Status Report

Status of production and injection of renewable / low GHG emission gas

Prepared for Energy Networks Australia

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EXECUTIVE SUMMARY

The objective of this report is to review the international status of renewable gas production and injection into the natural gas transmission and distribution networks, focussing on renewable energy fluids that could be considered for injection into Australian pipeline networks in the short- to midterm.

Availability of excess renewable electricity from wind and photo-voltaic electricity is becoming a reality at times in some electricity markets, providing an incentive for production of hydrogen by electrolysis, particularly if a service charge is available for using electrolysers to provide primary grid stability. Proton exchange membrane (PEM) electrolysers are being used in some projects in Europe for this purpose because of their high efficiency and ability to respond to rapid load fluctuations. However at present this technology is relatively expensive and has a short lifetime. In the near future, concentrated solar thermal heat with molten salt storage may be used to produce additional renewable electricity, and will extend the daily peak production of renewable electricity into the evening. This technology may add to the need to use electrolysis for seasonal storage of renewable energy.

Use of fossil fuels to produce "renewable" hydrogen (by steam methane reforming or coal gasification) with carbon capture and storage can be assessed on a project by project basis.

Renewable synthetic natural gas (SNG) is currently produced at small scale by anaerobic digestion of biomass or waste, and can be combusted on-site to produce power and heat, or injected into the natural gas network, bearing in mind it has a high carbon dioxide content. Renewable SNG can also be produced by methanation of renewable hydrogen or by gasification of biomass or crude bio-liquids. Solar thermal gasification of biomass is an option which is currently being investigated because it increases the yield of product.

There have been many small scale demonstration projects of renewable "power to gas" in Europe. Up to 20 of these have included injection of either hydrogen or SNG into the gas network at rates of 200 Nm^3/h. The largest project is the ETOGAS / Audi project, which uses alkaline electrolysers to produce over 1000Nm^3/h of H_2, which is then converted to SNG.

Current production costs are in the order of $16/GJ from natural gas reforming with other technologies producing hydrogen at higher costs. However, the costs of producing and transporting hydrogen from renewable electricity and electrolysis are expected to reduce dramatically over the coming 5 -15 years. There are some major issues related to road or rail transport of hydrogen, which provides an incentive to use the natural gas network for transport. For hydrogen and SNG to be competitive with other energy sources, high value end-uses will need to be found. In addition there will be a requirement for one or more market mechanisms and policy settings, such as:

- payments for use of excess renewable electricity and grid stabilisation;
- premium prices for seasonal storage of renewable gas;
- a premium for avoiding upgrades to electricity infrastructure;
- finance for large scale grid stabilisation and renewable gas production projects; and
- a price on carbon to incentivise renewable gas (including hydrogen).

Scenario modelling in the Australian context may help in setting policy goals.

Production of hydrogen and SNG from biomass and waste has lower cost than the electrolysis route, and is already established at a larger scale than electrolysis. Therefore it could be used to increase hydrogen production rates whilst technology improvements and cost reductions in electrolysis are occurring.

There is significant potential for hydrogen and SNG injection into natural gas networks in Australia and the current project will illustrate the current state of technology and research to achieve this potential; both in Australia and internationally.

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1. INTRODUCTION

This report is a review of the international status of renewable gas production and injection into the natural gas distribution networks. It provides background for more detailed work to generate a study that identifies the technical, commercial and regulatory issues for possible introduction of renewable gas in Australian gas networks.[1]

This report has been prepared for Energy Networks Australia. ENA has recently released its vision for the gas distribution sector.[2] This vision outlines how gas and the gas distribution networks can contribute to a low carbon economy. A component of this vision is to promote the development of renewable gas, in particular hydrogen, and whether this gas can be injected into the network.

The United Nations Framework Convention on Climate Change, Paris agreement, came into force on November 4th, 2016, after sufficient countries ratified it. The pledges from various countries aim to keep global temperature rise to less than 2^{o}C above pre-industrial levels during this century, and will create a driver for ongoing replacement of coal fired electricity with natural gas and renewables and use of carbon capture and storage in some locations to decarbonise coal and gas.

Natural gas transportation and distribution networks can potentially play a role in transporting and storing renewable energy in the form of hydrogen or synthetic natural gas for long term re-use, without degradation, and for stabilising the electricity grid. High capital costs and efficiency losses in processes involved in generating and using renewable gas mean that economic feasibility needs to be assessed on a case by case basis. Incentives or allowances to make use of excess renewable electricity or other renewable energy sources may be required.

A better understanding of potential issues for injecting renewable gas into the Australian gas transmission and distribution networks is required to ensure that operators can inject, transport and utilise renewable energy safely and effectively. The higher pressures used in gas transmission may present different materials and safety challenges than those presented in the distribution network.

This report reviews the international status of renewable gas production and injection into gas distribution networks. It will focus on fluids that could be considered for injection into Australian pipeline networks in the short- to midterm as listed in the table below.

Renewable Gas	Production process
Hydrogen	• Hydrogen from renewable electricity through electrolysis • Steam methane reforming and carbon capture and storage (CCS) • Coal gasification with carbon capture and storage (CCS) • Concentrated solar thermal methane reforming (partially renewable) • Processes at basic research stage: o Solar thermal water splitting o Biomass pyrolysis, liquefaction or fermentation, then reforming
Methane from biogas	• Anaerobic digestion
Synthesized Natural Gas Using processes that produce syngas which can then undergo methanation	• Gasification of coal, followed by methanation and CCS • Gasification of biomass, followed by methanation • "Power to Gas" - electrolysis + methanation of H_2 and CO_2 • Solar thermal gasification of biomass, followed by methanation • Solar thermal reforming to syngas and re-methanation cycle • Processes at basic research stage: o Supercritical water gasification of algae or wet biomass o Solar thermal thermochemical water and CO_2 splitting

Table 1 Listing of production processes for renewable gas

[1] (Energy Pipelines CRC, 2017)
[2] (Energy Networks Australia 2017)

2. INTERNATIONAL STATUS OF RENEWABLE GAS PRODUCTION

The availability of excess renewable electricity from wind and solar photo-voltaic sources is becoming a reality in some markets. This provides an opportunity for use of this electricity at low, zero or negative cost to produce renewable gas. Production of hydrogen by electrolysis during periods of excess solar photovoltaic or wind generated electricity supply (power to gas) has started to be practiced in Europe. Research efforts are underway for seasonal storage of hydrogen or synthetic methane for use in winter.[3]

Electricity from solar thermal processes, in which concentrated solar heat is used to drive a conventional steam Rankine cycle, may also become increasingly available for production of renewable gas in the future. For example, concentrated solar thermal with heat storage in molten salts is a proven technology that can provide renewable electricity in the late afternoon /evening after photo-voltaic generation has peaked for the day. Biomass is another potential source of renewable gas, and fossil fuels can also be decarbonised to produce low net emission hydrogen.

