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On the cost competitiveness of blue and green hydrogen

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Abstract

Despite huge cost reduction potential for green hydrogen production, it is uncertain when cost parity with blue hydrogen will be achieved. While technology costs, electricity and natural gas prices are key drivers, hydrogen's competitiveness will be increasingly determined by carbon costs or regulation associated with its life-cycle emissions. Theoretically and numerically we show that higher residual emissions of blue hydrogen can close its competitive window much earlier than cost parity of green hydrogen would imply. In regions, where natural gas prices will remain substantially higher (~40EUR/MWh) than before the energy crisis, such a window is narrow or may have closed already. Blue hydrogen could play a role in bridging the scarcity of green hydrogen, yet uncertainties about the beginning and end of blue hydrogen competitiveness might impede investments. By contrast, in regions where natural gas prices fall below 15 €/MWh, blue hydrogen can remain competitive until ~2040, if it is produced with high CO_2 capture rates (>90%) and low methane leakage rates (<1%).

1. Introduction

In the discussion about the future of hydrogen we see two main debates. There is the demand-related question about applications and sectors in which hydrogen can and should be used. This debate is linked to the underlying question about the general role and importance of hydrogen as a future energy carrier and feedstock. Across scenarios recently assessed by the IPCC, the median global hydrogen share in final energy in 2050 is 2-3% (Figure 6.31 in chapter 6 of the IPCC wg3 report[1]) with an interquartile range of 0.5% to 6.2%; yet, other scenarios show higher hydrogen shares of 10-12% (IEA's net-zero emission (NZE) scenario[2], IRENA's 1.5°C scenario[3]).

The focus of this paper is a second question that is related to the supply side of hydrogen. Seeking cost-efficient climate change mitigation from an economic perspective, to what extent can and should blue hydrogen made from natural gas with carbon capture and storage (CCS) complement green hydrogen from renewable electricity? Is blue hydrogen a bridging solution or long-term option and what are the associated prerequisites and drivers?

Our contribution is a techno-economic perspective on the cost competitiveness of green and blue hydrogen - with one another and with fossil fuels. Acknowledging the substantial uncertainty and regional heterogeneity, we seek to derive plausible parameter ranges with respect to technology cost, energy prices and technical parameters and carefully construct more progressive as well as more conservative supply cases (next section).

While there is substantial literature on the direct cost competition of blue and green hydrogen[4–8], as well as on their residual life-cycle greenhouse-gas (GHG) emissions [9–15], we propose a new analysis framework that combines these aspects. Therein we derive five "fuel-switching points" in time at which blue and green hydrogen become competitive with

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fossil fuels and green hydrogen becomes increasingly competitive with blue hydrogen. These fuel-switching points are conceptually introduced (section 3) and numerically estimated (section 4).

There is already one detailed case study for Germany[16] that analyses the competitiveness of green with blue hydrogen, while accounting for residual emissions and the impact of increasing CO2 prices. The authors conclude "that blue hydrogen is likely to establish itself as the most cost-effective option, and not only as a medium-term low-carbon alternative". The case study focuses on grid-connected electrolytic hydrogen locally produced in Germany, while neglecting methane emissions of blue hydrogen and assuming low future gas prices from before the 2021/22 energy crisis. We show that varying hydrogen supply cases, e.g. including off-grid green hydrogen projects, accounting for methane emissions and potentially higher future gas prices, can lead to substantially different results.

Our approach and findings are relevant to policy makers, investors as well as researchers and analysts. Policy makers are interested in the prospects of blue and green hydrogen as options to mitigate climate change and in the impact of emission-specific policies (e.g. CO2 pricing) or technology-specific subsidies. Investors are interested in the determinants of hydrogen's competitiveness and investment risks that might arise from residual emissions. We further hope that our analysis framework appeals to researchers and analyst. Note that it can be applied to evaluate any potential bridging option.

Against the backdrop of climate change, policy makers and societies will likely ensure that the residual life-cycle emissions of hydrogen will increasingly translate into additional private costs and thus impact competitiveness and investment decisions. This translation can happen in a direct way via CO_2 pricing[17], or more implicitly via emission-specific regulations such as the production tax credits for hydrogen in the US Inflation Reduction Act (IRA)[18]. We estimate that the IRA's production tax credits (PTC) for hydrogen are roughly equivalent to CO_2 prices of ~100 to 350 \$/tCO_2eq, depending on the four emission-specific PTC tiers. For this calculation the PTCs are divided by the respective required emissions' reduction (Supplemental information section 2). Note however that our purpose is *not* to analyse the short-term impacts of specific policies in selected regions. Instead, we seek to derive more general insights into the mid- to long-term development of the cost competitiveness of blue and green hydrogen.

While specifying regional cases is out of scope for this paper, we identify the conditions that impact results and conclusions, which can be extrapolated to selected regions. Translating the competitiveness results into scenarios with hydrogen production volumes would require to include other aspects such as potential bottlenecks in the upscaling dynamics of green[19] or blue hydrogen[20], path dependencies[21], region-specific infrastructure and regulation as well as the uncertain developments of overall hydrogen demands across sectors.

2. Green and blue hydrogen supply cases

Before the 2021/22 energy crisis[22], near-term production costs of green hydrogen were estimated to be substantially higher than those of blue hydrogen[15,23]. After Russia invaded the Ukraine, global natural gas prices skyrocketed in mid-2022, but have been declining since late 2022. Price futures indicate that for some countries, such as the US[1], price levels reach low levels again, while for import-dependent regions such as Europe[2] price levels might remain slightly higher than pre-crisis levels. For the latter regions, the cost gap between blue and green hydrogen thus narrowed.

Future green hydrogen production costs are also anticipated to show a region-dependent range, which depends on regional renewable electricity costs or prices, supply chain specifications (e.g. grid-connected or off-grid electricity, and transport costs), and technological developments. While there is agreement that increasing electrolyser sizes, establishing serial production, and plummeting renewable electricity costs will substantially reduce green hydrogen costs[6–8,24,25], assessments differ with respect to timing and long-term floor costs.

As a result, there is uncertainty and regional heterogeneity as to *whether* and *when* cost parity of green and blue hydrogen will be achieved. Building on recent data and evidence, we carefully choose more *progressive* as well as more

[1] https://ycharts.com/indicators/henry_hub_natural_gas_spot_price

conservative parameters and hereby design various supply cases for green and blue hydrogen (***Table 1***). All assumptions are discussed in detail in the methods and data section.

We account for additional uncertainties and regional differences in four complementing ways. First, we combine the technological supply cases with sensitivity cases for natural gas prices and the global warming potential (GWP) time horizon (***Table 1, bottom***). Second, while the technology and sensitivity choices capture broad ranges, we include error bars in some figures that show how small parameter variations (±5 %) impact results. Third, we conduct an even broader sensitivity analysis (**Figure 5**) that goes beyond the parameter ranges of the selected *progressive* or *conservative* cases. Finally, along with the paper, we publish an interactive tool (https://interactive.pik-potsdam.de/blue-green-H2)[26], which allows the user to reproduce all figures with their own parameter choices.

Table 1. Selected hydrogen supply cases and parameter ranges (including references and data sources)
*For both green and blue hydrogen, conservative and progressive cases are defined that cover a range of potential supply chain specifications. Conservative parameter choices are closer to the status quo (e.g. existing technology and projects), while progressive parameters reflect faster developments and innovation. Additional sensitivity cases are defined for global warming potential time horizon and natural gas prices. The overall parameter ranges (column 3) further expand the range of the technology cases and are used for sensitivity analyses (***Figure 5**, **Figure S7, Figure S8***).*

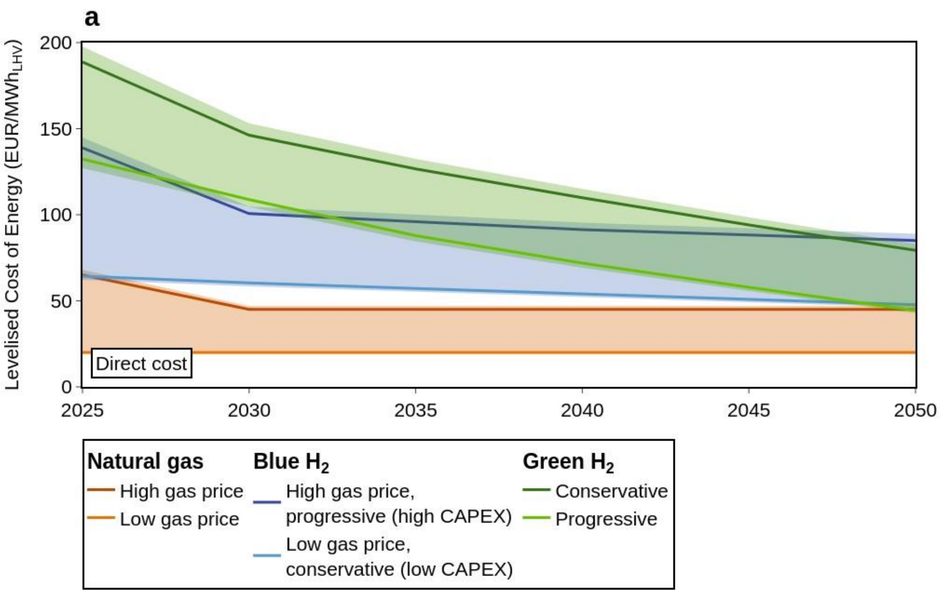
		Conservative case	Progressive case	Overall range analysed in this paper
Blue hydrogen	**CO_2 capture rate [%]**	56[4,9,13]	93[4,9]	56 – 100
	Net (i.e. plant-wide) capture rate. Capture rates at the capture step can be higher. See the methods and data section for a discussion on the feasibility of high capture rates and autothermal reforming technology (ATR).			
	Methane leakage rate [%]	1.5 (constant: 2025-2050)	1 (2025) 0.1 (2050)	0 – 5
	Methane emissions (fugitive, venting, incomplete flaring) in relation to natural gas supply. Cases are based on IEA data[27] reflecting the high regional heterogeneity and uncertainty (see methods section and Supplemental information section 3). Main cases include global average leakage rates (conservative), and best-practice examples (progressive). Sensitivity analyses also include higher leakage rates of up to 5%.			
Green hydrogen		Grid-connected electrolyser	Off-grid electrolyser (direct connection renewable plants)	
	Electricity costs of electrolysers [EUR/MWh]	100 (2025) 50 (2050)	50 (2025) 20 (2050)	50 - 90 (2025) 10 - 70 (2050)
	Electricity costs highly depend on the specific hydrogen supply case. A grid-connected electrolyser (conservative case) pays electricity prices and grid fees (~30 EUR/MWh)[3]. Flexible operation reduces their specific electricity price below average annual electricity prices (see the subsection cost data in methods and data). Electrolysers with a direct connection to renewable supply (progressive case) can operate at low renewable electricity costs[28] (with reduced full-load hours).			
	Renewable electricity in electrolyser input	75% (2025) 100% (≥2035)	100%	75% - 100%
	Through flexible operation, the grid-connected electrolyser can achieve higher renewable shares than in the average power mix. Electrolysers with a direct connection to renewable supply operate at 100% renewables (with reduced full-load hours). Note that we refer to grid-connected hydrogen production as *green* hydrogen, despite its 25% non-renewable electricity share (in 2025), which leads to GHG emissions similar to the conservative blue hydrogen case. Until 2035, the renewable share increases to 100% (see supplemental information section 4 and Figure S10).			
	H_2 transport, storage and distribution costs[29,30] [EUR/MWh]	10 (2025) 5 (2050) Close to hydrogen consumption	30 (2025) 15 (2050) Transport via ship and pipeline (~1000 km, 50% repurposed, 50% new). Distribution via pipeline.	
	Electrolyser system CAPEX [EUR/kW$_{el}$][24,25]	700 (2025) 300 (2050)	500 (2025) 100 (2050)	500 - 700 (2025) 100 - 300 (2050)
	Substantial cost reductions in the long term. High uncertainty about the timing of cost reductions in the medium term as they depend on scale-up and innovation cycles. Weighted average cost of capital: 8%. Lifetimes increase from 10 years for electrolysers built in 2025 to 20 years from 2035. Blue hydrogen plant lifetimes are 20 years.			
		Additional sensitivity cases		**Overall range analysed in this paper**
	Global warming potential of methane[50]	GWP20: 85	GWP100: 29	GWP20, GWP100

