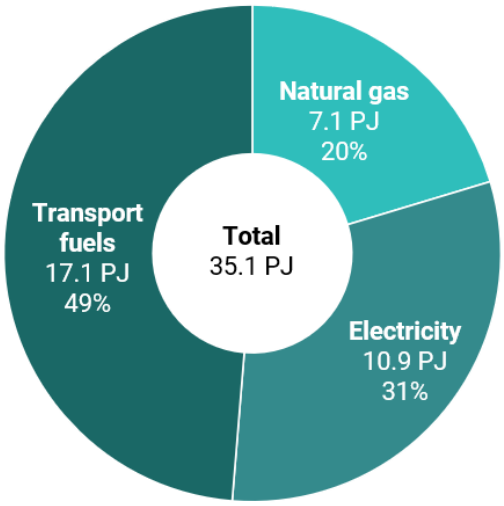

Figure 8: 2018-19 ACT energy demand by source. Data from ACT Greenhouse Gas Inventory 2018-19[9] .

Natural gas supplied to the ACT is produced interstate and transported over long distances in transmission pipelines. In particular, the Canberra region is connected to two upstream transmission pipelines:

- Dalton-Canberra lateral (branching off the Moomba to Sydney Pipeline), to the Watson Custody Transfer Station (CTS); and
- Hoskinstown-Fyshwick pipeline (branching off the Eastern Gas Pipeline), to the Fyshwick Trunk Receiving Station (TRS).

Downstream of the Watson and Fyshwick gateways, the network is subdivided into a hierarchy of distribution pipelines. These are shown in Figure 9 and are divided into:

- Primary network, operated at around 6000 kPa (purple lines)

[9] (Strategy. Policy. Research., 2019), ACT Greenhouse Gas Inventory 2018-19.
[10] PJ = petajoules, equal to 1,000 TJ or 1,000,000 GJ
[11] (Evoenergy, 2020), Evoenergy gas network 2021 draft plan.

- Secondary network, operated at around 1000 kPa (green lines)
- Reticulated network, operated at around 200 kPa (yellow lines).

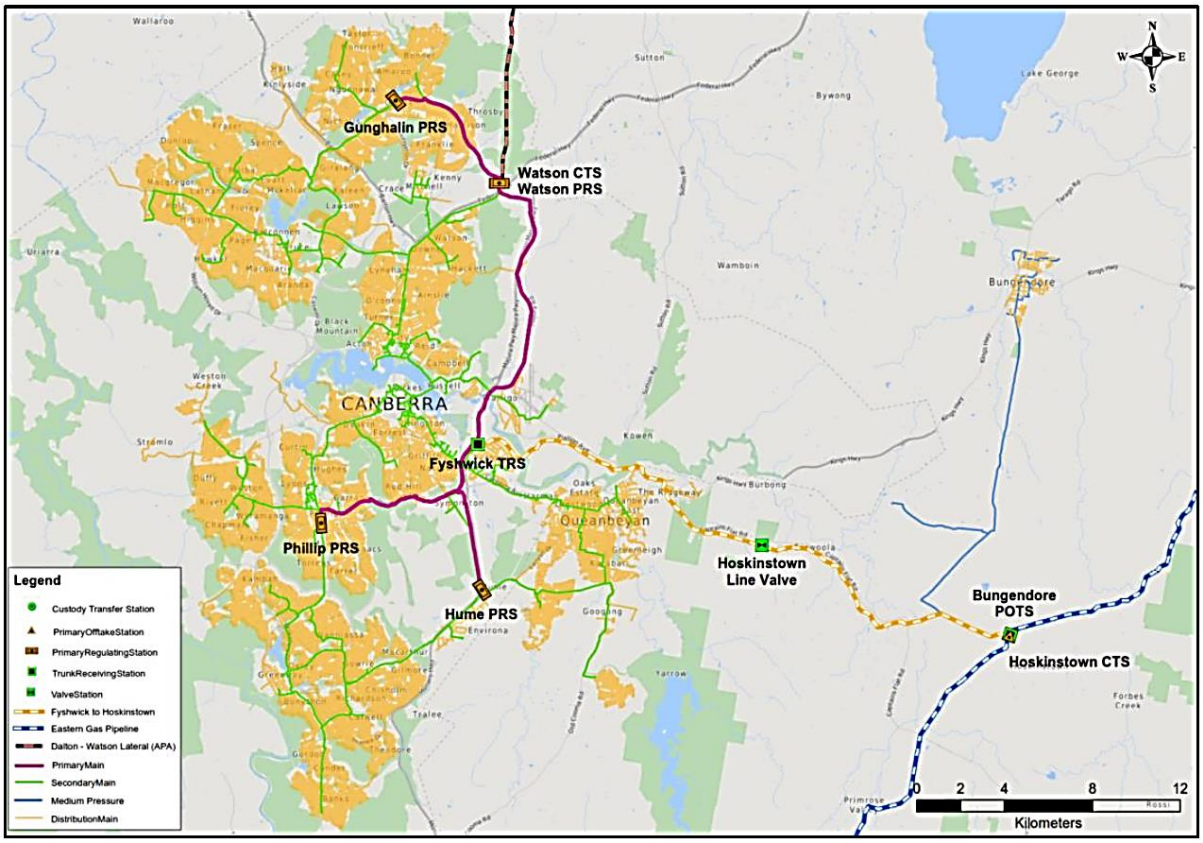

Figure 9: Canberra region gas distribution network, (Evoenergy, 2019).

The ACT natural gas distribution network is operated and maintained by Evoenergy. As of 30 June 2018, Evoenergy's natural gas network served 146,951 gas customers within the ACT, with an additional 3841 customers in New South Wales[12]. Of the total number of customers, 37 were non-tariff customers, i.e. users with yearly gas consumption larger than 10 TJ[13].

3.2 Seasonal Variability

In the ACT, residential and commercial buildings are responsible for around 80% of the total natural gas demand[14], mostly for space heating. Since this type of energy use is highly influenced by the average environment temperature, large seasonal swings in heating demand and therefore in gas consumption can be observed in the ACT.

Figure 10 shows the ACT monthly consumption of natural gas and electricity in 2018. The diagram indicates that gas demand at the winter peak is almost eight times as high as in summer, whereas peak electricity demand is only around 50% higher. Currently, this surge

[12] (Evoenergy, 2018), Annual Planning Report 2018.
[13] (ICRC, 2017), Utility Licence Annual Report 2017-18, Evoenergy.
[14] (Deloitte Access Economics, 2017), Decarbonising Australia's gas distribution networks.

in seasonal demand is handled by gas fields flexibility and large-scale gas storage in underground formations.

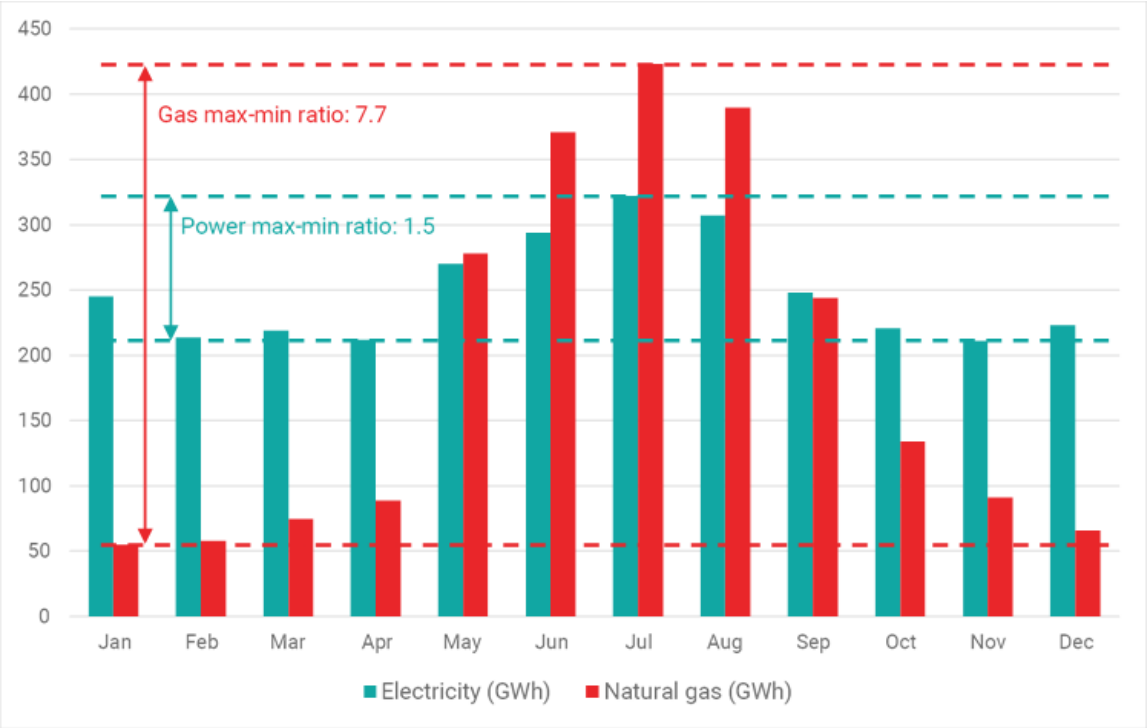

Figure 10: 2018 ACT monthly gas and electricity energy demand (GWh), data from Evoenergy.

Figure 11 shows the ACT daily natural gas imports in 2019.

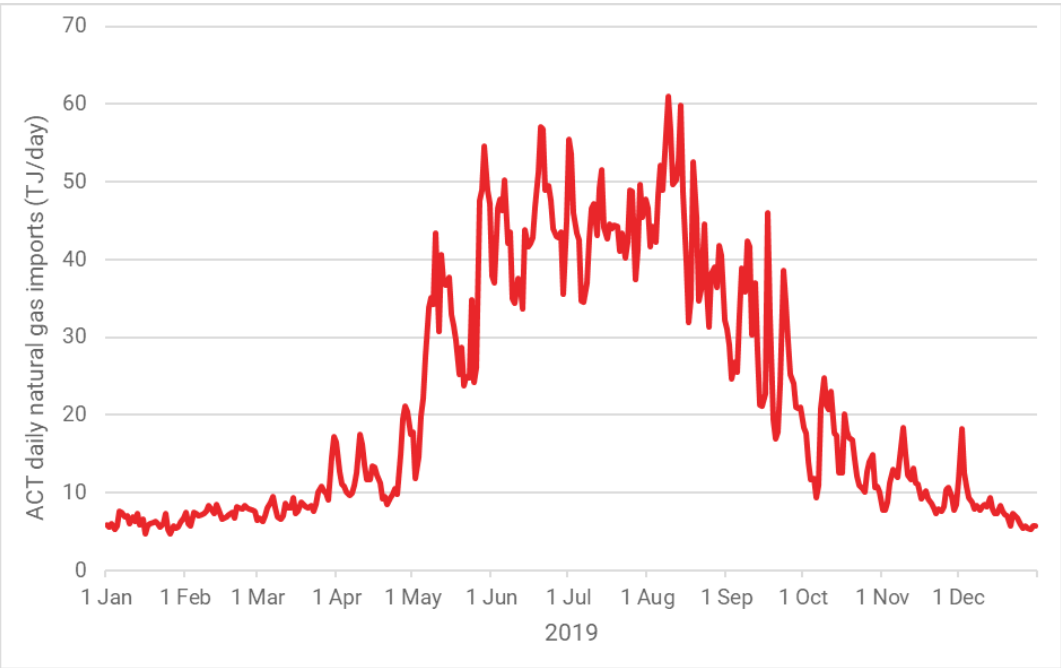

Figure 11: 2019 ACT daily natural gas imports (TJ), data from AEMO.

While the difference between summer and winter demand is evident, it is also clear the extent to which demand varies between subsequent days, demanding high flexibility from the energy supply system. This is made even more extreme by the fact that also within a day

demand varies considerably, with typical morning and evening peaks due to lower temperatures and residential users being more likely to be at home. These peaks can be seen on both electricity and gas demand curves.

3.3 Future demand forecast

For the *Evoenergy gas network – 2021 draft plan* report[11], Evoenergy commissioned the Centre for International Economics (CIE) to develop an independent and detailed forecast of demand and customer numbers for their gas distribution network for the 2021–26 period. The report explains:

"*The most significant source of uncertainty in forecasting Evoenergy's gas demand relates to the impact of the ACT Government's target of net zero greenhouse gas emissions by 2045.*"
"*The ACT Government's recently released Climate Change Strategy 2019–25 outlines the government's commitment to explore alternatives to natural gas to meet emissions targets. As one outcome, the strategy contemplates mass disconnection of customers from the gas network by 2025.*"

In the analysis, Evoenergy separated the gas demand between volume market consumers (around 150,000 customers using less than 10 TJ per year) and demand customers (around 40 large customers using more than 10 TJ per year).

The transition to electrical heating systems can especially influence the residential gas demand. This is expected to happen with a growth in installations of heat pumps, heating systems that can produce more heat than the electricity used to power them. The ratio between heat produced and energy in input is called COP (Coefficient of Performance) and it typically ranges between 2.5 and 3.5. One downside of heat pumps is that the COP decreases when outside temperatures are low, which coincides with the peak in heat demand. The widespread implementation of electrical heating systems would transfer the ACT's peak energy demand from gas to electricity.

A scenario of transferring all gas customers to electricity would require significant investment in virtually doubling the capacity of the electricity network, replacing the energy storage capability now provided by the gas storage infrastructure, as well as stranding gas network and user appliance assets.

Evoenergy estimated that the demand from volume market customers will decrease at an average 2.7% annual rate over the next seven years. This value is based on forecasts of new dwelling construction, population growth, percentage of new dwellings not connected to the gas network, number of disconnections of existing customers, improvement in the efficiency of gas appliances and improvement in buildings energy efficiency. The ultimate driver of gas demand will be the comparative cost of gas or electricity in peak heating periods along with the capital cost of switching fuel.

Demand market customers represent a fifth of the total gas demand and their number has remained substantially unchanged in recent years. This stable trend is expected to continue

in the 2021-2026 period and for the purpose of this analysis the total gas demand from demand market customers is forecast to remain constant at around 1.4 PJ[15] per year.

Figure 12 shows that, by applying these considerations, the total demand for gas in the ACT is expected to show a downwards trend from 7.1 PJ in 2018-19 to 6.1 PJ in 2025-26.

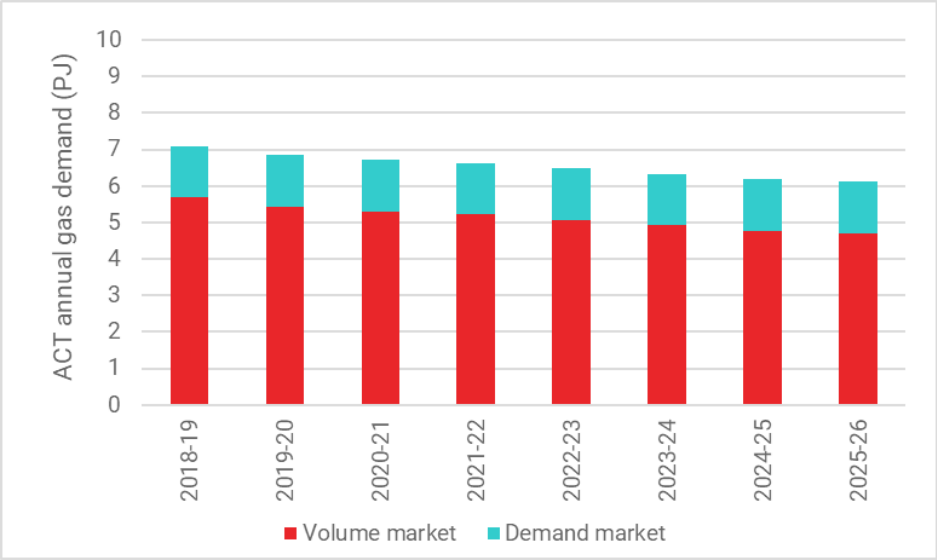

Figure 12: ACT's forecast gas demand from volume and demand market customers. Data on volume market future trends from Evoenergy.

3.4 Gas sector GHG emissions

Table 2 shows the 2018-19 ACT greenhouse gas (GHG) emissions by sector. The use of natural gas generated 401.1 kt of CO_2-e, including 33.1 kt from gas leakage, and it accounted for 13.5% of the total emissions.

