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'Clean' hydrogen? An analysis of the emissions and costs of fossil fuel based versus renewable electricity based hydrogen

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Abstract

Hydrogen produced using fossil fuel feed stocks causes greenhouse gas (GHG) emissions, even when carbon capture and storage (CCS) is used. By contrast, hydrogen produced using electrolysis and zero-emissions electricity does not create GHG emissions. Several countries advocating the use of 'clean' hydrogen put both technologies in the same category. Recent studies and strategies have compared these technologies, typically assuming high carbon capture rates, but have not assessed the impact of fugitive emissions and lower capture rates on total emissions and costs. We find that emissions from gas or coal based hydrogen production systems could be substantial even with CCS, and the cost of CCS is higher than often assumed. At the same time there are indications that electrolysis with renewable energy could become cheaper than fossil fuel with CCS options, possibly in the near-term future. Establishing hydrogen supply chains on the basis of fossil fuels, as many national strategies foresee, may be incompatible with decarbonisation objectives and raise the risk of stranded assets.

Keywords:
Renewable energy; hydrogen; electrolysis; carbon capture and storage; steam methane reforming; coal gasification

JEL Classification:
Q21, Q42, Q52

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1 Introduction

Hydrogen has the potential to become a globally traded, emissions-free energy carrier, which could help enable deep decarbonisation of industry, transport and the wider energy sector [1,2]. Global momentum to develop a hydrogen economy has never been stronger, and there has been a proliferation of national hydrogen strategies and international reports [3]. Some of the enthusiasm for hydrogen is based on declines in the cost of renewable energy and electrolysers [4], but there is also much support for scaling up traditional methods of producing hydrogen from fossil fuels with carbon capture and storage (CCS). Residual CO_2 emissions after CCS beg the question whether this is consistent with global decarbonisation objectives.

Carbon capture is a mature technology used in a range of industries, but the costs and CO_2 emissions reduction potential vary widely and in some cases are difficult to define. The amount of CO_2 captured depends not only on how and where in the process the CO_2 is captured, but also what is done with it after it is collected. Of the 21 currently operating large-scale CCS plants around the world over three quarters subsequently use the captured CO_2 for enhanced oil recovery, which means that the cost of capture can be partially offset by the sale of CO_2 [5]. However, unlike CCS, this type of carbon capture and use (CCU) can result in significant re-emission of the CO_2 into the atmosphere as enhanced oil recovery can have retention rates below 30% [6]. Carbon avoidance costs for CCS depend on the type of capture process, and include the transport and storage of captured CO_2, which is highly plant specific, as well as auditing and monitoring of capture rates and possible upstream methane or CO_2 leaks. Cost estimates for CCS usually do not always take all of these different elements into account [7,8].

In contrast, the cost of producing hydrogen with renewables depends mainly on the price of the input electricity, as well as the capital cost and load factor of the electrolyser. As renewables and electrolysers are up-scaled and deployed, the cost of this method of hydrogen production will decrease [9,10].

Currently, hydrogen is predominantly used as an industrial feedstock for ammonia and for oil refining. Its production is carbon-intensive, utilising fossil fuels without CCS. The estimated 74 million tonnes (Mt) of pure hydrogen used in 2018 generated approximately 830 Mt of CO2 emissions, or approximately 2 per cent of global greenhouse gas emissions from the energy sector

[11]. With governments promoting the use of hydrogen in other sectors, including transport, demand has been projected to increase dramatically. For example, Bloomberg NEF estimates range from 187Mt to 696 Mt for 2050 based on weak and strong policy scenarios. This increases to 1370 Mt if all the unlikely-to-electrify sectors in the economy were to use hydrogen [12]. Some strategies, notably those of Australia and Japan [13,14], also foresee the use and international trade of ammonia as an energy carrier; we do not explore ammonia in this paper, but broadly similar principles apply.

Decarbonisation can only be achieved through the use of hydrogen if the necessary expansion in its production comes from zero- or low-emission sources. Two types of low-emission hydrogen production technologies are under active consideration for early deployment: electrolysis using zero-emissions electricity (typically renewables, possibly also nuclear), considered to have no embedded greenhouse gas emissions (other than emissions incurred in the production of equipment); and existing fossil fuel production methods augmented with CCS, usually portrayed as ‘low-emission’ production. Some governments have given priority to the renewables electricity route in their strategies. Others make the case for a broader technology portfolio with a possibly prominent role for hydrogen from fossil fuels using CCS. These include Australia, Canada, China, Japan, Republic of Korea, Netherlands, Norway and the United States. Yet most of these strategies contain little detail of the emissions implications of CCS under real world conditions. Also, if the use of CCS does not coincide with the commencement of new fossil fuel based hydrogen supply chains then there will be a large increase in emissions during the start-up phase.

Under current carbon accounting mechanisms, potential hydrogen importers such as Japan and South Korea have little or no intrinsic incentive to buy ‘zero-emissions’ hydrogen or to push for high carbon capture rates. Any process emissions will occur and be accounted for in the producer countries [15]. Producer countries in turn may put the establishment of new export industries ahead of achieving lower national emissions outcomes, possibly with reference to emissions savings achieved overseas, as has been done in the case of exports of liquefied natural gas [16,17].

In Section 2 we provide an overview of the positioning of national strategies on hydrogen production technologies. We show that the overall emissions intensity of fossil fuel-based ‘low-emissions' hydrogen can be substantial if moderate CCS rates and fugitive emissions are considered (section 3.1). We find that the true cost of carbon avoidance using CCS varies widely and is often not well defined, and that current CCS cost projections rely on optimistic estimates of CO_2 transport and storage, and generally do not include monitoring and verification costs. This underestimates the true cost of hydrogen production when CCS is used (section 3.2). We show that the cost of producing hydrogen via electrolysis is highly dependent on the cost of electricity as well as electrolyser costs and capacity factors (section 4). Using a range of studies and projections, we also show that renewable hydrogen production could become cost-competitive in the near future with further reductions in renewable energy and electrolyser capital costs (section 5).

2 Existing strategies and statements on ‘low-emission’ hydrogen

This section gives an account of the positioning of key ‘low-emission’ and ‘zero-emission’ technologies in recent national policy statements and major reports. It draws on analysis of strategies and similar documents published by the European Union, the governments of Japan, the Republic of Korea, France, New Zealand, Australia, Norway, the Netherlands, Germany, Spain, Portugal, Chile, the United States of America, China and Canada [13,14,18–29], as well as the International Energy Agency (IEA) [12] and International Renewable Energy Agency (IRENA) [4]. Examination of these strategies shows that there is not, or not yet, international convergence around a single preferred technological approach. The IEA identifies both hydrogen from electrolysis with ‘zero-emission’ electricity and fossil fuel-based production with CCS as having a major ongoing role. For example, IEA projections have up to 40 per cent of global hydrogen production in 2070 from fossil fuels with CCS [30,31]. IRENA takes a contrary position, arguing that hydrogen from fossil fuels with CCS can only have a short-lived transitional role [32].

A number of national strategies focus solely on ‘zero-emission’ hydrogen as the preferred option (Table 1). Others, while promoting ‘zero-emission’ hydrogen as the superior option, support a transitional role for ‘low-emission’ hydrogen from fossil fuels with CCS and envisage some level of support for that. Still others are agnostic in their technology preferences, foreshadowing the likely ongoing use of ‘low-emission’ hydrogen as a significant component of their respective approaches. The Australian strategy professes a ‘technology-neutral’ approach and explicitly includes the possibility of ‘low-emission’ hydrogen, which it incorporates with ‘zero-emission’ hydrogen in its definition of ‘clean’ hydrogen. Norway’s strategy does likewise. The Canadian strategy describes ‘low-emission’ hydrogen from natural gas with CCS as a primary pathway for establishing a ‘clean’ hydrogen industry. The strategies of Japan and Korea both refer to plans to shore up sources of hydrogen supply through investment in production, including from fossil fuels, both domestically and internationally.

Few strategies provide realistic appraisals of the likely emissions consequences of relying on the ‘low-emission’ option. Only Australia and Canada provide detail of expected or necessary carbon capture rates for hydrogen produced from fossil fuels to be considered ‘clean’; these are at over 90 per cent [13,29] and therefore highly optimistic as we show below. In addition, fugitive emissions from the extraction of the coal and natural gas used as a feedstock in the production of hydrogen are rarely accounted for; these are important as they can be sizeable and their global warming potential is far higher than for CO_2, as we will show in section 3. In fact, many countries' strategies effectively treat 'zero-emission' and 'low-emission' hydrogen as equivalent technological options. For example, the Japanese strategy describes hydrogen produced from fossil fuels with CCS as "carbon-free" or "zero-emission" [14]. The US Department of Energy's plan for scaling up hydrogen describes fossil fuel with carbon capture use and storage as a potential means of supplying "carbon-neutral" hydrogen [33].

