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Renewable Gas - discussion on the state of the industry and its future in a decarbonised world

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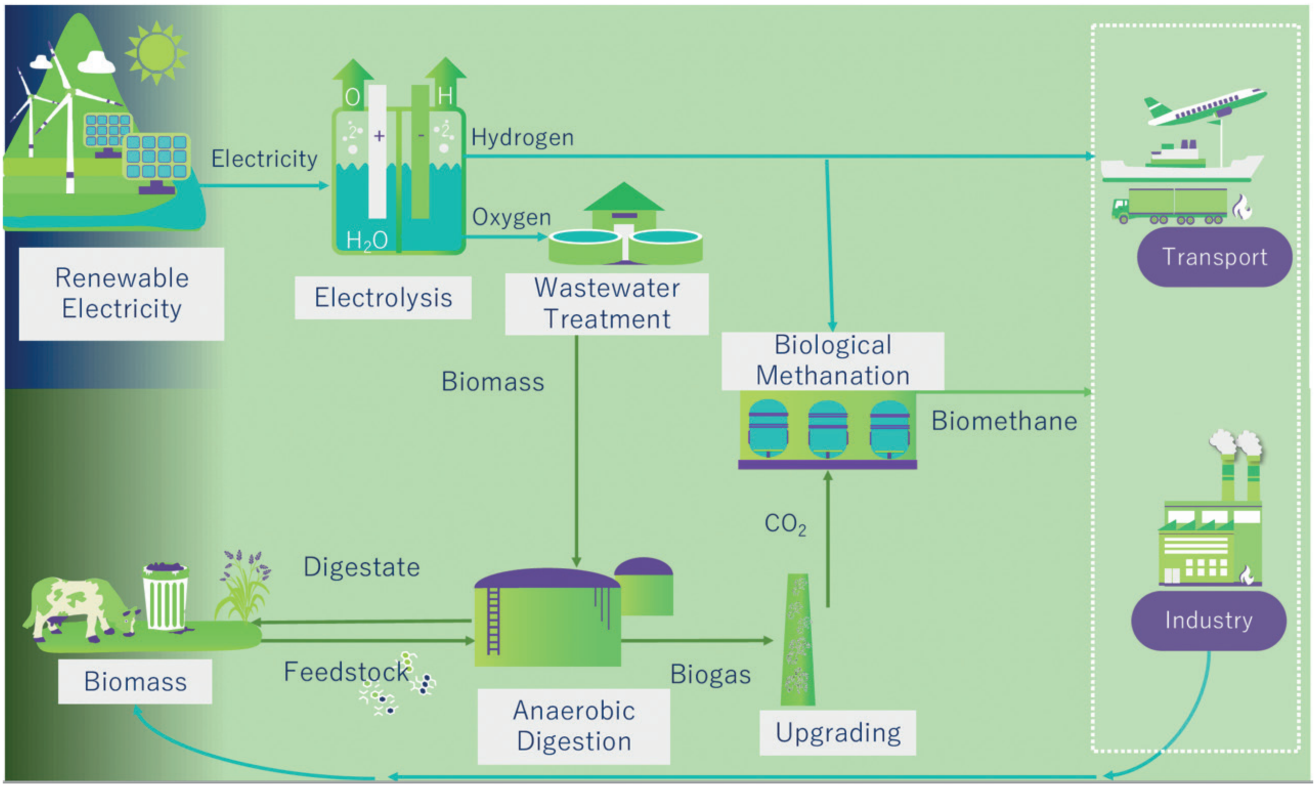

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Renewable Gas - discussion on the state of the industry and its future in a decarbonised world

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Executive Summary

Decarbonisation is about so much more than electricity; electricity itself only accounts for about 20% of final energy demand. As a society we must make decisions informed by scientists and engineers and implemented through policy as to what technologies and roadmaps will be employed to decarbonise the hard to abate sectors including for: heavy transport; high temperature industrial heat; agriculture; fertiliser and chemical production. When it is considered that at present in the EU and the USA the natural gas grid provides more energy than the electricity grid, it cannot be seen as a sensible process to abandon such infrastructure and start again, not with the imminent climate emergency and the need to act fast. We must be decisive as we eat through our ever-dwindling allocated carbon budget to limit world temperature rise to below 2°C.

The existing natural gas infrastructure is very extensive in many industrialised countries and rather than being viewed as a future redundancy associated with a fossil fuel system, it could instead be seen as offering huge benefits for green renewable gas as a future decarbonised energy carrier. The whole natural gas infrastructure system was put in place at huge cost and includes for an extensive transport system of transmission and distribution pipes and connections to industries and homes. Within specific industries, gas boilers, CHP units and associated systems are in place to provide the necessary ingredients and energy provision for end products that range from ammonia to whiskey.

Traditional renewable gas technologies (such as biogas and biomethane) can be considered mature. We have the technologies in place to make renewable gases from wet organic material, dry woody material and from electricity. In southern Sweden for example biomethane is used extensively as a transport fuel in buses, trucks and cars. We already inject gas to the gas grid. For example Denmark has at times substituted natural gas in the grid with over 25% biomethane; these values fluctuate over the year. In terms of policy we have devised and put in place trading mechanisms for trade between producer and user of renewable gas, some times in different countries.

The economic feasibility is questioned, however this is a green fuel which is being compared to a fossil fuel where the present cost of carbon in no way takes account of the climate emergency. As such, it is preferable to contrast the cost of renewable technologies with the cost of other renewable technologies which are viable in that sector; for example we should not compare the cost of abatement of mature technologies in readily decarbonised sectors (say PV arrays) with that of an advanced transport fuel that can power heavy transport but is at an early stage of development. We need to incentivise technologies at early market maturity and at low technology readiness levels (TRL) that are seen to have great potential for application as fuels of the future for hard to abate sectors such as hydrogen and associated electro-fuels.

At present however, the main barrier to uptake in the market for renewable gas is the cost. Future support systems and development strategies and policy must create conditions to integrate renewable gases into a new climate neutral economy. Whilst incentives are required at present to compete with fossil fuels, a strategy on the role renewable gas plays in the future market must be devised. Sustainable renewable gaseous fuels will be required to substitute for the huge market in place which uses natural gas and upcoming demand in new energy systems. In particular attention must be paid to the existing natural gas infrastructure and how this massive capital investment could be capitalised upon.

In this report, the following actions have been identified to optimise the future development of renewable gas systems:

- Create roadmaps for renewable gas development, including for availability of substrates (be they wet organic, woody or electricity), development costs, defined time specific targets as a portion of energy use and infrastructure required and/or already available.
- Introduce quotas which place an obligation on fuel providers to ensure renewable fuels meet a minimum proportion of the fuel market; this is a very effective tool to remove the necessity of renewable gas competing on price with fossil gas.
- Provide incentives which reflect the actual costs of investment and long-term operation of the renewable gas industry to ensure bankability for the developer and ensure a price effective market environment for the user of renewable gas.
- Eradicate as much as plausible, unnecessary barriers and inhibitory regulations on both a technical and regulatory level.
- Seek compatibility with other technologies (both existing and proposed) through a cascading approach to further develop the sector; this could include for example carbon capture from industry combined with hydrogen from electricity to produce methane, methanol or ammonia in electro-fuel systems.
- CO_2 emissions must have a realistic monetary value associated with them; a realistic carbon tax would stimulate development and drive the transformation of green gas whilst providing for competition between renewable technologies in specific sectors, which should consequently lead to the phase out of specific incentives.

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1 Introduction, Scope and Background

To comply with the Paris Agreement in limiting the global temperature increase to less than 2°C, a reduction of up to 80% greenhouse gas (GHG) emissions will be required by 2050 (Gao et al., 2017). Decarbonisation is not just concerned with renewable electricity but includes for domestic heat and private transport and the hard to abate sectors such as heavy transport (trucks, ships and planes), industry (steel and cement production, chemicals, fertilisers) and agriculture. This is the realm of renewable gas.

Renewable gas is a renewable energy vector derived from biomass or electricity. The renewable gas may be sourced from digestion of wet organic material or from thermal conversion of woody material and be termed biomethane. Alternatively electricity may be used in electrolysis to split water into hydrogen and oxygen; the hydrogen produced via this power to gas process may be termed a gaseous fuel from a non-biological origin or more simply, green hydrogen. Renewable methane (sometimes termed e-gas) may be generated when this green hydrogen is reacted with CO_2 in a power to methane process via the Sabatier Equation ($4H_2 + CO_2 = CH_4 + 2H_2O$). There is also blue hydrogen which is generated via steam methane reforming (SMR) of natural gas with carbon capture and storage (CCS); however this will still have a carbon intensity associated with it.

Renewable gas is viewed as a key component in the energy transition and decarbonisation of the broader energy sector especially beyond electricity. Energy rich gases are flexible energy carriers that can be used in sectors such as electricity, heat, and transport and in industry (such as the food and beverage sector) and for materials production (including for ammonia and methanol). Many countries have an existing infrastructure for gas transportation and handling (natural gas grid) with sufficient storage capacities to balance differing energy demand and supply rates. In 2018, it was reported that there was a current natural gas demand of 4000 billion cubic meters (bcm) and that this was expected to grow in the following decade (IEA, 2019b).

Whilst fossil methane (or natural gas) is better than coal or oil in terms of carbon dioxide (CO_2) and particulate emissions, it still has a high global warming potential (GWP) (IPCC AR 5 gives a GWP of 28 over a 100 year period). Thus, the benefit of substituting other fossil fuels with fossil methane is highly dependent on achieving low methane emissions over the whole provision chain. However, even with low emissions in the provision chain, the utilisation of fossil methane will inevitably release CO_2 to the atmosphere and therefore the future use of fossil natural gas should be phased out.

Transitioning to a carbon neutral economy and renewable energy supply will lead to a new energy supply system made up of different energy carriers. The sustainability of biomethane or renewable methane depends on its source and requires minimisation of methane slippage across the entire lifecycle. However, it should be far superior to the fossil fuel it replaces. The precise role of gas in this renewable energy supplied carbon neutral system has yet to be defined. However, the question remains as to which renewable alternatives can substitute current and future demand for natural gas and furthermore, satisfy strict sustainability requirements, while being cost efficient as compared to other renewable energy vectors. Currently, renewable methane, hydrogen and ammonia are the alternatives under discussion. The debate on the different options for renewable gas can include for many aspects such as the order of magnitude of future demand, the related costs of production and the technology maturity.

In the transition to a renewable energy supply, a substantial change in sources and technologies for electricity, heat and fuel will be required and the demand of each energy form will change substantially. In particular, electricity may become the key energy sector in achieving decarbonisation. Currently there are very few options to produce alternative fuels for heavy transport (trucks, ships and planes) and to allow for decarbonisation of this sector. It is likely that to provide a large-scale solution, electricity will be required to produce hydrogen and from there to electro-fuels such as renewable methane, methanol and ammonia. Hydrogen is seen as a key vector for climate neutrality as it can target fossil reliant sectors such as heavy transport, ammonia production processes and the steel industry, where few solutions are readily available to decarbonise. This raises the question of what the future demand for electricity will be. At present electricity is typically of the order of 20% of final energy demand, with heat and transport together accounting for the other 80%. If electricity demand increases by the expected order of magnitude to provide for renewable heat and electric cars and onto future electro-fuels for trucks, ships, and planes there will be a very significant impact on the availability and costs for other electricity consumers. This illustrates the challenge associated with electrification as the primary route to decarbonisation, and how closely linked the different energy sectors are in providing a renewable energy future with lower GHG emissions.

The gas sector currently provides natural gas to all energy sectors and additionally functions as an intermediate for materials production in the chemical industry. Typically, in the US and the EU of the order of 50% more energy is sourced from the gas grid as from the electricity grid (IEA, 2019b). The worldwide perspective on natural gas demand is that constant sale quantities will at least be required for the next two decades (IEA, 2019b). It is likely in the highly developed countries that domiciles will move from natural gas heating to electrification via deep retrofit and heat exchangers, but the move away from gas in industry is unlikely in the next two decades. Combining the current and future demand, and accounting for the perspective on natural gas in a changing energy system, it is clear that renewable gas will need to play a major role in a future decarbonised world. A strategic development of the renewable gas sector requires the prediction of the future gas demand; however, such predictions are difficult to make since gas is used in all energy sectors (electricity, heat, and fuel provision). The dependency of any development on political decisions adds even more uncertainty to any prediction.

Since natural gas is traded worldwide, there is technically no obstacle for international trade of renewable gas – in particular biomethane or synthetic natural gas (SNG) with its natural gas equivalent characteristics. Such trade offers a route for transfer of larger quantities of energy between producing and utilising regions. However, the utilisation of renewable gas requires new instruments to certify renewable energy sources and sustainability, and the distortion of competition by means of use of incentives in different countries needs to be avoided.

For renewable gas production, biomass derived biomethane needs to be considered carefully. Biomass is a limited resource, and its use comes with several economic, environmental, and social constraints. Thus, the potential for biomass availability for energy purposes must be accurately determined. In most developed countries, the energy obtainable from available biomass is much smaller than the overall energy demand provided by gas. Consequently, the challenge for implementing biomethane is a matter of how to provide sustainable biomass utilisation and to make key decisions on what areas to use the limited resource.

The provision of gas based on renewable sources is more costly than the provision of natural gas under current conditions with limited carbon taxes; therefore, the production and/or utilisation of renewable gas has to be incentivised to be competitive. A number of countries have implemented strategies and incentive systems to develop a viable renewable gas sector. Biomethane generated from anaerobic digestion is often a part of these strategies, but the details of implementation and the response of the market in each country can differ substantially. Hydrogen is proposed as a zero-carbon fuel source replacement for fossil fuels that is particularly applicable in hard-to-abate sectors such as long-distance heavy-duty transport (aviation, shipping and haulage), large-scale industrial users of natural gas, and load-following power plants. However it may be said that the hydrogen economy, though spoken of optimistically and of great potential resource, is some way behind the existing biomethane market.

This report discusses renewable gas in terms of the state of the industry and its future in a decarbonised world. The emphasis is more on biomethane via anaerobic digestion (which is a mature technology) and hydrogen produced via a number of pathways (grey, blue and green as discussed in this work) and electro-fuels (which is a less mature technology). Less emphasis is placed on biomethane produced via gasification; this is not a mature technology and also is the remit of IEA Bioenergy Task 33: "Gasification of biomass and waste"[1]

The report provides an overview of the state of the art of the production, the current incentive systems used and the view of stakeholders on the market of renewable gas. A survey was conducted of 14 selected countries (Germany, Canada, China, Finland, Sweden, Norway, Australia, Estonia, Austria, Switzerland, India, USA, UK, and Japan) and the relative findings are presented throughout the report. Based on the findings, recommendations for the sustainable development of the renewable gas sector are made.

