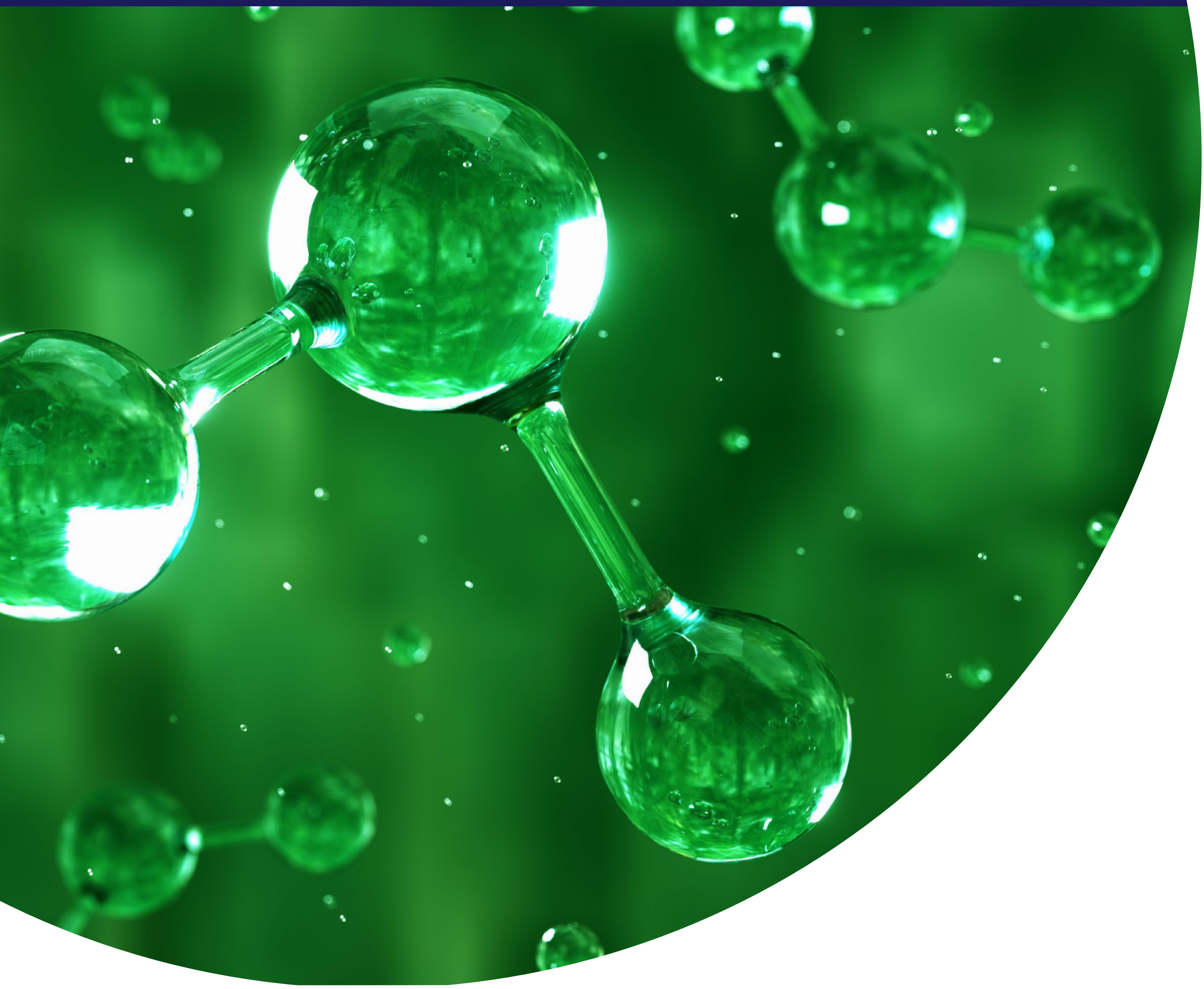
# A guide to 1.5°C-aligned hydrogen investments

## Practical steps to integrate 1.5°C criteria into investment decisions for hydrogen



# A word from our members

*WBCSD's report on how to align hydrogen investments with a 1.5 pathway sets an ambitious and pragmatic way forward for us all to reduce the full lifecycle emissions of hydrogen production towards net zero. This is paramount for hydrogen to deliver its vital role in the energy system of the future. At Shell, we are committed to being a net-zero company by 2050 and are actively investing in Hydrogen, such as at our Rheinland refinery or Holland Hydrogen I. We are considering how to include the proposed 1.5 aligned criteria in our decision-making process for hydrogen investments. We also recognize that the energy transition will require different solutions through 2050 and across various geographies. We thank WBCSD and all the member companies who shaped this report for such a clear and practical piece of work."*

**Harry Brekelmans**
Project and Technology Director, Executive Committee member, Shell

*"Arcadis has been heavily involved and a strong sponsor within the WBCSD Hydrogen working groups, supporting the workstreams of "1.5 aligned hydrogen investments" to support the adoption of Hydrogen with the lowest possible carbon intensity across the industry. With European Energy security challenges and rising fossil fuels costs contributing to the cost-of-living crisis, supporting the rapidly accelerating hydrogen sector is essential for decarbonizing our industries and averting our reliance on fossil fuels."*

**Peter Oosterveer**
CEO, Arcadis

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# Executive summary

In a net-zero carbon emissions world in 2050, hydrogen will meet a significant portion of global energy demand, ranging from 5% to 22%, according to different organizations.[1] Therefore, the world will require several times the quantities produced today and companies will need to produce it in a much less carbon-intense manner. Modeling shows that meeting this demand will happen through two main hydrogen production pathways: water electrolysis powered by renewable energies (otherwise known as green hydrogen) and natural gas reforming with carbon capture and storage (CCS) (otherwise known as blue hydrogen). Both will result in low levels of emissions. However, no one knows how low these levels need to be in a world where the climate's warming is kept to 1.5°C above pre-industrial levels.

Various countries and regions have defined carbon-intensity thresholds for hydrogen production to be labeled as "low-carbon" or "clean".[2] These definitions incentivize companies to meet those thresholds from the start of production and over the project's life cycle.

While such intensity thresholds provide a helpful framework to guide investments in different hydrogen production techniques, in a 1.5°C-aligned scenario, it is ultimately necessary to reduce the full life-cycle[3] emissions of an asset, not only the emissions related to its operation. Except for specific bio-based hydrogen production pathways that can reach net-zero or negative carbon emissions (meaning constitute additional carbon removals), no production pathway can produce hydrogen with zero emissions on a life-cycle basis. Additional emissions occur due to the downstream storage and distribution of hydrogen to the end-user that companies could neutralize by purchasing and retiring high-quality removal credits.

There is a lot of debate about the carbon intensity of the various hydrogen production methods (the "colors"). The main elements contributing to their carbon intensity are as follows:

- For hydrogen from electrolysis powered entirely by renewables (green hydrogen), emissions are low and stem mainly from capital expenditures (CAPEX)[4] (often referred to as infrastructure emissions), meaning they occur during the manufacturing of the assets used for power generation. Estimates show CAPEX emissions will go down as the grids of the manufacturing countries decrease their carbon intensity. Small residual emissions will remain, which companies can neutralize through equivalent high-quality carbon removals.
- For new natural gas-based hydrogen with CCS (new blue hydrogen), technologies exist that could enable a relatively low starting carbon intensity. Additional carbon-intensity reduction measures could allow those technologies to decarbonize further, enabling this hydrogen production method to reach a net-zero intensity. Such technologies look promising at the design stage but there has been no implementation at scale.

| |
|---|
| Decarbonizing all of today's hydrogen made from unabated fossil fuel would save nearly 1 gigatonne (Gt) of carbon dioxide equivalent ($CO_2e$) a year – or 2% of global emissions. |

- For existing[5] facilities producing hydrogen from the unabated reforming of natural gas (grey hydrogen), pathways exist to decarbonize the means of existing production (meaning transform it into lower-carbon hydrogen). However, some of those pathways require expensive retrofitting and depend on sustainable biomethane availability and carbon intensity.
- Hydrogen is also produced with numerous other (existing or developing) technologies. It includes yellow hydrogen – hydrogen production from electrolysis from grid-connected power; pink hydrogen – electrolyzers connected to nuclear power; or gasification of waste combined with CCS. Appendix 2 provides more details about their carbon intensity.

The decarbonization potential through **new uses** (ground mobility, aviation, maritime, industrial feedstock, power) of hydrogen could reach 730 million tonnes per annum (mtpa) of carbon dioxide ($CO_2$) abated by 2030 and a cumulative 50 Gt by 2050.[6]

Criteria will help companies and their investors understand whether a particular hydrogen project (or portfolio of projects) is indeed aligned.

**In our view, alignment with a 1.5°C scenario for hydrogen requires:**

- **A rate of decarbonization (of life-cycle emissions associated with hydrogen) in line with the International Energy Agency's (IEA) Net Zero Emissions scenario curve,[7] reaching net-zero life-cycle carbon emissions in 2050;**
- **Using hydrogen to decarbonize sectors where alternatives are not available, ill-suited to the use or less efficient;**
- **Respecting two redlines for natural (fossil) gas-based hydrogen – no reliance on new (meaning greenfield) fossil fuel exploration[8] or fossil fuel subsidies.**

We call on companies making hydrogen investments today and those who finance them to add "alignment with 1.5°C" criteria to investment decisions in addition to the usual investment (meaning financial and economic) criteria, with concrete actions such as:

- Map how they can reduce the full life-cycle carbon intensity (CI) of their hydrogen investments over time to reach net-zero emissions in 2050 and plan to invest in those CI reduction measures throughout the life cycle of their projects;
- Decarbonize existing grey hydrogen units in line with the global decarbonization required to meet a 1.5°C scenario;
- Deploy new hydrogen production with the lowest possible carbon intensity as a starting point;
- Respect IEA and WBCSD's redlines for blue hydrogen;
- Invest in greenhouse gas (GHG) emissions reduction measures to ensure those investments have net-zero emissions in 2050.