[3] https://static.agora-energiewende.de/fileadmin/Projekte/2021/2021_07_IND_FlexNetz/A-EW_224_Netzkostenallokation_WEB.pdf

	Describes how methane emissions are weighted, compared to CO_2 emissions. GWP100 is mostly used; yet, the main figures are reproduced with GWP20 as SI figures and the implications are discussed as part of the main paper.		
Natural gas price [EUR/MWh]	*Low:* 15	*High:* 60 (2025) 40 (≥2030)	10-70
	Regional heterogeneity. Based on gas price futures for the EU and the US (Figure S3). In addition, natural gas consumers pay grid tariffs of ~5 EUR/MWh[16].		

The *conservative* and *progressive* supply cases span cost ranges for both green and blue hydrogen that increasingly overlap and converge with time (**Figure 1**a). The cost range of blue hydrogen is mainly determined by the natural gas price range (compare cost breakdown in Figure S1), which is parameterized from gas price futures for the US (“low”) and the EU (“high”). Green hydrogen costs are mainly determined by whether electrolysers are grid-connected and thus have to pay higher electricity prices, including electricity grid fees (conservative case), or whether green hydrogen projects are directly connected to renewables (progressive case), such that their electricity costs are determined by low renewable electricity costs. We compare hydrogen costs to recent IEA data[4] (Figure S2). For 2030, our progressive off-grid hydrogen case is close to IEA’s median value for solar PV hydrogen costs, while costs of our grid-connected green hydrogen case are similar to those of the IEA’s median off-grid hydrogen projects based on onshore or offshore wind power. Hence, the results of our grid-connected case, when it operates on 100% renewable electricity from 2035, roughly correspond to how these IEA wind hydrogen cases would perform.

The GHG emission ranges of blue hydrogen ***(Figure 1b)*** are determined by different CO_2 capture and methane leakage rates[9,12] and by the selected time horizon of GWP. Green hydrogen emission ranges are mainly determined by the GHG footprint of electricity, which depends on whether electrolysers can be operated with 100% renewable electricity (progressive: electrolysis with a direct connection to renewable plants) or whether electrolysers are grid-connected and need to combine high-renewable hours with fossil generation (conservative), which substantially increases its GHG emission intensity.



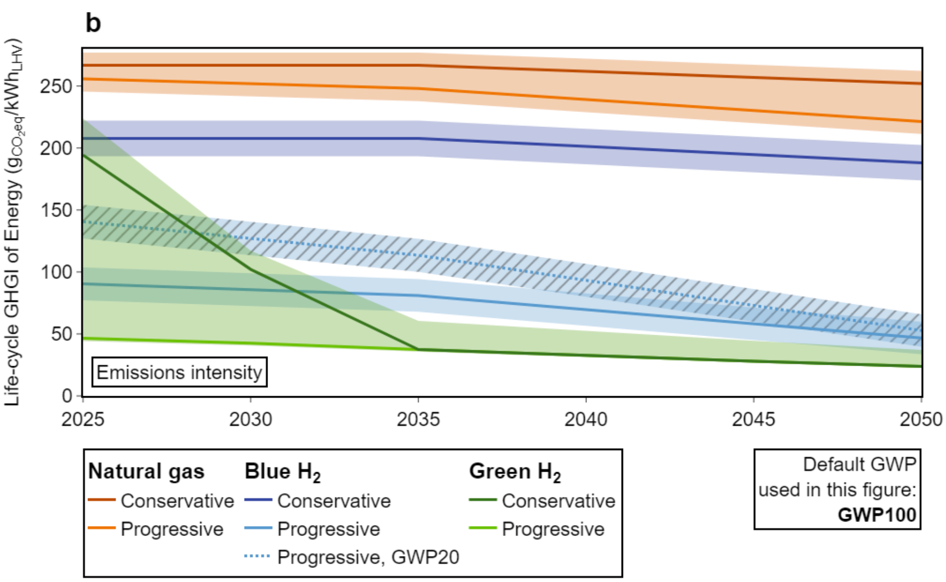


Figure 1: a) *Levelised costs of (gaseous) hydrogen supply (production, transport and distribution) and natural gas prices (including gas grid fees) and* ***b)*** *life-cycle GHG emission intensity of green (electrolytic) and blue hydrogen as well as natural gas. The corridors illustrate the ranges for the main technology and additional sensitivity cases analysed in this paper (see Table 1). See Figure S1 for a breakdown of both costs and emissions.*

For the *progressive* blue hydrogen case, we assume autothermal reforming technology (ATR) to become commercially available. This technology is sometimes suggested to be most suitable for achieving high net CO_2 capture rates[24,10,11,9]. However, the technology readiness level of ATR-based hydrogen production is reported[24] to be *5*, which means that there are large prototypes but no industrial or commercial plants. The IEA global hydrogen database 2022[31] reports twelve planned ATR+CCS hydrogen production projects of which one is in a conceptual phase, ten are in a feasibility study phase and one has reached a final investment decision. Six projects are reported with plans to start their operation in 2024-26. In methanol and ammonia production facilities[32,33], ATR technology is already used at industrial scale (e.g. the Haldor Topsøe methanol plant in Turkmenistan).

3. Five fuel-switching points

We derive five fuel-switching points that determine the points in time at which blue and green hydrogens become competitive with fossil fuels use, and show how green hydrogen becomes increasingly competitive with blue hydrogen.

For this purpose, we first calculate fuel-switching CO_2 prices (FSCPs), which can be defined as the carbon price at which lower emissions fuels become cost competitive with higher emission fuels (**Figure 2**a and b). FSCPs thus correspond to marginal abatement costs of the respective climate change mitigation options. This metric can serve as an indicator of the cost competitiveness of low-carbon fuels in regions with either explicit carbon pricing or regulation that is linked to the emission intensity of fuels. A prominent example of the latter is the US inflation reduction act that provides production tax credits for low-carbon hydrogen strongly depending on its emissions reduction.

From the temporal development and intersections of different FSCPs in time, we then theoretically derive five fuel-switching points (**Figure 2**c). We discuss why the fuel-switching points have a typical order in time and how they can be interpreted from a societal as well as from a private perspective. In the next section, FSCPs and the resulting fuel-switching points are then estimated for different supply cases.

Importantly, we show that the fuel-switching points determine a competitiveness window for blue hydrogen, which increasingly closes due higher residual emissions of blue hydrogen, increasing CO_2 prices and decreasing costs of green hydrogen. Note however that the order of the five switching points can invert (as we will see in the next section). This can happen with higher costs or very high residual emissions of blue hydrogen, faster cost reductions of green hydrogen or a slower increase of CO_2 prices. In some cases, the window of competitiveness for blue hydrogen could thus become very limited.

Deriving fuel-switching CO_2 prices (FSCPs)

Total costs of a fuel X are comprised of both the direct fuel cost $cost_X(0)$ (**Figure 1**a) and potentially carbon cost $\mathrm{p}_{CO2} * ghgi_X$ associated with its life-cycle GHG emission intensity $ghgi_X$ (**Figure 1**b). For the calculation of costs and emissions, see the equations in the Supplemental information section 5.

$$cost_X(\mathrm{p}_{CO2}) = cost_X(0) + \mathrm{p}_{CO2} * ghgi_X \quad (1)$$

The $FSCP_{X\rightarrow Y}$ of two fuels X and Y is defined as the CO_2 price p_{CO2} that is required to equalise the total costs $cost_X$ and $cost_Y$ of providing the same energy service, i.e.

$$cost_X(FSCP_{X\rightarrow Y}) = cost_Y(FSCP_{X\rightarrow Y}), \qquad \text{if } ghgi_X > ghgi_Y \quad (2)$$

Once, the CO_2 price exceeds the fuel-switching CO_2 prices, the fuel Y with lower GHG emission intensity becomes cost competitive despite its higher direct costs.

$$\mathrm{p}_{CO2} \geq FSCP_{X\rightarrow Y} \quad \Rightarrow \quad cost_Y(\mathrm{p}_{CO2}) \leq cost_X(\mathrm{p}_{CO2}) \quad (3)$$

Green and blue hydrogen compete with fossil fuels and with each other such that different FSCPs correspond to switching between the three fuels:

1. switching from a fossil fuel to blue hydrogen: $FSCP_{Fossil->Blue\ H_2}$
2. switching from a fossil fuel to green hydrogen: $FSCP_{Fossil->Green\ H_2}$

3. switching from blue to green hydrogen: $FSCP_{Blue\ H2->Green\ H_2}$ (also “*blue-to-green FSCP”*)

Geometrically, these three FSCPs can be derived from the intersections of the three fuels’ cost curves $cost_{fuel}(p_{CO2})$ (**Figure 2**a). In the near term, the FSCPs typically line up in a specific order irrespective of the choice of hydrogen application:

$$FSCP_{Fossil->Blue\ H_2} < FSCP_{Fossil->Green\ H_2} < FSCP_{Blue\ H_2->Green\ H_2} \tag{4}$$

This is because in 2025-2030, blue hydrogen tends to be cheaper but more GHG intensive than green hydrogen in many cases. With time, the order of FSCPs likely inverts, due to faster cost reductions of green hydrogen and higher residual emissions of blue hydrogen (**Figure 2**b).