Table 1: Positioning of national strategies on hydrogen production technologies

Prioritisation of low- versus zero-emission hydrogen technologies	Strategies
Prioritises 'zero-emission' H_2	Chile France New Zealand Portugal Spain
'Zero-emission' H_2 prioritised but 'low-emission' H_2 discussed as a transitional measure	European Union Germany
Likely significant production/use of 'low-emission' H_2	Australia Canada China Japan Republic of Korea Netherlands Norway United States

It therefore seems highly likely that a significant number of countries will pursue approaches to scaling up hydrogen production, either domestically or internationally, that involve the continued use of fossil fuels. In addition, it is unclear whether the use of CCS will be introduced immediately on commencement of new fossil fuel based hydrogen supply chains, creating the possibility of highly emissions intensive production in the start-up phase. The framing of this choice in national strategies suggests there is a real risk of emissions in practice being higher than foreshadowed in such documents if governments actively encourage and support industry to move down the path of using fossil fuels with CCS.

3 Emissions implications of 'low-emission' hydrogen production

3.1 Emission intensity of hydrogen production

The emissions from hydrogen production vary widely depending on the feedstock and process used. Our analysis compares the emission intensity of hydrogen production processes using coal and gas with the direct emissions from the combustion of the fossil fuels (Figure 1). These are calculated as kilograms of CO_2 equivalent emissions, which are released per unit of thermal energy or energy embedded in hydrogen with a lower heating value (LHV) [1].

Steam methane reforming (SMR) is currently the most common hydrogen production technology, accounting for roughly half of production globally. Black and brown coal are also commonly used as feedstocks in coal gasification (CG). In 2019 most GC facilities were located in China where CHN Energy produced 12% of global dedicated hydrogen production [30].

In both SMR and GC, hydrogen is separated from the carbon in the hydrocarbon feedstock, producing large amount CO_2 emissions relative to using fossil fuels directly, roughly 74 kg CO_2-e/GJ for SMR, 157 kg CO_2-e/GJ for CG with black coal and 170 kg CO_2-e/GJ for brown coal. The error bars in Figure 1 reflect the large variation in emissions that occurs due to natural differences in the carbon content of fossil fuels, estimated from the default IPCC default emission factors [34]. Since we are not considering the embedded emissions in capital assets, hydrogen produced by electrolysis powered with zero-emission electricity will result in zero emissions in this analysis.

The total emissions intensities of the production of hydrogen made from both coal and gas without CCS are significantly higher than combusting the fossil-fuel feedstock. This is due to large energy losses in conversion. Typical efficiencies[2] used in the calculation are 78% for SMR [35] and 65% for CG [36].

As detailed in Section 2, fugitive emissions are rarely included in national and international strategies when assessing the emissions from fossil fuel based hydrogen. We use IPCC default emission factors for fugitive emissions associated with natural gas, and brown and black coal

[1]The lower heating value is the net heat content excluding the energy used to vaporise water. Using a LHV is consistent with the method used by the IEA [30].

[2] Efiicency is defined as energy embedded in the hydrogen produced divided by the energy embedded in the feedstock and any additional fuel used.

extraction [34] to calculate fugitive emission intensities for hydrogen production. The error bars represent the low and high values given by the IPCC to account for global variations. Our analysis shows that fugitive emissions from hydrogen production can be significant, accounting for a further 13 kg CO_2-e/GJ for hydrogen made from gas, and 26 kg CO_2-e/GJ from black coal. Brown coal is typically produced in open cut mines, which are associated with significantly lower fugitive emissions, accounting for less than 2 kg CO_2-e/GJ.

Both CG and SMR are highly optimised industrial processes, and CO_2 emissions have already been reduced as far as possible by minimising the additional energy needed for processing [37]. This means that any further reduction in process emissions will require CCS technologies to remove waste gases.

Hydrogen production from fossil fuels is considered a good candidate for CCS as the CO_2 is released from the process in a concentrated stream, which facilitates capture. However, applying carbon capture technologies to this ‘process’ gas waste stream only captures up to about two thirds of the total emissions. The rest are released by burning the feedstock as fuel to provide the energy to run the process, and are released in a dilute stream known as the ‘flue’ gases. Flue gases are more difficult, and expensive, to capture. Several different techniques can be used to capture CO_2 from either stream, all of which require additional energy and themselves result in additional emissions [37]. Additional energy is also required to compress the CO_2 for transport and storage, which is included in the calculation. However, the fuel required to transport and store the captured CO_2 is not included in this analysis as it is not well defined and depends on the distance to suitable geological storage facilities. This results in a slight underestimation of emissions.

Rates of carbon capture achieved in practice are rarely reported. In early 2021 there were only four commercial scale hydrogen facilities in the world operating with CCS, and another three in early development [38]. Of the four existing hydrogen facilities with CCS, three use the captured CO_2 for enhanced oil recovery. The only facility that sequesters captured CO_2 is the Quest plant in Canada, which reported CCS rates of 80% for a high proportion of days during its first operating year [39]. Higher rates have been reported in relatively small-scale demonstration projects. The Tomakomai CCS demonstration project in Japan reported capture rates of 99% [40] and reached cumulative CO2 injection target of 300,000 tCO_2 into geological storage. The project has since ceased [41].

We set the carbon capture rates for 'low-emission' hydrogen production based on detailed techno-economic analyses provided by the IEA Greenhouse Gas R&D program for SMR [35], and the National Academy of Engineering [36] for CG. Both of these reports provided sufficient detail to analyse the effect of the variable carbon content of the feedstock on the overall emission intensity, which are illustrated by the error bars, and to include the contribution of fugitive emissions. We assume that all of the captured gas is sequestered underground in permanent geological storage.

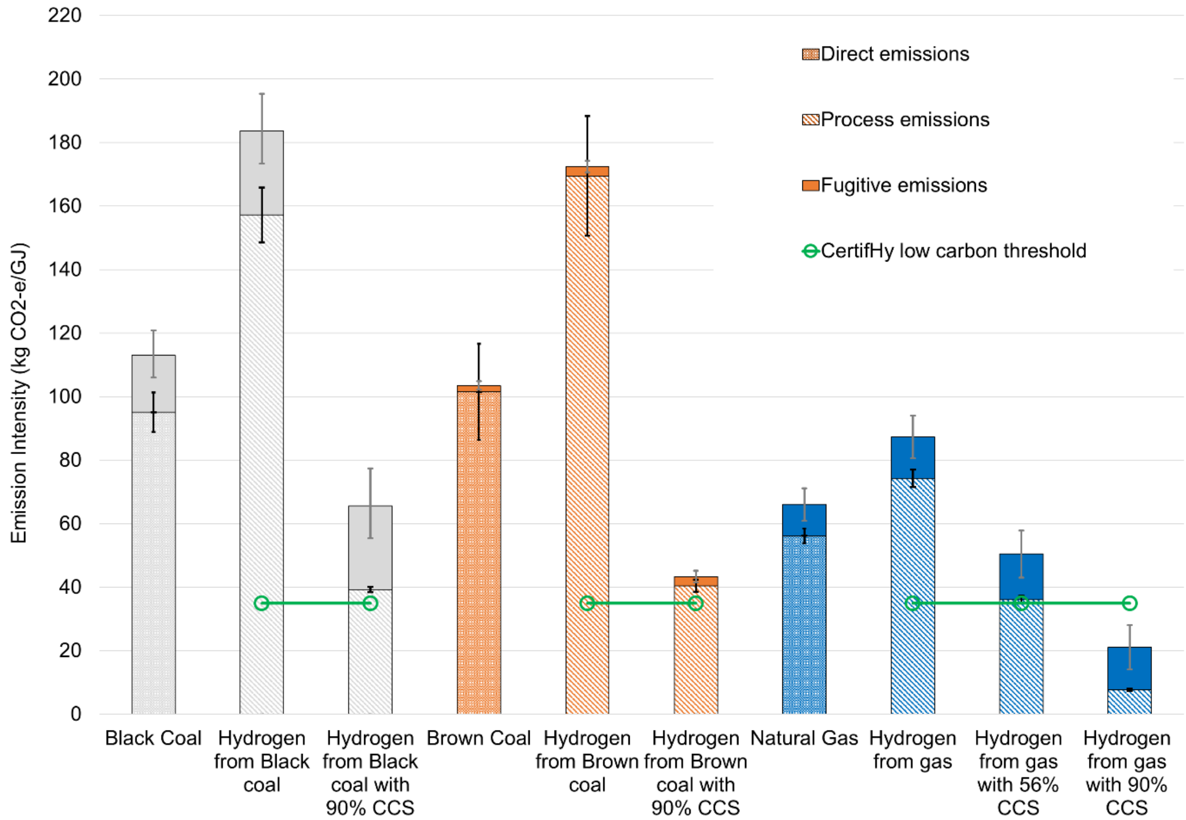
The IEA analysis provides a techno-economic evaluation of different carbon capture technologies for a standalone merchant hydrogen SMR plant [42,43]. They assess a range of technologies for capturing CO_2 from the process gas stream with capture rates of 53% to 67%. When capture is from the flue gas stream there is a high capture rate of 90%. We extract two representative capture rates for our analysis given in figure 1. Capturing carbon from the process stream results in a capture rate of 56% and reduces the emission intensity to 36 kg CO_2-e/GJ on average. This requires additional energy to be applied to the process, resulting in a reduction of energy efficiency of the SMR plant of 4 percentage points, from 78% to 74%. Achieving higher capture rates of 90% by targeting the dilute stream in the flue gases reduces the emissions intensity to 8 kg CO_2-e/GJ on average, and requires significantly more energy input, reducing energy efficiency by an additional 5 percentage points, to 69%.

