HYDROGEN POTENTIAL IN THE ENERGY TRANSITION

1. Introduction

In response the urgency of decarbonisation, policy makers have agreed in 2015 to what is known as the Paris agreement. In order to achieve its targets, the energy sector needs to reduce CO2 emissions by -80%, -95%. From the 1990 baseline of 5,751MtCO2e, a 24% reduction in emissions had been achieved by 2016 across Europe. Limiting the temperature increase to <1.5°C by 2050 will require a reduction of emissions by another three times the amount already achieved.

Many stakeholders have in the past favoured an 'All-Electric' approach of decarbonisation, which includes renewables but also nuclear power, biomass and interconnection. However, due to the lack of security of supply and the needed technological progress, this approach is risky. In 2017 wind and solar power accounted 85% of all new renewable capacity and will continue to increase. Environmentally, important net benefits associated with wind and solar generation are obvious, however, their renewable energy generation is variable and uncertain and its integration into the electrical system is a great challenge. With an increasing demand for flexibility in the electric system around the world, the electricity storage market faces great challenges. Currently, pumped hydro storage (PHS) represent 96% of current storage electricity capacity (IRENA, 2017), but PHS solutions are quite geographically limited, this opens an opportunity for other storage technologies, such as hydrogen

The EU targets are more likely to be achieved if zero carbon hydrogen from natural gas is included in the solution. In order to achieve a net-zero emissions EU energy system by 2050 all sources of gas consumed in the EU by 2050 must be net-zero emissions gas. The sources of gas can be either renewable gas, i.e. gas produced from renewable sources, or low-carbon gas–natural gas combined with Carbon Capture Storage (CCS) or Carbon Capture Utilization (CCU). Renewable gas includes biomethane, green hydrogen and power to methane. Low-carbon gas is gas that, during production, has small volumes of CO_2 that remain uncaptured. While biomethane and hydrogen are different gases, it can be used similarly in almost all energy sectors. Both biomethane and hydrogen can be transported through existing gas infrastructure and the two can even be mixed.

2. Hydrogen

Hydrogen is the lightest molecule and the most abundant element in the universe. On Earth, hydrogen only exists in a chemically bound form, so it must be produced by specific processes. Hydrogen does not emit greenhouse gases when being burned, however, volumes of hydrogen are much higher compared to natural gas on a per energy unit basis. There is a strong interest in hydrogen as an energy carrier for several reasons: i) It can be distributed, combusted and used in the same way as natural gas; ii) Electricity can be produced from hydrogen at very high efficiencies; iii) Hydrogen can be produced from fossil, renewable and biomass sources, facilitating a "bridging" from carbon to a future zero-carbon economy; iv) Hydrogen has zero tailpipe emissions after combustion, which facilitates lower cost CO_2 removal from the atmosphere; and v) Conversion from hydrogen to electricity is reversible, meaning that hydrogen can provide an "electricity storage" solution.

Three types of hydrogen can be distinguished based on greenhouse gas emission impacts.

- **Grey hydrogen** is gas produced by thermochemical conversion of fossil fuels without capture of CO_2.
- **Blue hydrogen** is a low-carbon gas produced by thermochemical conversion of fossil fuels with CCS.
- **Green hydrogen** is a renewable gas produced from renewable resources.

3. Hydrogen Production

In 2003, 96% of the hydrogen produced worldwide came from the thermochemical conversion of fossil fuels. Potentially, blue hydrogen production from natural gas can be coupled with a share of biomass feedstocks that could bring the overall hydrogen greenhouse gas footprint to net zero or even negative.

The most mature and most-discussed green hydrogen production route is via electrolysis of water. Electrolysis, while not leading to any direct emissions, can only be regarded as truly carbon neutral if the electricity that is used as an input into the process has been produced from a zero carbon source. Three main technologies are currently used/in development for electrolysis: Alkaline Electrolysers, Proton Exchange Membrane, Solid Oxide Electrolysis Cells SOECs.

Alkaline Electrolysers (AE) are the most mature and currently cheapest (€/kW) technology option. However, they have limited ability to respond to load changes, which is essential for the flexibility requirements of a power system with high penetration of renewables. Furthermore, the design is complex, implying limited cost-reduction options.

