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The hydrogen economy fairytale†

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We present a quantitative and realistic analysis of the current situation of hydrogen production worldwide. Subsequently, we calculate the thresholds needed for applying so-called "green hydrogen" as an energy carrier on a scale that would make a sizeable change in the world energy market. Using a simple back-of-the-envelope calculation, we show that green hydrogen cannot account for even 10% of the world energy demand by 2050. Considering also the time and investment required for building a worldwide green hydrogen infrastructure, we conclude that the hydrogen economy narrative, while elegant and desirable, has no basis in reality in the 21st century.

Green foundation

1. We discuss the feasibility of the hydrogen economy becoming a reality in the 21st century, based on simple economic and chemical calculations.

2. Many people are interested in the hydrogen economy. Some even think, mistakenly, that it is on our doorstep. Our realistic analysis shows that this is not the case.

3. Most likely, the future of the field of world energy demand in the coming decades will be fossil-carbon based, with an increasing role for wind and solar power. However, because of the growing demand for energy, especially by 2.5 billion people in Africa and Southeast Asia, the overall energy demand in the world will increase such that all energy sources will have to be utilised. Green hydrogen will not become a main energy carrier in this century. This might not be what people would like to hear, but it is the truth. Knowing the facts will help people steer towards a better future.

Introduction

Anthropogenic emission of CO_2 is one of mankind's most pressing problems.[1] It causes weather extremes, accelerates sea level rising, and damages ecosystems.[2] These emissions are caused by our burning of fossil fuels. In 2023, 80% of the global primary energy supply came from coal, oil, and natural gas, with over 37 billion tonnes of CO_2 emitted.[3,4] The total emissions of greenhouse gases (GHGs) topped 53 billion tons of CO_2-equivalents.[5]

Yet fossil fuels are not just energy sources, but also energy carriers. Any plan for phasing them out requires an alternative carrier. Hydrogen was already proposed as an alternative over a century ago by Haldane.[6] The term "Hydrogen Economy" was coined in 1972 by Bockris, who envisaged hydrogen production based on atomic power, and using it directly as a fuel for producing electricity in fuel cells and as a reductant and source of hydrogen for the chemical industry.[7] Since then, the Hydrogen Economy concept has gained popularity, thanks to a narrative based on five simple facts:

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†Electronic supplementary information (ESI) available. See DOI: https://doi.org/10.1039/d5gc00946d

• Hydrogen is the most abundant element in the universe;

• It is easily produced from water by electrolysis;

• When burned, in a combustion engine or in a fuel cell, it produces only energy and water vapor;

• Its gravimetric heating value is higher than that of natural gas, gasoline or diesel;

• The energy for making hydrogen can come from sunlight or wind (free and renewable energy sources).

This narrative carries a powerful message: Given enough wind turbines and/or photovoltaic cells, the world economy can run on hydrogen, with no fossil fuels and zero carbon emissions.

The problem is that this is only a good story. Hydrogen *is* the most abundant element in the universe, but there is no free hydrogen available on Earth. You *can* easily produce it from water by electrolysis (and many kids do so in school experiments), but large-scale electrolysis is simply too expensive. Its gravimetric energy density is very high, but unfortunately hydrogen is a gas, and its *volumetric* energy density is very low (see Table 1). And while it is true that given enough wind turbines and/or photovoltaic cells the world could run on hydrogen, the question is how much time and money would it cost to build these turbines and what is the alternative cost?

In this paper we compare the chemistry, thermodynamics and energy costs for producing hydrogen from fossil fuels and

Table 1 Energy densities of various fuels[8,9]

Fuel[a]	Energy density	
	Gravimetric (W h kg^{-1})	Volumetric (W h L^{-1})
Hydrogen	33.360	3
Hydrogen[b]	33.360	981
Hydrogen[c]	33.360	1659
Hydrogen[d]	33.360	2805
Natural gas	14.900	10
Gasoline	12.900	9500
Diesel	12.620	9611

[a] At 298 K and 1 bar, unless noted otherwise. [b] Compressed to 350 bar. [c] Compressed to 700 bar. [d] Liquified at 20 K and 1 bar.

renewable resources. We analyze the current situation of hydrogen production worldwide, examining the practical possibilities for making green hydrogen (defined as hydrogen made by water electrolysis using renewable energy) on a large scale. Subsequently, we compare the hydrogen production options in the US, Europe and China and examine the ambitious goals for renewable hydrogen, set by the US department of energy (1 US$ per kg H_2 in 2031), and the European Union (2.2 $ per kg H_2 by 2030).[10,11] Based on this data, we predict the likelihood for large-scale green hydrogen production in the coming decades.

