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The application of green finance to the production of blue and green hydrogen: A comparative study

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ABSTRACT

There is widespread agreement – and in particular between the IPCC and the IEA - that to meet global decarbonising goals a large scale and rapid scaling up of hydrogen production is necessary. However, there is a growing debate over the comparative economics of green renewable and blue gas derived hydrogen. This raises the question of where green finance should be most cost effectively directed. We highlight that when the most recent data on fugitive emissions and rises in the EU's carbon price are accounted for, green hydrogen is shown to be approaching cost parity with blue hydrogen - particularly where reasonably low-cost renewable energy is available - and exceeds it in cases in the most favourable locations. Indeed, this study indicates that, in most cases, given the high-risk levels attached to the production of blue hydrogen, the most cost-effective use of green finance would be to focus on supporting the scaling up of green hydrogen production in the early stages at a time when the investment environment may not fully reflect the medium to longer term prospects.

1. Introduction

Projections are that to meet the goal of carbon neutrality by 2050 global production of hydrogen will need to reach 8 gigatonnes, account for up to 15% of total energy demand and require investment of around US6.8 trillion. However, while there is a crowded field of contemporary studies covering hydrogen's potential there are far fewer studies on the extent to which production of blue or green hydrogen may predominate and over what timescale.

This paper's objectives are therefore to review recent findings on the comparative production costs and risks associated with the production of green and blue hydrogen and assess to what extent green finance should preference one or the other. The review of recent literature is focussed on issues which we find have not been covered in any systematic way: firstly whether the assumptions by the IPCC and the IEA and a number of other institutions regarding the use of carbon capture and storage (CCS) as a cost effective efficient means of enabling blue hydrogen production is backed up by available data. Secondly, we similarly assess whether the current assumptions by the IPCC, the IEA and other relevant institutions regarding supply chain methane emissions in the use of gas as a feedstock for hydrogen production, are properly reflected in costs and risks. Finally, we review the effect of economies of scale, capital intensity, interest rates and input prices – and in particular the varying efficiency of renewable solar and wind power - on comparative costing of blue and green hydrogen and the need to accommodate these differences in assessing the viability of green financing.

The outcome of this review has important implications for the role of blue and green hydrogen in the decarbonisation pathways outlined by the IPCC and the IEA and therefore the way in which green finance is preferred. This is because these key institutions do not adequately incorporate the evidently higher methane emissions in blue hydrogen's supply chain nor the high level of risk in relying on yet to be proven CCS.

Section 2 of this paper looks at the role of hydrogen in global decarbonisation paths as set out by the IPCC. Section 3 reviews the costs of blue hydrogen's production with other forms of manufacture while Section 4 describes the use of CCS in the production of blue hydrogen. Section 5 examines the problem of fugitive emissions in the production of hydrogen. The roles of learning curves, scale and energy costs in estimating the LCOE and total costs of hydrogen production, are explored in Section 6. The importance of fugitive emissions and the price on carbon in costing blue hydrogen production are described in Section

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7. In Section 8 the way in which investment risk is likely to differentially affect production of blue and green hydrogen is analysed. Section 9 discusses country and regional hydrogen production strategies and their implications for green financing. Section 10 summarises our conclusions and provides policy recommendations.

2. Hydrogen's role in carbon neutrality

The need for a significant upscaling of green finance to meet a rapid uptake of hydrogen production relates to its key role in global decarbonising strategies. Estimates put the value of the market for hydrogen at over $180 billion by 2030 and $1.2 trillion by 2050 [1]. As a proportion of global energy demand in a 2050 carbon neutral world, hydrogen is variously estimated to account for 6% by the International Renewable Energy Agency [2], 13% by the [3] 11% by the IPCC [4]; 20% by Ref. [5] and 25% by Ref. [6]. It share of total final energy consumption is variously estimated at between a quarter and one third [5,7,8]. The reasons for these differing estimates are discussed below.

Within the ranges of hydrogen use projected by various bodies the lowest levels are contained in one of IPCC's 1.5-degree scenarios in which there is very low growth in overall demand through to 2050 [9]. More generally the IPCC's mid-point of 11% is modest reflecting the age of the modelling literature available at the time, with hydrogen at the time being substantially more costly than current estimates [10].

At issue for the investment community and policy makers is the high level of uncertainty relating to the competing merits of blue hydrogen (derived from natural gas or coal but with CCS) and green hydrogen (derived from water electrolysis using renewable energy). A number of studies are now indicating that, as the price on carbon rises to meet the 2050 deadline and as renewables continue their rapid downward cost trajectory, blue hydrogen will be less cost effective for most if not all countries [5,10]). Both carbon-based hydrogen production processes – gas-based steam methane reforming (SMR) and coal gasification (CG) are responsible for high levels of C02 emissions as well as upstream (mining and extraction) and downstream (postproduction e.g. transport, storage and CCS) fugitive methane emissions. Nevertheless, CSS reliant blue hydrogen is embedded in IPCC carbon neutrality pathways and in a wide range of country and regional decarbonizing strategies including, importantly, that of the EU.

Projections of blue hydrogen's role in future hydrogen production vary widely. The International Energy Agency ([11], estimates that by 2070 40% of global hydrogen production will be from fossil fuels using CCS. Such a projection is based in large part on what we find is an as yet to be well evidenced acceptance of CCS as a viable, cost-effective method of decarbonising the use of fossil fuels. This position is reflected in the views of a number of countries - which are responsible for a substantial share of IEA's funding - including the US and Middle Eastern countries and which have supported the use of gas as a transition fuel (see section 9). The IEA's views are also based on an assumption that the exceptionally large scaling up of renewable power for green hydrogen will constrain its uptake and given geo-economic constraints on the adoption of renewable energy in some regions.

The IPCC's synthesis in the 1.5 Deg report (2022) highlights the fact that only a few modelling teams submitted scenarios that distinguish between blue and green hydrogen, nor does the report discuss the relative merits of blue and green hydrogen for achieving a transition to net zero carbon emissions. Several of the numerous academic studies which form the basis of these pathways do discuss key issues of life cycle emissions as they affect the carbon footprint of fossil fuels with CCS [12]. However, Li et al.'s estimates of life cycle emissions remain well below that of more recent estimates by Ref. [13]. Other studies [4] examine the efficacy of CCS's carbon reducing potential and the way the falling cost of renewables is producing uncertainties over the use of gas as a transition fuel.

But absent in the IPCC's summary reports is an up-to-date assessment of the comparative merits of blue and green hydrogen based on the recent substantial changes in blue/green hydrogen cost relativities. Nor is there detailed analysis of the likelihood and implications of substantially higher fugitive lifecycle methane emissions from the use of fossil fuels. However such assessments remain absent from the delayed balance of the IPCC's AR6 WG3 Synthesis Report [14].

Finally, it is noted that in IPCC summaries it is generally accepted that CCS will continue to play an important role in the transition to carbon neutrality based on an assumption that 80–90% carbon capture can be effected. Thus, in its 2018 description it is noted that:

> "*Studies have shown the importance of CCS for deep mitigation pathways , based on its multiple roles to limit fossil-fuel emissions in electricity generation, liquids production and industry applications along with the projected ability to remove CO2 from the atmosphere when combined with bioenergy. This remains a valid finding for those 1.5°C and 2°C pathways that do not radically reduce energy demand or do not offer carbon-neutral alternatives to liquids and gases that do not rely on bioenergy*" (page 134).