[1] https://www.ieabioenergy.com/blog/task/thermal-gasification-of-biomass/

2 Renewable Gas

2.1 WHAT IS A RENEWABLE GAS?

As a prelude it should be noted that renewable gases by definition must have an origin from a renewable source, such as for example a sustainable biomass (in the case of biomethane) or from electricity produced from a wind farm or from the sun via photo voltaic (PV) arrays (in the case of hydrogen). Renewable gas is an energy carrier which must meet a defined quality standard for use in existing gas infrastructure.

In the case of electro-fuels a combination of sources of electricity to produce hydrogen and CO_2 to process the hydrogen to methane dictates whether it is actually a renewable gas or the degree of renewability. The climate impact of the renewable gas (known as the carbon intensity) is a slightly different metric and can be calibrated with cognisance of the sources (and carbon intensity) of the electricity and the source of the CO_2. While carbon intensity can be calculated and given as a number with a unit such as gCO_2/MJ which can then be contrasted with a carbon intensity of a fossil fuel comparator, "renewability" has not such a quantifiable criteria as of yet.

Biomethane production can involve many sectors depending on the source of the biomass, be it agricultural slurry or food waste for example. As such, the provision of biomethane requires several processing steps in a number of sectors and the energy supply to these process steps can also involve both renewable and non-renewable sources. Thus, further complexity arises when these sources (renewable or non-renewable) are allocated to different sector processes (agriculture or waste treatment). In synthesis the differentiation between whether a renewable gas is actually renewable or the degree of renewability is complex. It is preferable and easier to manage the carbon intensity which can be assessed using methods such as the sustainability criteria in the recast Renewable Energy Directive. More details on the types of renewable gases or alternative gas vectors is given in the following sub-sections.

2.2 BIOGAS, BIOMETHANE AND SYNGAS PRODUCTION

2.2.1 Differentiation between biogas, biomethane and syngas

Biogas is a gas mixture containing methane (CH_4) and CO_2, along with water vapour and other trace gases. The composition of CH_4 in biogas is typically in the range of 50 to 70% whilst CO_2 comprises 30 to 50%. Biogas is generated from the degradation of wet organic biomass achieved by a large variety of microorganisms in the absence of oxygen in an anaerobic digestion (AD) process. Besides lignin, the majority of organic materials can be accessed by anaerobic microbial consortium. The rate of degradation is substrate (biomass) specific and is also dependent on the specific AD process parameters. Typical biomass sources for biogas production include for agricultural residues, energy crops, wastewater sewage sludge, the organic fraction of municipal solid waste and seaweeds. Biogas can be used directly in a combined heat and power (CHP) unit for the production of electricity and heat.

However, more recently there is significant increase in technologies converting biogas to biomethane by means of a range of upgrading processes. Upgrading denotes the separation of unwanted components in biogas, primarily CO_2, which leads to an increase in the total methane content (up to ca. 97%). The aim is to meet natural gas standards and inject biomethane to the existing gas grid network or use it directly as natural gas substitute. Once injected to the grid it can function as an equivalent natural gas substitute and be used in all natural gas applications. The gas grid rather than becoming a redundant infrastructure can become a distribution system for a gaseous renewable vector in the decarbonised world.

Solid biomass can undergo gasification at high-temperatures whereby it is thermally decomposed into a gaseous product (syngas) and a solid product (biochar). Syngas can subsequently be combusted for heat and power production or converted into various alternative fuels such as bio-Synthetic Natural Gas (bioSNG) via a methanation step. BioSNG, which may also be termed biomethane as it is produced from biomass, is a product comparable to natural gas which can be injected into the existing gas grid and used in known gas applications.

2.2.2 Growth in decarbonisation of methane

Gas has been and will continue to be an important energy carrier for private and industrial users. The utilisation pathways and quantities of gas will change significantly in the shift towards a renewable and decarbonised energy supply. In the past decade, the implementation of incentives for renewable energy led many countries to a concurrent support for renewable gas. As per Figure 1, most of the production is in the form of biogas delivered to CHP units, but the share of biomethane to the grid is increasing.

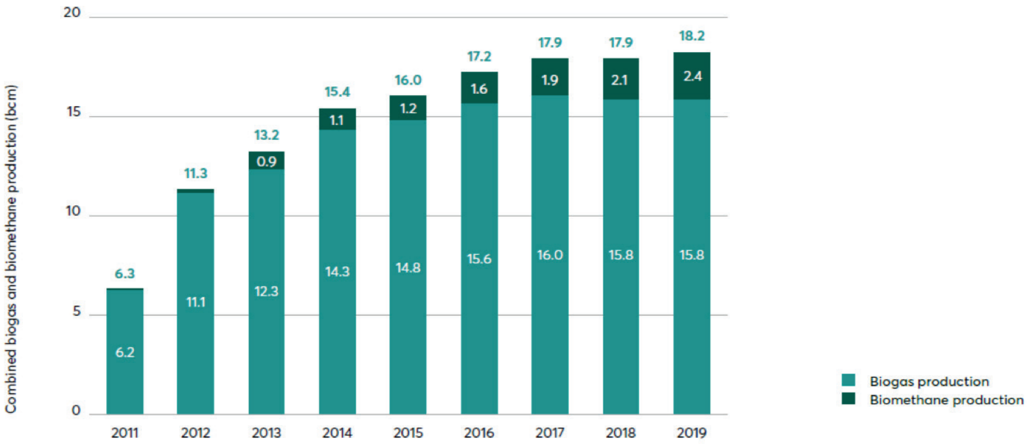

Figure 1: Growth in biogas and biomethane production in Europe (2011-2019) (EBA, 2021)

The AD technology can be considered as mature with a variety of component providers available with long-term operational experience. Initially many countries opted for the development of CHP applications. However, with the current low costs associated with solar and wind electricity, biogas based electricity is now less competitive. On the contrary, the gas sector and fuel sector face a persistent need to reduce emissions and thus biomethane has gained relevance in these sectors. Since biomethane is a substitute for natural gas with identical characteristics, the existing infrastructure for natural gas can function as a vehicle for the implementation, acceptance, and uptake of the technology. Natural gas is an important and significant energy carrier in many countries. Table 1 exemplifies the different needs and infrastructure availability for natural gas utilisation in a select number of surveyed countries. It is evident that some countries, such as Germany, have a large grid and high gas demand (in relation to the country size and population) whilst other countries have a significant lack of such infrastructure. The availability of existing infrastructure such as the gas grid and natural gas filling stations aids in the distribution and use of biomethane. This in turn makes the process of accruing customers easier since the change from natural gas to biomethane is very simple. Despite this, even with a lack of natural gas infrastructure the development of a biomethane industry may not necessarily be hindered. Sweden is an example of a country with little grid infrastructure which has developed many biomethane plants primarily for transport applications. In essence, an existing infrastructure does help biomethane implementation, but it is not imperative. Countries like Sweden or Finland show that with an aligned production and utilisation strategy, biomethane applications can be successful.

Table 1: Characteristics of the natural gas sector in selected countries

Natural gas sector	Germany	Canada	China	Finland	Sweden	Norway	Australia	Estonia	Austria	Switzerland	India	USA	UK	Japan
Utilised gas (TWh/a)	982	1230	3028	24	18.5	67.2			90	38		8296	880	
Length of gas grid (X 10^3 km)	511	571		1.15	3	0.81	126		46	20.2		4828	283	213
Number of gas filling stations	853	134		37	250			27	150	150		1000		
Utilised gas external to grid (TWh/a)					1.5					<0.1				

The number of installations and the overall capacity differs by country; Germany is leading in terms of the total number of AD plants, however the USA has the highest overall feed in capacity (Table 2). The majority of plants that have upgrading technologies are connected to the grid, but countries such as Sweden, Finland and China show that a decentralised production and gas utilisation approach is possible without grid access. In the USA, most plants are located at large landfill sites, which explains the large capacity per site. In Germany, the situation is slightly peculiar in that most plants use energy crops as the substrate and a large portion of the produced biomethane is used for electricity. The majority of other countries focus more on agricultural residues and wastes (in lieu of landfilling) for the provision of biomethane (such as Sweden and the UK).

Table 2: Number of plants and feed in capacities for selected countries

Anaerobic digestion plants	Germany	Canada	China	Finland	Sweden	Norway	Australia	Estonia	Austria	Switzerland	India	USA	UK	Japan
AD upgrading plants with grid injection	219	11		4		13	0	1	14	39		109	113	
AD upgrading plants without grid injection	1		172	13	68	2	0	1	1	3		13		
Total feed in capacity ($10^3 m^3 CH_4$(STP)/h)	134	16.2		11.5				0.856		8		207	68.5	
Latest available realised feed in (10^3GWh)	9.83		0.57	1	0.544			0.063	0.15	1			3.3	
Latest available data on realised feed in (year)	2019		2018		2018			2019	2019	2019			2018	

2.2.3 Substrates used for biogas, biomethane and syngas

In analysing the substrates used for AD, it is apparent that manure is used by all countries (Table 3). Municipal and industrial waste materials, and sewage sludge are also widely accepted for digestion. Landfill gas was only used in approximately half of the countries studied for biomethane provision. Energy crops were found to be eligible for financial incentive in 7 countries (see Table 11 in section 4.3), but only used in 5 of the countries assessed which is likely due to economic sustainability. Gasification processes for the production of natural gas substitutes are not well established, the use of the wood substrates was only confirmed in 2 countries. It is suspected that the currently available incentives are not sufficient to cover the production costs.

Table 3: Substrates utilised in AD and gasification for biomethane provision in selected countries

Base substrates	Germany	Canada	China	Finland	Sweden	Norway	Australia	Estonia	Austria	Switzerland	India	USA	UK	Japan
Energy crops	x	x			x				x				x	
Catch crops	x				x				x				x	
Agricultural residues and manures	x	x	x	x	x	x	x	x	x	x	x	x	x	x
Municipal organic waste	x	x	x	x	x	x	x		x	x	x	x	x	x
Organic industrial waste	x	x	x	x	x	x	x		x	x	x	x	x	
Landfill gas		x	x	x	x		x				x	x		
Sewage sludge	x	x	x	x	x	x	x	x	x	x	x	x	x	x
Food waste												x		
Wastewater at WWTP												x		
Mine gas	x													
Wood processing residues (gasification)		x								x				
Waste materials										x				
Short rotation forestry														

2.2.4 Energy used to run biogas facility

A further consideration in the provision of biomethane is the source of energy used to run the AD plant. Use of renewable energy supply to satisfy parasitic demand was evident in only a few countries (Table 4). In the UK, only heat supply is regulated to come from biogas whilst the electricity source is free for the operator to choose. The majority of participating countries leave it to the plant operators to source parasitic energy provision at the facility. It should be noted that the carbon intensity of electricity is very different in the selected countries and as such have differing impacts on the carbon footprint of the produced biomethane.

Table 4: Requirements in providing plant energy demand in selected countries

AD plant energy supply	Germany	Canada	China	Finland	Sweden	Norway	Australia	Estonia	Austria	Switzerland	India	USA	UK	Japan
Obligatory renewable										x	x	x	x	
Free to choose	x	x	x		x	x		x	x					x

2.2.5 Sustainable available resource of biogas and biomethane

The sustainable, albeit controversial, exploitation of substrates for AD has been a subject of much discussion. The use of limited biomass resources is debated in the context of competing interests of other utilisation pathways (such as for liquid fuels or materials production). Other concerns include for: land use change; general agricultural and environmental issues; and the food versus fuel debate. Substrates which are accepted as sustainable include for wastewater sewage sludge, varieties of wet organic waste, and agricultural residues such as manure where AD can provide a form of waste treatment. Typically, energy crops (including catch crops) give potential to scale up production, add significantly to the methane yield as compared to slurries and as a result, in some countries, enjoy widespread use in co-digestion with other substrates; in Germany energy crops such as maize can be the dominant feedstock. However, many countries do not support the use or production of energy crops.

In Table 5, several studies from Europe have been assembled for the future potential of biogas and biomethane. The estimates vary due to the different factors considered; for example, whether gasification is included (European Commission did not consider this), whether the inclusion of sequential (only Gas for Climate) or intermediate (only Eurogas) cropping or energy crops (only European Commission) are included. The table highlights the need for a specific analysis on the biogas and biomethane potential where substrates for gasification processes are included in the calculation (using woody biomass). Furthermore, if energy crops are considered to have a large impact on the overall potential it should be acknowledged that this is dependent on the assumption that the land area is available for production. In essence, development targets based on such potential estimates must be calculated with consideration of more specific details. Nonetheless, the determination of biomass quantities and availability is dependent on many factors and assumptions and consequently the results can vary substantially.

Table 5: Potential for biogas and biomethane production in Europe (adapted from (EBA, 2021))

Study	Year	Biogas and biomethane production potential (TWh)	Biogas and Biomethane potential production capacity (GW)
Current production	2019	193	33
Gas for Climate	2030	370	46
Eurogas	2030	375	47
European Commission	2030	467	58
IEA	2040	1,326	166
Eurogas	2050	1,008	126
Gas for Climate	2050	1,020	128
Cerre	No timeframe	1316	164

In addition to the general considerations around the inclusion of woody biomass and/or energy crops, many other factors will affect the availability of biomass. Available biomass potential and related gas potential in specific regions can be estimated with consideration of:

- Geographical specific resource, spatial distribution and gas potential of substrate types;
- Restrictions on access to substrates whether technical, sustainable, economic or legislative;
- Public acceptance of substrate utilisation and technologies;
- Competing substrate utilisation pathways (material use, production of other energy carriers such as liquid biofuels).

The accessibility of manure and its related costs are discussed in Liebetrau et al. (2021). The 'usable' gas potential of manure was found to be influenced by numerous factors such as the regional structure of husbandry, the type of animal housing (open or closed, in barns or pasture based), the type of animal feed used, the storage time of manure prior to digestion, the technical limitations for collection, and the applied methane potential. Since precise data is often lacking for these factors, assumptions need to be made in calculating the biogas potential. Consequently, estimations of biogas potential from different authors can vary substantially and comparisons between different studies or countries are difficult to make. In the case of energy crops, the renewable gas potential is typically based on the agricultural land available for production. This is often deemed an analysis that may be overly simplified. Furthermore, debate on the exact amount of agricultural land that can be set aside for energy production is controversial.

The concept of restricted biomass or competing interests for biomass use are considered in some studies, but typically only reflect a very specific viewpoint on the topic. For instance, straw is a substrate which has many potential applications. Thus, to avoid investment in specific plant technologies (such as dry anaerobic digestion of straw) which might ultimately face increasing substrate costs due to increasing demand and/or limited supply (negating the availability of straw for digestion), a controlled allocation of biomass resources (via policy) to a specific utilisation pathway is recommended. As biomass is a limited and valuable resource and considering the high uncertainties within the potential analysis, any implementation of a utilisation strategy should be accompanied by continuous monitoring.

Table 6 exhibits the overall substrate potential for renewable gas production for the selected countries and the actual resource potential to be exploited. Note only a small number of countries had data on the fraction of the potential to be utilised. Once the potential has been evaluated, a strategy should be developed on how this potential resource can become something tangible including for considerations around the consequences such utilisation comes with and what economic conditions are needed to realise the exploitation. When comparing the biomass potential to the current overall energy demand, it becomes evident that such limited resources of biomass cannot satisfy the overall energy demand but can potentially contribute a significant portion, ideally in a hard to abate sector with price competitiveness as compared to other renewable technologies.

