On the cost competitiveness of blue and green hydrogen

Falko Ueckerdt (1), Philipp C. Verpoort (1), Rahul Anantharaman (2), Christian Bauer (3), Fiona Beck (4), Thomas Longden (4), Simon Roussanaly (2)

(1) Potsdam Institute for Climate Impact Research, Potsdam, Germany
(2) SINTEF Energy Research (Norwegian: Stiftelsen for industriell og teknisk forskning, "The Foundation for Industrial and Technical Research"), Oslo, Norway
(3) Paul Scherrer Institute PSI, Switzerland
(4) Australian National University, Canberra, Australia

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 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]). Secondly and the focus of this paper is the supply-related question: to what extent can and should blue hydrogen made from natural gas with carbon capture and storage (CCS) complement green hydrogen from renewable electricity?

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).

A key innovation of this paper is to broaden the view from direct costs to also account for the different residual life-cycle greenhouse-gas emissions of producing green and blue hydrogen. We propose a new analysis framework that combines these aspects.

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[12], or more implicitly via emission-specific regulations such as the production tax credits for hydrogen in the US Inflation Reduction Act (IRA)[13]. We estimate that the IRA's production tax credits (PTC) for hydrogen are roughly equivalent to CO_2 prices of ~100 to 350 $/t$CO_2$eq, depending on the four emission-specific PTC tiers (Supplementary information).

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. Our analysis framework allows us to derive five “fuel-switching points” in time at which blue and green hydrogen become competitive with fossil fuels and green hydrogen becomes increasingly competitive with blue hydrogen. These fuel-switching points are conceptually introduced in section 3 and numerically estimated in section 4.

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[16] or blue hydrogen[17], path dependencies[18], 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[4], near-term production costs of green hydrogen were estimated to be substantially higher than those of blue hydrogen[5,6]. 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[7–11], 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 *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, username: preview, password: preview)[19], which allows the user to reproduce all figures with their own parameter choices.

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

Table 1: Selected hydrogen supply cases and parameter ranges. *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**, Extended Data Figure 5, Extended Data Figure 6*).*

		Conservative case	**Progressive case**	Overall range analysed in this paper
Blue hydrogen	**CO_2 capture rate [%]**	56	93	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. High regional heterogeneity and uncertainty. 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 (connection to dedicated 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). Flexible operation reduces their specific electricity price below average annual electricity prices. Electrolysers with a direct connection to dedicated renewable supply (progressive case) can operate at low renewable electricity costs (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).			
	H_2 transport and distribution costs [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]	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%.			
		Additional sensitivity cases		Overall range analysed in this paper
	Global warming potential of methane	GWP20: 85	GWP100: 29	GWP20, GWP100
	Describes how methane emissions are weighted, compared to CO_2 emissions. GWP100 is mostly used; yet, the main figures are reproduced with GWP20 as extended data 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 (accessed August 2022). In addition, natural gas consumers pay grid tariffs of 5 EUR/MWh.			

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 Extended Data Figure 1), 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 dedicated renewables (progressive case), such that their electricity costs are determined by low renewable electricity costs.

The GHG emission ranges of blue hydrogen ***(Figure 1b)*** are determined by different CO_2 capture and methane leakage rates[14,15] 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 dedicated renewable plants) or whether electrolysers are grid-connected and need to combine high-renewable hours with fossil generation (conservative), which substantially increases its GHG intensity.

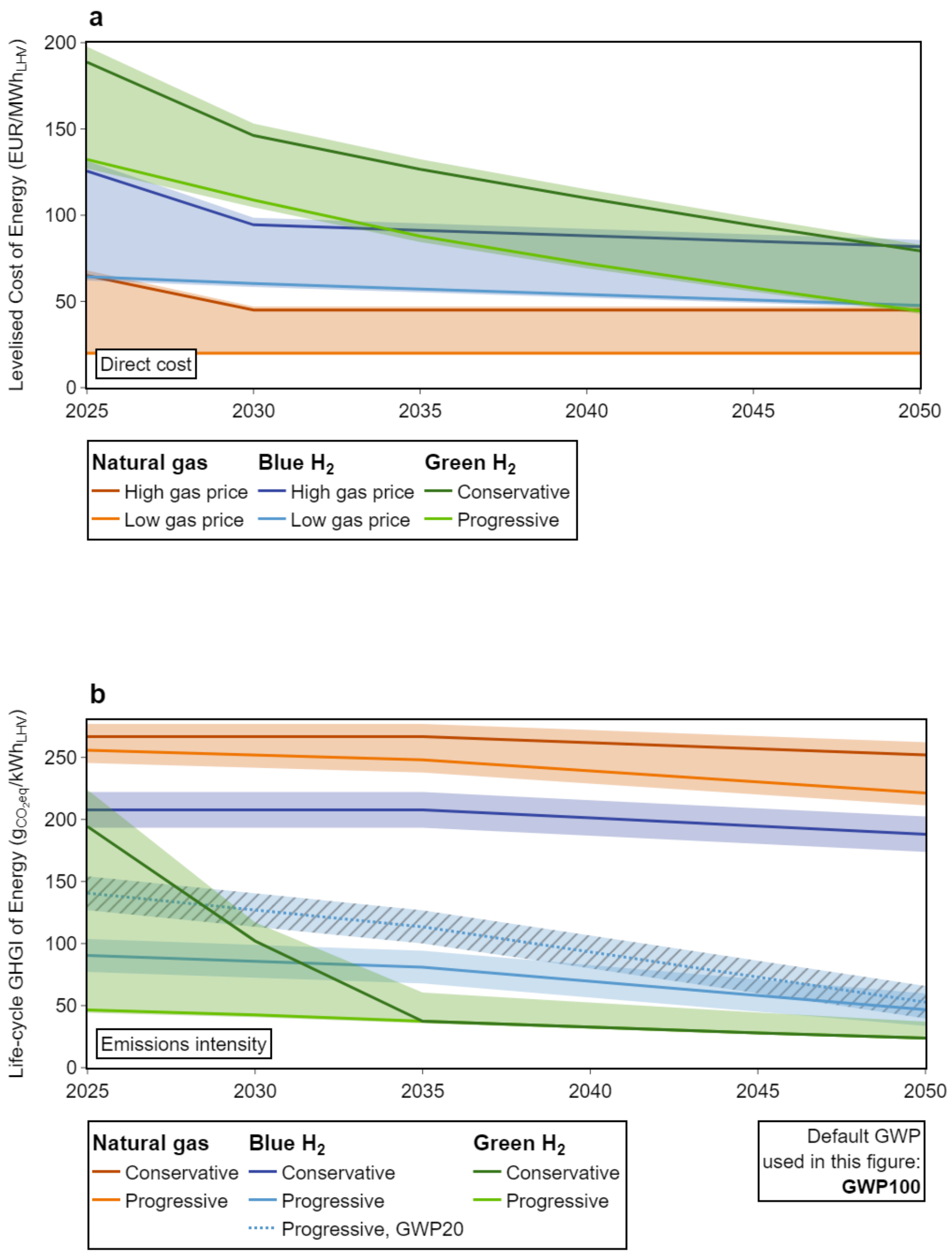


Figure 1: a) *Levelised costs of (gaseous) hydrogen supply (production, transport and distribution) and natural gas prices (including gas grid fees) and* ***b)*** *life-cycle GHG intensity of green (electrolytic) and blue hydrogen as well as natural gas. The corridors illustrate the ranges for the main technology and additional sensitivity cases analysed in this paper (see Table 1). See Extended Data Figure 1 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[7,20,21,14]. However, the technology readiness level of ATR-based hydrogen production is reported[7] to be *5*, which means that there are large prototypes but no industrial or commercial plants. The IEA global hydrogen database 2022[22] 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[23,24], 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) corresponding to the carbon price at which lower emissions fuels become cost competitive with higher emission fuels (**Figure 2**a and b). FSCPs are a core indicator of cost competitiveness 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.

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).

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

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.

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

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.

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

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 $cost_{fuel}(\mathrm{p}_{CO2})$ (**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).

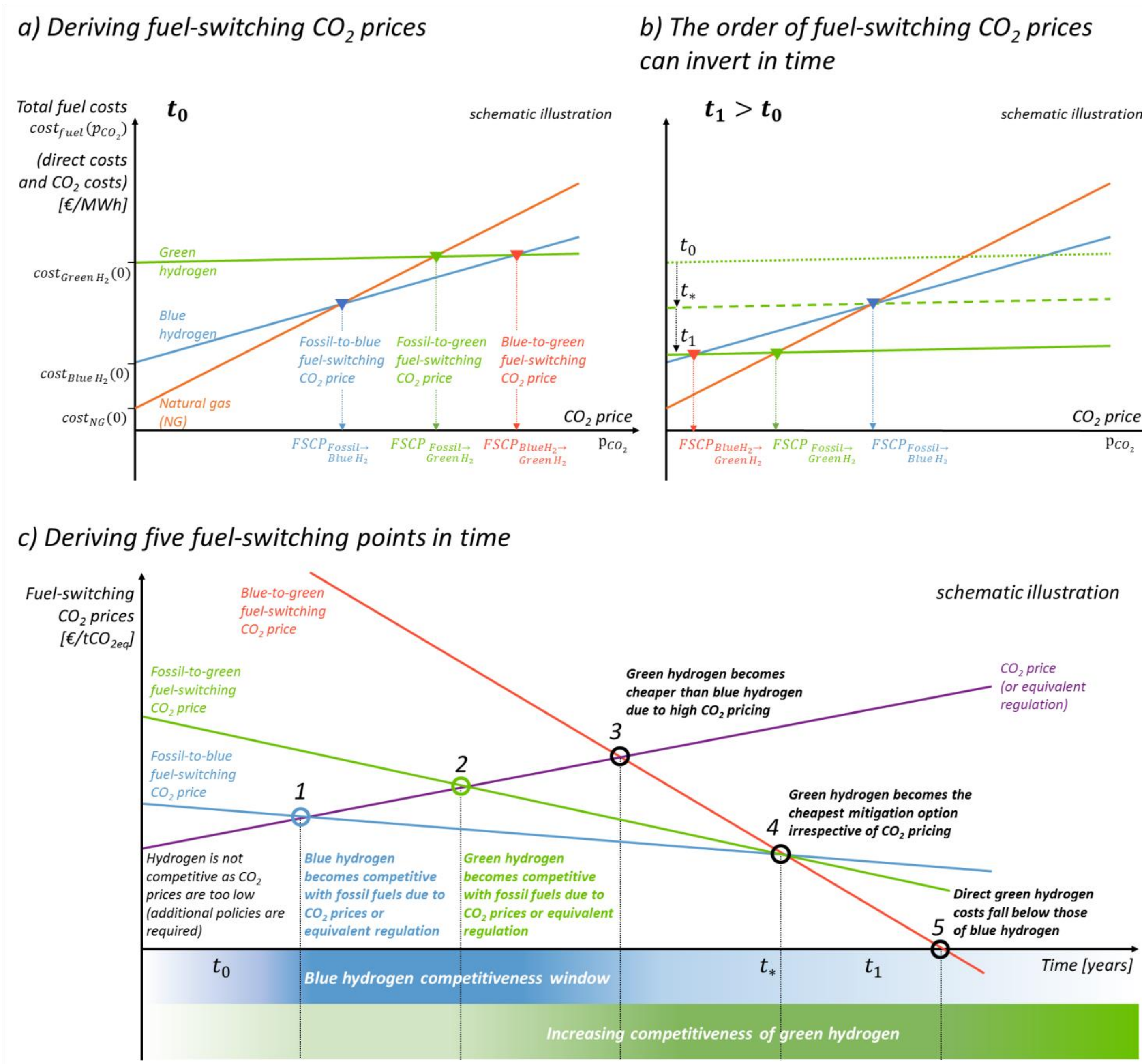


Figure 2**: **a) For a point t_0 in time we show total levelized fuel costs (schematic) as a function of CO_2 prices for green and blue hydrogen as well as for a fossil fuel (here: natural gas). Fuel-switching points (FSCPs) emerge from the intersections of two cost lines and mark the CO_2 price at which 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 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 supplementary information):

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

In contrast to switching point 3, the timing of this switching point is independent of CO_2 prices; 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).

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 $FSCP_{Blue\ H_2 \rightarrow Green\ H_2}$ becoming negative (**Figure 2**c).

Note 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 higher 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.

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[25]. 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 (Supplementary information).

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, 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 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). 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**).

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 due to 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 blue hydrogen competitiveness window** (**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).