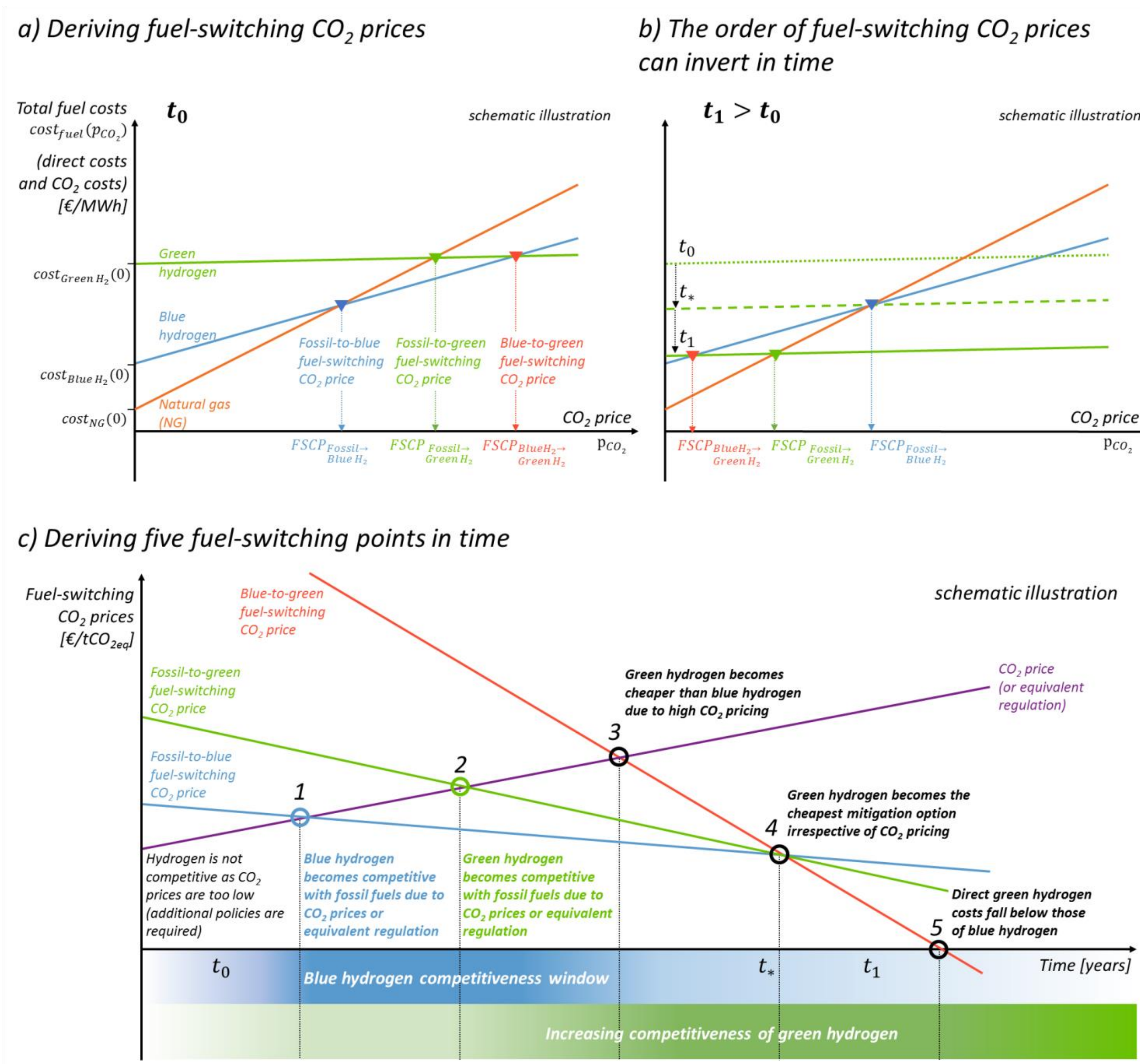


Figure 2**: **a) For a point t_0 in time we show total levelized fuel costs (schematic) as a function of CO_2 prices for green and blue hydrogen as well as for a fossil fuel (here: natural gas). Fuel-switching points (FSCPs) emerge from the intersections of two cost lines and mark the CO_2 price at which a low-emission fuel with higher direct costs becomes cheaper, and thus competitive, compared to a more carbon-intensive fuel. The fuel’s life-cycle GHG

emission intensity defines the slope of the respective lines. The y-intercepts equal the direct costs for each fuel. For any given CO_2 price there is one fuel that provides the selected energy service at the lowest cost. **b)** For $t_1>t_0$ we demonstrate that the order of FSCPs can invert, if green hydrogen costs decrease. ***c)*** From the intersections of FSCPs in time, five fuel-switching points can be derived that determine the expanding competitiveness of hydrogen with fossil fuels as well as the increasing competitiveness of green hydrogen with blue hydrogen.

Deriving fuel-switching points in time

Analyzing FSCPs in their temporal development allows deriving conditions for five fuel switching points across time (**Figure 2**c). With innovation and scale, the costs of producing low-emission hydrogen and associated FSCPs will likely decrease for all hydrogen supply pathways and hydrogen applications. Falling FSCPs together with increasing CO_2 prices (or equivalent regulation) lead to greater cost competitiveness of low-emission hydrogen over time to the extent that low-emission hydrogen can also compete with other mitigation options. At the same time green hydrogen becomes increasingly competitive with blue hydrogen.

Switching point 1: Once CO_2 prices equal $FSCP_{Fossil->Blue\ H2}$ (i.e. equation 3), the switch from a fossil fuel to a blue hydrogen application is incentivized.

Switching point 2: Analogously, once the CO_2 price reaches $FSCP_{Fossil->Green\ H2}$, green hydrogen becomes viable.

Switching point 3: Once the CO_2 price reaches $FSCP_{Blue\ H2->Green\ H2}$, the total costs of green hydrogen (including carbon costs) fall below those of blue hydrogen. Higher CO_2 costs are associated with higher residual emissions of blue hydrogen, creating a cost advantage for green hydrogen irrespective of the hydrogen application. However, if green hydrogen remains scarce by that time, blue hydrogen could still secure parts of the hydrogen markets. This switching point is only reached if policy makers allow for high carbon pricing or find alternative ways to impose costs or limits on residual emissions associated with climate change mitigation options. Investors will likely take decisions in response to the observed level of political commitment.

Switching point 4: An additional "blue-to-green" hydrogen switching point is reached, once green hydrogen becomes the cheaper climate change mitigation option. Where FSCPs of green hydrogen fall below those of blue hydrogen, all three FSCPs intersect (please find an analytical proof in the Supplemental information section 1):

$$FSCP_{Fossil \to Blue\ H_2} = FSCP_{Fossil \to Green\ H_2} = FSCP_{Blue\ H_2 \to Green\ H_2} := P^*_{CO2} \quad (5)$$

In contrast to switching point 3, the timing of this switching point is independent of CO_2 prices as it is determined solely by FSCPs (i.e., marginal abatement costs of both options), which only depend on the development of the respective direct costs and specific emissions' reductions. The FSCP intersection in figure 2c is thus independent of the CO_2 price curve. Yet, it requires CO_2 prices of at least P^*_{CO2} to unmask these new competitiveness relations. Without carbon pricing (or equivalent regulation) this switching point would not be seen by private investors as the direct costs of green hydrogen are still higher than those of blue hydrogen. Hereafter the typical FSCP relation (equation 4) will invert:

$$FSCP_{Fossil->Blue\ H_2} > FSCP_{Fossil->Green\ H_2} > FSCP_{Blue\ H_2->Green\ H_2} \quad (6)$$

This corresponds to the geometric inversion of the triangle in **Figure 2**b (triangular markers invert their positions compared to **Figure 2**a). Such an inversion occurs if two mitigation options compete of which one option is more expensive initially, yet has higher long-term cost and emission reduction potential (e.g. electrolysyer and renewable electricity), while the other option is initially cheaper with less specific emission reduction and cost reduction potential (blue hydrogen). Options of the first category are typically more transformative (e.g. direct electrification), while options of the second category could be more structurally conservative (e.g. CCUS).

Switching point 5: Finally, irrespective of GHG emission intensities and CO_2 prices, the direct production costs of green hydrogen might fall below those of blue hydrogen in the mid- to long-term. For countries with carbon pricing or other emission-related regulation, this will likely happen later than the other switching points. This switching point is thus most relevant for regions with weak CO_2 pricing or equivalent regulation. The point is characterized by the blue-to-green $FSCP_{Blue\ H_2 \to Green\ H_2}$ becoming negative (**Figure 2**c).

4. Estimating the cost competitiveness of blue and green hydrogen

Here we quantify the concepts introduced in the previous section to assess the timing of changes in cost competitiveness. The curves that we illustrated in **Figure 2**b are now estimated for four different cases (**Figure 3**, a-d), which we derive from combining different assumptions of hydrogen supply (*progressive* or *conservative* technology developments, ***Table 1***) with two natural gas price scenarios (*low* or *high*, ***Table 1***). We apply the framework for an energy service where hydrogen replaces natural gas. This can be a gas power plant or an industrial or residential heating application. Hereby we neglect additional costs for repurposing the end-use application and thus focus on fuel costs (with a differentiation of associated transport costs, ***Table 1***).

We further assume the implementation of CO_2 pricing or equivalent emission-specific regulation. The range of CO_2 price trajectories in **Figure 3** is derived from several model-based scenarios that achieve the EU climate targets[34]. The hydrogen production tax credits in the US inflation reduction can be interpreted as implicit CO_2 pricing in a similar range. We calculate emission-specific benefits of hydrogen compared to natural gas of ~100 to 350 \$/tCO_2eq (Supplemental information section 2).

With respect to the competitiveness of low-emission hydrogen with natural gas, there is one robust result across all parameter choices:

1. **To compete with natural gas, both green and blue hydrogen likely require substantial policy support until at least 2035.**

Despite rising CO_2 prices (or equivalent emission-related regulation), green and blue hydrogen stay more expensive than natural gas until at least 2035. Even in the case of progressive technology developments and high natural gas prices, green hydrogen requires CO_2 prices of 200 €/tCO_2eq at around 2035 to become cost competitive (switching point 2 in **Figure 3**c). In the case of low natural gas prices, it requires similar CO_2 prices to make blue hydrogen (progressive case) competitive with natural gas (switching point 1 in **Figure 3**d). Hence, to develop blue or green hydrogen options in the near and mid-term, it likely requires complementing policy instruments and regulation that bridge these competitiveness gaps.

