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The future of solar fuels: when could they become competitive?†

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Solar energy driven processes with H₂O and CO₂ as basic feedstocks can produce “solar fuels” that could substitute their fossil based counterparts. This article summarizes the main findings of a techno-economic analysis of systems that can generate different types of fuels with renewable energy as starting point. These “renewable fuels” could potentially play a key role in future energy systems, both as a storage medium in the power sector and as an energy carrier in e.g. the transport sector, or deliver fundamental building blocks for the chemical industry. We determine whether, how, and when renewable fuels might become competitive alternatives for fossil fuels. The technologies required to produce renewable fuels are analyzed by the application of learning curves associated with individual system components. We thereby make projections for possible decreases in investment costs and reductions in fuel production costs. In an optimistic scenario we find that competitiveness could be reached between 2025 and 2048 for all renewable energy production pathways that we investigate, for hydrogen, syngas, methanol, and diesel. Two techniques yield break-even costs before 2050 even in a conservative base case scenario: H₂ production through electrolysis and diesel production by Fischer–Tropsch synthesis. Both processes use solid oxide electrolysis, which profits from rapid cost reductions and high efficiency.

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Broader context

Although fossil fuels constitute ideal energy carriers in several ways, their combustion emits CO₂ into the atmosphere. To avoid the detrimental climate change impacts from emissions of this greenhouse gas, mankind has to look for renewable energy sources that preclude the use of fossil fuels. To date, most approaches that harvest renewable energy produce electricity. However, energy carriers with a high volumetric energy density may still be required, e.g. in the transport sector, for energy storage solutions, for heavy-duty industrial processes, or as feedstocks for the chemical industry. We investigate the prospects for a fast and efficient process to produce energy carriers with the same properties as fossil fuels but on the basis of renewable energy. Some routes to produce these renewable fuels already exist, but their production costs are not competitive with those of producing fossil fuels. Through a detailed learning curve analysis we show how fast these costs may go down and when competitiveness can be reached with fossil fuel based incumbents. Our insights support intensified fundamental research as well as enhanced investments in demonstration plants and manufacturing facilities, which could enable the large-scale deployment of renewable fuel production technologies.

1. Introduction

All processes that sustain life use energy. For billions of years this energy has mainly derived from the sun through photosynthesis, the conversion of water (H₂O) and carbon dioxide

(CO₂) to carbon-based feedstocks (see the left side of Fig. 1). Since the industrial revolution, global energy use has substantially increased as a result of bolstering human activities, driven by growth in both population and gross domestic product (GDP). To date, energy has mostly been supplied by the combustion of hydrocarbons, or fossil fuels, which can relatively easily be harvested from stocks of concentrated natural photosynthetic products: coal, oil, and natural gas. The energy provided by these fuels allowed the establishment of the economies and societies that we live in.

Total global primary energy supply reached more than 570 EJ in 2014 and is projected to further increase by about 40% in 2050.¹ The vast majority of this energy is supplied through fossil fuels, at around 81% globally today, because they are in some ways ideal energy carriers. Fossil fuels contain

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Fig. 1 About 81% of our current energy supply is derived from fossil fuels (left side). It took millions of years to build up these fossil resources, formed by natural photosynthesis. Today, burning these carbon-based fuels rapidly increases the concentration of CO_2 in our atmosphere, leading to unwarranted global climate change. We envisage a system that circumvents the use of fossil resources (right side). The conversion of H_2O and CO_2 in processes driven by renewable energy allows for the production of renewable fuels in a rapid circular system that precludes the slow fossilisation route.

mainly reduced carbon material, with either a low (coal), average (oil), or high (natural gas) hydrogen content. The energy is stored in their chemical C–C and C–H bonds. The chemical reaction with oxygen (O_2) burns these fuels to form CO_2 and H_2O . This exothermic reaction releases the stored energy, which can be used for several purposes, such as the generation of heat, motion, and electricity. Besides being ideal energy carriers, fossil fuels also yield many of the materials on which the chemical industry builds.

Although fossil fuels constitute in several ways perfect energy carriers, their combustion emits the greenhouse gas (GHG) CO_2 into the atmosphere, currently in quantities large enough so as to alter our planet's climatic system. Natural pathways to capture CO_2 from the atmosphere do not match the speed with which human activity presently emits this GHG. As a consequence, CO_2 is the main contributor to anthropogenic climate change, out-shadowing GHGs such as methane (CH_4) and nitrous oxide (N_2O). The detrimental impacts from global climate change induce mankind to look for renewable energy sources that preclude the use of fossil fuels.

Renewable energy sources will eventually need to take over fossil fuel usage. To date, most approaches that harvest renewable energy (apart from biomass for heating, cooking, and fuel production purposes) produce electricity, such as photovoltaic (PV) modules, wind turbines, hydropower dams, and geothermal systems. It will take time and concerted efforts to change global electricity supply – which today fulfills roughly 20% of our total energy demand – into a fully renewable power system. Currently, however, in some regions and at certain moments in time, more renewable electricity is generated than is needed. This illustrates that the intermittency of renewable sources may require storage solutions that allow the use of these forms of energy at any desirable point in time.

An energy source with a high volumetric energy density is also desirable in many heavy-duty industrial processes and in power backup systems. Electrification of the light-duty transport sector is ongoing, but trucks, ships, and planes will

probably continue to rely on liquid fuels for a long time to come. Simple synthetic building blocks are also required in the chemical industry for the preparation of, for instance, plastics, coatings, pharmaceuticals, and a broad range of materials.

An attractive prospect would be the establishment of a fast and efficient process to produce fuels (and chemicals) with the same properties as fossil fuels but on the basis of renewable energy (the right side of Fig. 1). These “renewable” fuels (in this paper we henceforth refer to REN fuels, or solar fuels if they are produced with energy from the sun) could then directly replace their fossil fuel counterparts and be implemented in society without the need for fully redesigning existing energy infrastructures. REN fuels could well contribute to the necessary forthcoming energy transition. Several routes exist and/or are under development to produce REN fuels.^{2–4} The first step in processes that produce REN fuels is to harvest renewable energy and convert it into a usable form. In a second conversion step the ensuing form of energy is used to produce fuels from the basic feedstocks H_2O and CO_2 .

The REN fuels generated in this way can be employed either as energy carriers or as building blocks in the chemical industry. In the former case the energy stored in REN fuels is used, usually within relatively short delays; their combustion releases H_2O and CO_2 , which subsequently need to be captured again in order to close the (fast) cycle. In the latter case the CO_2 is stored for longer periods of time; in this case the storage duration of captured CO_2 has important consequences for the carbon footprint of REN fuels. These implications should be accounted for in life cycle analysis of REN fuels,^{5–8} which we don't undertake in this study.

Routes for REN fuel production abound. For many options they involve proven technology.⁹ Their GHG emissions are generally low, or even close-to-absent if all processes (including those running in the background) are powered by renewable energy. Yet the share of fuels produced with renewable energy today is negligible. The use of REN fuels is particularly hindered by high production costs in comparison to those of fossil fuels.

It is thus important to study if cost reductions may lead to a higher market uptake of REN fuels, to investigate if cost reductions can actually be expected, and to calculate what the magnitude of the necessary cost reductions has to be. In this article we address the question whether, how, and when REN fuels might become competitive alternatives for fossil fuels. In Section 2 we summarize the main pathways for REN fuel production, based on an extensive literature review. In Section 3 we calculate the current levelized production costs of seven selected REN fuel manufacturing routes. In Section 4 we investigate how fast these costs can go down and when competitiveness can be reached with fossil fuel based incumbents. We summarize our insights and provide a few main conclusions in Section 5.

2. Pathways to produce REN fuels

To classify the pathways available for producing REN fuels we introduce four main categories that are characterised by the way in which energy is collected: concentration, transformation, natural photosynthesis, and artificial photosynthesis (see Fig. 2).

These categories represent different conversion processes that allow for making the fuels.

In category 1, solar light is concentrated to generate (high temperature) heat, which can be used in thermoconversion processes to produce fuels. The prospects for several thermal approaches to produce hydrogen (H_2) on the basis of solar heat have been reported.¹⁰ The estimated production costs vary between 3 and 17 \$ per kg H_2 ,¹¹ depending on the method used. Although the technique appears promising, the high temperature environment presents severe stability and radiative energy loss issues.^{10,12} Most options need a temperature above 1000 °C, for which sites with a direct solar irradiation above 2000 kW h per m² per year are most suitable.