Results and discussion

Comparison scales and nomenclature

A key difficulty in the discussion of the energy transition in general and hydrogen in particular is that different studies use different units. Energy and power are mixed, and units are hard to compare (MJ, kWh, toe and BTU are a few common examples). Moreover, many studies present relative values, rather than absolute ones. Even when such reports are written in good faith, this practice can be misleading. For clarity, we use here only three units: Watt (W) for measuring the rate of power, Watt-hour (Wh) for measuring energy, and US$ per kg ($ per kg) for measuring cost per amount. All other units are converted into these. A conversion table between all the major units used is included in the ESI.† Further, we present absolute numbers, rather than percentages (*e.g.*, "in 2023 there were 28.677 on-shore wind turbines operating in Germany, with a total capacity of 61.010 MW, compared to 53.912 MW in 2019", rather than "on-shore wind turbine capacity in Germany increased by 13% from 2019 to 2023").

The current situation

In 2023, 97 million tons of hydrogen were produced worldwide. Of these, 93.1 million tons were produced using fossil-carbon resources, mostly natural gas and coal. To put this in perspective, the energy needed for producing this much hydrogen is roughly equivalent to the annual energy consumption of Germany.[12,13] These 97 million tons are equivalent to 3.201.000 GW h or 3.201 TW h of energy. Again, this may

sound like a lot, but it is <2% of the world energy consumption, which was 183.000 TW h in 2023.[13] Of this total, less than 1 million tons were low-emission hydrogen (in combination with carbon capture and storage, CCS) and only 100.000 tons were green hydrogen (Fig. 1). Nearly half of the hydrogen produced today is used in petroleum refining. Another third is used for making ammonia.[12]

In a hydrogen economy, hydrogen would be used as an energy carrier. Not all processes would run on hydrogen – many sectors could be electrified directly. The ones that cannot are steel production (5% of the world energy demand),[14,15] shipping (3%, expected to double by 2050),[16] aviation (3%), and seasonal energy storage (10–15%).[17,18] Hydrogen would therefore have to account for at least 20% of the world energy demand, or 36.000 TW h in 2023 terms (giant circle in Fig. 1). Note that for mobile applications, the low volumetric energy density is a problem. This can be solved by compression, liquefaction or by converting it into chemicals that can release hydrogen on-demand.[19] However, this increases both infrastructure and operational costs.

Hydrogen production methods

Hydrogen can be produced from fossil resources such as oil, coal, and natural gas. Natural gas, which is mostly methane, has the highest hydrogen content.[20] It is also an abundant resource: In 2022, proven global reserves topped 180 trillion m^3, enough to meet current production rates at least until 2070.[13] Methane is the most common feedstock for making
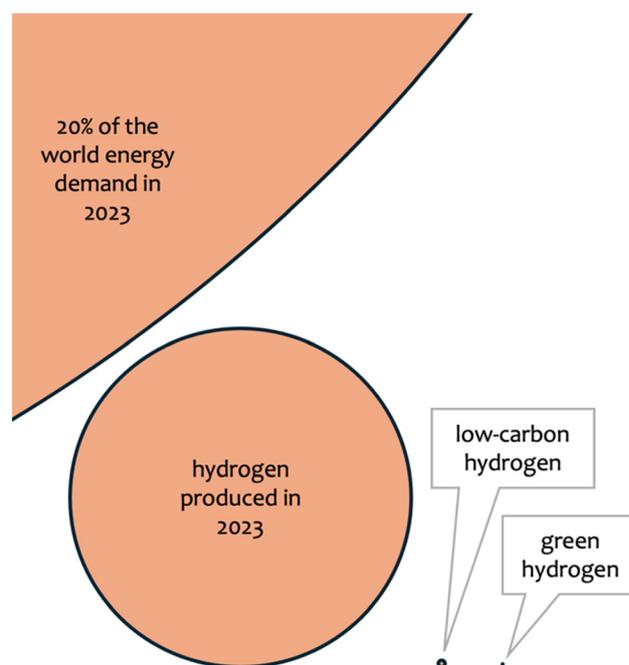

Fig. 1 Four circles, drawn to scale, showing 20% of the world energy demand in 2023, the amount of hydrogen produced, and how much of this is low-emission hydrogen and green hydrogen, respectively. The diameter of the circle representing 20% of the world energy demand is 50 cm on this scale.
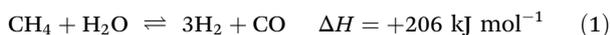
hydrogen, accounting for 62% of global production, and 95% of the hydrogen produced in the US.[12,21]