It has been noted that many integrated assessment models and net zero assessments (including that of the IEA) rely heavily on CCS to decarbonise industrial emissions. This produces very different outcomes to modelling alternative production technologies and product substitution options that utilise renewable energy.

Thus, for scenario 3 of the four 1.5° 'consistent no overshoot' pathways - which arguable most closely approximates the current global consensus –the primary share of gas between 2010 and 2050 rises 8% - an effective zero increase from gas output levels in 2020 [11]. Although not explicitly stated this indicates that the IPCC assumes a relatively major role for blue hydrogen.

3. Blue hydrogen: costs and carbon emissions

Of the current global hydrogen production of around 70 million tonnes, 22% is produced through coal gasification. Both brown and black coal (primarily in China) is used in the steam methane reforming (SMR) process with between 18 and 20 kg CO_2 being emitted per kg of hydrogen produced. The cost is around $US1-2 (Fig. 1).

Globally, some three quarters of hydrogen produced is grey accounting for 6% of global natural gas consumption. The cost of grey hydrogen varies significantly according to the price of gas - from as low as $US1 per kg in the US to around $US1.50 for the EU region - prior to the current sharp rise in gas prices [16]. Grey hydrogen emits between 9 and 12 kg of CO_2 per kg of hydrogen produced. Blue hydrogen

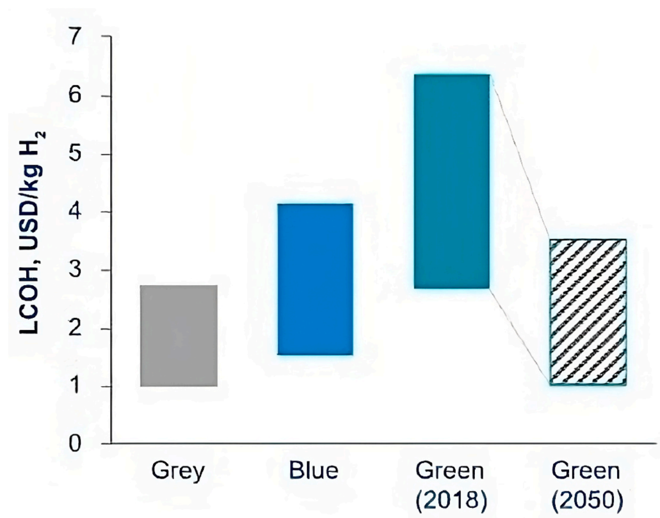

Fig. 1. LCOH blue, green and grey hydrogen.
Source: [15].

production – most of which uses gas as its feedstock in combination with the steam methane reforming process - reduces grey's emissions through the use of CCS and which is aimed to be 80–90% effective. As is the case for grey hydrogen, the cost of production can vary significantly due to differences in fuel costs. In locations with low-cost gas (e.g. the US - $US3/MMBtu), capex is the largest cost component, and the overall cost is around $US1-2 (Fig. 1).

4. Blue hydrogen: carbon capture and storage

The least know cost element of blue hydrogen's production is CCS which therefore presents financiers a high level of risk. Currently only around 1% of global hydrogen production is 'blue' [17] with only two commercial scale plants operating in 2021 [13]. Thus, while CCS has been used in oil production (largely as a means for enhanced oil recovery) its application to hydrogen production is in its infancy. Its cost and effectiveness are, therefore, the subject of considerable debate. Surprisingly, the IPCC's most recent study of CCS was published in 2008. Since then, there has been no substantive refreshment of their findings. The IPCC AR6 2022 synthesis report notes "Implementation of CCS currently faces technological, economic, institutional, ecological environmental and socio-cultural barriers. Currently, global rates of CCS deployment are far below those in modelled pathways limiting global warming to 1.5 °C–2 °C. Enabling conditions such as policy instruments, greater public support and technological innovation could reduce these barriers. (High confidence)" (page 56).

However, there are no references to new technological breakthroughs - without which greater public support would be largely wasted.

Problematically, the 2008 IPCC report does not address - other than a brief one-page reference - to what extent green hydrogen will, in the future, compete with blue hydrogen. That may be explained by the fact that in 2008 the cost of renewable solar and wind were so substantially in excess of what they are now – some 10 times and 4 times respectively (see Fig. 2). Given energy costs account for around 40–70% of green hydrogen production, presumably, in 2008 green hydrogen was not regarded as being competitive within the time horizons being considered.

The dramatic change in the cost relativities between renewables and carbon fuels since the 2008 report have therefore produced a quantum change in blue and green hydrogen cost relativities. Currently, there are estimates which put the use of CCS in blue hydrogen production increases its cost by around 45% if a 90% capture rate is achieved [18]. That still puts the current estimated LCOE of green hydrogen at around 25% more that of blue hydrogen.

Based on these differentials the IEA (2019) sees blue hydrogen as having a major role in the transition to carbon neutrality and an ongoing role in the energy mix. Thus, by 2070, it estimates 40% of hydrogen production would be blue.

Whether this share of the hydrogen market will be realised depends in part on the future cost curve for blue hydrogen. The UK's Climate Change Committee [19] projects the cost of hydrogen from SMR with CCS will increase by 2% on average from 2025 to 2040 and for hydrogen from coal gasification by 11% (with the assumption that costs of CCS technologies for hydrogen production were constant over the period). It is noted that such increases are relevant to the UK and parts of Europe which do not have access to low-cost renewable energy.

The [20] – nevertheless argues that: "… *the development of hydrogen production facilities based on fossil fuels, are justified by the assumption that CCS will be scaled up, will see greatly increased capture rates and efficiency improvements, and will ensure long-term storage with adequate MRV in place*". But the IEA goes on to admit that: " …. *as of today, CCS remains off track in both power generation* [21] *and industry* [22]; with only 2 and 17 projects, respectively, in operation as of September 2019".

The IPCC estimates 38 million tonnes of CO2 was in storage in 2020 in comparison to the global potential of 4900 million tonnes.

Australia has been one of the major test beds for CCS with the Federal Government allocating around $4 billion in subsidies since 2004. However, the only CCS operation opened – and the world's largest – which was integrated into the $AU3 billion Gorgon gas project has so far been beset with technical difficulties and has not been able to achieve anything near its target of 80% carbon capture - with capture rates 50% below the desired level. A further recipient of Australian Government subsidies - Queensland's Zeroed demonstration plant aimed at combining coal gasification with CCS – was abandoned after the initial $1.2 billion cost estimate blew out to $6.9 billion.