The National Academy of Engineering report on CG provides less detail about the CCS technology used, and assumes a capture rate of 90% [36]. In this case, 90% CCS reduced the emission intensity to 40 kg CO_2-e/GJ for black coal and reduces the energy efficiency of the process from 65% to 63%. Similar values are calculated for brown coal.

Of course, fugitive emissions associated with 'low-emission' hydrogen cannot be mitigated by CCS technology applied at the hydrogen processing plant. With 90% CCS, SMR has a total emission intensity of 21 kg CO_2-e/GJ on average, increasing to 28 kg CO_2-e/GJ when assuming high levels of fugitive emissions. For black coal, the inclusion of fugitive emissions is even more significant, increasing the total emission intensity with 90% CCS rates to 65 kg CO_2-e/GJ and this rises to 72 kg CO_2-e/GJ for high levels of fugitive emissions.

This analysis demonstrates that 'low-emission' hydrogen from fossil fuels will always have substantial emission intensities and that taking into account fugitive emissions is critical.

Figure 1: Emissions intensity of different fuels



Note: the error bars for direct and process emissions show the variation in emissions that occurs due to natural differences in the carbon content of fossil fuels. The error bars for fugitive emissions show the low and high values provided by the IPCC to account for global variations in fugitive emissions.

3.2 Assessing 'low-carbon' hydrogen using the CertifHy benchmark

This section compares the emission levels discussed in section 3.1 to a carbon intensity threshold that has been set by a recently developed certification scheme. In addition to national strategies, the development of certification is relevant to choices between technologies [44]. The European CertifHy Guarantee of Origin scheme accounts for the origin of the hydrogen and whether it was produced using renewable energy or non-renewable low emission energy sources, such as nuclear, or fossil fuels with CCS. CertifHy also defines an emission intensity for 'low-carbon' hydrogen as a 60% reduction in emission intensity below a standard SMR production process [45,46]. Otherwise, the hydrogen would be considered to be 'grey' hydrogen [47]. This emission intensity threshold may be adopted widely as CertifHy appears to be emerging as the standard to follow in the EU with The Netherlands, France and the United Kingdom indicating that they will adopt it [44].

Only hydrogen produced from gas with a high capture rate of 90% is below the CertifHy threshold (Figure 1). While these high capture rates are assumed in many national strategies and major reports, they have not yet been achieved in a large scale commercial plant and have only recently been achieved in the Tomakomai CCS demonstration project, which required very high expenditure (which were $127/tCO_{2,}$ as discussed in section 4) [40].

3.3 Implications for Global emissions

To put the emission intensity estimates from figure 1 in perspective, we illustrate the emissions that could occur under some demand scenarios (Table 2). Bloomberg NEF projects that with comprehensive government policy support, consistent with successfully limiting global warming to 1.5˚C above pre-industrial levels, demand for low emission hydrogen could be as high as 696 Mt/year, whereas with piecemeal policy approaches that projection is reduced to 187 Mt/year [12]. The IEA estimates that by 2070, 40 per cent of total hydrogen demand could be produced from fossil fuels with CCS [48].

Combining these projections with our emission intensities means that if SMR with CCS at a capture rate of 90% were to occupy 40% of total production in BNEF's strong scenario, the amount of GHG emissions generated annually (835 MtCO2e) would be equal to 2.5% of 2019 energy related CO2 emissions [30,49]. In the event that capture levels fell below 90 per cent, that projection would rise still further. In the context of a world seeking net carbon neutrality, this would represent a sizeable offset requirement.

Table 2: Emissions from fossil fuels with CCS production in future demand scenarios

Production from:	2050 emissions projected with fossil fuels at 100% of total production (MtCO2e)		2050 emissions projected with fossil fuels at 40% of total production (MtCO2e)	
	BNEF Moderate (187 Mt/yr)	BNEF High (696 Mt/yr)	BNEF Moderate (187 Mt/yr)	BNEF High (696 Mt/yr)
CG (Black coal)	4876	18150	1951	7260
CG (Black coal + 90% CCS)	1743	6487	697	2595
CG (Brown coal)	4578	17040	1831	6816
CG (Brown coal + 90% CCS)	1150	4281	460	1712
SMR	2319	8632	928	3453
SMR with 56% CCS	1340	4988	536	1995
SMR with 90% CCS	561	2088	224	835

4 Determinants of the production cost of hydrogen

4.1 Costs of producing hydrogen from fossil fuels

The production cost of hydrogen from fossil fuels is heavily determined by two factors: capital expenditure and the cost of the feedstock. CG has higher capital costs ($2670/kW) than SMR ($910/kW), but lower fuel costs for coal mean that these options will have a similar production cost in certain scenarios [30,50]. For CG processes, capital costs account for around 50% of production costs and fuel is between 15-20% depending on the cost of coal. For SMR processes, the IEA estimated that fuel costs are likely to be between 45%-75% of hydrogen production costs. The IEA estimates that adding CCS to CG would increase capital and fuel costs by 5% and increase operation costs by 130%. Adding CCS to an SMR plant will also increase costs, which the IEA has estimated to be, on average, a 50% increase in capital costs, an additional 10% for fuel costs and a doubling of operational costs for CO_2 transport and storage [30].

4.2 CO_2 avoidance cost

The CO_2 avoidance cost is the difference between producing hydrogen with and without emissions capture. It is equivalent to the carbon price that would need to be applied for these two options to have the same production cost. There are multiple methods for calculating the CO_2 avoidance cost, but the most valid approach is to compare a given facility with a fixed level of production with and without CCS. This requires detailed techno-economic modelling as in the reports used for the analysis in section 3 [36,43]. As well as the costs of CO_2 capture, it should include costs of transport and storage at suitable geological formations [51]. Many studies do not include transport and storage costs, which will differ based on location and whether storage is onshore or offshore [52]. Some studies do not use an exhaustive approach and only account for the costs of CO_2 capture without CO_2 transport and storage, which is consistent with a 'cost of CO_2 captured' [7,8]. Assessments also commonly do not account for the costs of long-term storage and monitoring to ensure that the carbon captured remains underground. Accordingly, the actual costs of carbon avoided will usually be likely to be higher than existing studies suggest.

CO_2 avoidance costs differ greatly and depend on the capture rate due to the process used and additional energy needs (Figure 2). The median estimates from the range of studies[3] included in this analysis are \$17/tCO2 for CG with CCS and \$76/tCO2 for SMR with CCS. While there is large variation in capture costs, it is clear that higher capture rates will be more expensive.

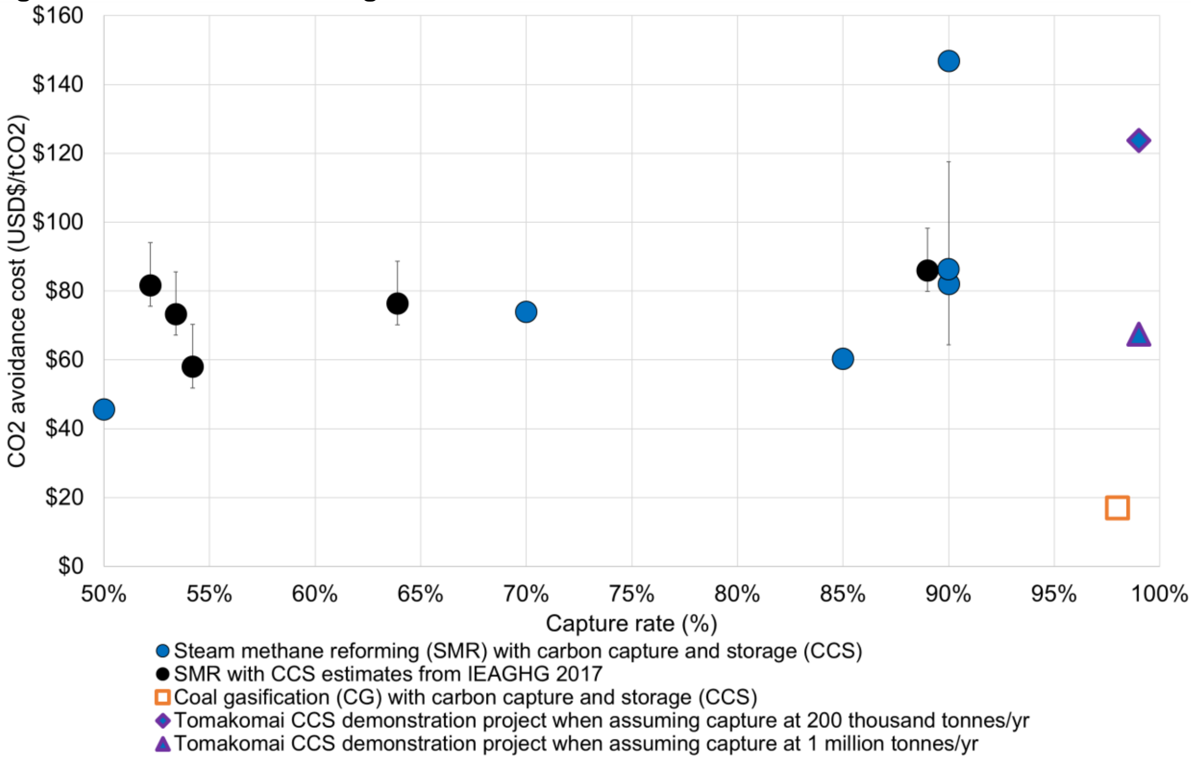
The IEAGHG study provides the most comprehensive techno-economic comparison between technologies with different capture rates [42,43]. Assuming relatively low transport and storage costs of \$11/tCO2, this work found that CCS at a 56% capture rate increases the cost of hydrogen by 18%, while 90% capture rates increase the cost by 45%.