The thermochemical reaction to produce carbon monoxide (CO) from CO_2 by the use of concentrated solar energy has also been analyzed.¹³ After a water gas shift (WGS) reaction and removal of excess CO_2 , syngas (a mixture of CO and H_2) is generated. The syngas can be fed into a synthesis reactor to produce methanol. Syngas can also be used in a Fischer-Tropsch (FT) plant to produce FT fuels. For all these options the solar concentrator system represents the predominant cost component in the overall capital expenditure (CAPEX).^{13,14} Aside from the

Fig. 2 To produce REN fuels, energy has to be harvested in a renewable way and used to convert the simple building blocks, H_2O and CO_2 , into liquid or gaseous fuels. Four main categories exist, each consisting of multiple options, characterized by different stages of development, efficiencies, and costs. Concentration: solar light is concentrated to generate heat, which can be used in thermoconversion processes or for electricity generation. Transformation: renewable energy (e.g. wind, solar, geothermal, hydro, or tidal) is transformed into electricity, which is used to drive electroconversion processes such as electrolysis. Natural photosynthesis: natural biosystems transform H_2O , CO_2 , and light into biomass, which subsequently can be converted into fuels, chemicals, heat, or electricity. Under this category, also (either genetically modified or not) organisms such as micro-algae can be converted into fuels, or can themselves produce fuels and chemicals in a direct photoconversion process by excreting the desired products out of their cells. Artificial photosynthesis: this category includes a collection of direct but non-bio based conversion processes, which use photoactive materials that capture sunlight and thereby drive a photoconversion process, e.g. in an artificial leaf, a photoelectrochemical cell, or photocatalytic powder.

thermochemical reactor, which is still in the development stage, the full system is based on well-established industrial processes and component designs. Analysis reveals that the estimated costs to produce methanol through this process would today be around 1.29 \$ per kg,¹³ which may ultimately go down to 0.82 \$ per kg in an optimistic cost reduction scenario.¹⁴ Similarly, production of FT fuels is expected to result in costs of 2.55 \$ per kg. Besides these thermoconversion routes, heat conversion into electricity (*e.g.* with a steam turbine) is another pathway by which heat can be transformed into REN fuels (which explains the horizontal arrow from heat to electricity in Fig. 2).

In category 2, renewable energy is transformed into electricity, which can subsequently be used in electroconversion processes to produce REN fuels. This is a broad category that contains not only solar photovoltaics but also technologies such as geothermal, hydro, tidal, and wind power. The best-known electroconversion process is electrolysis of H₂O, which generates O₂ and H₂. Several studies show that the levelized cost of electrolysis-based H₂ production varies between 2.91 and 10.92 \$ per kg, depending on factors like production scale and electrolyzer type, as well as the year of analysis.^{15–21} These values are well above the current costs of H₂ production by conventional means based on fossil fuels. Nevertheless, for reasons of flexibility with regards to scale, location, and application, today electrolysis accounts for about 4% of total global H₂ production. This share mostly emanates from H₂ generated as a by-product from chlorine production through alkaline electrolysis.

Renewable H₂ obtained through electrolysis is a valuable feedstock for chemical synthesis of carbon-based REN fuels. Some innovative companies already utilize electrolysis-based H₂ in processes producing fuels. Carbon Recycling International (CRI) couples alkaline electrolysis to methanol synthesis using H₂O and CO₂ as feedstocks.²² Also in other (pilot) projects CO₂ is used as feedstock for methanol production (*e.g.* MefCO₂, Stepwise, GreenSynFuel, Qafac, and FReSMe). Sunfire GmbH develops reversible solid oxide electrolyzers capable of generating H₂.²³ By means of a reverse WGS reaction, H₂ can be converted together with CO₂ into syngas, which can subsequently be fed into an FT plant to produce diesel. *Via* this route, diesel is produced in the Sunfire power-to-liquid pilot plant at a scale of ~100 kg per day on the basis of grid electricity.²⁴

Also methane can be produced by renewable electrolysis coupled to a thermochemical methanation process.^{2,25} In a recent integrated techno-economic and environmental impact assessment it is pointed out that this route provides methane at approximately five times the cost in comparison to methane production from natural gas.²⁶

Co-electrolysis with CO₂ gives access to a direct electroconversion method to produce carbon-based molecules from H₂O and CO₂. The use of (reversible) solid oxide electrolysis cells in a co-electrolysis process to produce syngas has been evaluated from both technical and economic perspectives.²⁷ The use of this syngas in either methanol synthesis or FT plants delivers methanol and gasoline at a cost of, respectively, 0.57 \$ per kg

and 1.49 \$ per kg. These values are based on an optimistic scenario and cover only the costs of electricity consumption, excluding investment and O&M costs. Full assessments of CO₂ co-electrolysis coupled to FT report fuel production cost estimates ranging between 0.4 and 3.3 \$ per kg depending on the assumptions made.^{3,28,29} Avantium, which recently acquired the start-up company Liquid Light, uses CO₂ electroconversion technology to fabricate feedstock molecules for chemicals and plastics.³⁰

Category 3 groups together all natural photosynthesis pathways, which involve organisms like algae, grasses, plants, and trees that harvest solar energy in the process of producing biomass or (in)directly biofuels. All types of organisms in this category can in principle be genetically modified in order to increase their performance. Whether and how natural photosynthesis can contribute to a global transition from fossil to REN fuels has been thoroughly investigated.³¹ At present, the only type of REN fuels produced at scale – biofuels – are generated from natural photosynthetic products. Biofuels provide around 1% of global energy consumption in the transport sector.³² Food constitutes the prime type of biomass that fuels most living organisms on Earth. This may limit the large-scale usability of biomass for fuel production in the energy sector because of possible unwarranted price effects in global food supply as a result of competition for biomass. Important sustainability concerns may also exist with regards to *e.g.* the required amounts of fertilizers, since their widespread use may be at loggerheads with the global nitrogen and phosphorus cycles. Likewise, water availability concerns may prevail.

Non-food and/or waste biomass materials possess a more advantageous social and environmental footprint than food-related forms of biomass. Conversion of non-food and/or waste biomass feedstocks can yield many types of fuels and chemicals.³³ In our scheme (see Fig. 2) the processes to produce fuels from biomass other than direct photoconversion approaches are referred to as “bioconversion” options, which cover both thermochemical and biological conversion routes. A few extensive techno-economic analyses have been performed for the thermochemical conversion of biomass to liquid fuels.^{34–37} The most recent publication shows that methanol and FT-diesel prepared from biomass gasification could be produced at costs of 0.48 \$ per kg and 1.51 \$ per kg, respectively. Besides the production of fuels and chemicals from biomass materials, biomass can also be combusted for heat or electricity generation purposes (hence the leftward arrow in Fig. 2).

In an approach more direct than bulk biomass (including algae, grasses, plants, and tree residues) processing, micro-organisms can be used to capture light and store solar energy in chemical compounds on the basis of natural photosynthesis. These micro-organisms can be genetically modified so that they produce the desired compounds, including H₂, ethanol, and higher value (*e.g.* hydrocarbon) products. Since these organisms excrete the products out of their cells, they can be considered small factories that run a photoconversion process to produce fuels and chemicals by means of natural photosynthesis.

A techno-economic analysis of biological pathways for H_2 production has illustrated that in the near term costs could be ~ 10 \$ per kg H_2 at 2% overall system efficiency.³⁸ If efficiencies reach the theoretical upper limit of $\sim 9\%$, costs are predicted to go down to around 3.60 \$ per kg. The majority of these systems require organic substrates as an energy source instead of only H_2O and light. This suggests that successful implementation is only possible if waste streams can provide these feedstocks.³⁹

Joule Unlimited, jointly with Audi, has built a demonstration facility in New Mexico that produces ethanol by the use of micro-organisms. According to Joule Unlimited, 95% of the harvested energy in its first plant is used to make ethanol. This implies production costs of 1–2.7 \$ per kg.⁴⁰ Similar approaches are followed by other companies: Photanol aims at the production of lactic acid, while Phytonix targets that of *n*-butanol.⁴¹

Private enterprises like LanzaTech and Ineos Bio use micro-organisms to produce ethanol in a gas-fermentation process. As feedstock for their processes, different ratios of CO/H_2 and $CO/CO_2/H_2$ are allowed. These streams can be converted by microbes into ethanol, acetic acid, or iso-propanol, as desired.⁴² No energy is captured by these technologies, which illustrates the power of nature to produce certain molecules selectively. One can couple these methods to a choice of the electroconversion processes listed under category 2, in order to obtain the required input gas mixture. These combined systems allow for the production of a large series of specific chemicals.