Table 6: Substrate potential and targeted substrate exploitation by implementation of incentives for renewable gas production in selected countries

Substrate potential (10^3 GWh/a)	Germany	Canada	China	Finland	Sweden	Norway	Australia	Estonia	Austria	Switzerland	India	USA	UK	Japan
Potential of supported substrates	123		1937	25	33	2.5	103	4.5		12.2		1260		200
Substrate potential to be accessed by implementation			733	10	10	0.9								

2.3 HYDROGEN PRODUCTION: GREY, BLUE AND GREEN

2.3.1 Hydrogen production to date

Hydrogen is a clean fuel that generates only water in combustion and has a high calorific value (141.8 MJ/kg). The current annual primary production of hydrogen is about 70 Mt globally and this equates to ca. 830 Mt of CO_2 per annum being released (IEA, 2019a). To date, hydrogen has been produced primarily from fossil fuels (ca. 96%) (natural gas, oil and coal) with relatively small amounts generated through water electrolysis (Corbo et al., 2011; IEA, 2019a). The hydrogen generated to date has largely been used for the production of chemicals, in particular ammonia for fertilisers, and in refineries as an element required for the overall production of petroleum products such as gasoline (Corbo et al., 2011).

2.3.2 Differentiation between the different colours of hydrogen

Hydrogen can be classified as "grey", "blue" or "green" based on the raw materials used in its production along with the extent of carbon released during the production process. The vast majority of current hydrogen production comes from the steam reforming of methane (SMR) with significant CO_2 emissions. This is deemed "grey" hydrogen. "Blue" hydrogen is the production of hydrogen from fossil fuels but with CO_2 emissions reduced through the use of carbon capture and storage (CCS). "Green" hydrogen is the term applied to the production of hydrogen from renewable electricity (such as wind or solar) through water electrolysis in a power to gas system. Figure 2 illustrates the different processes for grey, blue and green hydrogen production.

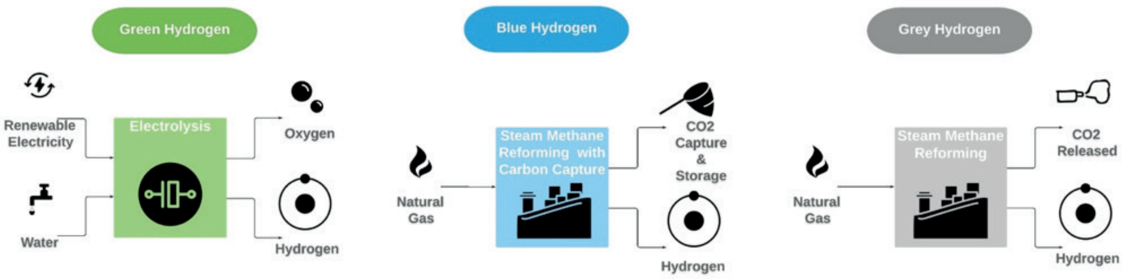

Figure 2: Green, Blue and Grey hydrogen production

2.3.3 Blue Hydrogen produced via steam methane reforming and carbon capture and storage

Blue hydrogen production is fundamentally a process involving the steam reforming of methane (SMR) whilst providing for CCS and can be regarded as a mature technology. Since the process relies on natural gas (fossil methane), it is still considered a technology that is dependent on the use of fossil fuels. The process of SMR involves the mixing of steam with natural gas, which then generates (or reforms) a synthetic gas of predominantly hydrogen (H_2), CO_2 and carbon monoxide (CO). The SMR process takes place at high temperatures and relatively low pressures, with optimum conditions suggested at 700–1000 °C (Carapellucci & Giordano, 2020), and below 25 bar (Taji et al., 2018). In the SMR process, ca. 30 – 40% of the natural gas is combusted to operate the SMR process, whilst the remaining 60-70% is used as a feedstock in hydrogen production. Natural gas enters the system and undergoes pre-treatment procedures such as desulphurisation and pre-reforming which simplifies hydrogen purification in later stages. The heat released by the combustion of the natural gas provides the necessary steam for the reforming reaction. Methane and steam then react with the use of a catalyst, producing a concentrated hydrogen synthesis gas (Carapellucci & Giordano, 2020). The contact between carbon monoxide and steam at high temperatures in the exothermic water-gas shift reaction stage results in the production of additional hydrogen and carbon dioxide. Equation 1 and Equation 2 describe the production of H_2 through the SMR process.

Equation 1

$CH_4 + H_2O \leftrightarrow CO + 3H_2$ $\Delta H = -206 kJ/mol$ at 15°C

Equation 2

$CO + H_2O \leftrightarrow CO_2 + H_2$ $\Delta H = +41.2 kJ/mol$ at 15°C

Following the shift reactor, the concentrated hydrogen synthesis gas, which also comprises of CO and CO_2, impurities and unreacted methane, is purified by pressure swing adsorption (PSA) to increase the hydrogen purity (Hosseini & Wahid, 2016).

As SMR uses natural gas as both a fuel and feedstock, the production of CO_2 is unavoidable. The input capacity of existing SMR plants currently vary from 10,000-200,000 normal m^3/hour (Nm^3/h) of natural gas (Dickel, 2020). Large quantities of CO_2 emissions are evident with an average production of ca. 7–10 kg CO_2/kg H_2; 12–19 kgCO_2/kgH_2 can be expected if oil or coal are used for hydrogen production instead of natural gas (IEA, 2019a; Soltani et al., 2014). In industrial SMR, carbon capture is based on chemical absorption technologies wherein 55–90% of the CO_2 is captured from the synthetic gas using MDEA solvent (Collodi et al., 2017). However, to capture ca. 90% of total CO_2 emissions produced, a 78% increase in capital costs are required as compared to the SMR process alone (Collodi et al., 2017).

The captured CO_2 from the SMR process can be stored in sizable subsurface formations such as depleted gas fields or suitable rock formations as a means of mitigating GHG emissions (termed SMR-CCS or blue hydrogen). The feasibility of such storage is inherently based on the availability of geographic-specific locations and the associated transport distances. Additional revenue may be accrued if alternative uses can be found for the CO_2; for example, this has been evident in oil recovery industries.

2.3.4 Green Hydrogen produced via electrolysis

Power to gas (green hydrogen) concepts have gained much traction in recent years. In its simplest form, power to gas involves the use of electrolyser technologies to convert electricity, preferably from intermittent renewable energy systems (such as wind turbines), to split water into hydrogen and oxygen as per equation 3. The electricity may be grid curtailed or grid constrained, and as such avail of resources that occur due to the potential mismatch between supply and demand as the share of variable renewable electricity increases on the grid. This however may lead to relatively low duration of use of the electrolyser which adds to the cost of the hydrogen produced. Alternatively the electrolyser can also operate directly off the grid and purchase electricity based on a low bid price and subsequently the run hours of the electrolyser can be increased, reducing the cost of hydrogen. This may however increase the carbon intensity of the electricity used to produce the hydrogen.

Equation 3

$H_2O \rightarrow H_2 + \frac{1}{2} O_2$

In the electrolyser cell, a direct current is connected to two electrodes (usually inert metals) and placed in water. As the water decomposes, hydrogen is produced at the cathode, while oxygen is produced at the anode. Three electrolyser technologies of relevance are the alkaline electrolysis cell, proton exchange membrane (PEM) and the solid oxide electrolysis cell (SOEC). A comprehensive technical summary for each electrolyser type can be found in Table 3 of the previously published Task 37 report *Integration of biogas systems into the energy system* (Liebetrau et al., 2020). An outline of the various electrolyser configurations are shown in Figure 3.

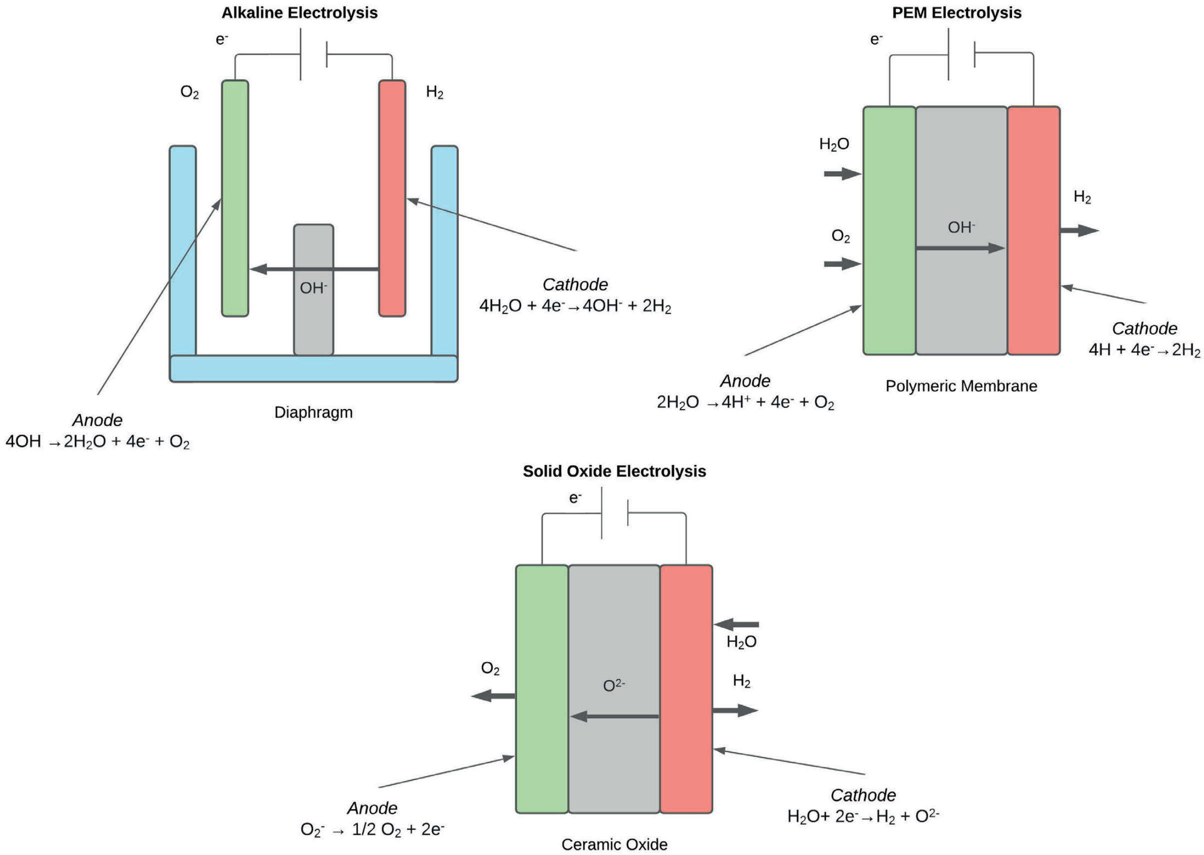

Figure 3: Illustration of Alkaline, PEM and SOEC electrolyser technologies (adapted from Sapountzi et al., 2017)

2.3.5 Electrolysis technology

Alkaline electrolysis is a mature commercial technology and is already used for large-scale hydrogen production (Zhang et al., 2015). The anode and cathode electrodes are immersed in a highly concentrated liquid electrolyte (typically NaOH or KOH). A gas tight diaphragm separates the two electrodes that is permeable to OH^-, which separates the product gases. Transition metal oxides (nickel, cobalt and iron-based electrodes) are typically used as electrodes due to their abundancy, relatively high activity and stability, and low cost (Fabbri et al., 2014). Alkaline electrolysis is presently characterised by relatively low capital costs compared to other electrolyser technologies due to the lack of precious materials required. However significant maintenance costs can occur due to corrosive solutions used (Götz et al., 2016). For an alkaline electrolyser, the lifetime of the cell stack is reported in the range 55,000-120,000 hours however this depends on the specific operating conditions such as the pressure, temperature, and current density (ENEA Consulting, 2016; Felgenhauer & Hamacher, 2015).

Proton Exchange Membrane (PEM) electrolysis is a comparatively new technology and is not yet considered commercially mature. The PEM was developed to overcome some of the operational shortcomings of alkaline electrolysers and is currently only used in small scale hydrogen applications (ENEA Consulting, 2016). In PEM electrolysis, the solid polymer electrolyte fulfils the function of the gas separator, and a liquid electrolyte is not needed. However, the corrosive acidic regime supplied by the PEM requires the use of expensive membrane material and noble metal catalysts such as iridium at the anode and platinum at the cathode (Millet et al., 2010). PEM electrolysers can facilitate variable energy devices such as solar and wind much better than the alkaline technology. The lifetime of PEM is currently shorter than that of alkaline electrolysers, due in part to the degradation of the catalysts

(Prokop et al., 2020). The cell stack has a lifetime of 40,000-100,000 hours (Buttler & Spliethoff, 2018; ENEA Consulting, 2016; Felgenhauer & Hamacher, 2015).

Solid oxide electrolysis cell is the most recent electrolysis technology and can be considered at a developmental stage (Götz et al., 2016). SOEC requires a heat source as steam is used in undertaking the water electrolysis. If this technology was used for power to gas processes in an exothermic reaction, potential exists to recover the waste heat for steam production in further SOEC electrolysis, enhancing the efficiency of the process in a circular approach (McDonagh et al., 2018). The crucial elements of a SOEC are a dense ionic conducting ceramic electrolyte and two porous electrodes, which have low material costs and facilitate higher operating temperatures (Ni et al., 2008). In SOEC, the solid ceramic electrolytes provide for gas separation. The higher operating temperatures in the SOEC provide greater efficiencies than alkaline or PEM technologies but can also lead to issues of material stability (Buttler & Spliethoff, 2018). Furthermore, unlike alkaline and PEM electrolysis, SOEC electrolysis can act as a fuel cell by operating in reverse mode, reverting hydrogen back into electricity (Kwon et al., 2020). This reversal could offer a balancing service to the grid in conjunction with hydrogen storage facilities thereby increasing the technology's overall rate of utilisation. In SOEC, the cell stack is likely to have a lifetime of less than 10,000 hours (Schmidt et al., 2017).

In terms of electrolyser technology, alkaline electrolysers are a durable technology with lower capital costs, a good system lifetime and are commercially available. However, system size and hydrogen production costs are negatively impacted by a narrow load range, low current density, and low operating pressure. Dynamic operation, that is frequent start-ups and varying power input as would be likely interacting with intermittent renewable electricity devices, is limited with alkaline electrolysers, and thus system efficiency and hydrogen purity can be negatively affected.

PEM electrolysis offers several advantages including greater potential energy efficiency, more compact design, high purity hydrogen production, and greater flexibility (Marshall et al., 2007). PEM may be the most apt system for generating hydrogen from surplus wind due to its relatively fast start up times and capacity to operate dynamically. However, PEM processes have a significant reliance on the availability of rare metals/materials.