At the recent Tomakomai CCS demonstration project in Japan, CO_2 avoidance costs for a high capture rate of 99% were \$127/tCO_2. This cost was for 200,000 tons of CO_2 captured between April 2016 and November 2019. Increasing the size of that demonstration project by a factor of five would decrease CO_2 avoidance costs by approximately 50% (from \$124/tCO2 to \$67/tCO2). Most of this projected cost reduction was attributed to reductions in the relative magnitude of capital costs and operation costs of the injection wells and storage. CO_2 transportation costs were not included in this analysis [53]. This means that the CO_2 avoidance cost below \$80/tCO2 for a capture rate of 99% quoted in that study has not been demonstrated but was extrapolated using assumptions.

[3] Note that we have only included studies published in the last ten years.

The estimates for transport and storage are particularly uncertain as very few CCS plants sequester the gases in long term underground storage and the magnitude of these costs will be highly site-dependent. The studies that we reviewed have transport and storage costs as low as \$5/tCO_2 and as high as \$29/tCO_2 (Tables A2 and A4 in the appendix). A recent study provided ranges for transport and storage costs when the storage site was assumed to be onshore (\$3-18/tCO_2) or offshore (\$5-50/tCO_2) [52]. The error bars in Figure 2 show the impact of doubling or halving the transport and storage costs for those studies that report them.

Figure 2: Cost of avoiding CO2



Note: the error bars show the impact of doubling or halving the transport and storage costs for those studies that report them.

4.3 Determinants of the production cost of hydrogen using electrolysis and renewables

4.3.1 Costs of producing hydrogen using renewables

The largest factor determining the cost of producing hydrogen using electrolysis is the cost of electricity [54,55]. With electricity costs between \$61/MWh and \$69/MWh, the magnitude of electricity expenditure has been estimated at 65-80% of total hydrogen production costs [56,57]. The other defining cost components are the capital cost of electrolysers and the capacity utilisation of electrolysers. Other costs, such as labour, land and water, are a minor determinant of the production cost of hydrogen by electrolysis.

Recent decreases in the cost of electricity generation from solar photovoltaic (PV) and wind have lowered the cost of producing hydrogen using electrolysis. Capital costs for solar PV installations fell by 79% from 2010 to 2019 and by 24% for onshore wind generators [58]. This results in lower average costs of generating electricity over the lifetime of assets. The levelised cost of electricity (LCOE) for solar PV installations was $35/MWh in 2020 and has been projected to decrease to $20/MWh by 2030 [58,59]. For wind, the equivalent numbers are $33/MWh and $31/MWh [58,60].[4]

Electrolyser manufacturing costs are expected to fall substantially as deployment of electrolysers increases [50]. The capital cost of alkaline electrolysers is between $500-1400/kW in 2019 and projected to fall to $400-850/kW by 2030. Polymer electrolyte membrane (PEM) electrolysers are between $1100-1800/kW in 2019 and projected to be between $650-1500/kW by 2030 [30]. However, lower capital costs have been reported. The electrolyser producing company Nel has reported an alkaline electrolyser cost of $700/kW for 2015 and a projection of a little over $490/kW for the near-term future [61,62].

4.3.2 Specification of the production cost of hydrogen from electrolysis

To assess the cost of producing hydrogen via electrolysis a multivariate specification is needed to account for the three main determining factors. We developed a simple equation that accurately captures the IEA estimations for hydrogen production costs using electrolysis [30]. The equation that estimates a hydrogen production cost (PC) for a given electricity cost (EC), capital cost (CC) and operating capacity factor (CF) [5] is:

$$PC = \beta_0 + \beta_1 EC + \beta_2 \frac{CC}{CF} \tag{1}$$

[4] The supplementary material includes a review of the levelised cost of electricity (LCOE) for solar PV and wind.
[5] The operating capacity factor is important for applications with standalone intermittent renewables as it impacts the number of hours an electrolyser runs. The IEA assumes that running an electrolyser at full capacity has an OCF of 90%. We lower the OCF to 45% and 30% for intermittent renewable scenarios.

where β_0 is an intercept and $\beta_{1,}\beta_2$ are parameters that define the impact of electricity costs and the ratio of capital cost and capacity factor. To specify equation 1 we used 24 data points from the IEA hydrogen cost relationship to estimate an Ordinary Least Squares regression. The high level of model fit (i.e. R-squared statistic) confirms that the other components of cost, such as labour, land and water, can be accurately estimated using a constant (Table 2).

We use these regression estimates to specify six cost curves for two levels of electrolyser capital costs (CC), i.e. \$1000/kW and \$500/kW, and three levels of capacity factors (CF), i.e. 90%, 45%, and 30% (Figure 3). The higher capital cost point proxies the costs of Alkaline electrolysers today and possible cost levels of PEM electrolysers in the near future. The lower capital cost point proxies costs that might be able to be achieved over the next decade. Note that considerable capital cost reductions could occur as a learning rate of 18% has been estimated for electrolysers [63–65].

The operating capacity factor for electrolysers will depend on the energy sources. An electrolyser run from the grid or from stand-alone renewable energy sources firmed with deep storage will be able to be run at high capacity rates, possibly exceeding 90%. Note that grid connection will generally mean some use of fossil fuel based electricity and emissions associated with the production of hydrogen. We focus on the case of using renewable electricity as a feedstock and assume that an electrolyser run off a wind farm could operate at capacity factors close to 45%, and a standalone solar farm at around 30%. We developed production costs of hydrogen using the LCOEs for solar PV and wind in 2020 and 2030 sourced from IRENA and discussed in section 4.3.1. These hydrogen production costs are \$2.43-3.05/kg and \$1.76-2.37/kg using the solar LCOEs for 2020 and 2030. The equivalent estimates are \$2.13-2.54/kg and \$2.04-2.44/kg for wind (Figure 3).

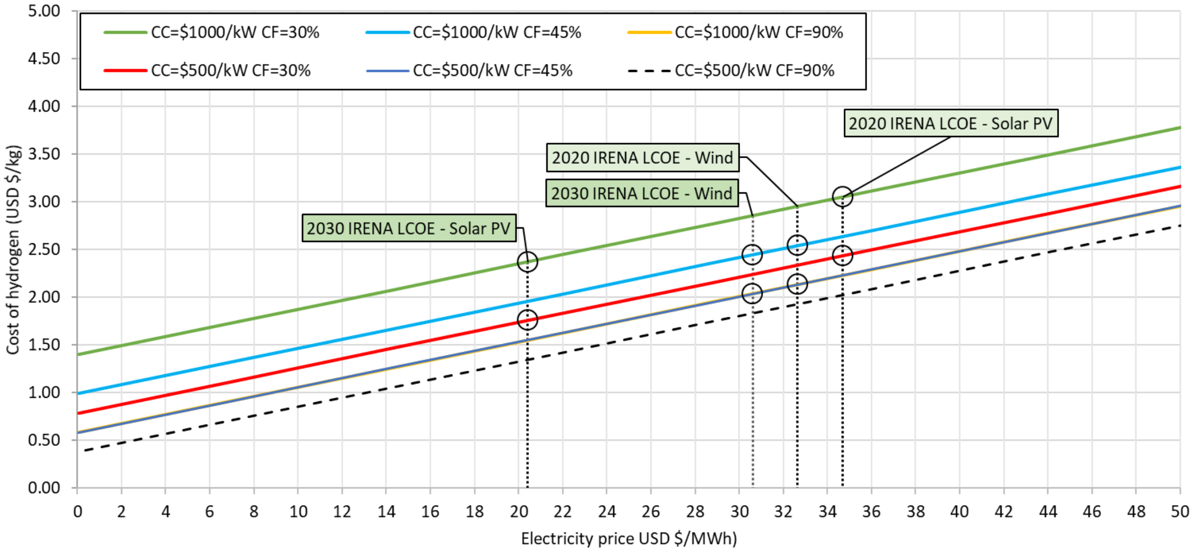
We have used low LCOE estimates and higher capacity utilization factors, as it is likely that these will be more relevant in practice as hydrogen production would be run on the lowest cost renewable energy generation opportunities. We also emphasize the uncertainty regarding future cost estimates, and the possibility of large and rapid cost reductions as the industry scales up.