Category 4 consists of all man-made methods to produce fuels in a direct conversion process: the capture of light and the use of its energy for fuel production. Given the similarities with natural processes, this category is referred to as artificial photosynthesis. The subject of artificial photosynthesis is receiving increasing attention, and various technologies in this category are currently under development, albeit still at a lab-scale. Concepts like the artificial leaf, photoelectrochemical (PEC) cell, and photocatalytic powder belong to this category, which all use a direct photoconversion process to produce fuels.^{43–52}

In photocatalytic H_2O splitting, the photoactive materials are directly coupled to the catalytic reactions. It is comparable to solar PV coupled to electrolysis, with the main difference that the former uses an integrated device. This similarity is the reason why many materials from PV and electrolysis technology are implemented in this option for, respectively, light absorbance and H_2O splitting. Benchmark energy conversion efficiencies of $\sim 12\%$ are obtained, comparable to those for PV coupled to electrolysis. Solar-to-hydrogen (STH) efficiencies of $>20\%$ have been reported, although such efficiencies require concentrated light and expensive materials.^{53,54}

Many designs to fabricate devices under category 4 are being researched. If the light harvesting surface area is kept similar to the catalytic area, the current densities under normal light irradiation are lower in comparison to typical electrolyzers. This requires the design and development of novel electrode materials and catalysts dedicated to direct photoconversion routes. The dependence of the H_2 production costs on the ratio

between the area of light capture and catalysis area has been studied for PV-electrolysis devices.⁵⁵ These analyses demonstrate that the photo-active component dominates the overall costs of such systems.

In this category two extensive techno-economic analyses have been performed that consider different types of systems.^{56,57} A bed-system with suspended photocatalytic powder is estimated to ultimately yield the lowest production costs (1.98 \$ per kg H_2). Yet many technological hurdles have to be overcome before this system can be implemented in a safe manner, since H_2 and O_2 are formed in combination, which is an explosive mixture. PEC systems that use two distinct electrodes for O_2 and H_2 evolution are in a more advanced stage of development. The base case production costs for such systems with either concentrated or normal light irradiation are 9.2 and 11.4 \$ per kg H_2 , respectively.⁵⁶ PEC systems possess advantages over systems in which PV modules are coupled to electrolyzers, because the transport of H_2 to compression units in the former is cheaper than the transport and conditioning of electricity to electrolyzers in the latter. A fundamental limitation of direct photo-conversion approaches driven by sunlight, however, is their low capacity factor of typically 10–30% depending on their set-up,⁵⁵ which translates into relatively high investment costs.

Choice of fuels and technologies

The categories described above reveal the many possible routes that can be followed to produce REN fuels. The desired fuel type and its properties constitute the first main determinant for which production route to select. The choice for a production pathway is also determined by the allowed costs, the availability and size of markets (both current and future), and the technology readiness level (TRL) of the route. We select four common fuels – hydrogen, syngas, methanol, and diesel – not only because they are already produced and used at a commercial scale, but also since they can be generated relatively easily through renewable energy pathways. We define seven REN fuel production routes – four for hydrogen and one for each of the other three fuels – which we choose because they allow for the production of these fuels under the highest TRL and/or in the most straightforward renewable fashion. Table 1 summarizes our seven REN fuel production pathways, and lists the efficiencies of the main components of the systems with which these REN fuels can be generated.

Hydrogen. Hydrogen is the simplest molecular form of fuel and has a high energy density per unit mass of about 120 MJ kg^{−1} (lower heating value, LHV). In energy terms, 1 kg H_2 corresponds to about a gallon (3.8 litre) of gasoline. Unfortunately, the volumetric energy density of hydrogen is low, which makes storage, in liquefied, compressed, or absorbed form, both difficult and costly. Still, it is a common bulk chemical with a 60 million ton per year market, and constitutes a versatile energy carrier for subsequent chemical conversion. Currently most H_2 is produced *via* steam methane reforming (SMR), partial oxidation of heavy oil, or coal gasification. The production cost *via* the most common route, SMR, is about 1.40 \$ per kg, which – although dependent on the price of natural gas – we take as a measure for the

Table 1 The seven REN fuels and corresponding production technologies analyzed in this paper

REN fuel	Category	System component 1	Eff ^a	System component 2	Eff ^a
REN H ₂ (AE)	2	Alkaline electrolysis (AE)	63% (68%) ^{19,21}	—	—
REN H ₂ (PEM)	2	Polymer electrolyte membrane electrolysis (PEM)	56% (64%) ^{18,19,21}	—	—
REN H ₂ (SOE)	2	Solid oxide electrolysis (SOE)	68% (97%) ^{17,59}	—	—
REN H ₂ (PEC)	4	Photoelectrochemical H ₂ O splitting (PEC)	10% ^{56,57}	—	—
REN syngas	2	CO ₂ solid oxide co-electrolysis (CO ₂ -SOE)	67% (96%) ^{17,59}	—	—
REN methanol	2	Polymer electrolyte membrane electrolysis (PEM)	56% (64%)	Methanol plant (MP)	84% ^{22,62}
REN diesel	2	CO ₂ solid oxide co-electrolysis (CO ₂ -SOE)	67% (96%)	Fischer-Tropsch (FT)	80% ³⁵

^a Eff = selected energy efficiency of the process (energy product out (LHV)/total energy in) based on indicated references; for electrolysis the electric efficiency of the electrolyzer is given in brackets; for PEC the solar-to-hydrogen efficiency is given.

break-even costs.⁵⁸ The conventional fossil-fuel based H₂ production process is accompanied by CO₂ emissions, but the H₂ combustion reaction with O₂ only forms H₂O and thus does not release any GHG like CO₂.

All four categories of Fig. 2 include pathways to form REN H₂. For our analysis we select four approaches across two categories, since they are at present considered the most likely to be adopted relatively early (see Table 1). The most evident route to produce REN H₂ is through electrolysis driven by renewable electricity. We investigate and compare three types of electrolysis: alkaline electrolysis (AE),^{15,19,21} polymer electrolyte (or proton exchange) membrane electrolysis (PEM),^{18,19,21} and solid oxide electrolysis (SOE).^{17,19,59} In addition to these three electroconversion approaches (category 2), we analyse one photoconversion route (category 4). In the latter, a PEC cell splits H₂O into O₂ and H₂ using (non-concentrated) sunlight.^{56,57} This emerging technology can also represent other pathways that are currently not mature but are promising as these will presumably follow similar trends if successful deployment occurs.

Syngas. Synthesis gas, or syngas, is a common feedstock for the production of various bulk chemicals. Syngas is usually prepared by SMR or partial oxidation of hydrocarbon feedstocks (fossil fuels or biomass). Its current production costs are estimated at around 0.19 \$ per kg,⁶⁰ which we take as our break-even cost-target. Syngas is used in processes like methanol manufacturing and FT synthesis of gasoline, diesel, and waxes. A pathway to make REN syngas can provide the principal building block for the renewable production of many fuels and chemicals. Although various possibilities exist, we only analyze the production of syngas by CO₂ co-electrolysis in solid oxide electrolyzers, since the cost prospects are good and they provide additional benefits such as operating at high efficiencies.^{17,29} In this high-temperature electroconversion approach, syngas (with a CO:H₂ ratio of 1:2) is produced in a single step from H₂O and CO₂.

