Solar RRL
www.solar-rrl.com

True Cost of Solar Hydrogen

Eero Vartiainen, Christian Breyer, David Moser, Eduardo Román Medina, Chiara Busto, Gaëtan Masson, Elina Bosch, and Arnulf Jäger-Waldau*

Green hydrogen will be an essential part of the future 100% sustainable energy and industry system. Up to one-third of the required solar and wind electricity would eventually be used for water electrolysis to produce hydrogen, increasing the cumulative electrolyzer capacity to about 17 TW_{el} by 2050. The key method applied in this research is a learning curve approach for the key technologies, i.e., solar photovoltaics (PV) and water electrolyzers, and levelized cost of hydrogen (LCOH). Sensitivities for the hydrogen demand and various input parameters are considered. Electrolyzer capital expenditure (CAPEX) for a large utility-scale system is expected to decrease from the current 400 €/kW_{el} to 240 €/kW_{el} by 2030 and to 80 €/kW_{el} by 2050. With the continuing solar PV cost decrease, this will lead to an LCOH decrease from the current 31–81 €/$MWh_{H2,LHV}$ (1.0–2.7 €/kg_{H2}) to 20–54 €/$MWh_{H2,LHV}$ (0.7–1.8 €/kg_{H2}) by 2030 and 10–27 €/$MWh_{H2,LHV}$ (0.3–0.9 €/kg_{H2}) by 2050, depending on the location. The share of PV electricity cost in the LCOH will increase from the current 63% to 74% by 2050.

1. Introduction

In the past two years, the hydrogen sector and the hydrogen economy have experienced another wave of strong political support as enablers for a future carbon-neutral energy system. This new wave is driven by an acceleration toward the energy transition and more ambitious decarbonization targets that are needed to achieve at least the ambitious 1.5 °C target of the Paris Agreement. Compared to previous hype, the current technology development, cost reduction, and a better view on the sectors that will benefit from it clearly point to the expectation that this time the hydrogen sector may be ready to deliver and live up to its promises about hydrogen as the enabler for a future carbon-neutral energy system.

There has been a long-lasting debate for what parts of an energy system hydrogen will be finally required.[1–3] Recent years have provided more and more insights that electrification is the way forward for sustainable and low-cost energy system solutions,[4–7] whereas hard-to-abate segments are very often linked to a hydrogen route, which may justify us summarizing these various routes as the hydrogen-to-X applications. The major hydrogen demand has been identified for long-distance transportation of goods in aviation and marine, as well as industrial applications for hydrogen-based steel making and chemicals. Minor hydrogen demand has been identified for road and rail transportation, heat supply, and seasonal balancing of power supply. Most of the hydrogen is expected to be further processed to e-methane,[8,9] Fischer–Tropsch fuels,[10,11] e-ammonia,[12,13] and e-methanol,,[14,15] while hydrogen as a final energy fuel is most important for hydrogen direct reduced iron.[16] There is an ongoing debate on the value of hydrogen for road transportation, but the about twice as efficient battery-electric vehicles[17] lead to clear commitments of major vehicle manufacturers for a dedicated battery-electric vehicle strategy, for cars, buses, and trucks.[18,19] However, a 100% renewable energy system in 2050 with a very high direct electrification approach and continued energy services demand growth which supports the United Nations Sustainable Development Goals leads to 41 760 TWh of hydrogen demand,[6] thereof most for e-fuels synthesis, which is the highest reported hydrogen demand to the knowledge of the authors.

A lot of emphasis is put on the different "colors" of hydrogen, which muddles the big picture: eventually, all energy sources need to be renewable and hydrogen will be "green." Solar photovoltaics (PV) and wind power will be the heart of the 100%

E. Vartiainen
Fortum Growth Oy
POB 100, FI-00048 Fortum, Finland
E-mail: eero.vartiainen@fortum.com

C. Breyer
LUT University
Yliopistonkatu 34, 53850 Lappeenranta, Finland

D. Moser
Eurac Research
Institute for Renewable Energy
Viale Druso 1, 39100 Bolzano, Italy

E. Román Medina
TECNALIA
Basque Research and Technology Alliance (BRTA)
Astondoa Kalea Edif. 700, Derio 48170, Spain

C. Busto
Eni S.p.A.
Via Fauser, 4, 28100 Novara, Italy

G. Masson, E. Bosch
Becquerel Institute
Rue Royale 146, 1000 Brussels, Belgium

A. Jäger-Waldau
European Commission
Joint Research Centre (JRC)
Via E. Fermi 2749, 21027 Ispra, Italy

The ORCID identification number(s) for the author(s) of this article can be found under https://doi.org/10.1002/solr.202100487.

DOI: 10.1002/solr.202100487

renewable system because both are substantially scalable and enabled by battery storage and hydrogen.[4,6] The technology for the various conversion steps along the hydrogen value chain (electrolysis, storage, hydrogen-to-X synthesis, fuel cell, transport) is approaching market maturity; however, it has not experienced yet a mass market able to achieve a significant cost reduction along a whole market segment. At the moment, the main benefits in terms of economy of scale are to be found in large-size electrolyzers, where anything below 1 MW still shows very high CAPEX.[20] Direct solar hydrogen generation via photoelectrolysis is less mature than electricity-based electrolysis, whereas fast progress in solar-to-hydrogen conversion efficiencies of up to 20% have been demonstrated for a growing number of materials.[21] The projected cost is indicated for about 100€/$MWh_{H2,LHV}$ (3.4€/kg_{H2}) for a midterm commercialization, based on present lab-scale technology status. This research investigates solar PV electricity utilized for solar hydrogen generation via electrolysis, as all technologies are commercially available for large-scale applications. A comprehensive literature review on various hydrogen production methods, including electrolysis in general, PV-based electrolysis in particular, but also photoelectrolysis, is provided by Dincer and Acar.[22]

For these reasons, this article investigates the current and future cost of utility-scale solar PV hydrogen, starting from the capital (CAPEX) and operational expenditure (OPEX) projections for solar PV and electrolysis technology. Historical learning rates (LRs) are used for the future cost projections together with several volume growth scenarios. The levelized cost of hydrogen (LCOH) is calculated for five European and five non-European locations with different solar irradiation levels and with several weighted-average cost of capital (WACC) rates.

A lot of reports on clean hydrogen have recently been published,[3,20,23] but very few have used an up-to-date and realistic future projection of the levelized cost of electricity (LCOE) for PV as it is a major issue outside the PV community.[24,25] PV LCOE is very significant because the major part of the future LCOH is electricity cost. Another aspect is that the current electrolyzer market is still very immature, most of the projects are tailor-made, site-sensitive, and quite small, and there is not yet real mass manufacturing. The scaling effect is very significant and for this reason it is not wise to use past CAPEX for small projects (<1 MW_{el} on average) with truly utility-scale (>100 MW_{el}) projects. The correct estimate of LCOH is of utmost importance for the policy makers when decisions are made for a carbon-neutral world between various technology options.

