REA position statement on Hydrogen

Background

Hydrogen is a carbon free energy carrier with the potential to decarbonise challenging sectors (e.g. industrial clusters, heating and transport - in particular aviation, marine and heavy freight). It can also be used for large scale energy storage. Hydrogen has zero emissions at the point of use, but its upstream or "well to tank" (WtT) emissions vary considerably, depending on how it is made.

There is much interest in the role that hydrogen can play in a future energy system. In July 2020 the European Commission issued a Hydrogen Strategy to boost clean hydrogen production in Europe, setting a target of 40 GW of renewable hydrogen by 2030. It highlighted hydrogen as an investment opportunity in its economic recovery plan from the Coronavirus epidemic, 'Next Generation EU'. Some European Countries also set ambitious targets for renewable hydrogen. Last summer, for example, the German Government announced a National Hydrogen Strategy, with a 5GW target for electrolysis by 2030.

There are several projects looking at the role that hydrogen can play in decarbonising the UK gas grid and serving the energy needs of industry. There are various ways that the development of hydrogen impacts, facilitates and interacts with renewable energy and clean technology deployment and with REA members' interests.

Hydrogen production routes and GHG characteristics

The table below summarises the various different means of producing hydrogen, the terminology used and indicative ranges of emissions involved which have been reported by some published sources. The emission characteristics vary widely, from being significantly higher than natural gas, to being negative. The degree of certainty regarding some of the figures is lower for some than for others. For example, there is significant uncertainty around the emissions performance of Carbon Capture and Storage (CCS).

During 2020 Zemo Partnership carried out a literature review of the lifecycle CO_2e emissions for different hydrogen production pathways and found that there is a wide range of figures reported in published studies and a high degree of uncertainty associated with them. The Partnership is now undertaking further work to examine with more accuracy the full lifecycle emissions of H_2 from different pathways across the supply chain, in particular when this is used in transport.

As highlighted in the Industrial Decarbonisation Strategy published in March 2021, the Government is also gathering evidence on the emissions associated with different hydrogen production technologies and will work with industry to develop a UK standard that defines low carbon hydrogen (further details will be provided in the UK Hydrogen Strategy). We aim at revising the figures in the table below as new, more accurate data is published.

Production methods	Terminology	CO_2e emissions in g/MJ HHV (savings as % of natural gas in 2030)	Notes / comments
Unabated SMR of fossil fuels (mainly gas)	**Grey (sometimes "Brown" Hydrogen though this more specifically refers to hydrogen from coal gasification)**	91.[1] This exceeds that of natural gas	Not advocated for by REA, opposed to continued use of fossil fuels in this way
Molten metal pyrolysis of natural gas	**Turquoise hydrogen**	NA	This technology is still in the laboratory phase
Electrolysis using electricity produced from grid electricity	NA	This will vary according to the carbon intensity of the grid and other assumptions on the timing of hydrogen production[2].	For information, the CertifHy 2019 project[1] suggests that the threshold for which hydrogen could be regarded as low carbon is 36.4 g CO_2e/MJ
SMR of fossil fuels, with CCS	**Blue hydrogen**	13 - 20 (65% - 76%) (Inputs for calculation taken from H21 report)	Variation is according to gas source and CCS capture rate. *Note: Some members have calculated GHG emissions as high as 40 g/MJ for blue hydrogen if the feedstock is LNG or gas transported from Russia, rather than natural gas from the North Sea. This is because associated emissions such as from re-compression stages on a pipeline or from cooling gas in a tanker cannot be easily captured.*
ATR of fossil fuels, with CCS	**Blue hydrogen**	6 - 12 (80% - 89%) Inputs for calculation taken from BEIS Hynet report.	Variation is according to gas source and CCS capture rate. *See also note above re SMR plus CCS.*
Gasification of biomass	**Biohydrogen**	13 (81%) (without CCS) -89 (232%) (with CCS)	REA strongly support with CCS

[1] CertiHy 2019 Project.

[2] This relates to how the fossil fuel generation levels on the UK electricity grid fluctuates over time – so the hydrogen generated will have different levels of carbon emissions based on the time of day.

		Based on Cadent/APP/Progressive Energy report on biohydrogen[3]	
SMR of renewable methane (from biogas)	**Biohydrogen**	111 (50%) (without CCS) -125 (157%) (with CCS) These figures should be better for ATR of biogas, but we don't have figures to support this.	REA strongly support with CCS
Electrolysis using renewable electricity	**Green hydrogen**	0 (100%)	REA strongly support. *Note: emissions from green hydrogen are normally regraded as zero, though there may be emissions associated with manufacturing and maintaining solar panes and wind turbines*

Note: ATR = Autothermal reforming. SMR = Steam Methane Reforming. An explanation of the difference is reproduced at the end of this paper.