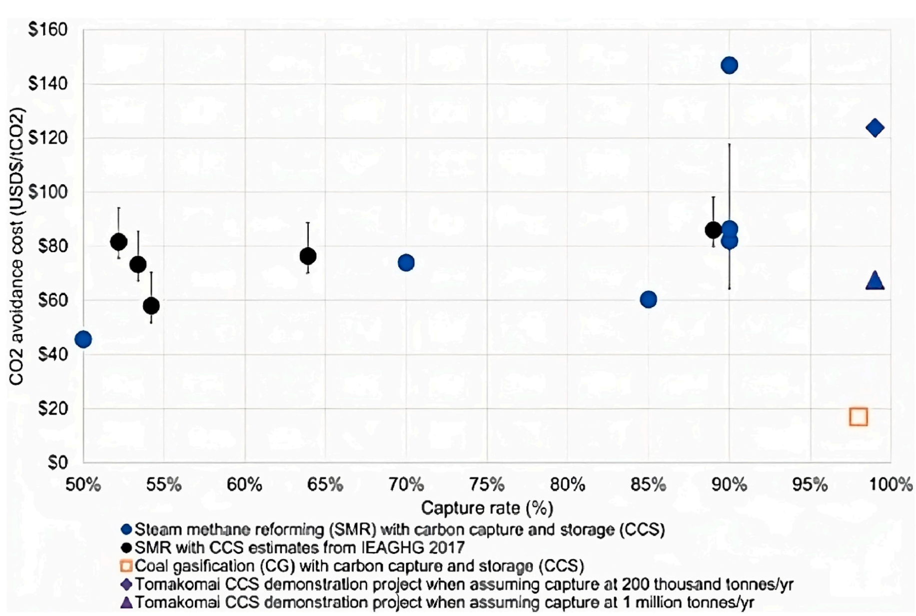

Fig. 2. Carbon capture and storage: cost of avoiding CO2.
Note: The error bars show the impact of doubling or halving the transport and storage costs for those studies that report them.
Source: [18].

5. Blue hydrogen: fugitive methane emissions

An emerging body of research is highlighting a further serious risk factor in financing production of blue hydrogen: the added cost of abating fugitive emissions which will rise in union with increasing price on carbon. Some 60% of fugitive industrial methane emissions come from the use of natural gas [23]. Moreover, a number of recent studies are finding evidence of substantial underestimation of global anthropogenic CH4 emissions of 25%–40% and in particular for oil and gas fugitive emissions [24–27].

However, a number of key reports associated with the gas industry and apparently prepared prior to and proximate to COP26 do not address this issue. Thus, there is no mention of fugitive emissions in The Hydrogen Council's major submission to COP26 "hydrogen net zero" [28] notwithstanding its lengthy and detailed focus on blue hydrogen's potential. Confusingly, the term 'clean hydrogen' -which, in most references refers to blue hydrogen – includes green in this document. This is an unfortunate confusion given the clear implication that blue hydrogen has the same 'clean' properties as green. This confusion is repeated by McKinsey and Company in its authorship of Australia's hydrogen adoption plan [29] in which this erroneous associations between blue and green hydrogen is achieved by including the two types with the term clean hydrogen [7]. analysis "the rise of clean hydrogen" makes no reference to fugitive emission and similarly vests green hydrogen with the term clean hydrogen. Further confusion is being caused by the reference in COP 27's final communique to "low carbon" fuels as a means to reduce carbon emissions. This term is also term widely also used by oil companies in their reference to investment which the categorise as addressing climate change.

Recent studies are now highlighting just how misleading the collective term '*clean hydrogen*' can be. Using satellite and 'unconventional' data sources drawn from 700 hotspot detections estimates of 2019 fugitive methane emissions from upstream oil & gas sector exceeded the equivalent CO_2 emissions from the sector's fuel combustion - equivalent to nearly 1 billion tons of CO_2 eq [30].

The IPCC's 5th Report [31] assumes curtailment of methane emissions of more than 2% a year, reaching 37% below 2017 levels by 2030 and 55% by 2050. It is accepted that if these targets are not met, the 1.5 °C objective would be effectively beyond reach.

A key problem in estimating fugitive emissions from oil and gas is the difficulty in regulating the gas industry given, in countries such as the United States, there are around 9000 independent producers drilling 95% of wells accounting for 85% of gas production. Similarly, the world's largest source of natural gas fugitive emissions – Russia – has notoriously lax regulations. The [11] claims that, depending on the price of gas, 20–40% of emissions could be eradicated at no cost. However, it equally admits some formidable barriers to any such eradication not the least that, to be effective, such regimes would be complex and time consuming to implement. Regulations would need to be "*tailored individually to a jurisdiction's local situation, political and regulatory context, the nature of the industry, the size and location of emissions sources, and the jurisdiction's policy goals*" [32]. The IEA further points out that a methane tax could not, currently be effectively enforced given there was no reliable data on how much methane is being emitted. Such knowledge is not readily available - peer reviewed research on the extent of fugitive emissions is sparse – an acknowledgement in part, it would seem, of the difficulties noted above in obtaining reliable global or even regional estimations.

A recent study by Ref. [13] notes there are "remarkably few" published peer-reviewed papers to compare their estimates of methane emissions (which included upstream and process fugitive emissions) from the use of coal and gas in hydrogen production and CCS.

What data there is on fugitive emissions are acknowledged to be unreliable: The [11] puts global fugitive methane emissions at around 5% of all energy related greenhouse gas emissions. Accuracy in these estimates is acknowledged to be problematic given multinational gas companies – let alone small operators - have not provided comprehensive estimates of emissions either from processing or from upstream and downstream fugitive emissions. However, estimations based on satellite data showing far higher levels of fugitive emissions, indicate natural gas emissions alone account for 5% of global emissions [33]).

[18] study using IPCC estimations puts emissions from hydrogen produced with 90% CCS at 21 g CO_2-e/MJ and at 28 g CO_2-e/MJ when fugitive emissions are accounted for [13]. put average CO_2 emissions – excluding fugitive - at around 78 g CO2 per MJ. However, once fugitive methane emissions - and in particular upstream methane emissions generated from natural gas extraction - were included the footprint grew to 153, 139 and 135 g CO_2-e/MJ for grey, blue (without flue CO_2 recovery) and blue (with flue CO_2 recovery) respectively.

These calculations indicate that, collectively, grey and blue hydrogen have CO_2 carbon footprints significantly above that from burning natural gas (over 20% greater for blue hydrogen). A substantial proportion of the total emissions - two thirds - are derived from fugitive upstream and process methane emissions. Even with flue CO_2 capture the extra methane used to drive this added process means there is little gain in net reduction of emissions.

[13] point out that parts of the processes involved in SMR, and carbon capture/storage are powered by methane which accounts for a substantial part of the total CO_2 emissions. They calculate that if green electrical power was used instead, blue hydrogen's emissions from the SMR process could be more than halved to a total 52 g CO_2eq per MJ (such an alternative may be unlikely given it can be assumed blue hydrogen plants will be located in regions where gas is readily available and low cost). But they note this still represents almost 50% of emissions from directly burning natural gas representing a substantial cost penalty where a carbon price is applied. Under these conditions they point out "… *renewable electricity would be better used to produce green hydrogen through electrolysis*."

In summary [13] produce a confronting conclusion for the gas industry. "… the greenhouse gas footprint of blue hydrogen is more than 20% greater than burning natural gas or coal for heat and some 60% greater than burning diesel oil for heat, again with our default assumptions". They thus conclude that it appeared that "… there really is no role for blue hydrogen in a carbon-free future".

Whether Howarth and Jacobson's estimate of fugitive emissions can be extrapolated globally cannot be assumed given the lack of data. However, given the apparent under estimation of fugitive methane emissions in regions such as Russia, Africa and South America there may be a good case for its use as a base model. It is noted that Howarth and Jacobson base their calculations on the SMR process. There are other processes for producing blue hydrogen being developed such as autothermal reforming, partial oxidation and pyrolysis and which could reduce emissions in the manufacturing process although these are modest compared to the upstream fugitive emissions. A lack of data from operating plants using these new technologies which are in the early stages of their technological development, does not currently allow for any precision about their potential.