2. Cost of Solar PV

The cost of solar PV systems has decreased dramatically over the past years. Market prices of PV modules have decreased by about 90%[26] and system prices by close to 80%[27] during a decade, making solar PV the cheapest form of electricity generation in many parts of the world with power purchase agreements (PPAs) as low as 12€/MWh[28] in some countries. The focus here is utility-scale PV systems with capacity of 100 MWp or more. The European Technology and Innovation Platform for Photovoltaics (ETIP PV) reported in 2020 the CAPEX for a fixed-tilt utility-scale PV system as 0.43€/Wp,[29] although in some countries such as India it can be significantly lower,[30] whereas in some countries such as the United States it is higher[31] because of soft costs and higher margins. Single-axis tracking PV is becoming increasingly more common in utility-scale systems,[32] increasing the CAPEX by about 7%[33] with an increased annual yield, and further positive energy system impact.[34] Another trend is bifacial modules, which also increase the yield, the price difference with corresponding monofacial modules being currently about 0.015€/Wp according to data collected from PVinfoLink and bifacial manufacturers.[35] A bifacial utility-scale PV system with single-axis tracking with a price of 0.47€/Wp in 2020 is assumed here. Research insights indicate that single-axis tracking bifacial PV may become the utility-scale standard in the years to come.[36]

The future development of PV CAPEX is projected with PV cumulative volume capacity growth and learning rates (LRs). **Figure 1** shows three different volume growth scenarios.[37] These growth scenarios reflect the range of long-term PV deployment projections, as the International Energy Agency (IEA) and the International Renewable Energy Agency (IRENA) indicate the slow-growth scenario,[38,39] whereas Haegel et al.[40] and Bogdanov et al.[6] strongly indicate the fast-growth scenario. Latest studies of the IEA[41] and IRENA[42] project a solar PV installed capacity in 2050 of about 14 000 GW, which is still substantially below the base growth scenario in this research. The base growth scenario reflects a compromise for the variety of studies.[37] Xiao et al.[24] and Victoria et al.[25] find a high range in PV cost assumptions in energy system studies and conclude that almost all studies are based on too high and often outdated cost assumptions, underestimating the role of solar PV. It is not intended to detail concrete PV technologies, which will enable the projected PV CAPEX, while there is a strong expectation that monocrystalline silicon PV may be the long-term technology platform, with high chances of c-Si/perovskite tandem applications.[32,43,44] A broad variety of technologies is under continued research with continuously increasing efficiencies and new developments,[45] which may further accelerate the overall PV deployment and cost reduction.

Historically, the average module price has decreased by an average 23.8% every time the global cumulative capacity has doubled.[32] However, from 2006 to 2020 this LR has been 40%.[32] A conservative 25% LR is assumed as base case here. For inverters, a lower LR of 20% shown by industry data[46] is assumed.

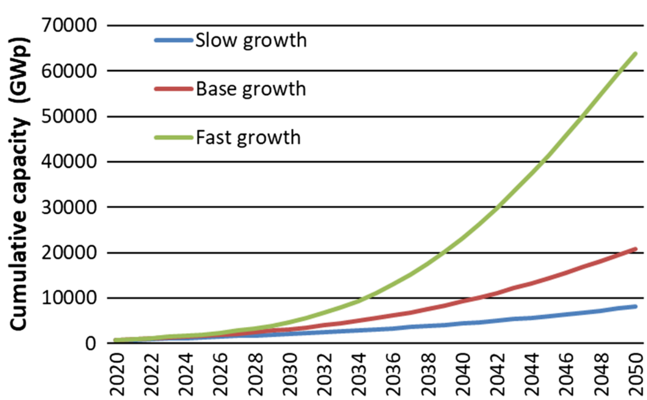

Figure 1. Global cumulative PV volume with three growth scenarios.

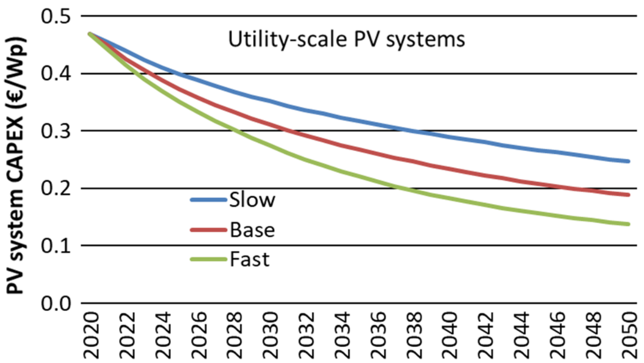

Figure 2. PV CAPEX for a system with single-axis tracking and bifacial modules with three different volume growth scenarios.

For other balance of system (BoS) components, an average 7.5%[37] LR is assumed. Because about 50% of BoS depends on the area of the modules,[46] higher efficiency will in addition drive down the BoS significantly. A historical average 0.4% point annual module efficiency increase[27] in the future is assumed here. **Figure 2** shows the CAPEX development with three volume growth scenarios.

The main component of OPEX is usually the operation and maintenance (O&M). The O&M cost varies greatly depending on the size of the system, scope of the O&M, and location. Bloomberg New Energy Finance (BNEF) reported the average full-scope O&M contract price as 6.7€/kWp/a in 2019, although with a large project or smaller scope it can be less than 4 €/kWp/a.[47] Here 1% of CAPEX (4.7€/kWp/a) in 2020 is assumed as the starting point. Apart from O&M, other components of OPEX include land lease, insurance, grid fees, balancing, asset management, and various taxes. The amount of these cost components varies by country and by project. It is assumed that their total amount equals the O&M price; i.e., the total OPEX in 2020 was 9.4€/kWp/a. The future OPEX is assumed to decrease with 10% LR.[37]

3. Cost of Electrolysis

Production of hydrogen with alkaline electrolysis cells (AECs) has been used for industrial applications since 1920.[48] The cumulative installed water electrolysis capacity since 1956 has been estimated to be around 20 GW_{el},[49,50] although the annual market volume in 2019 was just 140 MW_{el}.[51] Future volume growth is expected to be very relevant. Here three different scenarios are used. By 2050, the installed capacity is expected to be either 1, 5, or 17 TW_{el}. The first two are based on IRENA scenarios[20] and the latter would be required for the 100% sustainable energy and industry system by 2050.[6,52] For example, in a recent study[53] it was concluded that most of the examined European regions have sufficiently high technical potentials to be self-reliant using renewable energy. For the base scenario here, 5 TW_{el} global electrolyzer capacity by 2050 is assumed. The different scenarios are shown in **Figure 3**.

Electrolyzer CAPEX depends heavily on the scale. Currently a 200 kW_{el} electrolyzer has 2.3 times the unit cost of a 1 MW_{el} electrolyzer[54] and in turn a 1 MW_{el} electrolyzer has 2.4 times the unit cost of a 100 MW_{el} electrolyzer[20]; combined this makes a factor of 5.5 between 200 kW_{el} and 100 MW_{el}. This is significant because the majority of electrolyzer projects in 2018 were still below 1 MW_{el},[55] whereas 100 MW_{el} systems are now available. Scaling up is done with multistack systems,[56] which allow modular construction and cost savings by mass manufacturing. IRENA reports[20] the investment cost for a 100 MW_{el} electrolyzer system being 450\$/kW_{el} (370€/kW_{el} with the May 2021 exchange rate). This price level covers the full system cost, including the electrolyzer stack, balance of plant (BoP), installation, civil works, grid connection, and utilities.