Table 2: ACT greenhouse gas emissions 2018-19 by source[16].

Emission source	Emissions in 2018-19, kt CO_2-e	Share of total emissions
Electricity	863	30.8%
Natural gas (including leakage)	401.1	13.5%
Transport	1,169.1	41.8%
Industrial processes	242.4	8.7%
Agriculture	23.9	0.9%
Waste	88.1	3.1%

[15] Estimated as 20% of the 7.1 PJ ACT total demand.
[16] (Strategy. Policy. Research., 2019), ACT Greenhouse Gas Inventory 2018-19.

Other	11.4	
Sub-Total	2,799	100%
Agriculture and Land Use, Land-Use Change and Forestry (LULUCF)	-231	-8.3%
Total including LULUCF	2,568	

Until recently, the electricity sector was the largest contributor to the ACT's GHG emissions, accounting for more than 40% of the total emissions as recently as in 2017-2018[4](Saddler, 2018). Following the achievement of the 100% net renewable electricity target, these emissions are expected to be now zero and other GHG sources need to be addressed to further reduce emissions in the ACT.

4 POTENTIAL FOR ACT GREEN GAS SUPPLY

The potential value of renewable gas (i.e. gas that has low or zero carbon emissions) in Australia's decarbonisation pathway is well recognised.

This chapter discusses the possibility of repurposing existing biogas feedstock resources and establishing new biogas or hydrogen generation in the ACT/national capital region to deliver renewable gas for refuelling and injection into gas networks in the ACT.

4.1 Available Sources

To produce green hydrogen, renewable power and water are needed as input to the electrolysis process. On the other hand, a broader range of resources can be used to produce biogas from anaerobic digestion. In Australia, the majority of biogas is produced from food processing waste, agricultural waste, sewage waste and livestock waste. In the ACT, the biogas feedstock resources available are:

- Food waste from households and commercial activities (cafes, restaurants, etc)
- Garden waste from households and commercial operations (grass, leaves, prunings, etc)
- Sewage solids from wastewater treatment plants (WWTP).

Waste Management in the ACT

Since a large proportion of the biogas resources could be intercepted along the waste management chain, it is important to understand the ACT Government's waste collection arrangements.

In the ACT, households are provided with:

- a bin for general garbage which is disposed of at the Mugga Lane landfill,
- a bin for recycling of plastic, paper, cardboard, glass, steel, aluminium and cartons which are sorted at the Material Recovery Facility (MRF) in Hume, and
- a bin (optional) for garden waste (including prunings, leaves and grass clippings) which is treated in composting facilities and transformed into commercially valuable compost and mulch.

Currently, there is no separate collection available for household food waste.

The ACT Government does not provide collection services for Commercial and Industrial (C&I) waste. Instead, businesses are responsible for arranging their own waste and recycling services through commercial providers. In using these services, some ACT businesses separate and recover dry recyclables such as paper and cardboard. All C&I waste that is not recovered is sent to the Mugga Lane landfill for disposal.

There are two sorting and recycling facilities for Construction and Demolition (C&D) waste within the ACT. These facilities recover masonry, concrete, road pavement materials, various timbers and other materials. All C&D waste that does not get recovered and recycled is treated at the Mugga Lane landfill.

According to ACT NoWaste, 53% of the waste that goes to landfill in the ACT is composed of materials that in the landfill's anaerobic conditions can decompose and generate methane. These materials include food and garden waste, textiles, paper and cardboard, timber, and other organics like nappies, rubber, and leather. The estimated amount of methane produced after the complete decomposition of the organic materials accumulated in one year amounts to 14,800,000 m^3, equivalent to 530 TJ[17].

As of 2019, the ACT Government is developing a system to collect up to 15,000 tonne of food waste from local food retail businesses. The ACT Government's proposed scheme will require large producers of organic waste, like cafes and restaurants, to have a compulsory, separate collection of organic food waste.

4.2 Biogas / biomethane resources

The following resources for the production of biogas were identified within the ACT.

4.2.1 Food and Garden Waste

In 2017-2018, around 235,000 tonnes of waste were sent to landfill in the ACT. Household waste contributed 75,500 tonnes, of which 35% was estimated to be food waste and 10% to be garden waste. C&I waste contributed 117,000 tonnes, with around 13% being organic waste, primarily consisting of food waste from restaurants, cafes and supermarkets[3].

In addition, around 230,000 tonnes of garden waste[18] are separately recovered from private drop-offs to specific collection facilities. This type of waste is currently processed, composted and sold by private operators as potting mix and garden mulch.

According to NGER guidelines, composting generates 0.048 tCO2-e per tonne of green waste. This amounts to 11 ktCO2-e of emissions per year in the ACT. It is unclear whether these emissions are included in the emissions from solid waste disposal on land reported in the ACT Greenhouse Gas Inventory 2018-19 (76.2 ktCO2-e).

While this type of organic waste could theoretically be used as feedstock in anaerobic digestors to produce biogas, its water content is relatively low and other processing treatments are typically preferred instead (e.g. aerobic composting). Furthermore, this waste stream is already being upgraded and used in private commercial activities (e.g. Corkhill Bros), so its diversion to the production of biogas should be carefully considered.

Estimated revenue from the retail sale of composted material is $18 per tonne of green waste processed. On the other hand, anaerobic digestion is estimated to generate 5.4 GJ of biogas per tonne of green waste, providing a revenue of $54 per tonne of green waste[19].

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[17] Conversion factors for lifetime emissions from waste degradation in landfill from: Australian Government (Department of the Environment and Energy), National Greenhouse Accounts Factors, August 2019.
[18] (Point. Advisory, 2017), ACT 2050 emissions modelling – waste sector.
[19] Assumptions: Composting - mulch retail price: $24/$m^3$, mulch density: 0.65 t/$m^3$, mulch produced per tonne of green waste: 0.5 t. Anaerobic digestion – methane energy yield per tonne of garden waste: 5.4 GJ, biogas price: $10/GJ.

Additional revenue can be expected from the sale of the digestate, a by-product of the anaerobic digestion process that can be used as fertiliser.

Other organic materials that currently go to landfill (paper and cardboard, timber, textiles, nappies, rubber, leather) are not suited for composting nor for anaerobic digestion. The reduction of methane emissions from the decomposition of these materials in landfill should be tackled by higher diversion to recycling and more complete methane capture at the landfill.

4.2.2 Sewage sludge

In 2016, an estimated 52 biogas plants using sewage sludge as feedstock were operating in Australia[20]. In the ACT, the wastewater treatment is almost entirely carried out by the Lower Molonglo Water Quality Control Centre (LMWQCC) facility. In addition, a small facility in Fyshwick is used to treat industrial waste before being sent to LMWQCC for final treatment.

In a 2016 study conducted on behalf of Icon Water (responsible for providing sewerage and water services in the ACT), the consulting firm GHD determined that the potential biogas production at LMWQCC would be 16,000-20,000 m^3/day (equivalent to up to 173 TJ/year).

The estimated current fuel consumption for stationary uses at LMWQCC (mostly dedicated to the incineration of sewage solids) is 48 TJ/year. Assuming that biogas auto consumption would cover this energy demand, the surplus biogas would amount to **125 TJ/year**.

However, it is to be noted that GHD found the project to be economically unfeasible, unless additional funding from ARENA or other government agencies was obtained.[18]

4.2.3 Summary

Table 3 summarises these resources and indicates an overall total of 1537 TJ, equivalent to 21.6% of existing natural gas demand. If the garden waste is excluded, the subtotal of 237 TJ is equivalent to 3.3% of existing natural gas consumption.

Table 3: ACT waste biomass feedstocks and potential biogas production.

Waste stream	Available waste t/year	Specific methane yield[21] GJ/t	Total potential biogas energy TJ	% of ACT's natural gas demand
Food waste (household)	26,400	3.1	82	1.2%
Food waste (C&I)	15,200	3.1	47	0.7%

[20] (IEA Bioenergy, 2016), Country report Australia.
[21] Methane yield is highly variable as it is influenced by AD technology, feedstock quality, and feedstock water content. The reported values are only indicative. Sources: (ENEA Consulting, 2019), Biogas opportunities for Australia, and (Al Seadi, 2008), Biogas handbook.

Garden waste (from landfill waste collection)	7600	5.4	41	0.6%
Garden waste (from separate collection)	230,000	5.4	1242	17.5%
Sewerage		-	125	1.8%
Total (without garden waste from separate collection)			295	4.2%
Total			1537	21.6%

4.3 Green Hydrogen resources

The production of green hydrogen with the electrolysis process requires renewable electricity and water as inputs as shown to hypothetically meet a proportion of ACT gas demand in Table 4. The amount of electricity and water required are proportional to the quantity of hydrogen produced.

4.3.1 Renewable power

Since solar and wind energy resources in Australia are virtually unlimited, the limiting factor for the production of green hydrogen is its potential demand. Once demand is defined, it is possible to estimate the renewable energy requirements to meet it. In particular, demand can be defined as the hydrogen energy required to substitute a share of the natural gas in the natural gas distribution network. The share of hydrogen is typically defined as the percentage of natural gas volume replaced by hydrogen. A near short-term goal advocated by many stakeholders is to achieve 10% of hydrogen volume in the gas network as it is estimated that this could be implemented without requiring modifications to pipes and appliances.

When analysing the amount of energy required to substitute natural gas with hydrogen in the gas network it is important to understand the distinction between hydrogen volume share (H_2 v/v%) and hydrogen energy share (H_2 e/e%) in the network. In a hydrogen-natural gas mixture, the two values are different because of the difference in energy content per cubic metre between hydrogen and natural gas. Equation 1 shows the relationship between volume and energy hydrogen share.

Equation 1:

$$H_2\ e/e\% = \frac{10.6\ H_2\ v/v\%}{10.6\ H_2\ v/v\% + 37.8\ (100 - \ H_2\ v/v\%)}$$

Where:

$H_2\ e/e\%$ is the hydrogen energy share of the total energy in the gas network,

$H_2\ v/v\%$ is the hydrogen volume share of the total volume in the gas network,

10.6 is the volumetric energy content of hydrogen at 0°C and 1 bar, in MJ/m^3, and

37.8 is the volumetric energy content of natural gas at 0°C and 1 bar, in MJ/m^3.

From Equation 1, 10% of hydrogen volume in the network corresponds to 3.0% of the total natural gas energy consumption. This equates to an annual hydrogen production of 210 TJ (3% of 7.1 PJ).

With current electrolyser technologies, to produce one unit of hydrogen energy around 1.6 units of electrical energy are required as input[22]. This means that a 210 TJ annual hydrogen energy demand could be satisfied by the energy coming from a 31 MW wind farm. On the other hand, 1043 MW would be required to produce enough hydrogen to completely substitute ACT natural gas use. In addition to the renewable power plant, a similarly sized electrolyser would need to be installed.

The sizing of the wind farm is based on the assumption that the hydrogen gas can be produced at a constant daily rate throughout the year, and that the wide seasonal and daily variation in the ACT gas energy demand can be followed by storing excess hydrogen produced during periods of low gas demand and releasing hydrogen during peak demand periods. This scenario assumes the availability of large scale hydrogen storage systems that provide a buffer between hydrogen production and injection into the grid, depending on the instantaneous gas demand.

The installation of the required renewable electricity generators would need to happen outside the ACT borders, in high renewable resources areas. The electricity could then be transported along interstate power transmission lines so that the hydrogen could be produced within the ACT. This would likely require the upgrade of the existing transmission lines. Alternatively, the hydrogen could be produced close to the renewable generators and injected in the local natural gas grid or transported to the ACT via existing or purpose-built gas transmission pipelines.

4.3.2 Water

The production of hydrogen by electrolysis uses approximately nine litres of water per kilogram of hydrogen. To achieve 10% of green hydrogen in the natural gas grid, 16 million litres of water would be required each year. The amount of water needed would rise to 533 million litres per year for the complete replacement of natural gas with hydrogen. To put these figures into perspective, they correspond to, respectively, 0.023% and 0.8% of the Corin Dam water reserve's capacity[23].

[22] Based on PEM electrolyser technology efficiency, requiring 54 kWh of electricity per kilogram of hydrogen. Hydrogen energy content calculated based on its Lower Heating Value (LHV): 33.3 kWh/kg.
[23] Corin Dam storage capacity: 70,900 million litres. Source: https://www.iconwater.com.au/corindam

Table 4: Water and electricity inputs for hydrogen fractions of a total 7.1 PJ gas demand.

Hydrogen content in the gas network v/v%[24]	Hydrogen contribution to energy in the gas network MJ/MJ %	Annual hydrogen production PJ	Annual renewable energy production required PJ (GWh)	Annual water consumption Ml	Installed wind power required[25] MW
5%	1.5%	0.11	0.17 (48)	8	16
10%	3.0%	0.21	0.35 (96)	16	31
20%	6.5%	0.46	0.75 (208)	35	68
50%	21.9%	1.55	2.52 (700)	117	228
100%	100%	7.1	11.51 (3198)	533	1043

4.4 Current Supply

4.4.1 ACT's supply

Currently, the production of Green Gas in the ACT is limited. The only existing production is related to biogas generated and captured at the two main ACT landfills. In addition, a renewable hydrogen generation system for hydrogen vehicles refuelling is under construction in Fyshwick and should be in operation by the end of 2020.

ACT landfill gas

When the municipal solid waste is stored in landfills, the organic component of the waste goes through an anaerobic digestion process that causes the generation of biogas. Intercepting and burning the biogas avoids the release of methane and gives the possibility to generate heat and/or electricity, depending on the energy conversion system used.

In the ACT, emissions arise from the currently active Mugga Lane landfill site and the relatively recently closed Belconnen site. At the Belconnen site, the landfill biogas produced is simply flared, to transform the methane into carbon dioxide, a less powerful greenhouse gas. At Mugga Lane, instead, four power generators use the biogas to produce 34,900 MWh of renewable electricity each year. Unlike with the use of digesters, at landfill sites not all the methane produced is successfully captured. Around 30% of the biogas generated is still released to the atmosphere, contributing to 4% of the ACT's greenhouse gas emissions. The total production of biogas at this site is estimated to be around 450 TJ per year[26].

[24] v/v (or vol%) stands for volume concentration. Hydrogen volume concentration is calculated as number of hydrogen molecules per number of total gas molecules.
[25] Estimated capacity factor for wind power: 35%
[26] Estimated power generator efficiency: 40%, biogas captured share of total: 70%

ACT green hydrogen

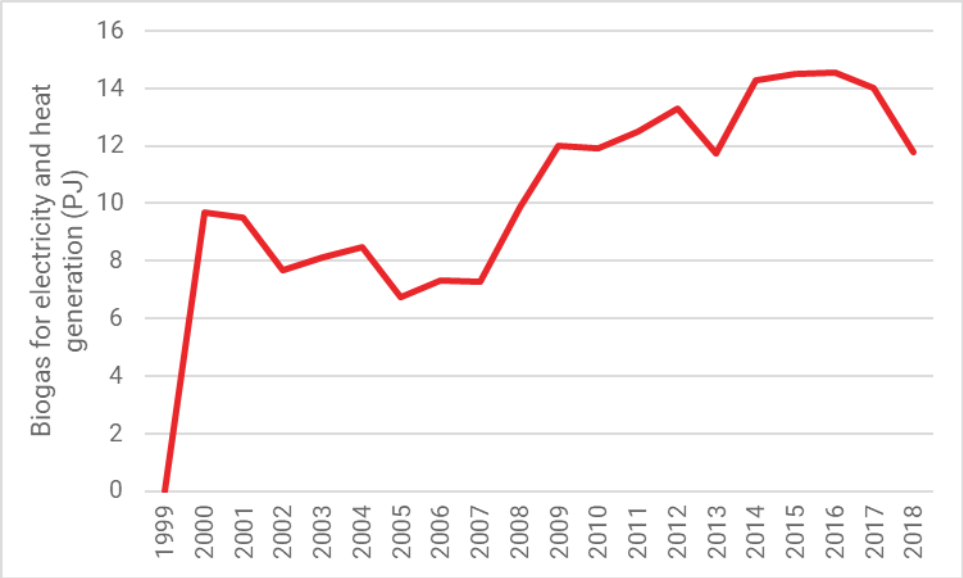
A green hydrogen generation and refuelling station is currently under construction in Mildura street, Fyshwick. The system, commissioned by renewable energy developer Neoen to ActewAGL, is set to be the first publicly available hydrogen refuelling station in Australia. The pilot plant will use renewable electricity to power an electrolyser to produce 20 kg/day of hydrogen, with the provision for an upgrade to 60 kg/day (equivalent respectively to up to **0.9 and 2.6 TJ per year**). The station will serve 20 Hyundai Nexo hydrogen vehicles that will form part of the ACT Government fleet.