We also call on policymakers to create support mechanisms that would preferentially reward projects aligned with a 1.5°C scenario and reach net-zero emissions in 2050.

Users of hydrogen should ask companies to source hydrogen of the lowest possible carbon intensity and that the production and distribution of this hydrogen be on a decarbonization trajectory in line with a 1.5°C scenario and respect the two redlines above.

Note that this is a first step for the hydrogen sector to define alignment with 1.5°C and what it means to be net zero. We welcome further collaboration to deepen this topic.

Full definitions of the terms used in this report and background information about the life-cycle carbon intensity of various hydrogen production pathways are available in Appendix 1.

# 1. Introduction

## Why this report?

Various normative scenarios, such as the International Renewable Energy Agency's (IRENA) Energy Outlook and the International Energy Agency's (IEA) Net Zero Emissions (NZE) by 2050 scenarios, estimate that hydrogen will be required to meet 12-13% of final energy demand in 2050[9] to decarbonize the energy system. Hydrogen technologies are broad and both scenarios mainly see a mix of hydrogen produced from natural gas with carbon capture and storage (CCS) ("blue") [10]or electrolysis connected to renewable electricity ("green") meeting this demand (for more detailed information about the different colors of hydrogen, please see Appendix 2). It will primarily happen in sectors where alternatives are limited, such as fertilizers, chemicals, steel production and heavy industry. The aim is for hydrogen to complement but not compete with electrification, which decarbonizes more efficiently.

Because society needs to reach net-zero emissions in 2050, it is paramount to **understand the life-cycle greenhouse gas (GHG) emissions of the hydrogen technologies deployed today and how they remain aligned with a 1.5°C scenario through time**. The infrastructure deployed in the coming years will likely still be in use in 2050, potentially creating GHG-emitting legacy assets.

Sometimes hydrogen is referred to as **"zero carbon"**. This terminology is, however, inaccurate. It usually means that hydrogen use does not emit $CO_2$. Yet, nearly every technology that produces and transports hydrogen has a life-cycle carbon intensity above zero.

We show how to make the various hydrogen production pathways consistent with a 1.5°C scenario and what it will take to ensure that the hydrogen sector truly has net-zero emissions in 2050. This report represents an **investment guideline based on carbon intensity**. The intention is not to create a standard or precise method (like the best-known and widely used one from the Science Based Targets initiative – SBTi) but rather to spark forward-thinking when making hydrogen investments. All companies involved in the hydrogen sector, investors and policymakers alike can refer to the carbon-intensity reduction pathway examples presented in this report to **decide how best to align their investments with a 1.5°C scenario**. It will help to design the infrastructure, energy systems, policies, incentives and business plans that will take the hydrogen economy on a path to net-zero emissions in 2050.

## What kind of hydrogen does society need to become net zero in 2050?

The contribution of hydrogen to achieving net-zero emissions in 2050 is a huge challenge[11] considering the need to increase hydrogen production to 5-8 times current levels with very few emissions from its production and distribution to users. It is essential to bring data and science to the evolving hydrogen economy to help make decisions that take society closer to a net-zero energy system in line with a 1.5°C scenario.

**We believe that a wide range of technologies is needed to deploy hydrogen at the scale required to meet the energy demand of a net-zero world in 2050. It is essential to understand the level of emissions of the various hydrogen technologies and how best to reduce them to the lowest possible level rather than limit options by excluding some production pathways outright.**

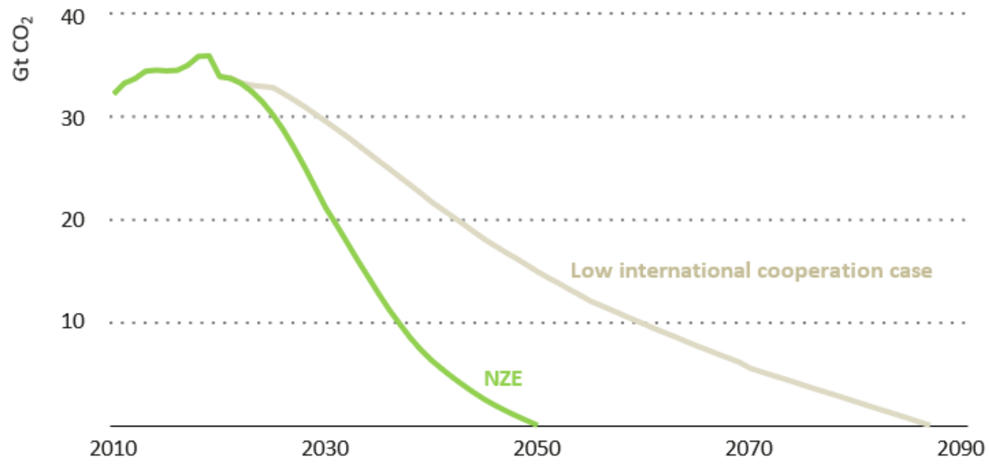
So far, policymakers and companies have focused on **determining a carbon-intensity threshold** that would qualify hydrogen as low-carbon, clean or equivalent terminology. While this is a helpful and necessary step in the short-term to ensure a reasonable starting point for new hydrogen production, it will not be sufficient in the long-term to ensure that the hydrogen sector will achieve net-zero emissions in 2050.[12]

**This guide defines what it means for hydrogen projects to be aligned with a 1.5°C scenario. It illustrates how various production (and distribution) pathways can align through carbon-intensity reduction measures, eventually reaching a net-zero state (whether at a project, portfolio or company level) in 2050.**

# 2. What does it mean to be aligned with a 1.5°C scenario?

We have explored several normative scenarios, such as the International Energy Agency's (IEA) *Net Zero Emissions (NZE) by 2050* scenario,[13] IRENA's *World Energy Transition Outlook*,[14] and *the 1.5°C Required Policy Scenario* (RPS).[15]

**Figure 1: Global energy-related $CO_2$ emissions in the net-zero pathway and low international cooperation case**




Note: Gt = gigatonnes.

*Source: IEA*[16]

While those scenarios are not explicit about the carbon intensity of hydrogen between now and 2050, all forecast that hydrogen will play a significant role in meeting energy demand[17] and all with the lowest possible carbon intensity. The IEA scenario also charts the rate of decarbonization required to reach net-zero emissions in 2050. We then refer to this curve to illustrate the emissions reduction down to net zero for hydrogen.

There are alternative ways a company can use to align with an emissions-reduction curve down to net-zero emissions. For example, the Science Based Targets initiative (SBTi) has developed a methodology based on several approaches: a carbon budget method, an absolute emissions contraction approach, and a sectoral decarbonization approach. To approve companies' targets, SBTi requires that "companies reduce their emissions by 90-95% by 2050, then use carbon removals to neutralize any limited emissions that cannot yet be eliminated."[18] There is, however, no guidance or sectoral decarbonization pathway yet available that details what it means for individual hydrogen projects or the entire sector to be aligned with a 1.5°C scenario.

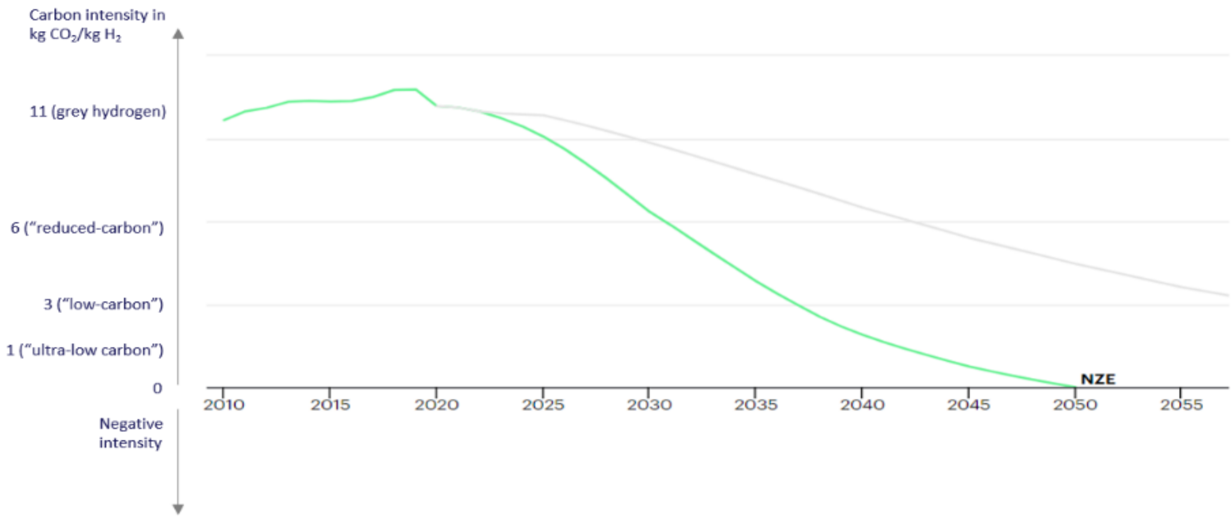
Inspired by both the IEA NZE scenario and SBTi framework, we therefore, propose three high-level principles for the hydrogen sector to be aligned with 1.5°C:

- **Follow a rate of decarbonization in line with the IEA NZE curve, reaching net-zero life-cycle carbon emissions in 2050;**
- **Use hydrogen to decarbonize sectors where alternatives are not available, ill-suited to the use or less efficient;**
- **Respect two redlines for natural (fossil) gas-based hydrogen: no reliance on new (meaning greenfield) fossil fuel exploration[19] or fossil fuel subsidies.**

## A decarbonization rate consistent with the IEA NZE curve

We propose an approach similar to SBTi's sectoral decarbonization method, which uses intensity targets (even though hydrogen spans several sectors, as mentioned previously) and is based on the IEA NZE curve displayed below.