Methanol. Methanol is produced on a large commercial scale from natural gas (80 million ton per year). The current (2017) market price, which mainly depends on the price of natural gas, is around 0.41 \$ per kg.⁶¹ We adopt this value as a requirement for reaching competitive production costs. Methanol is the base chemical for the synthesis of formaldehyde, acetic acid, and methyl *tert*-butyl ether (MTBE). For a few years methanol has also been increasingly used for fuel applications,

either for the production of dimethyl ether (DME) or directly by blending it with gasoline. A route for producing REN methanol is to use H₂, made by electrolysis, together with CO₂ in a methanol synthesis reactor.⁶² CRI has built a plant on the basis of this principle.²² We adopt this approach for the analysis in this paper, for which we combine PEM electrolysis with a methanol plant (MP).

Diesel. Diesel is refined from crude oil. It has a high volumetric energy density of 36 MJ L⁻¹ (LHV), which makes it a valuable fuel for the transport sector. Diesel can also be produced by refining syncrude, which is the output of the FT process. We take the average current (2017) global diesel price of 1.05 \$ per kg⁶³ – which is strongly dependent on the crude oil price and thus does not directly reflect the production costs – as a measure for the break-even costs in our calculations, because it is the price level that one needs to reach in order to establish competitiveness. In our analysis we assume that REN diesel is fabricated through FT synthesis,^{9,35,62,64} with syngas derived from CO₂ co-electrolysis as an input. For reasons of exposition, we assume that all syncrude is converted into diesel. In practice, the FT process yields a broad distribution of different hydrocarbon species, the ratio of which can be controlled by adjusting the catalyst and reaction conditions. The FT approach in principle therefore also allows for the production of hydrocarbons like gasoline or waxes.

Other fuels. Of course, many alternative fuels and production pathways exist. Most of them (such as ammonia, DME, and methane) can be produced by the use of similar approaches as the ones described above. Our research can thus be extended to include these other REN fuels.

3. Levelized costs of REN fuel production

We perform a levelized cost analysis for our seven routes to produce REN fuels, based on the assumptions and parameters listed in Table 2. We choose the same fuel production rate across all processes, by adopting for each of them a value with an equivalent energy content of 10 000 GJ per day (LHV). For H₂ this translates into a production of 83 metric ton per day, for syngas, methanol, and diesel 419, 500, and 233 metric ton per day, respectively. This scale is small in comparison to most of today's fossil-fuel based industrial processes. For instance,

Table 2 Base parameters used for our REN fuel production routes

Parameter	Selected value
Fuel production rate	10000 GJ per day
Plant lifetime	20 years
Discount rate	12%
US dollar reference year	2015
O&M costs	5% of CAPEX
H ₂ O	2 \$ per ton
CO ₂	50 \$ per ton
Electricity	0.063 \$ per kW h

Lurgi's MegaMethanol process has a single-train capacity of 5000 ton per day.⁶⁵ On the other hand, our scale (200–400 MW_p) matches well the amount of energy harvested by typical current solar PV and wind farm projects.

We adopt a plant lifetime of 20 years and a discount rate of 12%. Costs are reported in US\$(2015), unless otherwise noted. Other currencies are converted to US\$ in the year under consideration, and subsequently corrected for inflation by converting them to our reference year (2015). We assume that operating and maintenance costs (O&M, 5% of CAPEX) and feedstock costs (F, for H₂O 2 \$ per ton, for CO₂ 50 \$ per ton, and for electricity 0.063 \$ per kW h) remain constant over the plant lifetime. We calculate the overall levelized REN fuel production costs with formula (1).⁶⁶

$$C_{\text{Fuel}} = \frac{\alpha \times \text{CAPEX} + \text{O\&M} + F}{P_{\text{Fuel}}} \quad (1)$$

$$\alpha = \frac{r}{1 - (1 + r)^{-n}} \quad (2)$$

The levelized fuel production costs (C_{Fuel}) are determined by dividing the total annual costs by the amount of fuel produced annually (P_{Fuel}). The total annual costs consist of the discounted annualized initial investment costs (with α being the capital recovery factor), the annual operating and maintenance costs, and the annual feedstock costs. Formula (2) is used to calculate the capital recovery factor, which is a function of the discount rate (r) and the plant lifetime (n).

Investment costs

The value of CAPEX depends on the route used to produce a REN fuel, as well as the technologies adopted therein. For all routes, we calculate investment costs based on literature data and/or our own estimates (see Table 3). CAPEX data from the literature are corrected so as to obtain a plant-size of 10 000 GJ per day, for which we use a scale factor of 0.8. This is a relatively conservative value for the scale factor, as often 0.6 or 0.7 is used.⁶⁶ By the assumption that in our case electrolyzer stacks and PEC modules are scaled to size by multiplying small units in parallel (estimated scale factor of 0.9–1.0), we justify our choice of the value of 0.8 for the overall system as chosen to be right in between 0.6–0.7 and 0.9–1.0, thereby limiting but not excluding economies-of-scale.⁶⁷

Amongst all electrolysis techniques, AE has currently the lowest investment costs (1100 \$ per kWe). The average of today's CAPEX costs for PEM systems lies around 1500 \$ per kWe.

Table 3 CAPEX for our technology choices (reference year 2015)

Technology	Value ^a	Unit ^b	Value	Unit ^c	Ref.
AE	1100	\$ per kWe	2.6	\$ per GJ	15, 19 and 21
PEM	1500	\$ per kWe	3.7	\$ per GJ	18, 19 and 21
SOE	2000	\$ per kWe	3.3	\$ per GJ	17, 19 and 59
PEC	3000	\$ per kW _{pH₂}	23.8	\$ per GJ	38 and 56
CO ₂ -SOE	2150	\$ per kWe	3.6	\$ per GJ	17 and 29
MP	600	\$ per kW	1.1	\$ per GJ	22
PEM + MP			5.2	\$ per GJ	
FT	600	\$ per kW	1.0	\$ per GJ	35 and 64
CO ₂ -SOE + FT			5.7	\$ per GJ	
Solar PV	1450	\$ per kW _p	6.8	\$ per GJ	68 and 69

^a $\pm 25\%$ deviation from the listed value is used as the cost-range (see also Table S1, ESI). ^b kWe = kW electricity input, kW_{pH₂} = kW peak of H₂ production (LHV), kW = kW of fuel production capacity, kW_p = kW peak of electricity production. ^c Unit is expressed in \$ per GJ of fuel (LHV) produced.

SOE systems are currently not available at the MW scale, so that no CAPEX data exist at this scale. We assume a value of 2000 \$ per kWe for SOE systems, as it is a figure well above that for PEM systems while it accounts for scaling effects with respect to presently deployed systems. CAPEX data for PEC systems are not yet available, since the technology is in an early phase of development. Given their low TRL, we estimate that the investment costs of PEC systems would initially be around 3000 \$ per kW_{pH₂}. For SOE technology, the difference in CAPEX between using a mixture of H₂O and CO₂ *versus* H₂O only is small. For CO₂-SOE systems we therefore assume a CAPEX of 2150 \$ per kWe, slightly higher in comparison to that for conventional SOE systems. The cost margin represents the costs of the CO₂ gas-handling and mixing systems. The CAPEX values for methanol and FT plants are derived from numbers reported in the literature, by subtracting auxiliary system costs unwarranted for our analysis (for *e.g.* a gasifier) from the total investment costs of existing plants. We thus adopt overall investment costs for methanol and FT plants of 600 \$ per kW, which contribute by only a small amount to the overall investment costs of our REN fuel production routes. Table 3 also lists the CAPEX for solar PV (1450 \$ per kW_p, for a plant size of 340 MW_p), to point out that additional investment costs are required for the collection of renewable energy. Since light capture is already integrated in PEC technology, no additional investments for energy harvesting are required for this route. In a separate column in Table 3 we express the values for the CAPEX in \$ per GJ of produced fuel (LHV), which corrects for differences in efficiency and units of capacity and thus allows for a better comparison between technologies.

Operating and maintenance costs

For the base case scenario we assume that the annual O&M costs amount to 5% of the total initial investment costs. This percentage is an average of reported O&M costs: 3–5% for electrolysis,^{18,19} around 5% for methanol plants,⁷⁰ and 4–7% for FT plants.^{35,64,71} O&M costs are assumed to remain constant over the lifetime of the plant and include replacement costs of installed capital, such as for electrolyzer stacks and catalysts.