This section of the report provides an overview of the various technologies used to produce renewable and low emission hydrogen and synthetic methane. It also provides information about pilot and commercial scale trials of some of these technologies.

2.1. Hydrogen

Blending hydrogen into the natural gas network in small percentages may provide a potential short to medium term mechanism for increasing production of renewable hydrogen, whether the hydrogen is subsequently separated from natural gas for dedicated uses, or simply used as a component of natural gas. The International Energy Agency[4] recognises that storage, transport and distribution of hydrogen will be major issues that need to be addressed for the growth of a renewable hydrogen industry; in addition to issues related to cost reductions in hydrogen production technologies such as electrolysis and end-use technologies such as fuel-cells.

2.1.1. Hydrogen from fossil fuels

Steam methane reforming or coal gasification are used to produce syngas (carbon monoxide and hydrogen), followed by the water gas shift reaction to increase hydrogen content and reduce carbon monoxide content at the expense of increased carbon dioxide (CO_2) production (Figure 1). Currently, steam methane reforming is the major route to hydrogen, providing over 90% of the global hydrogen market. This hydrogen is then used in oil refining and chemical manufacturing. The cost of hydrogen from methane reforming is largely dependent on the natural gas price and ranges between AU$12 and $20/GJ.

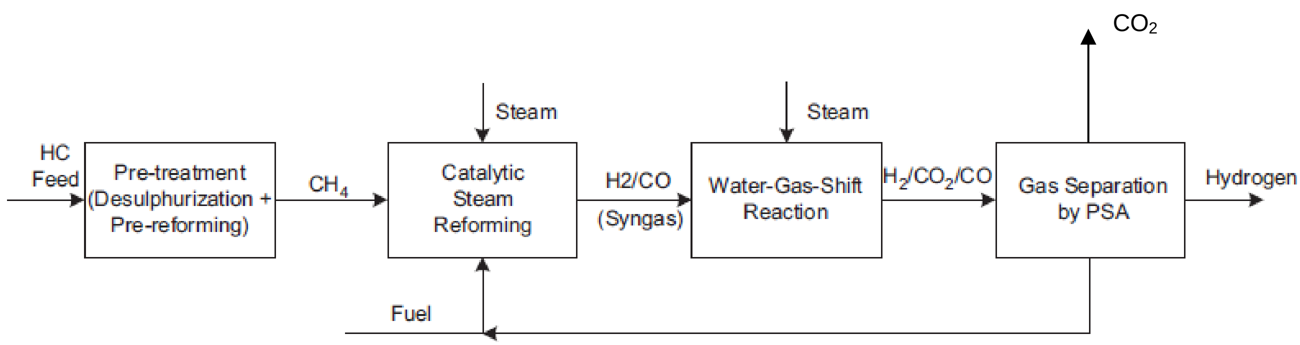

Figure 1: Steam methane reforming with water gas shift reactor and gas separation[5]

[3] (Gotz et al. 2016)
[4] (IEA 2015)
[5] (Agrafiotis et al. 2014)

In some recent projects, the CO_2 has been separated and used for Enhanced Oil Recovery (EOR) or permanent storage in deep geological formations. The process by which CO_2 is captured or separated at industrial facilities or power stations and then stored underground in depleted gas reservoirs or saline aquifers is also known as Carbon Capture and Storage (CCS). CCS is a proven technology, but implementation depends not only on technical issues, local geology and project economics, but also on policy settings and legal issues.[6] One deterrent to CCS is that it is perceived to have no positive economic value / payback (as opposed to EOR).

In Canada, Shell has recently commissioned a project whereby one million tonnes of CO_2 per annum is captured from Shell's oil sand operations (its Scotford upgrader) and permanently stored deep underground. In Australia, large scale CCS is being implemented as part of the Gorgon LNG project on Barrow Island (WA). In this project the CO_2 is separated from the high CO_2 content natural gas and stored in a deep saline formation below the gas reservoir. In Victoria, Kawasaki from Japan continues to investigate the possibility of producing hydrogen, along with CCS in Bass Strait. This project builds on the significant work done to identify the storage potential in the Gippsland and Bass Strait basins. The most immediate target for storage would be the southern end of the Gippsland basin which has a storage capacity of 825 Mt CO_2.[7]

Leeds City commissioned a study into the possibility of replacing the city natural gas network with 100% hydrogen by using natural gas reforming and CCS, with temporary storage of hydrogen in salt caverns to balance load. Replacement of iron / steel pipes with polyethylene would be required for hydrogen duty. The report claims that all users, except some domestic appliances, would be able to use the hydrogen with manageable changes to equipment.[8]

2.1.2. Biomass gasification

Biomass gasification uses the same process as coal gasification (Figure 2), but because of the logistics of collecting and transporting biomass, gasification plants and production rates are smaller scale. There are many commercial biomass gasification units worldwide, producing syngas, but few have been used to produce commercial scale hydrogen. However the technology is considered competitive with natural gas reforming and could be implemented with a short lead time.[9] Unlike coal gasification, CCS is not required to achieve near zero CO_2 emissions. However, carbon negative rates could be achieved when CCS is combined with biomass gasification.

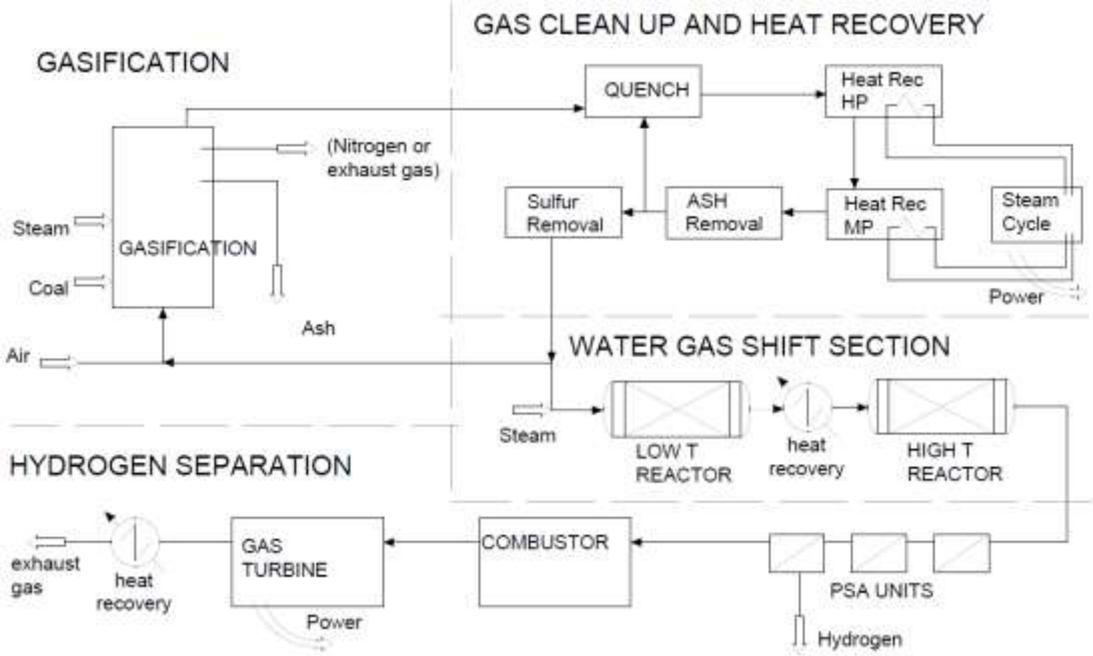

Figure 2: Process optimisation of hydrogen production from coal gasification[10]