What is REA's position on the various forms of hydrogen?

It is important that carbon emissions are reduced as swiftly as possible, and there is a balance to be struck between building scale by implementing measures which are not perfect, but which can be improved, or restricting deployment to only totally zero carbon measures, which may take longer to scale up. The extent to which non-zero emission hydrogen production methods (e.g. electrolysis when the grid is not carbon free, or SMR when carried out on fossil fuel) can be viewed as acceptable to stimulate the transition, has been subject to debate. Integrating hydrogen into the energy system also has aspects of the chicken and egg question. Deployment is required in both hydrogen production and the infrastructure for hydrogen utilisation, but at the same time demand for hydrogen is required to support development of hydrogen production and infrastructure.

Only renewable sources of energy provide the opportunity to achieve zero emissions (via electrolysis), or negative emissions (via biomass with carbon capture and storage - BECCS).

Clearly **grey hydrogen** is significantly polluting in terms of GHG emissions. It is produced for a number of reasons unrelated to addressing climate change, but it clearly has no role whatsoever in addressing global climate change, as it makes the problem worse. The REA advocates a move to greener production methods, irrespective of the end use. We will gauge views from our members in due course on whether we should advocate for a phase out date for grey hydrogen in the future.

[3] Biohydrogen: Production of hydrogen by gasification of waste. An NIA assessment o Biohydrogen for production and opportunities for implementation on the gas network. Cadent, Advanced Plasma Power and Progressive Energy, July 2017.

Blue hydrogen, where the CCS element is operational, effective and permanent, is an option in the transition towards a net zero carbon economy. Overall carbon budgets are important and the sooner the emissions are reduced the better. The REA will only support a transitional role for blue hydrogen where the carbon is captured and stored or utilised in in an application where the carbon is permanently sequestered. It is crucial in our view that all the carbon is tracked, monitored, and fully accounted for, regardless of the production pathway.

Green hydrogen and **biohydrogen** – which we will refer to in this paper as **Renewable hydrogen** - are normally regarded as zero emission and the latter is potentially negative emission, if combined with CCS. The REA strongly supports these production pathways as they represent the only truly zero or negative GHG emission forms of hydrogen production.

We support the use of hydrogen in industry, power, heat, transport, especially where these sectors are particularly difficult to decarbonise by other means. Hydrogen will also have a strategic role in delivering energy storage and grid balancing services.

How does hydrogen fit in with other REA positions on decarbonising heat and transport?

Heat

We believe renewable hydrogen will be a strategic technology to decarbonise heat, especially where other already established low-carbon options are not viable.

There are other various forms of renewable heat production (biomethane, solar thermal, heat pumps, biomass, biopropane and other bioenergy) which the REA continues to support and given the scale of the decarbonisation challenge it is clear that a combination of technologies will be needed and the REA very much believes in a truly multi-technology approach. Investment and policy for hydrogen must happen, but not at the expense of other available, established low-carbon technologies that can deliver immediate carbon savings.

With respect to biomethane injection, there are several interfaces with hydrogen. Last spring BEIS sought views on whether hydrogen should be supported under the longer-term support mechanism which is expected to take over from the Green Gas Support Scheme when this ends, from 2025/26 onwards. We believe it should. The REA supports a market-based obligation for greening the gas grid. A paper on the REA website[4] describes an obligation whereby green and low-carbon gases would earn a certain number of GHG certificates or credits depending on their associated carbon intensity. Renewable hydrogen injection could be explicitly included in this. Robust carbon accounting will be required, and if a source of hydrogen does not contribute to reducing the carbon intensity of the grid, it will not be incentivised by a GHG-based obligation on the grid.

The injection of hydrogen in increasing proportions (up to around [20%] by volume) can be seen by some as justifying the continued existence of the gas distribution network in a lower carbon future world. However, it also benefits biomethane (and other renewable gases that may seek to use this infrastructure). In addition, blending is seen as crucial to provide a reliable source of baseload demand to support early low carbon hydrogen producers and to deliver earlier carbon savings.

We support the view that the existing gas grid is a valuable asset in the transition to a lower carbon energy system, to the extent that it enables reaching net zero by 2050.