O&M costs also include all indirect costs, but the costs of the main feedstocks (H_2O , CO_2 , and electricity) are considered separately. For our sensitivity analysis we examine a broad range for values of the O&M costs of 3–10%. The upper value of 10% represents a scenario in which, for example, unexpectedly high replacement costs are incurred.

Feedstock costs

The feedstocks consist of all electricity, H_2O , and CO_2 that are required to run the plant. To avoid the use of fossil fuels, all heating is provided by electric means. Electric heaters are assumed to run with 100% energy efficiency. Total electricity consumption consists of electricity used for heating, for the electroconversion step (not required for the PEC route), and for running the plant.

Electricity costs

For this entry we use the levelized costs of electricity (LCOE) for crystalline solar PV at utility scale.⁶⁸ The average LCOE in 2015 for this technology was 6.3 \$ct per kW h. Higher numbers for the weighted averaged LCOE have been reported (13 \$ct per kW h),⁷² but we argue that our value corresponds better to the current costs of wind energy projects as well as present prices of solar PV auctions, which recently have dropped substantially (notably in regions such as the North Sea and the Gulf, respectively). To indicate how REN fuel production costs are influenced by the costs of input electricity, we inspect a range between 3 and 10 \$ct per kW h in our sensitivity analysis. The LCOE of almost all power-producing technologies fits within these limits. In other words, in principle it is possible to connect essentially any commercial renewable power generation technology to our REN fuel production systems; the only modification we need to make in our analysis is adjusting the electricity costs accordingly.

The capacity factor (CF, also referred to as the load factor) of a REN fuel production plant is determined by the type of energy supplier it is connected to. If, for example, a methanol production plant is connected to a solar PV farm, the CF of the electrolysis part of the system is 20%, even while the methanol synthesis unit itself runs for 95% of the time. The relative installed electrolysis capacity and CAPEX is in this case higher in comparison to a similar plant connected to a geothermal power source, which runs at a CF of 95%. In our base case scenario we set the CF for the electroconversion processes at 50%, which we consider representative of the plant being connected simultaneously to multiple renewable energy sources with different intermittency profiles (e.g. a combination of solar PV with a CF of 10–30% and wind power with a CF of 30–40%). In our sensitivity analysis we alter the CF for electrolysis to cover a wide range between 20 and 90%.

If H_2 or syngas production is coupled to another chemical process, the costs of H_2 storage in a gas tank also need to be accounted for (we assume typically at a level of 1 day's worth of production capacity). We include the associated costs (6–7% of CAPEX) as an additional component to the CAPEX.⁷³ Underground H_2 storage is probably cheaper, but is not always available,

while the installation of batteries for electricity storage as an alternative likely renders the system more expensive at the scale under consideration.⁷⁴

H_2O costs

Water is scarce in some regions, but as a feedstock for REN fuel production the necessary amounts are relatively low. The typical amount of H_2O feedstock is ~ 300 kg per MW h of fuel produced, while common power plants consume thousands of liters of H_2O per MW h of electricity generated only for cooling purposes. For our analysis we therefore adopt a conservative value for the costs of H_2O at 2 \$ per ton.

CO_2 costs

The CO_2 required in the overall process plays a fundamental part in the overall fuel cycle. Several sources of CO_2 can be used, each at their own costs. In January 2017, the CO_2 European Emission Allowances price was 5 US\$ per metric ton of CO_2 . The costs of carbon dioxide capture and storage (CCS) at power plants range from 50 to 200 \$ per MW h.⁷⁵ The costs of avoiding CO_2 in various industrial sectors vary strongly depending on the application, and could be as low as 20 and as high as 200 \$ per ton. The lowest costs, of 20–27 \$ per ton CO_2 avoided, are found in natural gas processing, as well as in the fertilizer and bio-ethanol industry. For closing the (fast) carbon cycle and avoiding the use of fossil resources, CO_2 should be captured from air. Under category 3 we describe how CO_2 can be captured from air and converted into biomass by natural photosynthesis. An alternative approach involves direct air capture technology. Demonstration systems that capture CO_2 from the atmosphere are currently under development by several companies (e.g. Antecy, Carbon Engineering, Climeworks, Skytree). Estimates of what today's and ultimately established direct air capture technology could cost vary significantly: 30–1000 \$ per ton.⁷⁶ We take 50 \$ per ton as our central value for CO_2 input costs, as we believe effects like learning-by-doing could eventually lead to low air capture costs. In order to cover a broad series of possible CO_2 capture technologies, we explore a range of 10–200 \$ per ton in our sensitivity analysis.

Levelized costs of REN fuels

With the numbers above we calculate the overall REN fuel production costs for all seven routes. The outcomes of our calculations illustrate the production costs if the REN fuel plant is built in 2015 and runs during its entire lifetime of 20 years without efficiency losses or changes in feedstock costs. The plant is connected to renewable energy sources that provide electricity for 50% of the time to drive the electroconversion process. In Table 4 we summarize the outcomes of our REN fuel cost calculations, as well as the costs from the literature of these fuels if they are produced by benchmark technologies on the basis of either fossil or renewable resources. We adopt today's costs of the fossil-fuel based routes as the break-even costs, as we consider it unlikely that the costs of these routes and the fossil fuels themselves will decrease significantly in the future (the opposite may well hold, as the internalisation of

Table 4 Current levelized fuel production costs (base case): our calculations are shown in bold, other values are reported in the literature

Fuel	Category	Feedstock	Technology ^a	Costs (\$ per kg)	Ref.
REN H ₂ (AE)	2	H ₂ O	AE	5.6	This work
REN H ₂ (PEM)	2	H ₂ O	PEM	7.1	This work
REN H ₂ (SOE)	2	H ₂ O	SOE	6.0	This work
REN H ₂ (PEC)	4	H ₂ O	PEC	10.8	This work
REN H ₂	1	H ₂ O	Solar thermal approaches	3–17	10
H ₂ ^b	2	H ₂ O	Electrolysis	3–11	15–20
REN H ₂	3	H ₂ O (+nutrients)	Biological photoconversion	~10	38
REN H ₂	4	H ₂ O	Photocatalytic powder	1.98	57
REN H ₂	4	H ₂ O	PEC	11.4	56
Fossil H ₂	—	Natural gas	SMR	1.40	58
REN syngas	2	H ₂ O and CO ₂	CO ₂ -SOE	1.3	This work
Fossil syngas	—	Natural gas	SMR	0.19	60
REN methanol	2	H ₂ O and CO ₂	PEM + MP	1.5	This work
REN methanol	1	H ₂ O and CO ₂	Solar thermal + MP	1.29	13
REN methanol	3	H ₂ O and CO ₂	Biomass gasification + MP	0.48	34
Fossil methanol	—	Natural gas	SMR + MP	0.41	61
REN diesel	2	H ₂ O and CO ₂	CO ₂ -SOE + FT	3.4	This work
REN diesel	1	H ₂ O and CO ₂	Solar thermal + FT	2.55	14
REN diesel	2	H ₂ O and CO ₂	CO ₂ -SOE + FT	0.4–3.3	3, 28 and 29
REN diesel	3	H ₂ O and CO ₂	Biomass gasification + FT	1.51	34
Fossil diesel	—	Crude oil	Refinery	1.05	63

^a Not all technologies are commercially available. ^b In some of the studies grid-electricity is used, so that the production of H₂ is not fully renewable (indicated by “H₂” instead of REN H₂).

their environmental burden – either through the application of CCS or the levying of a carbon tax – will have negative financial consequences). If the costs of the fossil fuel pathways increase, the break-even costs of REN fuels will be reached sooner than the years we calculate here.