ActewAGL New Energy submitted an EOI to ARENA for support towards a future 5 MW electrolyser under ARENA's 2020 hydrogen funding round. However, they were not shortlisted in that process. Such a system, if installed, would produce up to 110 TJ/year[27] of green hydrogen, equivalent to 1.5% of existing ACT gas demand.

4.4.2 Australia's supply

In 2019, bioenergy corresponded to 6.0% of total renewable electricity generated in Australia, or 1.4% of total electricity generated that year[28]. Of this percentage, biogas forms only a small part.

In 2017, there were 242 biogas plants in the country. Half of these plants were landfills collecting landfill gas, while plants generating biogas from sewage sludge represented a fifth of the total plants[20]. In 2017- 18, electricity generation from biogas was around 1250 GWh (4.5 PJ), representing about 0.5% of the national electricity generation[29], while the total biogas energy generation in the same year (including both electricity and heat) was 14.5 PJ.



[27] Considering a 70% capacity factor for the electrolyser
[28] (Clean Energy Council, 2020), Clean Energy Australia Report.
[29] (Australian Government, 2019), Australian Energy Update.

Figure 13: Biogas energy use for electricity and heat generation in Australia, between 1999 and 2018. Data from AGEIS Activity table: Stationary energy 2018.

Current biogas generation corresponds to just 4% of the total Australian biogas potential, which is estimated at 370 PJ[30].

To date, there has been no significant renewable hydrogen production in Australia. However, ARENA received 36 responses totalling more than $3 billion of renewable hydrogen projects to its recent dedicated funding round for large electrolysers of 10 MW or larger[31]. In July 2020, ARENA invited seven proponents that have developed projects with a total project value of almost $500 million to progress to the next stage of application.

4.5 Requirements and risks of substituting natural gas with Green Gas

The substitution of natural gas with Green Gas will require careful design to ensure an orderly transition and overcoming technical risks.

4.5.1 Security of supply

The considerations around the security of supply differ considerably depending on whether we think of green hydrogen or biogas.

The production of hydrogen via electrolysis is linked to the availability of renewable power and water. Green electricity supply depends on the availability of renewable resources (solar and wind in particular) and, for electrolysers not co-located with renewable generators, on the reliability of the transmission and distribution system.

The availability of water can be an issue due to the risk of drought, especially considering the uncertainties linked to the effects of climate change. Although the water requirements to produce hydrogen are relatively small when compared to other industries (e.g. mining), the installation of electrolysers in areas with low risk of water restrictions is recommended. As an alternative, the desalination and use of sea water could be a valid option for mitigating this risk for electrolysers installed on the coast.

The supply of biogas is linked to the availability of the organic material feedstock required for its production.

Securing feedstock suppliers, feedstock quality and quantity, as well as their cost or potential revenues, represent key success factors in biogas projects. Considerations around the supply of the feedstock are:

- Waste streams are predictable, allowing for reasonably long-term planning of resources supply
- Garden waste is not likely to decrease in the future
- Sewage feedstock is likely to grow in proportion with population growth.

[30] (Deloitte Access Economics, 2017), Decarbonising Australia's gas distribution networks.
[31] ARENA, Media release 'Seven shortlisted for $70 million hydrogen round', July 2020.

4.5.2 Life cycle emissions considerations

Life Cycle Assessment (LCA) is an important tool for achieving a more complete understanding of the impact of a product or of a service. The International Organisation for Standardisation (ISO) published standards that specify requirements and provide guidelines for this type analysis (e.g. ISO 41040 and ISO 41044).

When analysing the global warming impact, GHG emissions are of primary concern. This type of analysis considers the total emissions of an energy generating system, with a cradle-to-grave approach.

To determine the comparative GHG impacts of an energy source, each energy generating system should be analysed compared with a reference energy system, e.g. coal, natural gas, or renewable energy.

As an example, in case of biogas generation from waste streams in comparison to the waste disposal system currently in place, emissions are generated during the installation of the biogas plant, and in the phases of production, upgrading, and transport of the biogas. On the other hand, emissions are reduced by the avoided emissions from landfill (or composting facilities) and by using the digestate as an alternative to GHG-generating fertilisers. Further, the emission intensity of the electricity and/or heat generated from biogas should be compared to the LCA emissions of, for example, energy from a wind turbine (which generates emissions during the manufacturing, transport, installation, electricity transmission, and end-of-life phases).

A detailed investigation of LCA for Green Gas in the ACT should consider:

- The range of technologies used in the production of Green Gas and the type of renewable resource used as input. Where grid electricity is used as an input, the emissions intensity of electricity calculations needs to factor in contracted renewable electricity bought or sold from other States. It is important that consideration be given to not just the contracting of net renewable electricity, but the actual GHG emissions that result from the actual instantaneous generation needed to operate electrolysers;
- Direct emissions (e.g. methane leakage) and indirect emissions (e.g. embedded emissions in the biogas/hydrogen production equipment, biomass transport, fertilisers for biomass if coming from energy crops, etc); and
- The comparison between the emissions from Green Gas to the emissions from natural gas (business as usual) and emissions from other natural gas alternatives (e.g. electrification).

Avoided emissions should also be included in the analysis (e.g. avoided landfill/water treatment emissions).

4.5.3 Other considerations and risks

As for the considerations about the security of supply, the technical considerations and risks of adopting Green Gas also differ between biogas (or biomethane) and green hydrogen.

While the composition of biomethane is very similar to natural gas, hydrogen is a different molecule.

The natural gas industry has a well-established approach to safety, due to the significant hazards that exist related to flammability and other issues. Hydrogen has several properties that differ from natural gas, requiring a change in the approach to safety. While this does not mean that hydrogen is less safe, a careful assessment of the technical implications of using hydrogen in substitution of natural gas is required. Characteristics of hydrogen that must be considered include:

- **High flammability range**
  The flammability range of a combustible gas is defined as the range of concentrations of gas in air that can create an explosive atmosphere. The minimum and maximum gas concentration values are defined respectively as lower explosive limit and upper explosive limit. While a hydrogen-air mixture is flammable for hydrogen concentrations between 4% and 75%, natural gas has a similar lower explosive limit but a lower upper limit (15%).
- **Low density**
  Hydrogen is 14.5 lighter than air. This means that when hydrogen is released in air it rapidly disperses upwards. This is a useful property in case of a leakage in an open space as its concentration in air quickly drops below the 4% limit, making it unable to explode. Still, particular care needs to be taken to avoid potential overhead gas pockets in covered spaces.
- **Low ignition energy**
  The ignition energy is the energy required to initiate a combustion reaction between a flammable gas and the oxygen in air (e.g. a spark). Under optimal combustion conditions (29% of hydrogen concentration in air), hydrogen has an ignition energy 15 times lower than natural gas. At lower hydrogen concentrations, its ignition energy is comparable to that of natural gas.
- **Small molecule and low viscosity**
  These characteristics make hydrogen more prone to leaking than natural gas, but it is not an issue if hydrogen piping standards are implemented.
- **Odourless and transparent**
  Hydrogen cannot be detected with human senses. Natural gas and propane have the same characteristics, but the industry mixes them with a small quantity of sulphur-based odorant to make them detectable to the human smell. Natural gas odorants are not compatible with a gas with high hydrogen content; therefore a different odorant shall be used.
- **Invisible flame**
  A pure hydrogen flame is nearly invisible in daylight, making it hard to detect without thermal safety sensors. Also, hydrogen flames produce only a small amount of heat radiation (infrared radiation). This is a safety concern as someone standing close to a hydrogen flame will not be able to perceive the flame until in contact with it. On the other hand, hydrogen flames are less likely to ignite combustion reactions in nearby

combustible material unless the material is in direct contact with the flame. This is because of the absence of radiation from the invisible flame. Odorant additives may also have the effect of rendering the flame visible.

- **Steel embrittlement capability**
  Steel embrittlement is a deterioration process that involves the ingress of hydrogen within the atomic structure of steel, reducing its ductility and strength. It can cause cracking and catastrophic brittle failure of pressure equipment. The phenomenon is not completely understood but it is known to particularly affect high strength/high carbon steels. Low carbon (mild) steels are in general considered to be appropriate for the use in hydrogen applications. Polyethylene (PE) piping used in gas distribution networks are immune to hydrogen embrittlement

For injection into the gas network, assessment of the compatibility of hydrogen with the existing piping network and appliances is required.

In addition to technical risks, the substitution of natural gas with a new type of fuel like Green Gas can entail business risks as well. Table 5 and Table 6 summarise these risks for biomethane and hydrogen, respectively.

Table 5: Business risks of substituting natural gas with biomethane.

Nature of possible risk	Detail	Judgement
High feedstock prices due to competition in the procurement	Feedstock for biogas production can be valuable for other applications	This risk can be avoided by targeting waste feedstock with disposal costs (negative price) or no other possible use. E.g. sewage waste, food waste, low value agricultural residues.
Low quality of feedstock	Lower quality feedstock would reduce the biogas yield and therefore undermine the business plan for biogas plants	This risk is mitigated by careful assessing of the resources available, by incentivising suppliers to avoid feedstock contamination (higher quality feedstock at premium price), and by the implementation of regulation on feedstock quality
Risk of use of biomethane not conform to natural gas standards	The presence of contaminants can have consequences in terms of generation of pollutants when combusted (sulphur components), equipment corrosion (water, sulphur components), and lower heating value (carbon dioxide)	Unlikely. Due to obligations under Utilities Act and Gas Safety and Operating Plan Code, the distribution company will not accept below specification gas into its network.
Biomethane fugitive emissions	If injected into the gas distribution network, fugitive emissions can be expected. Fugitive emissions in the natural gas network are estimated at less than 2% of the gas	The risk can be mitigated by lower distance between biomethane injection and use areas and by adopting higher control of fugitive emissions

	delivered, a similar value can be expected for biomethane	
Risk of non-delivery of biomethane affecting achievement of climate change targets	Contract risk, usual remedies apply	Not a risk assumed or adopted by ACT Government. This risk is assumed by the retailer and wholesale buyer of renewable gas.
Difficulties in gaining supply of biomethane at a reasonable price (and costs passed on to consumers who elect for this option)	Chicken and egg problem; if there are no targets or obligations there will be less supply available.	May necessitate adjustment of policy to encourage more suppliers to enter the market. Experience of British Columbia suggests the opposite, difficulties for retailers in meeting consumer demand. Consumers who elect for the Green Gas option are in any event willing to pay a premium and are likely to be highly motivated with an inelastic demand
Risk of false carbon claims (e.g. extent of GHG emission abatement is exaggerated)	Covered by existing consumer protection and trade practices law	Unlikely. Can be avoided by rigorous certification regime. Gas distributors are subject to rigorous licensing regime at present.
Risk of conventional gas discounting making renewable gas less competitive	Wholesale gas pricing is influenced by many factors. Retail gas pricing has wholesale gas price as only one of its components. First Mover Consumers who elect to pay premium for Green Gas will not be deterred but may respond by making downward adjustments to the % of their supply that is renewable. This may have flow on effect on retailer and distributor and supplier.	Not within control of ACT government.

Table 6: Business risks of substituting natural gas with green hydrogen.

Nature of possible risk	Detail	Judgement
Reduced availability of water for electrolysis	Competition around the use of water could reduce the availability for hydrogen production, e.g. in case of prolonged drought	Even in a 100% hydrogen scenario, water consumption for hydrogen would have a small impact on current water use. Further, lower value water streams could be used (e.g. wastewater treatment plant output)
Higher than expected renewable electricity costs	High electricity costs would have a direct impact on the cost of green hydrogen	Unlikely. Renewable electricity cost is expected to decrease in the future.
Disruption in renewable energy supply for electrolysis	High impact issues (e.g. bushfires, storms) could disrupt the production and/or transmission of power to electrolysers in the ACT	Reliability measures for the power supply to the ACT are already in place. Further, most of the electrolysis capacity is expected to be installed next to renewable power generators, and reliably transported along gas pipelines.
Hydrogen injected in the gas distribution network not uniformly blended	Improper hydrogen injection could lead to gas network areas with higher hydrogen concentrations. This could lead to metering problems, malfunctioning of appliances and potentially leakages.	Not likely according to Evoenergy. Effective blending can be achieved by controlling hydrogen injection flowrate, choosing appropriate injection points and by ensuring turbulent flow.
Safety risks due to the lack of industry experience with hydrogen	Hydrogen has different properties compared to natural gas	Education and training of gas technicians needs to be updated to include hydrogen.

5 POTENTIAL MARKET DEMAND FOR GREEN GAS

In considering the possibility of Green Gas trading there needs to be some level of latent market demand to justify the effort in establishing frameworks.

The timeline and budget of this project was too small to allow for any comprehensive survey of gas users to quantify market demand. Rather the analysis that is presented here is based on discussions with a range of key relevant stakeholders as listed in Appendix A.

5.1 Voluntary uptake

In the absence of any mandatory measures to either establish demand for Green Gas or dis-incentivise the use of natural gas or petroleum products, there will be some level of voluntary demand that can be expected. This demand will very much depend on the relative economics of options which, setting aside energy efficiency options, essentially are:

- Continue to use existing gas or fuel,
- Adopt a fraction of Green Gas use,
- Convert energy use to electricity.

There will be some fraction of energy users who will wish to be principled first adopters. This subset will be most likely to accept a premium on existing energy costs. At the other extreme, a large body of energy users can be expected for whom minimum effort and disruption are driving considerations. In this case, a Green Gas would be favoured over the existing fuel if it were cheaper and required no investment in adapting for use. This means stationary use of natural gas and possibly existing CNG vehicles. It can be noted that for this cohort, even if the lifecycle costs of conversion to electricity were favourable, inertia and opportunity cost would tend to favour a move to Green Gas over electricity.

Considering the economics in detail is complex and outside the scope of this study. Some general observations are pertinent:

- Small gas users pay much higher prices (around three times) per unit energy than large users who are able to negotiate supply contracts that are much closer to wholesale costs of gas.
- The sudden collapse in 2019 of world oil prices has also led to a drop in internationally traded LNG prices and in turn the spot price in Australia. The price has fallen to around $4/GJ from $8 to $10. If these low prices are maintained for extended periods, then they will make the economics of renewable solutions challenging in the absence of mandatory measures. On the other hand, the production costs of new gas fields in Australia may struggle to be covered by a long term low wholesale price. Gas futures prices for 2024 remain at higher levels.
- It is apparent that a significant amount of locally produced biomethane could be provided at around $10/GJ wholesale. Depending on the changes in wholesale natural gas prices, this could be provided to gas users at a quite small price premium and could prove attractive.

- If continued use of natural gas is removed as an option by mandatory measures, the attractiveness of conversion to electrification will depend on the relative price of electricity. With increasing amounts of low cost PV and wind electricity added to the NEM mix, together with coal plant retirements, a trend to higher cost electricity at times when wind and solar inputs are low can be expected. With much of the current demand for natural gas linked to winter space heating and much of that concentrated in early evening and early morning daily peaks, these are precisely the times when electricity is likely to have a higher price. Large scale electrification will also require electricity distribution system upgrades that would also need to be passed on to electricity consumers. Added to this, the investment and opportunity costs of conversion for the end user are substantial. This last factor would be mitigated to a large extent however, if conversion takes place at the end of appliance life.
- In the transport sector, either hydrogen vehicles or electric vehicles appear to be already attractive in terms of running costs compared to conventional internal combustion engines. The uptake is limited by the current high upfront cost of the vehicles and the lack of universal availability of filling / charging infrastructure. As these aspects change over time, the share taken up by hydrogen-fuelled transport compared to battery electric is hard to predict. Again, it will depend on the relative cost of the energy supplies, and the vehicles, plus also the usage patterns. It is widely recognised that hydrogen use offers greater attractions for heavy vehicles under intense use. In any case some significant share of the transport market might reasonably be expected to go down the hydrogen route.