Notwithstanding such reservations over the difficulties of obtaining reliable global estimates, a number of related studies conclude that, given the problems posed by methane emissions, there should be a rapid phasing out of all fossil fuels, rather than relying on what they see as short-lived effects of fuel switching from coal to gas [25,34,35].

That assumption is nevertheless challenged by the [17] which argues that, given the challenge of generating sufficient renewables to meet the very large appetite of green hydrogen production, there is the risk that replacement of coal or gas fired grid electricity will not be possible. It is, therefore, argued that: "*Renewable electricity delivers three times more emissions abatement when used to displace NGCC (natural gas combined cycle) generation and eight times more emissions abatement when used to displace lignite fired generation than when used to produce hydrogen which then displaces the combustion of natural gas. Wherever possible, renewable electricity should be used to displace unabated fossil generation where it*

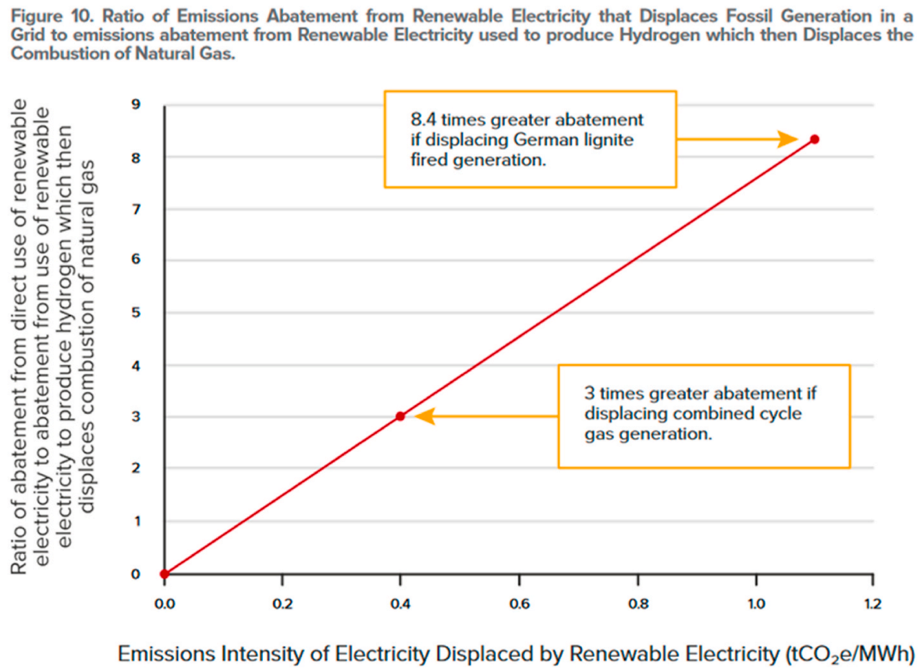

Fig. 3. Displacement of grid electricity and production of renewable hydrogen.
Source: [17].

delivers significantly more emission abatement than it would if used to produce hydrogen which then displaces natural" [17]. This trade-off is illustrated in Fig. 3.

However, such an advantage would seem to be challenged by US satellite data on fugitive emissions which indicates that, because of the far higher upstream fugitive emissions of blue hydrogen production, its greenhouse gas footprint is 20% above directly burning natural gas or coal [13]. Indeed, the Energy Watch Group (2019) points to a number of studies indicating that higher than admitted methane emissions mean replacing coal fired power plants with gas fired plants would in fact increase emissions.

There is a wider issue relating to the IEA's evident reluctance to accept the higher levels of methane emissions being derived from satellite data. This has led to claims of a systemic underestimation by the IEA. The differences in estimations are not small: Satellite data [36] indicating a 40% increase in methane emissions between 2019 and 2020 is matched by the IEA's estimation of a 20% reduction. Part of this gap may be explained by studies indicating high levels downstream emissions – up to 2,7% of extracted gas - not accounted for by the IEA [37, 38]. Another key issue is the IEA's uses of a multiple of 30 when converting methane to a CO2 equivalent - while others such as [18] use a multiple of 84[4].

For its part, the gas industry is on record [32] as claiming that as much 80% of fugitive emissions from oil and gas operations and 98% of emissions from the coal sector could be eradicated at no cost or a saving. However, such an encouraging undertaking does not appear to have been taken up to any substantive extent by the industries involved. That may in part reflect the paucity of data on fugitive emissions and/or that relevant corporations either have not sought to acquire data on the location and extent of emissions or are reluctant to publicly reveal such data.

6. Green hydrogen production costs

6.1. Hydrogen's LCOE

Green finance investment decisions relating to hydrogen production projects are further subject to uncertainty in relation to a number of variables. As discussed below, green finance decisions will need to be based on projected future metrics relating an emerging technology's future economics of input costs, interest rates, economies of scale and learning rates. A much-used metric – the levelized cost of energy (LCOE) - measures cost at the factory gate. However, there is currently a widespread in estimates - even from the same source. For example, IRENA estimates 2020 green hydrogen costs at between $2.56/kg and $6.66/kg. Most studies assume a notable reduction in costs at some point in the future, however, the timing can differ. Unpacking the assumptions used when formulating estimates of green hydrogen is an important part of understanding the range of projections. The main determinants of the LCOH are: electricity feedstock cost, capital cost, and the capacity factor. Other factors, such as land, labor, and water, are a relatively small component of the LCOH and can be assumed to be fixed costs per unit produced. The main determinant of the LCOH is the cost of electricity consumed -, a consistent finding across studies (Fig. 4) [18]. report that for every $10/MWh decrease in the cost of electricity there is a $0.60/kg decrease in the production cost of hydrogen.

There is an emerging consensus on green hydrogen's future cost (Fig. 5). There is also consistency in cost competitive target prices with a number of institutions putting the LCOE below $US2, the accepted point at which hydrogen is competitive with hydrogen derived from gas. These projections are supported by a number of other studies [18,39, 40].

[5] projects a cost between $1.21 and $1.93 by 2030 and between $0.7 and $1.6/kg by 2050, which places green hydrogen's cost substantially below that of blue hydrogen but also on par with that of gas (that is, equivalent to a gas price of $6–12/MMBtu). IRENA projects a similar price decline by 2050 linking it to falling electrolyzer and power costs. shows that it is only by 2050 when green hydrogen's cost range is fully below that of blue hydrogen's cost range. Fig. 5 shows that achieving an LCOH below $2/kg depends on the cost of electricity falling below $30/MWh and low capital costs (below $500/kW and towards $100 to $200/kW) – both in turn dependent on increasing scale of production.