The first three rows in Table 4 represent the standard electrolysis routes. AE is the most mature technology and therefore constitutes the lowest cost option at present. The PEM route is rapidly approaching the costs of AE, and MW-scale systems are currently market-ready. SOE systems are not in a commercial stage of development yet, although pilot projects already run at a 150 kW scale.²¹ If plant-size SOE systems could be installed today, their REN fuel production costs would probably be similar to those of AE installations. This is the case despite the relatively high CAPEX of SOE systems, because they imply low electricity consumption as a result of their high efficiency (68%). Still, today REN H₂ production costs are typically 4–5 times higher than fossil-fuel based H₂ generation. Similar values are obtained in assessments performed by others.^{18,19,56}

For the artificial photosynthesis approach to produce H₂ by PEC H₂O splitting the costs are higher (10.8 \$ per kg) than for electrolysis, which is mainly due to the high investment costs and a low capacity factor (20%) of PEC systems. The literature reports comparable base case production costs (11.4 \$ per kg) for PEC systems.⁵⁶ PEC technology offers the possibility for an all-in-one system without the need for a connection to the grid or a solar PV park and/or wind farm. The novelty of this approach implies substantial scope for cost reductions in the future.

REN syngas production by CO₂-SOE is not yet commercial, but this technology promises to deliver syngas at much lower costs in the future.⁷⁷ Syngas production costs *via* this route (with an energy efficiency of 67%) are 1.3 \$ per kg at present, which is an order of magnitude higher than if the syngas is produced from natural gas or coal.⁶⁰

In the process to produce REN methanol, more than 95 ton H₂ per day is generated by PEM electrolysis at an overall energy efficiency of 57%. The resulting H₂ is used together with CO₂ as feedstock in a highly efficient methanol plant (96%) delivering REN methanol at a levelized cost of 1.5 \$ per kg. This is roughly 3 times higher than the current market price for methanol.

We analyze a fast renewable synthetic route for the fabrication of higher alkanes such as diesel, by combining CO₂ co-electrolysis with FT diesel synthesis. In the electroconversion step an optimized mixture of syngas is prepared, which is subsequently fed into the FT synthesis reactor. To calculate the net energy consumption, the amount of fuel produced, and the amount of feedstocks required, we assume that 88% of the CO feed is converted into diesel (more precisely, C₁₄H₃₀). In the exothermic FT process most of the generated heat is re-used in the recycling and refining of the product stream. This permits an overall energy efficiency of 51% for producing REN diesel at a levelized cost of 3.4 \$ per kg, which is more than 3 times higher than the current diesel market price.

As an example of the sensitivity tests that we performed for all seven REN fuel production routes, we show in Fig. 3 the results of such a sensitivity analysis for PEM electrolysis coupled to a methanol plant to produce REN methanol. The central value of 1.5 \$ per kg represents our base case. Fig. 3 shows that the electricity costs (and to a lesser extent the CAPEX) for the PEM system have among the highest impacts on the costs of methanol production.

The most important factor is the CF, which at low levels (20%) translates into high investment costs for PEM systems. As a consequence, at low CF values the levelized costs for REN methanol production escalate. Inversely, increasing the CF to higher values (90%) yields significant production cost decreases. As with most discounted cost analyses like ours, the influence of the discount rate can be significant. On the other hand,

Fig. 3 Sensitivity analysis for REN methanol production. PEM electrolysis produces H_2 , which is used together with CO_2 as the input for a methanol plant (MP). Costs are shown relative to the base case of 1.5 \$ per kg methanol.

the effect of changes in the efficiency of the electrolyzer, the CAPEX of the MP, or the O&M costs are clearly less pronounced than for the other factors. The costs of REN methanol production are also not very sensitive to the cost of CO_2 , although the impact becomes quite substantial at high CO_2 prices of 200 \$ per ton. The discount rate and capacity factor are not directly related to technological progress. They depend mainly on the location of the plant, financial and economic risks associated with the required investments, as well as the renewable energy resource. The specific investment costs and renewable electricity generation costs, on the other hand, are influenced by the development and deployment of the technologies involved. In the next section we explain how cost reductions for these technologies can materialize, how these reductions can be projected and how they might influence REN fuel production costs in the future.

4. Cost reductions through learning-by-doing

An important reason why today our society relies predominantly on fossil fuels is their low costs. If REN fuels were cheaper than fossil fuels, the former would probably readily take over the role of the latter: market competition would thus render our present energy system renewable. The figures summarized above demonstrate that currently the production costs of REN fuels are well above those of fossil-based fuels. Substantial cost reductions are essential to achieve competitiveness for the seven REN fuel production routes that we investigate. Many phenomena – such as learning-by-doing, learning-by-searching, economies-of-scale, and automation – can reduce the manufacturing costs of energy technologies.⁷⁸ Single-factor learning curves are used to describe the mix of these cost reductions,⁷⁹ by expressing the observation that technology costs typically decrease by a constant fraction with every doubling of (global) cumulative installed capacity (CIC) or exercised activity. To determine the effects of phenomena like learning-by-doing on the costs of REN fuel production, we perform an analysis with

learning curves that we apply to our seven REN fuel production pathways. On the basis of this analysis we make cost projections for each of them until 2050.

For all learning curves that we employ, we adopt three different scenarios: a base case, an optimistic projection, and a conservative projection. The base case represents an intermediate scenario that starts from the mean current cost value. Central values for the learning rate (LR), CIC, and cumulative average annual growth rate (CAGR), listed in Table 5, determine the progress in these costs. Although unforeseen developments may always happen, the uncertainty based on technology maturity and complexity⁴ of the REN fuel production route is to a large extent covered by the ranges we use (see Table 5 and Table S1, ESI†). The extremes in these ranges lead to the most optimistic and most conservative cases. In the optimistic projection, the lowest current cost estimate is coupled to the same CIC as for the base case, but now on the basis of a high LR and a high CAGR. The conservative projection starts from a high current cost level and the CIC from Table 5, while here we apply a low LR and low CAGR.

To simulate a decreasing CAGR over time, we introduce a decline factor (DF). A DF of 1 indicates that the CAGR remains constant over time. If $DF > 1$ (not used in this article), the CAGR increases over time, while $DF < 1$ (used here) results in a gradually declining CAGR. The DF of the base case (0.96 in most cases) is chosen exactly in between that of the optimistic (0.99 in most cases) and conservative (0.93 in most cases) projections. The LR and CAGR figures for the various systems are derived from historical data reported in the literature.

Table 5 Input data for the generation of learning curves

Technology	Selected value 2015	Based on
Learning rate (LR)		
Solar PV	$23 \pm 2\%$	80
Wind	$12 \pm 4\%$	80
AE	$18 \pm 3\%$	15
PEM	$21 \pm 3\%$	81
SOE	$27 \pm 3\%$	79
PEC	$20 \pm 3\%$	Estimated, see ref. 78
Methanol plant	$10 \pm 3\%$	Estimated, see ref. 78
FT plant	$10 \pm 6\%$	Estimated, see ref. 78
Cumulative installed capacity (CIC)		
Solar PV	228 000 MWp	32
Wind	420 000 MWp	32 and 68
AE	21 000 MWe	15
PEM	800 MWe	81 and 82
SOE	200 MWe	79 and 82
PEC	580 MWp _{H₂}	Our plant size
Methanol plant	84 000 MWth	Estimated
FT plant	40 000 MWth	Estimated
Cumulative annual growth rate (CAGR)		
Solar PV	$25 \pm 5\%$	32
Wind	$18 \pm 3\%$	32
AE	$4 \pm 1\%$	15
PEM	$21 \pm 5\%$	81 and 82
SOE	$33 \pm 5\%$	79 and 82
PEC	$30 \pm 10\%$	Estimated
Methanol plant	$7 \pm 5\%$	83
FT plant	$13 \pm 5\%$	Estimated

If literature data are absent, we make our own assumptions supported by data for comparable technologies.

Learning curves for investment costs of the technologies

To estimate future REN fuel production costs, we first make cost reduction projections for the investment costs. Plotting costs *versus* global cumulative installed capacity on a double logarithmic scale yields a linear downward trend. The fit hereof is the learning curve, and its slope is the LR. We apply the LR (with the values reported in Table 5) to current costs so as to obtain CAPEX cost reduction projections. Since we want to project cost reductions over time, the learning curve is converted into a costs-*versus*-time plot on a double linear scale. The ensuing charts for AE and PEM systems are shown in Fig. 4 to illustrate the progress of CAPEX over time.

AE has been a commercial technology for decades and already has a relatively high CIC. Current system costs range between 800–1400 \$ per kW. For AE, a LR of 18% has been reported, and a CAGR of 4%.¹⁵ This low growth rate results in a relatively slow increase in CIC. This prevents a fast learning-by-doing process and explains why projected cost reductions are not very deep. Specific investment costs for AE decrease to 450–1200 \$ per kW in 2050.