SOEC will become a more attractive option in the future in the desire to use efficient climate mitigating energy technologies. However, SOEC electrolysis remains in a demonstration phase and has various issues surrounding degradation and stability which must be solved to make SOEC a viable option (Laguna-Bercero, 2012; Moçoteguy & Brisse, 2013).

2.3.6 Role of green hydrogen in facilitating intermittent renewable electricity

A key benefit of green hydrogen is the potential to store excess electricity, a procedure which becomes more important as the share of renewable electricity on the electricity grid increases in future years. Hydrogen fuel cells offer an alternative to batteries for the storage of excess electricity. Despite a much lower round trip efficiency of 30% from electricity to hydrogen and back to electricity again (as compared to 75-90% for batteries), hydrogen can currently still provide the equivalent total energy benefit of batteries in the storage of excess electricity from renewable wind sources, due to its relatively high $ESOI_e$ (electrical energy stored on invested) ratio. This is the ratio of electrical energy returned throughout a device's lifetime to the electrical-equivalent energy needed for the device construction (Pellow et al., 2015). In a future scenario, rather than curtailing electricity becoming of issue there is potential for hydrogen to be generated in off peak periods and converted back to electricity when the renewable source is unavailable, to stabilise the utility grid. There is an argument that as electricity typically is only ca. 20% of final energy there is significant benefit in changing the vector to make it available for other uses in heat and transport. Removing the step back to electricity can increase the round cycle efficiency. Green hydrogen from electrolysis, as a zero-carbon energy vector (when sourced from renewable electricity) has significant potentially in tackling hard to abate sectors such as heavy transport (aviation, shipping, haulage).

2.4 POWER TO X: METHANE, METHANOL AND AMMONIA

2.4.1 Power to methane

For renewable hydrogen production via electrolysis to become an economically viable pathway in the medium to long term for particular hard to abate sectors, substantial government policies on carbon tax and renewable subsidies need to be established (Sazali, 2020). Measures such as carbon tax that place value on emissions reductions will be required for hydrogen to compete with fossil fuels in sectors that are considered hard to abate such as transport, chemical manufacturing and heating.

Further conversion of the hydrogen is also possible to diversify the potential end-use applications. Green hydrogen can be converted to methane by combining it with carbon dioxide ($4H_2 + CO_2 = CH_4 + 2H_2O$) in a Sabatier reaction. This process can be carried out biologically in a biological hydrogen methanation system, whereby hydrogenotrophic methanogenic archaea consume both CO_2 and H_2 and produce methane (CH_4). Such technologies are at a relatively early stage. Methanation can also be achieved through a catalytic process using nickel-based catalysts. The CO_2 can be sourced from biogas plants which would negate the need for investment in traditional biogas upgrading systems at an anaerobic digestion facility. Thus, the positioning of electrolysers would be favourable at existing digesters. In particular, the coupling of electrolysers and wastewater treatment plants (WWTPs) that use anaerobic digestion as a form of treatment may be an advantageous location for power to gas systems. In this case, the oxygen generated in electrolysis could be recycled to the WWTP for aeration purposes, whilst a small proportion of the hydrogen could be used for carbon capture and utilisation, in this case, converting the CO_2 in biogas to biomethane as mentioned. Such an approach could increase the sustainability of biogas plants, potentially doubling the output of biomethane and promoting a circular economy solution (McDonagh et al., 2019). Furthermore, power to methane can potentially target the hard-to-abate sectors. For example, hydrogen could be used to capture CO_2 from the digestion of slurries and manures, or from the alcohol industry where high purity CO_2 is released in the fermentation process, or in cement manufacture where concentrated CO_2 streams exist. Targeting these hard-to-abate sectors is crucial for future decarbonisation and hydrogen acts as the key enabler with biomethane being the initial energy output vector. Furthermore, conversion to methane often suits existing natural gas grid infrastructure and is a well-established fuel for long distance transportation vehicles in either compressed or liquified form.

2.4.2 Power to methanol and ammonia

Power to liquid is a further option. Methanol can be produced from hydrogen and CO_2 via methanol synthesis. Methanol is a liquid energy carrier at room temperature and pressure, and thus has the advantage of being easily used in existing infrastructure (storage, distribution and refuelling) and is particularly suitable for retrofits in the maritime sector (Gray et al., 2021). Power to ammonia is also proposed as a future fuel that can progress the transport sector (particularly shipping) towards zero carbon.

Ammonia can be liquefied much easier than hydrogen and combusted as an alternative fuel and furthermore, much of the infrastructure is already in place for the trade of ammonia globally as a commodity (Gray et al., 2021). The conversion of (renewable) hydrogen to ammonia (NH_3) can be achieved through the Haber-Bosch process. Whilst power to ammonia presents an interesting opportunity for a decarbonised fuel in the future, power to hydrogen remains the more efficient production process (ca. 70% efficiency for hydrogen from electrolysis as compared to ca. 50% efficiency for ammonia production accounting for the additional synthesis process) (Gray et al., 2021). Obviously ammonia from hydrogen is a renewable fertiliser which as such can decarbonise the hard to abate sectors of fertiliser manufacture, agriculture and food production.

3 Development of the renewable gas sector

3.1 STRATEGIES FOR DEVELOPMENT

The development of the renewable gas sector has previously been facilitated more as a by-product rather than a primary target of legislation. The ideology of the legislation on the energy transition was to focus initially on the transition of electricity, heat and fuel sectors with a significant emphasis on electrification of heat and transport. With time, it became apparent that gas as a single energy carrier can play a significant role for applications where electricity is not readily amenable. Consequently, development strategies were required for renewable gas to ensure emissions reductions in sectors where electricity could not effectively substitute fossil-based energy.

The typical procedure in countries is for authorities to set specific sector targets and implement measures in these sectors to achieve GHG emissions reduction. The idea is that the overall GHG emissions reduction targets will be achieved resulting from the sum of all measures. Since biogas (and biomethane) can potentially provide electricity, heat and fuel and reduce emissions from waste materials and manures and generate biofertilisers in circular economy systems, a number of different support schemes are relevant as evident in the countries surveyed. The multiple support schemes come with varying conditions and requirements.

The future development of renewable gas from biomass needs to be developed according to a specific plan that requires consideration of numerous key factors to be successful:

3.1.1 Biomass is a limited resource

Biomass utilisation impacts many sectors and sustainable biomass utilisation is of high public sensitivity. Any incentive to use biomass should consider restrictions and or constraints from sustainability perspectives, land use conflict and economic effects on existing markets of the target biomass.

3.1.2 Production costs are not competitive with fossil gas

Renewable gas will require incentives to become competitive whilst there is a limited price for CO_2. Any incentive measure needs to be balanced to enable start up and development of the technology, allowing competitors to bring the most efficient technologies forward with a long-term perspective for transitioning to a commercially viable market. Approaches to balancing this cost/revenue differential and to develop the sector are numerous.

3.1.3 Investors need long term security

Investments in renewable gas facilities will only happen when investors see a business case. Therefore, incentives need to be oriented at production costs and deliver a sufficient long-term perspective for sustainable business development. Measures to force a provider of fossil gases to implement renewable gas in their business (as a quota) might further assist in sector development.

3.1.4 Timing of transition towards renewables and infrastructure

Significant reductions in emissions need to occur if compliance with the less than 2°C temperature rise target is to be achieved. However, not all the potential carbon-mitigation technologies are established yet. Some processes still need technical development, whilst some will require extensive infrastructure measures. This state of technology readiness must be considered when issuing support for sector development. Many countries have previously developed strategies for the electricity, heat and fuel sectors, with renewable gas forming part of the plans. Furthermore, much of the recent discussion has focused on hydrogen and this has further heightened the importance of renewable gas as an energy vector. Subsequently, some countries have developed (or are in the process of developing) strategies for hydrogen utilisation (see Table 7).

Table 7: Selected countries with strategies (or draft strategies) on biomethane (CH_4) and/or hydrogen (H_2)

Substrate potential (10^3 GWh/a)	Germany	Canada	China	Finland	Sweden	Norway	Australia	Estonia	Austria	Switzerland	India	USA	UK	Japan		Draft
for renewable CH_4			x	x		x		x	x		x	x				3
for renewable H_2	x					x	x							x		5

Despite relatively few countries publishing strategies on the development of renewable gas, many more have incentivised support for the sector. Thus, it can be assumed that when a strategic plan is not in place, supports for the renewable gas sector were based on strategic considerations (particularly in large countries such as the USA or Canada where federal states develop their own support mechanisms). However, the publication of a strategy, a target and/or the enforcement of a law does not guarantee successful development of the sector. There are previous examples of strategic plans that were abandoned after the proposed targets were missed and of support schemes which failed to initiate development of renewable gas systems.

Initiatives from industry must also be considered particularly where natural gas is an important fuel and there is a need to decarbonise. The continued use of natural gas is a controversial debate (particularly in Europe) and accordingly the further use of the infrastructure is somewhat unclear. The gas industry are adamant that they must be part of the transition toward renewable and decarbonised energy systems. Some companies actively develop renewable gas projects and publish targets towards a climate neutral future for their business.

3.1.5 Infrastructure

A particular argument for or against renewable gas is the infrastructure – either existing or needing to be built. Many countries have significant natural gas infrastructure, which represents a significant investment and a functioning system. A deviation away from this network towards a new system and its implementation would take much time and resources. For the owner of this infrastructure, how to convert to a renewable system is a crucial factor for any future development. Accordingly, discussion regarding the integration of hydrogen to the grid network, the convenience of renewable gas transportation and storage, and in particular the extent of the role of electrification drive the discussion.

3.1.6 Targets

Within a strategic plan, targets are usually defined. A realistic approach to achieve the envisaged development involves oversight by a responsible institution/body, verification or monitoring of target achievements and the option to steer the development when change is required. In particular, the limitation of biomass availability makes a target for biomass mobilisation and a subsequent progress monitoring necessary to avoid unwanted effects on the market and allow for its optimal and sustainable use. The formation of ambitious targets does not necessarily mean that the measures implemented will be successful. Germany for instance had set a target for biomethane production of 6 billion m^3CH_4/year to be reached by 2020, which was stated in a law regulating grid access. This volume was found to be far too large and would only be achieved if all existing biogas plants in Germany would feed biomethane to the gas grid. This was technically impossible and far too costly. The target was subsequently removed without substitution in 2014. In some countries, provinces or federal states define regional targets and develop the sector locally. Examples include Canada and the USA; for instance, in Canada the provinces British Columbia, Quebec and Ontario have individual programs for renewable gas development.

3.2 LEGISLATION

Legislation in support of renewable energy is diverse and the same applies to renewable gas. Legislation can include for technical regulations such as access to the gas grid, gas quality standards, and operational requirements for gas production, upgrading and for grid injection sites. Furthermore, the framework for the allocation of incentives plays an important role in the profitability of the sector.

The EU emissions trading system (EU ETS) is a central instrument of EU policy to reduce GHG emissions in a cost-effective manner. It is the world's first and largest carbon market. The EU ETS is based on the principle of 'cap and trade'. All emissions from installations covered by the system are capped to a total amount of specific GHGs that can be emitted. Emissions allowances are distributed and auctioned, and can be traded as needed. The system covers around 45% of the EUs emissions (See: https://ec.europa.eu/clima/policies/ets_en).

EU targets for the energy sector have been set previously such as within the recast Renewable Energy Directive (REDII). For biogas and biomethane, there is some information on the specific GHG emissions savings that need to be achieved by the energy carriers as compared to fossil fuels and which substrates are sustainable and eligible to be considered a biofuel. However, more information is needed on control measures to certify and track compliance within production and trade of renewable gas. Once the standard values for GHG reduction and technical requirements are set, countries are free to implement appropriate actions to achieve the targets.

The implementation of renewable gas needs to be technically defined in terms of accessing the market and certification. At a European level, such definition is provided within DIRECTIVE 2009/73/EC (concerning common rules for the internal market in natural gas) which states the non-discriminatory access to the gas grid and the equal treatment of biomethane and natural gas if effective standards are met. Member states are also encouraged to implement measures for a wider use of biogas and biomethane.

Despite this framework for all EU members, the implementation of renewables within each country is different. Since REDII allows each member state to decide how to reach the overall targets on GHG abatement, its implementation does not necessarily mean that an incentive for biomethane on national level will be put in place. Outside of the EU, in an international context, the state of affairs can be described as even more diverse.

3.3 REGULATION FOR INSTALLATION AND OPERATION

Typically, the necessary regulations regarding implementation of renewable gas technologies follow the targets for emissions reduction. Access to the grid, emissions control, environmental protection, safety related regulations, technical and constructive specifications must all be implemented. These regulations will differ for plants with different substrates; for example, municipal waste materials are treated differently to agricultural residues. For an emerging bioeconomy, legislation, regarding the use of residues and new processes for the conversion of biomass, is of importance for a circular economy approach, particularly in the recycling of nutrients and organic materials, and in the alternative treatment costs of residues. Technical regulations that have hindered development are rare. However, certain requirements (such as high gas quality standards) can result in excessive technical effort increasing costs, which may not be offset by the potential revenue on offer and thus hinder project development. In general, regulations control the administrative issues and permission to install biogas/biomethane plants. The specifications of the regulations result in technical and constructive solutions which influence the overall cost of building a biogas plant.

3.4 EFFICACY OF FUTURE HYDROGEN PRODUCTION

For grey hydrogen the efficiency of SMR to produce hydrogen ranges from 65–75% (Andrews, 2020). However, such efficiencies are indicative of a process trying to achieve the lowest cost and in effect, not necessarily attempting to optimise the overall efficiency. In the future, it may be possible to increase these levels of efficiency. Blue hydrogen (SMR-CCS) systems, with favourable economics, are likely to become the prevailing technology for large-scale hydrogen production in the short term (IEA, 2019a). It is anticipated that blue hydrogen production could grow from 0.6 to 3.3 Mt/year in the coming years (Robinson, 2020). However, the use of fossil fuels (natural gas) in the process has raised questions of process efficacy over the long term.

The argument against adopting CCS with SMR as a long-term solution to hydrogen production is that it is a practice that constantly battles the consequences instead of the source, that is, the production of CO_2 should be prevented in the first place. Concerns may validly be raised in terms of the role of blue hydrogen in facilitating the continued use of fossil fuel. There are also concerns over the longevity of blue hydrogen, with a finite number of storage sites and fears of possible damage to geological features due to underground storage (van Cappellen et al., 2018). Blue hydrogen is not considered a zero emissions technology as not all of the CO_2 will be captured.

The production of green hydrogen through renewable energy sources is viewed as a more promising approach in terms of climate mitigation. Green hydrogen offers benefits in terms of its role as a storage mechanism reducing wind curtailment and grid balancing; green hydrogen can thereby facilitate high shares of renewable electricity and integrate electricity in the form of hydrogen (or electro-fuels) into the wider energy system.