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.

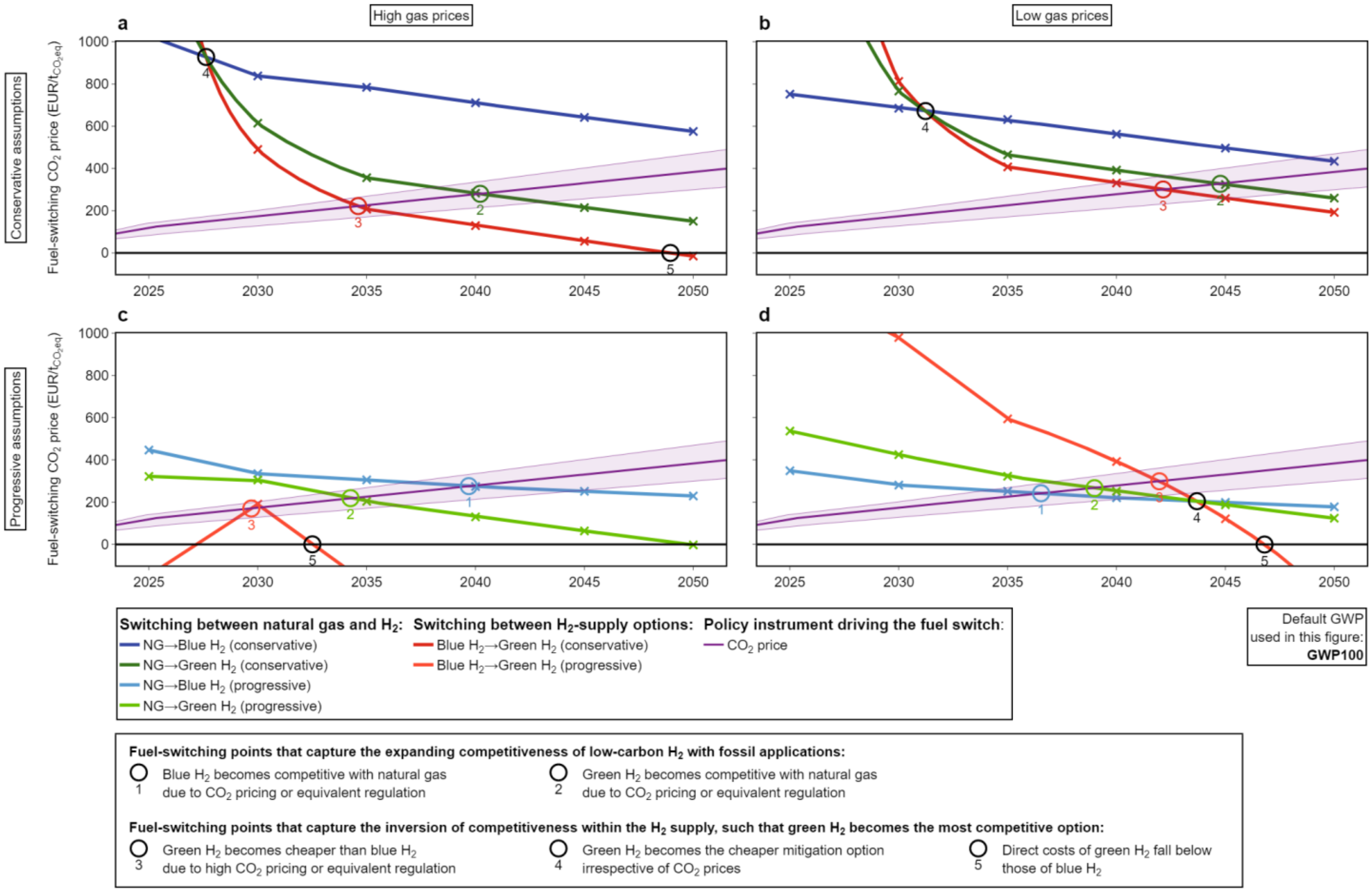


Figure 3: Same as conceptual *Figure 2*c, now estimated for four cases derived by combining technology cases (**top:** conservative, **bottom:** progressive) with natural gas prices (**left:** high, **right:** low). From the intersections of FSCPs in time, fuel-switching points can be derived that determine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

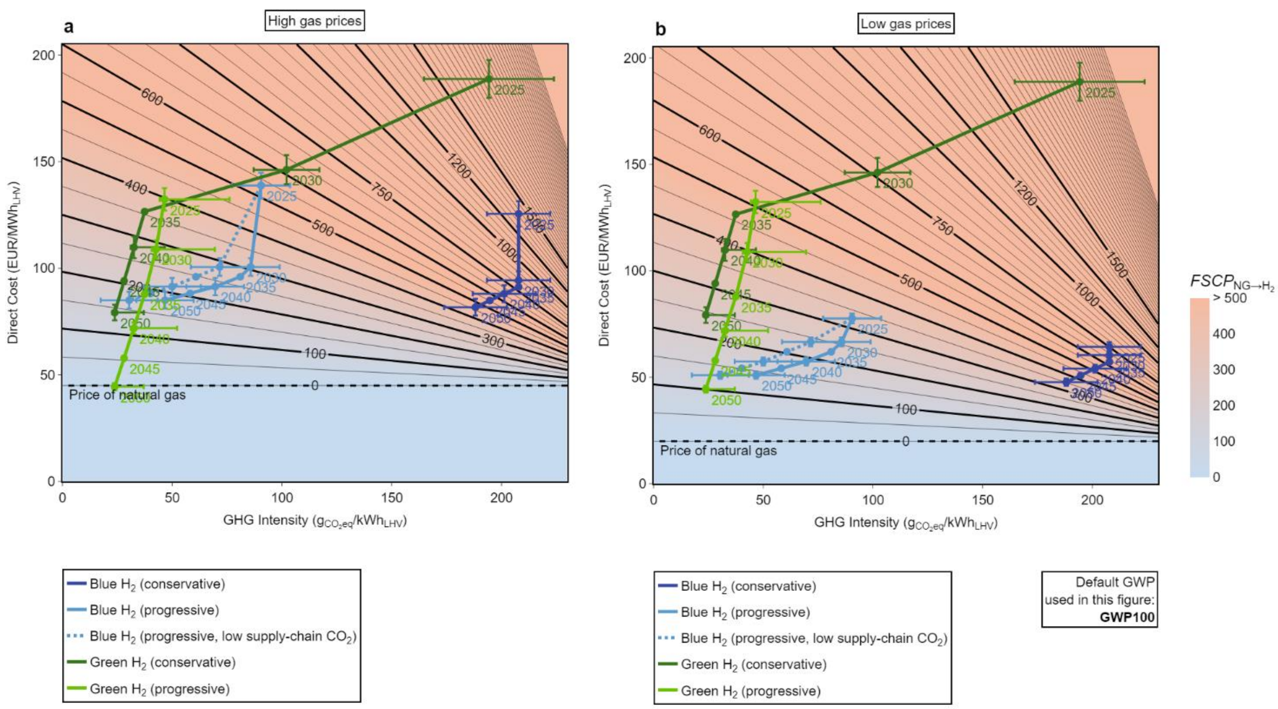


Figure 4: *E*mission intensities (x axis) and direct costs (y axis) of different hydrogen fuel options (scatter plot for several years), along with FSCP estimates (contour plot) required to make hydrogen competitive with natural gas for ***a)*** high natural gas prices and **b)** low natural gas prices. 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[26], dotted). We use GWP100 here. For a sensitivity case with GWP 20, see *Extended Data Figure 4*.

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**, Extended Data Figure 5, Extended Data Figure 6). 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.

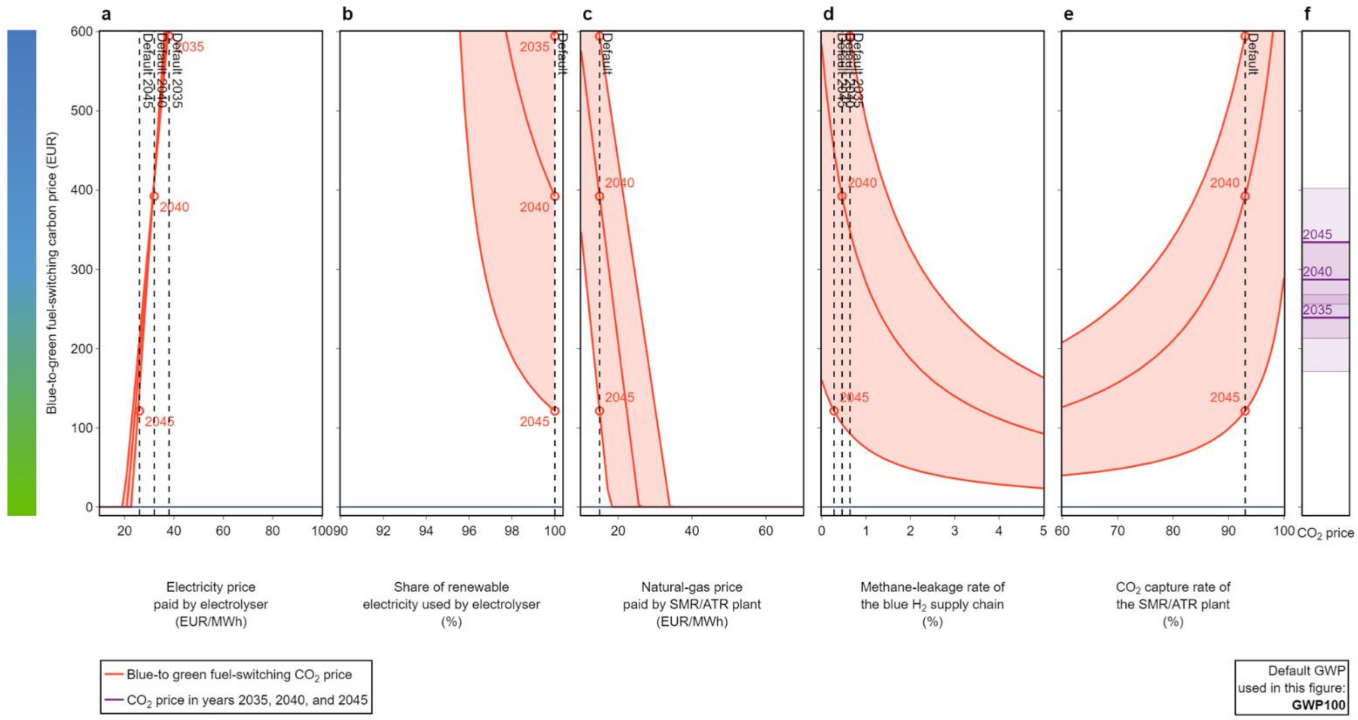


Figure 5: A sensitivity analysis varying five key parameter to evaluate their impact on blue-to-green fuel-switching carbon prices. The analysis is conducted for GWP100 and centered around low natural gas prices, progressive technology assumptions. For sensitivity analyses for GWP20 and centered around high natural gas prices see Extended Data figures 3 and 4. The color bar on the left side 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 (Extended Data Figure 5) 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 (Extended Data Figure 6) 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 (Extended Data Figure 2d).

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%[28,29]. 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[6]; 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 dedicated renewable power[9,30].

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[13]. 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[15,31].

We discuss five additional factors that can impact the competitiveness of blue and green hydrogen in addition to a pure 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. While these bottlenecks depend on dedicated near-term policy instruments for green hydrogen innovation and deployment, scarcity is anticipated until at least 2030-35[16]. If policy incentives improve, CCS investment risks decrease,[17] 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[32] 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) (Extended Data Figure 7). The IEA showed that official statistics substantially underreport methane leakage compared to satellite data[33], while >100 countries seek to reduce global methane emissions at least 30 percent from 2020 levels by 2030[34], the EU commission has proposed regulation on monitoring and third-party verification of life-cycle methane emissions[35] , and the USA is implementing a charge on methane emissions as part of the inflation reduction act[13]. 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.

Methods and data

In addition to the short introduction in the main text of the paper, we here 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 Supplementary 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)[14,15,28]. 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 Extended Data Figure 7 and supplementary information). 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[28]. However, we here assume the alternative technology autothermal reforming (ATR) with CCS[14] as it is sometimes suggested to be more suitable for achieving high net CO_2 capture rates[6]. 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%[21]. While ATR technology for hydrogen production is not commercial (TRL 5)[7], 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[7] 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)[14,33].

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 dedicated 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. 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.