It could be argued that in a hybrid PV and electrolyzer plant the investment cost would be significantly lower because,

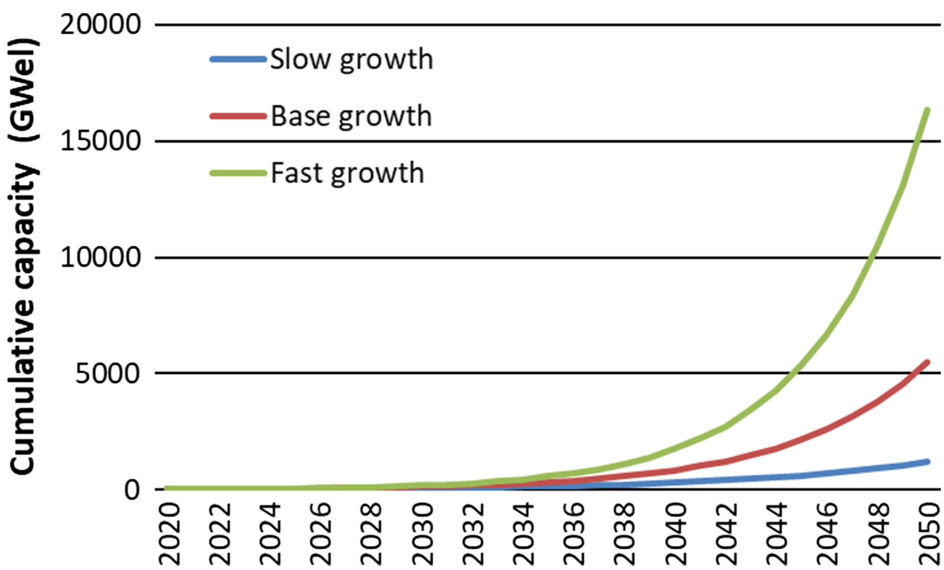

Figure 3. Global cumulative electrolyzer capacity growth in three different scenarios.

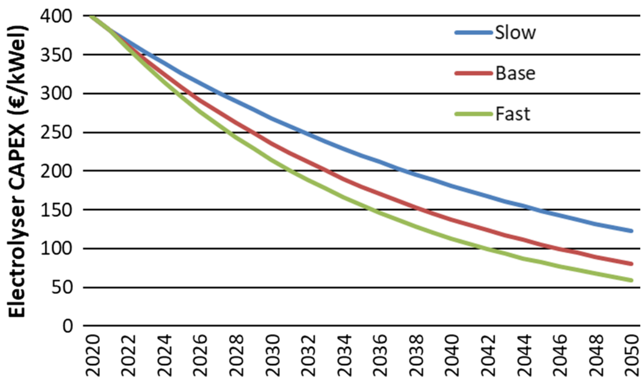

Figure 4. Electrolyzer system CAPEX with three different volume growth scenarios.

e.g., the grid connection can be used by both. Another advantage is that the electrolyzer plant could use directly DC generated by PV, thus saving most of the power electronics cost, which is about 20% of the total cost in a 100 MW_{el} system.[20] In fact, a system cost of as low as 200\$/kW_{el} has been reported by offers from Chinese manufacturers.[51] However, a conservative value of 400€/kW_{el} is used here as a base case price for a 100 MW_{el} electrolyzer system in 2020.

The future electrolyzer cost depends on the volume growth and the LR. Using the volume growth scenarios shown in **Figure 3**, 18% LR,[50] the electrolyzer system CAPEX would decrease according to **Figure 4**. In the base scenario, the system CAPEX would be 240€/kW_{el} in 2030, 140€/kW_{el} in 2040, and 80 €/kW_{el} in 2050.

The electrolyzer OPEX is assumed as 1.5% of the CAPEX[23] in 2020 (6€/kW_{el}/a), and decreasing with a 10% LR after that. Electrolyzer efficiency is defined as the lower heating value (LHV) of hydrogen divided by the electricity input. The LHV for hydrogen is 33.3 kWh/kg_{H2}.[57] The state-of-the-art efficiency for alkaline electrolyzers is reported as 67%,[20,57] which is assumed here to increase by 0.3% points per year to 76% by 2050. Costs of catalysts are not regarded as critical because nickel is the most common electrocatalyst in alkaline water electrolysis.[58] Research on a broad variety of catalysts[59,60] may improve the LCOH in the future.

4. Levelized Cost of Hydrogen (LCOH)

The LCOH is the sum of electricity and electrolysis cost over the utilization rate

$$\mathrm{LCOH} = \frac{\mathrm{CAPEX_{PV}} + \frac{\mathrm{InvRepl}}{(1+\mathrm{WACC_{nom}})^{0.5\times N}} + \sum_{t=1}^{N}\left[\frac{\mathrm{OPEX_{PV}}(t)}{(1+\mathrm{WACC_{nom}})^{t}}\right]}{\mathrm{Eff}\times\sum_{t=1}^{N}\left[\frac{\mathrm{Yield}(0)\times(1-\mathrm{Degr})^{t}}{(1+\mathrm{WACC_{real}})^{t}}\right]} + \frac{\mathrm{CAPEX_{el}} + \frac{\mathrm{StackRepl}}{(1+\mathrm{WACC_{nom}})^{20}} + \sum_{t=1}^{N}\left[\frac{\mathrm{OPEX_{el}}(t)}{(1+\mathrm{WACC_{nom}})^{t}}\right]}{\mathrm{Eff}\times\sum_{t=1}^{N}\left[\frac{\mathrm{FLH}(0)\times(1-\mathrm{Degr})^{t}}{(1+\mathrm{WACC_{real}})^{t}}\right]} \quad (1)$$

where N is the economic lifetime of the system; t is the year number, ranging from 1 to N; $\mathrm{CAPEX_{PV}}$ is the capital expenditure of the PV system, made at $t=0$ in €/kWp; InvRepl is the cost of inverter replacement, made at $t=N/2$ in €/kWp; $\mathrm{OPEX_{PV}}(t)$ is PV system operation and maintenance expenditure in year t in €/kWp; Yield(0) is the initial annual PV yield in year 0 in kWh/kWp without degradation; Degr is annual degradation of the nominal power of the system; Eff is the electrolyzer efficiency; $\mathrm{CAPEX_{el}}$ is the capital expenditure of the electrolyzer system, made at $t=0$ in €/kW; StackRepl is the cost of electrolyzer stack replacement, made at $t=20$ in €/kW; $\mathrm{OPEX_{el}}(t)$ is the electrolyzer operation and maintenance expenditure in year t in €/kW; FLH(0) is the initial annual electrolyzer full load hours in year 0 in hours without degradation; $\mathrm{WACC_{nom}}$ is the nominal weighted average cost of capital per annum; and $\mathrm{WACC_{real}}$ is the real weighted average cost of capital per annum.

The relationship between $\mathrm{WACC_{nom}}$ and $\mathrm{WACC_{real}}$ is expressed with the formula

$$\mathrm{WACC_{real}} = \frac{1+\mathrm{WACC_{nom}}}{1+\mathrm{Infl}} - 1 \quad (2)$$

where Infl is the annual inflation rate.

In this research, all results are given in real 2020 money. As nominal WACC rates are used here, inflation has to be taken into account to arrive at real values. For example, a 4% nominal WACC with 2% inflation rate corresponds to a 2% real WACC. Because the WACC rates are highly subjective and depend among other things on the country, market segment, investor type, and risk appetite, a set of three different nominal WACC rates are included in the sensitivity analysis: 4%, 7%, and 10%.

The PV yield is calculated from the Solargis database[61] for five European and five other locations: Helsinki (Finland), Munich (Germany), Toulouse (France), Rome (Italy), Malaga (Spain), Rajasthan (India), El Paso (Texas, USA), Western Australia, South Africa, and Atacama Desert (Chile). Because the PV system seldom generates electricity at the nominal peak power, it is wise to oversize the PV system in relation to the electrolyzer input power. A ratio of 1.33 is used here, which means that electrolyzers have 33% more full load hours (FLHs) compared to the PV yield in each location. A first-year 2% degradation and annual 0.5% degradation after that is assumed on the initial values of PV yield.[32] In a study of 11 commercial alkaline electrolyzer systems with electric power inputs between 0.3 and 3.3 kW, the annual efficiency degradation was 0.10–1.50% with stack lifetimes of 50 000–96 000 h.[62,63] As a base case, 0.5% degradation is assumed here. **Table 1** lists the PV yield and electrolyzer FLH for each location.