The world's largest producer of electrolysers, NEL, asserts substantial increases in economies of scale - and an associated heightening of the learning rate - will reduce overall production costs. Their stated aim is to

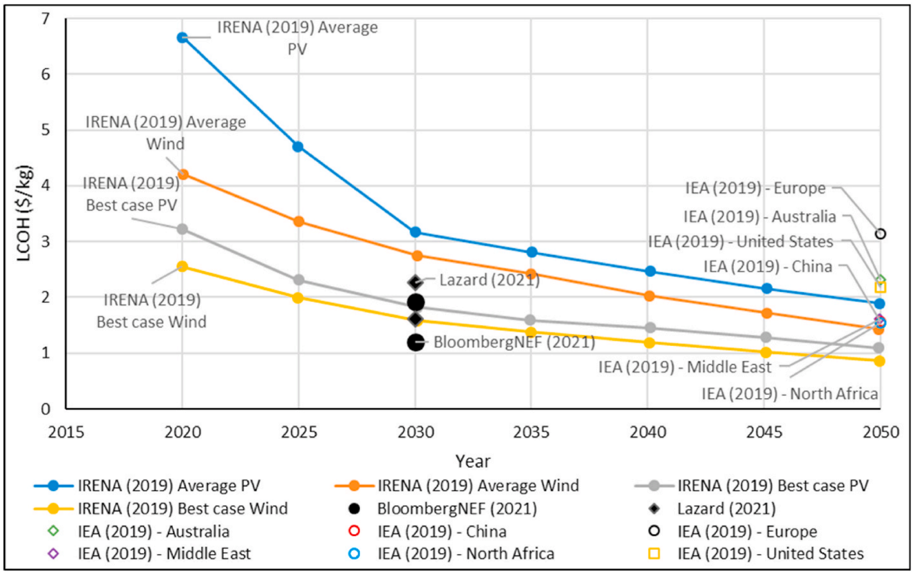

Fig. 4. Levelised cost of hydrogen produced using electrolysis.

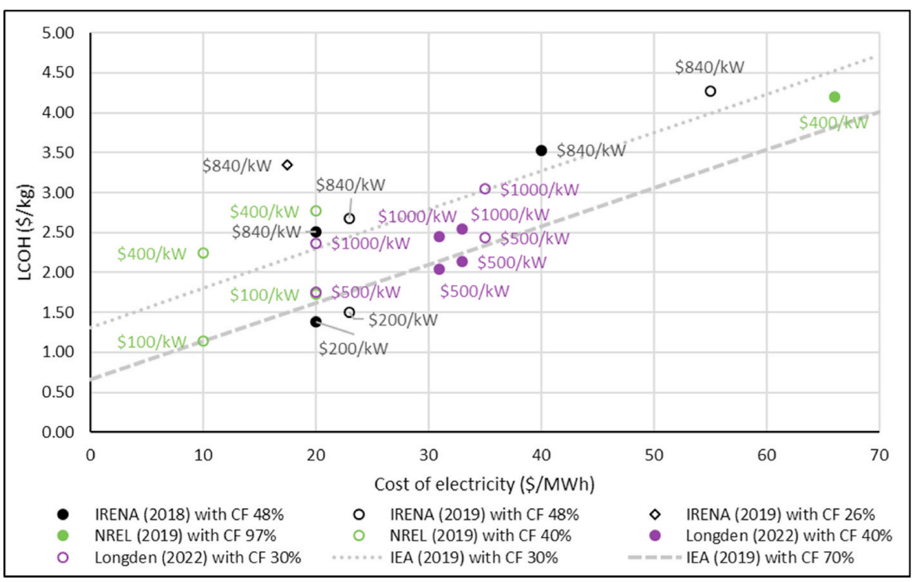

Fig. 5. Levelised cost of hydrogen produced using electrolysis: cost of electricity.
Note: [68].

produce hydrogen at $US1.50 from a scaled-up electrolyze complex of 500 MW. However, that is based on a cost of $20/MWh for renewables sourced from wind, which is well below current costs for wind power. Also assumed is that given NEL's plant would be the world's largest electrolyser, CAPEX would be reduced by 75%.

The electrolytic process for producing green hydrogen is at an early stage of its innovation cycle with no large-scale plants and only a handful of small plants in operation.

For these reasons, studies indicate that economies of scale are likely to produce a substantial lowering of the capital costs of green hydrogen together with further major contributions being made by learning curves and ongoing technological improvements to electrolysers. There is, however, a wide variation in the estimations of these effects.

The International Renewable Energy Agency [41] by applying past technological learning rates [25]; Louwen et al., 2018), sees a more than halving of electrolyser costs from USD 840/kW to USD 375/kW through to 2050. Other estimates project a substantially more rapid and sharper fall in electrolyser costs. It is on this basis that the IEA's most recent forecasts are that green hydrogen will play a major role in hydrogen's uptake.

BloombergNEF's assumption (2020) is that electrolyser CAPEX costs for a 4 MW PEM electrolyser will fall from around $1400 per Kw in 2019 to around either $1000 (conservative scenario) or $440 (optimistic scenario) in 2030 and $217 and $95 by 2050 (Fig. 6). This is based on an ongoing learning rate of 18% derived from the fall in electrolyser costs between 1956 and 2014. The IEA has similar projections of the extent of cost decline for 2030 [43].

IRENA has similar projections in which they apply the past learning rate of 18% producing a reduction in the cost of electrolysers of over 40% by 2030 and which they point out would be in line with a 1.5 °C global climate target [44]. IRENA's projections for 2050 put the fall in eletrolyser CAPEX at 80% delivering, together with capacity, durability

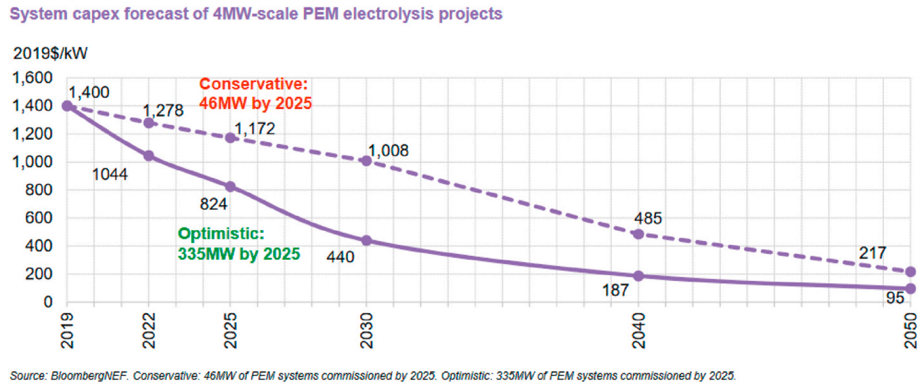

Fig. 6. System CAPEX cost projections for electrolyers
Source: [42].

Table 1
Learning rates and LCOH in the off-grid case.

Learning Rates	Alkaline Electrolysis (AEL)	Proton Exchange Membrane Electrolysis (PEMEL)
Learning rate (off-grid 10x deployment)	5 ± 2%	5 ± 1%
Learning rate-grid flexible and 10x deployment[19]	19 ± 4%	18 ± 2%
LCOH (off-grid current deployment)	2.77-2.86 €/kg	3.74-4.32 €/kg
LCOH (off-grid 10x deployment)	2.39-2.82 €/kg	3.22-3.59 €/kg
LCOH (off-grid flexible and 10x deployment)[20]	2.08-2.42 €/kg	2.75-3.04 €/kg

Notes: Two footnotes appear in this table to explain footnote 19 and 20. They are:
19. For the 10x deployment scenario, efficiency degradation and stack replacements costs were adjusted according to survey results and Hydrogen Europe (2020a).
20. For the 10x deployment scenario, efficiency degradation and stack replacements costs were adjustedaccording to survey results and Hydrogen Europe (2020a).
Source: [47].

and efficiency improvements, a hydrogen cost of around $US1 per Kg.