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, electrolysers can uncouple from those high-price hours by producing mainly at low-price and high-renewable hours. This increases the specific renewable electricity shares (see supplementary information) and lowers electricity prices paid by the electrolyser compared to the average electricity mix. On the other hand, it requires a flexible operation of electrolysers, which decreases their annual full-load hours (we assume a capacity factor of ~50%) and thus increases the specific CAPEX costs of producing hydrogen.

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)[36]. 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 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 [37–39]. 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 [40].

Note that hydrogen itself is an indirect GHG and recent calculations derived higher warming impacts[41,42] (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[43]. 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[44]. 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 [44], the choice of metric applied is especially relevant for systems with comparatively high methane emissions [14,45].

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 [46] and as implemented in the ecoinvent database [47]. 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 [44]. GWP100 is the established metric in UNFCCC context when assessing long-term stabilization scenarios [48]. 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. [21]: the SMR configuration corresponds to "SMR with CCS, HT, MDEA 90"; the ATR to "ATR with CCS, HTLT, MDEA 98" [21]. 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.[21] 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[21] 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.[49]

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)[33], which contains data on methane leakage for 2021. From this data, we calculate country-specific methane leakage rates in 2021 (red dots, Extended Data Figure 7) 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 supplementary information.

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 [14,50,51]. 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 [52]; energy supply on site can also be decarbonized, for example via electrification or application of CCS [53]; 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 [54,55]. 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[26].

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 [56]. 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. [57] 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 [56,58]. 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[27]. 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[59].

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[8] and IEA 2022[7], while Vartianen et al. 2021[10] 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[60–62]. By contrast, if electrolyser are connected to the electricity grid (*conservative* case), we assume they pay whole-sale electricity prices. We do not include region-specific taxes and levies, but generic electricity grid fees (~30 EUR/MWH_{el}). Grid-connected electrolysers can reduce their electricity costs by flexibly charging during low-price high-renewable hours. However, we assume high short-term electricity prices reflecting uncertainties such as a potential scarcity of electricity due to delays in the expansion of renewable electricity generators.

Costs for producing blue hydrogen plants are taken from the SMR parameterization in the IEA GHG report[28] (conservative case). The progressive case is parameterized based on 2030-2050 cost data for ATR hydrogen plants from the Hydrogen4EU report[63]. 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.

Data availability

The codes and input data needed for reproducing all plots presented in this article and the supplementary 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[19]. Accessible online: https://interactive.pik-potsdam.de/blue-green-H2, (restricted access during review. username: preview, password: preview). The methane leakage analysis is accessible here: https://github.com/FalkoUeckerdt/Methane-Leakage.

References

1. Clarke, L. *et al.* Energy Systems. in *Climate Change 2022: Mitigation of Climate Change. Working Group III Contribution to the IPCC Sixth Assessment Report* (eds. P.R. Shukla et al.) (Cambridge University Press, 2022). doi:10.1017/9781009157926.008.

2. IEA. *Net Zero by 2050*. https://www.iea.org/reports/net-zero-by-2050 (2021).

3. IRENA. *World Energy Transitions Outlook: 1.5°C Pathway*. (2021).

4. Goldthau, A. & Tagliapietra, S. Energy crisis: five questions that must be answered in 2023. *Nature* **612**, 627–630 (2022).

5. Longden, T., Beck, F. J., Jotzo, F., Andrews, R. & Prasad, M. 'Clean' hydrogen? – Comparing the emissions and costs of fossil fuel versus renewable electricity based hydrogen. *Applied Energy* **306**, 118145 (2022).

6. International Energy Agency. *Global Hydrogen Review 2021*. (OECD, 2021). doi:10.1787/39351842-en.

7. International Energy Agency. *Global Hydrogen Review 2022*. https://www.iea.org/reports/global-hydrogen-review-2022 (2022).

8. IRENA. Green hydrogen cost reduction: Scaling up electrolysers to meet the 1.5C climate goal. 106 (2020).

9. Hampp, J., Düren, M. & Brown, T. Import options for chemical energy carriers from renewable sources to Germany. *PLoS ONE* **18**, e0262340 (2023).

10. Vartiainen, E. *et al.* True Cost of Solar Hydrogen. *Solar RRL* 2100487 (2021) doi:10.1002/solr.202100487.

11. Lux, B., Gegenheimer, J., Franke, K., Sensfuß, F. & Pfluger, B. Supply curves of electricity-based gaseous fuels in the MENA region. *Computers & Industrial Engineering* **162**, 107647 (2021).

12. World Bank. State and Trends of Carbon Pricing 2021. at (2021).

13. United States Department of Energy. The Inflation Reduction Act Drives Significant Emissions Reductions and Positions America to Reach Our Climate Goals. at https://www.energy.gov/sites/default/files/2022-08/8.18%20InflationReductionAct_Factsheet_Final.pdf (2022).

14. Bauer, C. *et al.* On the climate impacts of blue hydrogen production. *Sustainable Energy & Fuels* **00**, 1–10 (2021).

15. Howarth, R. W. & Jacobson, M. Z. How green is blue hydrogen? *Energy Sci Eng* **9**, 1676–1687 (2021).

16. Odenweller, A., Ueckerdt, F., Nemet, G. F., Jensterle, M. & Luderer, G. Probabilistic feasibility space of scaling up green hydrogen supply. *Nat Energy* **7**, 854–865 (2022).

17. Wang, N., Akimoto, K. & Nemet, G. F. What went wrong? Learning from three decades of carbon capture, utilization and sequestration (CCUS) pilot and demonstration projects. *Energy Policy* **158**, 112546 (2021).

18. Rosenow, J. & Lowes, R. Will blue hydrogen lock us into fossil fuels forever? *One Earth* **4**, 1527–1529 (2021).

19. Verpoort, P. C. & Ueckerdt, F. Interactive web app: https://interactive.pik-potsdam.de/blue-green-H2 (username: preview, password: preview). at https://interactive.pik-potsdam.de/blue-green-H2 (2022).

20. Oni, A. O., Anaya, K., Giwa, T., Di Lullo, G. & Kumar, A. Comparative assessment of blue hydrogen from steam methane reforming, autothermal reforming, and natural gas decomposition technologies for natural gas-producing regions. *Energy Conversion and Management* **254**, 115245 (2022).

21. Antonini, C. *et al.* Hydrogen production from natural gas and biomethane with carbon capture and storage - A techno-environmental analysis. *Sustainable Energy and Fuels* **4**, 2967–2986 (2020).

22. IEA. *Hydrogen Projects Database*. https://www.iea.org/data-and-statistics/data-product/hydrogen-projects-database (2022).

23. Amhamed, A. I. *et al.* Ammonia Production Plants—A Review. *Fuels* **3**, 408–435 (2022).

24. *Ullmann's Encyclopedia of Industrial Chemistry*. (Wiley, 2000). doi:10.1002/14356007.

25. Pietzcker, R. *et al. Notwendige* CO_2*-Preise zum Erreichen des europäischen Klimaziels 2030*. 20 pages https://publications.pik-potsdam.de/pubman/item/item_26186 (2021) doi:10.48485/PIK.2021.007.

26. Konkraft. KonKraftrapport 2020 - FRAMTIDENS ENERGINÆRING PÅ NORSK SOKKEL. *2020* 64.

27. Ueckerdt, F. *et al.* Potential and risks of hydrogen-based e-fuels in climate change mitigation. *Nature Climate Change* **11**, 384–393 (2021).

28. IEAGHG. *Techno - Economic Evaluation of SMR Based Standalone (Merchant) Hydrogen Plant with CCS*. (2017).

29. Muradov, N. Low to near-zero CO_2 production of hydrogen from fossil fuels: Status and perspectives. *International Journal of Hydrogen Energy* **42**, 14058–14088 (2017).

30. IRENA. Renewable Power Generation Costs in 2021. https://www.irena.org/Publications/2022/Jul/Renewable-Power-Generation-Costs-in-2021 (2022).

31. Burns, D. & Grubert, E. Attribution of production-stage methane emissions to assess spatial variability in the climate intensity of US natural gas consumption. *Environ. Res. Lett.* **16**, 044059 (2021).

32. European Commission. *Communication from the Commission to the European Parliament, the European Council, the Council, the European Economic and Social Committee and the Committee of the Regions. The European Green Deal*. (COM(2019) 640 final, 2019).

33. IEA. *Global Methane Tracker 2022*. https://www.iea.org/reports/global-methane-tracker-2022 (2022).

34. European Commission & United States of America. Global Methane Pledge. at https://www.ccacoalition.org/en/resources/global-methane-pledge (2021).

35. EU Commission. Proposal for a REGULATION OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL on methane emissions reduction in the energy sector and amending Regulation (EU) 2019/942. at https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=COM%3A2021%3A805%3AFIN&qid=1639665806476 (2021).

36. Staiß, F. *et al. Optionen für den Import grünen Wasserstoffs nach Deutschland bis zum Jahr 2030: Transportwege – Länderbewertungen – Realisierungserfordernisse*. 128 https://energiesysteme-zukunft.de/publikationen/analyse/transportoptionen-wasserstoff-2030 (2022) doi:10.48669/ESYS_2022-6.

37. ISO. *ISO 14040. Environmental management - life cycle assessment - prinicples and framework*. (2006).

38. ISO. *ISO 14044. Environmental management - life cycle assessment - requirements and guidelines*. (2006).

39. Hellweg, S. & Milà i Canals, L. Emerging approaches, challenges and opportunities in life cycle assessment. *Science* **344**, 1109–1113 (2014).

40. Wernet, G. *et al.* The ecoinvent database version 3 (part I): overview and methodology. *International Journal of Life Cycle Assessment* **21**, 1218–1230 (2016).

41. Warwick, N., Griffiths, P., Archibald, A. & Pyle, J. Atmospheric implications of increased hydrogen use.

42. Hauglustaine, D. *et al.* Climate benefit of a future hydrogen economy. *Commun Earth Environ* **3**, 295 (2022).

43. Ocko, I. B. & Hamburg, S. P. Climate consequences of hydrogen emissions. *Atmos. Chem. Phys.* **22**, 9349–9368 (2022).

44. IPCC. *Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change*. (2021).

45. Mac Dowell, N. *et al.* The hydrogen economy: A pragmatic path forward. *Joule* **5**, 2524–2529 (2021).

46. Stocker, T. F. *et al. Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change*. (2013).

47. ecoinvent. ecoinvent v3.7. *The ecoinvent Database* (2021).

48. Lenton, T. M. *et al.* Climate tipping points — too risky to bet against. *Nature* **575**, 592–595 (2019).

49. Straus, J., Skjervold, V. T., Anantharaman, R. & Berstad, D. Novel approach for low CO_2 intensity hydrogen production from natural gas. *Sustainable Energy Fuels* **6**, 4948–4961 (2022).

50. Meili, C., Jungbluth, N. & Bussa, M. *Life cycle inventories of crude oil and natural gas extraction*. (2021).

51. Bussa, M., Jungbluth, N. & Meili, C. *Life cycle inventories for long-distance transport and distribution of natural gas*. (2021).

52. IEAGHG. CO_2 *capture in natural gas production by adsorption processes for* CO_2 *storage, EOR and EGR. IEAGHG Technical report 2017-04*. (2017).

53. Roussanaly, S. *et al.* Offshore power generation with carbon capture and storage to decarbonise mainland electricity and offshore oil and gas installations: A techno-economic analysis. *Applied Energy* **233–234**, 478–494 (2019).

54. Habert, G. *et al.* Environmental impacts and decarbonization strategies in the cement and concrete industries. *Nature Reviews Earth and Environment* **1**, 559–573 (2020).

55. Orsini, F. & Marrone, P. Approaches for a low-carbon production of building materials: A review. *Journal of Cleaner Production* **241**, 118380 (2019).

56. Bareiß, K., de la Rua, C., Möckl, M. & Hamacher, T. Life cycle assessment of hydrogen from proton exchange membrane water electrolysis in future energy systems. *Applied Energy* **237**, 862–872 (2019).

57. Zhang, X., Bauer, C., Mutel, C. & Volkart, K. Life Cycle Assessment of Power-to-Gas: Approaches, system variations and their environmental implications. *Applied Energy* **190**, (2017).

58. Palmer, G., Roberts, A., Hoadley, A., Dargaville, R. & Honnery, D. Life-cycle greenhouse gas emissions and net energy assessment of large-scale hydrogen production via electrolysis and solar PV. *Energy & Environmental Science* **00**, 00 (2021).