Proton Exchange Membrane (PEM) electrolysers have a simple design, are currently more expensive than alkaline electrolysers, and are assumed to have a high cost-reduction potential. PEM electrolyser technology can absorb over 100% of its rated energy capacity within seconds, producing renewable hydrogen, and can be shut down as fast. Because of their ability to operate at variable power supply rates, PEM electrolysers tend to be more suitable to a system coupled with wind and solar, which often present spikes in energy. On the other hand, the levelized cost of energy (LCOE) of PEM would be higher at present due to the fact that the technology is not yet as mature and commercially viable as AE.

The Solid Oxide Electrolysis Cells (SOECs) use high temperature electrolysis; they are at an early stage of development. Theoretically, solid oxide electrolysis is a promising technology due to its high efficiency, its ability to recover the heat needed for electrolysis, and its possibility to operate in reverse mode (regenerative electrolysis). The inability to have a flexible load and the high degradation of the membranes are the two major challenges of SOECs.

Blue hydrogen is an alternative low-carbon production route for hydrogen. Two production technologies are considered, the currently dominant **steam methane reforming** (SMR) and **autothermal reforming** (ATR), which has integrated carbon capture in its design. Blue hydrogen production either via SMR or ATR will bare residual emissions with lower bound between 11.5-23 gCO2eq/kWh of hydrogen. Methane **catalytic cracking** for large-scale hydrogen production may also turn out to become more cost-effective in the future. In ATR, around 5% of the CO2 emitted by the process cannot be captured cost-effectively. SMR can be optimised to capture 90% of their emissions. The remaining CO2 emissions could be compensated by using bio-based feedstocks. When scaling up blue hydrogen to ambitious levels of 1,500 TWh, around 30 MtCO2 negative emissions would be required to offset remaining emissions.

Methane **pyrolysis** is an existing technology, which uses high temperatures to break down natural gas molecules (CH_4) into hydrogen (2 H_2) and solid carbon (C) products, such as carbon black, not to be confused with soot or 'black carbon', or synthetic graphite. Pyrolysis becomes the key enabler of the development of a hydrogen based solution to decarbonisation: i) pyrolysis is more expensive than SMR with CCS but it is cheaper than electrolysis on a LCOE (Levelised Cost of Energy) basis. ii) Pyrolysis is more scalable than electrolysis enabling large quantities of hydrogen to be produced. Pyrolysis enables zero carbon hydrogen to be produced in areas that cannot easily access the CCS required for SMR production of zero carbon hydrogen, or which are far from renewables production.

4. Hydrogen applications

Hydrogen allows for a more efficient deployment of renewable electricity sources in the power sector and of alternative technologies in the heat and transport sectors. The heat sector can be split into non-process and process heating. Non-process includes heating in all buildings, whilst process heating is used for industrial processes.

In the non-process heat segment, a combination of heat pumps and hydrogen boilers can be deployed in the transition to a fully decarbonised sector. Heat pumps are impractical in extremely cold weather (-10° or lower) and poor insulated buildings. The process of switching a property from gas heating to a heat pump is complex and requires new radiators and pipework, the installation costs are high. In those situations hydrogen boilers provide a viable alternative, sometimes in hybrid systems together with heat pumps. Switch from a gas boiler to a hydrogen boiler can be achieved simply by the replacing the burner nozzle.

Hydrogen plays a key role in the process heat segment. Providing very high temperatures with electricity is challenging. Use of natural gas with post combustion CCS is a relatively low-cost option of decarbonising heat in this sector. Hydrogen is the most economical alternative in countries that don't allow the development of CCS. In heavy transport segments the large battery sizes required and long journeys make the use of electric vehicles impractical. In these segments, hydrogen fuel-cell vehicles provide an efficient alternative.