The PV system lifetime is assumed to be 30 years, which is becoming the industry standard for PV module production guarantees.[32] Inverter replacement is assumed to take place at the half-point of the PV system lifetime. Electrolyzer lifetime is also assumed as 30 years. The electrolyzer stack should last up to 90 000 h,[50] which should be adequate for the 30 years expected lifetime of the PV system in the chosen European locations. However, for locations closer to the equator, the electrolyzer utilization during 30 years could exceed 90 000 h. For this reason, one electrolyzer stack replacement representing 25% of the CAPEX of the time after 20 years is included in the equation. It must be noted that many reports quote much too high OPEX figures for PV electrolyzers because they include the stack

Table 1. PV yield and electrolyzer full load hours and capacity factors of five European and five non-European locations. PV yield is for a single-axis tracking system with bifacial modules.

	PV yield [kWh (kWp a)$^{-1}$]	PV capacity factor [%]	Electrolyzer FLH [h a^{-1}]	Electrolyzer capacity factor [%]
Helsinki, Finland	1220	13.9	1620	18.5
Munich, Germany	1370	15.6	1820	20.8
Toulouse, France	1580	18.0	2100	24.1
Rome, Italy	1900	21.7	2530	28.9
Malaga, Spain	2110	24.1	2810	32.1
Rajasthan, India	2120	24.2	2820	32.2
Texas, US	2530	28.9	3370	38.5
Western Australia	2660	30.4	3540	40.4
South Africa	2710	30.9	3610	41.2
Atacama, Chile	3230	36.9	4300	49.1

replacement in OPEX. This grossly exaggerates the effect of stack replacement in the LCOH because it is only made once later in the lifetime of the system and is discounted to the present time in real terms.

Figure 5 shows the LCOH for the five European locations and **Figure 6** for the other five locations with the base volume growth and cost assumptions for solar PV and electrolyzers. The current LCOH ranges from 31€/MWh$_{H2,LHV}$ (1.0€/kg$_{H2}$) in Atacama to 81€/MWh$_{H2,LHV}$ (2.7€/kg$_{H2}$) in Helsinki. By 2030 LCOH will decrease by about 33% and by 67% by 2050. It is notable that the cost of PV-generated electricity is already about 63% of the LCOH, increasing to about 74% by 2050. This suggests that electrolyzer CAPEX will not play a major role in the future LCOH development. It further indicates that low-cost CAPEX electrolyzers are not constrained by the solar PV yield, as it is still assumed in many publications. High FLHs are only required for high-CAPEX electrolyzers.

5. Sensitivity Analysis

Because there are substantial uncertainties on the future development of the various parameters affecting the LCOH, a thorough sensitivity analysis was made by varying 11 key input parameters. In addition to location, nominal WACC, annual inflation, PV volume growth, electrolyzer LR, FLH, CAPEX, volume growth, OPEX, efficiency, lifetime, and stack replacement were chosen. **Figure 7** shows the impact of each parameter on LCOH in Toulouse, France, in 2050.

As it is quite obvious, the location with the specific yield and FLH has the biggest impact on the LCOH. Changing the nominal WACC from 7% by 300 basis points has a more than ±20% impact on the LCOH and inflation is also a significant factor. PV volume growth has an almost as significant effect as WACC on LCOH because electricity cost is the major part of the LCOH and slow/fast growth has about ±30% effect on the PV CAPEX by 2050. Changing the electrolyzer LR or FLHs has a relatively smaller effect and increasing the electrolyzer CAPEX by 50% only increases the LCOH by 8%. This shows that even though there is a wide range of estimates on the current and future CAPEX of electrolyzers, it does not have a decisive impact in the end. Electrolyzer volume growth, OPEX, efficiency, and lifetime have a relatively minor effect and the impact of stack replacement is only 2% on the LCOH.

6. Use Cases

Hydrogen is a very versatile energy carrier that can be used in the power generation sector, in storage, in transportation, in heating and power for buildings, in industry and as industry feedstock, directly, but also indirectly for e-fuels and e-chemicals. In the following sections, comparison will be made with steam methane

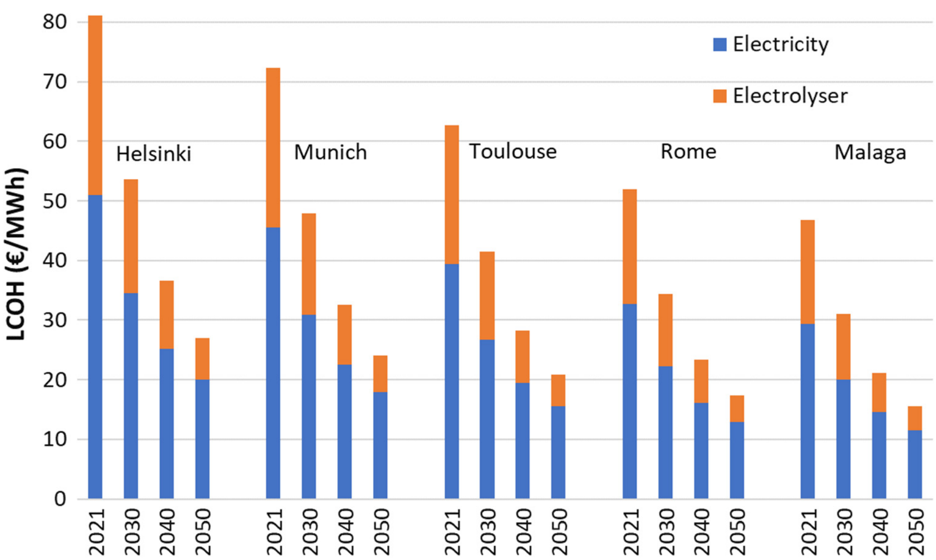

Figure 5. LCOH for five European locations with the base volume growth and cost assumptions, in €/MWh$_{H2,LHV}$.

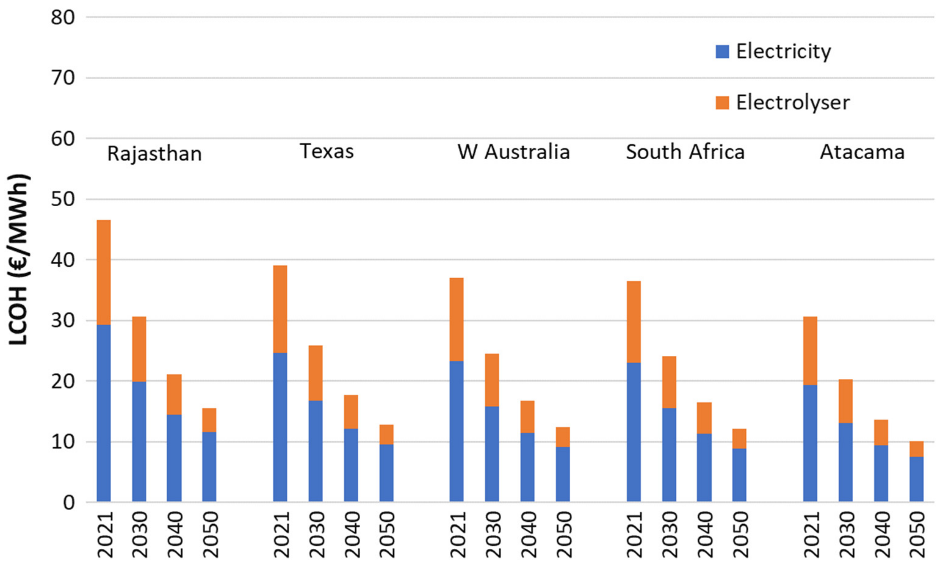

Figure 6. LCOH for five non-European locations with the base volume growth and cost assumptions, in €/MWh$_{H2,LHV}$.