Although no explicit learning curves are available for PEM and SOE, LR data for the related fuel cell (FC) technologies, PEMFC and SOFC, have been reported.^{79,81,82} The similarity between these technologies justifies the use of the LR, CIC, and CAGR of PEMFC and SOFC for PEM and SOE, respectively. The PEM and SOE learning curves reveal that their costs are likely to decrease faster than those of AE. This is because PEM and SOE have a higher LR and CAGR than AE, and their current CIC is lower than that of AE. Today, the costs of PEM systems (1100–1900 \$ per kW) are higher than those of AE systems. Learning-by-doing results in lower costs in 2050 (70–1100 \$ per kW) in comparison to AE, especially in an optimistic scenario. Likewise, investment costs for an SOE system range between 1500 and 2500 \$ per kW and decrease rapidly to 10–700 \$ per kW in 2050. For CO₂ co-electrolysis we assume the same learning curve values as those listed in Table 5 for SOE.

The Fuel Cell and Hydrogen Joint Undertaking (FCHJU) has published data on the projected costs of AE and PEM systems producing 500 kg per day.¹⁹ These data points are included in

the two graphs of Fig. 4 and show that our analysis for AE is rather conservative in comparison to their projections, although they fall within our range. For PEM the observed trend is similar to our projections, especially if corrected for economies-of-scale. The same trend is reported in a recent study in which the future system costs of electrolysis are estimated based on expert elicitations.⁸⁴ The study also includes the elicited CAPEX data for SOE. In their production scale up scenario for 2030 this elicited data range is covered by both their and our learning curve projection.

For methanol plants, FT plants, and PEC systems, no data for learning phenomena are available. We choose the LR for these technologies by estimating their position in the Gaussian distribution for LR reported in the literature.⁷⁸ More mature technologies, such as methanol and FT plants, generally have a lower learning rate (left of the mean value in the Gaussian), which justifies our choice of LR = 10%. Novel technologies have a higher learning rate, so that for PEC we select a value of 20%, around the mean of the distribution. The production capacity in 2015 of methanol and FT plants is taken as their CIC. No installed capacity for PEC exists at present and thus, as the starting point for the CIC, our plant size is used. In addition to a low LR, also the CAGR is low for mature commercial technologies such as AE (4%), methanol synthesis (7%), and FT synthesis (13%). As PEC is an emerging technology, we estimate its CAGR to be relatively high at 30%.

To compare the investment costs of all routes in one single scheme, we convert the commonly used units of capacity for our seven technologies (e.g. kW, kWe, and kWp_{H₂}) into a uniform unit: costs per GJ (LHV) of product generated. These costs are depicted in Fig. 5 on a logarithmic scale and reveal that for all routes investment costs in 2015 are above 4 \$ per GJ (blue bars). For PEC the CAPEX is high, but includes costs associated with the energy harvesting system, in this case solar light capture. This contribution is excluded in the other routes for which electricity is used as energy feedstock. The investment costs of a renewable power source at this scale would add approximately 7–17 \$ per GJ (based on a CF of 50–20% respectively) to the overall investment costs in 2015. For the levelized costs of REN fuel production this share of the investments is covered by additional electricity costs, which thus allows for a fair comparison of all routes.

Fig. 4 Projected reductions for investment costs (CAPEX, in US\$(2015) per kW) of AE and PEM systems.

Fig. 5 Investment costs (CAPEX, in US\$(2015) per GJ of product) for our seven REN fuel production routes. Blue bars indicate the cost range in 2015, green bars in 2050. Light colours denote our optimistic estimates, dark colours more conservative ones. Note the logarithmic scale of the x-axis.

Learning-by-doing has much influence on projected investment costs in 2050: this is illustrated by the green bars in Fig. 5. The intensity of projected cost reductions per technology follows the trends described above, and thus depends on the values of LR, CIC, CAGR, and DF. For all routes, except AE, it is possible in 2050 – in an optimistic scenario – to reach a value of the CAPEX below 1 \$ per GJ of product formed. For REN H₂ (SOE) and REN syngas (CO₂-SOE) the investment costs even decrease below 1 \$ per GJ in the base case situation, which is mainly caused by the high LR and CAGR for SOE technology.

Learning curve for renewable electricity

The processes considered in this paper are assumed to be fully electrified, that is, using only electricity and/or electric heating. All electricity required is generated by renewable sources. Solar PV is taken as benchmark renewable technology. Wind power is currently cheaper than solar PV electricity in many locations, but given the higher learning rate of PV (with an LR of 23%, against 12% for wind energy),⁸⁰ as well as its higher CAGR value and lower present CIC, future cost reductions for solar PV are expected to be higher than for wind power. We take the LCOE range (5.7–6.9 \$ct per kW h) for crystalline PV at utility scale from Lazard as starting point,⁶⁸ apply learning curves with varying LR values, and thereby calculate values for LCOE in the future. Fig. 6 shows our ensuing projected LCOE reductions plotted against time until 2050.

The base case plotted in Fig. 6 (black line) is constructed on the basis of the numbers shown in Table 5. This scenario heads towards a CIC value of 6 TW in 2050 with a corresponding LCOE of 1.9 \$ct per kW h. A more conservative deployment results in a CIC value of 2 TW and an LCOE of 3.4 \$ct per kW h in 2050, which is represented by the upper line of the yellow shading in Fig. 6. In these scenarios the power generated by PV covers around 7–22% of projected electricity demand in 2050. In an optimistic scenario we set the LR to 25% and assume a CAGR of 30% (declining at 4% per year, hence a DF of 0.96),

Fig. 6 Levelized costs of electricity (in US\$ct(2015) per kW h) generated with utility scale solar PV. Two data points representing recent bid prices of auctions in Denmark and Abu Dhabi are included for purposes of comparison between a low and high solar irradiation region, respectively.

which is represented by the lower line of the yellow shading in Fig. 6. This implies a CIC value of 35 TW in 2050, enough to satisfy all global electricity demand at an LCOE of 0.7 \$ct per kW h. Some publications report similar volumes for optimistic PV cost reduction scenarios.⁸⁵ As a consequence, excesses of generated electricity can be made available for REN fuel production, which is among the main drivers behind this optimistic scenario. Once direct solar conversion approaches (such as PEC systems) reach the commercial stage, the growth in solar PV deployment may perhaps be reduced.

Our projections indicate that renewable electricity production costs can continue to drop significantly. This matches real-life, as increasingly renewable energy projects are able to compete with market-price electricity generation without policy support such as subsidies. Recent bids show the competitiveness of some of the offered PV prices (see Fig. 6), although the precise underlying kW h production costs are unknown.

Learning curves for renewable fuel costs

With formula (1) cost reduction potentials can be calculated for each of our seven REN fuel production pathways. We use our investment cost projections in combination with the projected costs of electricity depicted in Fig. 6, both derived on the basis of learning curves, to determine the levelized REN fuel production costs until 2050 for each of these seven routes. Our findings are reported in Fig. 7.

Fig. 7 shows that for the first three routes, the electrolysis pathways to produce REN H₂, break-even with respect to current H₂ production cost estimates is reached before 2050 under optimistic technology deployment assumptions. For AE, PEM, and SOE the most optimistic break-even years are 2048, 2033, and 2027, respectively. For SOE, cost competitiveness can be reached before the middle of the century even under more pessimistic assumptions: break-even in the base case is reached in 2043, thanks to a combination of fast reductions in investment costs and a high efficiency of SOE cells (and thus low electricity usage). Projected cost-breakdown curves for the base-case and optimistic scenario (Fig. S1 and S2, ESI[†]) show that for

Fig. 7 Projected levelized costs (in US\$ (2015) per kg) until 2050 for the production of REN fuels based on learning curves for the underlying technologies. Among the four routes presented for REN H₂ production with H₂O as feedstock are three electrolysis options (AE, PEM, and SOE) and one photoelectrochemical approach (PEC). In three routes CO₂ is introduced as additional feedstock for the production of carbon-based REN fuels (syngas, methanol, and diesel). The horizontal dotted break-even lines represent the current costs of producing these fuels on the basis of fossil fuels.

both PEM and SOE electricity consumption is the major cost component. Due to a low learning rate for AE, CAPEX and O&M become the dominant component of the H₂ production costs *via* this route within a decade.