**Figure 1: How the global emissions curve should evolve to achieve net-zero in 2050**




*Source: Based on IEA[20]*

Here are the steps to build this approach:

- We use the **IEA NZE emissions scenario**, in particular the global emissions curve, to show how it should evolve to achieve net-zero emissions in 2050.
- Instead of the global GHG emissions on the Y-axis, we **overlay the carbon intensity of hydrogen**, matching the current existing grey hydrogen intensity (about 11 kg $CO_2e$/kg $H_2$) with the starting plateau around 2020.[21]
- We then chart the life-cycle[22] carbon intensity of the specific hydrogen project under consideration (or portfolio of projects, see section 3) and **investigate how to ensure its intensity curve follows the same shape or stays below the IEA net-zero curve through the project's lifetime.**

Companies can achieve carbon intensity reductions through various reduction measures (as detailed in the following chapters on grey, blue and green hydrogen). However, reaching net-zero emissions requires, in many cases, the use of removals (or neutralization offsets). While at this stage, we do not give specific recommendations about when to use offsets,[23] it is indeed critical that companies reserve them for the last residual emissions and make every effort to reduce emissions to the lowest possible level as a priority.

This report does not include quantitative economic assessments of carbon reduction measures because those processes exist within companies before making an investment decision.

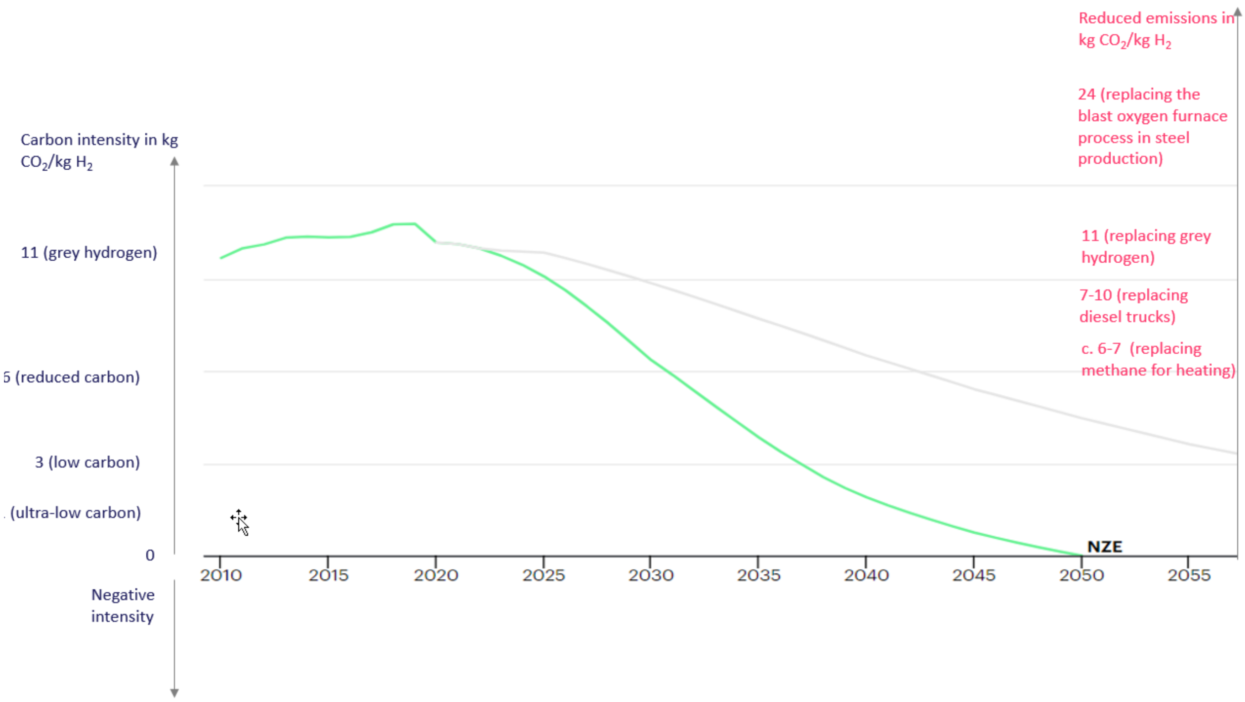
## Using hydrogen for efficient decarbonization

To determine the overall decarbonization potential of hydrogen, we need to look at the end use, in addition to its production. Outside of its use as a feedstock in the refining, fertilizer and chemicals sectors, the purpose of increasing the deployment of hydrogen is to decarbonize hard-to-abate and carbon-intense sectors. It includes steel, high-temperature heat in industry and heavy-duty mobility. It can also eventually provide long-term energy storage in a renewable-based energy system.

Companies must deploy decarbonized hydrogen as a priority[24] in sectors with no viable alternative to ensure that it does not compete with other decarbonization options, such as electrification, that are available, suited to the end-users and more efficient.

To map the estimated reduction level of carbon emissions by using hydrogen on the same curve as above, we add a second Y-axis to show how much $CO_2$ every kg of hydrogen prevents when used in various applications.

**Figure 3: Reduced emissions based on hydrogen application**




*Source: Based on IEA[25]*

Note that different uses of hydrogen will lead to different $CO_2$ reduction quantities. Without considering the intensity of hydrogen itself, which needs to be subtracted to get the net level of emissions, every kg of hydrogen used[26] reduces:

- Around 24 kg of $CO_2e$ in steel production by replacing the blast oxygen furnace (BOF) process with direct reduction of iron (DRI) using hydrogen and an electric arc furnace;
- Around 14 kg of $CO_2e$ when replacing shipping fuel (using hydrogen as ammonia);
- Around 12 kg of $CO_2e$ when replacing coal for high-temperature heat;
- Around 11 kg of $CO_2e$ when replacing hydrogen from steam methane reforming (SMR) (grey hydrogen) in the refining, fertilizer and chemical sector;
- Around 7 kg of $CO_2e$ when replacing natural gas for high-temperature heat.

**With this approach, the total decarbonization a specific project achieves is the area between its carbon intensity and the reduction of emissions by its use.**

Showing the emissions reduction potential from an end-use perspective helps understand how hydrogen contributes to decarbonizing carbon-intensive energy vectors. Still, the carbon intensity reduction is insufficient to indicate that a project is aligned with a 1.5°C scenario. It is also likely to evolve in time as new technologies mature.

**Please note that we do not suggest that the producer should account for the delta (difference) between the alternative energy vector and the carbon intensity of hydrogen** – as the end-use sector would already account for those in its own decarbonization. It is simply an illustrative and easy visual way to show the decarbonization potential using hydrogen, even when this hydrogen itself has a carbon intensity above zero.

## Energy transition redlines

Finally, because we remain technology-neutral and focus on achieving the lowest possible carbon intensity, it is essential to introduce guard rails regarding the use of fossil fuels. To ensure the effective reduction of emissions by 2050, we support certain "redlines" that help society move to a net-zero carbon emissions energy system:

- According to the IEA NZE scenario, **no new (greenfield) exploration for fossil fuel (gas)** resources.

  The IEA states that: "No fossil fuel exploration is required in the NZE scenario as no new oil and natural gas fields are required beyond those that have already been approved for development."[27] Therefore, to align with a 1.5°C scenario, companies would be required to "prove" that they did not derive hydrogen from natural gas from newly explored and developed fields.

  In practice, this could not be easy to prove. A few solutions could help:

  - Trace the origin of natural gas through guarantees of origin or certificates, which could also carry other attributes, such as the carbon intensity;

    - Source hydrogen from producers that have committed to not undertaking greenfield exploration;
    - Including contractual clauses to guarantee the origin of the hydrogen purchased;
    - Implement regulations that prevent the use of gas extracted from newly explored fields or new greenfield exploration.

- **The removal of fossil fuels subsidies** – following WBCSD's Vision 2050 report[28]
  WBCSD has long advocated for removing fossil fuel subsidies to transform the energy system and achieve net-zero emissions. In practice, this can be done when designing the project or by including contracting clauses avoiding the purchase of any fossil fuel hydrogen production above a certain carbon intensity. We do not consider supporting carbon capture and storage (CCS) as a fossil-fuel subsidy unless it actively incentivizes new oil and gas exploration because its deployment is a vital transitionary mitigation method in most net-zero emissions pathways. This is because it will help to decarbonize the still-considerable quantity of hydrocarbons in proven reserves.

# 3. Existing (grey) hydrogen

The most straightforward starting point is to look at existing grey hydrogen. Indeed, since it already exists – the refining, fertilizer and chemical sectors use about 90 million tons per annum (mtpa),[29] emitting nearly 1 Gt or 2% of global $CO_2e$ emissions – we therefore argue that its decarbonization should happen in line with the IEA NZE curve.

**It is essential to decarbonize existing uses of grey hydrogen on a consistent 1.5°C pathway and to not make any "new" hydrogen with this level of carbon intensity.**

For simplicity, we refer mainly to steam methane reforming (SMR) using methane or biomethane as feed. However, it is worth noting that by design, SMR units accept a wider feedstock, such as LPG, naphtha and equally light biobased feedstock or synthetic fuels (which are alternative feedstocks and can have a low-carbon intensity).

**Table 1: Typical make-up of the carbon intensity of grey hydrogen[30]**

| Technology | CI in kg $CO_2e$/kg $H_2$ | Comments |
|---|---|---|
| **Upstream emissions:**<br>**- Gas extraction, processing**<br>**- Methane leakage**<br>**- Transport (compression and pipeline or liquefaction and shipping as LNG)** | 1.2 UK gas mix<br>2.7 US gas mix<br>3.2 if LNG is used as the feedstock in the UK | As the application is hydrogen, we have calculated upstream gas intensity per kg of hydrogen (it would otherwise normally be expressed per kg natural gas). |
| **Stream methane reforming** | About 9-10 (for the SMR process on its own) depending on the design and feed of the SMR unit | This figure is for net emissions and includes credit for steam export from the SMR unit. Note that carbon intensity (CI) increases with the use of heavier hydrocarbons (LPG, naphtha) as feed. |
| **Storage, transport, and distribution** | Negligible if the SMR unit is located at the use point (e.g., in a refinery or fertilizer plant) | Most grey hydrogen is produced at the point of consumption. |

Source: Element Energy[31] and KBC[32]

Looking at an existing SMR unit, several options exist to lower its carbon intensity.