The [45] projections for 2030 and 2050 are linked to the assumption that globally, the cost of electrolysers will fall to that of the much lower Chinese production cost –currently around 50%–80% below than of those produced in the West. This is ascribed to lower raw materials and labour costs, higher factory utilisations and lower overheads.

The role of learning rates is a further critical element in CAPEX cost projections for green hydrogen. Jens's EU based study (2020) finds the IEA assumptions contained in its Future of Hydrogen [43] are based on outdated 2016 data from academic sources in contrast to more contemporary data from actual facilities gathered by the [46] and the 2 × 40 GW initiative (European Union, 2020b). Jens also claims that the IEA underestimates the timing and speed of adoption of green hydrogen. Thus, he finds their CAPEX projections for 2030 being achieved before 2024 and its goal for 2050 prior to 2030.

[47] reminds that learning rates for green hydrogen are critically dependent on the source of electricity given it typically accounts for around ½ to 2/3 of electrolyser costs. Where power is flexible (e.g., a combination of wind and solar) and where there are economies to be derived from a 10-fold increase in electrolyser deployment – as in the case of alkaline electrolysis (AEL) and proton exchange membrane electrolysis (PEMEL) - a more than tripling of the learning rate can be assumed (Table 1).

6.2. *Regional renewable efficiency, transport and storage*

As mentioned, a defining influence on green energy costs is that of renewable energy which can account for between 40% and 80% of total costs. In some countries with relatively high renewable energy costs that proportion is at the higher end of this range and therefore becomes an even more dominating factor in cost reduction. The global average for new PV and onshore/offshore wind has been estimated at around $US32, $US38 and $83 per MWh respectively [48] although more recently costs go below this in good locations – around $US24 for solar and onshore wind respectively and $48 for offshore wind [49]. By their nature these intermittent sources of energy mean curtailing ability of electrolysis becomes important. Most studies assume different capacity factors for solar and wind, however, they don't account for the impact of intermittent use on the lifetime of the electrolyser stack. At these low-cost levels [48] notes solar, and wind are cheaper than the marginal cost of both coal and gas combined cycle ($US42 and $US24 per MWh). Fig. 7 shows how large the geographical variations in renewable costs are and this is one of the key factors impacting the LCOH estimates as illustrated in Fig. 7.

While regions such as North Africa, the Middle East and Australia have extensive solar and wind resources their geographical remoteness from their markets imposes a cost penalty on green hydrogen. Piping hydrogen (which has the added advantage of providing a storage medium) is seen as a viable option where sources are geographically reasonably proximate.[1] Otherwise, supply from geographically remote counties such as Australia needs to be by tanker (Fig. 8). However [50], modelling shows that the cost of exporting hydrogen via a pipeline from a country such as Algeria to Germany would be between US25-0.50 cents per kg using either repurposed or low-cost new pipelines as indicated in Fig. 8.

[50] concur with the IEA that, in the medium term, blue hydrogen would be by far the cheapest form of production for both domestic and imported forms of hydrogen. However, as noted, a number of best-case studies – including the world's largest producer of electrolysers NEL – indicated an LCOE for green hydrogen in 2030 of around $US2 is achievable.

7. Carbon price and fugitive emissions

Projections on the future viability of hydrogen production projects will need to take into account the current and likely future price of

[1] Most estimates put 1500 km as the limit for economically viable transport of hydrogen. Beyond this distance shipping hydrogen is see as more economic.

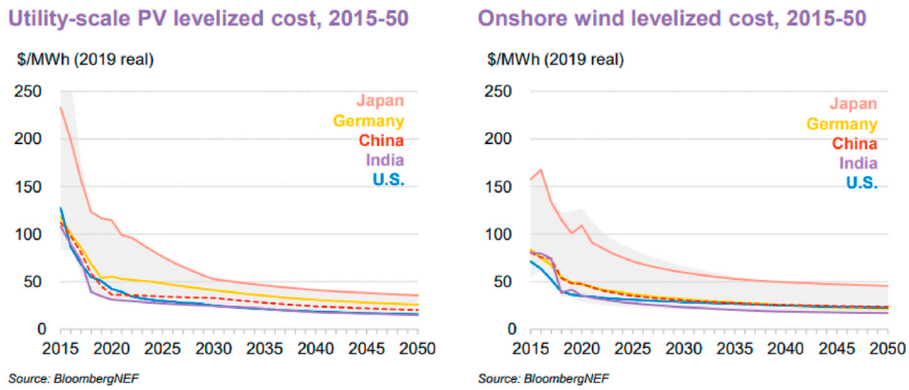

Fig. 7. Projected levelized cost of renewable energy.
Source: [42].

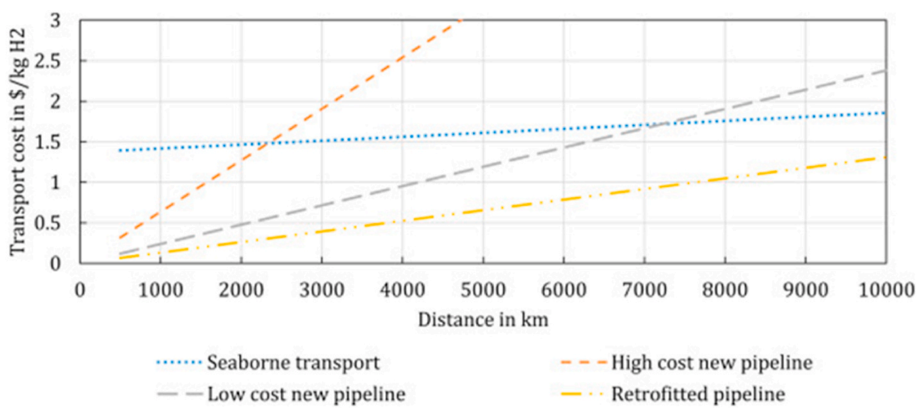

Fig. 8. Comparison of hydrogen sea and pipeline transport costs.
Source: [50].

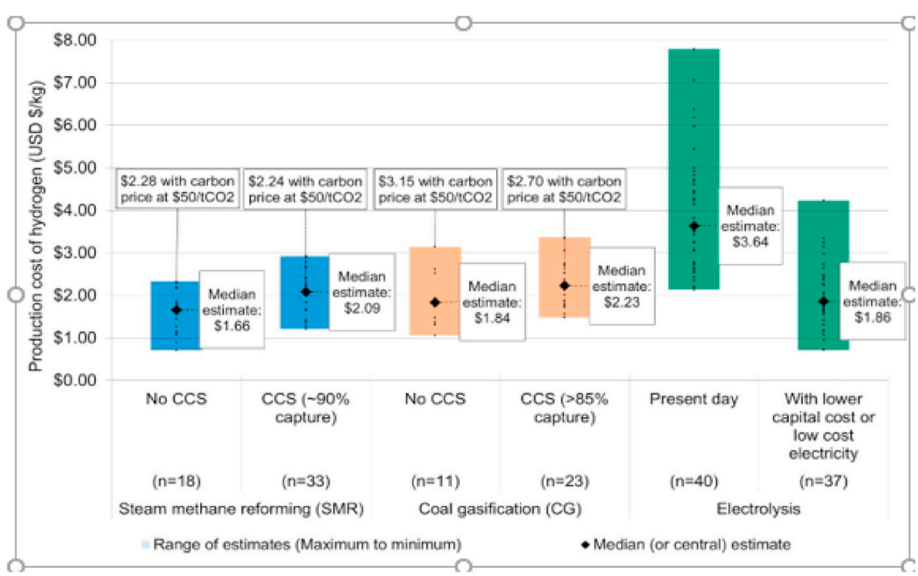

Fig. 9. Cost of hydrogen production with carbon price of $50.
Source: [18].

carbon. Given non-green forms of production are being shown to emit significant upstream and downstream levels of GHG emissions, the recent sharp increase in the carbon price translates into a substantial effect on the costs of blue hydrogen.