[6] (Consoli et al. 2016)
[7] (O'Brien et al. 2011)
[8] (Leeds 2016)
[9] (Hrbek 2016)
[10] (Biagini et al 2006)

2.1.3. Electrolysis

Three types of water splitting electrolysers for production of hydrogen and oxygen have been developed, i.e.:

- Alkaline electrolysers
- Proton exchange membrane (PEM) electrolysers
- Solid oxide electrolysers

Alkaline electrolysis has been the only commercial option until recently and has a capital cost of about Euro1000/kWe installed capacity.[11] For example, the Danish company Wind Projekt has installed a 210Nm^3/h alkaline electrolysis unit with hydrogen storage and also use a steam cycle to generate power and heat.

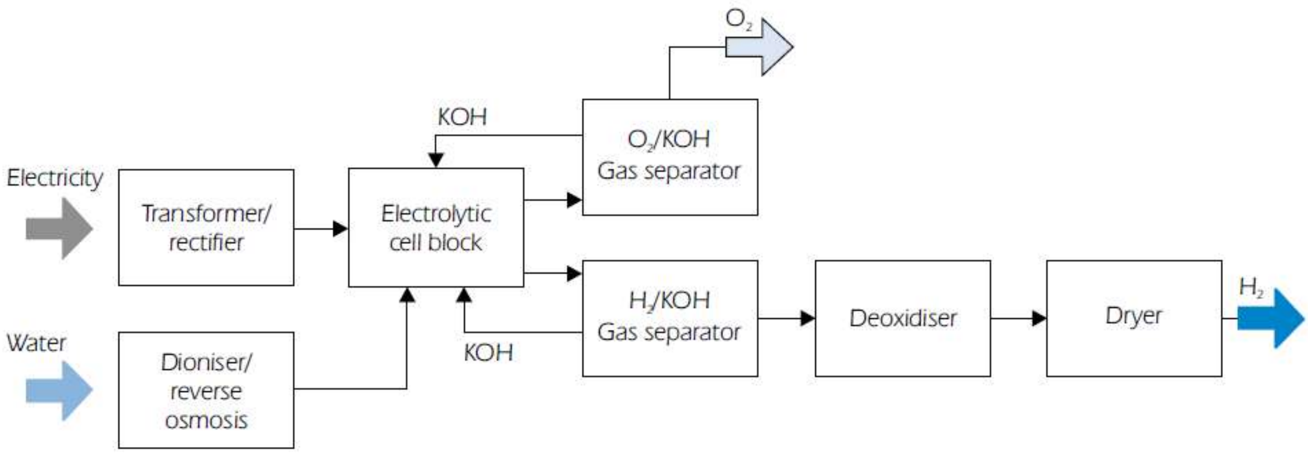

Figure 3: Alkaline electrolysis process[12]

A recent review listed many pilot scale "power to hydrogen" plant trials, which had started operation between 2001 and 2012, or were planned to start in 2012-13.[13] Trial locations included over 15 different countries, including Argentina, Canada, France, Germany, Japan, Turkey, United Kingdom and USA. Many were small scale and used batteries to minimise electrolyser cycling. Alkaline electrolysers were used in most cases. Efficiencies were found to be as much as 20% lower than suggested by manufacturers in some cases.

Proton exchange membrane (PEM) electrolysers are much more responsive to fluctuations in power input than alkaline cells, but have shorter lifetimes. They have recently been taken to similar scale as alkaline cells, i.e. into the MW range, by two companies, Siemens and Proton OnSite, and are projected to reduce in cost to similar levels as alkaline cells by 2020.[14]

Some of the pilot and demonstration scale trials used PEM electrolysers, and showed significantly higher efficiencies than alkaline cells, of up 83%, but with very short electrolyser life times of only 12 months being typical.[15] However, improvements in the PEM technology are rapidly being made, and other advantages include the ability to handle load changes, easy start up, and production of very high purity hydrogen (in excess of 99.999%).

A third type of cell, solid oxide electrolysis (high temperature water electrolysis), is not commercially available, having problems due to degradation of materials at high temperatures, and inability to handle intermittent power sources, but could be developed in the future.[16]

[11](Götz et al. 2016)
[12](IEA 2006)
[13](Gahleitner 2013)
[14](Götz et al. 2016)
[15](Gahleitner 2013)
[16](Götz et al 2016)

2.1.4. Hydrogen by hybrid concentrated solar thermal / fossil fuel methods

Several studies concluded that solar thermal steam methane reforming is both the most cost effective solar hydrogen production method and is nearly competitive with standard methods of hydrogen production.[17] The solar steam methane reforming process is depicted in Figure 4. Both direct and indirect solar heating has been used, with the former capable of higher temperatures and higher efficiencies, but the latter with potentially greater robustness. Most technologies require solar heliostats (mirrors) and a reformer located at a central receiver with temperatures of at least 800°C. CSIRO's membrane reformer operates at lower temperatures, which has advantages for materials life and reduction of heat losses.

There are now many types of solar thermal reformers that have been demonstrated at pilot scale. For example, the German research organisation, DLR have proven solar methane reforming at 900°C and 400 kW_{th} scale and the Weizmann Institute of Science has developed a catalytic volumetric solar reformer to pilot scale at 480 kW.[18] However, solar methane reforming only upgrades the energy value of natural gas by 25% and so still produces significant quantities of CO_2 which needs to be separated from the hydrogen.

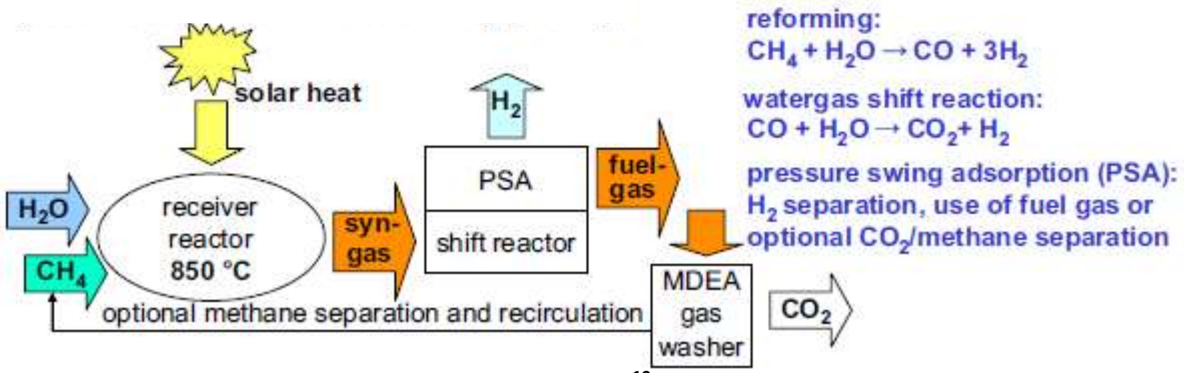

Figure 4: Solar thermal steam methane reforming.[19] (Note: mixed reforming with water and CO_2 as reactants, or CO_2 reforming could also be used.)