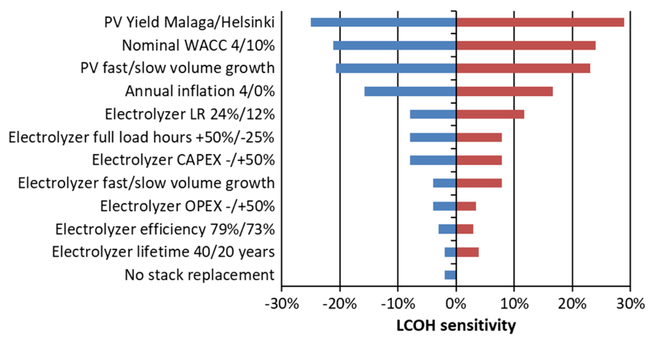

Figure 7. LCOH sensitivity on various parameters compared with a system in Toulouse, France, in 2050 with 7% nominal WACC, 2% annual inflation, base PV volume growth, electrolyzer 18% LR, 2100 FLH, 80€/kW$_{el}$ CAPEX, base volume growth, 2.6€/kW$_{el}$/a OPEX, 76% efficiency, 30 years lifetime, and stack replacement at 20 years of lifetime.

reforming and use cases are presented to showcase the importance of producing hydrogen by renewable electricity also in terms of costs.

6.1. Steam Methane Reforming Hydrogen Production

CAPEX for steam methane reforming (SMR) without carbon capture and storage (CCS) is currently 800€/kW$_{H2,LHV}$ and OPEX 38 €/kW$_{H2,LHV}$/a with 76% efficiency.[23]

Hydrogen produced by SMR with a natural gas price of 15€/MWh, 8000 FLH, 30 years lifetime, and nominal WACC of 7% with 2% annual inflation leads to an LCOH of 31€/MWh$_{H2,LHV}$ (1.0€/kg$_{H2}$) without carbon capture and storage (CCS).

The CAPEX for SMR with CCS is now about 1500€/kW$_{H2,LHV}$ and OPEX 44€/kW$_{H2,LHV}$/a with 69% efficiency.[23] With a natural gas price of 15€/MWh, 8000 FLH, 30 years lifetime, and nominal WACC of 7% with 2% annual inflation this leads to an LCOH of about 50€/MWh$_{H2,LHV}$ (1.7€/kg$_{H2}$) when the cost of CO_2 transport and storage[64] is included. In addition, the cost of the 10% CO_2 that is not captured by CCS should be taken into account.

Based on these cost figures, it can be said that solar hydrogen is already competitive with low-carbon natural-gas-based hydrogen in all five non-European considered locations as well as Southern Europe and will be competitive all over Europe around 2030. Even without considering the additional cost of CCS, solar hydrogen will be competitive in the long run in every European location.

6.2. Green Hydrogen for the Transport Sector

The cost of running 1 km on a fuel cell (FC) vehicle depends on the efficiency of the vehicle (in kg$_{H2}$/km) and on the relative cost given in €/kg$_{H2}$. If a hydrogen bus is considered as a case study, the efficiency is around 0.1 kg$_{H2}$/km (10 kg$_{H2}$/100 km). Using the cost reported in Section 6.1, the overall cost of covering 1 km using SMR produced H_2 (1.0€/kg$_{H2}$ without CCS and 1.7€/kg$_{H2}$ with CCS) would amount to 0.1 and 0.17€/km. The cost of hydrogen using utility-scale PV (shown in Figure 5 and 6) ranges from 1.0 to 2.7€/kg$_{H2}$ depending on latitude in 2021, which is reduced to 0.7 to 1.8€/kg$_{H2}$ by 2030. **Table 2** summarizes the findings.

Table 2. Comparative analysis between green hydrogen and SMR hydrogen for FC H_2 buses.

H_2 bus	2021	2030	2050
Production routes of H_2	€ km^{-1}	€ km^{-1}	€ km^{-1}
SMR without CCS	0.10	0.10	0.10
SMR with CCS	0.17	0.17	0.17
PV (Helsinki, Finland)	0.27	0.18	0.09
PV (Atacama, Chile)	0.10	0.07	0.03

By 2030, the cost of green hydrogen would decrease by about one-third and by 2050 by about two-thirds. It needs to be highlighted that although green hydrogen can quickly become economically more feasible than hydrogen generated via the SMR route, a further comparison would be needed with battery-electric buses, which are favored for lower CAPEX and lower cost of energy supply[17] and thus are at the moment the preferred choice of local transport organizations.[65] Khalili et al.,[17] discuss more efficiency and cost details of hydrogen-based and battery-electric road transportation. It is likely that hydrogen is going to be relatively more competitive in larger-scale applications such as in aviation or heavy duty road transport, where the weight of batteries is an issue. However, currently heavy-duty truck manufacturers increasingly favor battery-electric trucks due to the lower cost per driven kilometer,[19] the decisive metric in road freight transportation.

6.3. Green Hydrogen for the Building Heating Sector

Combined heat and power (CHP) can integrate FC systems to provide heat for buildings as well as electricity.[5,66] The preferred choice to heat and cool in new and refurbished buildings relies on the use of electrically driven heat pumps.[67] The use of hydrogen instead of running heat pumps requires the creation of a hydrogen infrastructure similar to the one currently used for natural gas or to transport in any other form to be delivered at the building infrastructure limiting the overall losses. This route seems to be out of scope for a vast deployment of green hydrogen and it is thus not the focus of a dedicated economic analysis, which would require the inclusion of the infrastructure cost.

6.4. Green Hydrogen in Industrial Processes

The increasing access to green hydrogen will open new possibilities in chemical processes, for example, in the “green steel” industry where hydrogen substitutes coke as a reducing agent[16] with water vapor as a byproduct instead of carbon dioxide. The FCH2-JU in the Hydrogen Roadmap Europe[68] foresees a hydrogen demand of 665 TWh (ambitious scenario), with 427 TWh for existing industry feedstock and 62 TWh of new industry feedstock. Even in the most ambitious scenario in 2030, hydrogen will play an important role, especially in hard-to-abate sectors and where hydrogen is already used as feedstock.

A chemical sector that might be of a particular industry is the chlorine/soda sector, where hydrogen is a byproduct. The chlorine-alkali process needs 97 kWh to produce 35.5 kg of chlorine, 40 kg of caustic soda, and 1 kg of H_2.[69] The production of 1 kg H_2 would thus require 1.3 kWh. It is important that the electricity needed to drive the process comes entirely from renewables. The cost of producing 1 ton of Cl_2 depends on the electricity cost, the cost of salt and water, treatment chemicals, steam and manufacturing. Eurochlor provides a cost range of 140–500€ per ton Cl_2 (with the electricity costs varying between 34 and 86€/MWh, 72€ and 290€ per ton of Cl_2 depending on EU electricity prices and process efficiency). Twenty-eight kilograms of H_2 gas is produced as byproduct, leading to a cost in the range of 0.064–0.23€/kg_{H2}. Access to electricity prices lower than 34–86€/MWh thanks to PV generation would enable the generation of H_2 as byproduct at even lower cost.