By applying a carbon price of $50 [18] shows the median price for grey and blue hydrogen increases from $1.66 and $2.09 per kg to $2.28 and $2.24 respectively (Fig. 9). Carbon pricing alone is shown to almost double the price of SMR without CCS to $3.50 per kg at a carbon price of

\$60/t CO2. While Longden et al. put the current cost of green hydrogen at \$3.64 its future production cost is projected to be around \$1.86 when economies of scale and low electricity costs are factored in - well below that of blue hydrogen with 85% CCS.

However, if [13] estimations of CO2 equivalent methane fugitive emissions for blue hydrogen – 135g CO2-e/MJ - are accounted for this increases Longden et al.'s (2021a) allowance (28 g CO2-e/MJ) 4.8 times. This increases the cost of blue hydrogen to \$AU2.91 per kg at a carbon price of \$AU50. If the current EU rate of around \$AU100 is used blue hydrogen's cost rises to \$AU4.26.

8. Drivers of hydrogen uptake: investment

Although from a very low base, the scale up of investment in hydrogen production is accelerating exponentially and will need to continue to do so if global decarbonising targets are to be met. The Climate Council (2021) puts investments in projects at a 'mature' stage at \$150 billion - an approximately doubling in value since February 2021. This represented a 60% increase in production capacity to 11 million tons with ongoing investment in hydrogen increasing weekly by roughly \$1 billion [51]. indicates some \$500bn will need to be allocated to investment in hydrogen projects globally over the next decade. Europe remains the centre of hydrogen development, accounting for more than 50% of announced projects and estimated investments of \$130 billion. The China Hydrogen Alliance, a government-supported industry group, predicts that by 2025 the output value of the country's hydrogen energy industry would reach 1 trillion yuan (\$152.6 billion), and by 2030 that China's demand for hydrogen would reach 35 million tons, accounting for at least 5% of China's energy system [52].

Behind this momentum is the recognition by the global financial community that carbon-based assets are attracting a greater risk premium. This has implications for blue hydrogen project finance. Australian Financial advisers [53] note that green hydrogen projects are likely to be favoured by lenders over grey, blue and brown projects. While blue hydrogen projects do remain bankable, they advise there will be a requirement to demonstrate how emission will be minimised. In this context they pose the question of whether CCS will be accepted as a means to minimise risk and/or whether the purchase of renewable certificates would be acceptable.

Such an evidently high-risk premium indicates authorities should be preferencing green over blue hydrogen where green financing is being offered. There is the argument, however, that if hydrogen's adoption as an end use is universally strong, the reduced demand for gas would lower its price and therefore the cost of blue hydrogen. But, as noted, a rising price on carbon and still falling renewable energy prices are likely to be the strongest influence on comparative prices. A further cost relevant issue is that, with current historically low interest rates projected to rise, so would the capital-intensive cost of green hydrogen plants' CAPEX. This will clearly be a factor in the short run although financing for green hydrogen electrolysers will reflect interest rates over a longer period. Moreover, as noted, economies of scale will be a more substantive over the next few years of rapid expansion. Finally, risk premiums will necessarily reflect the need for an unprecedentedly large increase in renewable energy supply if electrolysis is to be the preferred production method.

Underlying a rising risk premium for blue hydrogen is the threat of stranded assets. A number of estimates put the shelving of investments by global oil and gas majors at around \$US1 trillion over the next 20 years if the IEA's assumptions on what is needed to achieve carbon neutrality are adopted – that is no new coal oil or gas projects are allowed [54]. If so, the output of the world's 40 largest producers would shrink by an estimated 50% as current capacity runs down. It notes that, alone, the globe's five largest oil and gas projects approved in 2020 involve \$18 billion investment over the next decade - all in direct opposition to the IEA's carbon neutral timeline.

The surge in carbon fuel investment is therefore likely to reflect oil companies' moves to protect asset value and an intention to promote blue hydrogen production as a major end use for natural gas/LNG. There are, nevertheless, indications that green hydrogen is being regarded as the preferred lower risk investment option. The Hydrogen Council whose membership includes major gas producers - [51] notes that 131 new large-scale hydrogen production developments had been recorded since February 2021, a 60% increase for a total of 359 projects. Of these 70% were green hydrogen projects with the remainder using fossil fuels with CCS.

9. Country and regional hydrogen production and green financing strategies

According to a report published in February 2021 by the [51] more than 30 countries have developed hydrogen road maps, and 228 large-scale hydrogen projects were announced across the value chain,. The Council projects that hydrogen could meet 18% of total global energy demand and create a \$US2.5 trillion market with more than 30 million jobs by 2050.

The substantially different longer term investment risk between blue and green hydrogen is not, however, reflected in major producers' government green financing policies. In the UK there is indeed a specific very generous carbon allowance (4 kg per one kg of hydrogen produced) for proposals which seek green financial support and therefore opening blue hydrogen to green finance[55,56]. Thus, in effect, there is no differential incentive to steer investment to lower risk green hydrogen. Equally, in the United States financial incentives embodied in the Inflation Reduction Act are applied to 'low carbon' production of hydrogen. As for the UK, there are carbon emission limits which apply to one category of subsidies for hydrogen production and which effectively preferences green hydrogen over grey and brown H2. However, in the case of blue hydrogen there is a separate exclusive subsidy category which which has no limit on carbon emissions.

In 2020 the EU commission adopted a 'hydrogen strategy for a climate-neutral Europe' [57] designed to accelerate the uptake of 'clean' hydrogen (i.e. including blue hydrogen) which, it envisages, would have a 32% share of renewable energy in EU gross final consumption by 2030. The strategy is based on the development of both blue and green hydrogen in the initial phase beyond which green hydrogen would be predominant as its price falls in line with increasing scale of production hydrogen ([58]. Currently EU runs two streams of green finance – one for green hydrogen projects (by way of reverse auctions) and one – via The Innovation Fund - which accommodates blue. Currently 1 billion Euros is allocated to subsidising CCS projects covers 45% of project costs [59].

In the case of China, the policy relating to green finance is far less clear. A number of studies have indicated the efficacy of the application in China of green finance to hydrogen production [60]; [61,62]. However, China has less specific and less aggressive hydrogen adoption strategies. Its 14th Five-Year Plan (2021–2025) nominates hydrogen as one of China's six 'industries of the future' with projections of a \$US150 billion industry by 2030 by which time it would account for at least 5% of China's the energy share rising to 10% by 2050. Fifty-three large-scale projects have been publicly announced in China involving investment of \$17 billion [51] But it is unclear whether they are green or blue. Green finance is currently being issued at the provincial level under guidance from the central Government. There appears to be no specific distinction between green and blue hydrogen in policy documents although there is frequent emphasis on the production of green renewably sourced hydrogen in discussion on future development of the hydrogen industry.