The voluntary uptake of GreenPower electricity prior to the RET is probably a good analogy. This experience indicated that a 5-10% cost premium for green is the sort of premium acceptable to early movers. Large industrials however may have lower tolerance for a premium. The voluntary uptake in GreenPower electricity reached a maximum of 1 TWh/year at its peak in 2010, representing 0.5% out of a total NEM electricity demand of 207.5 TWh[32] at that time.

5.1.1 Domestic gas users

The analogy of voluntary uptake of GreenPower certified electricity prior to the RET is a good indicator of possible Green Gas uptake with domestic gas customers if similar certified products are available.

Carol Bond at RMIT is working with the Future Fuels CRC looking at community attitudes. Information so far regarding consumer attitudes is that around 65 - 80% of consumers simply do not care and want continued supply of gas they can use in a business as usual manner, irrespective of source.

[32] Data from Australian Energy Regulator, NEM annual electricity consumption in 2010-11.

The issue of naming / branding of fuels is important for consumer recognition, i.e. the idea of blue vs green hydrogen. Initial consumer surveys suggest that maybe 1 - 2% might be willing to pay a premium for Green Gas.

5.1.2 Large users

The top 13 largest natural gas users within the ACT borders are listed in Table 7**Error! Reference source not found.**. Where specific gas consumption data was not available, the gas demand was estimated from the emissions of pollutants reported in the National Pollutant Inventory (NPI). The combustion of natural gas causes the emission of pollutants like carbon monoxide, sulphur dioxide, nitrogen oxides and particulate matter (NPI Australia, 2015). In particular, nitrogen oxides (NOx) emissions are estimated at around 40 kg per TJ of natural gas. By applying this coefficient to the NOx emissions reported in the NPI it is possible to indirectly estimate the gas consumption.

Table 7: ACT largest gas users and approximate estimate of natural gas consumption.

Facility	Main use	Approximate natural gas consumption TJ	Data source / Estimation method
ACT Government buildings			
Canberra Institute of Technology	Space heating	26	ACT Government
CMTEDD	Space heating	27	ACT Government
Education Directorate	Space heating	81	ACT Government
Health Directorate	Space heating / laundries	125	ACT Government
Justice Community Safety Directorate	Space heating	40	ACT Government
Transport Canberra and City Services Directorate	Space heating	122	ACT Government
Others	Space heating	18	ACT Government
ACT Calvary Hospital, Bruce	Space heating	32	Estimated from NOx emissions[33]
Icon Water Ltd, LMWQCC	Heating, biosolids incineration	48	Estimated from Icon Water 2013 emission data
Australian National University, Acton	Space heating	400	Estimated from CO2-e emissions
ACT natural gas bus fleet	Transport	85	ACT Government

[33] Data from the Australian National Pollutant Inventory (NPI).

Department of Parliamentary Services	Space heating	50	Department of Parliamentary Services 2017-18
Downer EDI Works Pty Ltd, Hume	Industrial (asphalt manufacturing)	50	Estimated from NOx emissions[33]
CSIRO, Black Mountain	Agriculture / space heating	40	Estimated from NOx emissions[33]
Calvary Health Care ACT Ltd, Bruce	Space heating	30	Estimated from NOx emissions[33]
Bitupave Ltd, Mugga Lane	Industrial (asphalt manufacturing)	30	Estimated from NOx emissions[33]
Boral Resources (Country) Pty Ltd, Mugga Lane	Industrial (asphalt manufacturing)	20	Estimated from NOx emissions[33]
Quality Bakers Australia Pty Limited, Fyshwick	Industrial (bakery)	21	Estimated from NOx emissions[33]
University of Canberra, Bruce	Space heating	19	Estimated from NOx emissions[33]

Figure 14 illustrates the location of these users around Canberra. It is notable that the ACT Government is at the top of this list, representing 35% of the total gas demand from large users in the ACT. In this case it is a combined total across all government buildings across the territory. ACT Government actions could thus establish significant market pull if that was desired. The natural gas bus fleet is also notable as an area where the ACT Government could take action. There is no technical impediment to running those buses on contracted Green Gas. The option of directly linked Green Gas production in conjunction with the filling station would also be possible. In that regard, it may also be possible to operate those buses with an enhanced fraction of hydrogen in the gas mix.

The ANU is notable as the second biggest gas user. It is understood that they currently secure gas from the retailer Weston Energy and Weston Energy has developed an offering for Green Gas. ActewAGL has also talked to ANU about its interests in Green Gas. It is understood that ANU is considering the possibility of contracting for Green Gas. It can be noted however that as a large user it sees a natural gas price quite close to and linked to the wholesale price, which is currently low at a time when the university sector is known to be suffering badly from the Covid-19 driven downturn.

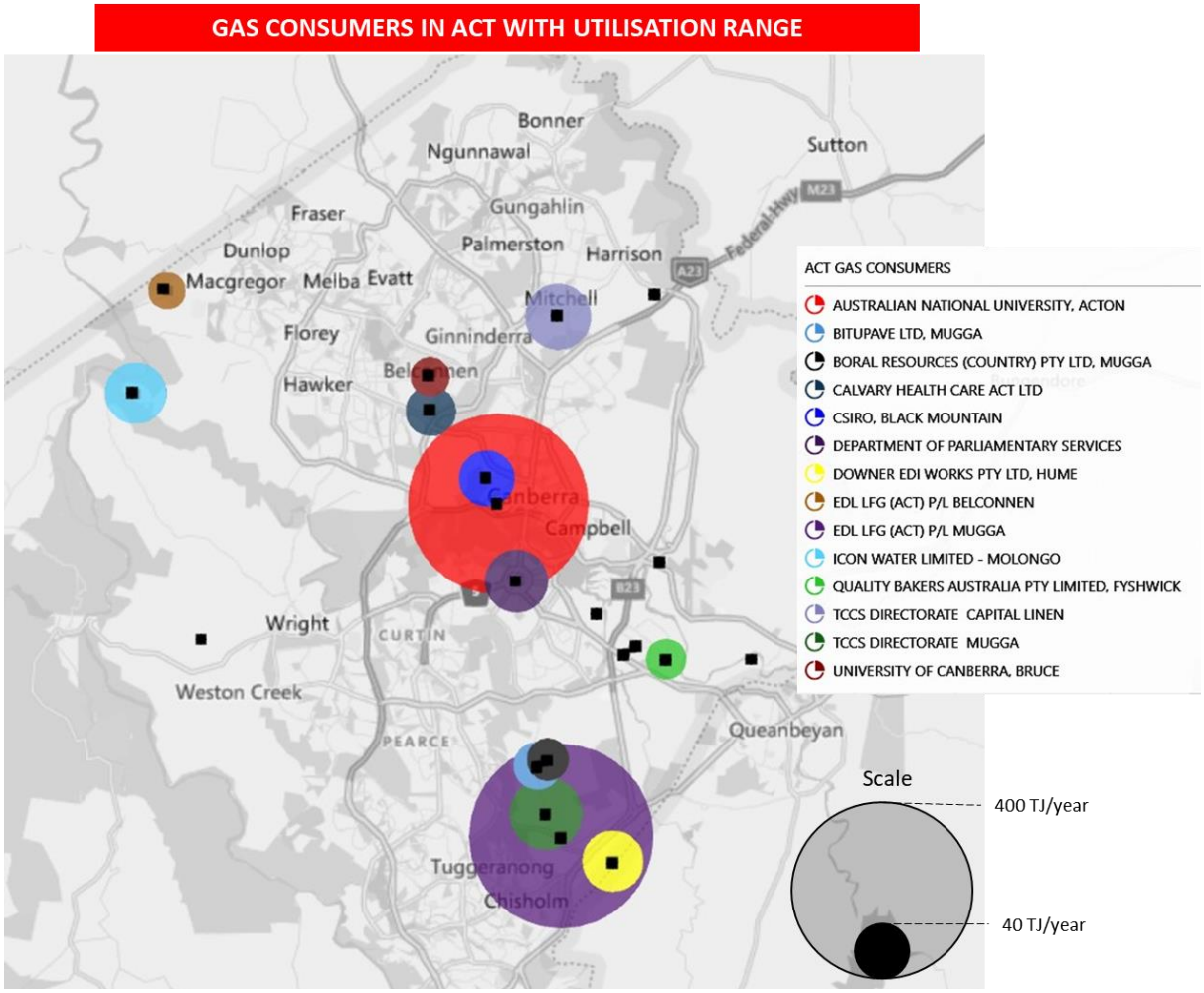


Figure 14: ACT large gas consumers registered with NPI and their gas utilisation range.

The Federal government is also a significant gas user in the ACT via Parliament House plus also CSIRO and tenancy in commercial buildings not in this list. Thus, as with the ACT Government, direct procurement action could add to Green Gas demand if that was desired.

Discussions with stakeholders has revealed a group of interested organisations, concentrated in NSW, in purchasing Green Gas. Jemena is facilitating a Renewable Gas Users Group in which the lead organisations include carpet manufacturer Interface Australia, the City of Sydney and commercial building owner Dexus.

A private register of potential offtakers has been developed by the gas retailer, Weston Energy, which includes Unilever, Carlton Breweries, Snackbrands and other large gas users. Weston Energy propose to undertake private certification in the absence of this being performed by a government entity for a pilot project. Whilst it is unlikely that these NSW based organisations would source Green Gas from the ACT, it is more to be taken as an indication that a similar level of interest may be expected in the ACT if Green Gas were suitably promoted.

In this regard, ITP has previously worked with a company in the asphalt business. Although they do not figure in the list of larger users, they are in the process of installing an asphalt plant of their own (having previously bought hot asphalt mix from other suppliers). They have

a strong interest in being able to offer a green asphalt product, however their uptake of Green Gas is contingent on their clients wish to procure that product. The ACT Government is obviously the prime client in the ACT for roadmaking.

5.1.3 Commercial buildings

Dexus and other commercial building owners are participants in the NSW Renewable Gas Users Group. Organisations in this sector often have government and corporate tenants who are increasingly adopting sustainability targets for their own operations. This carries over into a requirement to achieve minimum NABERS star ratings in buildings they occupy for example. Building managers indicate that full electrification is not an easy and readily commercially available approach at present. There is clearly an appetite for some level of Green Gas supply, noting that cost of supply will be important to this segment.

Where back up gas engine electricity generators are incorporated in commercial premises, there is potential for innovative approaches. With dispatchable renewable electricity an increasingly important complement to wind and PV, gas engines operated on Green Gas could help to provide this whilst directing the engine and exhaust heat towards building heating in an established co-generation approach. In Australia, natural gas fired co-generation has not progressed as much as might be anticipated due to rising natural gas prices and relatively low wholesale electricity prices. However, in the context of full zero emissions targets, it represents an important system optimisation tool, particularly if high value dispatchable / peaking renewable electricity were suitably rewarded.

5.1.4 Transport

Building on the comments above in regard the CNG bus fleet, hydrogen fuel cell buses would be an obvious potential step that would create Green Gas demand and work to reduce emissions in the large transport sector. Again, this is in the hands of the ACT Government.

The 20 Hyundai Nexus Fuel cell cars that are due to enter service in 2020 can be expected to create a demand for hydrogen of around 360 GJ/year. Once the filling station is established it is likely that others will gradually pursue fuel cell vehicles also.

The Elvin group have their origins as an ACT based concrete supplier. They have recently been associated with a new initiative (H2X) to manufacture hydrogen fuel cell vehicles at Port Kembla. It is understood that the initial motivation was consideration of suitable future fuels for their own truck fleet. Other commercial vehicle operators are likely to be attracted to the hydrogen option as pressure to reduce transport sector emissions grows.

5.1.5 Interstate demand

If Green Gas trading is established within the east coast gas network as a whole, then in principle, consumers outside the ACT could buy Green Gas produced within the ACT. This seems a bit unlikely other than fortuitous special cases in the early stages of Green Gas uptake. ACT does not have any particularly competitive advantages in production compared

to NSW. The opposite situation could be more likely; if the 2045 zero emissions target does lead to large Green Gas demand, it might be cost effectively supplied from outside the ACT.

5.1.6 Evoenergy and UAFG

Evoenergy are the monopoly gas distributor for the ACT. They are responsible for replacing Unaccounted For Gas (UAFG) at cost. UAFG arises from a combination of small leaks in the system and conservative meter calibrations slightly underestimating gas consumption to the customers advantage. Evoenergy is actively supporting the idea of Green Gas uptake. Using their own purchase of UAFG for Green Gas has been mooted as an administratively easy approach to establishing some demand. The issue of cost recovery of price premiums remains to be resolved, however.

5.1.7 Overall near term demand

Based on the above discussion, we estimate that with reasonable steps to certify and promote Green Gas, near term voluntary demand is likely to be approximately:

- Continuation of existing landfill gas use at 315 TJ/year
- New voluntary demand for lower cost Green Gas (< $12/GJ production cost) at 1- 2 % of existing gas demand being between 70 TJ and 140 TJ/year
- Demand for hydrogen for fuel cell vehicles of around 2.2 TJ/year (say 100 cars plus 20 large commercial vehicles) within 2-3 years.

However, this is subject to a great deal of uncertainty and strongly dependant on the various actions of the ACT Government.

5.2 Long term uptake

The ACT Government's legislated commitment to net zero GHG emissions across all sectors by 2045 means that essentially all current natural gas and petroleum fuel use must be replaced. Assuming the mechanisms chosen to mandate this outcome do not actively discourage or prohibit Green Gas usage, the issue becomes one of market competition between Green Gas based solutions and renewable electrification based solutions. In the absence of detailed modelling of cost evolution among technologies and possible uptake, some qualitative observations can be made that work to suggest that Green Gas will have a significant role:

- Green Gas is better able to match the seasonal and daily peaks in demand that are driven by space heating.
- Green Gas could drive conventional combined heat and power systems for larger commercial operations, helping to address both electric and gas sectors in an optimal way.
- The introduction to the market of combined heat and power fuel cell products could facilitate cost effective use in smaller / domestic buildings.
- Full electrification would require major investment in electricity network upgrades that would be passed on to consumers.

- As transport is decarbonised, at least some subsectors, such as high use commercial vehicles, are likely to favour the hydrogen fuel cell route over battery vehicles.
- The waste treatment issues that must be dealt with in an essential manner, will naturally lead to the production of Green Gas equivalent to between 10% and 20% of current natural gas use. It would be implausible to imagine that this would simply be flared, rather the supply demand balance should lead to its usage in economically preferred ways.

Putting this together we thus estimate that by 2045, Green Gas demand will be:

- between 30% and 60% of existing natural gas demand (i.e. between 2100 TJ/year and 4200 TJ/year), plus
- between 10% and 50% of the existing transport market, (i.e. between 1700 TJ/year and 8500 TJ/year).

6 POLICY AND INDUSTRY ADVOCACY IN AUSTRALIA

There is significant interest and focus on the hydrogen agenda by State Governments and at the national level via the COAG Energy Council. Interest by State Governments is primarily focused on the development of the hydrogen sector as a new export industry. These processes have driven and are driving a vast body of work (legal assessment, approach to incentives/market mechanisms, certification etc) that could be leveraged to inform broader considerations for Green Gas. Gas infrastructure owners also have long term interests in their assets, are undertaking pilot projects and are advocating for supportive policy. In addition, ARENA is considering mechanisms to support the development of the bioenergy sector and a certificate system for biogas is under active consultation. This is a notable development, with submissions made, and has significant scope to influence the considerations for Green Gas trading. There are businesses wanting Green Gas to meet their targets for sustainability, and the NSW Government is progressed in coordinating interests in NSW to undertake a pilot project for Green Gas trading.

The broader framework for carbon trading in the international context also factors in any considerations for Green Gas trading at state or national level. The pre-existing framework used in Australia is briefly discussed at the end of the section on Federal developments.