We complement **Figure 3** with a more detailed heat map analysis in figure 4, which distinguishes the two drivers of competitiveness: i) emissions intensity (x axis) and ii) direct costs of hydrogen (y axis) for the development of the different technology cases in time and for high (left) and low (right) natural gas prices. The trade-off between the two drivers leads to diagonal zones of similar competitiveness level, which are marked with diagonal contour lines of identical hydrogen-to-natural gas FSCPs. This confirms that to become competitive with natural gas, hydrogen needs to be both clean and cheap. While the conservative case of blue hydrogen (dark blue markers) lacks competitiveness due to its high residual emissions, green hydrogen (green markers) struggles due to high short-term costs, and in the conservative case (dark green markers), due to its short-term emission intensity. The progressive technology case for blue hydrogen is characterized by intermediate costs and intermediate emission intensities and thus lies in between the other technology cases. Despite falling FSCPs, even for the progressive technology cases and high natural gas prices, the required CO_2 prices exceed those that can currently be expected in most countries until 2035 (**Figure 3**).

The competitiveness of blue and green hydrogen with one another varies more strongly across the parameter cases (switching points 3-5):

2. **If blue hydrogen is produced with low capture rates or high methane leakage, it can neither compete with natural gas nor with green hydrogen** (**Figure 3**a and **Figure 3**b)**.**

The competitiveness window for blue hydrogen with high residual emissions (conservative case) closes already at around 2025-30, when green hydrogen is becoming the cheaper mitigation option (switching point 4 in **Figure 3**a and **Figure 3**b). This holds even if natural gas prices are low and green hydrogen remains costly (**Figure 3**b).

The steep decrease of blue-to-green FSCP trajectories (red lines) is mainly driven by a reduction of GHG emission intensity of green hydrogen until 2035 due to the transition from 75% to 100% renewable electricity input and by a continuous decrease in the costs of green hydrogen.

However, it requires increasing CO_2 prices or equivalent regulation to unmask these competitiveness relations as the direct costs of blue hydrogen can still be lower than those of green hydrogen (**Figure 4**). These cost advantages of blue hydrogen are then increasingly offset by carbon costs associated with its high residual emissions. To compete with natural gas, emission-intensive blue hydrogen would require CO_2 prices of 350-450 €/tCO_2 even in the long term. As a consequence, producing blue hydrogen with high CO_2 capture and low methane leakage rates is a necessary condition for its cost competitiveness.

The competitiveness of low-emission blue hydrogen strongly depends on future natural gas prices:

3. **For high natural gas prices, the competitive window for blue hydrogen has closed even for high capture and low methane leakage rates** (**Figure 3**c).

In regions in which natural gas prices remain higher compared to pre-crisis levels (~40 €/MWh), cheap green hydrogen (progressive case) can abate more emissions at lower specific mitigation cost. In those regions, blue hydrogen production would not be part of a cost-efficient marginal abatement cost curve (MACC) as it has higher mitigation costs than green hydrogen, while reducing less emissions. The green-to-blue switching point 4 (**Figure 3**c) would have already passed due to the energy crisis and fuel-switching CO_2 prices of green hydrogen remain below those of blue hydrogen.

Even with respect to direct costs, green hydrogen can fall below those of blue hydrogen already in the near term (switching point 5 in **Figure 3**). Already in 2025, the blue-to-green FSCPs are negative, indicating that due to the short-term impact of the energy crisis on natural gas prices, the direct costs of progressive green hydrogen are just below those of blue hydrogen. As the impacts of the energy crisis diminish slightly faster than green hydrogen costs decline, the FSCPs become positive at around 2030 and then negative again shortly after (compare direct cost **Figure 1**a).

In the short term (~2030), green and blue hydrogen are located closely in the heat map (**Figure 4**a) with only a slight advantage for green hydrogen mainly due to a lower emission intensity. However, from 2035 on the competitiveness advantage of green hydrogen can become substantial due to cost improvements.

4. **For low natural gas prices, there can be a substantial competitiveness window for low-emission blue hydrogen** (**Figure 3**d).

In regions in which natural gas prices stabilize at a low level (~15 €/MWh) and blue hydrogen is produced with high capture (93%) and low methane leakage rates (1% in 2025, 0.1% in 2050), the three blue-to-green switching points occur only after 2040. In the short to mid-term, blue hydrogen would be substantially cheaper than green hydrogen, which offsets the impact of its higher residual emissions (Figure 4b). The cost advantage of low-emission blue hydrogen decreases from ~50 EUR/MWh in 2025 to ~15 EUR/MWh in 2040, while cost parity is only reached after 2045 (switching point 5).

However, the competitiveness advantage in this blue-favorable case diminishes with the strongly decreasing costs of green hydrogen. While the direct costs of green hydrogen fall below those of blue hydrogen only after 2045 (switching point 5), already by 2035-40, fuel-switching prices of green and blue hydrogen are in the same range. For this parameter case (**Figure 3**d), cost competitiveness relations in the mid and long term are highly sensitive to small parameter changes. Accordingly, we perform a sensitivity analysis (**Figure 5**) that is centered around the case of progressive technology assumptions and low natural gas prices.

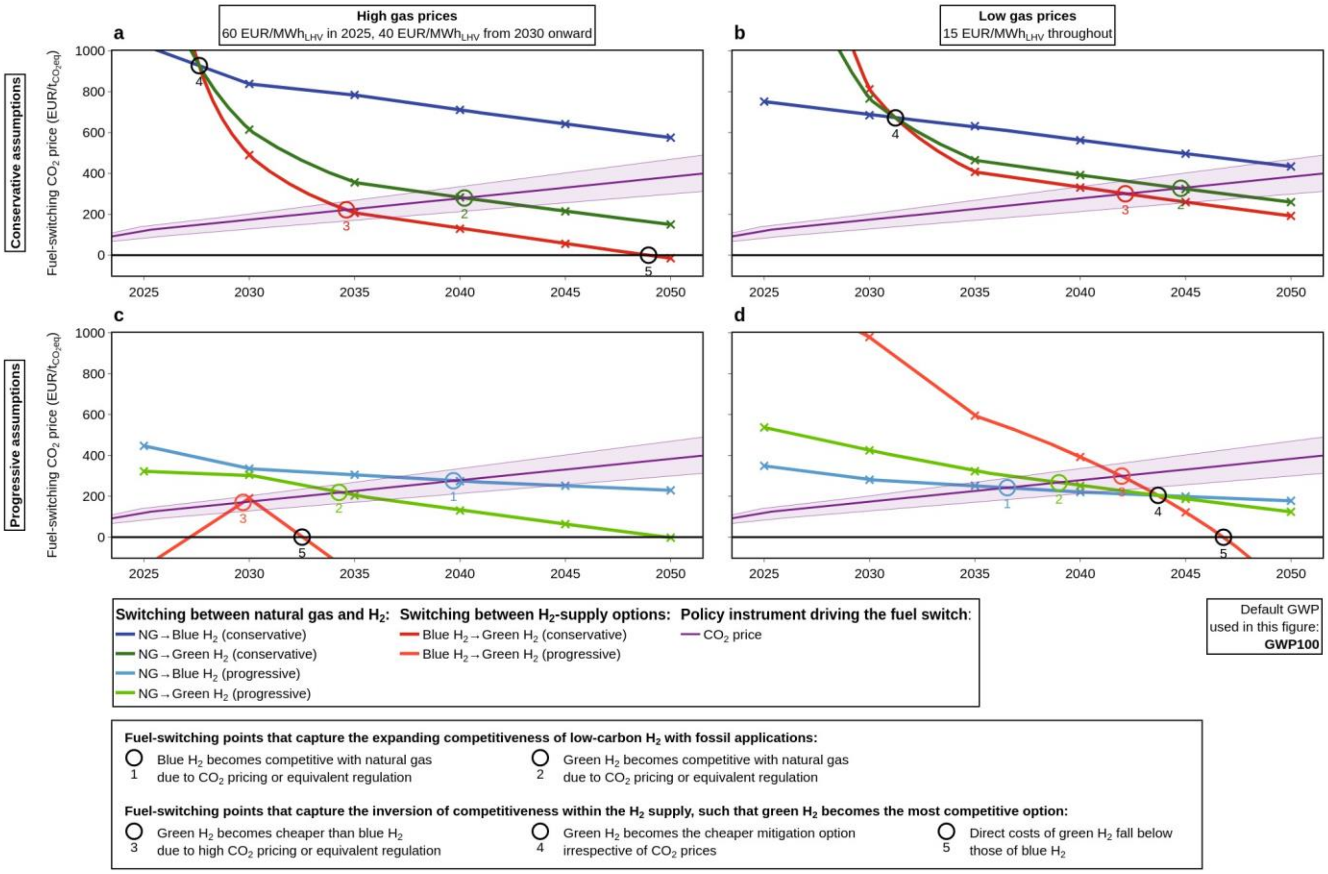
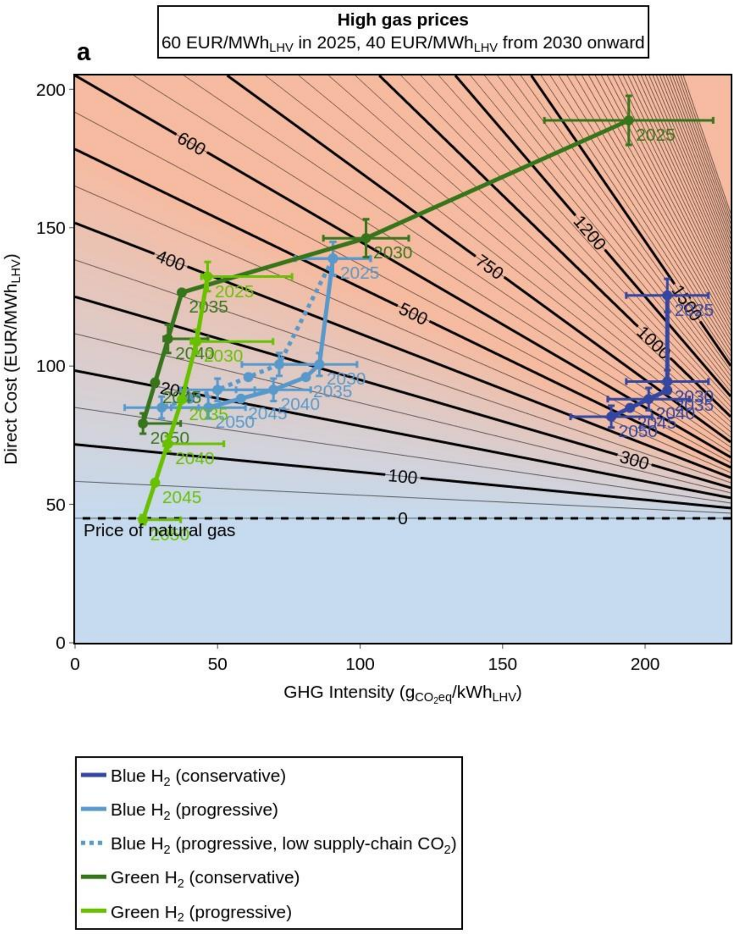


Figure 3: Same as conceptual *Figure 2*c, now estimated for four cases derived by combining technology cases (**top:** conservative, **bottom:** progressive) with natural gas prices (**left:** high, **right:** low). From the intersections of FSCPs in time, fuel-switching points can be derived that determine the improving competitiveness of hydrogen with fossil fuels as well as the increasing competitiveness of green hydrogen with blue hydrogen.