Hydrogen is also produced from coal, *via* energy-intensive gasification with steam. Coal gasification accounts for 20% of global hydrogen production.[12] China, which has large coal reserves but relatively little oil and gas, is by far the biggest player in this field, using it for almost two-thirds of its hydrogen.[12,22] Worldwide coal reserves are even more abundant than natural gas, and are estimated to last well over 100 years at the current usage rate.[13]

Although biomass is a sustainable feedstock for producing hydrogen, it has two critical drawbacks. First, it contains only 6 wt% hydrogen.[23] Second, it contains roughly 50% carbon,[24] much of which is bound to oxygen atoms. This lowers the utility of biomass gasification compared to coal. Similarly, biological and photochemical hydrogen production methods are excluded, as these low-TRL methods are not applicable on any scale >50 ktpa.[25,26]

Steam methane reforming (SMR)

This process accounts for nearly half of the global supply of hydrogen today.[27] It converts natural gas and steam into syngas (eqn (1)). The CO can be further reacted with water to give H_2 and CO_2 in the water gas shift reaction (WGSR, eqn (2)).[28] The combined process gives four equivalents of hydrogen per equivalent of methane (eqn (3)), and emits (on paper) 5.5 kg of CO_2 per kg H_2.

$$CH_4 + H_2O \rightleftharpoons 3H_2 + CO \quad \Delta H = +206 \text{ kJ mol}^{-1} \quad (1)$$

$$CO + H_2O \rightleftharpoons CO_2 + H_2 \quad \Delta H = -41.2 \text{ kJ mol}^{-1} \quad (2)$$

$$CH_4 + 2H_2O \rightleftharpoons CO_2 + 4H_2 \quad \Delta H = +164.8 \text{ kJ mol}^{-1} \quad (3)$$

eqn (1) is endothermic, with ΔH = +206 kJ mol^{-1}.[29] It typically runs at 700–800 °C and 20–35 bar, in the presence of Ni/Al$_2$O$_3$ catalysts.[30,31] eqn (2) is exothermic, ΔH = −41.2 kJ mol^{-1}. Although it does also occur during the SMR, the WGSR is usually performed at a lower temperature in separate reactors, using Fe$_2$O$_3$ and CuZnO catalysts.[32] The product mixture (75–80% H$_2$, 15–25% CO$_2$, a few percent of CH$_4$ and CO, and trace N$_2$) is then separated using pressure swing absorption.[33] A hydrogen purity of 99.9% can be achieved,[34] and the total SMR process produces on average 9.1 kg of CO$_2$ per kg H$_2$.[35]

Autothermal reforming (ATR)

The intrinsic energy need of SMR requires external energy, which is provided by burning methane. Another option is the partial oxidation (POX) of methane (eqn (4)). This exothermic reaction can provide energy to keep the reforming process running, while also producing two equivalents of hydrogen.[36]

$$CH_4 + \frac{1}{2}O_2 \rightarrow 2H_2 + CO \quad \Delta H = -22.6 \text{ kJ mol}^{-1} \quad (4)$$

POX typically runs at high temperatures, 1200–1500 °C.[37] A catalytic alternative using nickel-based catalysts can reduce the temperature to 800–900 °C, but the catalysts suffer from coking and sintering.[37,38] These catalysts can also catalyse SMR, so hydrogen can be produced simultaneously from both processes in a single reactor, by introducing oxygen in the stream. Just like in SMR, POX can be followed by the WGSR (eqn (2)).

Combining SMR and POX into a thermally neutral process is called autothermal reforming (ATR). Since both POX and WGSR are exothermic, they can offset the energy requirement of the SMR process. Theoretically, an energy-neutral ATR can produce 3.3 equivalents of hydrogen per mole of methane (eqn (5)), with a corresponding CO$_2$ production of 6.6 kg per kg H$_2$.

$$CH_4 + 1.30H_2O + 0.35O_2 \rightarrow 3.30H_2 + CO_2 \quad \Delta H = 0 \text{ kJ mol}^{-1} \quad (5)$$
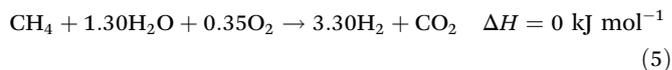
ATR requires a careful monitoring of the oxygen to carbon ratio, to limit the combustion of methane to CO$_2$. The process requires a stream of oxygen gas, which is produced with an air separation plant, at an added energy cost.[39] Hydrogen is then isolated from the gas stream using pressure swing absorption, leading to a 99.9% pure hydrogen stream, the total process emits 8.4 kg of CO$_2$ per kg of hydrogen.[35]

Coal gasification (CG)