6.1.1 Federal Developments

National Hydrogen Strategy

Hydrogen is under active consideration by the successor to the COAG Energy Council with a working group formed in 2018 and chaired by the Chief Scientist Dr Alan Finkel AO. In 2019, Australia's *National Hydrogen Strategy*[34] was released, outlining a vision for a clean, innovative, safe and competitive hydrogen industry to benefit all Australians. It sets out 57 nationally coordinated actions and is focused on positioning the industry as a major export player by 2030. It mentions a single global certification scheme for guarantee of origin as a desirable development from the point of view of Australian and international consumers. Although Australia has hopes to be a leader in the design and development of such an international scheme, the most advanced work completed to date has been undertaken in the EU under the CertifHy project.[35]

Given the potential for international agreement about certification to lag developments in hydrogen production, a staged approach to introducing a scheme that verifies and tracks production technology, Scope 1 and Scope 2 emissions and production location in the first instance, is discussed. A survey on hydrogen certification as a standardised process of tracing and certifying where and how hydrogen is made, and associated emissions, has been issued by the Department of Industry, Science, Energy and Resources and it closed on 22 June 2020. The intention of the survey is to inform high-level aspects of an international

[34] (COAG, 2019), Australia's National Hydrogen Strategy.
[35] See further: http://certify.eu.

and/or domestic hydrogen certification scheme and to guide future consultations on the detailed design of any scheme.

ARENA Bioenergy Roadmap

ARENA has commissioned ENEA Consulting and Deloitte Touche Tohmatsu to provide a *Bioenergy Roadmap* to inform the next investment and policy decisions in the bioenergy sector in Australia. The process includes consideration of certificates for biogas. The final report is expected by the end of 2020. A call for submissions has been made and closed on 10 June 2020.

Clean Energy Regulator (CER)

The CER is the administrator of the federal renewable energy target and carbon market mechanisms and schemes for measuring, reducing, and offsetting emissions as legislated by the Federal Government. The CER's responsibility includes administration of the National Greenhouse and Energy Reporting scheme, Renewable Energy Target, Emissions Reduction Fund (ERF), and Australian National Registry of Emission Units (the electronic system to track the location and ownership of Australian carbon credit units or ACCUs).

In its submission to ARENA's Bioenergy Roadmap consultations, the CER stated it had been approached by six gas network companies who are interested in the production of biomethane for injection into existing gas pipelines for sale to their customers. For this to be commercially viable, CER notes:

- Changes to some ERF methods would be needed to allow recognition of the destruction of captured methane at the point of capture and injection to the pipeline to allow the crediting of ACCUs at that point.
- A traceability mechanism so these companies can accurately prove to their customers the volume of biomethane that has been produced and injected into gas pipelines, noting that in the electricity sector, the traceability/recognition of the use of renewable electricity is through the purchase and surrender of LGCs.

The CER is in discussion with those companies on how it could assist in a pilot verification arrangement, noting that some form of certificate such as the CertifHy scheme in Europe is likely to be simpler to administer if this is scaled up beyond pilots.

The CER further notes the success of Guarantee of Origin (GO) schemes in Europe and increased demand for bioenergy and clean hydrogen GOs leading to requests for a harmonized European-wide gas GO market, as well as existing work underway to deepen and strengthen voluntary private markets by improving registry systems to provide information about the provenance of certificates.

From discussions it is apparent the CER is keen to take a lead role in certification. It does however require some form of federal legislated mandate to allow it to act.

Climate Active (Formerly the National Carbon Offset Standard)

Climate Active is a Federal Government endorsed, carbon neutral certification program.[36] The certification is awarded to organisations that have voluntarily achieved carbon neutrality for their entire or part of organisation, buildings, products, services or events, through emissions reductions and purchase of carbon offsets. The program recognises LGCs, ACCUs and other internationally recognised carbon units as legitimate units that can count toward carbon neutrality claims.

6.1.2 State Developments

NSW Government

The New South Wales Government has in place an aspirational target for 10% hydrogen in the state's gas networks by 2030. The NSW Department of Planning, Industry and Environment has been coordinating an interested group of potential renewable gas producers, buyers, and other stakeholders via the Sustainability Advantage program. This has included the development of a roadmap to address the barriers to establishing a renewable gas marketplace in NSW.[37] In the first instance, the roadmap process has identified a primary and secondary set of stakeholders as shown in Figure 15. The primary group includes those with interests in pilot projects, potential renewable gas producers and consumers for a pilot project, Green Gas certification process development, and Green Gas certificate scheme administration. The secondary group includes those have a general interest in renewable gas production due to the nature of their business and those who to have an interest in renewable gas products to meet their decarbonisation targets.[38]

As a precursor to any national market for Green Gas commencing, the NSW Government seems interested in a first phase pilot demonstration of a renewable gas project that would create a Green Gas offset product certified by gas retailer, Weston Energy. Weston Energy currently offers both traditional natural gas and Green Gas products to large gas users including the ACT Government, ANU and the Department of Defence. It has a number of gas users interested in Green Gas purchases and 100-300 TJ of potential supply from bioenergy producers which is being offered in 5-year offtake agreements. A second phase would involve a commercial scale project with an auditable Green Gas product similar to GreenPower.

GreenPower is a voluntary product for renewable electricity purchase from accredited sources that is available nationally. It is a joint initiative of the NSW, ACT, SA and Victorian Governments that was implemented before the existence of the mandatory national Renewable Energy Target (RET). At the time of introduction, the cost of renewable sourced electricity was not price competitive with conventional electricity and renewable electricity purchasing was not widespread practice. Under the program, accreditation occurs through

[36] https://www.climateactive.org.au/.
[37] (Blue Tribe Co, 2020), Renewable Gas: Roadmap for the development of a renewable gas marketplace in NSW.
[38] This includes manufacturing and property sectors, hospitals, schools/education institutions, and local governments who have targets for sustainability.

independent auditing of GreenPower providers each year. GreenPower has served to increase awareness and confidence in renewable electricity purchasing. The NSW Government has indicated the GreenPower scheme could be adapted to provide a similar role for gas. This would support consumer confidence in Green Gas through accreditation of providers but not necessarily involve administration of certificates or certificate trading, which would need to be managed by another entity.

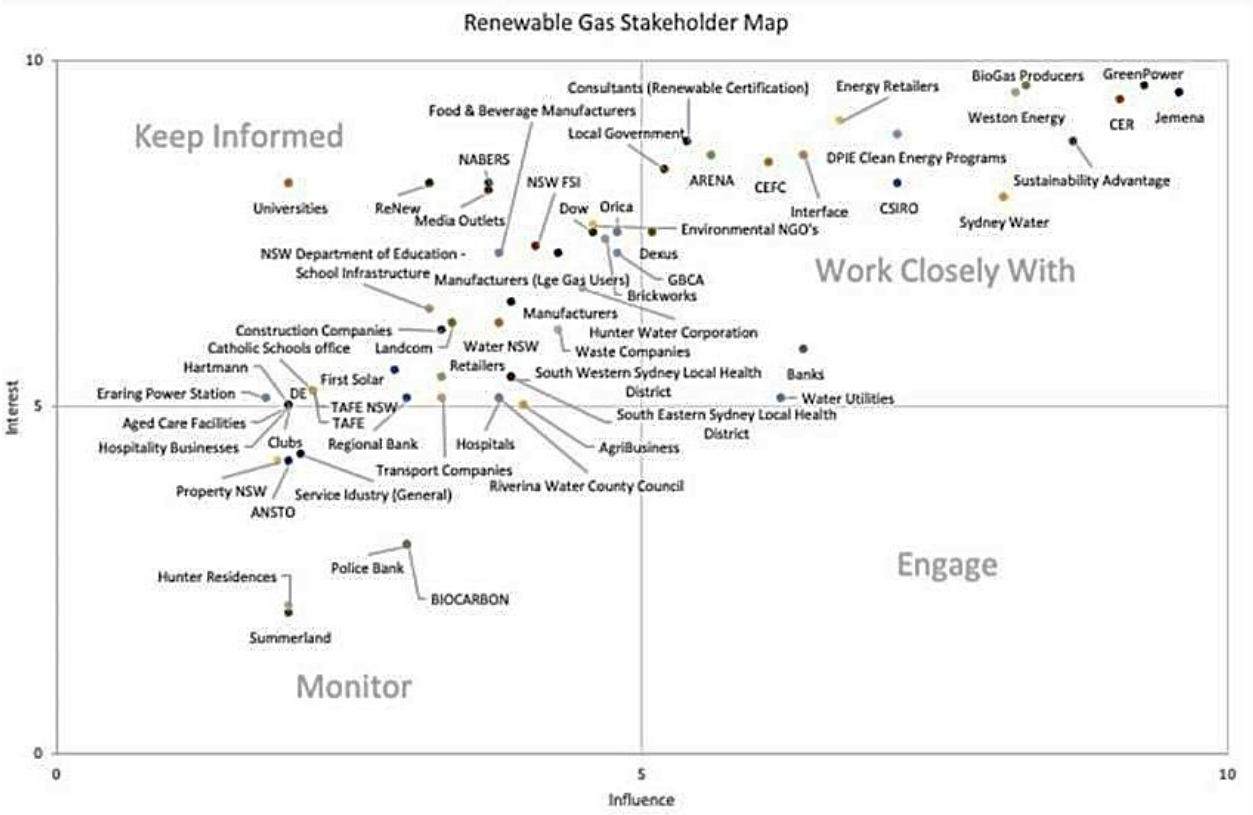


Figure 15: Renewable gas stakeholder map, (NSW Department of Planning, Industry and Environment, 2020).

Victorian Government

In November 2019, the Victorian Government commenced a consultation process on the green hydrogen drivers, barriers, and opportunities to inform the development of an Industry Development Plan. In calling for submissions to this process, the discussion paper indicates regulatory settings for the hydrogen sector as important, including those that will apply for trading.[39]

Tasmanian Government

The draft Tasmania Renewable Hydrogen Action Plan points to Tasmania as an ideal location for renewable hydrogen production, for export and for local use, with capacity for gigawatt scale production over the longer term. It states a “hydrogen certification or guarantee of origin scheme will provide importing countries and end users with assurances that the hydrogen they are purchasing is from sustainable resources and produced using

[39] (VHIP, 2019), Green Hydrogen Discussion Paper.

renewable energy…[and that the] Tasmanian Government will work collaboratively with other governments and industry to facilitate the development of a certification scheme that recognises and values Tasmania's renewable energy characteristics and sustainable water resources."[40]

Queensland Government

The Queensland Hydrogen Industry Strategy 2019-2024 has a focus on hydrogen as an export sector to support jobs, regional and economic development. The document refers to hydrogen-based fuels green certification being investigated by CSIRO through Hydrogen Mobility Australia. It indicates support for a national accreditation system as important for the development of the hydrogen industry.[41]

South Australian Government

The South Australian Government has funded four demonstration projects in South Australia and in February 2020 jointly funded with ARENA the Australian Hydrogen Centre. It is focused on implementation of these projects. Its overarching strategy document, the South Australian Hydrogen Action Plan notes 'The South Australian Government will continue to work with Australian and international jurisdictions, including through the National Hydrogen Strategy, to develop an appropriate mechanism to guarantee the origin of South Australian hydrogen production for domestic use and export."[42]

Western Australian Government

Western Australia is supporting a 18-month study into the feasibility of using hydrogen in the Dampier to Bunbury Natural Gas Pipeline. The Western Australian Renewable Hydrogen Strategy notes the WA Government will work with Federal Government on regulatory reform including certification of origin processes and potential incentive programs.[43]

6.1.3 Industry Developments

Bioenergy Australia

Bioenergy Australia is a not-for-profit association which advocates for the development of the bioenergy sector. Bioenergy Australia supports the introduction of a near-term Green Gas target by 2030, recognition of biomethane injection to gas networks as a net zero emission energy source including through the Emission Reduction Fund, the development of a renewable gas certification system that would enable tracking of biomethane injected to the grid (via an electronic unique identifier certificate containing information about where, when and how biomethane was produced) and development of a renewable gas injection feed-in tariff to provide biogas producers with a 20-year fixed price purchase guarantee. It also supports implementation of gas swapping of biomethane for natural gas, where

[40] (Tasmanian Government, 2019), Draft Tasmania Renewable Hydrogen Action Plan.
[41] (Queensland Government, 2019), Queensland Hydrogen Industry Strategy 2019-2024.
[42] (Government of South Australia, 2019), South Australian Hydrogen Action Plan.
[43] (WA Government, 2019), Western Australian Renewable Hydrogen Strategy.

consumers could purchase the environmental properties of biomethane separately to the gas commodity with changes to the National Greenhouse and Energy Reporting scheme.

Energy Networks Australia (ENA)

ENA is a national industry association representing Australia's electricity transmission and distribution network and gas transmission and distribution network companies. In its submission to ARENA's Bioenergy Roadmap consultations, ENA indicated "upgrading the biogas to biomethane and hydrogen technologies create the greatest opportunity to decarbonise the network sector" but that understanding the resource availability of different renewable gas options as important. It stated if "there is high confidence that enough biogas could be produced to replace domestic natural gas demand, then that could shape the national gas decarbonisation strategy. [But] if "only a portion could be replaced with biogas, then blends of renewable hydrogen with biogas or complete regional separation of gas composition could be planned." The ENA points to efforts in the UK main network of conversion to hydrogen and biomethane proposed in regional networks and for mobility.

ENA commissioned Energetics[44] to compare renewable gas incentives with those for renewable electricity. Energetics recommended a 2030 aspirational target for renewable gas injection into gas networks and as a financial incentive, a new method for the creation of Australian Carbon Credit Units for projects that injection renewable gas into gas networks.

ENA commissioned Oakley Greenwood[45] to advise on a policy framework for renewable gas blending. Oakley Greenwood noted a certificate scheme as likely the most appropriate means of incentivising blending (i.e. over an ex-ante feed-in tariff).

Overall, ENA supports the development of suitable incentives to support bio-methane blending in networks such as setting a target for renewable gas and/or providing grant funding to bridge the commercial gas with early blending projects. Discussions with ENA suggests there is not universal support for mandates in its membership and carbon pricing is a favoured approach.

Jemena

Jemena is an owner of energy infrastructure and the largest gas distributor in NSW. It is very active in Green Gas and is looking at biomethane and hydrogen. It also made a submission to ARENA's Bioenergy Roadmap consultations, highlighting its work with GreenPower in NSW and New South Wales customers' calls for access to the benefits of renewable gas and supporting the call for a national accreditation scheme.

A key policy position that was evident from discussions with Jemena was that changes are needed to ERF methods to allow ACCUs to be created by injection of landfill gas into the gas network and use, with consideration given to the escape of methane as a fugitive

[44] (Energetics, 2019), Renewable gas for the future: Policies to support Australia's sustainable and affordable gas network.
[45] (Oakley Greenwood, 2019), Renewable gas blending scheme – report for ENA. ITP were unable to obtain a copy of this report.

emission. Jemena (and Evoenergy) support 10% renewable gas mandate by 2030 with a trading certificate scheme as the mechanism to support achievement of the mandate.

Jemena's activities in this area are discussed further in Chapter 7 of this report.

Australian Gas Infrastructure Group (AGIG)

AGIG own gas distribution and transmission networks in Victoria, SA, Queensland, NSW, WA and NT. AGIG sees transitioning to net zero emission gas as part of its long term vision. AGIG's strategy for decarbonising the gas sector is focused on four technologies including hydrogen for injection into their gas networks and fuel cell vehicles.

AGIG provided a response to the ACT Sustainable Energy Policy 2020-2025 Discussion Paper which flagged the potential for a target for renewable gas consumption. AGIG welcomed the idea of a gas target at national or state level and noted *"no reason why 100% renewable gas couldn't be delivered before 2045"*.[46] AGIG supports a renewable gas blending target to require retailers to source zero emission gas into the gas distribution network (citing an equivalent of 10% hydrogen by volume by 2030). In discussions with AGIG, they did not express a preference for the mechanism to achieve the target (i.e. could be certificate-based or contracts for difference). As part of the target, AGIG proposes that gas networks be required to completely offset unaccounted for gas (UAFG) from distribution networks with renewable gases blended into the network by 2025.[47]

AGIG, Jemena, Ausnet and Evoenergy

The parties collaboratively released an Expression of Interest to seek information from the international hydrogen supply chain on the feasibility, approach and cost of achieving 10% renewable gas in networks in the eastern and southern states of Australia by 2030.[48] The expression of interest closed in May 2020.

Hydrogen Council

Formerly the Hydrogen Mobility Association, the Hydrogen Council has now widened its scope and added a range of new members. They have yet to finalise positions of Green Gas trading issues although support a 10% by 2030 hydrogen mandate. They have 10 separate working groups, with government representatives included, looking at a range of technical and market issues.