**Table 2: Options to lower the carbon intensity of an existing SMR unit**

| Decarbonization measure | Reduction of CI kg / kg | Comments |
| --- | --- | --- |
| **Reducing upstream carbon intensity (methane leakages) by 1%, e.g., from 2% to 1%** | 0.9 | Based on the 100-year global warming potential of methane, per the GHG protocol.<br><br>Note some companies have committed to keeping methane leakage well under 1%.[33] |
| **SMR efficiency measures such as: using 100% methane feed, minimizing reforming furnace stack exit temperature, reducing reformer feed steam-to-carbon ratio, and reconfiguring the heat exchanger network to recover more waste heat** | About 1.3 if all best available technologies (BAT) used for a typical SMR unit | In reality, only some of the BAT would likely be implemented. In the example below, we used 25% of this number to be realistic. |
| **Electrification of SMR** | Unknown | In theory, it will be possible to electrify future SMR units, thereby decreasing their carbon intensity if fed from renewable power. However, since this would apply to newly designed SMRs units and our focus is on existing installations, we have not considered this option. |
| **CCS – pre-combustion capture (achieving overall 60% to 70% of total $CO_2$ capture and storage)** | c. 5 | The capture and storage process itself requires some energy. The carbon removal from the effluent stream itself is assumed to be 95% (with a possible linear progression to 97% by 2050 in a BAT case). Because some additional $CO_2$ is released post-combustion, the total capture from pre-combustion technology is 60% to 70% of total emissions (when including a low-temperature (LT) shift reactor to maximize carbon conversion and, therefore, $CO_2$ capture).<br><br>As a real-world example, the Air Products plant (designed as a CCS pilot project rather than a blue hydrogen project) at Port Arthur achieves a 60% capture rate.[34] |
| **CCS –post-combustion capture (achieving overall about 90%-92% of total $CO_2$ capture and storage)** | c. 7 | Note that a real plant has not yet shown this capture rate, so the rate might be more applicable to a new plant. In addition, retrofitting such technology to an existing asset could be uneconomical. |
| **Using biomethane – for example 30% of feedstock**<br><br>**Examples:** | | These numbers depend heavily on:<br><br>- The upstream methane emissions of the fossil gas that the biomethane is replacing; |

| | | |
|---|---|---|
| **- Biomethane with CI of 26 g $CO_2$e/MJ (high case in the Zemo survey)**<br><br>**- Biomethane with a CI of 17 g $CO_2$e/MJ (central case in the Zemo survey[35])** | 1.5<br><br>1.8<br><br>Possibility of achieving greater reductions with greater % of biomethane in feedstock | - The upstream methane emissions associated with biomethane production and distribution;<br><br>- The source of biomethane.<br><br>In this report we use an inventory accounting method (e.g., attributional approach) to estimate the carbon intensity of biomethane, but not intervention accounting.<br><br>Using intervention accounting methods can lead to biomethane with a negative CI and much higher CI reductions. More details in Appendix 1. |
| **Replacing (some) grey with green hydrogen (e.g., electrolyzer collocated in a refinery or fertilizer plant)** | Proportional to % green hydrogen used | Some refineries are launching pilot projects to decarbonize (part of) their grey hydrogen consumption with green hydrogen, for example bp's Lingen (Germany)[36] refinery, Shell's Rheinland (Germany)[37] and Pernis (Netherlands)[38] refineries.<br><br>Equally, companies in the fertilizer sector are developing pilot projects, such as Iberdrola's Puertollano project[39] with Fertiberia.<br><br>Note that those projects currently do not have the scale to meet all the hydrogen needs of the refinery. |
| **Remove any residual emissions in 2050 via neutralization offsets** | As required to reach net-zero (only after exhausting all direct reduction measures) | Assuming the SMR unit is still in operation, which may not be the case (could be replaced with better technology at end of life, which will likely be before 2050 if it is already in existence today). |

**Error! Reference source not found.** illustrates a pathway for an SMR unit to reduce its carbon intensity in a way that follows the IEA NZE emissions reduction curve, meaning that this grey hydrogen "transforms" into blue hydrogen or other less carbon-intense types of hydrogen.

We make the assumption that there is no significant use of grey hydrogen for "new" applications that aim to decarbonize other energy vectors (e.g., steel, heavy-duty mobility, high-temperature heat, etc.) and therefore do not include in this section the decarbonization potential curves (for example, in this case the lower carbon hydrogen obtained is decarbonizing its former grey self).

EXAMPLE - SMR + pre-combustion CCS

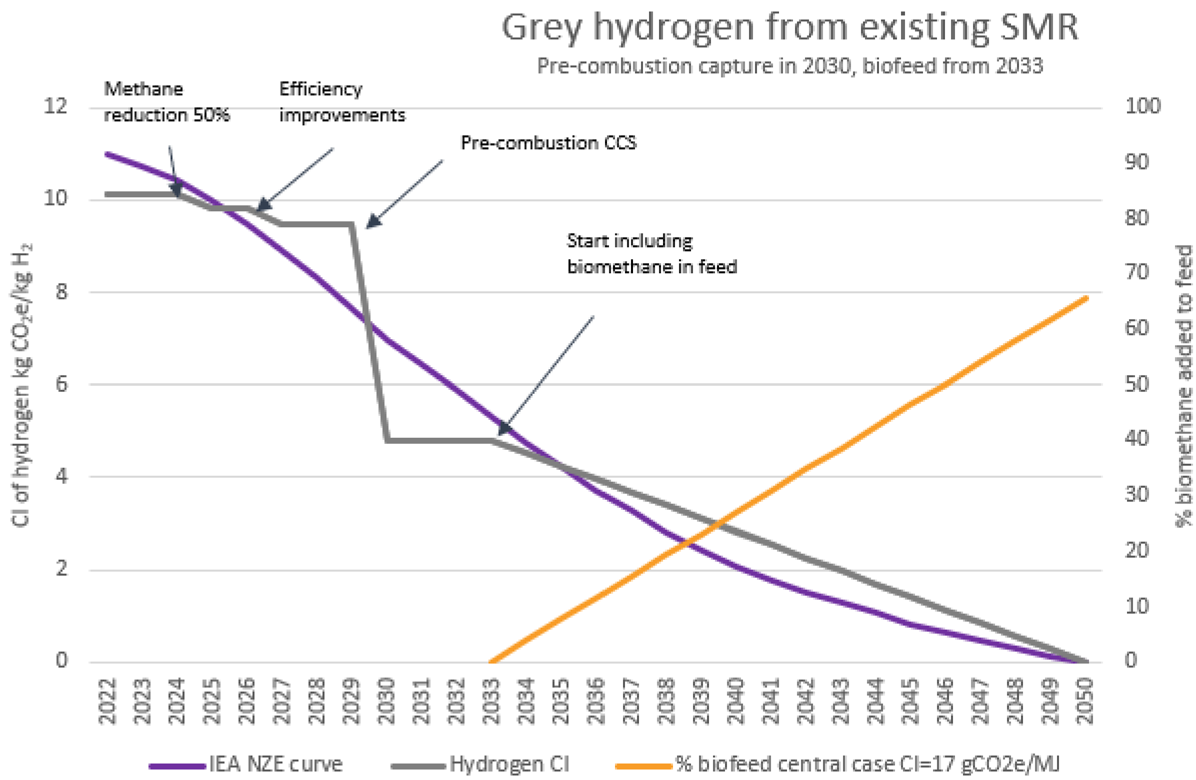
To illustrate this with a possible (but theoretical) example

- Base case in 2022:
    - Upstream gas with a CI of 0.47 kg $CO_2e$/kg $CH_4$,[40] corresponding to about 1.35[41] kg $CO_{2e}$/kg $H_2$, including 0.73% methane leak rate (UK gas mix – i.e., a realistic and not best-case assumption; however, methane leaks could also be higher)
    - SMR unit in the UK with a CI of 10.3 kg $CO_2e$/kg $H_2$ [42]
    - No emissions from distribution (the grey hydrogen is used on a site in a refinery or fertilizer plant, for example)
    - Starting intensity = 10.1 kg $CO_2e$/kg $H_2$[43]

- Application of the following CI reduction measures (dates are notional)
    - Reduction of methane leakages from 0.73 to 0.36% (0.3 reduction in hydrogen CI) in 2025. This would occur gradually over a period as the company identifies and controls leaks rather than at a specific date). Again, this is a realistic and not best-case assumption for methane leaks (some companies claim to achieve significantly lower levels than this).
    - Implementation of 25% of best available technology (BAT) measures to increase efficiency in 2027: CI reduction of 0.4 kg $CO_2e$/kg $H_2$.
    - Implementation of pre-combustion capture (60% of total emissions, i.e., the carbon in feed and fuel) CCS in 2028: CI reduction of = 4.9 kg $CO_2e$/kg $H_2$[44]
    - Introduction of biomethane to gradually reach net zero in 2050
        - Using the central case mix with an intensity of 17 g $CO_2e$/MJ in the SMR feedstock, starting in 2031 with 4% and increasing to 69% in 2050: gradual CI reduction of up to 4.7 (reaching net zero).
        - If more biomethane is incorporated and the biomethane pathway includes carbon removals (either technological or natural), there is a potential to reach net-negative emissions.)

Note that the same example using a more carbon-intense upstream gas mix (such as in the US) would require mixing biomethane with the feed a little earlier (1 or 2 years) and more biomethane to reach net zero in 2050. **Error! Reference source not found.** presents this pathway.

**Figure 4: Grey hydrogen from existing SMR**




Appendix 2 provides the assumptions used to build this graph.

In terms of volumes of biomethane required, if the SMR unit above produces 100 kilo tons per annum (ktpa) of hydrogen a year, 69% of the feed would represent 195 ktpa of biomethane, with a biomethane carbon intensity (CI) of 17 g $CO_2$e/MJ (central case).