This process has two steps. First, the coal is reacted with water to give syngas (eqn (6)). Then, to produce more hydrogen, this reaction is followed by WGSR (eqn (2)), giving a total conversion to CO$_2$ and hydrogen (eqn (7)).[40]

$$C + H_2O \rightarrow H_2 + CO \quad (6)$$

$$C + 2H_2O \rightarrow 2H_2 + CO_2 \quad (7)$$

CG is generally performed above 900 °C, and any quality of coal can be used.[41] The process is well established (the Wrinkler gasification process was commercialized already in 1926[42]). Of the fossil-carbon based methods, CG emits the most CO$_2$ at 11 kg per kg of hydrogen produced. Actual emissions, including heating and operating energy, are *ca.* 20.8 kg CO$_2$ per kg H$_2$.[43]

Natural gas decomposition (NGD)

Thermal decomposition of methane yields solid carbon and hydrogen, avoiding CO$_2$ emission (eqn (8)). The reaction is endothermic, requiring temperatures above 1200 °C. Catalytic decomposition can lower this to 450–750 °C.[44] The catalysts are nickel- or iron-based, commonly promoted with cobalt.[45] But just like with SMR and ATR, these catalysts deactivate by sintering and coking. At lower pressure, the equilibrium favors hydrogen production. To decrease the methane partial pressure nitrogen is co-fed into the reactor (this is more efficient than operating at sub-atmospheric pressures).[46]

$$CH_4 \rightarrow 2H_2 + C \quad (8)$$

NGD produces 3 kg of carbon per kg H$_2$. The carbon byproduct can be stored permanently, avoiding any CO$_2$ emissions.

It can also be sold, offsetting some of the production cost of the process, but the worldwide demand for such carbon is only 15 million tons.[47] The emissions of process heating using natural gas are 1.5 kg CO_2 per kg H_2.[48]

Electrolysis

Electrochemical water splitting (eqn (9)) was already used commercially in the 1890s to generate hydrogen for airships.[49] Water electrolysis involves two half-reactions, the cathodic hydrogen evolution reaction (HER) and the anodic oxygen evolution reaction (OER). It is done in an electrochemical cell, comprising an anode, a cathode, a separator or membrane, and a (liquid or solid) electrolyte that facilitates charge transfer.[50–52] For scale-up purposes, the electrochemical cells are assembled in a so-called stack.

$$2H_2O \rightarrow 2H_2 + O_2 \tag{9}$$

Stoichiometrically, making 1 kg of hydrogen requires 9 kg of water. Deionised water is used to optimize electrode lifetimes.[53] The energy needed for electrolysis is supplied by electricity, and the efficiency is described by the electrical power input per kilogram of hydrogen (Wh kg^{-1} H_2).[54]

Alkaline water electrolysis (AWE)

This is the most mature water splitting technology.[55] It relies on the transport of OH^- ions (generally supplied by dissolving KOH in water) for charge transfer between the electrodes. The two half-reactions are catalyzed by a nickel cathode and a cobalt oxide anode, respectively (eqn (10) and (11)).[50] A diaphragm that facilitates the transport of hydroxide ions separates the two half-cells. This diaphragm minimizes the distance between electrodes, while preventing hydrogen crossover. Most AWE systems use Zirfon® diaphragms, a polysulfone material containing ZrO_2 particles.[56]

Cathode:

$$2H_2O + 2e^- \rightarrow H_2 + 4OH^- \tag{10}$$

Anode:

$$4OH^- \rightarrow 2H_2O + O_2 + 4e^- \tag{11}$$
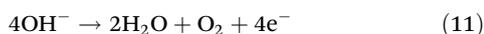
AWE electrolyzers can generate hydrogen of >99.99% purity at industrial scale. A typical electrolyzer produces hydrogen with a 76% efficiency, corresponding to 52 kWh kg^{-1} H_2.[57]

Proton exchange membrane (PEM) electrolysis

This system was developed by General Electric in the 1960s to overcome current density limits with AWE systems.[51] Unlike AWE, it uses an acidic medium, which is highly corrosive, requiring noble metal electrodes.[58] The HER is catalyzed by platinum, where protons are reduced and adsorbed on the surface, combining to form hydrogen (eqn (12)).[51] The OER (eqn (13)) is done using an iridium oxide (IrO$_2$) catalyst.[59]