Table 3: Regression estimates for the production cost of hydrogen (PC) using data sourced from IEA model

Variables	Coefficients
Electricity cost (EC)	0.475*** (0.00)
Ratio of capital cost (CC) and capacity factor (CF)	0.037*** (0.00)
Constant	0.174*** (0.01)
R-squared	0.999
Number of observations	24

Standard errors in parentheses. Statistical significance: *** $p<0.01$, ** $p<0.05$, * $p<0.1$.

Figure 3: Production cost of hydrogen via electrolysis using renewable electricity



5 Comparison of costs across hydrogen technologies

We complete the analysis by comparing estimates from 16 studies (listed in the appendix[6]) for the different hydrogen production technologies considered in section 3: SMR and CG with and without CCS. We also include the selected estimates for renewable energy powered electrolysis from section 4.3.2 (Figure 3). Currently, producing hydrogen with fossil fuels costs less than producing it with renewable energy powered electrolysis (Figure 4). The additional cost of CCS is significant and increases the median (or central) estimates from $1.66-1.84/kg without CCS to $2.09-2.23/kg with CCS. These median estimates increase by a considerable amount when a carbon penalty on remaining emissions of $50/tCO2 is assumed. This increases the median estimates for fossil fuels with CCS from $2.09-2.23/kg to $2.24-2.70/kg. In comparison, the median estimate for renewables-based electrolysis would decrease from $3.64/kg for the present day to $1.85/kg when capital and/or electricity costs are lower. The assumptions used differs by study and these are provided in the appendix. They include estimates that use an LCOE as low as $10/MWh and the lowest level of capital costs is $200/kW.

A range of target prices have been set in various strategies and $2/kg is a common benchmark for cost-competitive hydrogen. It has been set as a target by the US Department of Energy for the levelised cost of hydrogen at the plant gate [66]. A comparable figure (20 yen/Nm^3) was also included in the Japanese Hydrogen Strategy as a target for the landed cost of imports of hydrogen [14] [7]. Australia has a $2/kg (AUD) production cost target for ‘clean’ hydrogen, which is equivalent to $1.4/kg (USD) [67].

While the cost of producing hydrogen via electrolysis is expected to fall, fossil fuel and carbon capture options are mature technologies. Likewise, it is unlikely that there will be significant reductions in carbon transport and storage as cost improvements from economies of scale will be limited. The inclusion of realistic CO_2 transport, storage and monitoring costs would lead to higher costs than currently projected.

[6] The appendix contains the data points used to produce Figure 4 and has a description of the technology/scenario that was used to estimate a production cost of hydrogen. Figure 4 contains 97 data points from a wide range of studies.

[7] Note that this Japanese target would need to include the cost of transport and storage to be achieved.

From our analysis, we can extract an implied carbon price that would be required to make low emission fossil-fuel technologies (i.e. SMR and CG with 90% CCS) break even with current fossil-fuel hydrogen costs. Using the median estimates from Figure 4, a carbon price of \$22/tCO2 (CG) and \$46/tCO2 (SMR) would be required to make hydrogen production from fossil fuels with CCS achieve cost parity with the non-CCS option. This occurs at a production cost of \$2.23/kg (SMR) and \$2.43/kg (CG) (Figure 5). This is due to a high carbon abatement cost and reflects the costliness of CCS as an option to decarbonise hydrogen production. Achieving capture rates above 85% is expensive, the residual emissions are notable, and CCS has no impact on fugitive emissions, which are included in this analysis. So, it only takes a moderate increase in costs, either a carbon price or revised costs of transport, storage and monitoring, to shift the median CCS estimates away from the example target price of \$2/kg. These increases in cost also make these technological options less favourable compared to electrolysis with lower capital cost or low cost electricity.

Figure 4: Production cost of hydrogen by type

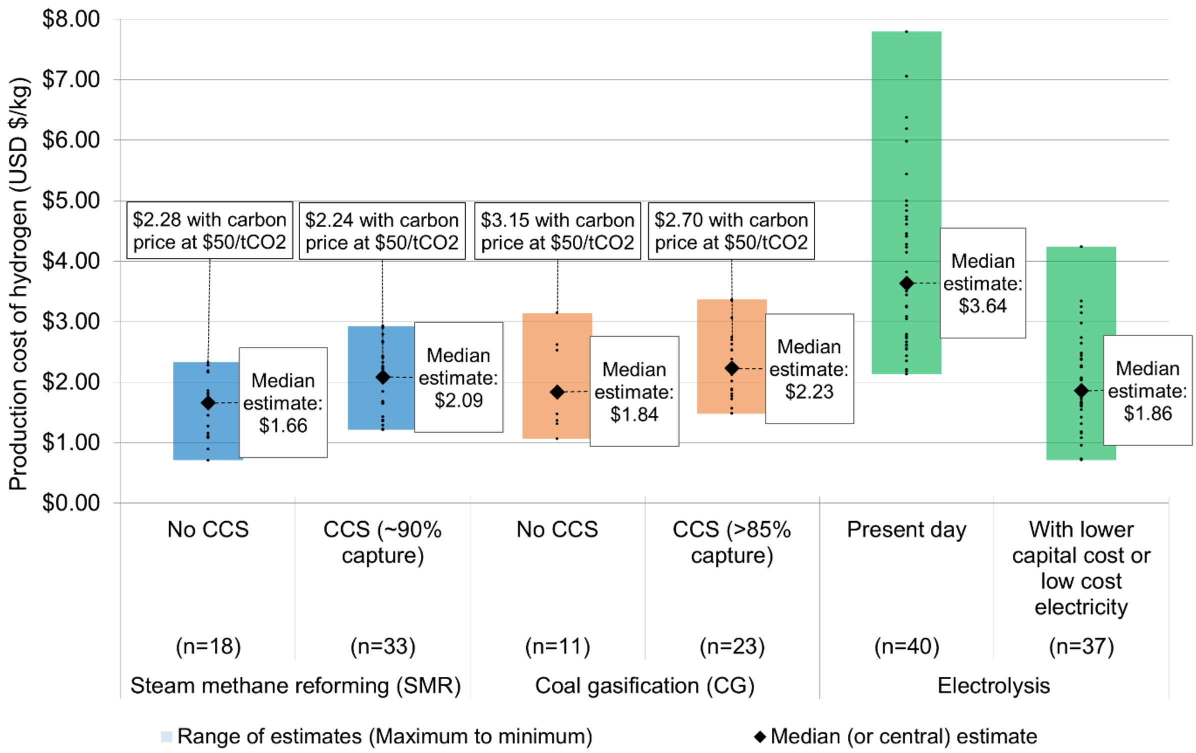
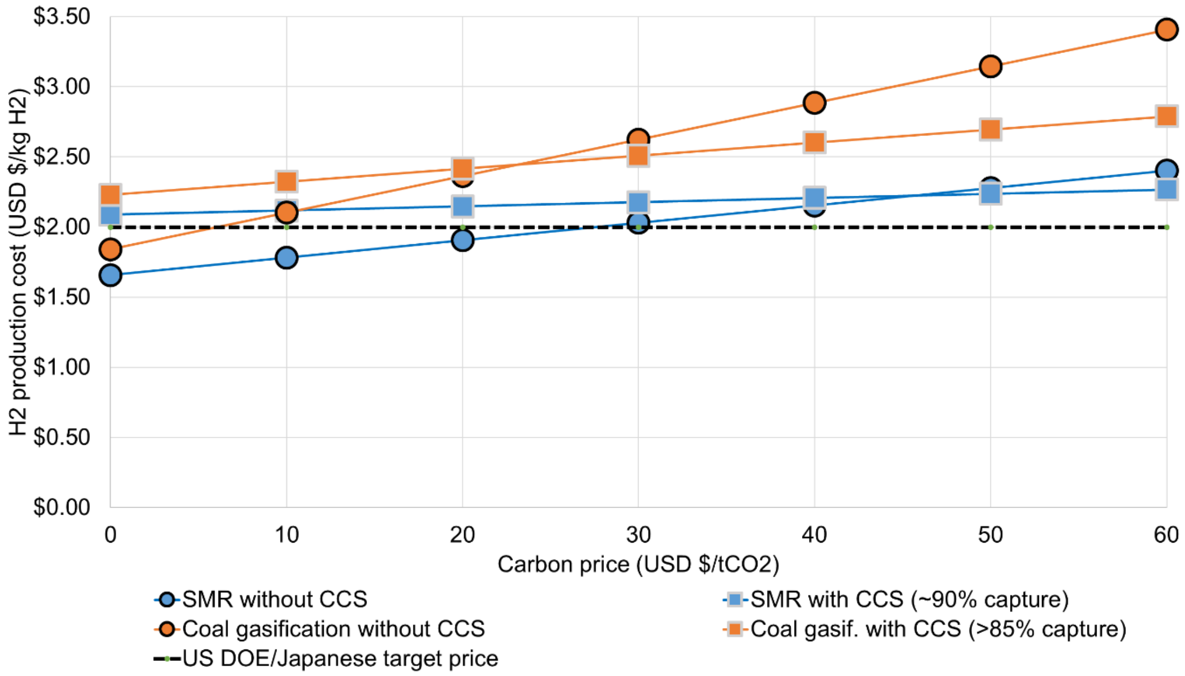


Figure 5: Impact of carbon pricing on the cost of fossil fuel based hydrogen



Note: this graphic is based on the median estimates shown in Figure 4 and does not incorporate the range of estimates for fossil fuel based hydrogen. The emission intensity used in the calucation are those shown as bars in Figure 1 and include both process and fugitive emissions.