2.1.5. Hydrogen by other processes at basic research stage

Whereas solar thermal methane reforming produces partially renewable hydrogen, solar thermal water splitting can produce fully renewable hydrogen. There are many research groups working on this endeavour, but it is unlikely to become commercial in the short to medium term. If it becomes a mature technology it would complement electrolysis because it does not use electricity, and could be of similar cost.[20] Other potential processes that are still at the stage of basic research include (a) biomass pyrolysis or liquefaction with subsequent bio-oil reforming and (b) biomass fermentation to produce either hydrogen or other fuels that can be converted to hydrogen.

2.2. Synthetic Natural Gas

Various assessments of the maximum quantity of hydrogen that can be safely added to the natural gas transmission and distribution networks have been made, with a common consensus that hydrogen concentration may be limited to approximately 15% due to materials issues. The update of the Australian pipeline standard includes a specification of limiting hydrogen content in natural gas for distribution networks to 15%. Hence to reach higher levels of renewable energy in the gas network, a more conservative approach than the 'Leeds vision' of converting the network to 100% hydrogen, is production and injection of synthetic natural gas into the network to keep the hydrogen concentration at low levels. Alternatively, the standard could be revised in a number of years to allow a higher proportion of hydrogen.

[17](Pregger 2009)
[18](Agrafiotis et al 2014)
[19](from Pregger et al. 2009)
[20](Graf et al 2008)

2.2.1. SNG from coal with EOR / CCS

Methanation of syngas (a mixture of carbon monoxide, hydrogen, and a smaller fraction carbon dioxide) is a well-established commercial process. Commercial vendors include Lurgi and Haldor Topsoe. However the Great Plains plant in North Dakota, USA, is the only commercial coal to SNG plant in the world. It operates large-scale catalytic fixed bed reactors for methanation of both carbon monoxide and carbon dioxide produced by coal gasification.[21] The CO_2 produced is captured and used for Enhanced Oil Recovery in the Weyburn oil field. Economics rely on low coal price, and good sales prices for SNG and CO_2.

Coal to SNG - Great Plains plant (from Kopyscinski)

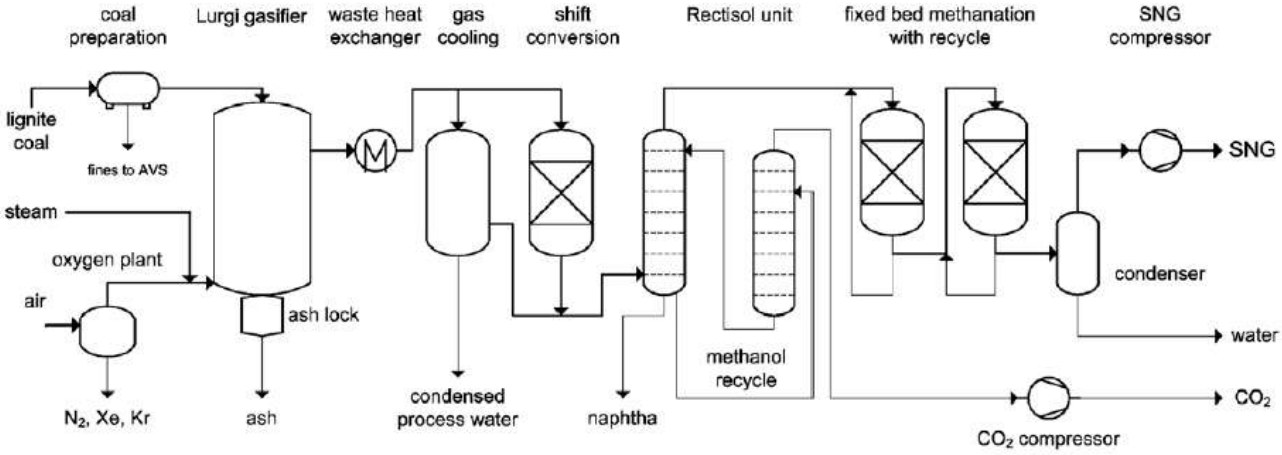

Figure 5: Coal to SNG process - Great Plains plant[22]

2.2.2. Biomass gasification

The new GoBiGas plant at Gothenburg, Sweden is the largest bio-SNG plant in the world. It uses gasification of forest residues, followed by methanation to produce SNG that is injected into the local natural gas network. The process is depicted in Figure 6 on the next page. Waste heat is also used in the local district heat network. The project received significant grant funding from the Swedish Energy Agency.[23] Phase 1, rated at 20MWgas was commissioned in 2015. The larger Phase 2 has been postponed indefinitely for financial reasons, which illustrates the difficulties involved in producing a viable business case for a relatively low value product like SNG.

2.1.1. SNG from electrolysis and CO_2

When producing synthetic methane from pure hydrogen produced by electrolysis, a source of carbon dioxide is also required as a reactant. CO_2 sources such as biogas and biomass gasification are well suited to the current scale of electrolysis units, whereas industrial sources such as flue gas from fossil fuel power generation, steel and cement industries involve much larger volumes, for which capture is unlikely to be economical and practical in the short to medium term.[24]

Despite being a commercial process, research continues to improve the catalytic H_2 + CO_2 methanation process. It is an exothermic reaction and most of the current research (about 30 research groups worldwide) aims to optimise heat removal to reduce reactor costs, improve yields and minimise catalyst sintering.[25] A wide range of reactor concepts are being investigated, mostly based on catalytic fixed bed reactors.