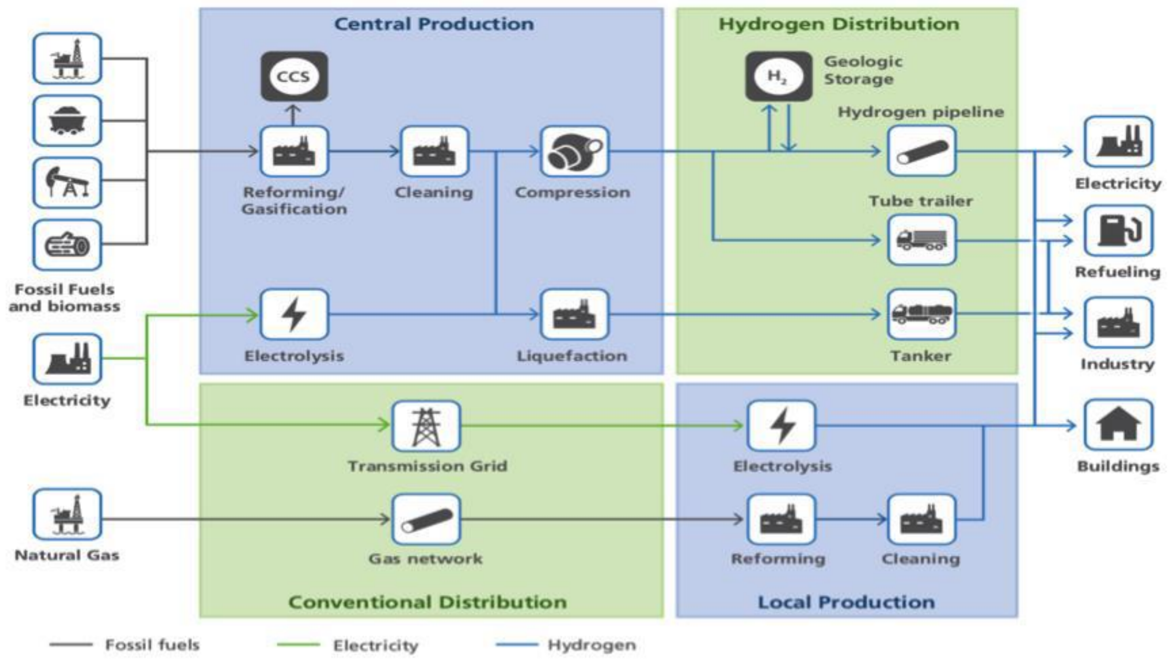

Figure 1: Hydrogen sources, production, distribution and applications.

5. **Hydrogen Demand**

The power demand is estimated to grow from around 3,330TWh in 2020 to around 5,000TWh in 2050. The majority of electricity will be produced by renewables. Coal, gas and nuclear power plants will be used as back up generation. The system also requires some additional power plants. Where available, natural gas power plants with post combustion CCS (41TWh in 2050) can be used, but in countries where CCS is not available, hydrogen combined cycle gas turbines (CCGT) (192TWh in 2050) fulfil this role.

In 2015, the total global hydrogen demand was estimated at 2,200 TWh (66 million tonnes of H2) with a total value of €102 billion. The International Renewable Energy Agency (IRENA) estimates additional 2,200 TWh (66 million tonnes of H2) in addition to existing feedstock uses (total of 4,400 TWh or 122 million tonnes of H2), while the Hydrogen Council puts the figure at 21,700 TWh (651 million tonnes of H2).

Currently around 270 TWh of hydrogen is produced in the EU. Most of this production is concentrated in North-western Europe. The production in the EU is largely produced by steam methane reformers (190 TWh). Nearly all steam methane reformers could be retrofitted with CO2 capture technology. Since most steam methane reformers are situated in or around industrial clusters, and the purity of the flue gas CO2 is relatively high, capture costs are among the lowest compared to other industrial processes.

Considerable demand for hydrogen may exist in the EU by 2050. There is a potential to produce 200 TWh of green hydrogen from excess electricity for storage purposes. The EU possesses a geological storage potential for CO2 of around 104 GtCO2. Besides storage in geological reservoirs (CCS), CO2 can also be used to increase the efficiency of manufacturing processes, to produce fuels, feedstocks or construction materials (CCU). In total, about 300 MtCO2 per year could be used in construction material (70 MtCO2) and chemical feedstock (230 MtCO2). To realise the full CO2 storage potential in chemical feedstock, a low-carbon EU power demand arises of 1,900 TWh for the entire chemical sector. This is around 60% of the 2016 power demand of the entire EU. The power-to-hydrogen demand has been quantified at 1,710 TWh of hydrogen, much beyond the around 200 TWh which uses excess electricity.

Besides the potential climate benefits, the main advantages of using hydrogen in the energy system are its storability, its prospective large-scale availability, and its wide range of applications.