In contrast, South Korean and Japan have put in place specific timelines for the adoption of renewable hydrogen. This reflects Japan's 90% dependency on energy imports – currently, 70% of its electricity is generated by imported LPG and coal. Japan's timeline involves making hydrogen cost-competitive with natural gas by 2030 and by 2050 consume some 20 million tonnes of renewable hydrogen largely through imports [63]. South Korea – also heavily dependent on imported energy - has evisages itself as a hydrogen powered society by 2050 and has targets of powering 10% of the country's cities, counties and towns by hydrogen by 2030, growing to 30% by 2040 [64]. Cities would use hydrogen as a fuel for cooling, heating, electricity and transportation. Blue hydrogen is to be a transitional method of production although the stated goal is to have 93% of hydrogen green by 2050. Canada and Australia similarly have policies which encourage both blue and green hydrogen production.

However, the opening up of flows of green finance to blue hydrogen projects in the above countries means the efficiency of CCS becomes a key issue. In the case of the UK for example eligibility for government support for hydrogen production is dependent on meeting an emission limit of 20gCO2e/MJHV. However, the risk of a high level of CCS inefficiency means a high level of financial risk. That would be only increased where a more realistic lifecycle methane emissions level is applied. Moreover, if there were to be a large scale uptake of blue hydrogen production - as is currently planned for the UK by major oil companies - projected higher emission would put upward pressure on the price of carbon and therefore on its overall cost. In countries where offsetting of blue hydrogen emissions was by way of the voluntary carbon market (VCM) this leaves the as yet unresolved issue of how they are to be verified. That is important given there is widespread acceptance that stated reduction of emissions of VCMs are more often than not achieved and that outright fraud is not uncommon.

10. Conclusion and policy recommendations

This review of the current literature including a range of institutional and commercial studies indicates that, if the EU's current price on carbon and a realistic inclusion of methane emissions are added to blue hydrogen's cost, green hydrogen is already an economic proposition in locations which are set to become major producers. Even in the absence of a carbon price, falling electrolyser and renewable energy prices are projected to be a major factor in narrowing the cost differential parity between blue and green hydrogen before the end of this decade.

Given the relatively short price parity timelines in countries with low-cost renewables it can be argued that green finance should be directed to green hydrogen production. Such a conclusion is informed by the already unprecedented sharp rise of the EU carbon price since mid-year (2021) - which has added 40% to the overall cost of blue hydrogen (factoring in the price as applied to carbon emissions). This percentage would further rise substantially if the cost of gas's upstream fugitive emissions is fully accounted for and will certainly rise much further as rising carbon prices in the future reflect the prospect of substantially over shooting the 1.5c.

Of consequent concern is that the roles of blue and green hydrogen in the IPCC's and IEA's decarbonizing pathways are not defined with any precisions and do not properly accommodate recent findings relating to fugitive emissions nor the role of rising carbon prices in the future on hydrogen production cost. That reflects the fact that the IPCC is a broad-church accommodating countries with very different resource bases and energy costs. While that form of democracy may have fitted the price relativities of a decade ago, the IPCC and the IEA now need to review their advice in light of the new data available. Of particular concern is the gas industry's substantial underestimation of its fugitive emissions' footprint and an apparent reluctance to fund substantive research on this issue. In addition, there is the industry's reluctance to engage on the issue of CCS's high costs and unproven status, and its related unprincipled semantic blurring of the definition of 'clean' hydrogen. In the case of green hydrogen, realizing economies of scale, the complexities flowing from differing regional costs of both gas[2] and renewable energy and costs of hydrogen's transportation will be the critical factors influencing its rate of uptake and the flow of green financing. Where blue hydrogen production does proceed risk analysis by green financiers will need to also factor in the likely effect on the carbon price of heavy offsetting of emissions and whether VCMs can in fact deliver claimed reductions in carbon emissions.

In addition, the rapid convergence of the blue and green price relativities should be of central concern for green financing institutions and government policy makers given the very real prospect of future extensive stranding of blue hydrogen production assets. As noted, the rapidity with which green hydrogen's cost curves are falling may sooner rather than later make blue hydrogen production uneconomic. This applies in particular to prospective hydrogen exporting countries which have yet to impose a carbon price directly on production. This is because impending carbon border tariffs will effectively impose a global carbon price on blue hydrogen exports.

Our review produces a number of policy observations and recommendations. In the immediate future governments will be constrained in developing comprehensive roadmaps for hydrogen's adoption while there remain uncertainties over blue hydrogen's carbon footprint and the effectiveness and costs of CCS. While commercial interests may prefer this lack of clarity to remain, it is in the interests of Governments to actively seek reliable environmental data and cost projections in relation to blue hydrogen in order to create sound hydrogen adoption strategies and financial support.

Assuming these issues can be resolved, Governments will need to clarify which of the variety of paths the IPCC and other advisory bodies have mapped out for reaching carbon neutrality, match their hydrogen adoption investment strategies. Our review indicates those paths which have a heavy dependence on CCS dependent blue hydrogen are at risk of being fundamentally misaligned with its current and future cost benefit.

To avoid such misalignment, we see a need for intervention and moderation of the evolving public discourse in which blue hydrogen and 'low carbon' fuels - are defined as a 'cost-effective fuels by commercial interests and governments wishing to ensure gas has a major role in hydrogen's uptake. This analysis indicates investment in blue hydrogen carries substantial risks at a time when green hydrogen's production costs are falling rapidly, and blue hydrogen's production will become subject to rising carbon prices. This changing risk profile would seem to be reflected in multi-billion-dollar investment commitments in green hydrogen production in Australia and in a number of other countries such as Saudi Arabia, Chile, The Netherland and Mongolia. And as indicated in the review of EU and other national policies, decisions on blue vs green hydrogen investment are at a critical stage of formation. Of concern here is that blue hydrogen figures prominently as a valid transitional choice and a legitimate avenue for green finance. This review indicates that such national policies are not based on solid scientific and economic data.

We underline that the argument for directing green finance to green hydrogen production rests heavily on the findings that there is a very high financial risk factor in blue hydrogen production's dependence on unproven CCS and the high, unaccounted for, level of fugitive emissions from the gas supply chain. These factors could double the cost of blue hydrogen (and account for as much as 5% of total global emissions). What appears to be the IEA's systemic underestimation of these risks may indicate their resolution is a more formidable problem than publicly acknowledged. In particular, it is noted that the capacity of the IEA's corporate membership to deliver on the stated target of eradicating 70% of fugitive emissions by 2030 is not well documented or costed. More generally, the continuing lack of reliable data on CCS and better and more comprehensive on the ground data on gas mining fugitive emissions means further research is called for. Without such data decisions on allocation of green finance will necessarily be based on an assumed risk factor rather than on concrete data on costs.

In order to provide green financiers with more specific information on hydrogen production risk profiles further studies could usefully seek

[2] Very low gas prices in the US also pose a particular challenge for the early adoption of green hydrogen in the US.

to quantify the effect of large-scale production of blue hydrogen on the carbon price. As well there is clearly a need to assess which specific type of green finance best suits the risk profile of green hydrogen production.

Declaration of competing interest

The authors declare the following financial interests/personal relationships which may be considered as potential competing interests: Jeremy Webb reports financial support was provided by Queensland University of Technology.

Data availability

No data was used for the research described in the article.

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