6 Conclusions

A number of government strategies foresee ‘low-emission’ hydrogen production from fossil fuels with CCS as an element of their hydrogen strategies. We find that these ‘low-carbon’ production methods create significant greenhouse gas (GHG) emissions when realistic capture rates and fugitive emissions from feedstock extraction are taken into account. The extent of the emissions is often downplayed or ignored in governments’ public statements about future hydrogen supply chains, with many treating low-emission and zero-emission production as functionally equivalent or interchangeable. The high rates of carbon capture typically posited in government strategies are likely to be both difficult to achieve in practice and costly. CCS is an inherently expensive option for decarbonising hydrogen production. Our analysis shows that carbon prices of \$22-46/tCO2e would be required to make hydrogen from fossil fuels with CCS competitive with hydrogen produced from fossil fuels without CCS. In contrast, the cost of producing zero-carbon hydrogen from electrolysis could fall in the foreseeable future, and be cost-competitive with fossil fuel options.

Hydrogen can help achieve decarbonisation of global energy systems, however the use of oil or natural gas would come with significant remaining emissions even if relatively high carbon capture rates were achieved. Using emission intensities that include fugitive emissions means that if SMR with CCS at a capture rate of 90% were to occupy 40% of total hydrogen production, the amount of GHG emissions generated annually would equal 2.5% of 2019 energy related CO2 emissions. Hydrogen produced from fossil fuels without CCS would result in much higher emissions compared to unmitigated combustion of fossil fuels. Setting up new fossil fuel based hydrogen supply chains using fossil fuels without CCS would be detrimental.

As CCS and fossil fuel based facilities have long lifetimes, early investment in fossil fuel-based hydrogen production creates a risk of lock-in. Tightening carbon constraints combined with decreases in the cost of hydrogen from electrolysis will raise the possibility that natural gas and coal- based hydrogen production assets could become stranded. Meanwhile, many national hydrogen strategies define both fossil fuel with CCS and renewable based options as ‘clean’ and/or ‘low-emission’. The current framing of these options suggests that there is a risk of government support for an option incompatible with stated objectives of energy system decarbonisation and net-zero emissions outcomes.

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Appendix

Table A1 Levelised cost of hydrogen (USD $/kg) – Steam methane reforming

Source	**Description**	**LCOH (USD $/kg)**
NREL 2013 [1]	Centralised hydrogen production facility with a design capacity of 379 tH2 per day with natural gas carried by pipeline.	2.19
Hosseini et al. 2016 [2]	Natural gas reforming without CO_2 capture.	1.11
Salkuyeh et al. 2017 [3]	Steam methane reforming producing 446 tH2 per day.	1.15
IEAGHG 2017 [4]	Hydrogen plant without CCS (base case).	1.68
Keipi et al. 2018 [5]	Steam methane reforming producing 209 tH2 per day.	2.33
IEA 2019 [6]	Natural Gas without CCUS (adjusted to have no carbon price) sourced from Figure 16.	1.87
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for Australia	1.45
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for Chile	1.64
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for China	1.69
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for Europe	1.73
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for India	1.82
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for Japan	2.16
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for Middle east	0.89
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for North Africa	1.27
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for United States	1.08
IEA 2020 [7]	Hydrogen cost via SMR – lowest 2019 value from Figure 2.14.	0.71
	Hydrogen cost via SMR – highest 2019 value from Figure 2.14.	1.62
Roussanaly et al 2020 [8]	Hydrogen production through natural gas reforming without CCS with plant capacity at 450 tH2 per day. Assumed to be located on the Northern Norway shore with a carbon intensity of 1.37 MtCO2/year without CO2 capture.	1.79

Table A2 Levelised cost of hydrogen (USD $/kg) – Steam methane reforming with carbon capture

Source	Description	LCOH (USD/kg)	CO2 Avoided (%)	Carbon avoidance cost (USD/tCO2)	Includes T&S cost (USD/tCO2)
Salkuyeh et al. 2017 [3]	SMR with CCS.	2.33	90%	146.9	
IEAGHG 2017 [4]	CO2 capture from syngas using MDEA (case 1A).	1.98	54%	58.0	12.3
	CO2 capture from syngas using MDEA with H2-rich fuel firing burners (case 1B).	2.15	64%	76.4	12.3
	CO2 capture from PSA tail gas using MDEA (case 2A).	2.09	52%	81.7	12.3
	CO2 capture from PSA tail gas using Cryogenic and Membrane Technology (case 2B).	2.06	53%	73.3	12.3
	CO2 capture from flue gas using MEA (case 3).	2.43	89%	86.0	12.3
CE Delft 2018 [9]	SMR without capture via flue gas.	1.98	50%	45.6	
	SMR without capture via flue gas.	2.15	70%	73.9	
	SMR with capture via flue gas or H2 used as fuel.	2.26	85%	60.4	
	SMR with capture via flue gas or H2 used as fuel.	2.43	90%	86.2	
CSIRO 2018 [10]	Best case for SMR with CCS.	1.66	92%		5.4
	Base case for SMR with CCS.	2.03	92%		29.3
	Best case for SMR with CCS.	1.38	92%		5.1
	Base case for SMR with CCS.	1.68	92%		29.3
IEA 2019 [6]	Natural Gas with CCUS (adjusted to have no carbon price) sourced from Figure 16.	2.41	89%		20.6
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for Australia.	1.85	89%		20.6
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for Chile.	2.07	89%		20.6
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for China.	2.11	89%		20.6
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for Europe.	2.22	89%		20.6
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for India.	2.22	89%		20.6
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for Japan.	2.67	89%		20.6
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for Middle east.	1.29	89%		20.6
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for North Africa.	1.65	89%		20.6
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for United States.	1.43	89%		20.6
IEA 2020 [7]	Hydrogen cost via SMR – lowest 2050 value from Figure 2.14.	1.21	95%		20.2
	Hydrogen cost via SMR – highest 2050 value from Figure 2.14.	2.13	95%		20.2
BNEF 2020 [11]	Natural gas with CCS – highest 2019 value from Figure 3.	2.93	90%		
	Natural gas with CCS – lowest 2019 value from Figure 3.	1.37	90%		
	Natural gas with CCS – highest 2030 value from Figure 3.	2.90	90%		
	Natural gas with CCS – lowest 2030 value from Figure 3.	1.36	90%		
	Natural gas with CCS – highest 2050 value from Figure 3.	2.79	90%		
	Natural gas with CCS – lowest 2050 value from Figure 3.	1.22	90%		
Roussanaly et al 2020 [8]	Hydrogen production through natural gas reforming without CCS with plant capacity at 450 tH2 per day. Assumed to be located on the Northern Norway shore with a well injection rate of 0.8 MtCO2 per year per well.	2.66	90%	82.1	35.5

Table A3 Levelised cost of hydrogen (USD $/kg) – Coal gasification

Source	Description	LCOH (USD/kg)
IEAGHG 2014 [12]	General Electric, Radiant Syngas Cooler.	2.62
IEA 2019 [6]	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for Australia	1.84
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for China	1.06
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for Europe	1.79
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for India	1.37
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for Middle East	1.47
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for North Africa	1.32
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for United States	1.85
	Coal without CCUS (adjusted to have no carbon price) sourced from Figure 16.	1.87
IEA 2020 [7]	Hydrogen cost via coal gasifier – lowest 2019 value from Figure 2.14.	1.92
	Hydrogen cost via coal gasifier – highest 2019 value from Figure 2.14.	2.53

Table A4 Levelised cost of hydrogen (USD $/kg) – Coal gasification with carbon capture