Cathode:

$$2H^+ + 2e^- \rightarrow H_2 \tag{12}$$

Anode:

$$2H_2O \rightarrow O_2 + 4H^+ + 4e^- \tag{13}$$
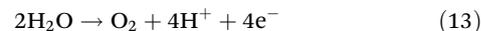
The proton transfer membrane is usually made of Nafion®, a stable copolymer[51] comprising a tetrafluoroethylene backbone, with perfluorovinylether side-chains terminated with sulfonate groups.[60] Nafion membranes give less crossover than AWE diaphragms, leading to higher H_2 purities (>99.999%). PEM can give a higher current density compared to AWE (1.5 A cm^{-2} and 0.5 A cm^{-2}, respectively[61]), but the bottleneck is the need for iridium. There is simply not enough iridium available for large-scale PEM electrolysis. Developments in iridium recycling are ongoing, but meeting iridium demand for a large-scale PEM industry requires a reduction of the catalyst loading from 700 kg per GW to 50 kg per GW. This will not happen in the foreseeable future.[59,62]

Solid oxide electrolysis cells (SOEC)

In this method, electrolysis is performed at higher temperatures (700–900 °C) converting steam to hydrogen.[63] The oxide anion (O^{2-}) is used as the charge carrier, transported through a ceramic electrolyte (usually yttria substituted zirconia, YSZ).[52] The cathode is typically a ceramic compound of the electrolyte with nickel (Ni-YSZ), which converts steam to hydrogen (eqn (14)).[64] At the anode, where the O^{2-} ion is oxidized (eqn (15)), a strontium-doped lanthanum material is generally used.[52]

Cathode:

$$H_2O + 2e^- \rightarrow H_2 + O^{2-} \tag{14}$$

Anode:

$$2O^{2-} \rightarrow O_2 + 4e^- \tag{15}$$
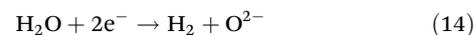
The higher operating temperature of SOECs improves process efficiency. Energy consumption is significantly lower than AWE or PEM systems. The electrolysis stacks take the majority of the energy but are near 100% efficient, although additional energy is needed for heating. To improve efficiency, SOECs can be coupled with other industrial processes, utilizing waste heat streams. Industrial production utility of hydrogen using SOECs is roughly 45 kWh kg^{-1} H_2 for a water feedstock, going as low as 40 kWh kg^{-1} H_2 when steam or waste heat is supplied from other industrial processes.[65,66]

Comparing economic viability

We use a simple model to calculate the production costs (in $ per kg H_2, see details and calculation examples in the ESI†) based on the prices of natural gas, coal, and electricity (the cost of water was fixed at 0.33 $ per m^3 and has a negligible effect[67,68]). The natural gas cost estimates in North America, Asia and Europe were done using the prices at the Henry Hub (Henry), the Japan/Korea marker (JKM), and the Title Transfer Facility (TTF) Dutch gas trading platform, respectively. For

comparing fossil-carbon-based methods, we fixed the industrial price of electricity at the global average of 12.7 $ per MWh (September 2023).[69] Fig. 2 shows the cost of hydrogen in different regions depending on the cost of natural gas, as well as the average price of natural gas in 2023. For SMR and ATR we also show the combination with carbon capture and storage (CCS). As carbon-based hydrogen is produced through mature technologies, we assume that the future production costs will depend mainly on the price of fossil fuels.

Looking at Fig. 2, we see that at lower natural gas prices, SMR is most cost effective, but as natural gas prices increase above about 8 $ per GJ, ATR becomes the more attractive option. This comes from the trade-off of higher capital cost with higher thermal efficiency, leading to a decreased natural gas consumption compared to SMR.[71]

Fig. 3 shows the analogous case for coal. We see that producing hydrogen by coal gasification is cost-effective at current coal prices in Europe (Antwerp–Rotterdam–Amsterdam, ARA), the US, and South China.[72] Note that making hydrogen *via* coal gasification is cheaper than using natural gas in both Europe (TTF, ARA) and China (JKM, South China).