4 Incentives for production

4.1 CLASSIFICATION OF INCENTIVE MECHANISMS

Biomethane can substitute directly for natural gas. The provision of biomethane from biomass substrates is more costly than the production of natural gas and will continue to be so long as a comprehensive system for budgeting and pricing of CO_2 emissions is not in place. Such a CO_2 pricing system is required to replace the concept of incentivised renewable gas systems, creating a competitive market scheme. Currently technologies with reduced GHG emissions but higher production costs need to be supported financially for cost effective operation. Cost effectiveness is impacted across the value chain starting from the substrate supply and continuing to the point of energy utilisation. Since substrates and utilisation pathways are numerous, the methods of incentivisation are also numerous. Besides the effectiveness in stimulating plant construction, incentive mechanisms can benefit additional aspects of the development (for example, sustainability). Incentives are effective when they result in a viable business case. AD plants have a highly individual design and site-specific conditions that makes a precise support system difficult. However, different systems have proved successful in the past.

Incentive mechanisms are complex and offer variability in design. For example, production chain incentives can be based on:

- The substrate, such as manure which generates emissions reduction;
- The facility, such as investment subsidies or capital grants;
- The end use, such as Feed in Tariffs for gas and or electricity or tax exemptions for renewable gas, or mandated quotas for use.

The incentive mechanisms include for variability in financial conditions such as:

- Eligibility;
- Duration of grant or incentive;
- Amount of incentive.

The regulation varies in terms of:

- Who is organising and covering the costs of the incentive system;
- The technical conditions for plant operation and grid injection;
- Access to the grid.

The major concepts in terms of incentives are described (based on on Regatrace 6.1):
https://www.regatrace.eu/wp-content/uploads/2019/11/REGATRACE-D3.1.pdf

Feed-in Tariff (FiT)

A feed-in tariff provides a specific remuneration per unit of renewable energy produced provided by authorities for a specific technology for a specific period of time. Feed in Tariffs can be auctioned, thus enabling a certain competition between technologies.

Feed-in premium (FiP)

A feed-in premium is a technology-specific bonus payment given per unit of renewable energy produced above the market price that can be at fixed or floating rate.

Quota/green certificates (GC) scheme

A quota signifies the production of renewable energy relative to an obligatory target. The target can state a specific share of renewable energy for producers, consumers, or distributors to achieve. Compliance is tracked by the trade of renewable energy certificates, which provide an additional supplementary revenue to electricity sales. If the penalty for non-compliance is high enough, quota systems are an effective measure to enforce renewable gas development. An obligation to fulfil a defined quota is more effective than a feed in tariff since the latter can be claimed or not. Quota systems allow (within the eligibility definition) competition between different renewable energy carriers and gas providers and enable therein a limited market.

Fiscal incentives

Tax exemptions or reductions are usually additional (and minor) support systems. Renewable energy producers can receive certain tax exemptions (such as carbon taxes) as additional support to increase competitiveness of the renewable energy market.

Investment support

An investment support is a fixed amount received before, during or shortly after the building phase of the plant and is independent of the production of renewable energy. Investment supports have the disadvantage of being independent of the performance and the long-term operation of the supported facility.

Emissions reduction bonus

Manure management (such as open storage of liquid slurry) results in fugitive methane emissions. An option is to incentivise the mitigation technologies, such as anaerobic digestion of manure and associated reduction in GHG emissions.

Private or industrial initiative

On an industrial or domestic level, a company or person may decide to buy or use renewable gas. Gas distributors offer biomethane (pure or mixed with natural gas) at a price that covers provision costs.

4.2 INCENTIVE SCHEMES CURRENTLY USED

In analysing the level of incentivisation applied across the 14 countries surveyed, it is evident that many countries make use of several support schemes for renewable gas production and utilisation (Table 8). The rationale is that several schemes can aid in the development of an economic business case for different sectors (such as for electricity, heat, transportation, each with their own respective form of incentive). For instance, in Germany, depending on whether electricity or fuel is the focus of supply, a completely different support scheme will apply with different eligibility and tariff conditions.

Fiscal incentives, investment support and cost control are all easy to implement and thus, most countries have such systems in place. Feed in tariffs are more sophisticated to manage and are only effective if coupled with a long-term commitment. This option is normally chosen from the three most commonly used incentive schemes. As per Table 9, most countries opt for state funds as the financing body as opposed to allocating the costs directly to the consumer of a specific energy carrier. Increasing energy prices for the consumer can quickly lead to undesirable public attention and shine a negative light on any renewables introduced.

Table 8: Incentive mechanisms applied in selected countries

Legal framework/ legislation of the gas sector	Germany	Canada	China	Finland	Sweden	Norway	Australia	Estonia	Austria	Switzerland	India	USA	UK	Japan
Feed in tariff	x		x	x					x		x			x
Feed in premium								x					x	
Quota/green certificates scheme	x	x						x			x	x		
Fiscal incentives		x		x	x	x		x	x	x	x			x
Investment support		x	x	x	x	x		x			x			x

Since gas is applicable to different sectors, the respective support schemes might differ depending on where the gas is utilised. National schemes are complex combinations of several incentives, overall economic conditions, technical regulations, and eligibility requirements. Due to this complexity, and the variety of support mechanisms used across different countries (and even within the countries themselves), it is difficult to give a comprehensive overview or evaluation on the levels of support available. Incentives are a measure in kick-starting a market and encouraging growth in technology uptake, and therefore enabling cost reductions through mass production. The incentives need to be available as long as the production costs remain uncompetitive in the prevailing market price.

With a successful support scheme, a significant number of new technology installations can lead to rapidly rising costs to cover the incentives. Therefore, the decision as to which funds should be used to cover this cost can create political debate. The costs to be covered are typically lower if the technology is at an early market stage. Renewable gas is a product that reduces GHG emissions, however as long as the costs for fossil energy do not include significant carbon prices, renewable gas is unlikely to be competitive on a cost basis. Consequently, the creation of a renewable gas market needs to be accompanied by a tax on emissions from fossil fuels. The energy sector will change substantially when decarbonised. It is difficult to determine where renewable gas will be applied and the exact cost at which the sector will prevail in the future. There are some applications where the substitution of fossil energy with renewable alternatives cannot be achieved at low cost; a case in point is aviation fuel which has very little if any tax as compared to land transportation. Thus, the related costs for wider decarbonisation will be variable for the numerous current and future applications of gas.

Table 9: Means of covering the costs of incentives in selected countries

Incentive costs covered by	Germany	Canada	China	Finland	Sweden	Norway	Australia	Estonia	Austria	Switzerland	India	USA	UK	Japan
State funds		x	x	X	x	x			x		x		x	
Gas industries										x				
Tax for gas users	x													
Tax for specific gas utilisation	x	x							x	x		x		x

4.3 GAS, TECHNOLOGY, AND SUBSTRATE SPECIFIC INCENTIVIZATION

The specific gases that are supported through incentives are shown in Table 10 for the 14 surveyed countries. From the table, it is evident that Australia does not incentivise the gas itself; however, existing biogas facilities are instead supported through an emissions reduction program. Gasification is typically not included as part of the support scheme as often as anaerobic digestion but is still supported in approximately half of the countries evaluated. The lack of large-scale installations of gasification processes illustrates the need for incentive mechanisms that match the economic conditions of the target technology. Power to gas as a potential add on to biomethane provision is only incentivised in five countries. In comparison, hydrogen is more frequently eligible for support due to the recent dynamic developments associated with strategies for large acceleration of provision of intermittent renewable electricity. As such, an opportunity exists for biogas plant operators to integrate hydrogen systems. This can be achieved through the aforementioned power to gas process, upgrading biogas to methane through conversion of CO_2 to methane or through reforming of biomethane to hydrogen in combination with carbon caption and storage. Power to gas or more specifically here power to methane would be an attractive addition to anaerobic digestions plants since the conversion of the CO_2 within the biogas has many advantages including increasing the energy output by ca. 70%; it is also relatively straight forward to implement if the regulations and economics are suitable. Currently regulation overseeing the integration of methane and hydrogen systems is lacking.

Substrates play a major role in the development of the renewable gas sector. Not only does the substrate choice have a great impact on the overall production cost of the gas, the resource and availability of the substrate determines the overall energy potential. Furthermore, the choice of substrate will define

Table 10: Incentivised gases in selected countries

Incentivised gases	Germany	Canada	China	Finland	Sweden	Norway	Australia	Estonia	Austria	Switzerland	India	USA	UK	Japan
Biomethane from AD	x	x	x	x	x	x		x	x	x	x	x	x	
Biomethane from gasification	x	x		x	x	x		x		x				
Biomethane from Power to gas	x	x		x		x				x				
Hydrogen from electrolysis	x	x	x	x		x				x	x	x		x

the overall sustainability of the production process and hence the gas itself. In renewable gas production, the GHG balance and land use issues are frequently debated. Manures and wastes are typically eligible for incentives as indicated in Table 11. The utilisation of such substrates is common amongst the countries where data was provided. Landfill gas and sewage sludge are also very often included in the support mechanisms. Energy crops and specific catch crops are much more controversial substrates to use and thus support is only provided for in approximately half of the countries surveyed. Switzerland is the exception in making a distinction between catch crops and energy crops in their support mechanisms.

Table 11: Substrates eligible for incentives in selected countries

Supported substrates	Germany	Canada	China	Finland	Sweden	Norway	Australia	Estonia	Austria	Switzerland	India	USA	UK	Japan
Energy crops	x	x		x		x		x	x				x	
Catch crops (not main crop)	x	x		x		x			x	x			x	
Agricultural residues and manures	x	x	x	x	x	x		x	x	x	x	x	x	x
Municipal organic waste	x	x	x	x	x	x		x	x	x	x	x	x	x
Organic industrial waste	x	x	x	x	x	x		x	x	x	x	x	x	x
Landfill gas	x	x	x	x	x	x		x			x	x		
Sewage sludge	x	x	x	x	x	x		x	x		x	x	x	x
Others (e.g. mine gas))	x	x	x	x	x	x			x					
Wood processing residues	x	x		x	x				x					
Waste materials	x		x	x	x				x					
Short rotation forestry	x			x	x				x					

4.4 DURATION OF INCENTIVES AND FUTURE PERSPECTIVES

Due to the variety of incentives available in each country, it is difficult to report a definitive, guaranteed duration for the support mechanisms. For instance, an investment grant is a one-off payment, where the plant operator does not rely on long term payments or initiatives. With a feed in tariff, it is different as the payback is over the long term and the duration of the guaranteed tariff becomes of great importance. Table 12 illustrates the duration of existing incentives in the surveyed countries.

In Germany the renewable resources act (EEG) initially started with a period of 20 years. A subsequent extension was given to existing plant owners that guaranteed a further 10 years, however this was only applicable for electricity production. Biomethane as a fuel is regulated in the form of a quota for fuel providers. The respective laws can be changed which represents a certain element of risk for investors, with the quota resulting in a competition between producers of biomethane and other renewable fuel alternatives; this removes fossil fuels from the competition. For the stable development of a renewable gas industry, a sufficiently long-term perspective with predictable framework conditions is crucial. The upper limit of guaranteed payment periods is typically 20 years. For shorter amortisation periods (5 or 6 years) higher (gas specific) incentives are required.

Table 12: Duration of guaranteed incentivisation in selected countries

Duration of support	Germany	Canada	China	Finland	Sweden	Norway	Australia	Estonia	Austria	Switzerland	India	USA	UK	Japan
Duration of incentives (in years)	20 (10)	15		10				6	15		5		20	20

In many countries, the future development of incentivisation for renewable gas production is under discussion (Table 13). Depending on the circumstances and the different levels of sector development, some countries are in the process of devising how to develop a sector whilst other countries are framing discussions around the existing number of plants installed.

Table 13: Discussion on new or changes to incentives in selected countries

	Germany	Canada	China	Finland	Sweden	Norway	Australia	Estonia	Austria	Switzerland	India	USA	UK	Japan
Existence of plans for other/ new incentives	x	x	x	x	x			x	X			x	x	

In terms of prioritising renewable gas production going forward, it is clear each country will take their own individual actions. In Germany, the current discussion regarding biomethane is concentrated on providing electricity to the south of the country and the national implementation of REDII. A biomethane strategy for Germany was postponed to progress a hydrogen strategy that was subsequently published in 2020. In China, the current trend seems to be focused on decreasing subsidies. In Norway, the potential for gas vehicles to be exempt from tolls has been discussed; however, this has yet to be introduced. Estonia is striving to move towards a market-based solution for renewable gas and is creating a trading platform for certificates of origin based on transport statistics. The plan is that such a platform would be used for trading by fuel suppliers who are obliged to have a share of renewable fuels in their portfolio by 2030 (to fulfil the 14% RES transport target in the national implementation of REDII). In Austria, a future quota for biomethane is under discussion whereby energy utilities would be required to deliver a specific share of renewable gas. There is also much discussion on the reimbursement of fossil gas tax for sustainably certified renewable gas. Once more, much focus is now on the establishment and design of certificate systems to ensure a specific quality criterion for renewable gas products. In the UK, a consultation process for the next generation of biomethane production closed in 2020, with the start of new measures announced for 2021. The significant points of debate were the appropriate tariff level (p/kWh), tariff lifetime and degression mechanism, whilst the substrate choices were also under review. Japan's Ministry of Economy, Trade and Industry (METI) will implement the "Green Growth Strategy towards 2050 Carbon Neutrality" which includes ambitious goals in a number of priority fields.

No matter the extent of tax exemptions, green tariffs, investment support or quotas to be implemented, a substantial growth of the sector will only occur if the attainable income is sufficiently high that the cost and the risk of the investment is limited. The introduction of an obligatory quota combined with penalties for non-compliance is a means of incentivisation that would force the implementation of renewable gas. Other methods may rely on market development, which is difficult to predict since it depends on voluntary investments. If several technologies are eligible for incentivisation and the scheme allows for competition between the technologies, ultimately the most cost-efficient process will prevail. In the early phase of technology development, too much competition can hinder the broader technology development and favour the cheapest options at that point in time, however this may not be the technology with the most potential to develop over the longer term.

5 Pathways to utilisation for renewable gas

5.1 ELECTRICITY, HEAT AND TRANSPORT

Biomethane is a direct substitute for natural gas and thus can be used in the same applications. Depending on the country, the use of biomethane can vary (Table 14). Typically, decisions are driven by the availability of natural gas infrastructure or the need for alternative fuels in the specific energy sector, or even the technical/economic conditions of the specific biogas plant site. Historically biogas has been utilised onsite at the AD plant for electricity and heat provision. For sites with limited substrate potential, this is still the preferred option since the undertaking of biogas upgrading and grid injection typically does not pay off at small scale. A lack of access to a grid or lack of gas consumers are other common restrictions that hinder the pathway for biomethane. If biogas upgrading is applied, the biomethane generated can be used in a decentralised manner (as fuel for vehicles) or transported by truck and fed to the grid (virtual pipeline).