Pipeline injection under ERF

As noted above, a range of stakeholders have identified a need for a new methodology under the ERF to recognise that pipeline injection of biomethane is as an effective a destruction mechanism as destruction at the point of capture. As things stand injection cannot generate ACUs and so flaring of biogas is perversely incentivised over productive

[46] (AGIG, 2019), AGIG submission the ACT Sustainable Energy Policy 2020-2025.
[47] UAFG is a cost-pass through to customers and any proposal to introduce renewable gas to cover UAFG would require approval by the Australian Energy Regulator.
[48] https://www.agig.com.au/media-release---greater-hydrogen-use.

use. This issue simply requires the federal department to formulate a formal methodology, it does not require any legislative change.

7 GREEN GAS CERTIFICATION

This chapter discusses the options for certifying Green Gas. It considers the approaches to verifying zero emissions claims and auditing and compliance processes used. The focus is on the technical aspects of certification. This is analysed with respect to national and international best practice to certification around the world.

7.1 Introduction to Certification: Guarantees of Origin

In the broadest sense, certification involves creating a paper or electronic certificate for each unit of energy (electricity or gas) to guarantee the origin assuring buyers that the source is genuine, the environment benefits are real, and the gas has not been sold to someone else. Each certificate is given a unique identifier that can be traced back through the supply chain to the producer.

In the European context, for instance, the 2nd EU Directive on Renewable Energy (of Dec 2018) states (Art.55) *"Guarantees of origin issued for the purposes of this Directive have the sole function of showing to a final customer that a given share or quantity of energy was produced from renewable sources. A guarantee of origin can be transferred, independently of the energy to which it relates, from one holder to another. However, with a view to ensuring that a unit of renewable energy is disclosed to a customer only once, double counting and double disclosure of guarantees of origin should be avoided. Energy from renewable sources in relation to which the accompanying guarantee of origin has been sold separately by the producer should not be disclosed or sold to the final customer as energy from renewable sources."*

It is useful to distinguish between certification of origin (or guarantees of origin, GO as commonly known in the UK and Europe) from the notion of tradeable certificates with an economic value, which is associated with quota-based policy incentives for renewable gas production. In other words, certification of origin should not be conflated with tradeable certificate incentives.

In the absence of any certification, claims for marketing purposes e.g. "Our company has consumed 100% renewable gas this year" cannot easily be reliably verified. Private certification approaches can help to apply rigor to guarantee of origin claims and may have a place in the establishment of pilot projects. However, where justified by the size of the market, certification by a central authority tends to increase market confidence and trust in the environmental/emissions credentials of the energy.

7.1.1 Essential components of certification

The key elements of a certificate are:

- the energy source
- the production date
- The type of gas including biomethane or hydrogen
- where and who was responsible for production using what method

- the date and place of issue of the certificate
- a unique identification number

A key aspect of certification is the verification of zero emissions claims auditing and compliance processes used. There are numerous models for this nationally and overseas.

7.1.2 Key functions of certification

Certification serves to facilitate the following functions:

- Measurement of gas production and transfer
- Reporting and registration
- Independent verification of producer claims
- Integrity of the registry including prevention of fraud and tax fraud
- Facilitating a marketplace for transactions, with liquidity, price discovery and transparency

7.1.3 Certification Models

There are a range of certification models on a continuum from simple to complex. The simplest model is a *bulletin board*, a simple registry to match buyers and sellers and to track production. The most complex is a *futures trading model* linked to the stock market operating alongside a federal legislative model (which is the case for the Federal RET and the ASX listed futures in LGCs).

In the absence of certificates, Green Gas trading can still occur via bilateral, private contracts between buyer and seller. However, under such an approach there will not be significant market growth, and the price premium paid for renewable gas, compared to conventional/fossil natural gas would not be transparent to the market.

If a system of certificates was introduced, accessible on a voluntary basis, this would encourage greater buyer engagement with the product/concept of Green Gas.

Certificates encourage market growth because they reduce the need for the buyer to contact the seller directly. They decouple the buyer from the seller, using the certificate as the intermediary.

Certificates enable the environmental attributes of renewable gas to be detached from the gas itself. It is technically possible for a buyer or trader to just buy the renewable gas certificates but not the gas itself.

To drive greater supply of renewable gas to the market, as a substitute for fossil natural gas, the introduction of a quota obligation on gas utilities could be introduced. This quota obligation could be designed to fall upon the wholesale buyers of gas (effectively the retailers), as is the case in the national renewable electricity certificates market.

Certificates of origin *either* can be generated by the seller (and subject to audit) or generated only by the registry operator.

7.1.4 Further detailed design questions:

There are some fundamental questions in the design of Green Gas certification:

i. Which Gases are included?
ii. What Units are to be used?
iii. What Carbon Intensity is allowed?
iv. What Quality standard must the gas meet?
v. How are questions of differential heating value of different gases per volume to be resolved, or accounted for?
vi. Which sectors are included in the certification?
vii. Is the certification system nationally compatible?
viii. Is the certification system internationally compatible?
ix. Who is running the scheme? Who is administering it? Under what legal authority?
x. Who pays for its operation?
xi. Who audits and enforces it?

7.1.5 Choice of Units and their link to certificates

As is the case for renewable electricity under Australia's federal law for the RET, Green Gas certificates could be based on their energy value. In other words, for renewable electricity certificates, the standard is that 1 certificate is created per MWh of additional renewable generation above the baseline for an accredited RE generator. Under the *Renewable Energy (Electricity) Act 2000* (Cth), s.18, an eligible power station can create one certificate per MWh of additional renewable electricity created.[49]

For renewable gas, there is a choice in terms of units: between GJ (traditional energy value for gas) or MWh / kWh (traditional energy value for electricity). In any case these units can be converted with the equivalence, depending on the gas involved. The Danish approach for renewable gas uses certificates is based on MWh. In Denmark, *"A certificate certifies that an amount of gas with an energy content of 1 MWh has been produced and supplied to the natural gas grid."*[50]

In energy terms, there is a simple conversion of 1 MWh = 3.6 GJ. However, this should not be confused with the conversion efficiency of electricity to hydrogen or the conversion of gas to electricity in a power station.

7.1.6 Scope of certification

On the question of which gases can certificates be created for, as highlighted in Chapter 6, much of the existing work in Australia relates to certification of hydrogen, although work is also in progress for biomethane. Most EU countries already have registries for biomethane. A general principle is that an effective scheme should make provision for all viable sources that are measurable and not seek to specifically prohibit any zero emission types. The

[49] Commonwealth Consolidated Acts, *Renewable Energy (Electricity) Act 2000* (Cth), s.18. Retrieved from http://www.austlii.edu.au/cgi-bin/viewdoc/au/legis/cth/consol_act/rea2000283/s18.html
[50] (Eneginet.dk, 2017), Model Paper for Rules for Biomethane Certificates in Denmark.

experience of the RET has been to allow certificate creation from a range of sources, with the price mechanism determining certificate creation by the least cost source. It could be reasonably expected in the Green Gas context for certificates to be created for biomethane and hydrogen. In the long-term, ideally, the certificates should be fungible so that a customer can buy a combination of renewable gases, e.g. hydrogen and biomethane, depending on price and availability.

There is a boundary question about whether certificates should be created for transport applications, or stationary energy, or industrial input, or all three.

There are additional questions about the scope of certification, some of which are most relevant to the Federal government and not to the ACT. Three separate scenarios for certification, raise slightly different policy considerations. These are:

a. Certification of H_2 for export
b. Certification of H_2 for domestic market only
c. Certification of biomethane for domestic market

In the context of hydrogen export, the Federal government is considering proposals for hydrogen produced with offsets and CCS to come within the definition of low emissions hydrogen.

This raises the question of whether the ACT wishes to enact a legislative definition of green hydrogen. Analysis produced by Dr James Prest for the Energy Change Institute of the ANU argues that there is a need to legislate for a definition of 'green hydrogen'.[51] This is necessary to create an incentive for the use of renewable energy in the production of hydrogen rather than its production from steam methane reformation of natural gas, which is usually considered (at present) to be more cost-effective than renewably produced hydrogen. European approaches to this question emphasise the need for precision in terms of requiring the producer to give guarantees of origin, for example, to prove that a specified quantity of hydrogen was produced from a renewable energy source and whether a specified quantity of hydrogen was associated with specific levels of GHG emissions (e.g. in kg of CO_2-equivalent per MWh of hydrogen).[52] In 2017, a South Australian hydrogen study suggested the following definition of green hydrogen: *"hydrogen that has been produced using energy from renewable sources or is net carbon zero energy through carbon capture and/or emissions offsets."*[53] This definition, due to the reference to offsets, leaves the door open for production of hydrogen from steam reformation of natural gas and other fossil fuels. It is important that Government and policy makers consider whether they wish to allow carbon offsets in the definition of clean or green or renewable hydrogen.

[51] (ANU ECI, 2019), Submission to National Hydrogen Strategy Discussion Paper.
[52] California Senate Bill No. 1505, adding Section 43869 to the Health and Safety Code of California. http://www.leginfo.ca.gov/pub/05-06/bill/sen/sb_1501-1550/sb_1505_bill_20060930_chaptered.pdf
[53] (Advisian and ACIL Consulting, 2017), South Australian Green Hydrogen Study.

7.2 Policy options in certification

The first question is whether certification is considered an issue for government, warranting the passage of legislation.

Certificates for Green Gas can be entirely voluntary or linked to mandatory obligation on retailers. Another way of conceptualising this is whether certification is applied on the demand side or supply side, in other words 'producer facing' or 'consumer facing' (or both).

Options for certification include:

i. Privately run on a fully commercial basis (cost recovery through certificate price) from largest consumers only
ii. Privately run but paid for by early adopter small consumers as well as largest consumers
iii. Privately run but paid for by government
iv. Privately run but paid for by all consumers
v. Co-regulation (government and industry)
vi. National (Commonwealth) legislation
vii. National (co-operative COAG based) legislation
viii. State and Territory ad hoc legislation

In Europe, national level governments have been required to set up systems of guarantees of origin for energy, by means of an EU Directive.

Non-Governmental Certificates (NGCs) have a structure that is similar or identical to GOs, but they are guaranteed by commercial law rather than national GO legislation.

"*Independent Certification Schemes (ICS) are not certificates in themselves: ICSs categorise certain types of energy sources (i.e. fuels) or supplier products under a specific sustainability scheme according to a set of agreed criteria; and an indication of such can be placed on each qualifying certificate. These ICSs have been defined and governed by organisations independent of suppliers.*" [54]

7.3 Certification overseas

7.3.1 EU

The European biogas market is well established and mature. Fifteen European countries engage in the process of upgrading biogas to biomethane, and 10 countries inject the biomethane into the natural gas grid.[55] There were already 610 biogas upgrading plants,

[54] (Association of Issuing Bodies), Independent Criteria Schemes.

[55] European Commission, European statistics (Eurostat, 2017) Retrieved from http://ec.europa.eu/eurostat>; European Biogas Association (EBA), 'Biomethane Fact Sheet' Retrieved from https://www.europeanbiogas.eu/wp-content/uploads/files/2013/10/eba_biomethane_factsheet.pdf.

producing biomethane by 2018 in the EU, UK and EFTA countries. This represents a tripling of the number of plants since 2011.[56]

A combination of EU Directives and member state laws incentivise the uptake of biogas and its injection into the natural gas system. The main instrument that has promoted biomethane injection into natural gas grids is the *Renewable Energy Directive*.[57]

The EU uses the term 'guarantee of origin' (GO) in preference to 'certificate'. GOs can relate to electricity, gas or heating or cooling. The EU is already moving towards a unified certificate approach to enable cross border biomethane trading under the European Energy Certificate System (EECS). The EU Directive states that GOs for renewable electricity *"should be extended to cover renewable gas"* (Art.59). It states that this would facilitate greater cross-border trade in biomethane. It also encourages *"the creation of guarantees of origin for other renewable gas such as hydrogen."*[58]

7.3.2 United Kingdom (UK)

The UK has a Green Gas Certification Scheme (GGCS), which tracks the contractual flow of each unit of biomethane – from injection into the grid, to trades and sale to consumers.[59]

The GGCS was established in 2010 as a not-for-profit, industry-led scheme to support the development of the new Green Gas market. The scheme provides certainty for purchasers, and the contractual flows prevent double-counting. It creates a unique identifier known as a Renewable Gas Guarantee of Origin (RGGO) for each kWh (rounded to the nearest whole number) of biomethane injected into the grid and registered with the scheme.[60]

RGGOs are traded by GGCS suppliers, then sold to gas consumers and retired from the GGCS system. The reliability of this certification can be checked online by entering the identifier number of the gas, providing online assurance that the gas has not been sold to another customer.[61]

7.3.3 Germany

According to DENA, the German Energy Agency that administers the German biogas register:

"Dena developed the biogas register together with 14 leading companies from the ***biogas and biomethane industry.*** *With its help, biomethane producers can verify the quantity and quality of biomethane in the natural gas network −from production to consumption. The information obtained in this manner can then in turn be used by intermediaries, final*

[56] (Bioenergy Europe, 2019), Biogas Statistical Report 2019.
[57] Directive (EU) 2018/2001 of the European Parliament and of the Council of 11 December 2018 on the promotion of the use of energy from renewable sources; recasting European Commission, Directive 2009/28/EC of The European Parliament and of The Council of 23 April 2009 on the promotion of the use of energy from renewable sources; 2009.
[58] Article 59, Renewable Energy Directive II of 2018.
[59] (Renewable Energy Assurance Limited), 'The Green Gas Certification Scheme'.
[60] Ibid.
[61] Ibid.

consumers, and public utilities for marketing and legally required documentation. The biogas register is regularly certified according to the prevailing quality and safety requirements. Auditors ensure the correctness of the information; and ena, in the role of the registrar, subsequently checks them for plausibility."[62]

7.3.4 Denmark

Denmark's voluntary certificate scheme is administered by Energinet, the national gas transmission utility under the Danish *Natural Gas Supply Act*. The certificate of origin scheme tracks biogas when it is mixed with natural gas, which ensures that the biogas can be sold from manufacturer to consumer – even though the molecules in the network are mixed. Each MWh of biogas is equivalent to one certificate. Denmark offers an incentive for renewable gas similar to a feed-in tariff. The certificates are issued on the basis of the amount of upgraded biogas that receives support in the form of the Danish Energy Agency's price supplement.

The various tracking mechanisms used and details of institutions involved overseas are shown in Table 8.

Table 8: Tracking mechanisms for origin of biomethane in various European countries[63]

Country	Name of mechanism	Institution in charge	Status
Austria	Biomethane Register Austria	AGCS	In operation since May 2012
Denmark		Energinet	In operation
France	GoO register	Gaz réseau distribution France (GrDF)	Under development
Germany	German Biogas Register	German Energy Agency (dena)	In operation since 2011
The Netherlands		Vertogas	In operation since July 2009
Poland	Register of energy companies producing agricultural biogas	Agricultural Market Agency	In operation since January 2010.[64]

[62] (DENA), Biogas Register.
[63] (Strauch et al, 2013), A Biomethane guide for decision makers: Policy guide on biogas injection into the natural gas grid.
[64] Journal of Laws of the Republic of Poland, 2010., No 21, item 104.

Sweden		Energigas Sverige	In operation
Switzerland	Swiss national biogas registry	Federation of Swiss Gas Industry	In operation since 2011
UK	Green Gas Certificate Scheme	Renewable Energy Association REA	In operation

Note also that a Europe-wide a biogas Registry has already been set up, with a European Certificate of Origin. The European Renewable Gas Registry (ERGaR) is an association set up to enable cross-border transfer of certification including via a voluntary mass balancing scheme *"to trace virtually the chain of custody of renewable gas distributed along the gas network of Europe. The operation of a mass balance system enables monetising the intrinsic ("bio") value of exported renewable gas without explicitly tracking the physical cross-border movements."*[65]

7.4 Certification in Australia

7.4.1 Collaborations and Organisations

Jemena is coordinating a Renewable Gas Certification Group of stakeholders with interests in renewable gas certification including the Green Building Council of Australia, National Australian Built Environment Rating System (NABERS), GreenPower, NSW Government, retailers, and customers. This group has put forward a concepts brief to the CER outlining the desired principles of scheme design (credible, adaptable and usable), administration by the CER to ensure independence/governance, design options[66], tracking options, energy accounting and other details of operation.