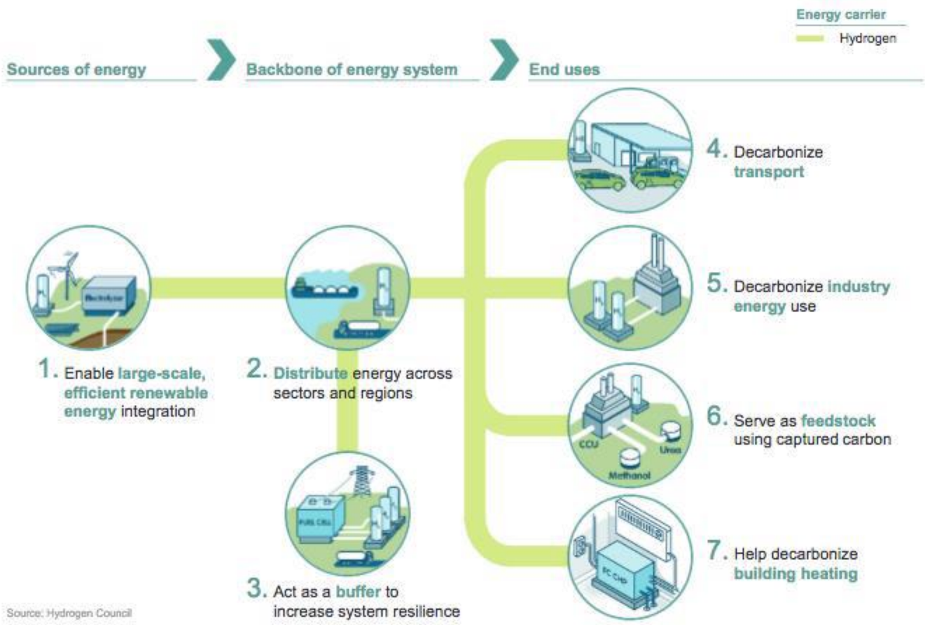

Figure 2: Seven roles of hydrogen in enablng the Grand Transition.

6. Challenges

According to the International Energy Agency energy-related CO2 emissions have to fall by 70% until 2050 to stay within the carbon Budget, while the Hydrogen Council states that the energy transition needs to overcome major challenges which come from five areas, and hydrogen has the potential for successfully overcoming all of them: i) increasing renewables share leading to imbalances of power supply & demand; ii) to ensure security of supply, global and local energy infrastructure will require major transformation; iii) buffering of the energy system through fossil fuels will no longer be sufficient to ensure smooth functioning of the system; iv) some energy end uses are hard to electrify via the grid or with batteries; v) renewable energy sources cannot replace all fossil feedstocks in the petrochemicals industry.

The Hydrogen Council finds that there is insufficient recognition of the importance of hydrogen for the energy transition, the absence of mechanisms to mitigate and share the long-term risks of the initial large-scale investments, a lack of coordinated action across stakeholders, a lack of fair economic treatment of a developing technology, and limited technology standards to drive economies of scale

Hydrogen presents unique challenges because of its high diffusivity, its extremely low density as a gas and liquid, and its broad flammability range. Creating an infrastructure for hydrogen distribution and delivery presents many challenges. Because hydrogen contains less energy per unit volume than all other fuels, transporting, storing, and delivering it to the point of end-use is more expensive on a per gasoline gallon equivalent (per-GGE) basis. Building a new hydrogen pipeline network involves high initial capital costs, and hydrogen's properties present unique challenges to pipeline materials and compressor design. However, because hydrogen can be produced from a wide variety of resources, regional or even local hydrogen production can maximize use of local resources and minimize distribution challenges.

7. BioMethane

Biomethane can be produced from agricultural residues and crops (via biogas) or from woody biomass. Sustainable biomethane must not displace existing food and feed production nor lead to unwanted direct or indirect land use change and should have a short carbon cycle. The combustion of biomethane for power and heat production results in greenhouse gas emissions like those of natural gas. Yet in the process of growing the biomass feedstock, an identical quantity of CO2 is captured from the atmosphere. This means that biomethane combustion emissions have a short carbon cycle and, according to the IPCC guidelines, count as zero emissions. At the same time, emissions occur in the cultivation, processing, and transportation of biomass feedstocks. It should be noted that other forms of renewable energy including wind power and solar PV also have associated lifecycle greenhouse gas emissions related to steel production and logistics.