[4] https://www.r-e-a.net/resources/reas-latest-position-on-a-future-green-gas-mechanism-submitted-to-beis/

The evolution should be as follows:

- Increasing amounts of biomethane replace fossil gas (and continuing to do so until ultimately the only carbon containing molecules in the gas grid are biogenic. This could ultimately entail a reduction in size of the gas grid if there is not enough zero-carbon gas to go around).
- In parallel, increasing amounts of hydrogen are injected until the 20% “blend wall” is reached
- Once the blend wall is reached, parts of the network are converted to 100% hydrogen. The remainder of the grid becomes more and more biomethane rich until fossil fuel is completely replaced.

We also think that there could be a strong role for hybrid systems, which use a heat pump most of the time, but then switch to (green) gas during stress periods.

Industry

Industrial users are likely to be early adopters of hydrogen for a number of reasons, including but not limited to the following: industrial end users are likely to have fewer cost-effective alternative decarbonisation options. In addition, it is also easier to convert to hydrogen a large appliance (e.g. a large boiler) than many small appliances, and the transportation of hydrogen is also easier to address (e.g. when the SMR plant can be built next to the industrial user).

Hydrogen is likely to play a key role in decarbonising hard-to-abate industrial sectors such as steel, ammonia, refineries and chemical plants, where other decarbonisation options such as electrification or bioenergy are not available. Hydrogen can either be used as a fuel to produce industrial high temperature process heat (e.g. in cement production), as a feedstock/chemical reagent (e.g. in ammonia or methanol production) or as a reducing agent in the production of direct reduced iron (DRI) (steel). For example, the first ‘green steel’ plant powered by hydrogen has been announced in Sweden[5].

Transport

The REA expects hydrogen to be a key transport fuel for sectors which are hard to decarbonise by other means, for example maritime, heavy duty vehicles and rail (where electrification is not possible).

Hydrogen can also be used as a feedstock for the manufacture of synthetic fuels which could play an important role to decarbonise hard-to-abate sectors such as aviation.

Although the UK government policy and the CCC favours battery electric vehicles over hydrogen fuelled cars, the latter have the advantage of being long range and fast to refuel. A technology-neutral approach to zero carbon light vehicles includes battery electric vehicles, hydrogen fuel cell electric vehicles and series hybrid range extended vehicles fuelled on 100% renewable fuel.

[5] https://www.h2greensteel.com/newsroom/h2greensteel

Electrolysis and carbon intensity of electricity

In the case of an electrolyser directly connected to a renewable energy generating station, it is clear that the power for electrolysis is renewable. The only carbon emission that could be attributed to this would be in the embodied energy in the generator (e.g. wind turbines or PV and the electrolyser itself).

When the electrolyser is taking electricity from the grid, the carbon intensity of the electricity needs to be taken into account. However, this is not necessarily straight forward. The degree to which it is temporally linked is debated, along with how to deal with future expected changes in the carbon intensity of the grid over the operating life of the plant. This is not discussed further here, but it is certainly challenging, and has been discussed internally in the context of the rules of the eligibility of grid electricity for the purposes of producing hydrogen for the Renewable Transport Fuel Obligation (RTFO). The DfT is expected to address this when it consults on the RTFO in 2021.

Power and energy storage

Electricity can be converted into hydrogen by electrolysis, and later used to generate electricity. The round-trip efficiency of this is currently lower than other storage technologies such as batteries, but the capacity is very much greater, opening up the potential for inter-seasonal storage of renewable energy via geological storage. In light of such longer duration, large scale energy storage is necessary if we are to successfully transition our power system to a net zero world and so hydrogen could play a very valuable role in the mix in a future energy system.

Carbon storage

Even when the CCS/CCUS element of blue hydrogen is operational, effective and permanent, blue hydrogen can never be zero carbon. Carbon accounting must be used to the full life cycle carbon emissions including taking into account the longevity of the storage and any methane leaks upstream of reformers, as well as the energy costs of compressing the CO_2 for storage and the emissions from the source of natural gas (e.g. extraction and distribution).

Any economic analysis should cover the full costs of the storage, including insuring the high-pressure CO_2 pipeline infrastructure against future catastrophic leaks.

CCS/CCUS is a technology applicable to storing biogenic carbon as well as fossil carbon. When combined with biohydrogen production (BECCS/BECCUS), it can deliver negative carbon emissions and is therefore a Greenhouse Gas Removal technology.