Source	Description	LCOH (USD/kg)	CO2 Avoided (%)	Carbon avoidance cost (USD/tCO2)	Includes T&S cost (USD/tCO2)
IEAGHG 2014 [12]	General Electric, Radiant Syngas Cooler with additional MDEA solvent scrubbing to achieve near zero CO2 emission.	2.74	98%	16.93	12.70
CSIRO 2018 [10]	Hydrogen cost for coal gasifier with CCS – base case lower range value for black coal.	1.88	85%		5.13
	Hydrogen cost for coal gasifier with CCS – base case upper range value for black coal.	2.30	85%		29.29
	Hydrogen cost for coal gasifier with CCS – best case lower range value for black coal.	1.48	85%		5.13
	Hydrogen cost for coal gasifier with CCS – best case upper range value for black coal.	1.81	85%		29.29
	Hydrogen cost for coal gasifier with CCS – best case lower range value for brown coal.	1.57	85%		5.13
	Hydrogen cost for coal gasifier with CCS – best case upper range value for brown coal.	2.02	85%		29.29
IEA 2019 [6]	Natural Gas with CCUS (adjusted to have no carbon price) using assumptions for Australia	2.30	90%		20.62
	Natural Gas with CCUS (adjusted to have no carbon price) using assumptions for China	1.48	90%		20.62
	Natural Gas with CCUS (adjusted to have no carbon price) using assumptions for Europe	2.23	90%		20.62
	Natural Gas with CCUS (adjusted to have no carbon price) using assumptions for India	1.72	90%		20.62
	Natural Gas with CCUS (adjusted to have no carbon price) using assumptions for Middle East	1.87	90%		20.62
	Natural Gas with CCUS (adjusted to have no carbon price) using assumptions for North Africa	1.77	90%		20.62
	Natural Gas with CCUS (adjusted to have no carbon price) using assumptions for United States	2.32	90%		20.62
	Coal with CCUS (adjusted to have no carbon price) sourced from Figure 16.	2.38	90%		20.62
IEA 2020 [7]	Hydrogen cost via coal gasifier and CCS – lowest 2050 value from Figure 2.14.	2.13	90%		20.24
	Hydrogen cost via coal gasifier and CCS – highest 2050 value from Figure 2.14.	2.63	90%		20.24
BNEF 2020 [11]	Coal with CCS – highest 2019 value from Figure 3.	3.37	90%		
	Coal with CCS – lowest 2019 value from Figure 3.	2.54	90%		
	Coal with CCS – highest 2030 value from Figure 3.	3.35	90%		
	Coal with CCS – lowest 2030 value from Figure 3.	2.53	90%		
	Coal with CCS – highest 2050 value from Figure 3.	3.06	90%		
	Coal with CCS – lowest 2050 value from Figure 3.	2.23	90%		

Table A5 Levelised cost of hydrogen (USD $/kg) – Electrolyser (present day)

Source	Description	LCOH (USD/kg)
CSIRO 2018 [10]	PEM – base case lower range value with a capital cost of $2497/kW and an LCOE of $43/MWh.	4.45
	PEM – base case upper range value with a capital cost of $2497/kW and an LCOE of $43/MWh.	5.44
	AE – base case lower range value with a capital cost of $962/kW and an LCOE of $43/MWh.	3.50
	AE – base case upper range value with a capital cost of $962/kW and an LCOE of $43/MWh.	4.28
NREL 2019 [13]	PEM with a capital cost of $841/kW and an LCOE of $66/MWh.	4.92
	PEM with a capital cost of $841/kW and an LCOE of $20/MWh.	4.74
	PEM with a capital cost of $841/kW and an LCOE of $10/MWh.	4.23
IEA 2019 [6]	Electrolysis with grid based electricity at $98/MWh (Fig. 16).	5.00
	Electrolysis, upper value from Fig. 19 with assumptions for Australia including capital cost at $700/kW and variable electricity at $31/MWh.	3.82
	Electrolysis, upper value from Fig. 19 with assumptions for Chile including capital cost at $700/kW and variable electricity at $23/MWh.	3.09
	Electrolysis, upper value from Fig. 19 with assumptions for China including capital cost at $700/kW and variable electricity at $18/MWh.	2.35
	Electrolysis, upper value from Fig. 19 with assumptions for Europe including capital cost at $700/kW and variable electricity at $47/MWh.	4.14
	Electrolysis, upper value from Fig. 19 with assumptions for India including capital cost at $700/kW and variable electricity at $19/MWh.	2.76
	Electrolysis, upper value from Fig. 19 with assumptions for Japan including capital cost at $700/kW and variable electricity at $63/MWh.	6.38
	Electrolysis, upper value from Fig. 19 with assumptions for Middle East including capital cost at $700/kW and variable electricity at $25/MWh.	4.41
	Electrolysis, upper value from Fig. 19 with assumptions for North Africa including capital cost at $700/kW and variable electricity at $23/MWh.	3.25
	Electrolysis, upper value from Fig. 19 with assumptions for United States including capital cost at $700/kW and variable electricity at $31/MWh.	3.63
IRENA 2019 [14]	Electrolysis with capital cost at $840/kW and electricity at $40/MWh.	3.64
	Electrolysis with capital cost at $840/kW and electricity at $20/MWh.	2.59
	Electrolysis with capital cost at $840/kW and electricity at $85/MWh.	6.19
	Electrolysis with capital cost at $840/kW and electricity at $55/MWh.	4.69
	Electrolysis with capital cost at $840/kW, capacity factor at 26% and electricity at $85/MWh.	7.06
	Electrolysis with capital cost at $840/kW, capacity factor at 48% and electricity at $55/MWh.	4.42
	Electrolysis with capital cost at $840/kW, capacity factor at 26% and electricity at $17.50/MWh.	3.44
	Electrolysis with capital cost at $840/kW, capacity factor at 48% and electricity at $23/MWh.	2.73
IRENA 2020 [15]	High point of current day electrolysis estimate.	5.98
	Mid. point of current day electrolysis estimate.	4.84
	Low point of current day electrolysis estimate.	2.67
IEA 2020 [7]	Hydrogen cost via electrolysis – highest 2019 value from Figure 2.14.	7.79
	Hydrogen cost via electrolysis – lowest 2019 value from Figure 2.14.	3.24
BNEF 2020 [11]	Renewable H2 – highest 2019 value from Figure 3.	4.61
	Renewable H2 – lowest 2019 value from Figure 3.	2.55
Estimates from section 4.3.2 using 2020 LCOE data from IRENA 2020 (shown in Fig. 3)	Electrolysis with capital cost at $1000/kW, capacity factor at 30% and electricity at $35/MWh.	3.05
	Electrolysis with capital cost at $1000/kW, capacity factor at 45% and electricity at $33/MWh.	2.54
	Electrolysis with capital cost at $500/kW, capacity factor at 30% and electricity at $35/MWh.	2.43
	Electrolysis with capital cost at $500/kW, capacity factor at 45% and electricity at $33/MWh.	2.13
Estimates from section 4.3.2 using 2020 LCOE data from GenCost 2020 [16]	Electrolysis with capital cost at $1000/kW, capacity factor at 30% and electricity at $29/MWh.	2.79
	Electrolysis with capital cost at $500/kW, capacity factor at 30% and electricity at $29/MWh.	2.18
	Electrolysis with capital cost at $1000/kW, capacity factor at 45% and electricity at $34/MWh.	2.62
	Electrolysis with capital cost at $500/kW, capacity factor at 45% and electricity at $34/MWh.	2.21

Table A6 Levelised cost of hydrogen (USD $/kg) – Electrolyser (with lower capital cost or low cost electricity)