By using intervention accounting methods (the consequential approach that compares emissions from a counterfactual scenario, which can result in negative CI), a lower CI for hydrogen is reached and thus lower volumes are required, for example with the Zemo survey low-case biomethane CI (20 g $CO_2$e/MJ) reaching net zero would require only 37% of this biomethane in the feed – or about 105 ktpa. The use of interventional accounting methods is common in policymaking and for decision-making for companies to define their net-zero strategy. They report CI calculated using intervention accounting methods separately from the scopes, according to GHG Protocol standard reporting and do not include them in corporate Scope 1, 2 and 3 inventories.

In Appendix 3 we also present a similar case with post-combustion CCS implemented (a much higher proportion of $CO_2$ captured and stored), which requires 16% of the central case biomethane to reach net zero (and 9% for the low-case biomethane with CI=-20 g $CO_2$e/MJ).

We also present a global modelling, which shows that if all of today's grey hydrogen units are still in operation by 2050[45] (producing 93 mtpa of hydrogen) and if they are all gradually fitted with pre-combustion CCS starting now, by 2050 they would require about 181 mtpa of biomethane with a CI of 17 g $CO_2$e/MJ to reach net-zero emissions.

According to the IEA,[46] “more than 700 Mtoe [mega tonnes of oil equivalent] of biomethane [equivalent to about 600 mtpa] could be produced sustainably today, equivalent to more than 20% of global natural gas demand and by 2040 this potential grows to more than 1,000 Mtoe [or 870 mtpa] with a global average production cost of less than USD $15/MBtu [million British thermal units].” This means that if companies retrofit all SMR units with pre-combustion CCS, biomethane could meet the demand to decarbonize existing global grey hydrogen production (needing about 16% of global demand in biomethane for that purpose – and knowing that it’s unlikely all of today’s SMR units would still be in operation in 2050).

As a point of comparison, the *Future Energy Scenario* report[47] from National Grid ESO finds in its net-zero Systems Transformation scenario (note: UK only, not global) that the UK dedicates 17% of the total use of biomass to hydrogen production, producing 1 mtpa of hydrogen (compared to about 700 ktpa today). It in fact (in this scenario) contributes significantly[48] to generating negative emissions (meaning carbon removals) that help neutralize emissions from elsewhere in the energy system.

**In conclusion for existing grey hydrogen**

It is possible to reach net-zero emissions for an existing grey hydrogen unit by reducing methane leakages, retrofitting carbon capture, and mixing a significant share (a range between 17% and 66% depending on the carbon intensity of that biomethane and the CCS technologies used) of sustainably sourced biomethane with the feed. Recent IEA analysis[49] shows that the potential for biomethane is much larger than what is currently being produced and this would suggest that this pathway is feasible on a global scale. However, the implementation of carbon-intensity reduction measures such as CCS will require appropriate policies (such as a carbon price) to be economically viable.

Alternatively, if further CI reduction measures are not feasible and it is not possible to balance the emissions elsewhere in the system (such as at company or portfolio level) the company could shut down the SMR unit just when it “hits” the IEA curve.

Another alternative to lower the emissions of grey hydrogen would be to replace it with electrolytic low-carbon hydrogen (rather than try to transform it into blue hydrogen). For example, the Hydrogen Council[50] forecasts that by 2030, companies will “convert” 25 mtpa of grey hydrogen to green hydrogen.

In conclusion, a company could therefore map a pathway to lower the emissions of a grey hydrogen unit in line with a 1.5°C scenario and reach net-zero emissions in 2050 or decide when it needs to stop operating that unit based on carbon intensity (meaning when the unit, despite carbon-reduction measures, is no longer aligned with the 1.5°C trajectory).

# 4. New blue hydrogen

By "new blue" we mean purpose-built, new hydrogen production installations that will meet "new" demand or replace current grey hydrogen for decarbonization purposes – meaning not retrofitting an existing grey hydrogen installation (see section 3 on grey hydrogen for that case).

Various jurisdictions[51] have defined or are defining thresholds for the consideration of new blue hydrogen as "clean" or "low-carbon".

**Our view is that new blue hydrogen should be of the lowest possible carbon intensity** (for example, well under 3 kg $CO_2e$/kg $H_2$ (low-carbon) and closer to 1 (ultra-low carbon) **from the start and that it should also follow a path to reach net-zero emissions by 2050.**

In addition, it should respect the energy transition redlines we mention in section 2 and rely on already discovered gas reserves.

In this section, we focus primarily on new efficient technologies such as autothermal reforming (ATR) with high capture rate levels. We cover using SMR technology in section 3 on grey hydrogen, although new SMR designed from the start with a high CCS capture rate would likely be more effective than retrofitting old installations.

**Table 3: Carbon intensity make-up of (new) blue hydrogen, based on ATR technology[52]**

| Technology | CI in kg $CO_2e$/kg $H_2$ | Comments |
|---|---|---|
| **Upstream gas intensity** | 1.2 UK gas mix<br>2.7 US gas mix<br>3.2 LNG in the UK | As the application is hydrogen, we have calculated upstream gas intensity per kg of hydrogen |
| **ATR with 95% emissions capture and storage (unproven at scale), including upstream gas intensity above)**[53] | 2.0 (with typical UK gas mix)<br>3.5 (with typical US gas mix)<br>4.0 (when LNG is used as feedstock)<br>3.91 in Alberta, Canada based on relatively carbon intense grid mix and 91% capture[54] | Only by using best practices for the elimination of upstream methane emissions can blue hydrogen be a low-emissions option, regardless of the capture rate. |
| **Best case scenario (unproven at scale) – ATR with 98% capture** | 1.2 (e.g., Norwegian gas + pipeline[55] )<br>1.7 (with typical UK gas mix)<br>3.2 (with typical US gas mix)<br>3.7 (when LNG is used as feedstock) | |
| **Storage, transport and distribution – compressed hydrogen (diesel) truck** | 1.5 | Number from UK, most of those emissions are from diesel trucks, could be lower or higher depending on distance and mode of transport. |
| **Storage, transport and distribution – liquid hydrogen truck (diesel)** | 4.4 | Liquefaction of hydrogen represents close to 99% of those emissions. |

| | | |
|---|---|---|
| **Storage, transport and distribution – gas grid delivery** | 2 decreasing to 0.65 in 100% hydrogen pipelines | Deblending from a mixed gas grid requires energy (but in some case the mix $H_2/CH_4$ can be used directly). |
| **Fugitive hydrogen leaks** | Not yet assessed | As described in Appendix 1, it is essential that potential hydrogen leaks be kept to a minimum. |

### Table 4: Reductions in CI based on decarbonization option

| Decarbonization measure | Reduction of CI kg / kg | Comments |
|---|---|---|
| **Reducing upstream methane leakages, e.g., from 2% to 1%** | 0.9 | Uses the 100-year global warming potential of methane (per GHG Protocol).<br>Note some companies have committed to keeping methane leakage well under 1%.[56] |
| **Use, e.g., 30% biomethane as feedstock**<br>**Examples:**<br>**- Biomethane with CI of 26 g $CO_2$e/MJ (high case)**<br>**- Biomethane with a CI of 17 g $CO_2$e/MJ (central case)** | <br><br>1.9<br><br>2.4 | Those numbers depend heavily on:<br>- The upstream methane emissions of the fossil gas that the biomethane is replacing;<br>- The upstream methane emissions associated with biomethane production and distribution;<br>- The source of biomethane.<br><br>Note in this report we use inventory accounting (e.g., attributional approach) to estimate the carbon intensity of biomethane. Inventory accounting provides a complete assessment of the product life-cycle emissions. This is compliant with the GHG Protocol corporate and Scope 3 standard. Intervention accounting (also known as consequential approach), in contrast, is used to estimate GHG impacts of actions/products relative to counterfactual baseline scenarios or other performance standards. A number of regulations and jurisdictions use intervention accounting methods (i.e., estimate the carbon intensity of biomethane in relation to counterfactual scenarios) as a means to promote low-carbon fuels, including biomethane. Using intervention accounting methods can lead to biomethane with a negative CI and therefore to much higher CI reductions.<br><br>Also note that if the company uses this blue hydrogen mainly to replace natural gas (say for high-temperature heat in industry), it would be more efficient to use the biomethane directly as a replacement for |

| | | |
|---|---|---|
| | | natural gas. However, the ATR process does allow for the capture and storage of biogenic $CO_2$ in this case, so it may still be interesting on a CI basis. |
| **Sourcing fully renewable-based power for the ATR unit** | c. 0.3 | In the example above with a CI of 2 for an ATR unit in the UK, 0.3 corresponds to power for the plant. |
| **Emissions reduction during transport such as:**<br>**- From blended mix to 100% in pipeline**<br>**- Distribution as compressed hydrogen but with zero-emissions trucks** | Reduction of 1.35<br>Reduction of 0.3 to 0.4 | Going from 2 to 0.65 |
| **Remove any residual emissions in 2050 via neutralization offsets** | As required to reach net-zero emissions | Only after exhausting all direct reduction measures |