High gas prices
60 EUR/MWh$_{LHV}$ in 2025, 40 EUR/MWh$_{LHV}$ from 2030 onward
a
Direct Cost (EUR/MWh$_{LHV}$)
GHG Intensity (g$_{CO_2eq}$/kWh$_{LHV}$)
Price of natural gas
600
400
500
750
1200
1000
1500
300
100
0
2025
2030
2035
2040
2045
2050
Blue H$_2$ (conservative)
Blue H$_2$ (progressive)
Blue H$_2$ (progressive, low supply-chain CO$_2$)
Green H$_2$ (conservative)
Green H$_2$ (progressive)

1

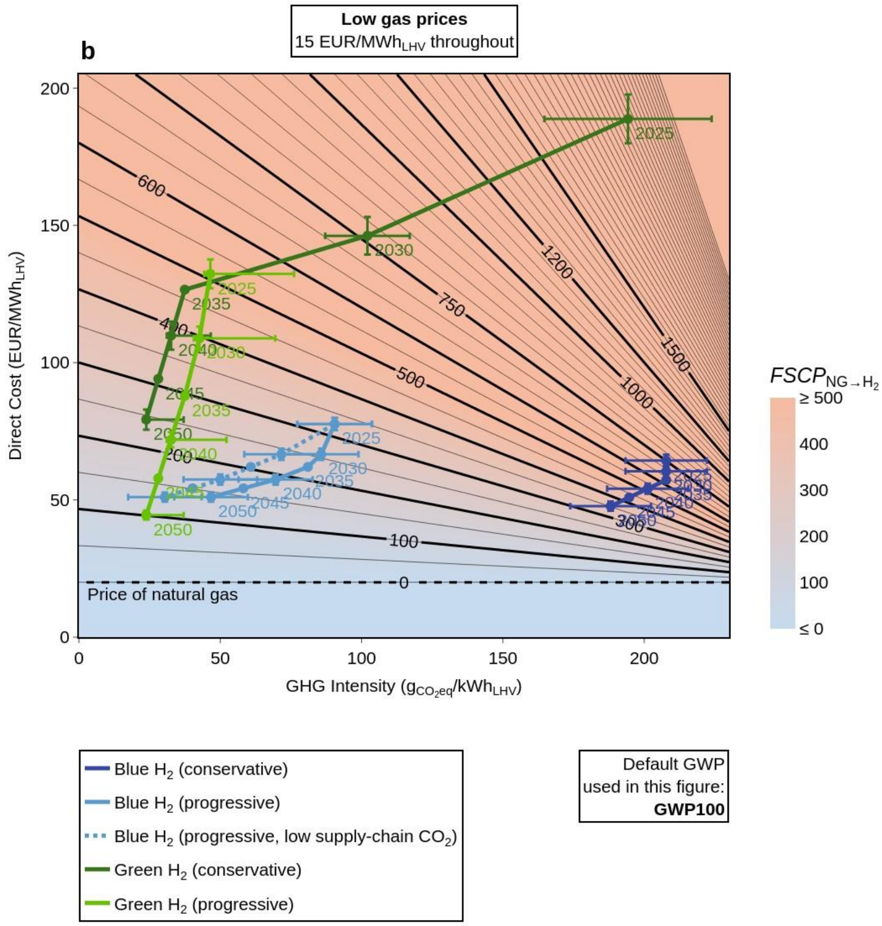


Figure 4: Emission intensities (x axis) and direct costs (y axis) of different hydrogen fuel options (scatter plot for several years), along with FSCP estimates (contour plot) required to make hydrogen competitive with natural gas for ***a)*** high natural gas prices and **b)** low natural gas prices. In addition to the progressive and conservative technology cases, we here include a sensitivity case with very high upstream CO_2 emission reductions, which reflects the high ambitions of the oil and gas industry in Norway[35], dotted). We use GWP100 here. For a sensitivity case with GWP 20, see Figure S6.

From the main parameter cases, we found two conditions for a substantial blue hydrogen competitiveness window. Most importantly, blue hydrogen would need to be produced with high CO_2 capture rates and low methane leakage rates. In addition, if green hydrogen can be produced cheaply, blue hydrogen requires low natural gas prices to compete.

To derive these conditions in higher detail, we conduct three sensitivity analyses of green-to-blue FSCPs (**Figure 5**, Figure S7, Figure S8). For each sensitivity analysis, we vary five parameters individually (e.g. **Figure 5**a-e) and show the results for different years (various solid lines). Importantly, the result of an individual parameter variation will depend on the default values of all other parameters which are also indicated for given years (dashed lines). These default values are different for the three sensitivity studies that are centered around different technology and parameter cases:

1) First (**Figure 5**a-e), in case of low gas prices, progressive technology development and GWP100 (same as in **Figure 3**d), blue-to-green FSCPs are highly dependent on each of the five selected parameters. Changing a single parameter within a plausible range shifts the blue-to-green FSCP substantially and thus determines the competitiveness of blue and green hydrogen.

   Only in the long term (~2045), the competitiveness of green hydrogen (i.e., blue-to-green FSCPs of <200 €/tCO_2) stabilizes and the blue competitiveness window closes fairly independently of other parameter choices, if green hydrogen can be produced from cheap (<30 €/MWh_el, **Figure 5**a) and low-emission electricity (renewable share >97%, **Figure 5**b). In general, varying the average electricity price paid by the electrolysis project leads to a narrow and steep sensitivity corridor (**Figure 5**a) confirming its decisive impact on competitiveness.

This sensitivity analysis reveals more detail on an aforementioned condition for a substantial window of blue hydrogen competitiveness: high capture and low methane leakage rates (in addition to low natural gas prices). If the GWP100 metric is applied and CO_2 capture rates are high (progressive case: 93%), blue hydrogen competitiveness requires a methane leakage rate of below 3% in 2035 and below 1% in 2040. Analogously, if the GWP100 metric is applied and methane leakage rates are low (progressive case: 1% in 2025, 0.1% in 2050), blue hydrogen competitiveness requires CO_2 capture rates above 80% in 2035 and above 90% in 2040.

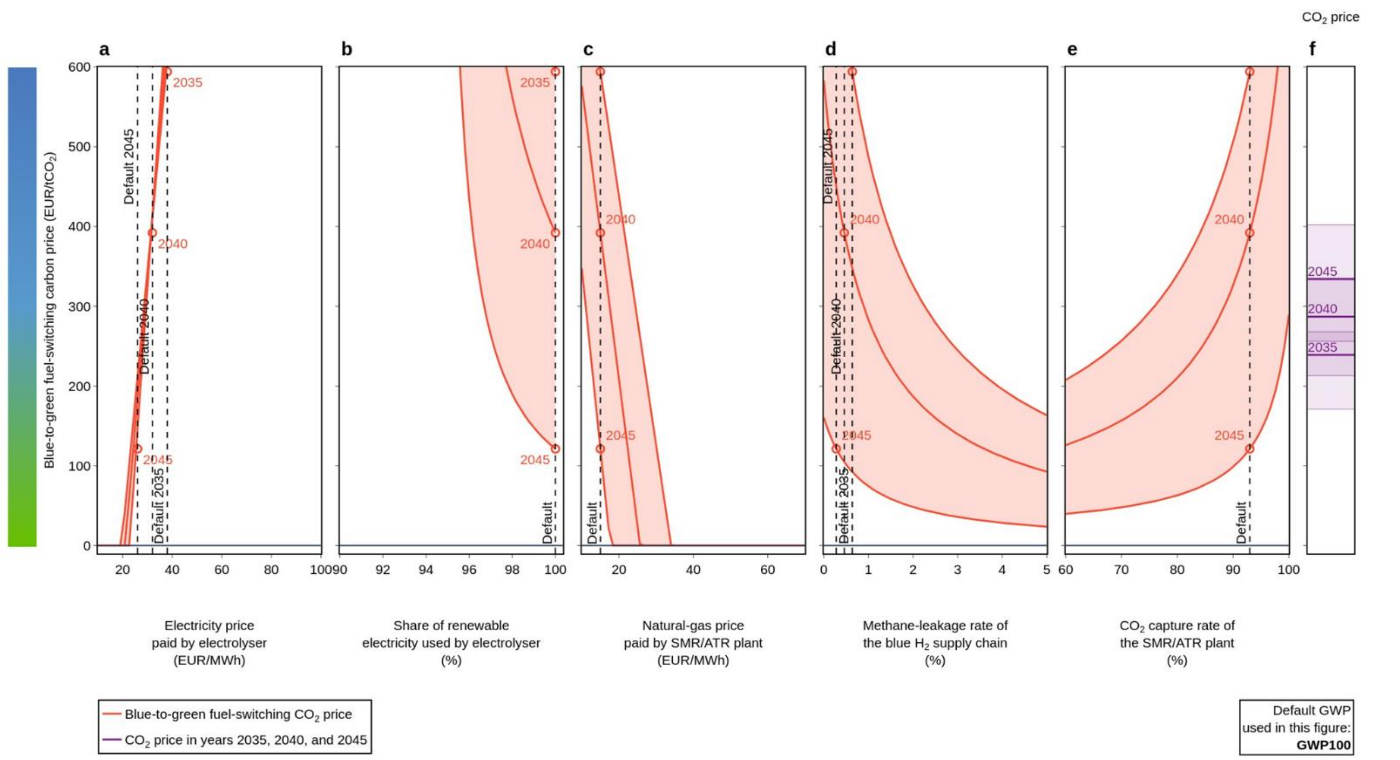


Figure 5: A sensitivity analysis varying five key parameters to evaluate their impact on blue-to-green fuel-switching carbon prices. The analysis is conducted for GWP100 and centered around low natural gas prices and progressive technology assumptions. For sensitivity analyses for GWP20 and centered around high natural gas prices see Figures S7 and S8. The color bar on the left side applies for all panels and indicates how low (or high) blue-to-green FSCPs would translate into a competitiveness advantage for green (or blue) hydrogen given the *CO_2* price range shown on the right side.

2) A second sensitivity analysis (Figure S7) is centered around the case of high natural gas prices (40 EUR/MWh, same as in **Figure 3**c). This leads to a robust competitiveness advantage for green hydrogen across other parameter choices and across time. Hence, the most important competitiveness driver for blue hydrogen is the natural gas price. If green hydrogen cost reductions materialize quickly (progressive case), low-emission blue hydrogen competitiveness requires natural gas prices of below 30 €/MWh in the short term and below 10-15 €/MWh in the long term (figure 5c).