59. Bard, J. *et al.* THE LIMITATIONS OF HYDROGEN BLENDING IN THE EUROPEAN GAS GRID.

60. Haegel, N. M. *et al.* Terawatt-scale photovoltaics: Transform global energy. *Science* **364**, 836–838 (2019).

61. Vartiainen, E., Masson, G., Breyer, C., Moser, D. & Román Medina, E. Impact of weighted average cost of capital, capital expenditure, and other parameters on future utility-scale PV levelised cost of electricity. *Prog Photovolt Res Appl* **28**, 439–453 (2020).

62. Luderer, G. *et al.* Impact of declining renewable energy costs on electrification in low-emission scenarios. *Nat Energy* **7**, 32–42 (2022).

63. Deloitte Finance. Hydrogen4EU report. at https://www.hydrogen4eu.com/_files/ugd/2c85cf_69f4b1bd94c5439f9b1f87b55af46afd.pdf (2021).

64. Joint Organisations Data Initiative (JODI). *Gas World Database*. https://www.jodidata.org/_resources/files/downloads/gas-data/GAS_world_NewFormat.zip (2022).

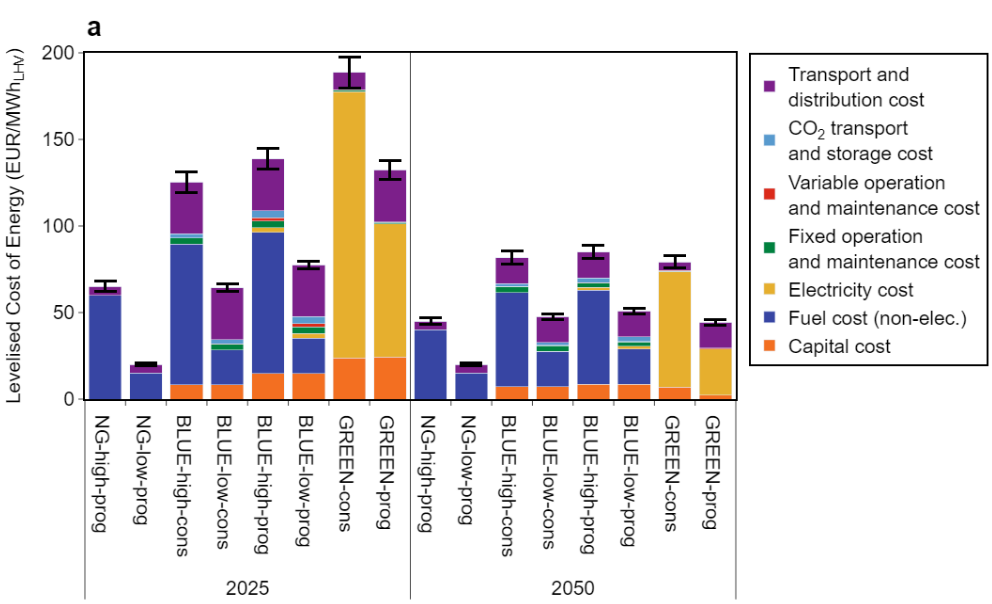
Author contributions

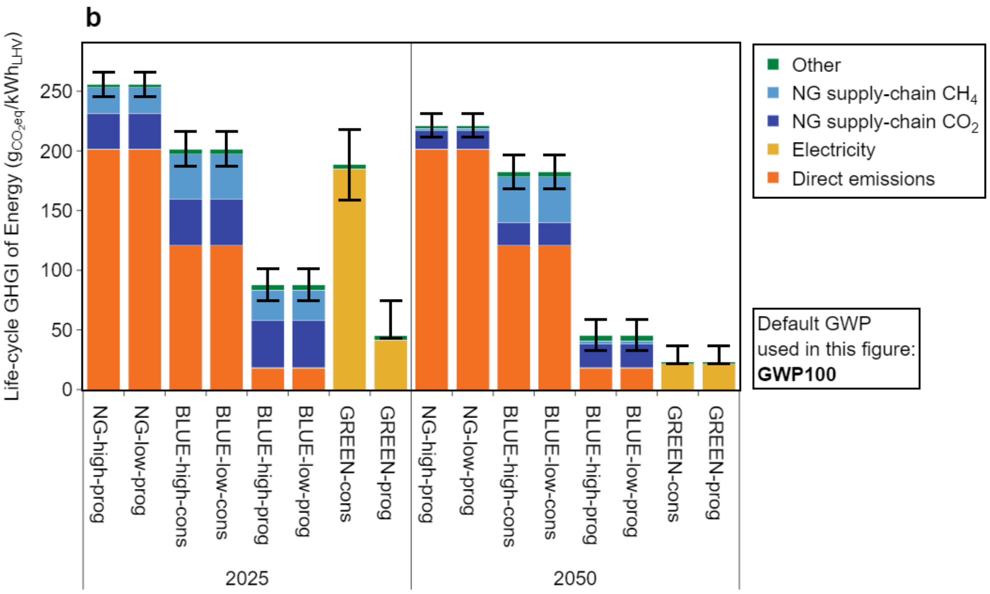
F.U. designed the study, coordinated the work, wrote the paper and created the schematic figures. P.V. curated the data, conducted the overarching analysis, produced the associated figures and developed the interactive web application. C.B. carried out the life-cycle GHG analyses. F.B. and T.L. provided 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.

Acknowledgements

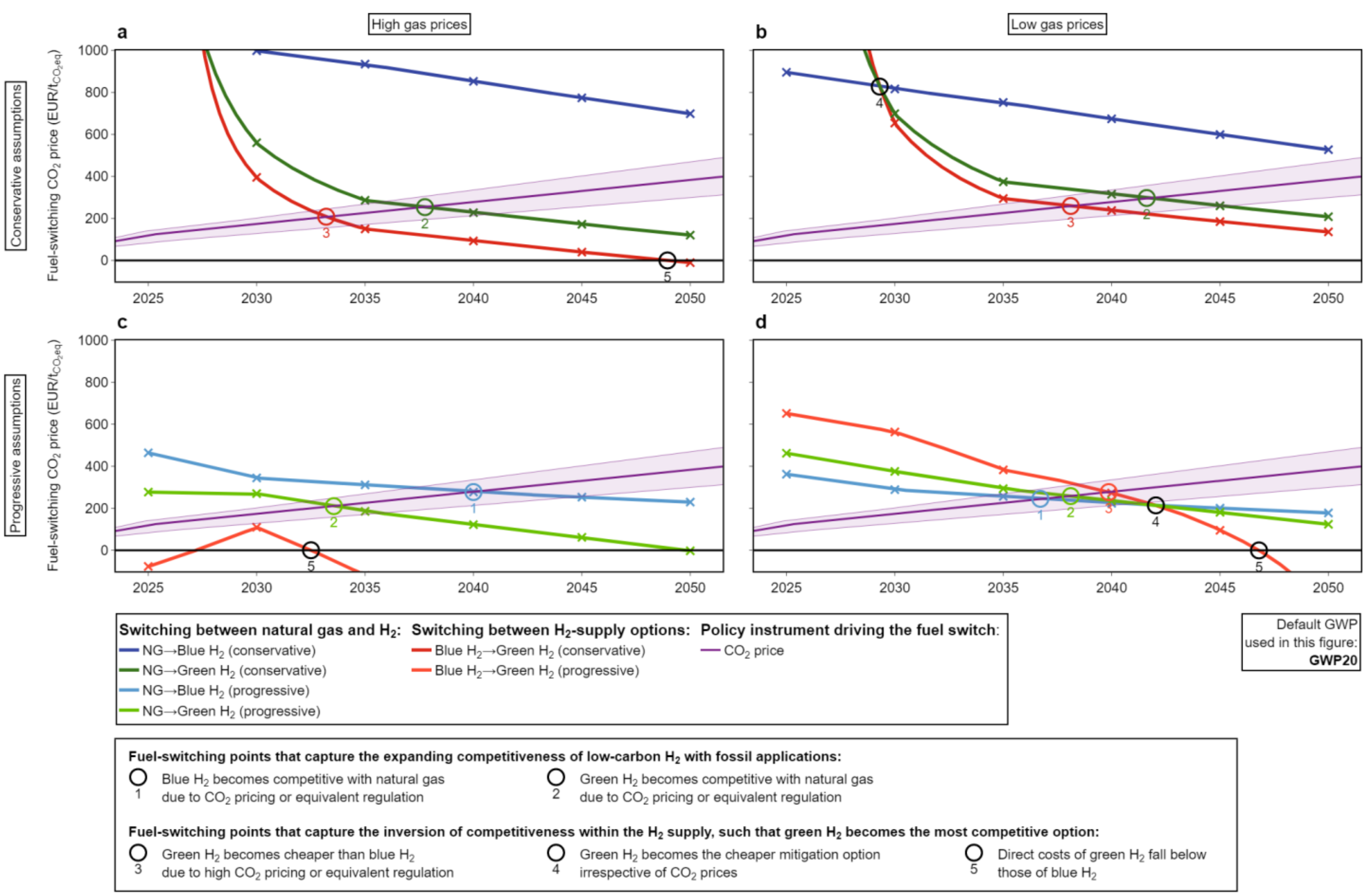
We thank Adrian Odenweller, Christoph Bertram, Gunnar Luderer and Felix Schreyer for their valuable review and comments. We thank Roger Grzondziel and Karsten Kramer for their help in setting up the interactive web app on our own web server. We also thank the participants of the International Energy Workshop 2022, in particular Johannes Hampp and Geoffrey Blanford, for their valuable comments. We gratefully acknowledge funding from the Kopernikus-Ariadne project (FKZ03SFK5A).