[21](Kopyscinski et al 2010)
[22](from Kopyscinski et al 2010)
[23](Hrbek 2016)
[24](Götz et al 2016)
[25](Götz et al 2016)

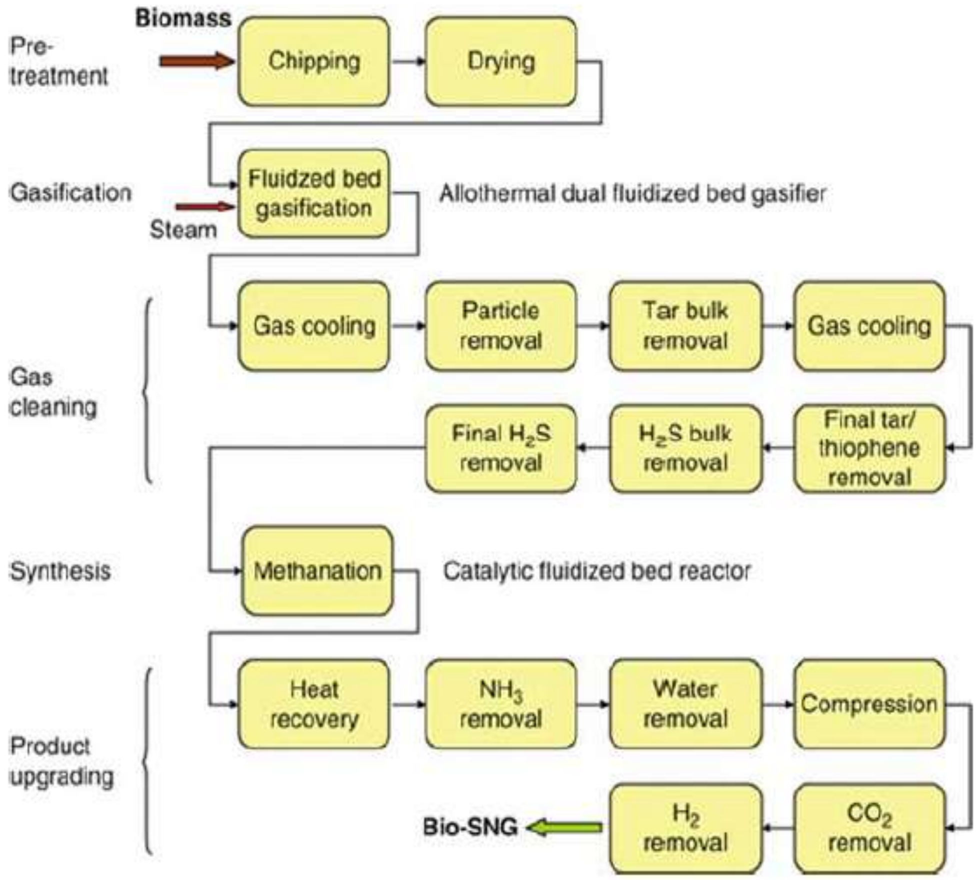

Figure 6: Biomass gasification to SNG.[26]

2.1.2. SNG from biogas

Biogas plants produce methane and CO_2 by anaerobic fermentation of high moisture content waste in anaerobic digesters, or at landfill sites. Biogas has significant CO_2 content and requires clean up to remove CO_2 down to acceptable levels if it is to be added to the natural gas network as SNG. The technology is mature for plant sizes in the order of 1MWe. Biogas is often used for onsite electricity generation. Anaerobic digestion is one of the cheapest means of producing electric power from biomass, although not competitive with natural gas at current prices. A concerted effort to increase production of biogas would require appropriate policy settings.

In the future the CO_2 produced and separated from anaerobic digestion could potentially be used to make additional SNG by combining with hydrogen produced by either electrolysis or biomass gasification.

2.1.3. Solar thermal methane reforming cycle

The solar thermal methane reforming process can be incorporated into an electric "power to gas to power" cycle, in which syngas is stored for use when required. This process was discussed in the1990's[27] and has not been developed commercially, but can be discussed along with the other options now being considered. The process for solar thermal methane reforming is depicted in Figure 7 on the next page.

[26](Hrbek 2016)
[27](Levy et al. 1993)

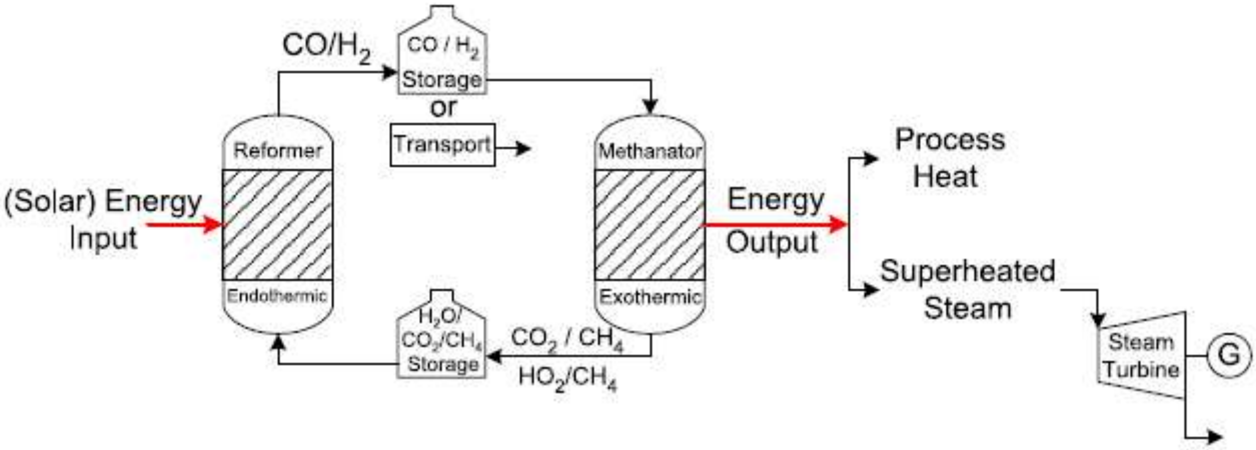

Figure 7: Solar thermal methane reforming power cycle[28]

2.1.4. Solar thermal gasification of biomass

The University of Adelaide is researching solar thermal / fossil fuel hybrid processes such as solar thermal coal and biomass gasification (Figure 8).[29] When using coal, greenhouse gas emissions are high, unless CCS is used. However, when using biomass, GHG emissions can be negative even without CCS. The product of biomass gasification is syngas, which can be used to make either hydrogen or SNG.