3) In a third sensitivity analysis (Figure S8) we analyse the impact of using the GWP20 metric (instead of GWP100) when converting methane emissions into CO_2 equivalent. This increases the climate impact of methane emissions and thus reduces blue-to-green switching prices. This effect is high in the short and mid-term and reduces over time as we here again assume progressive technology assumptions (as in **Figure 3**d and **Figure 5**). In 2035 (methane leakage rate 0.65%) blue-to-green switching prices fall by ~200 EUR/tCO_2. In 2040 (methane leakage rate 0.5%) blue-to-green switching prices fall by ~100 EUR/tCO_2, while by 2045 (methane leakage rate 0.3%) blue-to-green switching prices are already low and hardly change anymore. Note that the overall effect of

switching to GWP20 also depends on all other parameter developments and across the different cases, the blue competitiveness windows shorten by about 2 to 5 years (Figure S4d).

Conclusions and discussion

While technology costs, electricity and natural gas prices are key drivers, hydrogen's competitiveness will be increasingly determined by carbon costs or equivalent regulation associated with its life-cycle emissions. Theoretically and numerically we show that higher residual emissions of blue hydrogen can close its competitive window much earlier than cost parity of green hydrogen would imply. The length of this window is determined by several uncertain future developments and regional circumstances.

From our techno-economic analysis, we can derive two main scenarios.

1. The blue hydrogen window can remain open for a long time (until ~2040), if several conditions are fulfilled simultaneously. Firstly, blue hydrogen would need to be produced with high net CO_2 capture rates (>90% in 2040) and low methane leakage rates (<1% in 2040, for GWP100). Combining SMR, today's predominant technology for producing hydrogen, with CCS, by capturing ~90% of CO_2 from the syngas, only leads to a net CO_2 capture rate of <60%[13,14]. Competitiveness would require to also capture the CO_2 associated with the heat supply of the SMR plant. ATR-CCS plants are becoming a promising alternative to achieve high net CO_2 capture rates[23]; yet, they need to be demonstrated at industrial scale for hydrogen production. Secondly, if green hydrogen cost reductions materialize quickly, blue hydrogen competitiveness requires natural gas prices of below 30 €/MWh in the short term and below 15 €/MWh in the long term.

2. By contrast, in regions where the natural gas prices remain substantially higher than before the energy crisis, a blue hydrogen competitiveness window is narrow or might have closed already. This remains true even if blue hydrogen production fulfills the above conditions for low methane leakage and high CO_2 capture. Green hydrogen has a competitiveness advantage already in the short term if i) natural gas prices stabilize at ~40 EUR/MWh, and if ii) electrolysers operate at electricity costs below 50 EUR/MWh and renewable electricity shares of >90 %. Achieving both conditions before 2030 is challenging for grid-connected electrolysers in many regions, but achievable for off-grid electrolysis projects with a direct connection to renewable power plants [8,36].

Investment uncertainty for blue hydrogen projects is large in regions such as the EU, where there is uncertainty about both short-term policy support for blue hydrogen and long-term natural gas prices. We show that typical CO_2 price projections (e.g. for the EU ETS) alone are too low to create cost parity of low-carbon hydrogen with natural gas before 2035 such that both green and blue hydrogen require substantial complementary policy support in the near and mid-term. This translates into an uncertain beginning and a potentially early end of blue hydrogen competitiveness, which might impede major blue hydrogen investments.

By contrast, the situation is different in countries such as the US, where natural gas prices are anticipated to be low, while at the same time substantial subsidies have been announced without differentiating the source of hydrogen[18]. Here, substantial investments in both green and blue hydrogen projects are likely. A blue competitiveness window might end in the long term - depending on the technological progress of green hydrogen, the phase-out of subsidies and regulation of the residual hydrogen-related emissions, especially as methane leakage rates of individual sites can be high in the US[12,37].

Overall, our analysis demonstrates the importance of accounting for the full life-cycle GHG emissions, when evaluating the prospects of hydrogen as a climate mitigation option. Because hydrogen is a secondary energy carrier (and feedstock) that can be provided via very different processes and supply chains, the associated life-cycle GHG emissions can vary widely. Policy instruments such as subsidy schemes or CO_2 pricing should incentivize high CO_2 capture rates and the reduction of upstream emissions. The latter include CO_2 and methane emission from natural gas supply as well as the GHG emission intensity of electricity to produce green hydrogen.

Importantly, we show that despite rising CO_2 prices, green and blue hydrogen stay more expensive than natural gas until at least 2035, even for progressive hydrogen supply case assumptions. Hence, to develop blue or green hydrogen options, it likely requires complementing policy instruments and regulation that bridge these competitiveness gaps potentially even beyond 2035 (in case of conservative hydrogen developments).

We discuss five additional factors that are out of scope of this analysis, yet they impact the competitiveness of blue and green hydrogen beyond our purely techno-economic perspective.

1. *Scarcity of green hydrogen.* Despite unfavorable economics, investments in blue hydrogen can also be spurred by the short- to mid-term scarcity of green hydrogen due to scaling limits of additional renewable power and electrolysis capacity. Hydrogen scarcity combined with a high willingness to pay on the hydrogen end-use side could translate into hydrogen prices that exceed hydrogen production costs such that both blue and green hydrogen could be competitive. While these bottlenecks depend on dedicated near-term policy instruments for green hydrogen innovation and deployment, scarcity is anticipated until at least 2030-35[19]. If policy incentives improve, CCS investment risks decrease,[20] and large-scale blue hydrogen plants and associated carbon dioxide transport and storage infrastructure can be built within a decade, this would allow for a more substantial build-up of required hydrogen infrastructures and an earlier transformation towards hydrogen end-uses. In fact, as many hydrogen applications (especially in industry) require a continuous hydrogen input and as local hydrogen storage is expensive, fossil fuels (e.g. natural gas, grey or blue hydrogen) are required as a backup in times when green hydrogen is not available due to renewable electricity variability. These backup requirements gradually resolve with the build-up of hydrogen pipeline and central storage infrastructure.

2. *Climate change mitigation ambition and the overall role of hydrogen.* If ambitious climate targets such as those set by the EU[38] are translated into stringent CO_2 pricing schemes or equivalent regulation, this would not only immediately close the competitiveness window for higher-emissions blue hydrogen, but narrow the window of any bridging technology with substantial residual GHG emissions. For countries with earlier climate neutrality targets such as Germany (2045) or Austria (2040), short-term emission reduction requirements might not leave time for even a low-emission blue hydrogen bridge. In contrast, for countries with later climate neutrality targets, such as China or India, there could be an extended competitiveness window for blue hydrogen.

3. *Regional resource availability and hydrogen transport costs.* It is uncertain if long-distance hydrogen shipping will become cheap enough to create a global hydrogen market. If transport costs remain high, markets will be regional and competitiveness of blue and green hydrogen will be shaped by the regional availability of low-cost renewable electricity, geological CO_2 storage reservoirs, natural gas supply with low methane leakage and existing pipelines. For example, if natural gas pipelines can be repurposed to hydrogen, and if natural gas reservoirs are co-located with geological CO_2 storage sites, transporting natural-gas-based hydrogen instead of natural gas can lead to transport cost advantages for blue hydrogen that extend its competitiveness. On the other hand, if hydrogen shipping costs become low enough for global markets to emerge, blue-green competitiveness will be increasingly determined by low-cost green hydrogen exports from renewable-rich countries to meet growing demand in regional markets.

4. *The importance of methane emissions.* The relative importance of short-lived methane emissions increases if the focus of climate change mitigation shifts from long-term stabilisation to shaving the global temperature peak. Reflecting this by evaluating blue hydrogen based on the GWP20 metric instead of GWP100 would shorten the competitiveness window of blue hydrogen. In some countries (e.g., Norway, Netherlands, UK) the natural gas industry demonstrates that near-zero leakage rates are possible; yet, huge regional differences remain with some countries having average leakage rates of ~1.5% (e.g., USA) or as high as 8% (e.g., Kazakhstan, Turkmenistan) (Figure S9). The IEA showed that official statistics substantially underreport methane leakage compared to satellite data[27], while >100 countries seek to reduce global methane emissions at least 30 percent from 2020 levels by 2030[39], the EU commission has proposed regulation on monitoring and third-party verification of life-cycle methane emissions[40] , and the USA is implementing a charge on methane emissions as part of the inflation reduction act[18]. This could translate into a clear differentiation and competition among blue hydrogen suppliers and the incentive to quickly reduce methane leakage rates.

5. *CCS synergies and competition.* There is an additional incentive to develop blue hydrogen as an entry point to CCS technology innovations and building CO_2 transport and storage infrastructure, which will be required for unavoidable process emissions (e.g. from cement production) as well as for some CO_2 removal options (e.g. direct air capture with permanent storage, and bio-energy use with CCS), which are increasingly in demand for offsetting. On the other hand, blue hydrogen production will then partially compete for geological storage sites. This might impose additional scarcity costs for CO_2 storage, in regions where overall storage or injection capacity is scarce.

Our objectives for this paper were i) to share an analysis framework that combines cost and emission data to assess hydrogen competitiveness, ii) to identify the associated drivers, dynamics and uncertainties, as well as iii) to derive rough estimates based on broad and generic parameter ranges. A promising future research direction could be to apply this framework for highly-resolved regional cases or for other technologies. Specifically, the approach allows for an evaluation of bridging technologies that reduces emissions at rather low additional costs, while not being compatible with climate neutrality due to substantial residual emissions.

Experimental procedures

Resource availability

Lead contact

Further information and requests for resources and materials should be directed to and will be fulfilled by the lead contact, Falko Ueckerdt (ueckerdt@pik-potsdam.de).

Materials availability

No materials were used in this study.

Data and code availability

The codes and input data needed for reproducing all plots presented in this article and the Supplemental information are openly available on GitHub (https://github.com/PhilippVerpoort/blue-green-H2) and may be interactively explored in the associated interactive web app:
Cost competitiveness of blue and green H_2, P.C. Verpoort, et al 2022[26]. Accessible online: https://interactive.pik-potsdam.de/blue-green-H2. The methane leakage analysis is accessible here: https://github.com/FalkoUeckerdt/Methane-Leakage.

Methods

In this section we add detail on i) the different technology cases analysed in this paper, ii) its associated life-cycle GHG emission and iii) cost data. For a comprehensive overview and discussion of all input data see the Supplemental information.

Green and blue hydrogen supply cases

For both green and blue hydrogen, *conservative* and *progressive* cases are defined such that they cover a range of potential supply chain specifications. *Conservative* parameter choices are closer to the status quo, while *progressive* parameters reflect faster developments and innovation.