A very large industrial demand will arise from the chemical industry as a feedstock for bulk chemicals, in particular e-ammonia[12,13] and e-methanol,[14,15] as the chemical industry can be mainly built on these fundamental bulk chemicals.[70,71] The demand for green hydrogen for the chemical industry in 2050 for e-ammonia may reach a level of 3800 TWh_{H2} and for e-methanol 15 200 $TWh_{H2.}$.[72]

6.5. Green Hydrogen for Electricity Production

Hydrogen is also discussed as a relevant fuel for managing the imbalance between electricity consumption and renewable generation. Gas turbines fueled with natural gas are today used for example for peak power generation. Gas turbine manufacturers have already developed large units capable of using high blends of hydrogen fuel and turbines using solely hydrogen are on their way. The gas turbine manufacturers have committed themselves for 100% hydrogen-fueled gas turbines by 2030.[73]

Combined cycle gas turbine (CCGT) CAPEX is estimated to be 10–20% higher with hydrogen as fuel compared with natural gas and the efficiency 10% lower.[74] Applying 15% increase on natural-gas-fueled CCGT CAPEX[6] gives 900€/kW_{el} CAPEX and 10% lower efficiency is 47%. The annual OPEX is assumed as 2.5% of the CAPEX and the lifetime is 35 years.[6] Hydrogen storage in large-scale salt caverns or small-scale containers is estimated to cost about 0.2€/kg_{H2} and local distribution in pipelines about 0.1€/kg_{H2}.[51] With the current LCOH (1.0€/kg_{H2}) in Atacama, the hydrogen cost at the CCGT plant would be 40€/$MWh_{H2,LHV}$ (1.3€/kg_{H2}). With 3000 annual FLH for the CCGT, 7% nominal WACC, and 2% annual inflation, LCOE with solar hydrogen in Atacama would currently be 111€/MWh. For Helsinki with the current hydrogen cost of 90€/$MWh_{H2,LHV}$ (3.0 €/kg_{H2}), LCOE would be 217€/MWh with the same parameters. By 2050, LCOE with solar hydrogen would decrease to 64€/MWh in Atacama and 102€/MWh in Helsinki.

7. Discussion

With the current cost of solar hydrogen, 31–81€/$MWh_{H2,LHV}$ (1.0–2.7€/kg_{H2}) in the locations of this study, green hydrogen is not yet competing with natural gas as a fuel. However, this will change rapidly as both solar electricity and water electrolysis costs are decreasing fast, and as soon as the CO_2 emissions cost of a realistic level is fully factored in. By 2030, the LCOH of solar hydrogen will decrease to 20–54€/$MWh_{H2,LHV}$ (0.7–1.8€/kg_{H2}), making it a competitive clean fuel globally compared with hydrogen produced from natural gas with CCS. And there is an even bigger cost reduction potential when mass production of electrolyzers really kicks in. So far, electrolyzer projects have been quite small and often tailor-made with very high CAPEX. Currently, there is high demand of electrolyzers and not enough manufacturing capacity, which increases the prices. In the future, growing volumes and competition from Asian manufacturers should decrease electrolyzer prices, as has happened in the PV industry.

Another factor currently increasing the LCOH in many estimations is the extremely high OPEX used in the calculations. In reality, there is not a lot of operation and maintenance to be done for an electrolysis system. And if the OPEX is calculated as a percentage of the initial CAPEX, which is too high, then the OPEX becomes too high too. The main component included in the OPEX in most estimations is the electrolyzer stack replacement. This should not be included in the OPEX every year but applied at the point of time when it is really done and then discounted to present time. With high WACC rates, this makes a big difference. Furthermore, stack replacement may not be needed at all in locations with relatively low solar yield and electrolyzer FLH.

Proper sizing of the system is key: the peak power of the PV system should always be oversized compared with the electrolyzer input power because the PV system seldom generates electricity with its full peak power. Because of the complementary generation curves of solar and wind power, a hybrid PV–wind system would significantly increase the electrolyzer FLH. Such hybrid plants could be integrated on site[75] or separated at sites of best resources and finally interconnected with power lines. The longer-term value of hybrid PV–wind systems may be limited due to the very low-cost PV electricity, as concluded in Fasihi and Breyer.[76] A full hourly optimization using cost assumptions from 2018 and hybrid PV–wind systems led to a green hydrogen production cost of about 40–80€/$MWh_{H2,LHV}$ (1.3–2.7€/kg_{H2}) in 2030 in a range of comparable regions in the world, compared to a decrease to 20–54€/$MWh_{H2,LHV}$ (0.7–1.8€/kg_{H2}) found in this research for PV-based green hydrogen, which documents the strong dynamics in cost reduction of solar PV and electrolyzers.

Further LCOH reduction would be possible using directly DC power generated by the PV system. Because both PV and electrolysis work with DC, conversions to AC and back to DC again are inefficient and increase cost. Direct DC systems are not yet standard solutions in the hydrogen sector but should be developed for local solar hydrogen production. Another potential further cost reduction potential may come from polymer electrolyte membrane (PEM) electrolyzers, which are not yet at the same maturity level as alkaline electrolyzers. However, there is concern over the adequacy of certain materials in the PEM cells. For example, the availability of iridium could be a problem when the installed capacity reaches the multi-GW scale.[60]

Electrolyzers have been optimized for industrial baseload conditions in the past, and thus it may be claimed that the ramp rates of solar PV would compromise the functionality, durability, and lifetime of electrolyzers. This potential concern ignores the very high technical ramping features of electrolyzers, which can easily follow the PV ramping rates of utility-scale applications, as even frequency containment regulation services in electricity markets could be served by electrolyzers.[64]

Finally, as the electrolyzer technology further matures, the related risk perceived by investors should decrease, lowering the WACC rate of the investment. This is significant because as shown by the sensitivity analysis, WACC is the most important input parameter in the calculation of LCOH after location and solar yield.

Still, it needs to be clearly noted that hydrogen is part of an overall energy and industry system optimization,[6,77] which finds direct electric solutions in practically all cases lower in cost and higher in efficiency than hydrogen alternatives, in case a direct electrification and hydrogen solution is available. However, some applications cannot be directly electrified in the foreseeable future or by nature, such as long-distance marine and aviation transportation, chemical and steel making, and these demand segments are expected to dominate green hydrogen demand in the years and decades to come.

8. Conclusion

Green hydrogen will be the main fuel as well as a fundamental energy vector for the future 100% sustainable energy and industry system. Up to one-third of the required solar and wind electricity would eventually be used for water electrolysis to produce hydrogen, increasing the cumulative electrolyzer capacity to about 17 TW_{el} by 2050. There is a huge growth potential from the current 20 GW_{el} and the cost of electrolysis will decrease accordingly with mass production and volume growth, as well as with scaling up the electrolyzer unit size.

Electrolyzer CAPEX for a large utility-scale system is expected to decrease from the current 400€/kW_{el} to 240€/kW_{el} by 2030 and to 80€/kW_{el} by 2050. Together with the continuing solar PV cost decrease, this will lead to an LCOH decrease from the current 31–81€/$MWh_{H2,LHV}$ (1.0–2.7€/kg_{H2}) to 20–54€/$MWh_{H2,LHV}$ (0.7–1.8 €/kg_{H2}) by 2030 and 10–27€/$MWh_{H2,LHV}$ (0.3–0.9 €/kg_{H2}) by 2050, depending on the location. The share of PV electricity in the LCOH will increase from the current 63% to 74% by 2050. Already during this decade, solar hydrogen will be globally a less expensive fuel compared with hydrogen produced from natural gas with CCS.