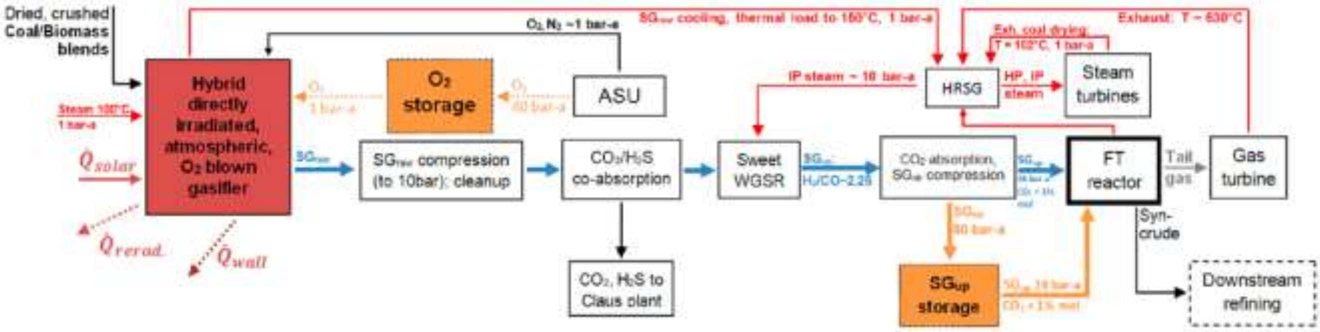

Figure 8: Solar thermal coal or biomass gasification – here showing use of syngas for Fischer – Tropsch liquid production instead of SNG[30]

2.1.5. Potential renewable SNG processes at stage of basic research

Other processes which are still at the stage of basic research, but might potentially be used in the future to produce renewable SNG include:

- Super-critical water gasification of algae or wet biomass
- Solar thermal thermochemical water and CO_2 splitting

2.1.6. Other potential products of renewable energy

Renewable energy can also be used to produce other fluids that are less suitable for transport in the natural gas and distribution network. These include syngas, which due to its carbon monoxide content would encounter additional safety and "social licence to operate" demands. In the future, it is possible that some projects could be developed requiring transport of syngas by pipeline in sparsely populated areas, and certainly within process plant boundaries, but not as part of the natural gas network. Production plants of renewable liquid fuels are another potential end-user of syngas or hydrogen and SNG.

[28](Agrafiotis et al 2014)
[29](Kaniyal, van Eyk et al. 2013)
[30](from Kaniyal et al)

2.2. Summary of technology status of hydrogen and SNG production processes

The following table provides a summary of the state of commercialisation of technologies for production of hydrogen and SNG. The electrolysis options can be linked with any of the commercial renewable electricity generation technologies, i.e. solar photo-voltaic, solar thermal, wind, hydro etc.

Technology	Commercial Status	Applications
Steam methane reforming	Commercial - large scale	Hydrogen for chemicals, ammonia, plastics, refining
Coal Gasification	Commercial - large scale	SNG with EOR Syngas for Fischer-Tropsch fuels
Biomass Gasification	Commercial – small scale	Hydrogen, SNG, district heat, renewable electricity
Alkaline Electrolysis	Commercial - modular, scalable	Hydrogen
PEM Electrolysis	Commercial – small scale	Hydrogen
High Temp Electrolysis	Pilot scale	Hydrogen
Anaerobic Digesters	Commercial – small scale	Biogas, SNG, CO_2 production, electricity, heat
Solar thermal methane reforming	Pilot scale	Hydrogen, SNG electric power to gas to power cycle
Solar thermal biomass gasification	Pilot scale	Hydrogen, SNG
Methanation of H_2 and CO_2	Commercial – small scale	SNG
CO_2 capture	Commercial – large scale	SNG, CO_2
Solar thermal water splitting	Lab scale	Hydrogen
Biomass pyrolysis, liquefaction or fermentation then reforming	Lab scale	SNG
Super-critical water gasification of algae or wet biomass	Lab scale	SNG
Solar thermal thermochemical water and CO2 splitting	Lab scale	SNG

Table 2 Technology status of hydrogen and SNG production

2.3. SNG and hydrogen compositions

This section on renewable gas compositions and possible impurities is relevant for identifying the technical and other issues asscociated with transporting SNG and hydrogen in gas distribution networks. The previous sections included a number of basic flow-sheets of some of the processes referred to in the text for production of hydrogen and SNG. These flow-sheets illustrate some of the gas cleaning steps involved in improving gas quality. Gas users have varying maximum sulphur levels. For example power generation turbine manufacturers may specify 10 – 30 ppm H_2S. Other users and pipelines are potentially sensitive to moisture and CO_2 content.

After drying and deoxidising, the alkaline electrolysis process produces approximately 99.9% hydrogen, with the impurities being carryover alkaline electrolyte (KOH, NaOH). The PEM electrolysis process produces essentially pure hydrogen.

Pressure swing adsorption (PSA) used for the final step of hydrogen purification from reforming or gasification produces highly pure hydrogen up to 99.99%.[31] The natural gas, steam reforming process uses nickel catalysts that are poisoned by sulphur. So the incoming natural gas used has very tight limitations on sulphur content, and consequently hydrogen produced by natural gas reforming will have very low levels of sulphur, even before the PSA step.

[31](Linde Group 2016)

Raw syngas from biomass or coal gasification can contain up to 2% sulphur compounds, even when limestone is used in the gasifier. Cleaning of raw syngas from gasification first requires cooling, solids and tar removal, then removal of acid gases and use of the water gas shift reaction to increase hydrogen content and produce CO_2. After acid gas clean-up the H_2S content can be reduced below 30 ppm, or by the most expensive Rectisol process it can be reduced to < 0.1ppm.[32] The production of CO_2 in the water gas shift reactor necessitates another CO_2 removal step if the desired product is hydrogen.

If methanation is used to produce SNG from syngas, then some ammonia is also produced as a by-product and needs to be removed, in addition to drying and CO_2 removal steps.

From anaerobic digestion, biogas is typically 50-75% methane, 25-50% CO_2, with some oxygen, nitrogen, hydrogen sulphide and water vapour. Gas cleaning and drying can remove water, CO_2 and sulphide.

If implemented, the solar thermal dry methane reforming power cycle would require materials that could cope with gases including both CO_2 and moisture due to the incomplete reactions involved in the cycle.[33]

As a general note, the gas consumers in this study could be limited to heating and/or power generation. Gas supply for chemical purposes may require additional separation facilities. Syngas from wood gasification can undergo water-gas shift reaction, scrubbing and pressure swing adsorption to produce hydrogen with levels of tars, ammonia and sulphur compounds, and aromatics (such as xylene, benzene and toluene) below detectable levels.[34] The Fischer-Tropsch process to produce synthetic fuels requires impurity levels in syngas of < 1 ppmV for compounds such as COS, H_2S, organic sulphur compounds, NH_3 and HCN due to the potential for poisoning of catalysts, and even lower at < 10 ppbV for chlorides and alkaline metals.[35] Processes that use hydrogen to produce chemicals such as ammonia and hydrogen cyanide are also sensitive to the gas supply composition.

[32] (Mondal et al 2011)
[33] (Levy, Levitan et al 1993)
[34] (Fail et al 2014)
[35] (Hofbauer et al 2007)

3. INTERNATIONAL STATUS OF INJECTION OF RENWABLE GAS INTO GAS DISTRIBUTION NETWORKS

The potential benefits of, and the main drivers for, injecting renewable hydrogen or SNG into distribution networks are to:

- reduce the greenhouse gas emissions of natural gas;
- use the existing network to reduce transmission costs of clean energy; and
- make use of excess of renewable electricity or waste biomass.

These benefits are recognised by a number leading gas network operators and renewable gas production companies across the world. These companies have implemented a number of demonstration projects associated with the production of renewable gas and the injection of this gas into gas distribution networks. An overview of these projects is provided below.