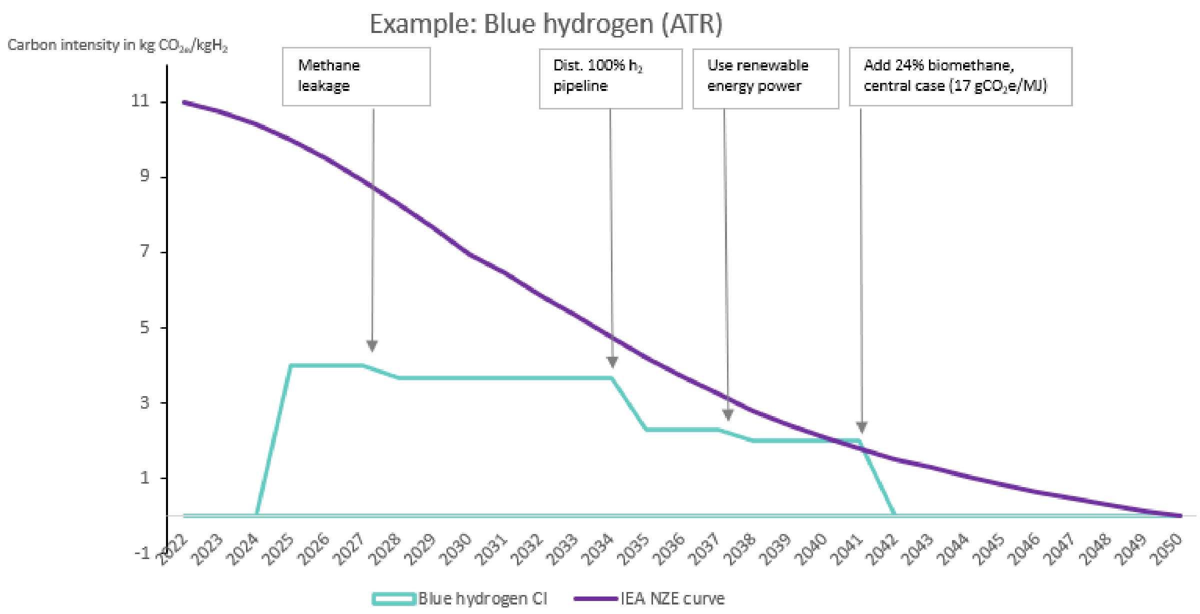
<u>EXAMPLE – ATR unit in UK</u>

To illustrate this with a possible (but theoretical) example:

- Base case in 2025:
  - Using upstream gas with a CI of 1.2 (upstream methane emissions at 0.73%), e.g., UK gas mix (i.e., a realistic and not best-case assumption; however, methane leaks could also be higher)
  - BAT ATR unit (capturing 98% of emissions) in the UK with a CI of 0.8 kg $CO_2$e/kg $H_2$ – this is a best available technology assumption
  - Distributed through existing gas grid with deblending: CI of 2
  - Starting life-cycle intensity in 2025: 4 kg $CO_2$e/kg $H_2$

- The following CI reduction measures are applicable (dates are illustrative)
  - 50% reduction of methane leakages from 0.73% to 0.36% (0.33 reduction in CI) in 2028 (in reality this would occur gradually over a period of time as the company identifies and controls leaks, rather than at a specific date) – again a realistic and not best-case assumption as some companies claim to achieve significantly lower levels of methane emissions.
  - Distribution through 100% dedicated pipelines in 2035: CI reduction of 1.35
  - Source fully renewable power for the plant in 2038: CI reduction of 0.3
  - Either:
    - We assume in this case biomethane is not available, therefore the remaining neutralization offsets required to reach net zero in 2050 are 2 kg $CO_2$e/kg $H_2$.
    - We assume biomethane with an intensity of 17 g $CO_2$e/MJ (central case) is available and we need to mix 24% in the feed to reach net-zero emissions. Using more would result in carbon removals and an overall net-negative system (e.g., 30% results in a -0.5 kg $CO_2$e/kg $H_2$ intensity). The company could also use this to neutralize any CAPEX/infrastructure emissions that might become more significant net zero comes closer.

**Figure 5: CI intensity change for blue hydrogen ATR example**

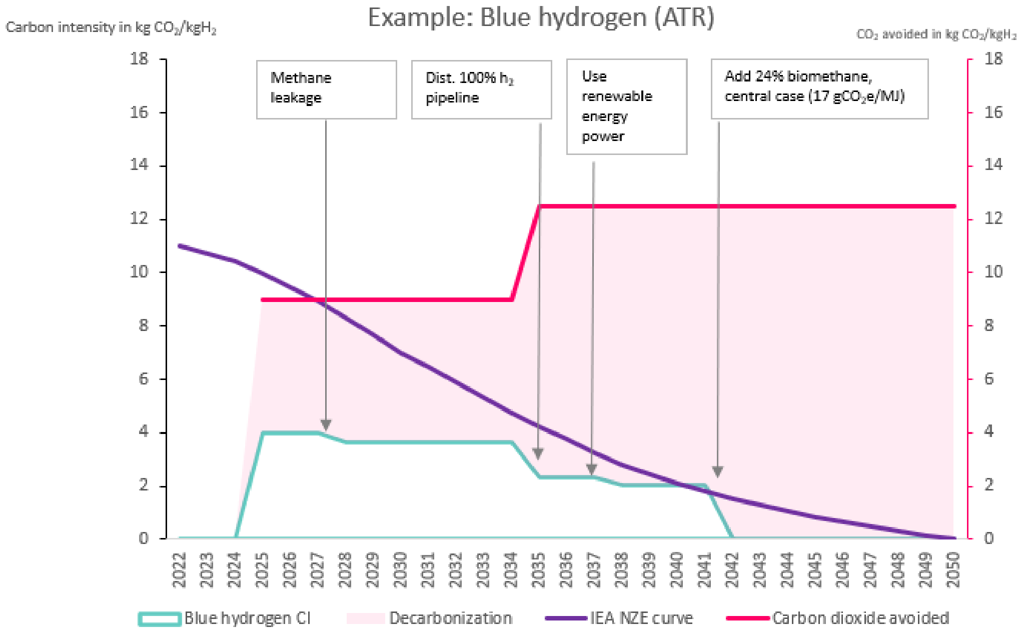



**Decarbonization potential**

To illustrate the decarbonization that achievable with the use of the hydrogen as described in Figure 6, we assume that:

- In the first 10 years of operation
    - Half the hydrogen is co-fired in a gas plant (avoiding c. 7 kg of $CO_2e$ per kg of $H_2$ used)
    - The other half replaces grey hydrogen (avoiding c. 11 kg of $CO_2e$ per kg of $H_2$ used)
    - Giving an average of 9 kg of $CO_2e$ avoided per kg of $H_2$ used or 1.8 mtpa $CO_2e$ avoided (gross) / year of operation (assuming this plant produces 200 ktpa hydrogen).
- In the following years of operation
    - Half the hydrogen is used to replace marine transport fuels (avoiding c. 14 kg of $CO_2e$ per kg of $H_2$ used)
    - The other half is used to replace grey hydrogen (avoiding c. 11 kg of $CO_2e$ per kg of $H_2$ used)
    - Giving an average of 12.5 kg of $CO_2e$ avoided per kg of $H_2$ used or 2.5 mtpa $CO_2e$ avoided (gross) / year of operation

**Figure 6: CI intensity change for blue hydrogen ATR example**




Various technologies exist for blue hydrogen, which can be mapped in similar ways.
One of the advantages of blue hydrogen (when it reaches very low levels of emissions as described above) is that it could produce very high volumes from the start.
A typical hydrogen plant of this kind may be able to produce about 200 ktpa of hydrogen per year. For comparison, the equivalent of the plant described above producing 200 ktpa of hydrogen would require an equivalent of about 2 GW of renewable electricity installed (this is more than 50% bigger than the current world's largest offshore windfarm, Hornsea 2, spanning 462 km2 or nearly 8 times the size of Manhattan) to produce the same amount of green hydrogen.

**In summary for new blue hydrogen**

Technologies exist today that would enable the production of blue hydrogen with very low emissions levels. It is possible to further reduce the remaining emissions, for example by using renewable power for the plant or mixing biomethane in feed, to reach net zero (or use neutralization offsets when those are not available). Companies would have to verify design promises in terms of carbon capture and methane leaks once in operation.

While blue hydrogen could deliver large volumes, there are, however, a number of drawbacks, such as the continued reliance on fossil fuels (and how to "prove" that the feedstock does not come from newly explored fields) and the possibility of methane leakages, which could significantly affect the carbon intensity.

# 5. Green hydrogen

Various scenarios model hydrogen from electrolysis powered by renewable electricity as the preferred hydrogen production pathway in 2050 and thus with the greatest production capacity. They often see it as the goal in terms of production methods because it is renewable and making it – by splitting a water molecule – does not emit $CO_2e$ nor greenhouse gases. Thus, its direct production is effectively carbon-free.

In this regard, it is worth noting that many jurisdictions and many methodologies consider the emissions associated with renewable electricity to be zero (meaning they do not include infrastructure emissions from generation assets). Therefore, green hydrogen is often called "zero-carbon". Our intention here is not to unfavorably represent green hydrogen but rather to take a full life-cycle and system approach to ensure that companies are eventually able to reach net-zero emissions on all emissions scopes. Indeed, on a life-cycle basis, there are infrastructure emissions from renewable generation assets, in particular solar panels whose manufacturing requires energy-intense processes often powered by coal-based grids. Given the decarbonization potential of hydrogen, this should not be seen as barrier today.

In addition, the carbon intensity of the solar panel manufacturing process will go down as manufacturing countries increase the share of renewables in their electricity mix. Green hydrogen with power from wind assets already has one of the lowest carbon intensities and this should also decline over time as the carbon footprint of steel manufacturing and mining goes down.

**Nonetheless, when the goal is to reach net-zero emissions through all emissions scopes (or the entire value chain), it is important to understand the full life-cycle emissions and therefore what actions to take to eventually reach net-zero emissions – even for green hydrogen.**

Given that for green hydrogen most of the GHG emissions come from the infrastructure, it is also worth noting that its decarbonization will likely require the efforts of the entire supply chain – not just the hydrogen producer. Some companies are already working to do so. For example, WBCSD member Iberdrola has joined the SteelZero initiative[57] and committed to procuring 100% net-zero emissions steel by 2050, sending a strong demand signal to the steel industry.