Acknowledgements

This study was made under the framework of the European Technology and Innovation Platform for Photovoltaics (ETIP PV). Open access of this study has been supported by the ETIP PV Secretariat which works in the framework of the ETIP PV-SEC II project. The project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement no. 825669. A.J.-W. works at the European Commission – Joint Research Centre (JRC), Ispra, Italy. The views expressed are purely those of the author and may not in any circumstances be regarded as stating an official position of the European Commission.

Conflict of Interest

The authors declare no conflict of interest.

Data Availability Statement

The data that support the findings of this study are available from the corresponding author upon reasonable request.

Keywords

green hydrogen, levelized cost of electricity, levelized cost of hydrogen, solar photovoltaics

Received: June 30, 2021
Revised: August 18, 2021
Published online:

[1] J. O. Bockris, *Science* **1972**, *176*, 1323.
[2] L. Barreto, A. Makihira, K. Riahi, *Int. J. Hydrogen Energy* **2003**, *28*, 267.
[3] C. J. Quarton, O. Tlili, L. Welder, C. Mansilla, H. Blanco, H. Heinrichs, J. Leaver, N. J. Samsatli, P. Lucchese, M. Robinius, S. Samsatli, *Sustainable Energy Fuels.* **2020**, *4*, 80.
[4] M. Z. Jacobson, M. A. Delucchi, M. A. Cameron, S. J. Coughlin, C. A. Hay, I. P. Manogaran, Y. Shu, A.-K. Von Krauland, *One Earth* **2019**, *1*, 449.
[5] S. Teske, T. Pregger, S. Simon, T. Naegler, J. Pagenkopf, Ö. Deniz, B. Van Den Adel, K. Dooley, M. Meinshausen, *Energies* **2021**, *14*, 2103.
[6] D. Bogdanov, M. Ram, A. Aghahosseini, A. Gulagi, A. S. Oyewo, M. Child, U. Caldera, K. Sadovskaia, J. Farfan, L. D. S. N. S. Barbosa, M. Fasihi, S. Khalili, T. Traber, C. Breyer, *Energy* **2021**, *227*, 120467.
[7] Early decarbonisation of the European energy system pays off | Nature Communications, https://www.nature.com/articles/s41467-020-20015-4 (accessed: June 2021).
[8] Bioenergy and renewable power methane in integrated 100% renewable energy systems, http://publica.fraunhofer.de/documents/N-139644.html (accessed: June 2021).
[9] H. Blanco, A. Faaij, *Renewable Sustainable Energy Rev.* **2018**, *81*, 1049.
[10] S. Drünert, U. Neuling, T. Zitscher, M. Kaltschmitt, *Appl. Energy* **2020**, *277*, 115578.
[11] M. Fasihi, D. Bogdanov, C. Breyer, *Energy Procedia* **2016**, *99*, 243.
[12] M. Fasihi, R. Weiss, J. Savolainen, C. Breyer, *Appl. Energy* **2021**, *294*, 116170.
[13] O. Osman, S. Sgouridis, A. Sleptchenko, *J. Cleaner Prod.* **2020**, *271*, 121627.
[14] F. Lonis, V. Tola, G. Cau, *Fuel* **2021**, *285*, 119160.
[15] Synthetic Methanol and Dimethyl Ether Production based on Hybrid PV-Wind Power Plants—LUT Research Portal Converis—LUT University, https://research.lut.fi/converis/portal/Publication/10574933?auxfun=&lang=en_GB (accessed: June 2021).
[16] A. Otto, M. Robinius, T. Grube, S. Schiebahn, A. Praktiknjo, D. Stolten, *Energies* **2017**, *10*, 451.
[17] S. Khalili, E. Rantanen, D. Bogdanov, C. Breyer, *Energies* **2019**, *12*, 3870.
[18] Volkswagen join GM in rejection of hydrogen technology – report | CarAdvice, https://www.caradvice.com.au/933112/volkswagen-join-gm-in-rejection-of-hydrogen-technology-report/ (accessed: June 2021).
[19] TRATON GROUP boosts investment in electric mobility, https://www.volkswagenag.com/en/news/2021/03/traton-group-boosts-investment-in-electric-mobility.html (accessed: June 2021).
[20] IRENA, Green Hydrogen Cost Reduction, **2020**, https://www.irena.org/publications/2020/Dec/Green-hydrogen-cost-reduction (accessed: June 2021).
[21] Y. Wang, A. Sharma, T. Duong, H. Arandiyan, T. Zhao, D. Zhang, Z. Su, M. Garbrecht, F. J. Beck, S. Karuturi, C. Zhao, K. Catchpole, *Adv. Energy Mater.* **2021**, *11*, 2101053.
[22] I. Dincer, C. Acar, *Int. J. Hydrogen Energy* **2015**, *40*, 11094.
[23] IEA, Data and Assumptions—The Future of Hydrogen—Analysis—Assumptions Annex, **2019**, https://www.iea.org/reports/the-future-of-hydrogen/data-and-assumptions (accessed: June 2021).
[24] M. Xiao, T. Junne, J. Haas, M. Klein, *Energy Strategy Rev.* **2021**, *35*, 100636.
[25] M. Victoria, N. Haegel, I. M. Peters, R. Sinton, A. Jäger-Waldau, C. Del Cañizo, C. Breyer, M. Stocks, A. Blakers, I. Kaizuka, K. Komoto, A. Smets, *Joule* **2021**, *5*, 1041.
[26] PVinsights, http://pvinsights.com/ (accessed June: 2021).
[27] Photovoltaics Report - Fraunhofer ISE. Fraunhofer Institute for Solar Energy Systems ISE, https://www.ise.fraunhofer.de/en/publications/studies/photovoltaics-report.html (accessed June: 2021).
[28] IEA PVPS, *Snapshot of Global PV Markets 2021*, https://iea-pvps.org/snapshot-reports/snapshot-2021/ (accessed June: 2021).
[29] ETIP-PV, *Fact Sheets about Photovoltaics - ETIP PV,PV the Cheapest Electricity Source Almost Everywhere*, https://etip-pv.eu/publications/fact-sheets/ (accessed June: 2021).
[30] Fortum to divest 500 MW of solar power plants in India – agreement with Actis for solar investments. Fortum, https://www.fortum.com/media/2021/06/fortum-divest-500-mw-solar-power-plants-india-agreement-actis-solar-investments (accessed June: 2021).
[31] IEA PVPS, *Trends in PV Applications 2020*, https://iea-pvps.org/trends_reports/trends-in-pv-applications-2020/ (accessed June: 2021).
[32] ITRPV, *ITRPV: Twelfth Edition Online*. https://itrpv.vdma.org:443/viewer/-/v2article/render/67038287 (accessed June: 2021).
[33] D. Feldman, V. Ramasamy, R. Margolis, Solar Photovoltaic BESS System Cost Benchmark Q1 2020 Report, Published online 2021, https://doi.org/10.7799/1762492.
[34] S. Afanasyeva, D. Bogdanov, C. Breyer, *Solar Energy* **2018**, *173*, 173.
[35] Bifacial modules: The challenges and advantages – pv magazine International, https://www.pv-magazine.com/2020/08/19/bifacial-modules-the-challenges-and-advantages/ (accessed June: 2021).
[36] C. D. Rodríguez-Gallegos, H. Liu, O. Gandhi, J. P. Singh, V. Krishnamurthy, A. Kumar, J. S. Stein, S. Wang, L. Li, T. Reindl, I. M. Peters, *Joule* **2020**, *4*, 1514.
[37] E. Vartiainen, G. Masson, C. Breyer, D. Moser, E. Román Medina, *Progr. Photovoltaics: Res. Applic.* **2020**, *28*, 439.
[38] World Energy Outlook 2020 – Analysis, IEA, https://www.iea.org/reports/world-energy-outlook-2020 (accessed: August 2021).
[39] Global energy transformation: A roadmap to 2050 (2019 edition), https://www.irena.org/publications/2019/Apr/Global-energy-transformation-A-roadmap-to-2050-2019Edition (accessed: August 2021).
[40] N. M. Haegel, H. Atwater, T. Barnes, C. Breyer, A. Burrell, Y. Chiang, S. De Wolf, B. Dimmler, D. Feldman, S. Glunz, J. C. Goldschmidt, D. Hochschild, R. Inzunza, I. Kaizuka, B. Kroposki, S. Kurtz, S. Leu, R. Margolis, K. Matsubara, A. Metz, W. K. Metzger, M. Morjaria, S. Niki, S. Nowak, I. M. Peters, S. Philipps, T. Reindl, A. Richter, D. Rose, K. Sakurai, et al., *Science* **2019**, *364*, 836.
[41] Net Zero by 2050 – Analysis - IEA, https://www.iea.org/reports/net-zero-by-2050 (accessed: August 2021).
[42] World Energy Transitions Outlook: 1.5°C Pathway, https://www.irena.org/publications/2021/Jun/World-Energy-Transitions-Outlook (accessed: August 2021).
[43] P. J. Verlinden, *J. Renewable Sustainable Energy* **2020**, *12*, 053505.
[44] The race for the best silicon bottom cell: Efficiency and cost evaluation of perovskite–silicon tandem solar cells - Messmer - 2021 - Progress in Photovoltaics: Research and Applications - Wiley Online Library, https://onlinelibrary.wiley.com/doi/10.1002/pip.3372 (accessed: August 2021).
[45] M. A. Green, E. D. Dunlop, J. Hohl-Ebinger, M. Yoshita, N. Kopidakis, X. Hao, *Progr. Photovoltaics: Res. Applic.* **2021**, *29*, 657.
[46] Fraunhofer ISE, Publication - Current and Future Cost of Photovoltaics, **2015**. https://www.agora-energiewende.de/en/publications/current-and-future-cost-of-photovoltaics/ (accessed: June 2021).