CSIRO and the Australian Hydrogen Council are currently investigating hydrogen-based fuels green certification.

The CER has received approaches for pilot verification by proponents of biomethane to grid injection demonstration projects. In its submission to the ARENA Bioenergy Roadmap consultation process, the CER proposed a mass balance reconciliation for these initial projects.

7.4.2 Potential National Approaches

Certification can be done either on a voluntary basis or by combining the certificate of origin scheme with a quantity obligation that would be placed on the wholesale buyers of gas. The

[65] European Renewable Gas Registry. Retrieved from http://www.ergar.org/abous-us/

[66] The options include book and trade where certificates are created on injection and openly bought and sold, mass balancing where specific matching of injection and withdrawal from a network, or a hybrid of the two. A preference is expressed for book and trade.

latter is equivalent to a renewable portfolio standard used in the electricity market – for example, the tradeable green electricity scheme that underlines Australia's federal RET, detailed in the *Renewable Energy (Electricity) Act 2000* (Cth).

A staged approach to a **renewable gas certificate administered at the national level** could involve:

1. the creation of a **guarantee of origin certificate scheme**, which would amount to a voluntary Green Gas scheme, like Green Power
2. the creation of a **market obligation mechanism** similar to the RET but involving tradeable renewable gas certificates.

Stage 2 would require government, through the federal Clean Energy Regulator, to set a mandatory Green Gas portfolio standard for each of the gas retailers. The Clean Energy Regulator would require a legislative mandate to introduce this market mechanism as its functions are restricted to its governing Act. This is a market obligation mechanism based on a total quantity of renewable gas that must be supplied. It would create a market incentive for renewable gas production, as the certificates would attain a market value and would be tradeable by parties subject to the obligation that they do not have the facilities to make their own renewable gas to meet their portfolio obligation.

The advantage of this approach is that it involves the adaptation and amendment of the existing model of renewable electricity incentive legislation, which is well known. The tradeable certificate model for electricity involves policy concepts and design elements that are already familiar to the Australian energy industry and government.

8 OPTIONS FOR FACILITATING GREEN GAS UPTAKE

This chapter examines potential incentive mechanisms for Green Gas.

8.1 Policy Options to introduce Green Gas Incentives

Policies are necessary to accelerate the production of Green Gas and its injection as hydrogen or biomethane into gas distribution networks and encourage its use for transport.

8.1.1 General observations

Internationally, it is possible to identify six main models of policies and laws to create economic incentives for gas grid injection of Green Gas: [67]

i. feed-in tariffs (plus CFD/auctions) for Green Gas
ii. renewables obligation for Green Gas
iii. grid injection priority (i.e. guaranteed priority of access to gas networks for renewable gas meeting quality standards)
iv. grants for construction of facilities
v. tax/regulatory exemptions for construction of facilities
vi. emissions caps/carbon pricing

Whilst many of these are much easier to implement at a national level, there is still considerable scope for the ACT to address some on a unilateral basis.

Given the current emphasis in policy debates on hydrogen, it is necessary to distinguish between policy measures to encourage renewable heat or renewable gas, or renewable transport, which are technology neutral and those which are specific to the hydrogen sector.

The type of interventions under consideration depend on whether we are looking at the transport sector, electricity sector, gas sector or energy policy generally.

Australia has some general incentives (such as grants from ARENA) for the development of biogas, but no government policies exist to incentivise the development and production of upgraded biogas (biomethane) or hydrogen and support its injection into natural gas networks.

Associated policies that can have an impact are also discussed. This includes bans on sending waste to landfill, such as those that have been introduced in some European nations, which can affect biomethane production from landfill gas. To promote the use of alternative food waste treatment methods, many governments have begun to impose financial incentives and other policies to help them compete against landfill. For example, in the Netherlands a range of landfill bans were introduced in 1995.

[67] (Olczak & Piebalgs), The European experience with Renewable Gas.

8.1.2 Quota approach

This involves setting a mandatory obligation on liable parties to obtain Green Gas certificates[68]. It is designed as a market growth mechanism, or incentive. There are conceptual similarities to the federal RET for renewable electricity, under the *Renewable Energy (Electricity) Act 2000* (Cth). The RET places the obligation on wholesale purchasers of electricity. In the gas context the mandate would apply to wholesale buyers of gas (who are effectively the gas retailers). The wholesale purchasers [retailers] would be required to purchase certificates equivalent to x% of their total gas purchases. For example, 5% of all gas sales by a retailer.

Parties who are subject to the quota obligation, i.e. liable parties, must obtain certificates equivalent to a percentage of their annual gas sales.

If the system were designed to apply to consumers instead of retailers, then a percentage of consumption would be set down in legislation. This would require further detailed consideration.

Whilst it would seem impractical for the ACT to develop its own certificate scheme, it appears likely that the combination of NSW leadership and federal action, which the ACT can support, will produce a workable system in the near future. Assuming this does occur, it becomes practical to leverage such certificates to implement a mandatory quota for Green Gas.

A quota obligation will not require federal legislation or the unanimous agreement of the Council of Australian Governments (COAG). There are several precedents for this approach. The *Renewable Energy (Jobs and Investment) Act 2017* (Vic) was the legislative basis for the Victorian RET. The ACT Greenhouse Gas Abatement Scheme, a quota scheme for ACT electricity retailers, was implemented through the *Electricity Greenhouse Gas Emissions Act 2004 (ACT)* and related instruments.[69]

Conceivably it would also be possible to create a quota obligation on suppliers of transport fuel so that a minimum percentage of fuel sold (by wholesale buyers of fuel) comes from renewable sources (e.g. biogas (compressed biomethane) or biofuel or renewable hydrogen.

8.1.3 Feed in Tariff and/or Auctions for Renewable Gas

It is possible to design a FIT for renewable gas. This can be designed for feed in of renewable gas into the natural gas network, or a dedicated hydrogen network. Germany, for example has had (and will have until at least 2021) a feed-in tariff for biogas from biowaste, manure, landfill gas and sewage gas.[70] The feed-in tariff imposes conditions – such as

[68] It may be possible to design a quota obligation that does not rely upon a certificate mechanism, however this seems unlikely.
[69] The ACT Greenhouse Gas Abatement Scheme was modelled on and worked with the NSW Greenhouse Gas Abatement Scheme. The NSW Independent Pricing and Regulatory Tribunal was the administrator of both schemes.

[70] Renewable Energy Source Act (EEG 2017) (Germany), ss 436, 53(1), 44, 41 par 1-2.

capacity limits, obligations to employ combined heat and power (CHP) technology and obligations to keep a record of which type of biomass is used, as well as other technical and location requirements.[71] The Gas Network Access Ordinance regulates the injection and transportation of gas. [72]

If the intention is to incentivise large scale supply of renewable gas at the lowest possible cost, the ACT could draw upon its experience with the reverse auctions and contracts for difference approach applied in the renewable electricity sector. The existing FIT legislation in the ACT could be adapted to offer a specific incentive for feed-in of electricity using generation from renewable gas, or it could be amended to encourage feed-in of renewable gas to gas networks. It may be preferable to enact stand alone legislation for this or to amend gas and utility sector legislation. This would require further investigation in order to evaluate the benefits and potential issues with of particular designs.

8.2 Overseas case studies

There are a range of examples of successful incentives for Green Gas overseas. These are in Europe, where Germany and the UK are exemplars and in North America, where California and British Columbia are also leading.

8.2.1 Europe

Many governments in the European region have introduced incentives to reduce the high upfront capital costs for the installation of biogas clean-up and upgrading equipment (apart from aiming for the largest possible plant and site to ensure economies of scale).

Overall, the EU approach of 2020 to Energy is to achieve deeper decarbonisation, partly by ongoing operation of the EU Emissions Trading Scheme, through national level initiatives, and through EU programmes encouraging hydrogen with multi-billion Euro subsidies. The EU has made commitments to higher renewable energy targets. As a result, the EU is intending to include renewable gas and to pursue sector coupling/integration (i.e. between electricity/gas/transport). This is evident in the EU Green Deal of 2020 and in the EU Renewable Energy Directive of December 2018, as well as the EU Hydrogen Strategy of 2020 and several specific reports on barriers to sector coupling [73].

The EU is a leader in the number of hydrogen projects being developed and has an ambitious target for 2 x 40 GW of electrolysers by 2030. [74] The Emissions Trading System provides the basis of a supportive policy framework. Almost all members states have included plans for clean hydrogen in the national energy plans. In the immediate term, the focus is on hydrogen use in the industrial sector, heavy duty transport and scaling up the size of electrolysers. Specific policies being considered include end-use sector quotas of hydrogen, standard approaches to assessing carbon intensity of installations, contracts for

[71] Ibid ss 44(1)–(3) par 2–3, 44(c) par 1, 9.
[72] (Urban, 2013), Biomethane injection into natural gas networks.
[73] (Frontier Economics, 2019), Potentials of sector coupling for decarbonisation.
[74] (European Commission, 2020a), A hydrogen strategy for a climate-neutral Europe.

difference, and developing criteria for the certification of hydrogen building on existing monitoring, reporting and verification processes under emission trading system.

8.2.2 Germany

Since 2011, Germany has pursued the *Energiewende*, or 'energy transition' with the aim of decarbonising that nation's energy sector. [75] As part of this goal, Germany aims to replace 6% of its natural gas demand with biomethane in 2020, and 10% by 2030. [76]

Germany has incentive schemes that are intended to increase the production and uptake of biogas injection into the gas distribution network. By 2020, there were 232 plants feeding in biomethane, making Germany the clear leader in Europe in biomethane plants which upgrade biogas as shown in Figure 16.

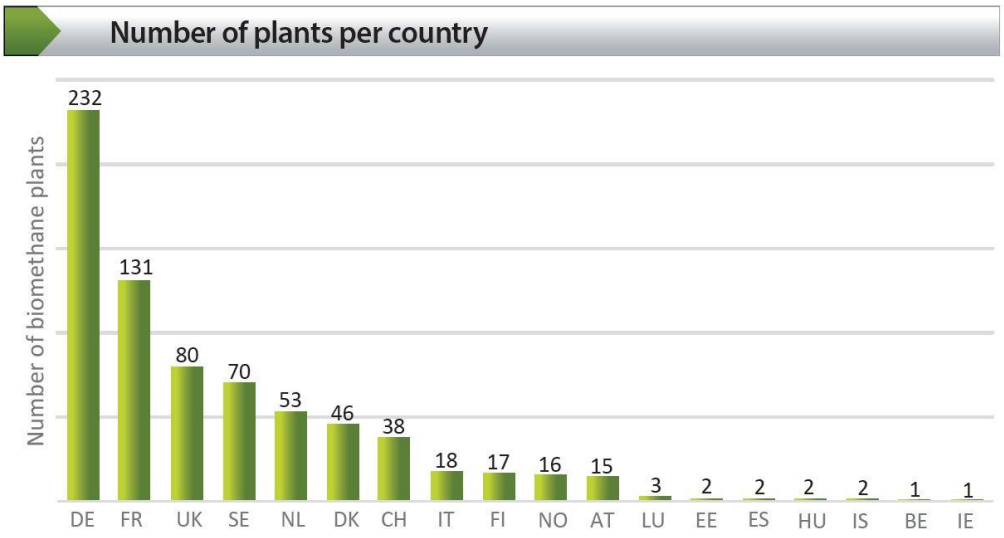


Figure 16: Biomethane Plants per Country, EU in 2020, Source: EBA

The German Government changed the gas grid connection requirements in March 2008 to allow upgraded biogas to be fed into the grid at guaranteed conditions. Under the grid access regulation:

- grid operators have an obligation to connect biogas plants on demand with fixed time schemes
- the biogas plant is responsible for upgrading to (general) natural gas quality (according to the standard)
- the grid operator is responsible for adjustment to local grid conditions (e.g. by adding propane or air to adjust the calorific value)
- the grid operator is responsible for gas quality control, metering, and compression
- operational expenditure and capital expenditure for the injection station and connection pipeline are paid by the gas grid operator

[75] (German Federal Foreign Office, 2016), The German Energiewende: Transforming Germany's energy system.
[76] (German Government, 2007), Integrated Climate and Energy Programme (IEKP).

- a fixed connection fee of €250,000 is paid by the biogas plant operator (some exemptions apply if the connection pipeline is longer than 1km). [77]

Gas feed in tariff

Germany has enacted a gas feed-in tariff for biogas from biowaste, manure, landfill gas and sewage gas. [78] The feed-in tariff imposes conditions – such as capacity limits, obligations to employ combined heat and power (CHP) technology and keep a record of which type of biomass is used, as well as other technical and location requirements.[79] The *Gas Network Access Ordinance* regulates the injection and transportation of gas.[80] In 2005, a special provision for biogas was introduced, regulating access to local distribution networks, setting a priority for biogas transport and outlining responsibility with regard to necessary expenditures.[81] Section 34 'Priority network access for shippers of biogas' states that grid operators are obliged to conclude feed-in contracts and exit contracts with shippers of biogas and to transport biogas as a priority, as far as these gases are network-compatible within the meaning of section 36(1).

The Ordinance does provide that grid operators may refuse to accept biogas if it is technically impossible or economically unreasonable.[82] However, the feed-in cannot be denied on the basis of capacity bottlenecks in a network, as far as the technical-physical capacity of the network is a given. The network operator must take all economically reasonable measures to increase capacity in the network to ensure year-round feed-in and to ensure the ability to meet the demand for biogas transport capacity.

Technology bonus

The German government introduced a technology bonus for upgrading biogas to biomethane. [83] This involves the government paying operators:

- a baseline bonus of 8ct/kWh for the utilisation of energy from biomass
- a technology bonus of 2ct/kWh for biogas upgrading (both as vehicle fuel or for injection into the gas grid) and offers
- grants of 30% of the capital investment for a biogas upgrading plant.

The bonus is paid on top of the feed-in tariff paid for biogas CHP at the site. The bonus is in place to justify the effort for upgrading biomethane, because biomethane CHPs compete for appropriate heat sinks not only with other renewable heat sources but especially with natural gas CHPs, which are supported by an individual incentive mechanism. [84]

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[77] Gas Network Access Ordinance, 'Regulation on access to gas supply networks' of 3 September 2010 (Federal Law Gazette I p. 1261), which was last amended by Article 1 of the Ordinance of 13 June 2019 (Federal Law Gazette I p. 786), s 36 ('Gas Network Access Ordinance').
[78] Renewable Energy Source Act (EEG 2017) (Germany), ss 436, 53(1), 44, 41 par 1-2.
[79] Ibid ss 44(1)–(3) par 2–3, 44(c) par 1, 9.
[80] (Urban, 2013), Biomethane injection into natural gas networks.
[81] Ibid.
[82] Gas Network Access Ordinance, s 34(2).
[83] (Balkenhoff & Jamieson, 2008), Upgraded Biogas as Renewable Energy.
[84] (DENA, 2013), Green Gas Grids: Biomethane market matrix.

Hydrogen

Germany's Hydrogen strategy is linked to its implementation of the EU's Second Renewable Energy Directive (RED II) which came into force in December 2018.

"*The use of green hydrogen for the production of fuel and as an alternative to conventional types of fuel is to be embedded as part of a swift and ambitions transposition of the EU Renewable Energy Directive (RED II) into German law (implementation in 2020). We want to create clear incentives for investments in electrolysers so that the ramp-up can start soon.*" [85]

The German National Hydrogen Strategy was launched in July 2020. [86] It sets a target of 5 GW of electrolyser capacity by 2030. [87] The Strategy sets a target for an additional 5 GW of hydrogen production capacity by 2040.

The German targets appear large compared to the EU targets. The EU Hydrogen strategy released in July 2020 proposes that the EU will support the installation of at least 6 GW of renewable hydrogen electrolysers in the EU, and the production of up to 1 million tonnes of renewable hydrogen, by 2024. [88]

Germany offers a range of subsidies and grants for hydrogen, particularly for the establishment of hydrogen filling stations, of which there are now 84 in operation and another 22 in approval and pre-commissioning stages.[89] Grants for filling stations are provided by the German Federal Ministry of Transport and Digital Infrastructure (BMVI) as part of the National Innovation Programme for Hydrogen and Fuel Cell Technology (NIP) and from the European Commission in the Hydrogen Mobility Europe project.