Extended data figures

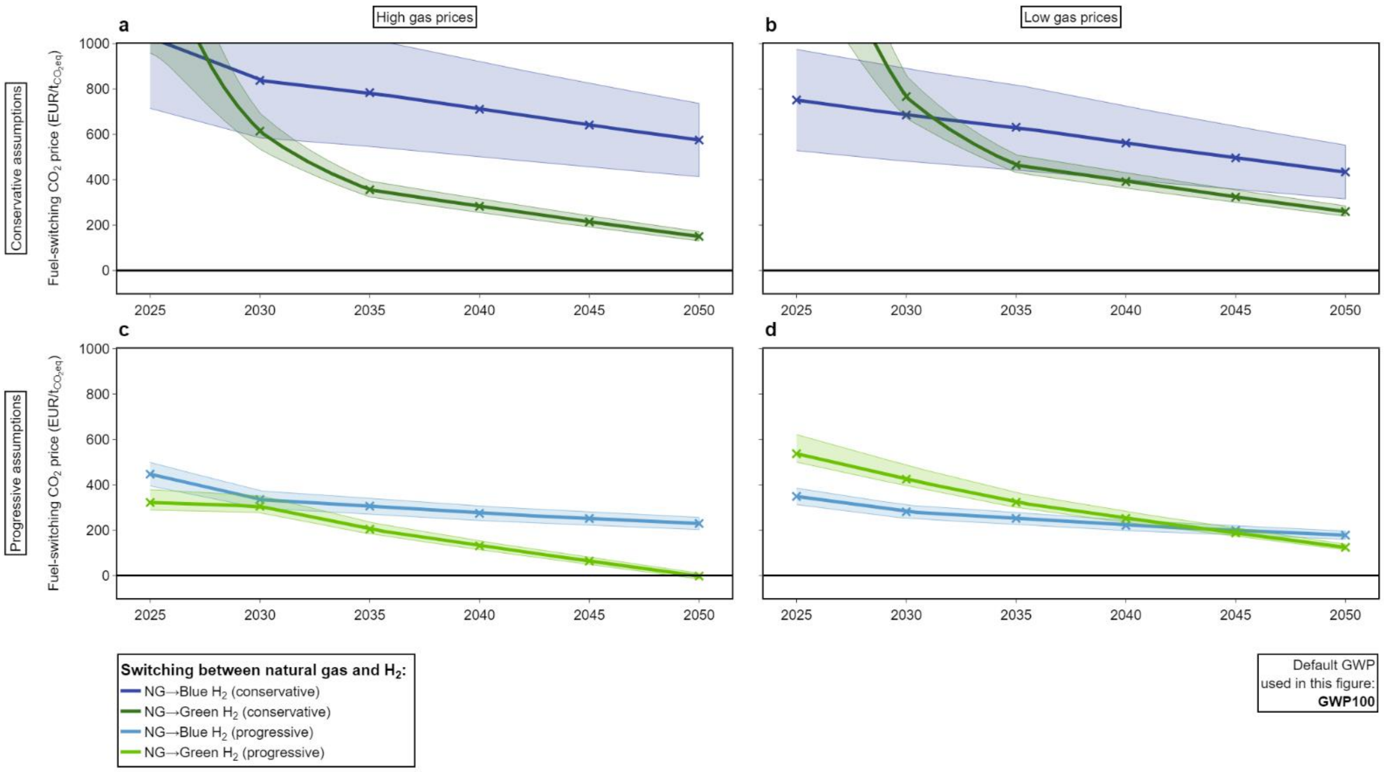




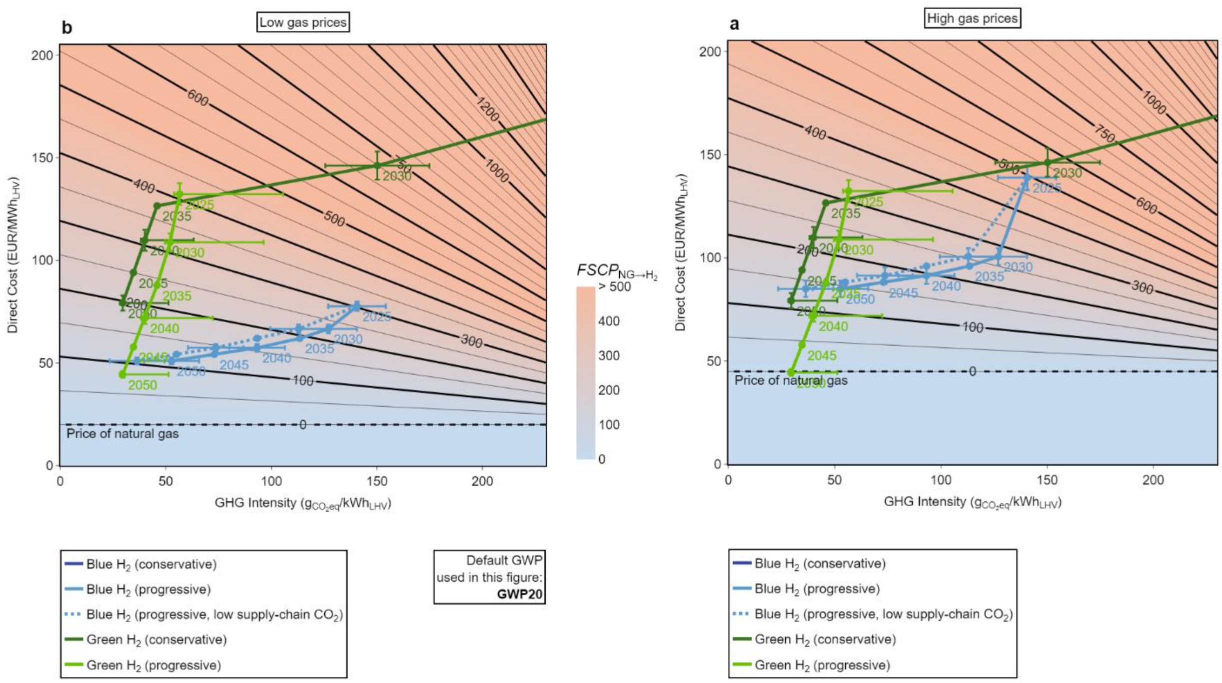
Extended Data Figure 1 **a)** Breakdown of levelised costs and **b)** breakdown of life-cycle GHG intensity of green (electrolytic) and blue hydrogen as well as natural gas (NG) for 2025 and 2050. We distinguish progressive and conservative parameter developments as well as low and high gas prices (see **Table 1**). See ***Figure 1*** for the development of aggregated costs and emissions in time.



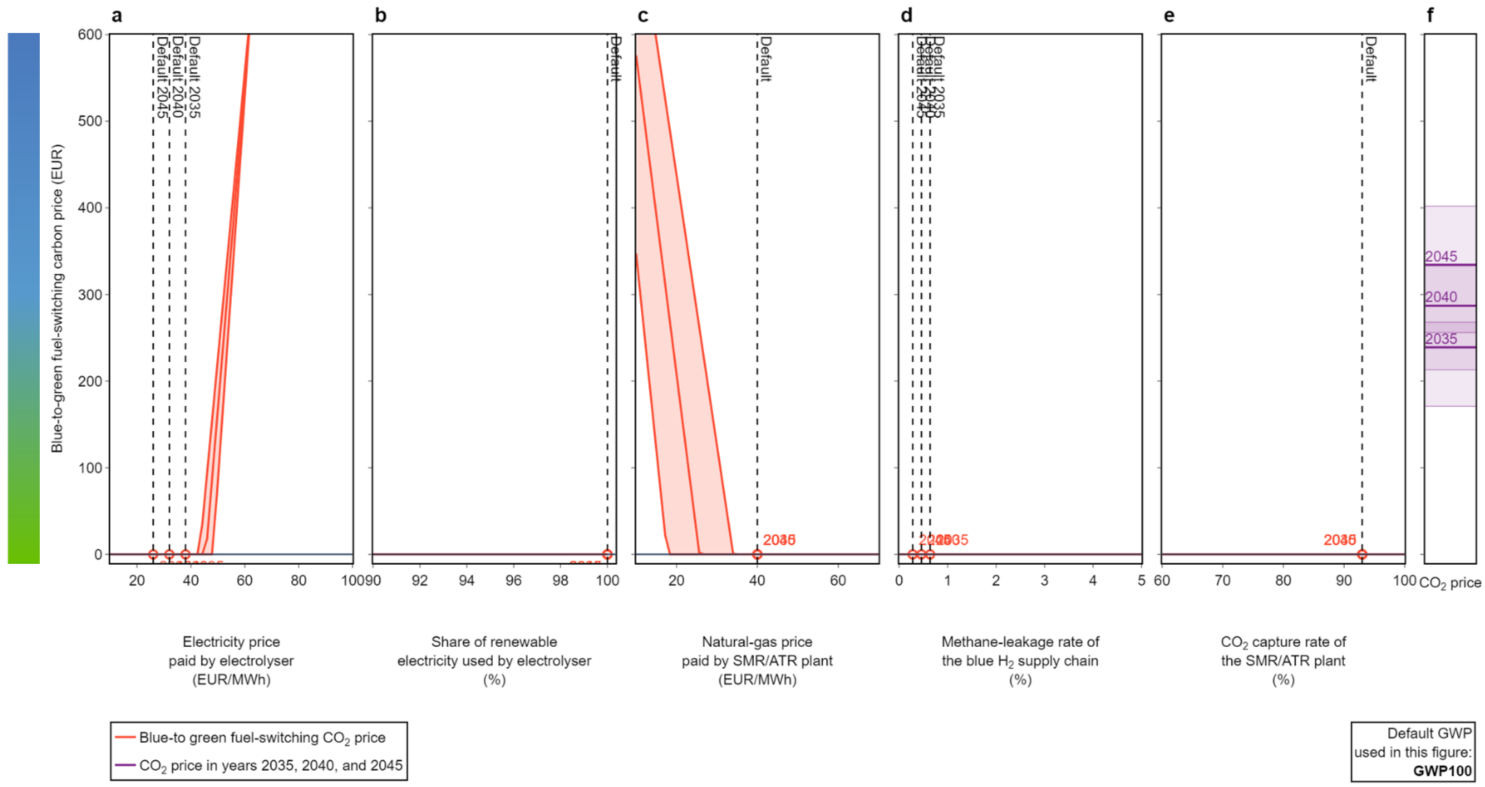
Extended Data Figure 2: Same as ***Figure 3*** but with GWP20 (instead of GWP100). FSCP for four cases derived by combining technology cases (**top:** conservative, **bottom:** progressive) with natural gas prices (**left:** high, **right:** low). From the intersections of FSCPs in time, fuel-switching 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.



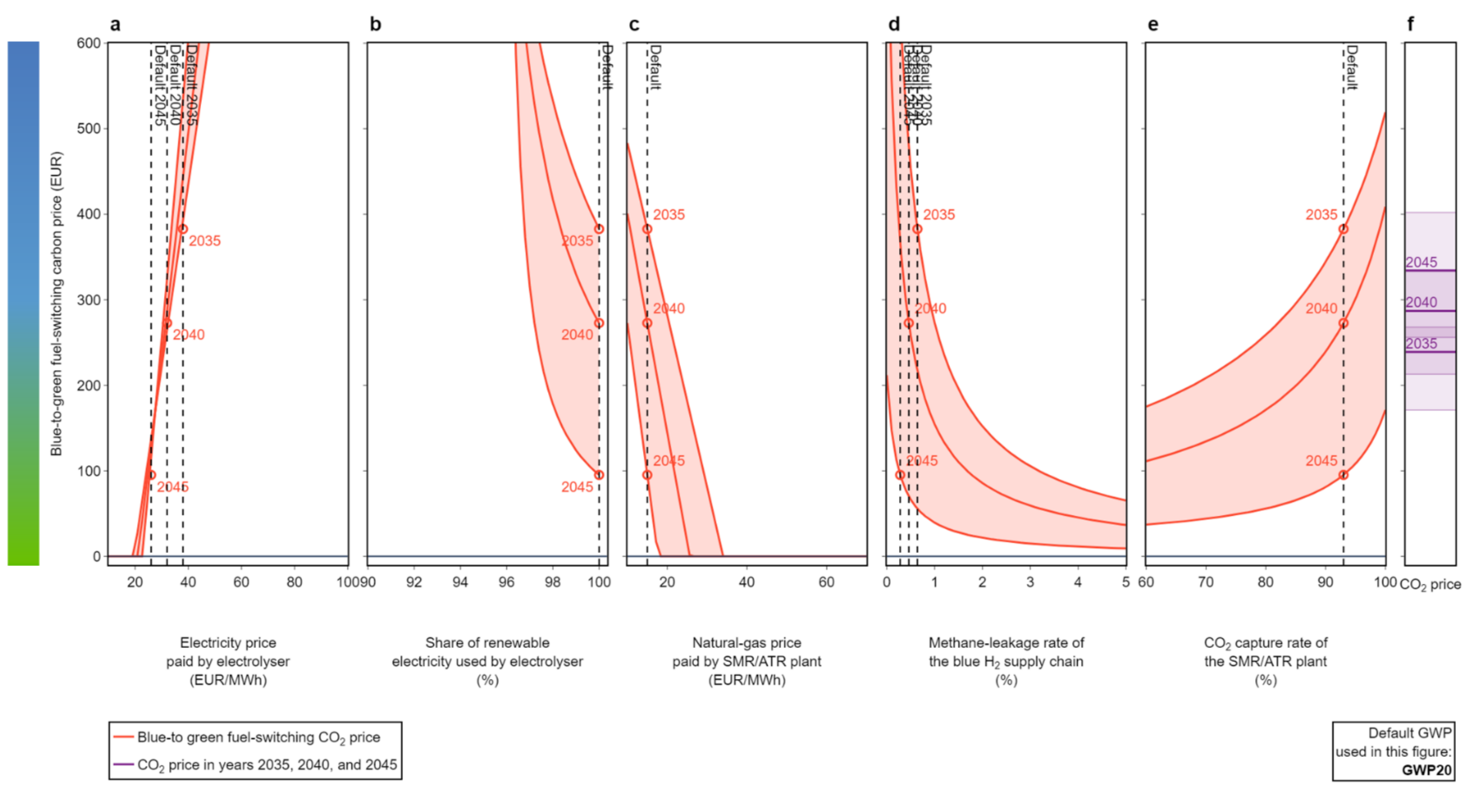
Extended Data Figure 3: Same as ***Figure 3*** but reduced to only FSCP of green and blue hydrogen (with natural gas) also including uncertainty ranges from parameter variations of 5%. The four cases are derived by combining technology cases (**top:** conservative, **bottom:** progressive) with natural gas prices (**left:** high, **right:** low).