Blue hydrogen (*conservative* case) is produced from today's predominant technology for producing hydrogen: steam methane reforming (SMR) of natural gas. Combining SMR with CCS allows capturing from the syngas prior to the hydrogen purification pressure swing adsorption (PSA). A CO_2 capture ratio of 90% is considered during the capture step, however this only allows for a net (i.e., plant-wide) CO_2 capture of about 56% as there are additional CO_2 emissions - which are typically not captured - from combusting natural gas to provide process heat (in the reformer furnace)[9,12,13]. In addition, we assume a constant methane leakage rate of 1.5%, which is close to what we calculate as the 2021 global average (~1.6%, see Figure S9). For the conservative case we do not assume improvements in reducing methane leakage. In the sensitivity analyses we also include higher methane leakage rates of up to 5%.

Blue hydrogen (*progressive* case) is produced with high net CO_2 capture rates (~93%). It would be technically possible to increase CO_2 capture rates with SMR technology by adding an additional post-combustion CO_2 capture unit on the SMR flue gas[13]. However, we here assume the alternative technology autothermal reforming (ATR) with CCS[9] as it is sometimes suggested to be more suitable for achieving high net CO_2 capture rates[23]. As the ATR is driven by heat produced in the reformer itself, it does not include a reformer furnace, which allows to remove the majority of the CO_2 directly from the syngas (~98%). Some remaining CO_2 is emitted from a small natural gas fired heater usually part of an ATR, which reduces the overall CO_2 removal rate to ~93%[11]. While ATR technology for hydrogen production is not commercial (TRL 5)[24], ATR technology is already used at industrial scale for methanol production (e.g. the Haldor Topsøe plant in Turkmenistan), though without CO_2 capture. There are several projects that plan to use ATR technology for hydrogen production[24] with CCS. The first ATR-CCS hydrogen plants HyNet and H2H Saltend are announced to start operating in the United Kingdom in 2025 and ~2026/27, respectively. With respect to methane leakage rates, we here assume a progressive decline from 1% in 2025 to 0.1 % in 2050, which reflects today's best-practice examples (e.g. Norway)[9,27].

Green hydrogen (conservative case) is produced with a grid-connected electrolyser that is located close to consumption. Such a green hydrogen project does not require a direct connection to renewable plants or a hydrogen transport infrastructure. It is similar to how grey hydrogen is locally produced and consumed today. Such a project will partially operate on non-renewable electricity, while it needs to pay electricity prices and electricity grid fees (see more in the cost data subsection below).

Note that the first grid-connected electrolysis projects will likely realize their electricity supply via renewable power purchase agreements (PPAs). This can be understood as improving the bankability given the substantial investment uncertainty in many regards (techno economic uncertainties, economic uncertainties e.g. with respect to future willingness to pay for hydrogen, and regulatory uncertainty). As the competitiveness of hydrogen improves and the electricity price distributions at wholesale markets become more heterogenous, we anticipate an increasing incentive to produce green hydrogen based on the increasing number of low-price hours at wholesale electricity markets.

For 2025, we assume that a grid-connected electrolyser can achieve a renewable share of ~75 %, while grid electricity has a share of ~65 % renewable electricity (see Supplemental information section 4). This increases to 100 % renewable electricity in ~2035, when many power systems are likely to be dominated by low-carbon electricity. This roughly reflects the compromises that were found around qualifying electrolytic hydrogen as RFNBO (renewable fuel of non-biological origin) in the EU[4]. Therein the criteria for additionality as well as spatial and temporal correlation of renewable electricity and hydrogen production are gradually phased in until 2030. Note that also after 2030, electrolysers are allowed to operate on minor shares of non-renewable electricity as a renewable electricity grid share of >90% is one option to comply with the set of criteria.

On the other hand, it requires a flexible operation of electrolysers, which decreases their annual full-load hours and thus increases the specific CAPEX costs of producing hydrogen. Our choice of full-load hours, i.e. annual capacity factor (~50%), is motivated such that it achieves a high renewable share and low specific electricity prices for electrolysers without a substantial increase in specific CAPEX costs. Flexible operation then requires either hydrogen storage, which can be realized increasingly through central grid and storage infrastructures, or flexible hydrogen offtakers (e.g. blending green hydrogen into grey hydrogen when producing ammonia). In an endogenous optimization for the EU, Zeyen et al. (2022)[30] show that electrolysis capacity factors range between 45–52% if any hydrogen storage is available. Utilising underground salt caverns, which are a low-cost storage option that is widely available across Europe[41], translates into additional costs of ~5 EUR/MWh in the levelized costs of green hydrogen[30].

[4] https://energy.ec.europa.eu/system/files/2023-02/C_2023_1087_1_EN_ACT_part1_v8.pdf

Green hydrogen (progressive case) is produced with a large-scale electrolyser that is directly connected to low-cost renewable electricity supply at a remote site. The renewable electricity source is assumed to be a solar PV or wind power plant. Hence, the capacity factor is low (35% in 2025) but increases with time (50% in 2050) due to i) combining wind power and solar PV and ii) lower-cost electricity storage such as lithium-ion batteries.

Hydrogen transport. While the grid-connected green hydrogen supply case is produced close to consumption, the other three supply cases involve long-distance transport from central and large-scale production sites to hydrogen load centers. Transport is realized via shipping (especially 2025-30) and increasingly via pipeline (~1000 km, 50% repurposed, 50% new)[29]. Additional distribution costs can vary strongly depending on the specific use case. As we compare competitiveness to natural gas applications, we assume distribution to large load centers such as industrial sites. For hydrogen applications in road transport it would require additional costs for distributing hydrogen to more dispersed hydrogen-fueling stations.

Life-cycle Greenhouse Gas emissions

Greenhouse gas emissions (GHG) quantified in this analysis represent – unless otherwise stated – life-cycle emissions, for hydrogen from both water electrolysis and methane reforming. These emissions have been quantified applying the well-established Life Cycle Assessment (LCA) methodology [42–44]. Therefore, all processes along the value chains from extraction of resources, manufacturing of infrastructure components, transport activities and energy supply chains to the hydrogen production itself are included and their direct and indirect GHG emissions contribute to the GHG intensities of all hydrogen production pathways. Attributional LCA has been performed using the ecoinvent database with its system model "allocation, cut-off by classification" as source of background inventory data [45].

Note that hydrogen itself is an indirect GHG and recent calculations derived higher warming impacts[46,47] (GWP100 central values of 11 to 13). We neglect these effects here, which can be interpreted as an implicit assumption of <1% hydrogen leakage rates[48]. Accounting for a scenario with higher hydrogen leakage would further worsen its competitiveness with fossil fuels, while leaving the cost competitiveness relations of green versus blue hydrogen roughly unchanged.

Global warming potential

The relative importance of methane leakage depends on the choice of GHG emission metric used to compare short-lived methane emissions to CO_2 emissions. The most prominent metric is the global warming potential (GWP) that compares the future global warming caused by an idealized emission pulse of different GHG[49]. It is defined in multiplicative terms compared to CO_2 such that the GWP of CO_2 is 1. Importantly, the GWP is a metric that aggregates impact over time such that its estimation requires the specification of a time horizon until which future warming shall be captured and compared (e.g. 100 years in GWP100). Given the short atmospheric lifetime of methane of roughly 12 years [49], the choice of metric applied is especially relevant for systems with comparatively high methane emissions [9,50].

We use Global Warming Potentials (GWP) for a time horizon of 100 years ("GWP100") and 20 years ("GWP20") to quantify climate impacts of all individual GHG according to IPCC AR5 [51] and as implemented in the ecoinvent database [52]. The most notable difference lies in the equivalence factors of methane, which are around 29 (GWP100) and 85 (GWP20), respectively.

The choice of metric relies on the context of the metric's application, and there is no single right choice [49]. GWP100 is the established metric in UNFCCC context when assessing long-term stabilization scenarios [53]. However, if the focus of climate change mitigation shifts from long-term stabilization to shaving the global temperature peak (in order to reduce short- to mid-term climate impacts and tipping elements).

CO_2 *capture rates*

The quantification of GHG emissions of both cases (conservative and progressive) builds upon the integrated process simulation/LCA of natural gas reforming with CCS as performed by Antonini et al. [11]: the SMR configuration corresponds to "SMR with CCS, HT, MDEA 90"; the ATR to "ATR with CCS, HTLT, MDEA 98" [11]. Both include CO_2 capture from the synthesis gas using methyl diethanolamine (MDEA) as absorbent. The acronyms HT and HTLT represent the use of high-temperature water gas-shift only and the use of a low- and high-temperature water gas-shift, respectively. Plant-wide, overall net CO_2 removal rates amount to 56% for the SMR (conservative) and 93% for the ATR (progressive).

Reducing CO_2 emissions of blue hydrogen further than our ATR case by increasing the overall CO_2 removal rate beyond 93% will likely be technically feasible. First, an additional CO_2 capture unit could be installed to capture the CO_2 emissions of the small natural gas fired heater, which would increase both CAPEX and OPEX and was not considered here. Second, the capture rate could be increased to almost 100% as, for example, demonstrated by Antonini et al.[11] with a novel vacuum pressure swing adsorption (VPSA) process that combines hydrogen purification and CO_2 separation in one cycle. This increases electricity requirements and decreases the efficiency of the hydrogen production process[11] and therefore, it is unclear whether it will decrease or increase the life-cycle GHG emissions of the process. Cost data for this VPSA process are not (yet) available and the technology was not considered. Finally, another method was recently suggested that incorporates a partial recycling of the flue gas.[54] Note that the IEA includes an informative box “Box 3.2 Can high plant capture rates be achieved?” in their recent IEA hydrogen 2023 review[4].

Methane emissions of natural gas supply

We derive two methane leakage scenarios for the two technology cases (conservative and progressive) based on the IEA methane tracker (2022)[27], which contains data on methane leakage for 2021. From this data, we calculate country-specific methane leakage rates in 2021 (red dots, Figure S9) of natural gas extraction, transport and distribution. The size of the red dots indicates the absolute values of methane leakage, while the black circles present the absolute country-specific natural gas production. These calculations are accessible here: https://github.com/FalkoUeckerdt/Methane-Leakage and are described in higher detail in the supplemental information section 3.

For our parametrization we account for the broad regional heterogeneity and uncertain future developments. In the progressive case, we assume that leakage rates decline to 1% (in 2025) and further decline to 0.1% in 2050, which represents today’s best-practice examples such as Norway or Netherlands. In the conservative case, we assume that leakage rates remain close to the global average of ~1.5 % even in the long term. In addition, we demonstrate the impact of worst-case methane leakage rates of up to 5% in our sensitivity analyses.