Table 14: Gas utilisation in selected countries

Destination sector for renewable gas	Germany	Canada	China	Finland	Sweden	Norway	Australia	Estonia	Austria	Switzerland	India	USA	UK	Japan
Unspecific gas sector	x	x	x	x	x				x				x	
Electricity	x	x	x	x				x	x	x	x			x
Heat	x	x	x	x	x			x	x	x	x			x
Transportation	x	x	x	x	x	x		x	x	x	x	x		
Material use	x								x					

In relation to biogas upgrading technologies, there has been an interesting trend in recent years. Traditionally, water-scrubbing technologies dominated the upgrading process for biogas; however, in recent years membrane technologies have since gained ground (Figure 4). Membrane upgrading units are easy to scale due to their modular structure. This could potentially be an advantage in the future for sites which intend to exploit a limited substrate supply for the provision of biomethane but would have plans for future growth.

If biomethane is fed to the grid, several options for utilisation may result from the associated incentive system in place. If a feed in tariff is provided based on the gas fed to the grid, the utilisation pathway is equivalent to natural gas use. If the incentive is bound to a specific sector (such as electricity or fuel for transportation), the gas would then be directed for use in this sector. Furthermore, some industries and gas traders may purchase the gas to blend with natural gas, which in turn allows for the production of green products in their respective markets (such as the heat market). As per Table 14, most countries support the application of renewable gas in the transportation sector. However, many other utilisation pathways are also employed. Thus, since countries have several support mechanisms in place, the plant owner can decide what end use to employ for the gas produced. The UK is an example of a country whereby the gas has no defined specific utilisation pathway. However, the rationale to steer biomethane towards a specific utilisation pathway may be explained as below:

- Maximisation of emissions reduction can be effected by steering renewable gas to a specific end use;
- There may be a lack of alternative renewable options available to reduce emissions in specific sectors besides the use of the renewable gas.

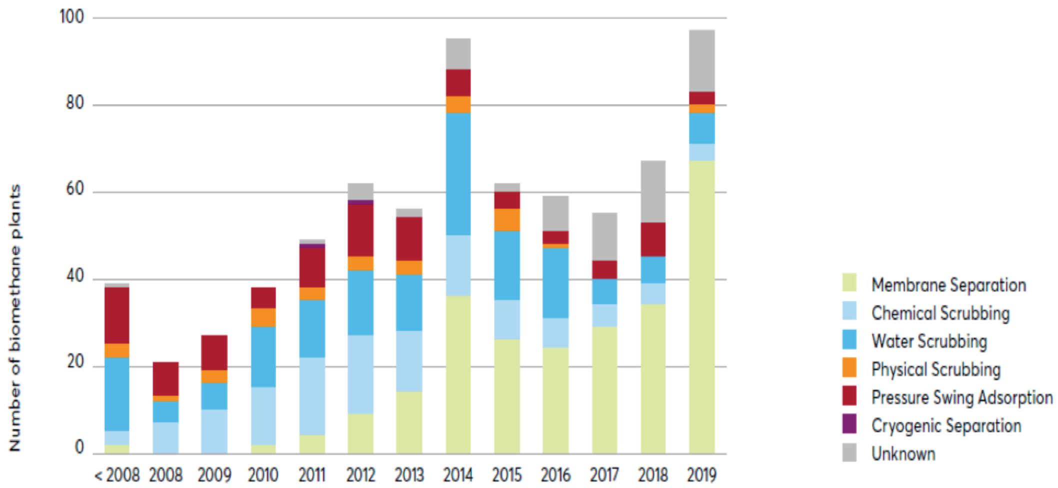

Figure 4: Total number of newly installed biomethane plants per year with respective upgrading technology (EBA, 2021)

The respective energy sectors in each country (state) have specific emissions profiles. For example, Sweden has a lot of hydropower which leads to low emissions in electricity provision, whereas Germany and Poland still rely on significant coal capacities leading to higher emissions within the electricity sector. The impact of biomethane on the emissions of a specific sector will consequently depend on the specific emissions of the energy carrier or the mix of energy carriers which are replaced. Additionally, there are certain applications where there are few options to replace fossil energy carriers; the so called hard to abate sectors. For instance, heavy-duty transportation or high temperature industrial processes rely on energy carriers with specific requirements and currently there are not many options other than gas to replace them. Biomethane and hydrogen are viewed as advanced fuels for future transport systems where limited alternatives to fossil fuels currently exist. Whilst electric vehicles (EVs) have been identified as a key solution to private vehicles, sustainable, renewable hydrogen or biomethane could be very beneficial in replacing diesel in heavy transport (particularly haulage) especially with the use of highly efficient fuel cells.

5.2 ACCESSING THE GAS GRID

The cost of connection to the grid after upgrading depends primarily on the pressure of the grid. For biomethane, the exact gas quality standards to be reached vary according to local characteristics of natural gas and the requiements of the grid operator. The gas grid can also offer a potential route for hydrogen distribution. Many EU countries have an extensive existing gas grid; such as Ireland, the Netherlands and the UK. Such infrastructure is extremely beneficial as a transport infrastructure for decarbonised gas and can be a significant asset to renewable energy provision. In the decarbonised energy future, the gas grid would become a stranded asset unless the gas flowing through it is renewable. Hydrogen blends are permitted in the gas grid with many EU countries stating a limiting range of ca. 0-10 vol.% (Rusmanis et al., 2019). The reason for the low blend is due to safety concerns around direct injection of hydrogen which may cause embrittlement of pipes (iron or steel) causing losses to the system (Messaoudani et al., 2016). This issue can however be overcome through the use of the gas distribution network (as opposed to the transmission network) which typically uses polyethylene pipes which are not susceptible to embrittlement (Quarton & Samsatli, 2018). Thus, existing gas grid infrastructure could facilitate the future uptake of hydrogen. This will most likely be exploited in the coming years through the addition of green hydrogen from power to gas systems to the gas network.

Since AD plants producing biomethane rely on local substrate supply, they are somewhat limited in terms of site selection. Access to agricultural substrates may require a decentralised plant and consequently, ease of access to the grid becomes an important consideration in sector development. Specific cases can be made for the transportation of raw gas from several anaerobic digestion sites to a centralised upgrading facility; this is a potential solution in cases where a number of AD plants are located close to each other. The feed in station or injection point, where the gas is transferred to the gas grid operator, also becomes an important location. Besides permission to access the grid, there will be technical infrastructure requirements at the feed in station which requires financial investment and responsibility for operation; the agent responsible for cost and management may vary between the gas grid operator and the developer/plant operator.

As per Table 15, the majority of countries grant grid access for biomethane production plants, and in many cases, the costs for the connection need to be covered by the plant owner. In Germany, the costs are shared but the costs for the plant owner are capped. The responsibility for the operation of the injection point lies primarily within the grid operator (Table 15).

Table 15: Responsibility for feed in station to gas grid and guarantee of access for investors

Access to gas grid	Germany	Canada	China	Finland	Sweden	Norway	Australia	Estonia	Austria	Switzerland	India	USA	UK	Japan
Access must be granted	x	x		x		x	x	x	x	x	x		x	
Costs allocated to:														
Grid operator	x						x			x	x			
Plant owner	x	x	x	x		x		x	x			x	x	x
Responsibility of operation:														
Grid operator	x	x	x			x	x			x	x		x	
Plant owner								x	x			x	x	

In the electricity grid, the (back) feed from low-level distribution grids to higher-level transportation lines is possible. However, in the gas grid this is not as easy and sections of the grid that experience low consumption in summer might be limited in terms of feed in capacity. Technically this can be overcome by stations increasing pressure, however whether this is economically favourable or not needs to be decided on a case-by-case basis.

5.3 TRADE

Trade of renewable gas operates physically under the same conditions as the trade of its fossil-based counterpart. However, additional characteristic aspects such as "renewability" and "carbon intensity" can also be traded. Whilst carbon intensity can be defined by a specific number, renewability has no such quantifiable criteria as of yet. The provision of biomethane requires several steps and the energy supplied in these process steps may be renewable or non-renewable, thus the exact definition is difficult. The transportation and utilisation of the physical gas and the trade of these characteristics can be carried out independently of each other. Trade is currently achieved by means of bilateral contracts (Table 16). Public trade platforms are not common as of yet. A significant number of countries have no international trade of biomethane. Within Europe significant volumes of biomethane are traded into Sweden and Switzerland (Figure 5) driven by the incentive systems in the respective importing and exporting countries.

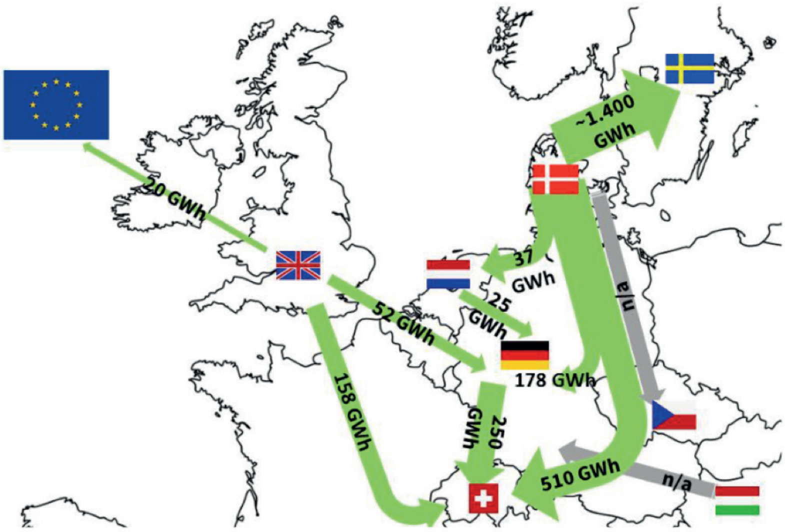

Figure 5: International biomethane trade in 2020 (GWh) excluding transfers below 10 GWh (April 2021) (DENA, 2021)

Interestingly, it may be observed that more countries import than export biomethane. Trade of biomethane is most attractive when production is supported in the country exporting and utilisation is supported in the country importing, as in such cases, revenues can be maximised. Particularly in Europe, the diverse incentivisation programs lead to favoured trade conditions such as exemplified in Denmark where capital investments are available to build facilities and where they trade to Sweden where end use incentives are in place. This can lead to market distortion as exemplified by the Swedish biomethane industry which is now under pressure from twice subsidised Danish biomethane. Incentive systems can be limited to national production, but in some countries or within specific markets the origin of the gas is not relevant.

Table 16: Details on the trade of biomethane in selected countries

Access to gas grid	Germany	Canada	China	Finland	Sweden	Norway	Australia	Estonia	Austria	Switzerland	India	USA	UK	Japan
No international trade		x	x			x	x	x						x
Import	x			x	x				x	x	x	x	x	
Export	x				x				x				x	
Mass balance system in place	x		x	x				x	x	x		x	x	x
Available national renewable gas registry	x			x				x	x	x	x	x	x	
Direct, bilateral trade	x	x	x	x		x	x	x	x	x	x	x	x	
Indirect trade via trade platforms or stock market					x	x		x						
Requirement for certification system	x			x	x				x	x		x	x	

For the physical trade of biomethane, necessary systems such as mass balancing and national gas registries are required, and are already common practice in many countries with significant renewable gas uptake (Table 16). However, the trade of the additional characteristics such as carbon intensity will require new mechanisms, which may not be fully established yet; this holds true on a national level and consequently for a common system on an international level. Based on the similar development of the electricity sector, EU legislation has ordered instruments such as guarantees of origin, proof of sustainability and appropriate certification systems to be implemented to support the trade of renewable gas. However, the sector has struggled with such applications. An initiative on a European level (European Renewable Gas Registry (ERGAR)) is now attempting to enable international trade by harmonising the certification process.

A certification system has been implemented in seven of the fourteen countries to date, and several more are in the process of discussing the introduction of certification (if only for specific utilisation pathways). The variety of regulations and support schemes in different countries makes any trade of biomethane difficult and complicated since several national, market and certification conditions for eligibility need to be fulfilled. Trade on national level is established in some countries; typically countries with incentive systems have the instruments to trade in place. Trade across borders is also happening but solely on a bilateral basis. In Europe, several stakeholders are working towards universal conditions for certification and mass balancing in order to facilitate the trade of biomethane, accounting for the characteristics of renewability and carbon intensity. Trade of renewable gas and in particular of biomethane is recommended to:

- Widen the market for producers and allow for management of national market disruptions;
- Allow large consumers to acquire desired resources of biomethane;
- Access sustainable substrate resources in countries without a subsidy scheme;
- Develop a distribution system for renewable gas noting that biomethane may only be a fraction of the required gas distribution in the future.

Due to differing incentive systems, trade across borders can lead to an addition of incentives, for example, if the exporting country is incentivising the production and the importing country is incentivising the final gas utilisation. To create an international trade with similar conditions for gas providers, the national incentive systems will need to be harmonised. As discussed within the EU there is also an initiative (Ergar) to harmonise and align national activities for international trade. Mass balance systems, proof of sustainability and respective certification and registration systems are available or under development in many countries where biomethane incentivisation is in place. These systems need to be at least compatible in order to enable and enhance trade.

6 Cost of renewable gas

6.1 ECONOMICS OF BIOGAS AND BIOMETHANE

Anaerobic digestion plants are highly variable in their configuration and thus the plants costs also vary significantly. In Figure 6, the specific costs for electricity production of ca. 50 plants are illustrated and it is evident that the costs fluctuate. Production costs depend on the plant size, the substrates used, regulatory requirements, and the site-specific construction/labour and the associated operational costs (including for any maintenance and repair). With a growing numbers of AD plants, the construction experience of such facilities will increase and should translate to higher economic and energy efficiencies, however this progress is not always evidenced in economic efficiency.

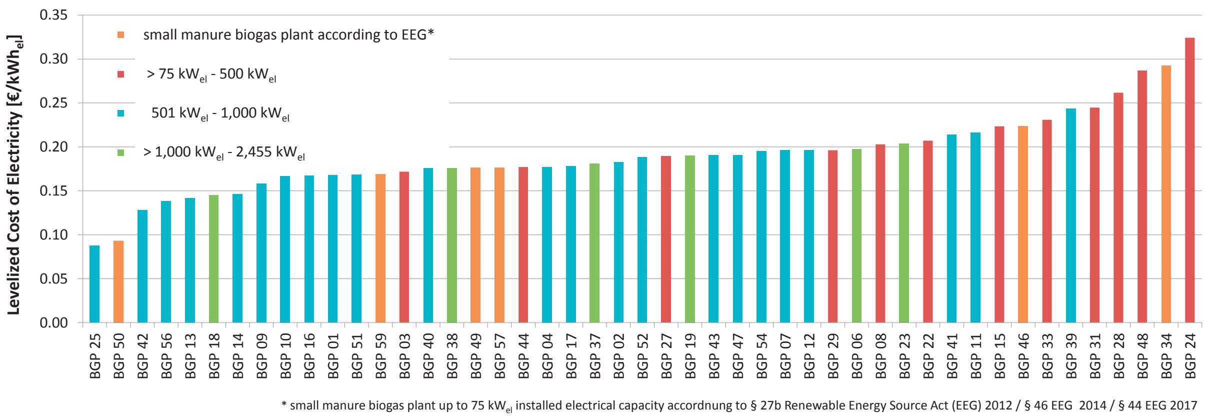

Figure 6: Specific production costs (electricity) dependent on plant size (average output) (Barchmann et al., 2021)

Certain components of the plant, such as CHP or upgrading units, have more predictable costs as they are usually manufactured and can be considered off the shelf items. The potential availability and supply of substrate to a specific site will define the capacity of the plant. The available resource of biomass to a specific plant site will depend on the supply infrastructure. In an agricultural setting, the operational logistics of the farm and the herd sizes can result in a range of possible plant sizes (from capacities of kW up to several MW). In the waste sector, the availability of biomass can vary substantially and is dependent on upstream industrial processes of different municipalities.