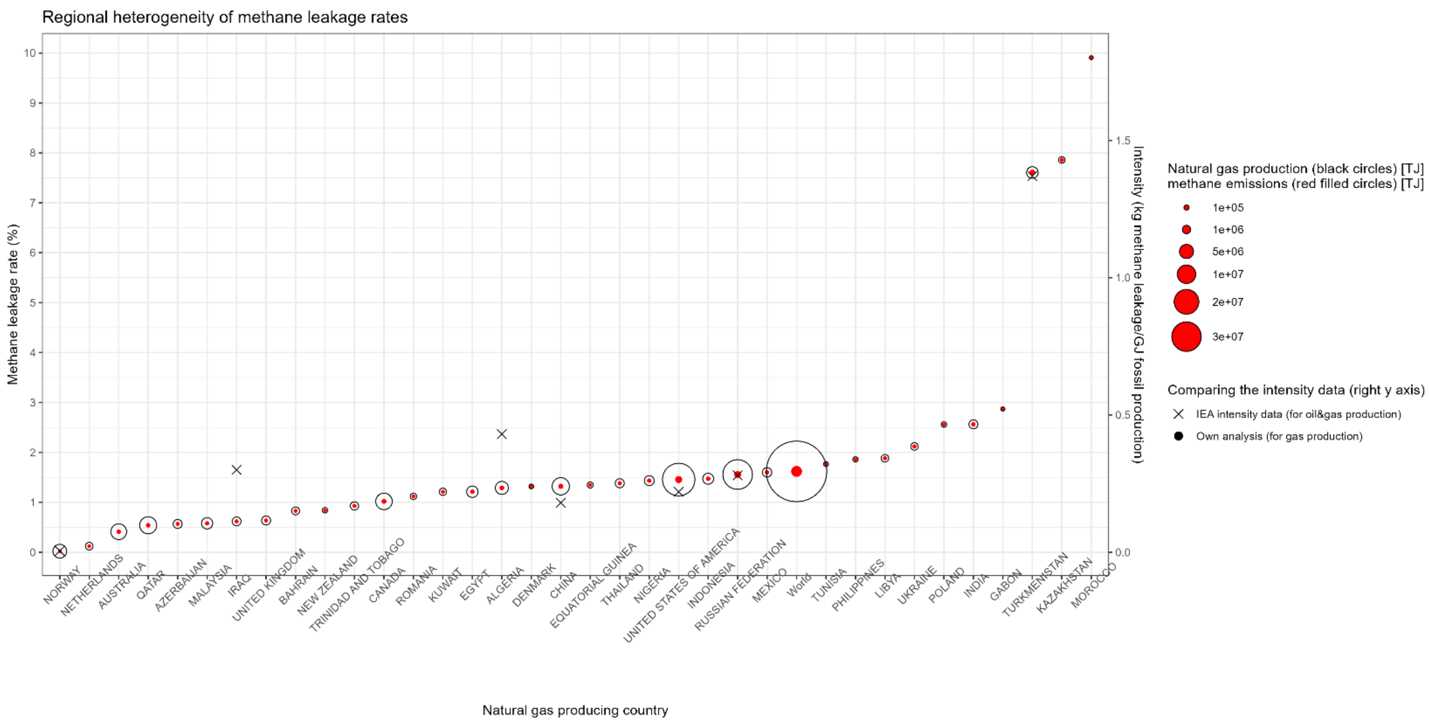
Extended Data Figure 4: ***Same as Figure 4, but with GWP20.*** *E*mission intensities (x axis) and direct costs (y axis) of different hydrogen fuel options (scatter plot for several years), along with FSCP estimates (contour plot) required to make hydrogen competitive with natural gas for ***a)*** high 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[26], dotted).



Extended Data Figure 5: Same as figure 5, but with high natural gas prices (compare table 1).



Extended Data Figure 6: Same as figure 5, but with global warming potential GWP20.



Extended Data Figure 7: Country-specific average methane leakage rates (left y axis) of natural gas extraction and transport for 2021 calculated from IEA methane leakage data[33] and gas production volumes from the JODI gas world database[64]. The methane leakage data includes satellite-detected large leaks, while the IEA also reports to underestimate these methane emissions as the geographical coverage of satellite measurements is limited. Leakage rates are calculated in relation to the natural gas produced in a respective country. We focus on countries that produce substantial amounts of natural gas (>10% than what they import). Absolute volumes are indicated by the size of the red circles (absolute methane leakage volumes) and the black circles (natural gas production). For the methane emission intensity (right y axis), we show additional IEA data for oil and gas production combined (X markers), which can be compared to our natural-gas-only estimates. The alignment is good for those countries that predominantly produce natural gas, while there are deviations for oil exporting countries such as Iraq and Algeria.

On the cost competitiveness of blue and green hydrogen

Falko Ueckerdt, Philipp C. Verpoort, Rahul Anantharaman, Christian Bauer, Fiona Beck, Thomas Longden, Simon Roussanaly

Supplementary information

1. Intersection of FSCPs

In Fig. 2 and 3 of the main paper, it becomes apparent that the three FSCPs (Fossil→Blue H_2, Fossil→Green H_2, Blue H_2→Green H_2) intersect in one single point. This may be perceived as a coincidence at first, however this is in fact a fundamental requirement of the interrelationship of the FSCPs. We provide a brief mathematical proof of this assertion.

Let $X \neq Y \epsilon \{b, g, f\}$ be two of the three fuels (blue H_2, green H_2, fossil), and let

$FSCP_{Y\to X} = \frac{cost_X - cost_Y}{ghgi_Y - ghgi_X}$

be the FSCP for switching from fuel Y to fuel X, which depends on the cost and GHG intensity of the respective fuels. We can use this to write

$cost_g = cost_f + FSCP_{f\to g} * (ghgi_f - ghgi_g)$,

$cost_b = cost_f + FSCP_{f\to b} * (ghgi_f - ghgi_b)$,

and hence

$cost_g - cost_b = FSCP_{f\to b} * ghgi_b - FSCP_{f\to g} * ghgi_g + (FSCP_{f\to g} - FSCP_{f\to b}) * ghgi_f$,

and substitute this into the definition of $FSCP_{b\to g}$, which yields

$$FSCP_{b\to g} = \frac{FSCP_{f\to b} * ghgi_b - FSCP_{f\to g} * ghgi_g + (FSCP_{f\to g} - FSCP_{f\to b}) * ghgi_f}{ghgi_b - ghgi_g}$$

$$= \frac{FSCP_{f\to b} * ghgi_b - FSCP_{f\to b} * ghgi_g}{ghgi_b - ghgi_g} + \frac{FSCP_{f\to b} * ghgi_g - FSCP_{f\to g} * ghgi_g + (FSCP_{f\to g} - FSCP_{f\to b}) * ghgi_f}{ghgi_b - ghgi_g}$$

$$= FSCP_{f\to b} + (FSCP_{f\to g} - FSCP_{f\to b}) * \frac{ghgi_f - ghgi_g}{ghgi_b - ghgi_g}$$

This equation reveals that when $FSCP_{f\to b}$ and $FSCP_{f\to g}$ coincide, this results in an equality of all three FSCPs:

$FSCP_{b\to g} = FSCP_{f\to b} = FSCP_{f\to b}$

Moreover, assuming that $ghgi_g < ghgi_b < ghgi_f$, we find that for $FSCP_{f\to b} \neq FSCP_{f\to b}$ it is either

$$FSCP_{b\to g} > FSCP_{f\to b} > FSCP_{f\to b}$$

or

$FSCP_{b\to g} < FSCP_{f\to b} < FSCP_{f\to b}$.

The case of $ghgi_b < ghgi_g < ghgi_f$ is readily obtained from the above by exchanging b and g.

2. Translating hydrogen production tax credits into implicit carbon pricing

In the main paper we state that our results and conclusions do not only apply to countries or states with explicit CO2 pricing, but also to those that have other emission-specific regulation. One example are the hydrogen production tax credits in the US inflation reduction act[1]. The below table shows the tax benefits for the associated hydrogen emission ranges, which improve competitiveness with fossil fuels similar to a CO2 price. We calculate emission-specific benefits to be in the range of ~100 to 350 $/tCO2eq.

Inflation reduction act:
translating production tax credits of hydrogen into indirect carbon prices

PTC hydrogen ($/kg H2)	Emission ranges (kg CO2eq/kg H2)		Emissions mitigated compared to natural gas (kg CO2eq/kwh)		Resulting CO2 prices ($/tCO2eq)	
0.60	2.50	4.00	0.19	0.14	96	126
0.75	1.20	2.50	0.23	0.19	99	120
1.00	0.45	1.50	0.25	0.22	121	138
3.00	0.00	0.45	0.27	0.25	343	362

Unabated natural gas was chosen as a fossil reference case (0.265 kg CO2eq/kwh)

3. Methane leakage rates

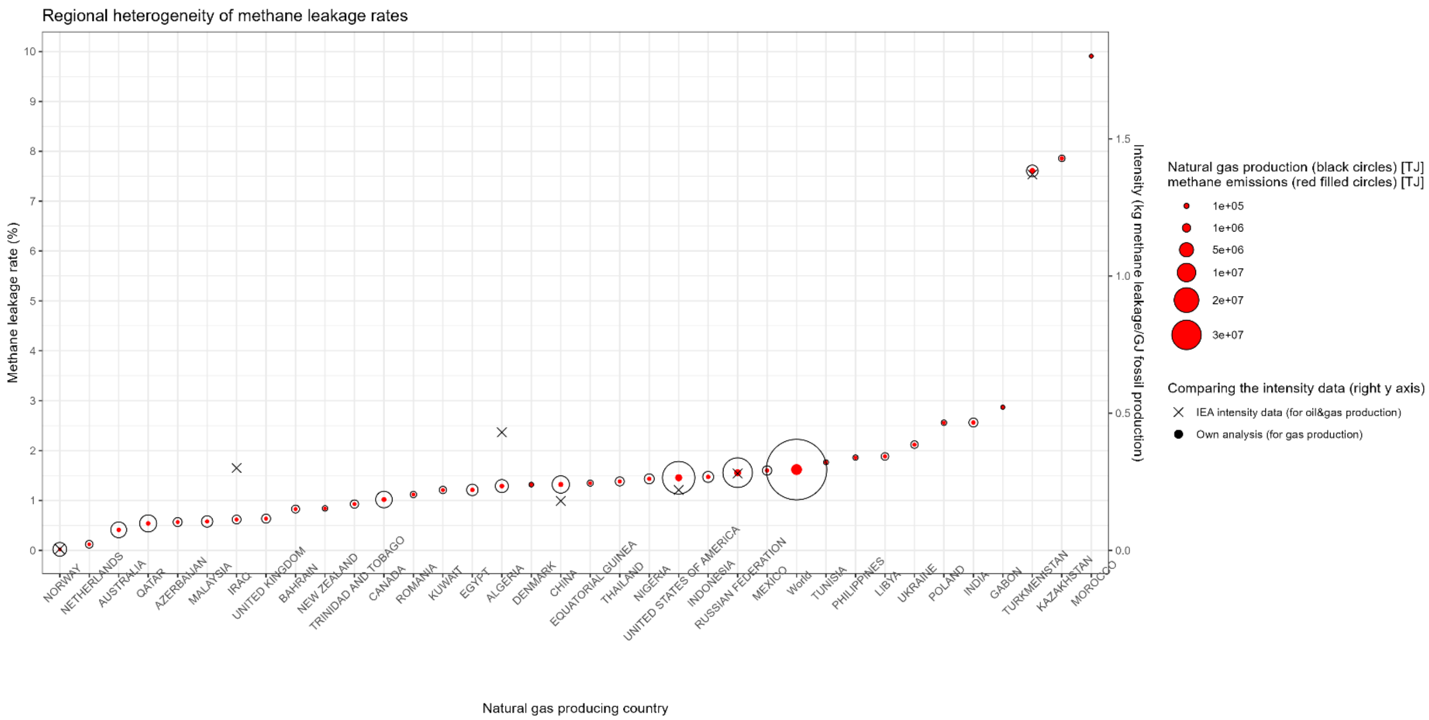
Methane emissions along natural gas supply chains reduce the climate change mitigation contribution of blue hydrogen[2–4]. Methane emissions mainly originate from venting natural gas at extraction wells, natural gas leaks or releases during pipeline transport and incomplete flaring. These sources are typically aggregated into one parameter *methane leakage rate*, which is the relation of emitted methane per natural gas supplied.

We derive two methane leakage scenarios for the two technology cases (conservative and progressive) based on the IEA methane tracker (2022)[5], which contains data on methane leakage for 2021. Combining this data with and the JODI[6] gas world database for natural gas extraction, we calculate country-specific methane leakage rates in 2021 (red dots, **Error! Reference source not found.**) 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.

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.

The IEA did not publish data on leakage rates for natural gas production in their methane tracker. The associated IEA database only contains absolute values (separated for gas and oil), but no specific values (i.e., rates). However, the IEA presents emission intensities for both oil and gas combined in *kg methane/GJ of oil&gas* for 10 selected countries in a figure that is shown in **Error! Reference source not found.**. Comparing our own analysis (**Error! Reference source not found.**) for only natural gas with the oil&gas analysis shown by the IEA, we find good consistency especially for those countries that mainly export natural gas.