8.2.3 UK

There are two British biomethane schemes – Green Gas Certificate Scheme (GGCS) issuing Renewable Gas Guarantees of Origin (RGGOs) and Biomethane Certificate Scheme (BMCS) issuing Biomethane Certificates (BMCs).

A 2019 report states that, at present, 98 biomethane plants in the UK are injecting biogas into the gas network. [90] Overall, 500 m^3/h of biogas flow is rewarded by financial incentives.

There are two main mechanisms provide economic incentives to increase the injection of biomethane into the natural gas network in the UK: the Non-Domestic Renewable Heat Incentive and the feed-in tariff. These have been effective in increasing the number of biogas upgrading facilities from one facility in 2011 to 85 in May 2019. [91]

In addition the UK has a Renewable Transport Fuel Obligation for biofuels in transport.

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[85] Germany (2020) op cit., p. 18.
[86] (European Commission, 2020b), A Hydrogen Strategy for a climate neutral Europe.
[87] (German Government, 2020), The National Hydrogen Strategy.
[88] (European Commission, 2020b), A Hydrogen Strategy for a climate neutral Europe.
[89] H2 Mobility Deutschland GmbH, at https://h2.live/en/netzausbau
[90] (Lytton & Shorthouse, 2019), Pressure in the pipeline: Decarbonising the UK's gas.
[91] (NNFCC), The Official Information Portal on Anaerobic Digestion, AD Portal Site List.

Renewable Heat Incentive (RHI)

The (RHI) was introduced in 2011 to encourage the generation of renewable forms of heat, including heat from biogas and from the injection of biomethane into gas networks. The Non-Domestic Renewable Heat Incentive (NDRHI) is the part of the scheme relevant to biogas and biomethane producers, as it applies to renewable heating systems in commercial, public or industrial premises.

The NDRHI guidelines specifically *block landfill gas facilities from accessing the incentives.* They state that biogas consumption must be from anaerobic digestion, gasification or pyrolysis and that the participant *must not use biogas which is landfill gas.* Further, the facility must not generate heat from solid biomass, and the fuel must meet sustainability requirements.

The RHI pays third parties a tariff for gas produced from renewable sources, like biomethane fed into the existing gas network. It provides a fixed income (per kWh) to generators of renewable heat, and producers of renewable biogas and biomethane. Anaerobic digestion facilities completed after 15 July 2009 are eligible for the RHI.

A biomethane injection project which is an accredited RHI installation is subject to a tiered tariff, which is used to calculate the initial or subsequent tariff for the biomethane.[92]

The *RHI Regulation 2018* contains specific provisions applicable to producers of biomethane who wish to become registered producers of biomethane for injection. Applications are made to the Office of Gas and Electricity Markets (OFGEM) on behalf of the Gas and Electricity Markets Authority.[93]

RHI also allows for pre-accreditation for support at financial closure, subject to a limit of the amount of heat or biomethane injection that will be covered by a single tariff guarantee, to 250GWh per annum. This is important as the support is subject to degression at 25% per quarter, with caps on overall expenditure.

A review was conducted in relation to controversy over the Renewable Heat Incentive and maladministration particularly in Northern Ireland. These were problems of administration and compliance rather than fundamental problems with the incentive mechanism[94].

The lessons learnt related to flaws with the design of the scheme and scheme monitoring. The scheme was considered to be complex and risky due to exposure to variables such as volatile fuel costs and the lack of a cost control mechanism. A lack of scheme monitoring also compounded issues with scheme participants accessing incentives inappropriately (e.g. biomass boilers installed to heat energy inefficient farm sheds).

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[92] Renewable Heat Incentive Scheme Regulations 2018, SI 2018/611, reg 63(8)–(9).
[93] Ibid reg 32. OFGEM is a non-ministerial government department and an independent National Regulatory Authority, formally governed by the Gas and Electricity Markets Authority (GEMA).
94 Sir Patrick Coghlin, (2020) Report of the Independent Public Inquiry into the Non-domestic Renewable Heat Incentive (RHI) Scheme, Belfast. See Inquiry site at https://www.rhiinquiry.org/news/chairmans-statement-rhi-inquiry-report-launch-friday-13th-march-2020

Feed-in tariff

Since April 2010, renewable electricity feed-in tariffs have provided a guaranteed price for a fixed period to small-scale electricity generators in England, Scotland and Wales. Feed-in tariffs are intended to encourage the provision of small-scale, low-carbon electricity projects. Only anaerobic digestion facilities with less than 5MW capacity, completed after 15 July 2009, are eligible for feed-in tariffs. The government offers preliminary accreditation for anaerobic digestion, with a guarantee that the project will be eligible for the tariff, payable at the time of accreditation. Each tariff runs for 20 years.

UK and Hydrogen

At this point the UK does not have a National Hydrogen Strategy. At least six industry associations, led by the UK Hydrogen and Fuel Cell Association have been calling for a strategy during 2020, with an open letter to the Chancellor. [95]

8.2.4 Other EU countries

Countries and sub-national governments in the EU have made much progress in Green Gas.

- The Swedish have invested in biomethane for transport in response to national and sub-national law and policy.
- The Italian Government re-oriented its biogas policy from electricity generation (except for small plants) to biomethane production and it set up a FiT for biomethane production for natural gas vehicles, high-efficiency co-generation and grid injection.
- The City of Helsinki in Finland has a vision to become carbon neutral by 2050 and has a variety of incentive approaches including renewable energy target of 38 per cent by 2020, feed-in premium of 60 per cent for electricity from wind, biogas, and forest residues, carbon tax for fossil fuels in heating and landfill ban for organic waste.
- Denmark has a target to supply the gas grid with 100% Green Gas by 2035. There are subsidies for upgrading biogas to biomethane, and existing biogas plants are guaranteed until 2032 or at least 20 years from commissioning each plant. Denmark has a scheme in place for biomethane certificates. These certificates are issued to the biomethane upgrading plant and when sold allow the gas supplier to document to a gas consumer that renewable gas has been injected to the gas grid and has substituted natural gas.[96]

8.2.5 North America

The Renewable Fuel Standard (RFS) is a federal program administered by the Environmental Protection Agency requiring transportation fuel sold in the United States to

[95] See open letter at https://hydrogenstrategynow.co.uk/#whyhydro
[96] (Eba et al., 2020), Renewable Gas Trade Centre in Europe, D6.1: Mapping the state of play of renewable gases in Europe.

contain a minimum volume of renewable fuel. The original RFS program was created in the Energy Policy Act of 2005.

California the 5th largest economy in the World, has set a goal of establishing 100 hydrogen fuelling stations in that State, under Assembly Bill 8. There is a further goal of 200 hydrogen stations by 2025, set by Governor Brown's Executive Order B-48-18.[97] Since 2006, Californian law has required 33% of hydrogen to come from renewable sources.[98]

California has made specific policies and laws to increase the uptake of hydrogen, particularly in the transport sector, in the commercial light duty hydrogen refuelling and fuel cell electric vehicle (FCEV) market. For example, the California Energy Commission's Clean Transportation Program, has made competitive grant calls for H_2 refuelling infrastructure projects, earlier calling for FCEV refuelling stations, and most recently in 2020 calling for projects involving fuelling agreements with fleets of commercial vehicles and transit buses.

In the transport sector, in 2010 California adopted a 10% reduction in carbon intensity by 2020 under the Low Carbon Fuel Standard (LCFS). Since it was adopted, the LCFS has reduced carbon pollution emissions in California by more than 30 million metric tons, equivalent to removing 6.4 million gasoline-fuelled cars from the state's roads per year. The success of this policy has led to a new target of 20% reduction in the state's transportation fuel carbon intensity by 2030. This policy is also credited with kickstarting the sustainable aviation fuel industry in California. In addition to State based policies such as the LCFS, the US Federal Government created the renewable fuel standard (RFS) program to reduce greenhouse gas emissions and expand the nation's renewable fuels sector, while reducing reliance on imported oil. The EPA administers the RFS program, which sets a target of 36 billion gallons of renewable fuel by 2022. This program has delivered significant investment and helped the agricultural industry diversify their income.

The Canadian province of British Columbia has a renewable portfolio obligation since 2017 for 5% renewable natural gas in the natural gas system. However, that quota obligation system operates through its connection to carbon pricing and laws controlling greenhouse gas emissions.

In British Columbia, a low carbon fuel standard is used to reduce the carbon intensity of fuels used in the province.[99] Under the standard, carbon intensity targets decline each year and fuel suppliers create credits for supplying fuels with a carbon intensity of below the targets and receive debits for supplying fuels with a carbon intensity above the targets. A market for the trade of credits exists and at the end of each compliance period suppliers must have a zero or positive balance of credits to avoid non-compliance penalties.

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[97] Baronas, Jean, Gerhard Achtelik, et al. 2019. Joint Agency Staff Report on Assembly Bill 8: 2019 Annual Assessment of Time and Cost Needed to Attain 100 Hydrogen Refueling Stations in California. California Energy Commission and California Air Resources Board. Publication Number: CEC-600-2019-039.
[98] California Senate Bill No. 1505, adding Section 43869 to the Health and Safety Code of California. http://www.leginfo.ca.gov/pub/05-06/bill/sen/sb_1501-1550/sb_1505_bill_20060930_chaptered.pdf
[99] (Government of British Columbia), Renewable and Low Carbon Fuel Requirements Regulation.

9 CONCLUSION AND RECOMMENDATIONS

The ACT's legislated target of net zero greenhouse gas emissions by 2045 implies that there needs to be close to zero use of natural gas or petroleum based transport fuels by that time.

Green Gas in the form of biogas, biomethane and renewable hydrogen has strong technical potential for contributing to this zero emissions outcome.

Whilst complete electrification of all existing gas use and transport is technically possible, evidence suggests that this would not be the overall cheapest solution for the community. Amongst other things, it would imply around a tripling of the capacity of electricity generation, transmission, and distribution infrastructure for the territory. It would also lead to the write down of existing gas assets plus unknown but large expenses in removal and remediation. It is also clear that in Australia and in other jurisdictions Green Gas will be used as part of a zero GHG emissions future.

In parallel with consideration of future energy supply, the ACT has unavoidable waste issues that must be addressed. Around 30% of the methane produced in landfills still leaks to the atmosphere and accounts for 4% of non-electric GHG emissions. The ACT's wastewater system is old and inefficient in regards its ability to capture energy that might be available, it also has secondary GHG emissions that must be addressed. Production of biogas from these sources seems to be an inevitable consequence of adopting best practices. ACT's waste streams could produce biogas equivalent to 10 - 20% of current natural gas demand. Optimising the value that this opportunity gives to the energy sector is essentially a no regrets strategy.

In the transport sector, use of hydrogen for vehicles is a clear alternative to battery electric vehicles. There are pros and cons between the two, however as long as vehicle producers pursue both options (as Toyota and Hyundai are doing) it can be assumed that some significant share of the future market will be taken by hydrogen vehicles.

The waste based biogas potential for the whole country is also equivalent to around 10 - 20% of existing nation wide natural gas use. Given that Green Gas trading is intended to cross borders there is potential for the ACT, if it takes a first mover position, to gain preferential access to low cost Green Gas from interstate. Given Australia's enormous solar and wind resources, there is essentially no limit on how much renewable hydrogen can be produced. Renewable hydrogen is however more expensive than waste-derived biomethane.

Trying to predict the ideal future technical mix is virtually impossible. This suggests that for the ACT Government the best course is to concentrate on the final end result of zero emissions whilst allowing as many technology options as possible to contribute in a fair competitive manner.

Putting these considerations together, some level of Green Gas use and hence trading seems to be a certainty. To ensure that zero emissions are achieved and to protect consumers, some form or certification of Green Gas becomes essential. It is apparent that

this is an issue getting wide consideration in other Australian states and federally. NSW is the most active in this regard. Thus, it would not be logical for the ACT to do its own thing in this regard. Rather it should join and encourage proactive action by NSW and the Federal Government. It seems likely that NSW GreenPower will take the lead in the first instance and that when federal measures proceed the CER is the most sensible body to manage this.

There are strong precedents around the world for certification of biomethane and hydrogen, which can be used to guide actions. In particular, Europe and Germany are the most advanced. It seems likely that the most pragmatic approach is to separate certification of biomethane and hydrogen with subsequent work to identify conversions and interchangeability between them. Australia should move to its own approaches whilst watching international developments and aligning methods over time.

The ACT Government has many options to choose between on how to move forward. It could set a target to signal a long term policy intent to decarbonise gas in the same way it did for electricity.[100] As one of the biggest natural gas users itself, it could use its own procurement to create some market pull for network injected Green Gas. A combination of targets and reverse auctions for Green Gas supply would replicate the approach to achieving 100% renewable electricity supply in the ACT.

In summary, it is recommended that the ACT:

1. Consider the introduction of a target for renewable energy gas supply in the ACT under the Climate Change and Greenhouse Gas Emission Reduction Act 2010. A target of 10% from 2025 for both the gas sector and 10% for the transport sector from 2025 could be appropriate.
2. Investigate potential sources of low cost Green Gas from local and interstate sources and consider becoming a first mover in the procurement of Green Gas via competitive processes.
3. Consider mandating the replacement of unaccounted for gas in the network with Green Gas as a short term measure.
4. Move to treat all ACT waste in an international best practice manner that maximises the contribution of Green Gas that it produces.
5. Work to establish mandatory mechanisms that progress the reduction over time in GHG emissions to zero in 2045 in a manner that does not unnecessarily disadvantage Green Gas uptake or lead to higher than necessary costs for ACT citizens.

It is also recommended that the ACT Government continue to work with NSW and the Federal Government to ensure that a national approach to Green Gas verification and certification emerges in the near future.

[100] The existing legislative provisions provide for this to be done easily by making a disallowable instrument (The Act, in s.9(2)(b) states that the Minister may determine a target for “The use of renewable energy in the ACT other than electricity”.

The ACT Government has indicated an interest in considering broader life cycle assessment (LCA) emissions associated with Green Gas production and use. This is a complex area that warrants further analysis.

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APPENDIX A. STAKEHOLDERS CONSULTED

Organisation	Personnel consulted	Comments
ActewAGL New Energy	Mark Smeaton, Ed Gaykema	ActewAGL New Energy is installing a hydrogen vehicle refuelling station in Fyshwick and have lodged an EOI with ARENA for a 5 MW electrolyser
AGIG	Drew Pearman, Kristin Raman	AGIG are a gas transmission / distribution company active with Green Gas pilot systems in SA and Qld
Australian Renewable Energy Agency (ARENA)	Amy Philbrook, Matt Walden	Have provided grant support to a range of Green Gas projects. Currently undertaking a bioenergy roadmap.
Bioenergy Australia	Georgina Greenland, Shahana McKenzie	Advocacy group for bioenergy sector industry development
Clean Energy Council (CEC)	Darren Gladman, Anna Freeman	Strong interest in area, still working on Green Gas policy
Clean Energy Regulator (CER)	John Smeltink, Matthew Power	CER administers RET and ERF and other federal mandated market mechanisms
Capital Asphalt		Installing a new hot mix Asphalt plant
CBRE / Dexus	Anton Lockhurst	Manager of large commercial buildings with government tenants
Energy Networks Australia (ENA)	Dennis Van Puyvelde	Represent combined interests of Australian gas and electricity network owners
Evoenergy	Bruce Hansen	Part of the ActewAGL group. Monopoly gas distributor in the ACT
Future Fuels CRC / RMIT	Carol Bond	Examining community attitudes to Green Gas as well as technical issues.

GreenPower	Tim Stock, Manuel Weirich	Accreditation program for voluntary renewable electricity purchases.
Hydrogen Council	Fiona Simon	Represent a range of companies actively involved with hydrogen including manufacturers of FCEVs
ICON Water	Benjamin Bryant	Provides waste water treatment for ACT. Currently working on a zero emissions roadmap
Jemena	Mike Davis	A gas distribution and transmission company promoting Green Gas initiatives in NSW. 50% owner of Evo Energy in ACT
National Hydrogen Task Force	James Hetherington	Leading efforts following National Hydrogen Roadmap
NSW Department of Planning, Industry and Environment (Sustainability Advantage)	Turlough Guerin	Lead state government agency for Green Gas pilot project development
WA Department of Primary Industries and Regional Development	Joe Wyder	Department with interests in bioenergy and renewable hydrogen
Weston Energy	Chris McPherson	A large gas retailer to commercial organisations, developing Green Gas offerings

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