**Typical make-up of the carbon intensity of green hydrogen**

- Power generating assets

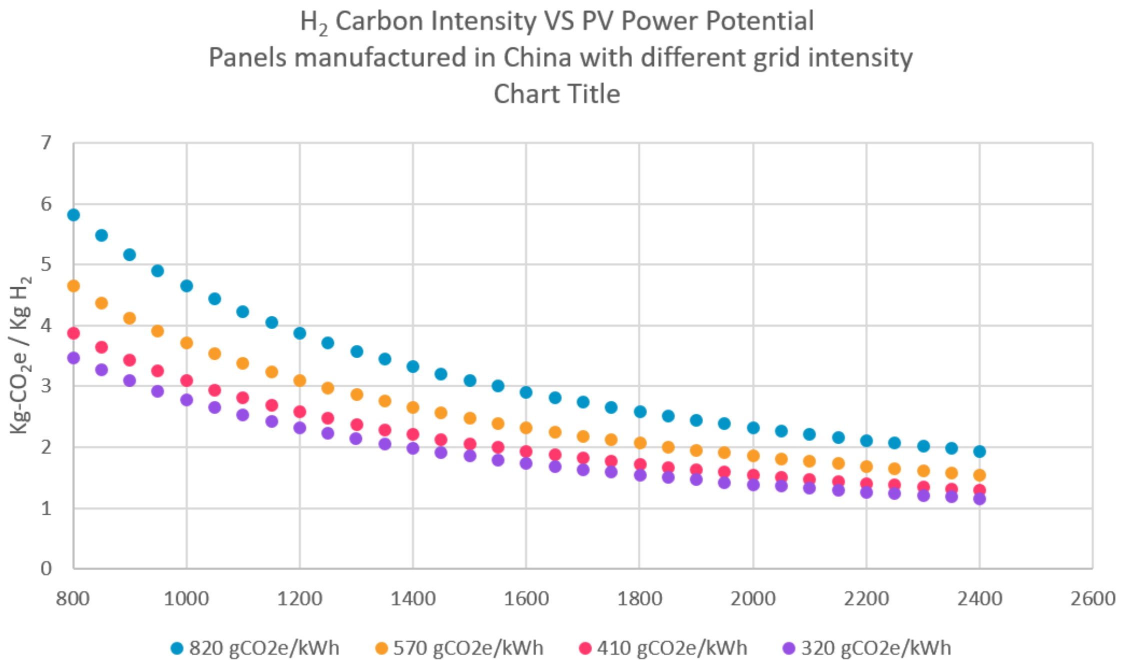
Most of the emissions from green hydrogen come from manufacturing the power generation assets: wind turbines, solar panels (and concrete for dams and methane emissions from the decomposition of flooded organic material for hydropower; however, as their amortization happens over a much longer lifespan, they result in the lowest intensities, so we do not cover them here).

- Solar power

The manufacturing of solar panels is an energy-intense process.[58] How the emissions from manufacturing will impact the carbon intensity of solar-based green hydrogen depends on:

  - the yield of the panel: it will be higher and therefore the carbon intensity lower in countries with higher solar radiation;
  - the carbon intensity of the energy used in the manufacturing process; Figure 7 illustrates how the grid carbon intensity of the manufacturing country affects the carbon intensity of hydrogen produced by solar panels located in areas with different photovoltaic (PV) power potentials;

**Figure 7: CI intensity change for blue hydrogen ATR example**




Note that Solar Power Europe and their partners are currently updating the photovoltaic carbon footprint estimation. The study's preliminary results seem to show a reduction of the PV carbon intensity that would lead to a diminished carbon footprint for hydrogen produced from solar power compare to the ranges displayed in Figure 7.

  - The lifetime of the panels (the longer the time to amortize those emissions, the lower the intensity; however, at some point, panel efficiency will decrease, resulting in a higher carbon intensity).

- Wind power

The assessment of the carbon intensity of renewable hydrogen from wind power is usually[59] around 0.6 kg $CO_2e$/kg $H_2$.

Data from one of our members on a real offshore wind project based in northwestern Europe indicates that the production from this project would emit just over 0.4 kg $CO_2e/kg\ H_2$ (this is without downstream emissions for transport and distribution).

Note that the same three characteristics highlighted above about solar power apply to wind but already lower in carbon.

- Electrolyzer and process emissions

Studies analyzing the life-cycle emissions (including infrastructure) of green hydrogen are scarce; however, available data[60] indicates that embodied emissions from the electrolyzers themselves and ancillary systems required in the plant aren't significant – less than 5%. These should go down in time as manufacturers source low-carbon materials (such as steel) and power.

There are some differences in the carbon intensity of the various electrolyzer technologies due to their efficiency (meaning the energy they require to make hydrogen and therefore how much embodied emissions from power generation they require). For example, high-temperature steam water electrolysis (also known as solid oxide cell electrolysis – SOEC) has the lowest energy requirement and therefore emissions: when coupled with solar energy, it results in 1 to 1.8 kg $CO_2e/kg\ H_2$ compared to 2 to 2.3 for alkaline-based electrolysis[61] with solar energy.

Like for other technologies, process emissions (such as hydrogen leakages) are not yet known or monitored and companies should ensure they are at the lowest possible level as hydrogen's global warming potential (GWP) could be significant (see Appendix 1 for background information about the life-cycle carbon intensity).

- Storage, transport and distribution

As in previous sections, we use data from the Zemo survey to estimate the emissions for storage, transport and distribution.

**Table 5: CI for storage, transport and distribution**

| Technology | CI in kg $CO_2e/kg\ H_2$ | Comments |
|---|---|---|
| **Storage, transport and distribution – compressed hydrogen (diesel) truck** | 1.5 | Number from UK, most of those emissions are from diesel trucks, could be lower or higher depending on distance and mode of transport. |
| **Storage, transport and distribution – liquid hydrogen truck (diesel)** | 4.4 | Liquefaction of hydrogen represents close to 99% of those emissions. |
| **Storage, transport and distribution – gas grid delivery** | 2 decreasing to 0.65 in 100% hydrogen pipelines | Deblending from a mixed gas grid requires energy (but in some case the mix $H_2/CH_4$ can be used directly). |

Note that due to lack of available data, we have not included the additional option of exporting hydrogen and transporting it by ship to the end-user. In this case, the carbon intensity would depend on the energy requirements (and the energy source) of the conversion process (since hydrogen would have to be either liquified or transported in other molecules such as ammonia, methanol or liquid organic carriers) and the fuel used for shipping.

- Fugitive hydrogen leaks

As described in Appendix 1, given the uncertainties surrounding the level of hydrogen leaks and its GWP, we have not included this in our calculations. But it is essential for companies to ensure potential hydrogen leaks are kept to a minimum.

**Measures to reduce the carbon intensity of green hydrogen**

A range of measures could reduce the carbon intensity of renewable hydrogen, such as:

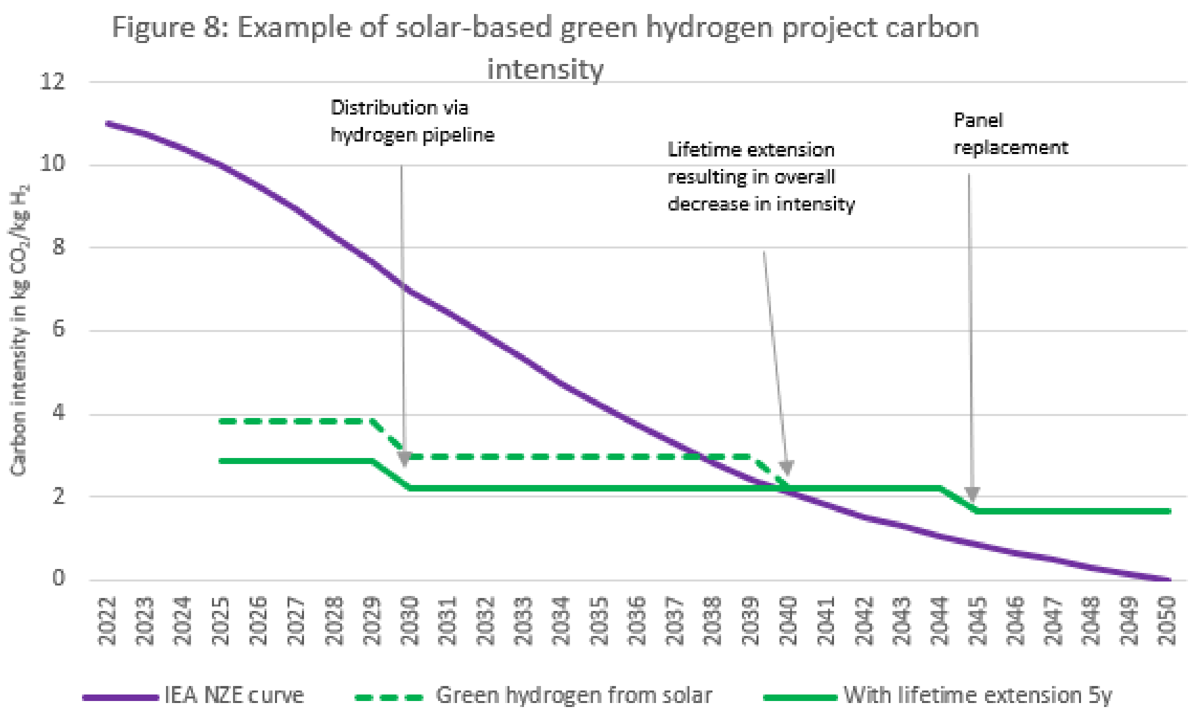
- Increasing the yield from power generating assets;
- Increasing the lifetime of assets (for example, if companies make initial CI calculations with a 20-year lifetime but can extend it to 25 years, there would be a 20% reduction in the calculated CI); however, this could also be counterproductive if the yield of the asset decreases over time;
- Increasing the efficiency of the electrolyzers or choosing the most efficient electrolyzer technology available;
- Replacing equipment with high embodied emissions with equipment with lower embodied emissions (which is expected in time as electricity grids and industrial production processes such as steel decarbonize); however, this would obviously constitute additional emissions, so it is important that companies fully use existing assets until the end of their lifetime and then recycle and reuse materials to avoid further burden on critical raw materials;
- The remaining emissions would require neutralization offsets to reach net-zero carbon emissions.