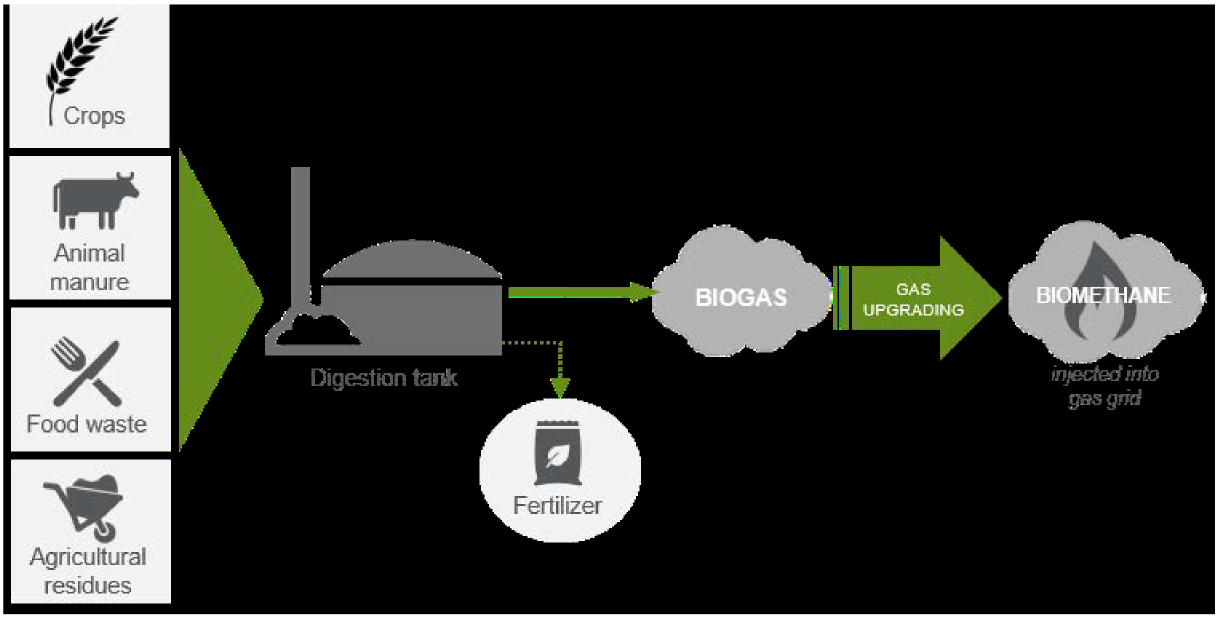

Figure 3: Schematic overview of the anaerobic digestion process.

8. BioMethane Production

Two main technologies exist to produce biomethane: **anaerobic digestion** and **thermal gasification**. **Anaerobic digestion** involves a series of biological processes in which microorganisms break down biodegradable material in the absence of oxygen. The process results in biogas and digestate. Biogas contains around 55% methane, the rest being mainly short carbon cycle CO_2. To enable injection into the gas grid, biogas needs to be upgraded to biomethane with 97% methane content by removing CO_2. Digestate can be used as a fertiliser. Virtually all biogas and biomethane produced today is based on anaerobic digestion. At the end of 2017, Europe had nearly 18,000 biogas plants producing about 6.5 TWh of electricity.

Thermal gasification involves a complete thermal breakdown of woody biomass and consumer wastes, which takes place in a gasifier in the presence of a controlled amount of oxygen and steam. A mixture of carbon monoxide, hydrogen, and CO_2 is produced, called syngas or synthesis gas. The gas is cooled, and ash content is removed. In a gas cleaning unit, pollutants like sulphur and chlorides are separated. Methanation of the syngas is then performed in a catalytic reactor using nickel catalysts. With methanation, the cleaned gas is converted into biomethane, CO_2, and wáter, which are then removed in a gas upgrading unit. Thermal gasification technology is not yet commercially available and, therefore, requires a proper assessment of biomass supply chains for ensuring operational and financial feasibility.

The EU biomethane potential is based on sustainable feedstock availability across Europe. Thermal gasification plants will be large installations with a capacity of 200 MW each, typically located at port locations. Woody biomass will be transported to these installations per ship. By 2050, over 200 of such installations could be in operation. Anaerobic digesters need to be closer located to the places where biomass is sourced and therefore are smaller in size (150-200 m3/hr). It is expected that by 2050 the average biogas plant can have a size of 500 m3/hr and over 30,000 installations will be in operation.