The IEA data[5] is the most comprehensive source of energy-related methane emissions both in terms of countries and emission sources covered. In particular, it also includes satellite-detected methane leaks and presents numbers that are ~70% greater than the sum of official estimates submitted by national governments. Such gaps to official values have been pointed out in scientific assessments before.[7,8] Note that the IEA numbers still underestimate methane emissions as the geographical coverage of satellite measurements *"is still far from complete: existing satellites do not provide measurements over equatorial regions, northern areas (including the main Russian oil and gas producing areas) or for offshore operations"* [5].



SI Figure 1: Country-specific average methane leakage rates (left y axis) of natural gas extraction and transport for 2021 calculated from IEA methane leakage data*[5]* and gas production volumes from the JODI gas world database*[6]*. The methane leakage data includes satellite-detected large leaks, while the IEA also reports to underestimate these methane emissions as the geographical coverage of satellite measurements is limited. Leakage rates are calculated in relation to the natural gas produced in a respective country. We focus on countries that produce substantial amounts of natural gas (>10% than what they import). Absolute volumes are indicated by the size of the red circles (absolute methane leakage volumes) and the black circles (natural gas production). For the methane emission intensity (right y axis), we show additional IEA data for oil and gas production combined (X markers), which can be compared to our natural-gas-only estimates. The alignment is good for those countries that predominantly produce natural gas, while there are deviations for oil exporting countries such as Iraq and Algeria.

For the globally averaged methane leakage rate, we calculate 1.6 %. However, methane leakage rates vary widely across countries reflecting the heterogeneity in procedures of the respective natural gas industries and the status of their infrastructure. In particular, so-called "super-emitters" heavily contribute to the high values in the leakage rate distribution[9]. Our methane leakage rate assessment confirms that there is huge heterogeneity across countries (**Error! Reference source not found.**).

On the one hand, in some countries (e.g., Norway, Netherlands) the natural gas industry demonstrates that near-zero leakage rates are possible. Such low rates are also part of up-to-date life-cycle inventory data[10,11] and reported by peer-reviewed literature[12,13]. The Foulds et al.[12] state that for the case of Norway, operator-reported data, inventory data and (air) measured data are consistent (focus is the gas and oil extraction). Pettersen et al.[13] calculate GHG emissions of hydrogen supply cases mainly based on other literature. For Norway, they cite an industry report by Equinor[14]. The IEA 2022 show close-to-zero methane intensities (see Extended data figure 8) and states "Methane emissions are avoidable, the solutions are proven and even profitable in many cases." and "If all producing countries were to match Norway's emissions intensity, global methane emissions from oil and gas operations would fall by more than 90%."

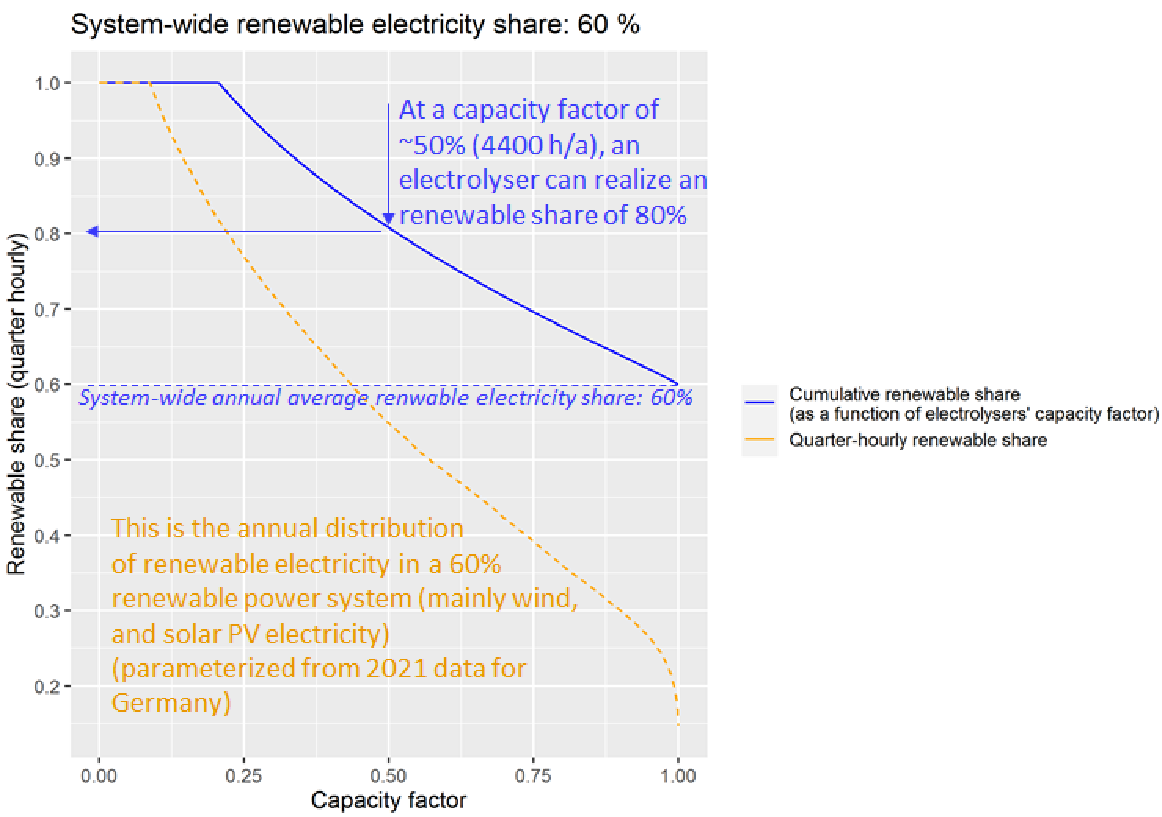
On the other hand, some large producers have average leakage rates of 1.5%-3.5% (e.g., USA, Russia, Libya, or Tunesia)[15] or much higher rates (e.g., Kazakhstan). For Europe, natural gas supply chains exhibit a methane emission rate of around 1.3%[3,10,11,15]. For the USA, the methane leakage rate, aggregated for gas and oil, was found to be 2.3% for 2015, which was ~60% higher than the US Environmental Protection Agency inventory estimate.[7] Average methane leakage rates associated with only the production (excluding transportation and distribution) of combined gas and oil production in the USA for 2015 were found to be 1.3% and 1.4%. This value (1.4 %) is confirmed for the natural gas (not oil) production for 2018, while estimates are shown to vary across US states from 0.9% to 3.6% [16]. Howarth and Jacobson[2] assume a default methane leakage rate of 3.5% in their blue hydrogen emission analysis. With respect to the future reduction of methane leakage, the IEA summarises that "If all countries adopted tried and tested abatement policies, this would cut oil and gas methane leaks by half" and that it would require new types of measures to further reduce methane emissions.[5]

4. Renewable shares of electricity for electrolysers

In our *progressive* case, green hydrogen projects are directly connected to dedicated renewables and thus achieve 100% renewable shares. Most of the announced electrolysis projects in the IEA hydrogen database[17] are planned to operate on dedicated renewables.

The *conservative* green hydrogen case is a grid-connected electrolyser. Such electrolyser projects will achieve renewable shares higher than the average renewable shares in the system. For this, flexible generation is required. For example, if the system average renewable share is 60%, the electrolyser can achieve an 80% renewable share at a capacity factor of 50%. We show this in SI Figure 2 below based on duration curves. The orange curve indicates all hours of a 60% renewable system, while the blue curve shows the cumulative renewable share of an electrolyser as a function of its capacity factor.

There is a third way of achieving high renewable shares in grid-connected electrolyser, which we do not consider in this paper. That is purchasing renewable electricity via PPAs (power purchase agreements), while producing on grid electricity. Depending on the PPA prices, this case might lead to the most favorable business case.



SI Figure 2

5. Input data

In addition to the core data shown in table 1 of the main paper, we here provide two expanded tables with i) base parameters that are the same across parameter and technology cases (table 1, below) and ii) case-specific parameter choices (table 2, below). Please note that all code and input data needed for reproducing all plots presented in this article is openly available on GitHub (https://github.com/PhilippVerpoort/blue-green-H2).

The uncertainties on the results of our calculations of the cost and GHGI, which we present in several figures, are computed based on a relative uncertainty of 5% on relevant parameters (as indicated in the below table). All parameters are assumed to be independent and hence uncorrelated, allowing us to add up their contributions using the Gaussian method of uncertainty propagation. The FSCPs of any two fuels X and Y are computed from the respective cost and GHGI results, and consequently the uncertainties on cost and GHGI can be further propagated to the FSCP. By keeping track of the uncertainty component associated with each independent parameter, correlations between uncertainties of cost and GHGI of different fuels can be taken into account.

Table 1: Base parameter that are the same across the analyses

Parameter name	Unit	Type	Year	Value	Source
Natural gas grid cost	EUR/MWh	0	const	5	0
Base Emissions of NG (per LHV; supply-chain and combustion)	gCO2eq/MJ	DIRECT, GWP100	const	56	LCA data produced by Christian Bauer at PSI. Most contributions to the LCA emissions stay mostly constant, as outlined in subsection 'Life-cycle emissions of blue hydrogen' in the Methods section. Supply-chain CO2 emissions are reduced to 87.5% between 2035 and 2050. The uncertainty is assumed to be 5% throughout, except for the uncertainty of supply-chain CO2 emissions in 2050, which are 50% +- 37.5% of those in 2035.
		DIRECT, GWP20	const	56	
		ELEC, GWP100	const	0	
		ELEC, GWP20	const	0	
		SCCO2, GWP100	2025	8.3	
		0	2035	8.3	
		0	2050	4.2	
		SCCO2, GWP20	2025	9.3	
		0	2035	9.3	
		0	2050	4.7	
		OTHER, GWP100	const	0.7	
		OTHER, GWP20	const	0.7	
GHG emissions due to methane leakage per CH4 emission rate (per LHV)	gCO2eq/MJ	GWP100	const	606.06	Part of the LCA data produced by Christian Bauer at PSI.
		GWP20	const	1727.273	0
Blue CAPEX	EUR/kW	SMR-CCS-56%	2025	673	SMR data from IEAGHG report, Sec. 8.1.3, Table 2, Sheet 84. Assuming a 0.5% yearly learning rate, i.e. 0.995**25 = 88% of cost in 2050. ATR data provided by Simon Roussanaly at Sintef. Assuming uncertainty of 10%.
		0	2050	593.7	
		ATR-CCS-93%	2025	1200	
		0	2030	900	
		0	2040	700	
		0	2050	700	
Fixed Operation and Maintenance Cost	EUR/kW	SMR-CCS-56%	2025	29	SMR data from IEAGHG report, p. 18, Table 4. ATR data provided by Simon Roussanaly at Sintef. Assuming uncertainty of 10%.
		0	2050	29	
		ATR-CCS-93%	2025	32	
		0	2030	24	
		0	2040	21	
		0	2050	21	
Variable Operation and Maintenance Cost (w/o fuel cost)	EUR/MWh	SMR-CCS-56%	2025	0.209	SMR data from IEAGHG report, p. 18, Table 4. ATR data provided by Simon Roussanaly at Sintef. Assuming uncertainty of 10%.
		0	2050	0.209	