As with any technical process, the product specific costs for biogas production, upgrading and feed-in components to the grid will depend on the economies of scale; in effect smaller biogas or biomethane plants will have significantly higher specific costs. Figure 7 illustrates this trend for CHP costs in relation to capacity.

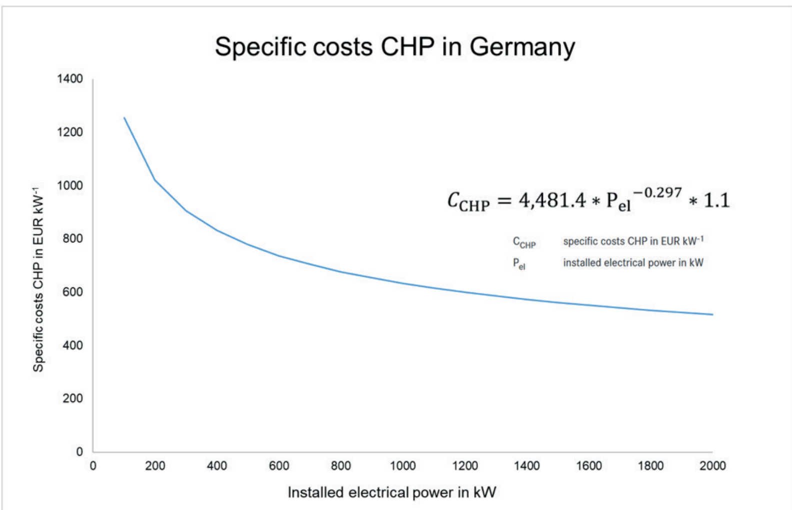

Figure 7. Specific investment costs of CHP units (source: Haensel et.al 2020)

Since upgrading biogas and subsequently grid injecting is typically more costly than a CHP unit, much larger capacities are applied to reduce the overall costs and thus capitalise on economies of scale. In Figure 8 the specific costs for biogas upgrading are shown. In order to put Figure 7 and Figure 8 in context, 200 m³/h raw biogas would equate approximately to an electrical capacity of 480 kW.

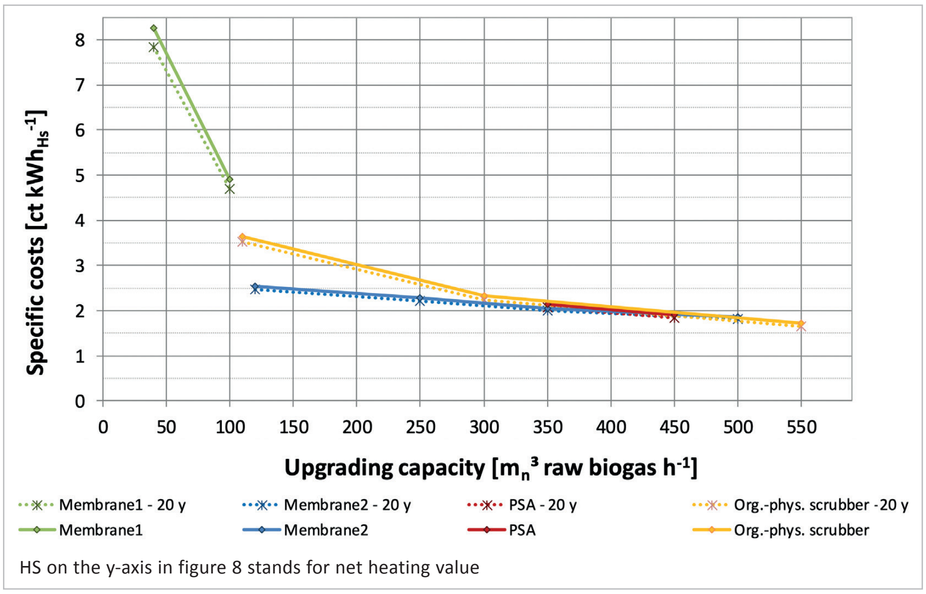

Figure 8: Specific production costs of upgrading units in relation to capacity; source: (Daniel-Gromke et al., 2017)

Sparse information on production costs of biomethane are available on an individual country basis but a range of 2.5 to 10 c€/kWh can be reported. Cost analyses are typically not publicly available for most countries studied. The reason for this may be the limited interest of plant operators and manufacturers to publish such data, the lack of financial support for such an evaluation and/or the lack of a sufficient number of plants in the sector for evaluation.

In terms of the renewable gas economy, the selling price of biomethane is another consideration. Since most trade is accomplished on a bilateral basis, the information available is again sparse. Conditions of the purchase can be highly variable. Some plant owners sell to a trader or the customer at the feed-in point to the grid. Other customers might buy at the feed-out point or even purchase the certificate alone for the renewable gas. Taxes and fees relative to grid use tend to be different for different countries also. Ultimately, the price of biomethane will vary depending on the substrate used and the incentive systems in place.

6.2 ECONOMICS OF HYDROGEN PRODUCTION

Low-carbon blue hydrogen produced from steam methane reforming (SMR) combined with carbon capture and storage (CCS) may be economically attractive in areas with large reserves (and associated lower price) of natural gas and availability of suitable carbon storage infrastructure (reducing cost of CCS). The captured carbon is often stored in existing or depleted gas fields and as such is beneficial to countries with existing infrastructure and associated experience in the gas industry (Hydrogen Council, 2020). In such countries blue hydrogen possesses the capacity to enter the market at costs of just 10-20% higher than that of standard grey hydrogen, while supplying a low-carbon hydrogen at scale. The cost of the CO_2 capture process is estimated to be roughly US\$0.20-0.30/kg H_2 for an SMR plant (Hydrogen Council, 2020); at 33.33 kWh/kg H_2 this is equivalent to about 1\$c/kWh or 10 \$c/L diesel equivalent.

Fuel costs typically account for 45-75% of the total cost of hydrogen production in SMR, thus the accessibility to cheap natural gas is vital for process viability. By implementing CCS in SMR, capital expenditure costs increase by 50% on average and fuel costs by 10% on average, however this will vary by design (IEA, 2019a). Due to the cost of CO_2 transport and storage, it may also lead to a doubling of operational expenditures (Collodi et al., 2017). The overall cost of blue hydrogen currently from SMR with CCS is reported at a range of US\$2.10- 2.32/kg H_2 (Hydrogen Council, 2020; IEA, 2019a) or about 7\$c/kWh, however this can vary by region and may be cheaper in areas with lower gas prices. It has been reported that a carbon price of US\$50/tCO_2

would suffice for blue hydrogen to reach a cost parity with grey hydrogen (Hydrogen Council, 2020).

Although renewable green hydrogen has many benefits in terms of carbon footprint as compared to blue hydrogen, it is viewed as more expensive. Green hydrogen is currently judged to be competitive in niche markets, but if market trends continue and sufficient policies are implemented it may be viable on a larger scale (Glenk & Reichelstein, 2019). For the green hydrogen process, capital and electricity costs, conversion efficiency and the mean operating hours of the electrolyser are the most significant parameters. As an electrolysers' operating (run) hours rise, the significance of capital costs decreases and that of electricity costs increase in determining the cost of hydrogen production. Thus operating the electrolyser for high load hours but paying for electricity may actually be cheaper than relying solely on surplus electricity available for only a few hours a day (IEA, 2019a). Positioning electrolysers at locations with dedicated interconnection to renewable resources could provide low-cost hydrogen, even when hydrogen transmission and distribution costs are accounted for (Fabbri et al., 2014).

Both renewable green hydrogen and blue hydrogen are currently not cost-competitive with grey (fossil-based) hydrogen. The estimated cost of grey hydrogen in the EU is currently low at €1.5/kg H_2 (ca. US$1.70/kg or 5.1$c/kWh), however this depends on natural gas prices but does not include for the carbon cost of CO_2.

Renewable green hydrogen is suggested to range between €2.5-5.5/kg H_2 (or 8.8 to 19.4 $c/kWh) and as such can be quite more expensive that blue hydrogen (7$c/kWh) and grey hydrogen (4.5$c/kWh) both of which depend on the price of natural gas. It is suggested that carbon prices of between €55-90/tCO_2 are required for blue hydrogen to become cost competitive with grey hydrogen based on the current level of CO_2 emissions of each (European Commission, 2020), while in locations with cheap renewable electricity, green hydrogen is suggested by some potentially to be cost competitive with grey hydrogen by 2030 (BloombergNEF, 2020; Glenk & Reichelstein, 2019; IRENA, 2019). According to analysis by IRENA, by 2050 the cost of producing green hydrogen from wind (including electrolyser costs of US$370/kW) should be ca. US$1/kg H_2 (3 $c/kWh), which is lower than any estimation for blue hydrogen with a carbon price of more than US$50/t$CO_2$ for any emissions not captured (IRENA, 2019). When considering these low prices for hydrogen it must be considered that cheap hydrogen may impact on the financial sustainability of the green electricity from which it is produced. There is a need to find the sweet spot between a viable hydrogen economy and a viable renewable energy economy. For example, McDonagh et al. (2020) found when investigating a hybrid electricity hydrogen production facility from an offshore wind farm that curtailment of cheap electricity (when demand is less than supply) may be preferable than hydrogen production if the price of hydrogen is too low; a levelised wind farm cost of €42.3/MWhe gives a levelised H_2 cost of €3.77/kg (13$c/kWh).

The extent to which hydrogen production costs are impacted by the availability of renewable electricity and natural gas becomes particularly apparent when comparing different countries. In countries with a relatively consistent supply of renewable resource such as combinations of wind, solar and hydroelectricity and that import natural gas, producing green hydrogen may be the most favourable outcome economically from a whole systems perspective. Conversely, for countries with significant reserves of natural gas and adequate storage availability, blue hydrogen may be a better option economically (IEA, 2019a). Table 17 gives a summary of hydrogen costs expected to 2030 (Hydrogen Council, 2020; IEA, 2019a).

Table 17: Summary of predicted changes to hydrogen costs

Hydrogen	2020 US$/kg H_2 ($c/kWh)	2030 US$/kg H_2 ($c/kWh)	Reason for Difference
Grey	1.60 (4.8)	N/A	Planned expansion of blue and green hydrogen production methods and likelihood of carbon price increases will lead to grey hydrogen production becoming unfavourable.
Blue	2.10 (6.3)	1.80 (5.4)	Price decline is expected to be due to the decreased cost and increased efficiency of carbon capture and storage (with no consideration of increasing natural gas prices).
Green	6.00 (18)	1.20 - 2.50 (3.6 - 7.5)	Price decline driven by economies of scale, advances in technology, operations and maintenance and declining costs of renewables. A range is provided due to the location, whereby optimal conditions will provide a lower cost. Care must be taken to ensure economic viability of renewable electricity sources for cheap hydrogen production

7 Sustainability considerations

7.1 GHG EMISSIONS REDUCTIONS

The sustainability of biomass-based energy has seen much debate and scrutiny in recent years. In essence, within the EU, the recast Renewable Energy directive (REDII) sets the standard for renewable fuels (including for the electricity sector) by providing the methods, standard values and thresholds for calculating the GHG emissions of a process as compared to the displaced fossil fuel on a whole life cycle basis. Some sustainability criteria are set with technical requirements of the production process. For example in biomethane production from anaerobic digestion, some countries will enforce a limit of methane emissions allowable from the upgrading process. The sustainability of renewable gas must be officially monitored and certified through defined mechanisms. The information must also be transferred if the gas is traded, and preferably transferred in a universal way that allows for the broad application of the gas and compatibility with existing incentive systems. Within REDII, the Proof of Sustainability is the basis for monitoring national target compliance (besides providing the proof of compliance). An additional instrument introduced by REDII is the Guarantees of Origin which is for customer information.

The sustainability requirements of biomethane plants are numerous and include for:

- Emissions emanating from plant operation (in particular methane emissions);
- Substrates used;
- Potential emission credits (such as for manure utilisation);
- Land use change.

The resulting regulations for sustainability (driven by REDII in the EU) apply for the use of renewable gas in a given sector. Within REDII, thresholds for GHG reduction to be achieved by the plant operation are defined (Table 18). Standard values for the calculation of emissions have been specified according to technology (such as upgrading technology used, post treatment) and substrate. Thresholds for each sector (transportation, heat, electricity) differ and the fossil fuel comparators for the sectors also vary. REDII mandates that sustainable transport fuels must achieve 65% GHG emissions savings as compared to the a fossil fuel comparator for transport (94g CO_2eq/MJ) (European Parliament, 2018). The target for heat and electricity is 80% GHG emissions savings as compared to the fossil fuel comparator after 2025 which in this case is 80 CO_2eq/MJ. As such, the same gas, which comes with a certain CO_2 footprint, may comply with the threshold in the transport fuel sector but not in the heat sector. See also Table 21.

Table 18: Development of greenhouse gas savings thresholds in REDII (EU, 2018)

Requirement for GHG emissions savings as per REDII			
Time period	Transport Fuel	Renewable fuels of non-biological origin (Transport)	Electricity and Heat
Post January 2021	65%	70%	70%
Post January 2025	65%	70%	80%

Most of the countries surveyed seek GHG emissions reduction through renewable gas utilisation (Table 19). Of 14 countries surveyed, 9 countries reported requirements for GHG emissions savings. India stated a 50% reduction target, whilst Germany and Sweden declared 60% reductions; as Germany and Sweden are EU states these values will need to rise (as per Table 18), to meet REDII criteria. Any requirement needs to be monitored with respect to compliance evaluation. This can be accomplished via a certification process.

Table 19: Countries indicating GHG reduction requirements

GHG reduction requirements	Germany	Canada	China	Finland	Sweden	Norway	Australia	Estonia	Austria	Switzerland	India	USA	UK	Japan
GHG reduction requirements	x			x	x			x	x	x	x	x	x	

7.2 PROOF OF SUSTAINABILITY AND GUARANTEES OF ORIGIN

Sustainability needs to be proven and certified according to application specific requirements. Some requirements result directly from national regulatory frameworks (REDII within the EU), but additionally there may also be market driven initiatives (adapted from Königsberger et al. 2021):

- REDII sets out sustainability criteria, additionally, the Fuel Quality Directive refers to sustainable biofuels for the transportation sector, setting specific national and European quotas;
- Article 19 of the REDII extends the system of Guarantees of Origin (GoO) for consumer disclosure to cover renewable gas;
- Consumption of renewable gas for industrial purposes such as in the chemical industry (for production of ammonia, methanol) and other refinery applications.
- Corporate social responsibility including for commitment of industry to use a certain share of energy from renewable resources or to reduce GHG emissions.
- National subsidy schemes.