The PEC approach to produce REN H₂ might also yield a competitive production cost during the timeframe considered, by 2031 in our most optimistic scenario. Like with the AE and PEM routes, however, PEC technology does not reach competitiveness before 2050 in our base case. The high learning rate of this novel technology allows for fast cost reductions if enough capacity is installed. Before the PEC route can be implemented on the necessary scale, many technical hurdles still have to be overcome. To date, PEC technology has only been shown to work in the laboratory and has not entered the demonstration or commercial phase yet. As a result, high uncertainties exist in our cost projections, as can be observed in Fig. 7. PEC technologies might for a long time to come continue to suffer from high upfront investment costs, since they involve “all-in-one” systems and thus cannot directly benefit from cost reductions

realized in existing systems such as those based on solar PV. This is also demonstrated in the cost-breakdown curves for the base case and optimistic scenario, which reveal that the major cost-components are CAPEX and O&M, while electricity demand is very low (Fig. S1 and S2, ESI†).

Fig. 7 shows that REN syngas production by CO₂-SOE becomes competitive in 2039 under optimistic technology deployment assumptions, but remains uncompetitive in 2050 in the base case. If CO₂-SOE is coupled to FT synthesis producing REN diesel, a more competitive situation is obtained. With this approach (see last plot in Fig. 7) the base case arrives at break-even costs in 2037, while in our most optimistic scenario competitive costs are reached already in 2025. For PEM electrolysis coupled to CO₂-based REN methanol production, break-even costs are not achieved before 2050 in the base case, but are in our most optimistic scenario, by 2032. Under our most conservative projections, none of the seven REN fuel routes reach break-even cost values before 2050. For all carbon-based REN fuels, for the optimistic scenario in 2050, not only electricity but

also CO₂ becomes a critical component for REN fuel production, representing approximately 32–48% of the overall costs (Fig. S1, ESI†).

The cost reduction trajectories depicted in Fig. 7 are based on stylistic representations of technology progress phenomena summarized by learning curves. While they do not reveal all the relevant details of real-life plants, they quite accurately demonstrate the general trends if learning-by-doing occurs. Also, our REN fuel production cost projections cannot necessarily be compared directly to the current costs of their fossil-fuel based alternatives, as the latter are subject to change too. But at least they reveal when a certain level of competitiveness can possibly be reached under a given set of assumptions. From our results we conclude that SOE technology can be considered an early winner, since both REN H₂ and REN diesel production may reach break-even costs in the base case before 2050. To get there, current 150 kW-sized systems must be successfully scaled up to the MW level, so as to more readily expand the overall installed capacity. Novel artificial photosynthesis approaches from the fourth category of Fig. 2, such as PEC, should definitely be pursued, since their novelty implies that they could learn rapidly and thereby yield fast cost reductions.

An important feature of carbon-based REN fuel production is the required input of CO₂. REN fuel production plants can initially use the concentrated and thus relatively cheap CO₂ streams from point sources, such as large fossil fuelled power plants or industrial facilities used in the chemical industry. Ultimately, air capture would be necessary, by which CO₂ is extracted from the atmosphere. The commercial availability and costs of CO₂ acquired from air capture technology will be an important determinant for the feasibility and future of REN fuel production.

Whether our seven REN fuel production routes will truly become competitive depends on many factors, such as installed capacity, taxes, subsidies, other policies, and the price of CO₂. Our results show, however, that the costs to produce REN fuels may drop significantly over the coming decades. For several approaches this cost reduction process may go fast enough so as to reach competitive break-even within ten years from now. Fig. 8 summarizes our comparison between future REN fuel production costs in 2050 and the costs of fossil based fuel production in 2015. Our work reveals that renewable fuels might become a valuable option for replacing current fossil-fuel based incumbents. As a prerequisite for their success, it is of prime importance to invest in research in these technologies as well as in approaches to stimulate learning-by-doing. Efforts to improve the scalability, efficiency, integration, and affordability of the necessary components are all important aspects for successful large-scale deployment of the technology. Research topics of interest consist of advanced construction of technology (e.g. 3D printing, automation, and mass production); development of efficient and scalable materials for energy harvesting, CO₂ capture, and catalysis; system integration and optimization (e.g. use of waste heat); development of cost-effective grid-scale storage of intermittent renewable energy, among many others.^{44,45,86–88}

At certain locations and under specific conditions, the production of REN fuels can already compete with fossil based alternatives, especially if customers are willing to pay extra for being more sustainable. Such locations and conditions serve well for building pilot projects. A good example is the CRI George Olah methanol plant in Iceland. If in our model we employ an AE system with 95% capacity factor (since the CRI facility runs on geothermal electricity) and couple it to a methanol synthesis

Fig. 8 Levelized production costs of four REN fuels produced via seven routes. The numbers in the chart represent the lowest achievable costs among our most optimistic projections. The bars indicate the entire cost range from lowest to highest possible values. Blue bars represent 2015 cost estimates, green bars the costs projected for 2050. Light coloured are our optimistic calculations, dark coloured our conservative calculations. Black dotted lines denote current fossil-fuel based production costs. These (break-even) lines cross the green bars in all seven cases, which illustrates that before 2050 competitiveness can be reached for each of our examples. Note the logarithmic scale of the x-axis.

system under relatively optimistic assumptions (e.g. a CO₂ cost of 0 \$ per kg, a discount factor of 8%, an AE efficiency of 71%, and an electricity price of 3.5 \$ct per kW h), a REN methanol production cost of 0.65 \$ per kg is obtained. This is in good agreement with the market value of “green” methanol (~0.7 \$ per kg as reported by CRI),²² and shows in a concrete case the potential attractiveness of REN fuels if the conditions are right.

5. Conclusions

Today most approaches to synthesize REN fuels are unattractive due to their high costs in comparison to fossil-fuel based production pathways. We find, however, that sufficient deployment investments for REN fuel production routes may yield learning-by-doing processes that relatively rapidly reduce the leveled production costs. Especially for electroconversion routes, it is of prime importance that renewable electricity generation costs continue to decrease. This requirement is met if the thus far observed learning curve for solar PV power production can be extrapolated into the future.

Our analysis reveals that for mature technologies such as AE, MP, and FT, the expected investment cost reductions are relatively modest. This limits the prospects for REN fuel production *via* AE, since both PEM and SOE have a higher LR and CAGR. Especially SOE appears an early winner, as in an optimistic scenario it could yield competitive costs for REN H₂ production already in 2027. The base case might reach break-even costs in 2043. For REN diesel production we obtain the best projections, as in the base case it can be produced at competitive prices in 2037 (partly because it also benefits from SOE technology progress).

The most novel REN fuel production routes are of particular interest because, in the case of our optimistic assumptions, we show that they may become competitive relatively soon. Photo-conversion techniques are among the most innovative pathways. The expected high LR and CAGR make these technologies susceptible to rapid cost reductions, as we demonstrate for PEC. A disadvantage of photoconversion routes is the relatively low CF of only ~20%, as well as the high initial investment costs. Only if investment costs become low enough, these approaches become interesting and can emerge from the demonstration phase that they are currently in. Manufacturing a fully integrated conversion device in which light harvesting, charge separation, and catalysis produce the desired REN fuel in a single step, possesses the potential to generate low investment costs – this effect has been observed for analogous integrated systems, such as PV cells producing electricity.

Our calculations show that several opportunities exist to produce REN fuels at competitive costs in the medium term if learning-by-doing phenomena proceed as expected. The study described in this paper provides confidence that REN fuel production can become a valuable contribution to establishing a CO₂ neutral energy system. Other fuels or production routes not analysed in our study might even show more promising opportunities: we recommend expanding our analysis to such possibilities. A combination of intensified fundamental

research and enhanced investments in demonstration plants and manufacturing facilities is required to achieve the necessary cost reductions and thereby stimulate the development and eventually large-scale deployment of REN fuel production technologies.

Conflicts of interest

There are no conflicts to declare.

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