3.1. Applications of injection of renewable hydrogen into the gas network

A remarkable increase in technology deployment in terms of ongoing projects dealing with renewable gas production processes started after 2010 with over 40 new demonstration projects commencing since then. Currently available information predicts that this period will last, at least, until 2025.

Although the first pilot plant was erected in Japan, the current leadership holds in Europe, mainly thanks to the support of the governments of Germany, Denmark, Netherlands and Switzerland. These experiences combine pilot and demonstration plants whose electrolyser sizes vary from few kWe (lab-scale plants) to 3×2.0 MWe (largest existing plant). An overview of the ongoing “Power to Gas” projects can be found on the website of the European Power to Gas Platform.[36]

The United States has also contributed to the deployment of the technology with up to four projects since 2009. Data show that the average budgets for demo-plants projects are around one million euro per year in most cases.[37]

The main technology suppliers include Hydrogenics, ITM, McPhy, AREVA and Siemens. Hydrogenics have supplied 1MW PEM electrolysers to pilot trials in Puglia, Italy and Denmark for injection of hydrogen into the natural gas grid, with production rates of 200 Nm^3/h. It should be noted, however, that much larger alkaline electrolysis units, of the order of 100MW, have been used in some refineries for some time.

ITM Power have supplied PEM electrolysers to the Thuga group, who are producing up to 60 Nm^3/h hydrogen and injecting it into the natural gas network in Frankfurt. They claim this was the first application in Germany of power to gas with injection into the gas network. Thuga have found that the greatest economic benefit can be obtained through payments for primary grid stabilisation, i.e. being able to ramp up hydrogen production within 10 seconds when excess electricity becomes available. Control systems are used to limit the injection of hydrogen to a maximum of 2% in natural gas[38].

It should be noted that the majority of hydrogen production pilot plants are located in Germany, where three alternatives for injection of hydrogen into existing or new infrastructure have been considered[39]:

- renewable hydrogen in dedicated infrastructure for use in road transport
- renewable hydrogen into the natural gas network
- renewable hydrogen to make synthetic methane and feed into natural gas network

3.2. Applications of renewable SNG injection into the gas network

Regarding methanation technologies, large projects cover mainly catalytic processes due to its scale up capability, although recently some biological projects also rose up to the MW range. Current pilot plants prefer biogas as source of CO_2 since the energy penalty associated to carbon capture from industrial processes is removed. For the same reason, syngas upgrading emerges as a future suitable

[36] http://www.europeanpowertogas.com/demonstrations
[37] (Bailera et al 2017)
[38] (ITM Power 2016)
[39] (Schiebahn et al 2015)

option. Few others have experienced with more innovative CO_2 sources such as industrial processes, the atmosphere, natural gas extraction processes or wastewater treatment plants.[40]

The largest methanation project at present is the 6MWe (1250 Nm^3/h H_2) plant built for Audi in Werlte, Germany by the company ETOGAS. The plant is powered by an offshore wind park in the North Sea and produces hydrogen by alkaline electrolysis, followed by methanation of hydrogen and CO_2 to methane, which is then injected into the natural gas network. Audi trucks running on natural gas extract gas from the network at other locations.[41]

The new 20 MWgas GoBiGas plant at Gothenburg, Sweden produces SNG that is injected into the local natural gas network. There are economic issues with the plant, rather than any technical issues with gas injection, which has meant that the plant has not moved to its second, larger, stage of operation.

Hydrogenics also have a small 60 Nm^3/h hydrogen methanation pilot plant in Stuttgart producing SNG using hydrogen from electrolysis and CO_2 from biogas.

The following table provides a representative listing of some of the larger scale renewable gas production projects that are either currently operational, or planned for the near future. As pointed out earlier in this chapter, the majority of the existing projects are being undertaken in Europe.

Supplier/Project	***Technology***	***Scale***	***Location***	***Status***
Hydrogenics	PEM Electroysers – H_2	200 Nm^3/h	Italy	Operational
Hydrogenics	PEM Electroysers – H_2	200 Nm^3/h	Denmark	Operational
ITM	PEM Electroysers – H_2	60 Nm^3/h	Germany	Operational
Hydrogenics	PEM Electroysers to SNG	60 Nm^3/h	Germany	Planned
GoBiGas	Biomass Gasification to SNG	20MWgas	Sweden	Operational
ETOGAS, Audi	Alkaline electrolysers, SNG injection into gas network	1250 Nm^3/h H_2	Germany	Operational

Table 3: Listing of notable renewable gas injection projects in Europe (not all-inclusive)

[40](Bailera et al 2017)
[41](Schiebahn et al 2015)

4. ENABLING RENEWABLE GAS IN AUSTRALIA

4.1. Cost of hydrogen and carbon dioxide

The commercial viability of using hydrogen as a fuel will depend on its cost competitiveness with other energy sources. Natural gas wholesale prices in Australia have fluctuated between AUD$3.8/GJ and AUD$10.3/ GJ since January 2015 and July 2017.[42] The cost of hydrogen from methane reforming is largely dependent on the natural gas price and ranges between AU$12 and $20/GJ.

An overview of how the estimated costs associated with the production of renewable hydrogen compares to these prices is provided in Table 4. The basis for these cost estimates is provided in the remainder of this section.

Reference	Cost per GJ	$AUD/GJ
Schiebahn et al. (2015) **- H2 by electrolysis**	Euro 40-55	55-75
Lemus et al. (2010) **- H2 by electrolysis**	US $30	39
US DoE (2016) **- H2 by electrolysis (2020)**	US $33	43
US DoE (2016) **- H2 from biomass (2020)**	US $33	43
Hinkley et al. (2016) **- H2 by electrolysis (solar PV)**	AUS $152	152

Table 4: Estimated cost of hydrogen production

For a wind power to hydrogen project, a recent German study estimated the levelised costs of hydrogen over the project lifetime, assuming a cost of wind power of Euro 0.06/kWh, was Euro 40 - 55/GJ.[43] The cost is significantly more than the current natural gas price in Germany of Euro 11/GJ and gasoline at Euro 22/GJ).

In 2010 costs of hydrogen produced by the wind in the US using the electrolysis route were estimated at US $30/GJ hydrogen by 2020.[44] Likewise the U.S. Department of Energy[45] have very low estimates for hydrogen production costs. They target a dispensed (untaxed) cost of hydrogen from photovoltaic electricity of US $4.0/kg in 2020, which equates to US $33/GJ, (based on the hydrogen LHV of 120.0 MJ/kg) and assumes a low electricity price of US $0.031/kWh. It should be noted that this very aggressive target requires major technology break-throughs and scale-up. They have the same cost target for hydrogen from biomass in 2020.

A recent Australian study estimated current costs of hydrogen from solar photo-voltaic electricity to be AUD$18/kg and estimated the cost in 2030 to reduce to approximately AUD $9.1/kg, ($76/GJ based on LHV of hydrogen) allowing for significant cost reductions in photo-voltaic electricity and electrolysis units between now and 2030. These are more realistic costs, based on a thorough assessment of component costs and likely improvements.