The effect of carbon taxes

Carbon taxation strongly influences the final production costs, and can increase the economic viability of green hydrogen. Currently, there is no carbon tax in the US or in China. However, several European countries implement a carbon tax, ranging from $2/ per t CO_2 in Estonia up to $120 per t CO_2 in Switzerland.[73] Fig. 4 shows the European case where low-carbon hydrogen (using carbon capture and storage) becomes competitive at a carbon tax of approximately 60 $ per t. From
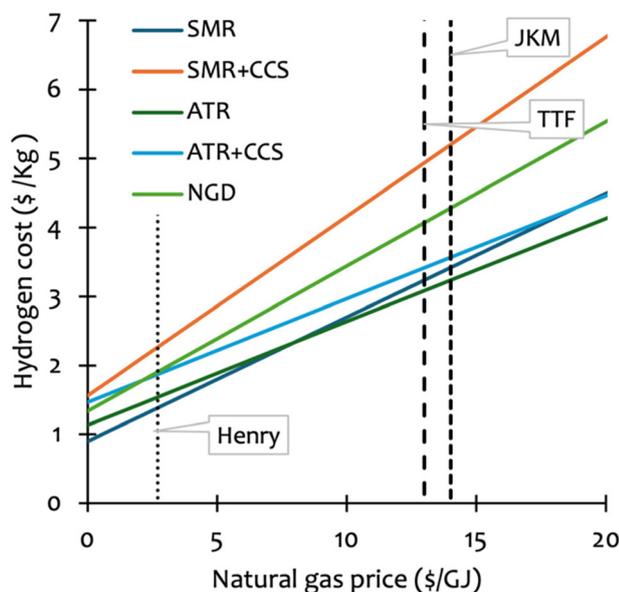

Fig. 3 The cost of hydrogen produced through coal gasification in $ per kg H_2, depending on the coal price per metric tonne, with the coal price marked in the US (149 $ per mt), Europe (ARA, 119 $ per mt) and China (South China, 100 $ per mt).[72] Figure based on data from ESI.†

Fig. 4 The effect of carbon taxation on the cost of hydrogen, based on natural gas prices in Europe (13 $ per GJ), coal prices (119 $ per t), and levelised cost of electricity (LCOE, 0.130 $ per kWh).[3,70,71] The percentages with CCS represent the fraction captured. Figure based on data from ESI.†

Fig. 2 The cost of hydrogen in US dollars, depending on natural gas price. With the 2023 average natural gas price at the Henry hub (Henry, 2.7 $ per GJ) the Japan Korea Marker (JKM, 14 $ per GJ) and the Title Transfer Facility (TTF, 13 $ per GJ).[70] Figure based on data from ESI.†
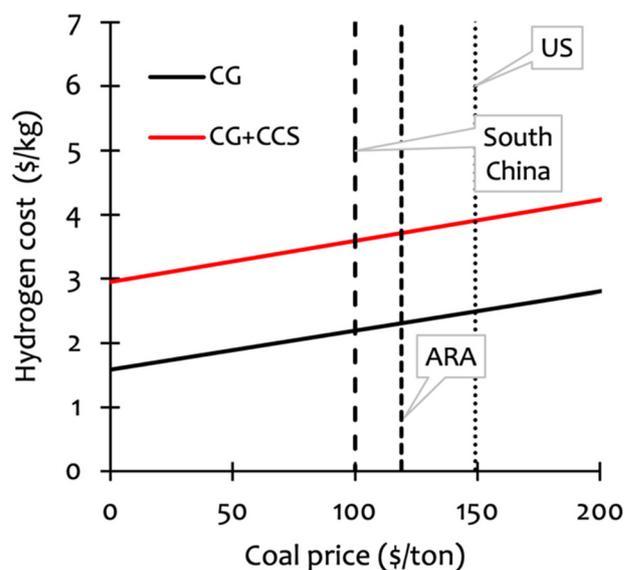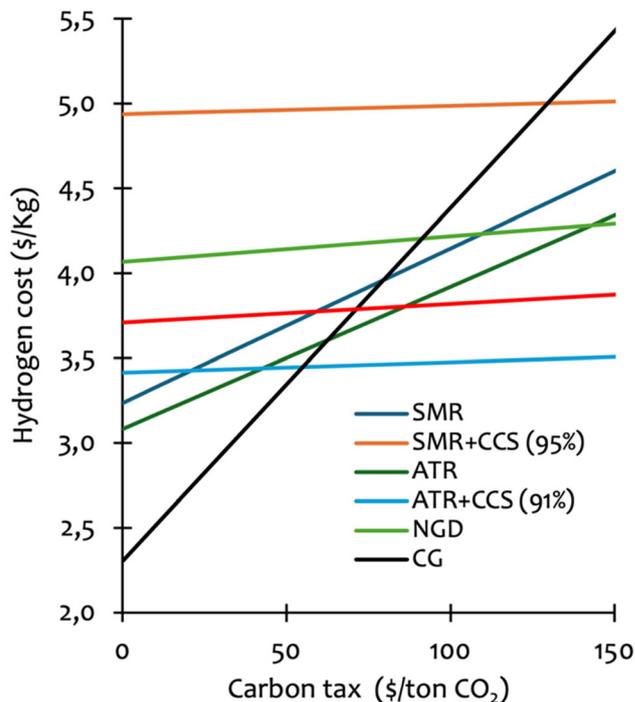
that point onward, ATR with CCS becomes the most cost-effective method of producing low-carbon hydrogen from fossil-carbon in Europe. This is one reason why it is the pre-