The biomass to biomethane yield is feedstock-specific, leading to a total biomethane production potential of 95 bcm in natural gas equivalent terms (1,010 TWh) per year by 2050. This consists of 62 bcm (660 TWh) produced through anaerobic digestion and 33 bcm (350 TWh) produced through thermal gasification. Additional biomethane could be imported from outside the EU, for example from Ukraine and Belarus. It is estimated that an additional volume of 13 bcm (138 TWh) of biomethane could become available for the EU market annually from these countries.

Soil organic carbon enhancement measures that are stimulated by the production of biogas can compensate 16–21% of hard-to-abate remaining emissions. Upgrading half of the EU anaerobic digestion plants by 2050 could generate an additional green methane supply of 160 TWh leading to a total renewable methane potential of 1,170 TWh. This quantity of renewable methane can be supplied at substantially lower costs compared to todays production cost levels.

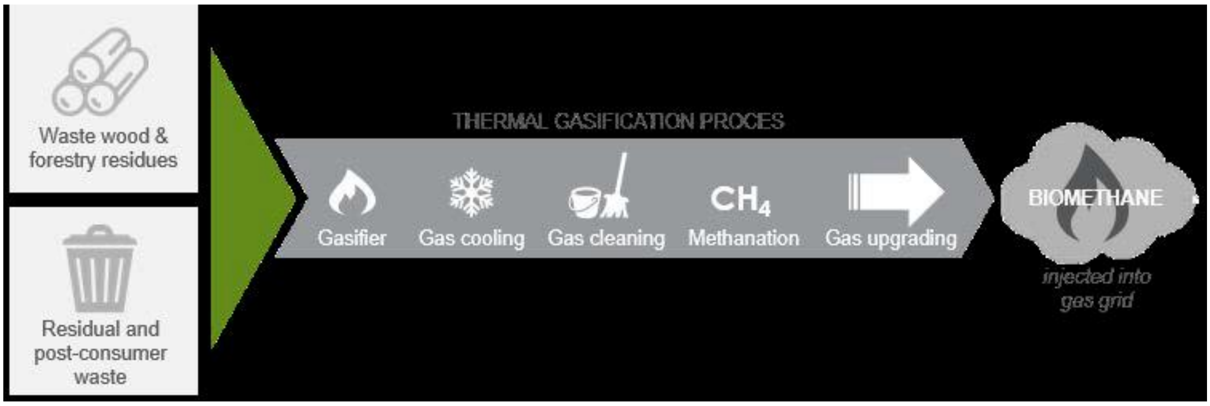

Figure 4: Schematic overview of the thermal gasification process

9. Transport

The choice of gas delivery mode is depended upon specific geographic and market characteristics. Producing hydrogen centrally in large plants cuts production costs but boosts distribution costs. Producing hydrogen at the point of end-use cuts distribution costs but increases production costs. Two types of hydrogen delivery can be considered: hydrogen transmission and hydrogen distribution. In addition to that, there are typically three hydrogen delivery modes such as liquid storage, compressed truck storage and pipelines. The suitability of which depends on the size of demand and the transport distance. From the economic point of view, the cost of liquid tanker storage delivery is about 10% of truck storage and pipeline compressed storage shown.

Compressed truck storage is better suited for relatively small quantities of hydrogen and the higher costs of delivery could compensate for losses due to liquid boil-off during storage. Distribution by compressed truck storage becomes less economic as demand rises and over long distances. The volumetric density of hydrogen can be increased significantly by liquefaction. Liquid hydrogen delivery is used today to deliver moderate quantities of hydrogen medium to long distances. Delivery by cryogenic liquid hydrogen tankers is the most economical pathway.

It has been reported that pipelines are the most efficient method of transporting large quantities of hydrogen, particularly over short distances. New pipelines would be required for high-pressure hydrogen networks, as existing high carbon steel natural gas pipelines would be affected by hydrogen embrittlement. Embrittlement is a pressure-driven process and is less of a concern at lower pressures. Polythene pipes replacing iron pipelines are compatible with hydrogen. These are currently limited to 7 bar, but larger plastic pipes up to 17 bar have been proposed. Many modern natural gas infrastructure extensions and upgrades replace the metal pipelines with polyurethane, which does not suffer from embrittlement and is hydrogen rated.