Source	Description	LCOH (USD/kg)
CSIRO 2018 [10]	PEM – base case lower range value with a capital cost of $691/kW and an LCOE of $29/MWh.	1.68
	PEM – base case upper range value with a capital cost of $691/kW and an LCOE of $29/MWh.	2.04
	AE – base case lower range value with a capital cost of $723/kW and an LCOE of $29/MWh.	1.86
	AE – base case upper range value with a capital cost of $723/kW and an LCOE of $29/MWh.	2.27
NREL 2019 [13]	PEM with a capital cost of $462/kW and an LCOE of $20/MWh.	3.15
	PEM with a capital cost of $462/kW and an LCOE of $10/MWh.	2.64
IEA 2019 [6]	Electrolysis with renewable electricity at $40/MWh (Fig. 16).	2.97
	Electrolysis, upper value from Fig. 19 with assumptions for Australia including capital cost at $450/kW and variable electricity at $31/MWh.	2.39
	Electrolysis, upper value from Fig. 19 with assumptions for Chile including capital cost at $450/kW and variable electricity at $23/MWh.	1.62
	Electrolysis, upper value from Fig. 19 with assumptions for China including capital cost at $450/kW and variable electricity at $18/MWh.	1.62
	Electrolysis, upper value from Fig. 19 with assumptions for Europe including capital cost at $450/kW and variable electricity at $47/MWh.	3.24
	Electrolysis, upper value from Fig. 19 with assumptions for India including capital cost at $450/kW and variable electricity at $19/MWh.	1.72
	Electrolysis, upper value from Fig. 19 with assumptions for Japan including capital cost at $450/kW and variable electricity at $63/MWh.	4.24
	Electrolysis, upper value from Fig. 19 with assumptions for Middle East including capital cost at $450/kW and variable electricity at $25/MWh.	1.66
	Electrolysis, upper value from Fig. 19 with assumptions for North Africa including capital cost at $450/kW and variable electricity at $23/MWh.	1.60
	Electrolysis, upper value from Fig. 19 with assumptions for United States including capital cost at $450/kW and variable electricity at $31/MWh.	2.25
IRENA 2019 [14]	Electrolysis with capital cost at $200/kW and electricity at $20/MWh.	1.42
	Electrolysis with capital cost at $370/kW and electricity at $23/MWh.	1.08
	Electrolysis with capital cost at $370/kW and electricity at $22/MWh.	2.06
	Electrolysis with capital cost at $200/kW and electricity at $23/MWh.	1.55
IRENA 2020 [15]	High point of future electrolysis estimate.	1.18
	Mid. point of future electrolysis estimate.	0.95
	Low point of future electrolysis estimate.	0.73
IEA 2020 [7]	Hydrogen cost via electrolysis – lowest 2050 value from Figure 2.14.	1.32
	Hydrogen cost via electrolysis – highest 2050 value from Figure 2.14.	3.34
BNEF 2020 [11]	Renewable H2 – highest 2030 value from Figure 3.	2.73
	Renewable H2 – lowest 2030 value from Figure 3.	1.16
	Renewable H2 – highest 2050 value from Figure 3.	1.66
	Renewable H2 – lowest 2050 value from Figure 3.	0.71
Estimates from section 4.3.2 using 2030 LCOE data from IRENA 2020 (shown in Fig. 3)	Electrolysis with capital cost at $1000/kW, capacity factor at 30% and electricity at $20/MWh.	2.37
	Electrolysis with capital cost at $1000/kW, capacity factor at 45% and electricity at $31/MWh.	2.44
	Electrolysis with capital cost at $500/kW, capacity factor at 30% and electricity at $20/MWh.	1.76
	Electrolysis with capital cost at $500/kW, capacity factor at 45% and electricity at $31/MWh.	2.04
Estimates from section 4.3.2 using 2030 LCOE data from GenCost 2020 [16]	Electrolysis with capital cost at $1000/kW, capacity factor at 30% and electricity at $18/MWh.	2.25
	Electrolysis with capital cost at $500/kW, capacity factor at 30% and electricity at $18/MWh.	1.63
	Electrolysis with capital cost at $1000/kW, capacity factor at 45% and electricity at $31/MWh.	2.48
	Electrolysis with capital cost at $500/kW, capacity factor at 45% and electricity at $31/MWh.	2.07

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Supplementary material

Discussion of levelised cost of electricity (LCOE) – solar PV and wind

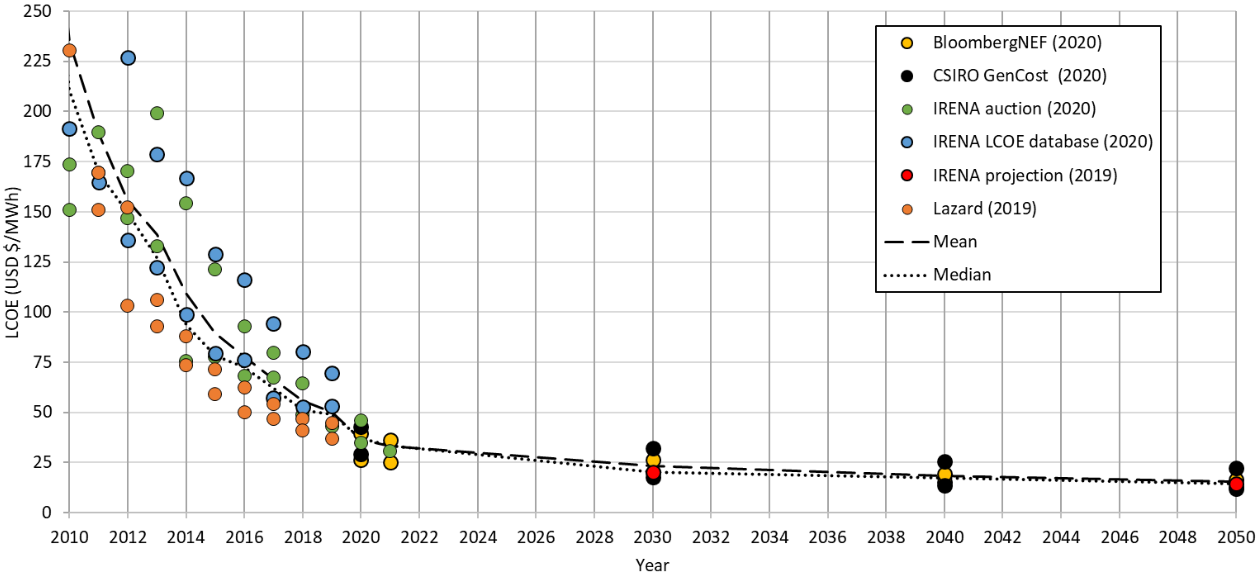
Typical up-front capital costs for solar PV installations fell by 79% from 2010 to 2019 and by 24% for onshore wind generators [1]. This means lower average costs of generating electricity over the lifetime of assets (Figure 1). The levelised cost of electricity (LCOE) for large scale solar PV installations in 2020 is between $29-42/MWh in Australia according to CSIRO estimates [2], and $34-45/MWh internationally according to the IRENA auction database [1]. The equivalent numbers for onshore wind are $34-42/MWh [2] and $32-45/MWh [1]. The LCOE is a measure of average electricity generation costs over the lifetime of a generating plant.

The expected future trend is for further reductions in costs from solar PV with a projected mean LCOE in 2030 at $23/MWh, which drops to $18/MWh in 2040. Onshore wind is projected at a mean LCOE of $32/MWh and $30/MWh for 2030 and 2040, respectively. However, offshore wind has seen recent dramatic reductions in recent costs that have been reflected in the global average auction price dropping from $127/MWh for 2020 to $82/MWh for 2023, with prices in the lower ranges (5th percentile) between $54/MWh and $71/MWh for 2020 to 2023 [1].

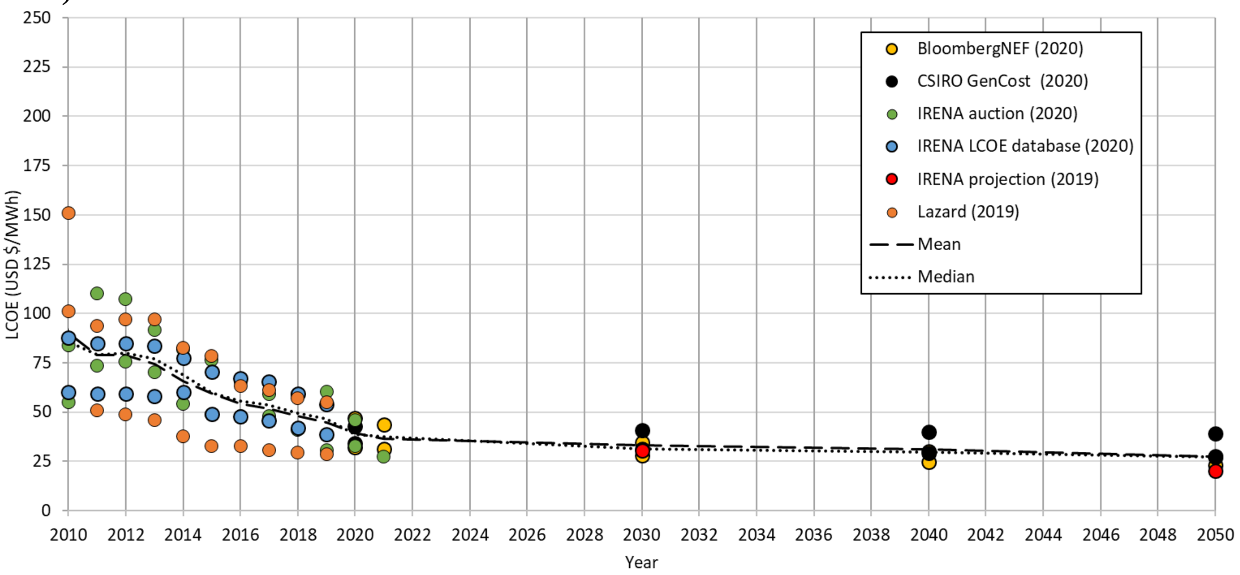
The history of renewable energy projections has been to underestimate capacity and overestimate investment costs [3,4]. One factor that suggests that reality may once again lead to lower costs than currently projected is that capital is now available at very low cost, and interest rates are likely to remain low on account of a global recession. Note that the IRENA LCOE calculation applies an interest rate of 7.5% for the OECD and China over a lifetime of 25 years.

Figure A1: Levelised cost of electricity 2010-2020 and projections to 2050

a) Solar PV



b) Onshore wind



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