		ATR-CCS-93%	2025	1.908	
		0	2030	0.252	
		0	2050	0.252	
Full load hours of blue-hydrogen plant	h	0	const	8322	IEAGHG SMR data from IEAGHG report, p. 18, Table 4. Assuming same for ATR.
Captured emissions for transport and storage	kgCO2/Nm3_H2	SMR-CCS-56%	const	0.466	SMR data from IEAGHG, p. 16, Table 2 (Plant Performance Summary), Specific CO2 Captured. ATR data estimated from NG consumption and capture-rate of facility.
		ATR-CCS-93%	const	0.8004	
Carbon transport and storage cost	EUR/tCO2	0	2025	15	Smith et al 2021[18] In countries where CCS acceptance is low or where limited geological storage opportunities exist, CO_2 would have to be transported over substantial distances by pipeline or by ship, which would add approximately 0.1 €/kg H_2 to the cost of the project https://www.globalccsinstitute.com/archive/hub/publications/119811/costs-co2-transport-post-demonstration-ccs-eu.pdf
		0	2030	10	
		0	2050	10	
Base emissions of blue hydrogen (per LHV)	gCO2eq/MJ	DIRECT, SMR-CCS-56%, GWP100	const	33.5 +- 0.0	LCA data produced by Christian Bauer at PSI. Most contributions to the LCA emissions stay mostly constant, as outlined in subsection 'Life-cycle emissions of blue hydrogen' in the Methods section. Supply-chain CO2 emissions are reduced to 87.5% between 2035 and 2050. The uncertainty is assumed to be 5% throughout, except for the uncertainty of supply-chain CO2 emissions in 2050, which are 50% +- 37.5% of those in 2035.
		DIRECT, SMR-CCS-56%, GWP20	const	33.5 +- 0.0	
		DIRECT, ATR-CCS-93%, GWP100	const	4.9 +- 0.0	
		DIRECT, ATR-CCS-93%, GWP20	const	4.9 +- 0.0	
		ELEC, SMR-CCS-56%, GWP100	const	0.03	
		ELEC, SMR-CCS-56%, GWP20	const	0.04	
		ELEC, ATR-CCS-93%, GWP100	const	0.2	
		ELEC, ATR-CCS-93%, GWP20	const	0.2	
		SCCO2, SMR-CCS-56%, GWP100	2025	10.7	
		0	2035	10.7	
		0	2050	5.4	
		SCCO2, SMR-CCS-56%, GWP20	2025	10.7	
		0	2035	10.7	
		0	2050	5.4	
		SCCO2, ATR-CCS-93%, GWP100	2025	10.9	
		0	2035	10.9	
		0	2050	5.5	
		SCCO2, ATR-CCS-93%, GWP20	2025	10.9	
		0	2035	10.9	
		0	2050	5.5	

		SCCO2, ATR-CCS-93%-LOWSCCO2, GWP100	2025	10.9	
		0	2030	7.09	
		0	2040	3.82	
		0	2050	1.09	
		SCCO2, ATR-CCS-93%-LOWSCCO2, GWP20	2025	10.9	
		0	2030	7.09	
		0	2040	3.82	
		0	2050	1.09	
		CTS, SMR-CCS-56%, GWP100	const	0.2	
		CTS, SMR-CCS-56%, GWP20	const	0.2	
		CTS, ATR-CCS-93%, GWP100	const	0.3	
		CTS, ATR-CCS-93%, GWP20	const	0.3	
		OTHER, SMR-CCS-56%, GWP100	const	1	
		OTHER, SMR-CCS-56%, GWP20	const	1.3	
		OTHER, ATR-CCS-93%, GWP100	const	1	
		OTHER, ATR-CCS-93%, GWP20	const	1.3	
Capture rate of blue-hydrogen technologies	percent	SMR-CCS-56%	const	56 +- 5	Value given by assumed technology.
		ATR-CCS-93%	const	93 +- 5	
Same as above but to be kept constant as a reference parameter.	percent	SMR-CCS-56%	const	56	Value given by assumed technology.
		ATR-CCS-93%	const	93	
Methane leakage emissions per CH4 emission rate (per LHV)	gCO2eq/MJ	SMR-CCS-56%, GWP100	const	707	Part of the LCA data produced by Christian Bauer at PSI.
		SMR-CCS-56%, GWP20	const	2010	
		ATR-CCS-93%, GWP100	const	710	
		ATR-CCS-93%, GWP20	const	2032	
Fuel efficiency (natural gas)	percent	SMR-CCS-56%	const	73.51	SMR data from IEAGHG report, p.16, Table 2 (Plant Performance Summary), total energy of inlet & outlet stream. ATR data provided by Simon Roussanaly at Sintef.
		ATR-CCS-93%	const	73.53	

Fuel efficiency (grid electricity)		SMR-CCS-56%	const	-200	SMR data from IEAGHG report, p.16, Table 4 (Plant Performance Summary), total energy of inlet & outlet stream. ATR data provided by Simon Roussanaly at Sintef.
		ATR-CCS-93%	const	25	
Fixed Operation and Maintenance Cost	percent	0	const	3	AEMO Integrated System Plan assumptions.
Variable Operation and Maintenance Cost (w/o fuel cost)	EUR/MWh	0	const	0.4 +- 0.1	Assuming USD 0.01-0.02/kg H2 from IEA for water consumption.
Electricity price	EUR/MWh	0	2025	70	0
			2030	60	0
			2050	40	0
GHGI of electrolysis	kgCO2eq/kgH2	GWP100	2025	0.12	Based on LCA data provided by Christian Bauer at PSI.
			2050	0.06	
		GWP20	2025	0.14	
			2050	0.07	
GHGI of electricity	kgCO2eq/kWh	RE, GWP100	2025	0.027	Based on LCA data provided by Christian Bauer at PSI. Fossil is assuming natural gas as a source for power generation.
			2050	0.016	
		RE, GWP20	2025	0.033	
			2050	0.02	
		FOSSIL, GWP100	2025	0.400 +- 0.0	
			2050	0.400 +- 0.0	
		FOSSIL, GWP20	2025	0.650 +- 0.0	
			2050	0.650 +- 0.0	
Elec. efficiency	percent		2025	65	Own estimates based on various sources.
			2030	65	
			2040	70	
			2050	75	
Lifetime of electrolysis plants.			2025	10	Stack lifetime is 95kh according to IEA Future of Hydrogen (2019) report. With 50% OCF that is ~21 years.
			2030	15	
			2035	20	
			2040	20	
			2050	20	
Lifetime of blue-hydrogen plants.			const	20	IEAGHG repor
Interest rate	percent		const	8	Assuming a typical WACC value.
Transp. cost	EUR/MWh		2025	30	Acatech 2022[19].
			2050	15	
GHGI of energy used in H2 transportation	percent		const	3	Roedle et al 2018[20] state “Recompression every 100 km, 0.02 kWh(Strom)/kg hydrogen”, which gives 0.4 kWh/kg H2. Using a compressor with 40% efficiency, this results in 1kWh_LHV-H2 per kg_H2. This means a 3% surplus on the GHGI.

Table 2: Parameters that are differentiated in cases (e.g. conservative and progressive)

Fuel type	Case	Parameter name	Unit	Year	Value	Source

NG	gas_prices high	Natural gas price (per LHV)	EUR/MWh	2025	60	0
0	0	0	0	2030	40	0
0	0	0	0	2050	40	0
0	gas_prices low	Natural gas price (per LHV)	EUR/MWh	2025	15	0
0	0	0	0	2030	15	0
0	0	0	0	2050	15	0
0	cons_vs_prog cons	Amount of methane leakage in production chain (relative to total amount used)	percent	2025	1.5	Based on IEA data and own analysis. See detailed discussion above.
0	0	0	0	2050	1.5	0
0	cons_vs_prog prog	Amount of methane leakage in production chain (relative to total amount used)	percent	2025	1	Based on IEA data and own analysis. See detailed discussion above.
0	0	0	0	2050	0.1	0
BLUE	gas_prices high	Natural gas price (per LHV)	EUR/MWh	2025	60	0
0	0	0	0	2030	40	0
0	0	0	0	2050	40	0
0	gas_prices low	Natural gas price (per LHV)	EUR/MWh	2025	15	0
0	0	0	0	2030	15	0
0	0	0	0	2050	15	0
0	cons_vs_prog cons	Amount of methane leakage in production chain (relative to total amount used)	percent	2025	1.5	Based on IEA data and own analysis. See detailed discussion above.
0	0	0	0	2050	1.5	0
0	cons_vs_prog prog	Amount of methane leakage in production chain (relative to total amount used)	percent	2025	1	Based on IEA data and own analysis. See detailed discussion above.
0	0	0	0	2050	0.1	0
GREEN	cons_vs_prog cons	Electricity price	EUR/MWh	2025	100	0
0	0	0	0	2030	80	0
0	0	0	0	2050	50	0
0	0	Green CAPEX	EUR/kW	2025	700	0
0	0	0	0	2030	500	0
0	0	0	0	2040	400	0
0	0	0	0	2050	300	0
0	0	Share of renewable and grey electricity. 100% means RE only.	percent	2025	75.0 +- 5.0	Assuming dedicated RE production.
0	0	0	0	2030	90.0 +- 2.5	0

0	0	0	0	2035	100.0 + 0.0 - 2.5	0
0	0	0	0	2050	100.0 + 0.0 - 2.5	0
0	0	Operational capacity factor	percent	2025	50	Feasible OCF for RE-only operation mode.
0	0	0	0	2050	50	0
0	0	Transp. cost	EUR/MWh	2025	10	Acatech 2022[19].
0	0	0	0	2050	5	0
0	cons_vs_prog prog	Electricity price	EUR/MWh	2025	50	0
0	0	0	0	2050	20	0
0	0	Green CAPEX	EUR/kW	2025	500	0
0	0	0	0	2030	400	0
0	0	0	0	2040	200	0
0	0	0	0	2050	100	0
0	0	Share of renewable and grey electricity. 100% means RE only.	percent	2025	100.0 + 0.0 - 5.0	Assuming dedicated RE production.
0	0	0	0	2050	100.0 + 0.0 - 2.5	0
0	0	Operational capacity factor	percent	2025	35	Feasible OCF for RE-only operation mode.
0	0	0	0	2030	40	0
0	0	0	0	2035	50	0
0	0	0	0	2050	50	0

References

1. United States Department of Energy. The Inflation Reduction Act Drives Significant Emissions Reductions and Positions America to Reach Our Climate Goals. at https://www.energy.gov/sites/default/files/2022-08/8.18%20InflationReductionAct_Factsheet_Final.pdf (2022).

2. Howarth, R. W. & Jacobson, M. Z. How green is blue hydrogen? *Energy Sci Eng* **9**, 1676–1687 (2021).

3. Bauer, C. *et al.* On the climate impacts of blue hydrogen production. *Sustainable Energy & Fuels* **00**, 1–10 (2021).

4. Mac Dowell, N. *et al.* The hydrogen economy: A pragmatic path forward. *Joule* **5**, 2524–2529 (2021).

5. IEA. *Global Methane Tracker 2022*. https://www.iea.org/reports/global-methane-tracker-2022 (2022).

6. Joint Organisations Data Initiative (JODI). *Gas World Database*. https://www.jodidata.org/_resources/files/downloads/gas-data/GAS_world_NewFormat.zip (2022).

7. Alvarez, R. A. *et al.* Assessment of methane emissions from the U.S. oil and gas supply chain. *Science* eaar7204 (2018) doi:10.1126/science.aar7204.

8. Rutherford, J. S. *et al.* Closing the methane gap in US oil and natural gas production emissions inventories. *Nat Commun* **12**, 4715 (2021).

9. Lauvaux, T. *et al.* Global Assessment of Oil and Gas Methane Ultra-Emitters. *Science* **561**, 557–561 (2022).

10. Meili, C., Jungbluth, N. & Bussa, M. *Life cycle inventories of crude oil and natural gas extraction*. (2021).

11. Bussa, M., Jungbluth, N. & Meili, C. *Life cycle inventories for long-distance transport and distribution of natural gas*. (2021).

12. Foulds, A. *et al.* Quantification and assessment of methane emissions from offshore oil and gas facilities on the Norwegian continental shelf. *Atmos. Chem. Phys.* **22**, 4303–4322 (2022).

13. Pettersen, J. *et al.* Blue hydrogen must be done properly. *Energy Science & Engineering* ese3.1232 (2022) doi:10.1002/ese3.1232.

14. Equinor. Greenhouse gas and methane intensities along Equinor's Norwegian gas value chain. at (2021).

15. IEA. Methane Tracker 2021. https://www.iea.org/reports/methane-tracker-2021 (2021).

16. Burns, D. & Grubert, E. Attribution of production-stage methane emissions to assess spatial variability in the climate intensity of US natural gas consumption. *Environ. Res. Lett.* **16**, 044059 (2021).

17. IEA. *Hydrogen Projects Database*. https://www.iea.org/data-and-statistics/data-product/hydrogen-projects-database (2022).

18. Smith, E. *et al.* The cost of CO2 transport and storage in global integrated assessment modeling. *International Journal of Greenhouse Gas Control* **109**, 103367 (2021).

19. Staiß, F. *et al.* Optionen für den Import grünen Wasserstoffs nach Deutschland bis zum Jahr 2030. 128.

20. Rödl, A., Wulf, C. & Kaltschmitt, M. Assessment of Selected Hydrogen Supply Chains—Factors Determining the Overall GHG Emissions. in *Hydrogen Supply Chains* 81–109 (Elsevier, 2018). doi:10.1016/B978-0-12-811197-0.00003-8.