Policies to develop hydrogen

We set out below examples of key policies to support hydrogen. This is a list of possible options and would need to be explored in more detail for any follow-on consequences and efficacy, if taken further:

- A clear strategy and joined-up policy framework are required urgently to support investment and mass deployment of low-carbon hydrogen.
- The revenue support schemes being developed by BEIS under their business models work must be adequate to support investment and mass deployment of green, blue (in certain circumstances

and only as a transitionary option) as well as bio-hydrogen. The eligibility criteria being set out under the schemes must be pragmatic and not act as a barrier to investment and development of zero and negative emissions hydrogen projects.

- Exempting electrolysers from 'green levies' on electricity bills - i.e. electrolysis could be on the list as energy intensive users, thereby qualifying such sites for exemption from the indirect costs of funding Contracts for Difference (CFDs), the Renewables Obligation (RO) and the small scale Feed in Tariff (FIT).
- Exempting electrolysers that provide grid services from use of system fees (on a time limited basis), or adopting a system akin to the new rules for grid balancing charges borne by energy storage assets – i.e. on a net usage basis (exemption from final consumption levy double charging like storage devices).
- Business Rates could also be reduced or removed for early adopters, to speed adoption. Tax efficient restrictions (EIS, VCT ineligibility) should be removed from hydrogen production from renewables. Positive tax treatment should become a priority as a lot of capital is required to decarbonise and small schemes should be encouraged where local people/communities should know the government supports their investment.
- Introduce a GHG based mechanism to follow on from the Green Gas Support Scheme, as described in the paper (referred to earlier) on the REA website[6]. This could be linked with national quotas/targets for renewable hydrogen injection into the gas grid, for 2025, 2030 and onwards.
- Amend the Gas Safety (Management) Regulations 1996 (GSMR), or at least grant an exemption for H_2 injection, to allow 10% to be added.
- The Gas (Calculation of Thermal Energy) Regulations (CoTER) and billing methodology also need revising to allow blending of hydrogen into the network without the need to add significant propane.
- Amend the Gas Safety (Management) Regulations 1996 (GSMR), or at least grant an exemption
- Create capacity in the distribution network to allow hydrogen to be injected.
- Amend the Renewable Transport Fuel Obligation to enable more flexible rules for qualification of renewable electricity for making renewable hydrogen. Also provide adequate support for biohydrogen.
- Waive VAT on renewable hydrogen for transport applications until 2030, or charge at the lower rate of 5% (as applied to Energy Saving Materials).
- Take into account the use of renewable hydrogen as an intermediate product for the purpose of calculating renewable energy targets (as per Article 25 of the EU's RED II Provisions).
- Consider defining permissible ownership and operating models for Power to Gas (P2G) so that renewable hydrogen can be injected into gas networks (either legislation is required to establish rules for third party P2G operators on a commercial basis, or legislation to make P2G part of the regulated asset base).

[6] https://www.r-e-a.net/resources/reas-latest-position-on-a-future-green-gas-mechanism-submitted-to-beis/

- Collaboration is required between BEIS and DfT around hydrogen to better understand where the greatest demand for hydrogen will come first and ensure a joined-up approach is adopted across Government.

V1, March 2021

Annex

The difference between SMR and ATR Hydrogen Production

SMR (Steam Methane Reformation) and ATR (Autothermal Reforming) are two alternative routes of hydrogen production. ATR is more suited to the removal (and subsequent storage) of CO2. An explanation of the difference between the two processes is given below [7]

Reformer

In the reformer the methane is converted into syngas, a combination of carbon dioxide and hydrogen gas, using heated steam. ATR and SMR use different techniques for the reforming step.

a Steam methane reforming (SMR)

In a SMR reforming step a mixture of hydrogen and carbon monoxide is produced using an endothermic reaction. The process operates in a range of 500-900°C for which heat is generated via the burning of natural gas. Capturing the CO_2 of these flue gasses outside the reformer is difficult, among other because of the large nitrogen percentage and lower operating pressure.

The chemical reaction of the process is: $CH_4 + H_2O \leftrightarrow CO + 3H_2$ (endothermic)

b Autothermal reforming (ATR)

ATR produces hydrogen via an endothermic and exothermic reaction creating a heat balance. The process temperature is between 900-1,150°C. ATR requires oxygen as input, however does not require the burning of natural gas for heat input. All the CO_2 is contained in the reactor at elevated pressure enabling high-capture percentages.

The chemical reactions for the process are:

$CH_4 + H_2O \leftrightarrow CO + 3H_2$ (endothermic)

$C_mH_n + \frac{m}{2}O_2 \leftrightarrow mCO + \frac{n}{2}H_2$ (exothermic)

[7] CE Delft, Hydrogen Report, July 2018, https://www.cedelft.eu/en/publications/download/2585