Additional CO_2 *emissions*

In addition to methane leakage, supply of natural gas also causes direct and indirect CO_2 emissions – main sources for those are native CO_2 emissions, flaring of natural gas at the extraction wells, natural gas combustion for compression along the transport chain, other electricity generation on offshore gas platforms, which is often supplied by on-site gas turbines and CO_2 emissions embodied in materials used for the infrastructure such as steel and concrete for pipelines and other infrastructure. Regarding the current average natural gas supply to the European market, these emissions account for about two thirds of the GWP100 related climate impacts of natural gas supply chain [9,55,56]. Reducing these CO_2 emissions is technically feasible: CO_2 emissions directly originating from natural gas wells can be captured at moderate costs, as implemented at the Norwegian gas fields Sleipner and Snøhvit [57]; energy supply on site can also be decarbonized, for example via electrification or application of CCS [58]; and also GHG emissions embodied in steel and concrete are supposed to be lower than today in the future due to new low-emission production processes and the application of CCS [59,60]. Implementing all these measures at a global scale is likely to take time. To the best of our knowledge, there is no published life-cycle analysis that comprehensively modeled these measures and derived a residual GHG emission estimate for blue hydrogen or natural gas supply chains. We thus have to assume an overarching reduction and calculated sensitivities to account for the associated uncertainty. For our main specification, we assume a reduction of these CO_2 emissions of 50% until 2050 (with respect to 2025 values), with a linear phase-in period between 2035 and 2050. In a sensitivity case, we assume a stronger reduction of 90% until 2050, with 35% reduction already by 2030 (compared to 2025), which reflects the high ambitions of the oil and gas industry in Norway[35].

Life-cycle GHG emissions of green hydrogen

A rich body of literature has shown that life-cycle GHG emissions of hydrogen production via electrolysis primarily depend on the GHG-intensity of electricity needed for water splitting; additional GHG emissions are caused by potentially required water desalination, subsequent compression of hydrogen and by the construction and end-of-life of the electrolysis infrastructure [61]. That holds especially true for alkaline and PEM electroysers. We consider PEM electrolysis in our analysis, as this is the technology that can better deal with intermittent renewable electricity supply as it allows for more flexible operation. We build our quantification of GHG emissions upon the LCA of a PEM electrolyzer by Zhang et al. [62] who calculated indirect GHG emissions of the construction and end-of-life phases of a PEM electrolyzer of 0.12 kg CO_2eq per kg of hydrogen, which we use as default value. This fixed contribution is added to the GHG emissions associated with electricity supply to operate the electrolysis and further compress hydrogen to a reference pressure of 200 bar. This electricity consumption amounts to 55 kWh per kg of hydrogen in 2025 and 50 kWh per kg of hydrogen in 2050 [61,63]. Further, we use GHG intensities of power generation with wind turbines and PV panels, which evolve over time until 2050. Representing good, but not best conditions in terms of wind and solar resources, those GHG intensities are 13 g CO_2eq/kWh and 40 g CO_2eq/kWh for wind and solar power, respectively, in 2025 and 8 g CO_2eq/kWh and 24 g CO_2eq/kWh, respectively, in 2050[64]. Linear interpolation is performed for years in between. The above-mentioned infrastructure related GHG emissions are likely to decrease in the future in line with international decarbonization of economic activities such as steel and concrete production. Decreasing ore concentrations might, however, result in increasing indirect GHG emissions in other processes being part of the value chain. Overall, these effects are hard to quantify – a reduction by 50% seems plausible by 2050, but due to lack of evidence and the very minor impact on our overall results, we refrain from adjusting this “fixed” emission factor of 0.12 kg CO_2eq per kg of hydrogen.

Cost data

We compare fuel costs from a techno-economic perspective without accounting for region-specific taxes, regulation or subsidies. We treat the gaseous fuels as almost perfect substitutes on a final energy level. This approach is sensible for the comparison of blue and green hydrogen. For natural gas and hydrogen, we consider fuel-specific transport and distribution costs; yet, we do not account for cost differences of end-use applications. This approximation is sensible for applications in which the specific end-use CAPEX costs of using hydrogen are not substantially larger than those of using natural gas. This includes hydrogen boilers and burners in industrial process heat applications as well as the blending of hydrogen into natural gas grids within its technical limits[65].

Electrolysis costs (***Table 1***) represent electrolyser plant costs and not only the costs of the electrolysis stack. The cost ranges represent regional and technological heterogeneity as well as uncertainty. The values represent average production sites contributing to the bulk of production. The parameters are based on IRENA 2020[25] and IEA 2022[24], while Vartianen et al. 2021[6] present lower estimates. The short- to mid-term cost reduction reflects that the electrolysis manufacturing industry transitions from small-scale, "hand crafted" and first-of-a-kind electrolysis plants to serial production with increasingly larger stack and plant sizes. While the timing of these cost reductions are uncertain, most assessments show very low electrolysis costs in the long term.

Electricity costs for green hydrogen (***Table 1***) depend on the source of electricity. If electrolysers are directly connected to renewable electricity supply at a remote site (*progressive* case), electricity costs are determined by the declining levelized costs of electricity of wind and solar PV power plants[28,66]. By contrast, if electrolyser are connected to the electricity grid (*conservative* case), we assume they pay whole-sale electricity prices.

A substantial part of electricity costs of grid-connected hydrogen production is grid fees. In 2021, Consentec[5] calculated hypothetical grid fees for a flexible electrolyser in Germany to be in the range of 20 to 60 EUR/MWh_{el} depending on the electrolyser’s location and full-load hours. Based on this analysis, we parameterize grid fees to 30 EUR/MWh_{el}. We do not include any regional differentiation of grid fees. Future grid fees are uncertain and depend on regulation and overall future grid investments. While future renewable-based electricity systems likely require higher per-unit-electricity grid costs, electrolysers might be partially exempt from grid fees to the extent that they support the electricity grid and overall power system,

With respect to electricity prices, we assume rather high short-term electricity prices reflecting uncertainties such as a potential scarcity of electricity due to delays in the expansion of renewable electricity generators. This is reflected in high

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[5] https://static.agora-energiewende.de/fileadmin/Projekte/2021/2021_07_IND_FlexNetz/A-EW_224_Netzkostenallokation_WEB.pdf

current electricity price futures for instance at the European Energy Exchange (EEX) of 125 EUR/MWh base price in 2025, which decreases to 86 EUR/MWh in 2029 (accessed 29 Oct 2023).

However, electrolysers can operate at lower electricity price hours by flexibly producing mainly at low-price and high-renewable hours (See supplemental information section 4 and Figure S11). This increases the specific renewable electricity shares and lowers electricity prices paid by the electrolyser compared below the average electricity price. Note that the average electricity price is partly coupled to natural gas prices through peak-demand hours in which natural gas plants are typically the marginal and thus price-setting plants. However, through flexible operation, electrolysers can uncouple from those high-price hours by producing mainly at low-price and high-renewable hours.

Costs for producing blue hydrogen plants are taken from the SMR parameterization in the IEA GHG report[13] (conservative case). The progressive case is parameterized based on 2030-2050 cost data for ATR hydrogen plants from the Hydrogen4EU report[67]. The <2030 costs are higher (1200 €/kW in 2025). We have used a learning rate approach to back-calculate it from future costs using a learning rate of 10%. The data was also confirmed by data from the "HyNet Low Carbon Hydrogen Plant" from BEIS, which reported CAPEX of 1170 €/kWH_2 for the 100 kNm^3/h plant.

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Author contributions

F.U. designed the study, coordinated the work, wrote the paper and created the schematic figures. P.V. curated the data, conducted the overarching analysis, produced the associated figures and developed the interactive web application. C.B. carried out the life-cycle GHG analyses. F.B. and T.L. provided data and insights on green hydrogen technology. S.R. and R.A. provided data and insights on blue hydrogen technology. All co-authors discussed the results and conclusions, reviewed the analysis and manuscript text.

Declaration of Interests

The authors declare no competing interests.

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Figure titles and legends

Figure number	Figure title	Figure legend
Figure 1	Levelised costs and life-cycle GHG emission intensity for hydrogen and natural gas	a) Levelised costs of (gaseous) hydrogen supply (production, transport and distribution) and natural gas prices (including gas grid fees) and b) life-cycle GHG emission intensity of green (electrolytic) and blue hydrogen as well as natural gas. The corridors illustrate the ranges for the main technology and additional sensitivity cases analysed in this paper (see Table 1). See Figure S1 for a breakdown of both costs and emissions.
Figure 2	Deriving five fuel-switching points in time based on fuel-switching CO_2 prices	a) For a point t_0 in time we show total levelized fuel costs (schematic) as a function of CO_2 prices for green and blue hydrogen as well as for a fossil fuel (here: natural gas). Fuel-switching points (FSCPs) emerge from the intersections of two cost lines and mark the CO_2 price at which a low-emission fuel with higher direct costs becomes cheaper, and thus competitive, compared to a more carbon-intensive fuel. The fuel's life-cycle GHG emission intensity defines the slope of the respective lines. The y-intercepts equal the direct costs for each fuel. For any given CO_2 price there is one fuel that provides the selected energy service at the lowest cost. b) For $t_1>t_0$ we demonstrate that the order of FSCPs can invert, if green hydrogen costs decrease. c) From the intersections of FSCPs in time, five fuel-switching points can be derived that determine the expanding competitiveness of hydrogen with fossil fuels as well as the increasing competitiveness of green hydrogen with blue hydrogen.
Figure 3	Estimating fuel-switching points in time based on fuel-switching CO_2 prices	Same as conceptual Figure 2c, now estimated for four cases derived by combining technology cases (top: conservative, bottom: progressive) with natural gas prices (left: high, right: low). From the intersections of FSCPs in time, fuel-switching points can be derived that determine the improving competitiveness of hydrogen with fossil fuels as well as the increasing competitiveness of green hydrogen with blue hydrogen.
Figure 4	Fuel-switching CO_2 prices as a function of costs and residual emissions	Emission intensities (x axis) and direct costs (y axis) of different hydrogen fuel options (scatter plot for several years), along with FSCP estimates (contour plot) required to make hydrogen competitive with natural gas for a) high natural gas prices and b) low natural gas prices. In addition to the progressive and conservative technology cases, we here include a sensitivity case with very high upstream CO_2 emission reductions, which reflects the high ambitions of the

		oil and gas industry in Norway[35], dotted). We use GWP100 here. For a sensitivity case with GWP 20, see Figure S6.
Figure 5	Sensitivity analysis for blue-to-green hydrogen fuel-switching CO_2 prices	A sensitivity analysis varying five key parameters to evaluate their impact on blue-to-green fuel-switching carbon prices. The analysis is conducted for GWP100 and centered around low natural gas prices and progressive technology assumptions. For sensitivity analyses for GWP20 and centered around high natural gas prices see Figures S7 and S8. The color bar on the left side applies for all panels and indicates how low (or high) blue-to-green FSCPs would translate into a competitiveness advantage for green (or blue) hydrogen given the CO_2 price range shown on the right side.

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