The proof of compliance of sustainability criteria documents the evidence of a specific volume of renewable gas with a defined GHG footprint or saving. This provides evidence for the gas user that the used biofuels or renewable gas comply with the sustainability requirements, and are the basis for proof of meeting any quota requirements. Typically, the issuing body of certificates needs to be recognised by the authorities, within the EU by the European Commission.

Guarantees of origin (GoO) provide evidence that the energy used can be characterised as that coming from a specific renewable energy source. GoOs can be traded in the form of certificates and are not tied to the physical trade of energy carrier. Within the EU, the GoO serves "the purposes of demonstrating to the final customer the share or quantity of energy from renewable sources in an energy suppliers energy mix" (EU, 2018). GoOs cannot be used to verify compliance to target achievements according to RED II. Further reading is available in:

- ISCC 206 Regulations to issue Proofs of Compliance with Sustainability Requirements
- REGATRACE Renewable Gas Trade Centre in Europe D3.1 Guidelines for establishing national biomethane registries.
- REGATRACE Renewable Gas Trade Centre in Europe D2.4 Investigative study of IT system options for harmonized European cross border title-transfer of biomethane/renewable gas certificates

7.3 CERTIFICATION AND REGISTRATION

Any proof of characteristics which are tradable (either with the physical commodity or otherwise) need to be certified based on a standard from an authorised body and subsequently registered in a manner which allows tracking from production to consumption, and avoid multiple trades or sales of one item. A register tracks, as well as the quantity of energy, the characteristics of the renewable energy carrier. As natural gas is traded worldwide, the most obvious initiative would be to establish a register that allows a similar trade for biomethane. However, registers are established currently on a national level. In Europe, the European Renewable Gas Registry (http://www.ergar.org/) has an ambition to harmonise the initiatives on a national level and provide a European instrument which would enable trade across borders (Figure 9).

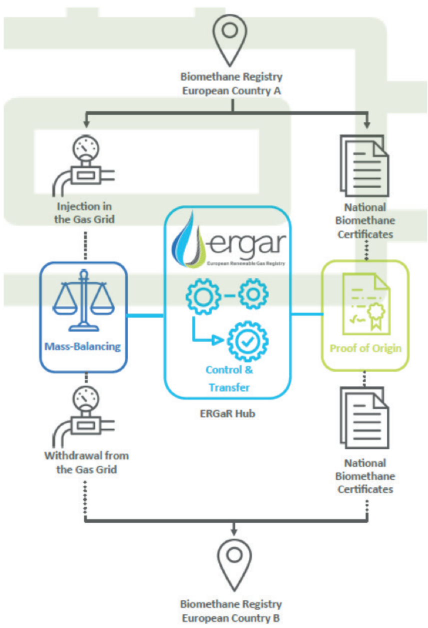

Figure 9: Certification via Ergar from EBA sourced from: https://www.europeanbiogas.eu/wp-content/uploads/2019/08/Biogas-Basics-v6.pdf

Table 20 shows the breakdown of GoOs, registries and certification systems that have been developed in a selected number of surveyed countries.

Table 20: Guarantee of origin, registry, and certification in the surveyed countries

Trade schemes	Germany	Canada	China	Finland	Sweden	Norway	Australia	Estonia	Austria	Switzerland	India	USA	UK	Japan
Established system for guarantees of origin			x					x	x	x		x	x	
Available national renewable gas registry	x			x				x	x	x	x	x	x	
Requirement for certification system	x			x	x				x	x		x	x	

Figure 10 gives an overview on the requirements for biomethane in the EU. The international compatibility of these systems needs to be considered going forward.

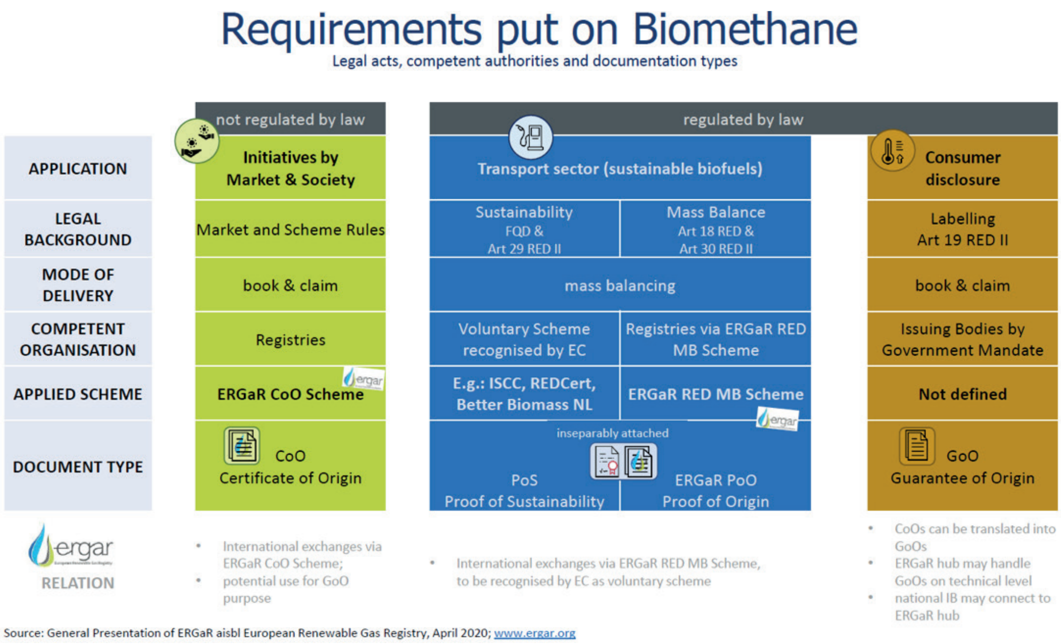

Figure 10: Requirements on biomethane and potential solutions from (ERGaR)

7.4 SUSTAINABLE RENEWABLE GAS PRODUCTION

The sustainability of biomethane production over conventional fossil fuels will depend on many factors but particularly the type of substrate used. Wastes and residues (such as food waste and slurry) are typically the most sustainable (offering high GHG emissions savings) since they involve minimal emissions in their production, save fugitive emissions of methane from landfill or open slurry tank and would otherwise be sent to landfill (in the case of food waste) or open slurry tank prior to land application (in the case of slurry). Despite energy crops having higher methane potential, such substrates can be more complex from a sustainability perspective (offering lower GHG emissions savings), particularly in relation to intensive crop production measures and the need for additional fertiliser. In essence, every AD plant is unique in terms of system configuration, the substrate used, biogas upgrading method, energy end-use and digestate application. However, biomethane must effect of the order of 14.4g CO_2-eq/MJ for renewable heat and 32.9g CO_2-eq/MJ for transport fuel (Table 21) to be deemed sustainable according to the recast REDII (Long & Murphy, 2019). It should be noted that the calculation for heat is field to wheel while for transport is field to tank (hence the 90% conversion efficiency for the heat calculation). This is purely from a GHG emissions perspective on a lifecycle basis. Ensuring the reduction of GHG emissions is crucial and can be achieved through high biogas yields, closed storage of digestate and the avoidance of methane slip from the AD reactor and in the biogas upgrading process. Co-digestion of substrates can also offer another useful approach in achieving the sustainability criteria, particularly when offsetting high proportions of energy crop with slurries or other residues.

Table 21: Comparison of sustainability criteria for renewable heat and transport according to the Renewable Energy Directive REDII (Long & Murphy, 2019)

End Use	Fossil Fuel Comparator g CO_{2eq}/MJ	Conversion efficiency	Effective fossil fuel comparator g CO_{2eq}/MJ	Emissions allowed g CO_{2eq}/MJ
Heat	80	90%	72	72 g CO_2/MJ/ (1 -0.8) = 14.4
Transport	94	100%	94	94 g CO_2/MJ/ (1 -0.65) = 32.9

At present, grey hydrogen from SMR (without CCS) is deemed to have an emissions factor of ca. 285 gCO_2/kWh (9.5 kgCO_2/kg H_2) (Climate Change Committee, 2018). Thus, the use of grey hydrogen is not the solution to future energy decarbonisation, and cleaner alternative hydrogen sources will be essential going forward. Both blue and green hydrogen are under assessment for their ability to contribute to the objective of energy decarbonisation. Green hydrogen has significant potential for climate mitigation as it is based on renewable energy sources such as solar and wind but issues currently exist in terms of the economics. Blue hydrogen is currently the global standard for hydrogen production. It is considered a good short to medium term option to begin the transition to a hydrogen based economy. However, questions are typically raised regarding the storage of captured carbon, the continued use of fossil fuels, slippage rates, and the sustained CO_2 production in blue hydrogen production.

The use of water electrolysis to produce green hydrogen can potentially have negligible GHG emissions but this depends on the origin of the electricity. Producing hydrogen from renewable energy resources such as wind would imply essentially zero GHG emissions. However, the use of electricity directly from the grid does not guarantee the production of renewable green hydrogen as this electricity may include for generation from carbon intensive technologies, resulting in GHG emissions. Furthermore the carbon footprint of the hydrogen is increased over that of the electricity by the reciprocal of the hydrogen production efficiency expressed as a decimal; for example if the electrolysis efficiency is 70% then the increase in magnitude of the carbon footprint of the hydrogen over that of the electricity grid is (1/0.7 =) 1.43. Often there is a conflict between sustainability and economic viability for green hydrogen production. Grid electricity is largely responsible for the environmental impact of green hydrogen production, yet, relying solely on curtailed or constrained renewable electricity (when supply exceeds demand) can reduce the operational capacity of the electrolyser and lead to expensive hydrogen (McDonagh et al., 2019).

A study by CE Delft indicated that in Norway, the CO_2 footprint for blue hydrogen (SMR-CCS) of ca. 1.14 kg CO_2-eq./kg H_2 would be analogous to that of green hydrogen with a range of 0.92-1.13 kg CO_2-eq./kg H_2 produced via electrolysis from the electricity grid in 2015 up to 2030 (assuming constant carbon intensity of electricity of 17gCO_2/kWh), however this did not take into account natural gas slippage rates for blue hydrogen production (CE Delft, 2018). On the contrary Howarth and Jacobson (2021) using an assumption of a 3.5% emission rate of methane from natural gas suggested that CO_2eq emissions for blue hydrogen are only 9-12% less than for grey hydrogen.

Using electricity at times of low cost, or when high renewable electricity penetration is forecasted, can lead to 56% more decarbonised electricity than the grid average when used in a green hydrogen production system (McDonagh et al., 2019). The use of low carbon electricity is seen as key to achieving future sustainability of green hydrogen (Collet et al., 2017).

8 Conclusions

Decarbonisation is about so much more than electricity; electricity itself only accounts for about 20% of final energy demand. As a society we must make decisions informed by scientists and engineers and implemented through policy as to what technologies and roadmaps will be employed to decarbonise the hard to abate sectors including for: heavy transport; high temperature industrial heat; agriculture; fertiliser and chemical production. When it is considered that at present in the EU and the USA, the natural gas grid provides more energy than the electricity grid, it cannot be seen as a sensible process to abandon such infrastructure and start again, not with the imminent climate emergency and the need to act fast. We must be decisive as we eat through our ever-dwindling allocated carbon budget to limit world temperature rise to below 2°C.

The existing natural gas infrastructure is very extensive in many industrialised countries and rather than being viewed as a future redundancy associated with a fossil fuel system, it could instead be seen as offering huge benefits for green renewable gas as a future decarbonised energy carrier. The whole natural gas infrastructure system was put in place at huge cost and includes for an extensive transport system of transmission and distribution pipes and connections to industries and homes. Within specific industries, gas boilers, CHP units and associated systems are in place to provide the necessary ingredients and energy provision for end products that range from ammonia to whiskey.

Traditional renewable gas technologies (such as biogas and biomethane) can be considered mature. We have the technologies in place to make renewable gases from wet organic material, dry woody material and from electricity. In southern Sweden for example biomethane is used extensively as a transport fuel in buses, trucks and cars. We already inject gas to the gas grid. For example Denmark has at times substituted natural gas in the grid with over 25% biomethane; these values fluctuate over the year. In terms of policy we have devised and put in place trading mechanisms for trade between producer and user of renewable gas, some times in different countries.

The economic feasibility is questioned, however this is a green fuel which is being compared to a fossil fuel where the present cost of carbon in no way takes account of the climate emergency. As such, it is preferable to contrast the cost of renewable technologies with the cost of other renewable technologies which are viable in that sector; for example we should not compare the cost of abatement of mature technologies in readily decarbonised sectors (say PV arrays) with that of an advanced transport fuel that can power heavy transport but is at an early stage of development. We need to incentivise technologies at early market maturity and at low technology readiness levels (TRL) that are seen to have great potential for application as fuels of the future for hard to abate sectors such as hydrogen and associated electro-fuels.

At present however, the main barrier to uptake in the market for renewable gas is the cost. Future support systems and development strategies and policy must create conditions to integrate renewable gases into a new climate neutral economy. Whilst incentives are required at present to compete with fossil fuels, a strategy on the role renewable gas plays in the future market must be devised. Sustainable renewable gaseous fuels will be required to substitute for the huge market in place which uses natural gas and upcoming demand in new energy systems. In particular attention must be paid to the existing natural gas infrastructure and how this massive capital investment could be capitalised upon.

In this report, the following actions have been identified to optimise the future development of renewable gas systems:

- Create roadmaps for renewable gas development, including for availability of substrates (be they wet organic, woody or electricity), development costs, defined time specific targets as a portion of energy use and infrastructure required and/or already available.
- Introduce quotas which place an obligation on fuel providers to ensure renewable fuels meet a minimum proportion of the fuel market; this is a very effective tool to remove the necessity of renewable gas competing on price with fossil gas.

- Provide incentives which reflect the actual costs of investment and long-term operation of the renewable gas industry to ensure bankability for the developer and ensure a price effective market environment for the user of renewable gas.
- Eradicate as much as plausible, unnecessary barriers and inhibitory regulations on both a technical and regulatory level.
- Seek compatibility with other technologies (both existing and proposed) through a cascading approach to further develop the sector; this could include for example carbon capture from industry combined with hydrogen from electricity to produce methane, methanol or ammonia in electro-fuel systems.
- CO_2 emissions must have a realistic monetary value associated with them; a realistic carbon tax would stimulate development and drive the transformation of green gas whilst providing for competition between renewable technologies in specific sectors, which should consequently lead to the phase out of specific incentives.

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