ferred low-carbon hydrogen production method in the port of Rotterdam, where the current carbon tax is $80 per t CO_2, and expected to increase to $140 per t CO_2 in 2030.[74,75] Taking the 2023 average prices for coal and natural gas, we see that CO_2 taxes would need to surpass 80 $ per t for ATR-CCS to become the most attractive method in the US. For China CG-CCS becomes the financially preferred method at a tax rate of 70 $ per t CO_2 eq. Carbon taxes are sensitive to political changes. For example, they were repealed by new governments in Australia and locally in Alberta, Canada.[76,77] The resulting uncertainty drives investors away from large-scale green hydrogen projects.[78]

The viability of green hydrogen

The cost of hydrogen produced through water electrolysis depends on fixed costs and on the cost of electricity. The former depends on the capital expenditure (CAPEX) as well as operating costs and plant lifetime. Fixed costs are expected to decrease as technology improves and production scales up.[79,80] Fig. 5 shows the current hydrogen production cost, depending on the price of electricity and assuming production at full capacity. We see that hydrogen from AWE is cheaper at lower electricity costs, but is overtaken by SOEC with waste heat at higher energy prices, as that needs significantly less energy. However, electrolysis is more expensive compared to carbon-based methods, when coupled with grid electricity. This could be addressed by using other sources of energy, directly coupled with the electrolysis systems. In the US, EU, and China, the levelized cost of energy (LCOE) is lowest for onshore wind power, with respectively 0.04, 0.06, and 0.045 $

Fig. 5 Calculated cost of hydrogen produced through different electrolysis technologies, depending on the regional levelised cost of electricity (LCOE). Data based on current costs of technology, and assuming production at full capacity. See ESI for calculation details.†

per kWh.[3] But even at this price, green hydrogen cannot compete with fossil-carbon-based hydrogen in China and the US.

Another issue is the intermittent availability of Wind and solar power for hydrogen production. This requires compensation through higher production capacity. For example, if solar or wind power is available 20% of the time, a five-fold increase in electrolyzer capacity is needed. Of the available options, wind turbines offer an optimum between energy cost and availability (geothermal energy is continuous, but comes at triple the cost of wind power[81]).

A typical modern wind turbine is about 100 meters high, generates 2 MW, costs about $2.5 million and weighs about 200 tons. Large offshore turbines can generate up to 15 MW, cost about $13 million and weigh 500 tons.[82] Operational capacity depends on the wind available, but the average across wind farms is about 65%. With 8640 hours in a year, a 2 MW wind turbine generates typically $2 \times 8640 \times 0.65 = 11.232$ MW h or 11.2 GW h every year.

An ideal electrolyzer would require 39.4 kilowatt hours (kWh) of electricity to produce a kilogram of hydrogen. Typical real-life values are *ca.* 50 kWh kg^{-1} H_2. Based on this, meeting the 2023 world demand of 97 million tons *via* electrolysis would require 4.850 TW h, or 434.000 wind turbines. The installed world wind turbine capacity in 2023 was 5.879 TW h.[83] So in theory, if nearly all the wind power worldwide would be used for making hydrogen *via* electrolysis, it could cover the 97 million tons. But this is only in theory. In real life, <100 TW h of renewable energy was used for making hydrogen in 2023.[12]

Even the theoretical capacity for making green hydrogen is still a far cry from the transition to the hydrogen economy. A 20% share for hydrogen as an energy carrier would require 36.000 TW h. This would mean a six-fold increase of the number of wind turbines worldwide, to 2.5 million turbines. At the current rate of installation, this will take 50 years (in 2023, a record of 100 GW were installed, which equates to 50.000 turbines of 2 MW).[83] But since the average lifetime of a turbine is 20 years, the installation capacity will have to double every 20 years to increase the numbers of turbines thereafter. Reaching the 20% hydrogen threshold by 2050, or indeed even by 2060, is unrealistic. In fact, considering that in 2023 green hydrogen accounted for only 0.05% of the world energy demand, reaching even a 10% share by 2050 is unrealistic.