A recent techno-economic study, for the Swiss market, comparing alkaline electrolysers with proton exchange membrane (PEM) electrolysers, suggests that PEM electrolysers are more expensive over their life cycle, due to operating costs towards the end of life, but that rapid improvements are being made in the PEM technology.[46] The study suggests that since selling hydrogen into the wholesale hydrogen market or SNG into the wholesale natural gas market were not yet profitable, that high value markets for hydrogen need to be established for profitable operation. Other value propositions such as avoidance of carbon tax, sale of co-produced oxygen and waste heat, and receipt of payments for a renewable energy premium were also suggested.

[42] (AER 2017)
[43] (Schiebahn et al. 2015)
[44] (Lemus et al 2010)
[45] (US DOE 2016)
[46] (Parra et al 2016)

In summary, it appears that in addition to ongoing cost reductions through RD&D, it will be necessary to target high value hydrogen markets and use market mechanisms to introduce and promote renewable hydrogen and SNG technologies. There is potential for use of the gas transmission and distribution network to transport hydrogen for downstream separation and use as a high value product in industry, refining, domestic, vehicles or “Gas to Liquids” processes.

4.2. Reducing costs through R&D

Australia has significant opportunity to adapt existing natural gas distribution infrastructure for use by renewable gas. Whilst the use of new fuels is technically feasible today, conversion at scale is l challenging on many levels. In order to bring down cost hurdles associated with the deployment of renewable gas, further demonstration of technology is required to foster technology learning and bring down the cost of existing technologies for renewable gas production and handling. Furthermore, R&D of advanced breakthrough technologies (e.g novel process equipment / reactor technology) will provide an opportunity to significantly reduce costs on the longer term.

Whilst the process technologies for the SNG and hydrogen production requires further R&D, it is equally important to develop new knowledge, technology and skills that are needed for renewable gas use and handling. More investment is needed to develop new equipment in homes and workplaces, and to design new or retrofitted transmission and distribution networks. A number of potential R&D areas that could be considered as part of a consolidated R&D agenda for the introduction of renewable gas in Australia include:

- Development of new market models and techno-economic models of entire production and delivery systems for renewable gas.
- Accelerated development of strategic, early stage, breakthrough renewable gas production technologies.
- R&D into full extent of changes required to the network materials, instrumentation, customer appliances and plant equipment need to be understood for renewable gas and in particular hydrogen-methane mixtures.
- Development of new materials with improved performance characteristics and degradation resistance for handling renewable gas.
- Safety considerations need to be reviewed for hydrogen generation, transport and injection.
- Uncertainties regarding the lifecycle costs for hydrogen production, transmission, storage and injection need to be reduced.

Specifying R&D priorities will not only result in reliable and safe transportation of renewable gas in Australian distribution networks, but will also assist in bringing down the lifecycle cost associated with the production, handling and use of renewable gas.

4.3. Reducing costs through market incentives

Policy and regulatory drivers to assist in the introduction of renewable gas into the market need to have an end goal in mind. To set these goals it is suggested that scenario modelling in Australia should first be undertaken to compare options. Then policy can be set to encourage investment and research and development in renewable gas technologies that are a good fit with existing Australian energy infrastructure and (renewable) resources.

The primary market driver is production and sale of high value hydrogen or SNG for use as a transport fuel or for production of renewable CNG, LNG or liquid transport fuels and chemicals. However, additional incentives will probably be required to establish a renewable gas industry. Targets can be set and market drivers can be established to assist with development of a renewable gas industry in a similar manner to the way in which renewable energy certificates and carbon pricing has been used in the past to assist the renewable electricity industry. Although detailed discussion of specific measures are beyond the scope of the current report, measures that may be considered to promote a renewable gas industry include, but are not limited to:

- Renewable Gas Certificates

- A Renewable Gas Target (similar to the Renewable Energy Target)
- Direct Subsidies
- Allowances – i.e. being paid to use excess renewable electricity
- Offsets – i.e. being able to inject hydrogen at one location in the natural gas network and extracting and equivalent amount of ‘renewable’ gas elsewhere in network
- A premium price paid for seasonal stored energy to ensure grid stability
- Use of electrolysers as primary and secondary loads for grid stabilisation when there is excess renewable electricity available – with an appropriate service pricing mechanism
- “Power to gas” economic assessments need to include a premium for avoiding upgrades to electricity infrastructure, by maintaining both gas and electricity near current capacity, instead of increasing electricity and reducing or eliminating gas
- Establishment of a regional large scale electricity grid stabilisation project - if national and international funding can be attracted with the motivation of demonstrating technologies that could later be applied elsewhere.
- In addition to electricity grid stability, such a project could include staged increases in delivery of hydrogen or SNG to specific end-users. The whole of South Australia, which has weak electricity grid interconnection to Eastern Australia, is a candidate for this sort of project, as are many smaller regional areas throughout the country.

5. SUMMARY AND CONCLUSIONS

1. In the short to midterm renewable hydrogen and SNG can be produced from:
    a) renewable electricity and electrolysis, or
    b) biomass gasification and water gas shift, or
    c) from biogas.
2. Solar thermal heat has the potential to be used for improving production rates from biomass gasification. Waste biomass is a relatively cheap source of carbon and hydrogen, so biomass and waste gasification has the potential to be an early mover.
3. Fossil fuel based hydrogen production with CCS is another potential route to low carbon hydrogen depending on project economics, suitability of local geology for sequestration, local policy / regulatory settings and obtaining social licence to operate.
4. Alkaline electrolysers are the state of the art technology and are being used in the largest power to gas applications such as the ETOGAS / Audi project, rated at 6MWe. PEM electrolysers are more efficient than alkaline electrolysers and show potential to be ideally suited to power to gas duty. Research is ongoing improvement the lifetime and reduce cost of PEM electrolysers.
5. Power to Gas is suited to long term storage of electricity in the form of gas, i.e. storage for more than a few days to months (seasonal storage). Other methods of electricity storage such as batteries or pumped hydro are more cost effective for in-day storage and peak shaving.
6. Power to gas is relatively expensive so will require commercial or regulatory incentives, or payments for stabilising the grid, so the focus in Europe has been to start with small demonstration projects demonstration feasibility and to bring down cost of technology.
7. Economic assessments of “Power to gas” need to include a premium for avoiding upgrades to electricity infrastructure, by maintaining both gas and electricity near current capacity, instead of increasing electricity and reducing or eliminating gas.
8. Scenario modelling (different production processes, and varying funding, costs and payment options) in the Australian context may help in setting policy goals.
9. There is significant potential for hydrogen and SNG injection into natural gas networks in Australia and this report has provided some initial R&D areas and potential policy settings that could facilitate the introduction of renewable gas in Australian distribution systems. .

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