Figure 5: Existing Natural Gas Network between North Africa and Europe

10. Production and Delivery Costs

The most mature green hydrogen production route is the electrolysis of water. The technology maturity is expected to reduced electrolyser system costs of €420/kW by 2050. Green hydrogen from dedicated production in Southern Europe (PV or hybrid) are estimated at €44–59/MWh and from North Sea wind power at €48–61/MWh by 2050, while the current costs of green hydrogenis at €90–210/MWh.

Production cost from excess electricity (at zero electricity cost) is cheapest at €17/MWh at high capacity factor (2,881 FLH) but it is limited to 19 bcm natural gas equivalent [6]. In case of low capacity factor (709 FLH), the production cost increases to €71/MWh. It is posible to supply a large part of Europe's energy consumption with solar energy from North Africa. Green hydrogen production cost in North Africa could be between 34-44 €/MWh (1-1.3 €/kg H2). However, if such large-scale production would use liquefaction for delivery, the cost spikes to 92-160 €/MWh.

There are issues associated with the scale and costs of electrolysis. Hydrogen from electrolysis will need to be produced in areas and regions with a strong potential for renewable electricity in order to be economic. There would also be a requirement for many new transmission connection points. The alternative, and more feasible, approach is to produce hydrogen from natural gas closer to demand centres. The competitiveness of electrolysis versus either SMR with CCS or pyrolysis is therefore dependent on the relative prices for electricity and natural gas.

The costs of producing blue hydrogen in a SMR, optimised to capture and sequester 90% of the CO2 emissions, is estimated at €39–63/MWh in 2050, depending on the natural gas price. Hydrogen from SMR seems somewhat costlier to produce than through ATR with 95% greenhouse gas emissions capture, which has a production cost of €36–56/MWh in 2050. Current (2019) production costs for blue hydrogen are estimated at €47 and €51/MWh, for ATR and SMR, respectively. When capacity expansion is foreseen, ATR will likely be more economically attractive than SMR. Assuming a typical lifetime of 30 years, many SMRs will have to be replaced by 2050.

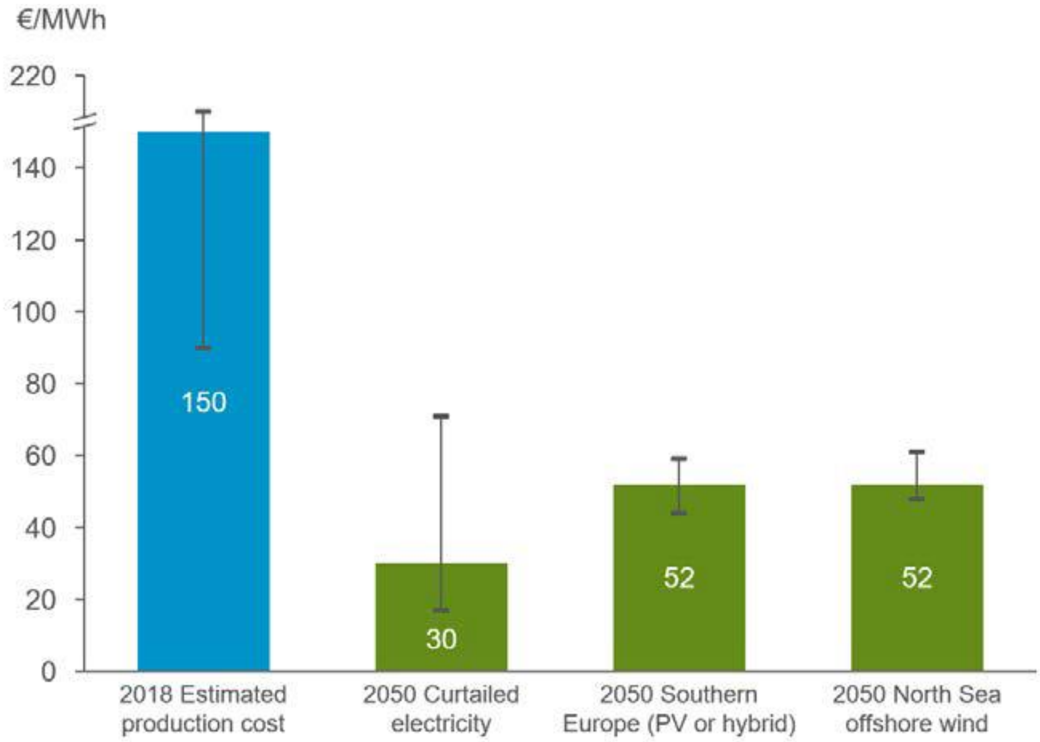

Figure 6: Green hydrogen production cost estimation for 2018 and 2050.