Other regions

The Middle East and North Africa (MENA) have abundant solar possibilities. The problem is that they are also rich in oil and gas. Low fossil fuel prices limit the development of renewables. Furthermore, improving living standards are increasing energy consumption in MENA by 3% annually.[84] Renewable energy will be used to fulfill increasing demand, before attempts are made to phase out fossil-carbon based energy. Similarly, Australia has significant renewable energy potential. It is projected to produce up to 3 million tpa of green hydrogen by 2040, and could export this hydrogen to resource-strained
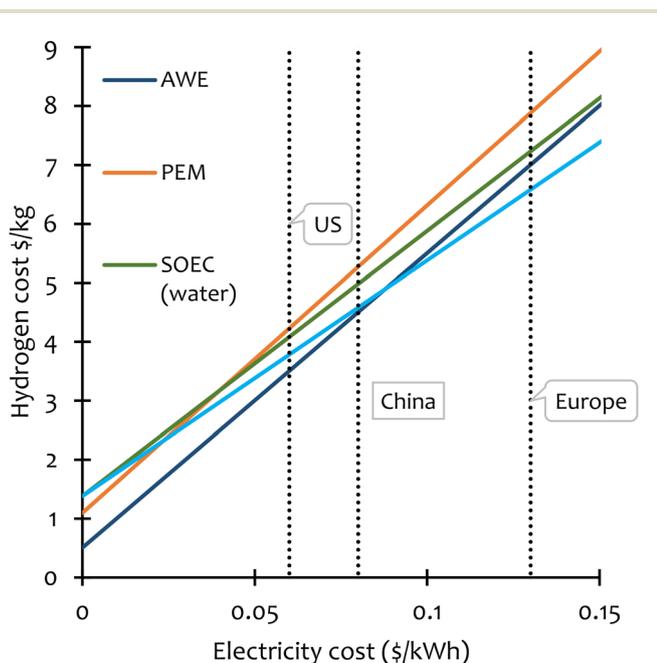
trading partners such as South Korea and Japan. But this is only 3% of today's hydrogen market.[85]

The outlook for hydrogen in the coming decades

Today, fossil-carbon based hydrogen is the most cost-effective. In the US, low natural gas prices make SMR the most attractive option. In Europe, the geopolitical situation has strongly influenced natural gas prices.[86] As a result, CG is followed by ATR in producing the lowest-cost hydrogen. However, if CO_2 emissions are taxed at 60 $ per t, ATR-CCS becomes cheaper. In China, the difference between coal and natural gas prices is even larger, making CG the cheapest method. Green hydrogen is not competitive.

By 2030, US natural gas prices at the Henry Hub are expected to rise to 5.13 $ per GJ.[87] SMR would still be the most cost-effective production method, at just under 1.5 $ per kg H_2. The European price of green hydrogen is expected to be on-par with today's ATR-CCS production methods, when emissions are taxed at >60 $ per t CO_2 eq. However, when the current geopolitical tensions ease, the European and Asian natural gas prices are expected to move towards about 7.60 $ per GJ.[88] This means that in Europe, SMR would be the cheapest method of producing hydrogen, but if CO_2 taxes would exceed 70 $ per t, ATR-CCS will be the most cost-effective. In China, lower natural gas prices result in similar costs for SMR and CG (1.85 and 1.79 $ per kg H_2, respectively). A carbon tax of 70 $ per t would make hydrogen *via* ATR-CCS the cheapest. Green hydrogen would remain uncompetitive.

By 2040, US natural gas prices are expected to increase to 6.22 $ per GJ.[87] If European and Asian gas prices follow a similar trend from 2030 onwards, natural gas would cost about 9.21 $ per GJ. Carbon-based hydrogen would still remain the cheapest option.

Conclusions

Current hydrogen production is based on demand from the petroleum refining and ammonia sectors, not as an energy carrier. Decarbonizing industrial sectors or transportation requires large-scale investment and long-term worldwide government support, neither of which are available.

The hydrogen economy narrative glosses over the barriers for building the required infrastructure. It assumes a joint global commitment and a surplus of cheap renewable energy. In reality, world energy demand will only increase in the coming decades. India, Africa and South America are home to over 40% of the world's population, yet account for only 13% of its energy demand. To reach the same quality of life as in Europe or North America, their energy footprint would have to increase five-fold. This means that the world will continue using all available energy, irrespective of its source.

The ambitious green hydrogen goals of the US Government and the European Union are unrealistic. With no clear and convincing business case, there is no incentive for large-scale investment in water electrolysis. The low cost and abundance

of fossil fuels, and the absence of a unified worldwide carbon tax policy rule out any chance that green hydrogen would account for even 10% of the world energy demand by 2050. Even if there were a clear incentive by then, building a worldwide green hydrogen infrastructure would take decades. Fairytales are nice, but in reality there will be no hydrogen economy in the 21st century.

Methods

The methods and models used for calculating the hydrogen production costs, as well as example calculations and a full set of parameters and their sources are included in the ESI.†

Data availability

The data supporting this article have been included as part of the ESI.†

Conflicts of interest

There are no conflicts of interests to declare.

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