[47] BNEF, PV O&M 2020: Plant Owners Get More With Less. https://about.bnef.com/ (accessed: June 2021).
[48] X. Zhang, S. H. Chan, H. K. Ho, S.-C. Tan, M. Li, G. Li, J. Li, Z. Feng, *Int. J. Hydrogen Energy* **2015**, *40*, 6866.
[49] K. Schoots, F. Ferioli, G. Kramer, B. Vanderzwaan, *Int. J. Hydrogen Energy* **2008**, *33*, 2630.
[50] O. Schmidt, A. Gambhir, I. Staffell, A. Hawkes, J. Nelson, S. Few, *Int. J. Hydrogen Energy* **2017**, *42*, 30470.
[51] Bloomberg New Energy Finance, *Hydrogen Economy Outlook, Will Hydrogen Be the Molecule to Power a Clean Economy*, Bloomberg New Energy Finance **2020**.
[52] M. Ram, T. Galimova, D. Bogdanov, M. Fasihi, A. Gulagi, M. Micheli, K. Crone, C. Breyer, *Powerfuels in a Renewable Energy World: Global Volumes, Costs, and Trading 2030 to 2050*, **2020**.
[53] G. Kakoulaki, I. Kougias, N. Taylor, F. Dolci, J. Moya, A. Jäger-Waldau, *Energy Convers. Manage.* **2021**, *228*, 113649.
[54] A. T. Mayyas, M. F. Ruth, B. S. Pivovar, G. Bender, K. B. Wipke, *Manufacturing Cost Analysis for Proton Exchange Membrane Water Electrolyzers*, National Renewable Energy Lab. (NREL), Golden, CO **2019**.
[55] Hydrogen Projects Database – Analysis, IEA, https://www.iea.org/reports/hydrogen-projects-database (accessed: June 2021).
[56] Joris. Proost, *Int. J. Hydrogen Energy* **2020**, *45*, 17067.
[57] IEA, Data and Assumptions—The Future of Hydrogen—Analysis, **2019**. https://www.iea.org/reports/the-future-of-hydrogen/data-and-assumptions (accessed: June 2021).
[58] F. M. Sapountzi, J. M. Gracia, C. J. Weststrate, H. O. A. Fredriksson, J. W. H. Niemantsverdriet, *Progr. Energy Combust. Sci.* **2017**, *58*, 1.
[59] S. Wang, A. Lu, C.-J. Zhong, *Nano Convergence* **2021**, *8*, 4.
[60] M. Bernt, A. Hartig-Weiß, M. F. Tovini, H. A. El-Sayed, C. Schramm, J. Schröter, C. Gebauer, H. A. Gasteiger, A. Hartig-Weiß, M. F. Tovini, *Chem. Ing. Tech.* **2020**, *92*, 31.
[61] Solar Irradiance data, https://solargis.com/ (accessed: June 2021).
[62] M. David, C. Ocampo-Martínez, R. Sánchez-Peña, *J. Energy Storage* **2019**, *23*, 392.
[63] M. Felgenhauer, T. Hamacher, *Int. J. Hydrogen Energy* **2015**, *40*, 2084.
[64] S. Santos, G. Collodi, G. Azzaro, N. Ferrari, *Techno-Economic Evaluation of SMR Based Standalone (Merchant) Plant with CCS*, International Energy Agency **2017**.
[65] German bus depots clearly favoring batteries over fuel cells | S&P Global Platts, **2021**, https://www.spglobal.com/platts/en/market-insights/latest-news/electric-power/030421-german-bus-depots-clearly-favoring-batteries-over-fuel-cells (accessed: June 2021).
[66] P. Puranen, A. Kosonen, J. Ahola, *Sol. Energy* **2021**, *213*, 246.
[67] A. Rinaldi, M. C. Soini, K. Streicher, M. K. Patel, D. Parra, *Appl. Energy* **2021**, *282*, 116110.
[68] Hydrogen Roadmap Europe: A sustainable pathway for the European Energy Transition, https://www.fch.europa.eu/news/hydrogen-roadmap-europe-sustainable-pathway-european-energy-transition (accessed: June 2021).
[69] Home. Eurochlor, https://www.eurochlor.org/ (accessed: June 2021).
[70] Á. Galán-Martín, V. Tulus, I. Díaz, C. Pozo, J. Pérez-Ramírez, G. Guillén-Gosálbez, *One Earth* **2021**, *4*, 565.
[71] A. Kätelhön, R. Meys, S. Deutz, S. Suh, A. Bardow, *PNAS* **2019**, *116*, 11187.
[72] New Study: Powerfuels in a Renewable Energy World, https://www.powerfuels.org/newsroom/news/new-study-powerfuels-in-a-renewable-energy-world/?person=697&cHash=56c21d6df8a7e2365579bcd9fa20c7dc (accessed: June 2021).
[73] E. U. Turbines, Media Centre | EUTurbines, https://www.euturbines.eu/media-centre/ (accessed: June 2021).
[74] Hydrogen in the electricity value chain DNV. DNV, https://www.dnv.com/Publications/hydrogen-in-the-electricity-value-chain-141099 (accessed: June 2021).
[75] D. Ludwig, C. Breyer, A. A. Solomon, R. Seguin, *AIMS Energy* **2020**, *8*, 988.
[76] M. Fasihi, C. Breyer, *J. Cleaner Prod.* **2020**, *243*, 118466.
[77] D. Bogdanov, A. Gulagi, M. Fasihi, C. Breyer, *Appl. Energy* **2021**, *283*, 116273.