Pyrolysis may provide hydrogen at reasonable cost and sufficient scale, and alleviate some of the concerns associated with CCS. Another potential benefit of pyrolysis is the production of solid carbon products, which can be utilised in other processes. In those countries where CCS is not available, pyrolysis provides an alternative to both hydrogen production and heat decarbonisation.

Biomethane can be produce for €70/MWh today when produced in large digesters with manure as feedstock. Most production today takes place in small digesters at a cost of close to €90/MWh. Based on literature and market observations the cost of biomethane from anaerobic digestion can be reduced to €57/MWh by 2050.

Thermal gasification costs of €88/MWh represent the costs for the Gothenburg Biomass Gasification (GoBiGas) project, where a first-of-its-kind demonstration plant to produce 20 MW biomethane was commissioned in 2013. The production costs of €47/MWh for 2050 are estimated against a plant size of 200 MWth[3]. Woody residues contribute 53% to the total biomethane production volumes from thermal gasification whereas post-consumer wastes produce 47%. Using these percentage shares, the estimated weighted average feedstock cost from thermal gasification turns out to be €15/MWh. On-farm liquefaction is possible at a cost of €12/MWh in addition to biomethane production costs of €57/MWh. This leads to a total bio-LNG cost of €69/MWh by 2050.

11. Recommendations

The IEA report encourages International co-operation between the governments to accelerate the growth of clean hydrogen around the world and bring down the costs. Increasing renewables deployment requires an increase in electricity interconnection and collaboration between countries. This is because the potential for renewable technologies differs significantly between regions. Policy must enable industries to make the investments and adaptations necessary in order to develop a hydrogen energy economy and consider the following. Also, policies that allow different technologies to compete on an equal basis should be developed and must eliminate unnecessary regulatory barriers and harmonise standards

Targets for zero carbon gas in the European energy mix should be set. Research into implementation of hydrogen technologies should be supported to bring down the costs. Commercial demand for clean hydrogen should be stimulated and investment risks of first-movers addressed. Furthermore, investments in energy networks should be considered based on the impact of the investment on decarbonisation. Current legislative and regulatory limitations would have an impact on the CO_2 storage potential in the EU, reducing it from 104 GtCO2 to around 77 GtCO2.

Extensive communication, education and training initiatives are necessary to promote public acceptance and hydrogen and to build skills and workforce to deliver tha transition to hydrogen-based low carbon economy.

Conclusions

The time is favourable to allow hydrogen to become widely used. The IEA has identified four near-term opportunities to boost hydrogen on the path towards its clean, widespread use:

- Encourage the plants based in industrial ports to shift to cleaner hydrogen production;
- Use the natural gas network to transport hydrogen;
- Expand hydrogen in transport through fleets, freight and corridors;
- Launch the hydrogen trade's international shipping routes.

Climate scientists are convinced that some degree of negative emissions is needed to compensate for the most hard-to-abate emissions in the energy system. Remaining hard-to-abate emissions in the agriculture sector by 2050 are projected to be around 300 MtCO2 based on an ambitious scenario by the European Commission. A fuel to biogenic feedstocks such as biomethane or solid biomass combined with CCS leads to negative emissions.

It is clear that there is not one single solution that can solve all challenges with decarbonisation. In a future where zero carbon hydrogen is produced from natural gas, the gas wholesale market could continue to operate in a similar way to today. Instead of gas being used predominantly as an end use fuel, it would become mainly a feedstock for zero carbon hydrogen.

References and links

- THE FUTURE OF HYDROGEN IEA SUMMARY
- HYDROGEN FROM NATURAL GAS
- RENEWABLE AND LOW-CARBON GASFORTHE "OPTIMISED GAS" SCENARIO
- HYDROGEN AN ENABLER OF THE GRAND TRANSITION

Video : What is Green Hydrogen and wil it power the future?
https://www.youtube.com/watch?v=aYBGSfzaa4c