To illustrate this with a possible (but theoretical) example for solar-based green hydrogen:

- Base case in 2025:
    - Solar photovoltaic (PV) park connected to electrolyzers, lifetime assumed 15 years (until 2040), manufacturing in a country with a fairly carbon-intense grid of 570 g $CO_2e$/kWh and located in a country such as Spain with above average[62] solar panel output of 1600 kWh/kPv), CI=1.72
    - Distributed as compressed hydrogen in trucks, CI = 1.5
    - Starting CI = 3.22

- The following CI reduction measures are applicable (dates are notional)
  - Distributed in hydrogen pipelines in 2030 (CI=0.65 so a reduction of 0.85)
  - Lifetime extension of the solar panels to 20 years (so recalculating the carbon intensity over 20 years instead of 15 initially leads to a CI decrease of 25%), we assume without a significant decrease in yield
  - In 2045, the solar panels are replaced with new panels manufactured in a low-carbon grid (CI = 1) and distribution emissions by pipeline with CI of 0.65, resulting in total CI = 1.65
  - The remaining emissions would require neutralization offsets to reach net zero (or could be further reduced, for example by co-locating green hydrogen production with its consumer, removing distribution emissions).

**Figure 8: Example of solar-based green hydrogen project carbon intensity**

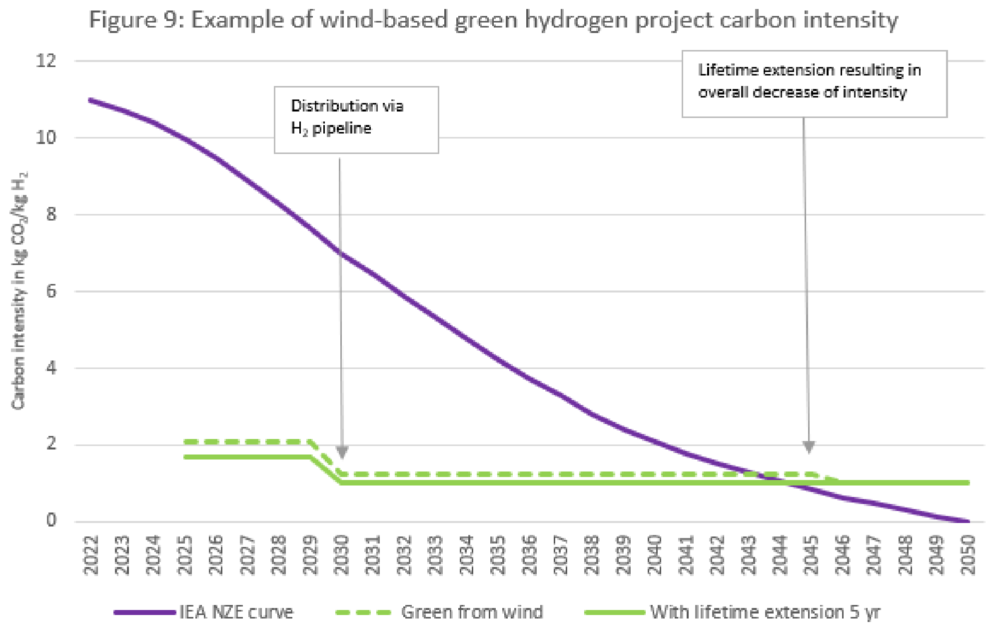



To illustrate this with a possible (but theoretical) example for wind-based green hydrogen:

- Base case in 2025:
  - Wind farm connected to electrolyzers, lifetime assumed 20 years (until 2045), CI = 0.6
  - Distributed as compressed hydrogen in trucks, CI = 1.5
  - Starting CI = 2.1

- The following CI reduction measures are applicable (dates are notional)
    - Distributed in hydrogen pipelines in 2030 (CI=0.65 so a reduction of 0.85)
    - Lifetime extension of the wind turbine panels to 25 years (so recalculating the carbon intensity over 25 years instead of 20 initially leads to a CI decrease of 20%), we assume without significant decrease in yield
    - The remaining emissions would require neutralization offsets to reach net zero (or could be further reduced, for example by co-locating green hydrogen production with its consumer, removing distribution emissions).

**Figure 9: Example of wind-based green hydrogen project carbon intensity**

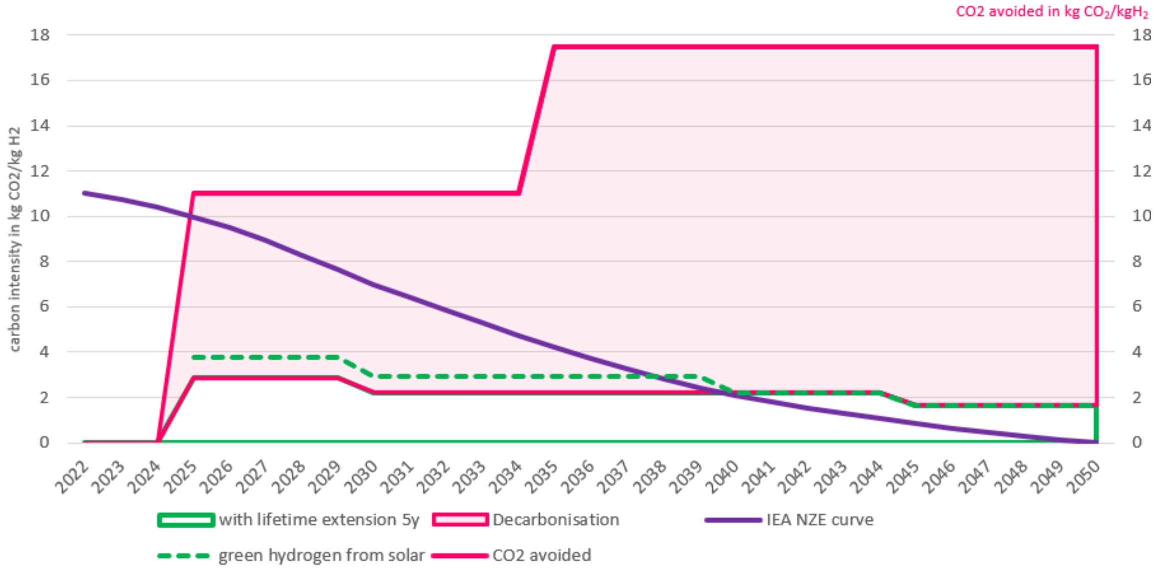



**Decarbonization potential**

We imagine in this example that this hydrogen is:

- First used to replace grey hydrogen (avoiding c. 11 kg $CO_2$e) in the first 10 years;
- Then about half continues to be used to replace grey hydrogen and the other half is used in the steel sector for direct reduction of iron (DRI) (avoiding 24 kg $CO_2$e per kg of hydrogen, so an average of 17.5 kg). The area in pink in **Error! Reference source not found.** represents the decarbonization potential.

**Figure 10: Example of solar-based green hydrogen project carbon intensity and decarbonization**




**In summary for green hydrogen**

While the starting carbon intensity for green hydrogen can be very low, it is important to understand the ways in which companies can minimize the infrastructure emissions from the generation assets to achieve the maximum decarbonization potential over time. It is also important to be aware of potential neutralization offsets required in 2050 to create a fully net-zero emissions system.

# 6. Other technologies

This section includes information about other less common technologies for hydrogen production.

**Table 6: Other technologies**

| Technology | CI in kg $CO_2e/kg\ H_2$ | Comments |
|---|---|---|
| **Black or brown hydrogen** (from coal or lignite gasification) | About 22 | Companies could use CCS to lower some of the emissions from black/brown hydrogen. However, given the need to move away from coal, we have not included it in this report. |
| Electrolysis fed by nuclear electricity – **pink hydrogen** | 0.6 | Studies on the exact details of the carbon footprint of nuclear are scarce but those available[63] indicate that the largest GHG contribution (about 40% to 60%) comes from the mining and enrichment of the fuel; production (15 to 30%), construction (CAPEX/infrastructure emissions at 10 to 15%), decommissioning and waste disposal make up the rest.<br><br>Therefore, opportunities may exist to further reduce emissions along the value chain (for example by reducing the energy required for mining and enrichment or using low-carbon energy) before neutralizing the last residual emissions with offsets. |
| Electrolysis fed by the grid – **yellow hydrogen** | Extremely variable depending on grid mix:<br>Norway: 0.9<br>France (majority of nuclear): 2.77;<br>UK: 8 (average 2020 grid mix)<br>Current global grid mix: 25 but expected at 11 in 2030;<br>Country with a coal-based grid: 35 | Electricity grid mix decarbonization, e.g., replacing unabated fossil fuel power generation with lower carbon alternatives (using renewable electricity, high % CCS or nuclear).<br><br>Note: In most countries this option does not make sense as it would result in hydrogen with a higher CI than grey hydrogen.<br><br>Note those numbers do not include infrastructure emissions from generation assets.<br><br>Many jurisdictions are defining “additionality” criteria to ensure that using grid electricity to produce hydrogen does not “cannibalize” existing renewable energies but results in |

| | | |
|---|---|---|
| | | additional renewable energy capacity deployment. |
| Methane pyrolysis – **turquoise hydrogen** | Between 0.8 to 8 | The intensity depends mainly on:<br><br>- The intensity of the upstream gas used (including methane leakages);<br><br>- The use of the solid carbon co-produced, for example if used to displace materials with significant GHG emissions (like replacing cement in concrete) instead of being simply sequestered; this will enable a reduction in life-cycle GHG intensity of the hydrogen produced (GHG credits).<br><br>So, to reduce the CI to the lowest possible levels, companies should take measures to reduce the upstream gas intensity (e.g., through methane leakage reduction) and use the carbon black co-produced to displace carbon-intense materials. |
| **Blue hydrogen** using partial oxidation (POx) of methane and CCS[64] | 2.4 kg $CO_2$e/kg $H_2$ for the Netherlands in 2020, dropping down to 1.5 kg $CO_2$e/kg $H_2$ in 2030 because of drop in grid carbon intensity | **Decarbonization options**<br><br>Electricity use accounts for the largest contribution to the carbon footprint. This includes electricity needed to run the POx plant and $H_2$ compression. Additionally, it includes O2 production using an air separation unit (ASU). Natural gas (production and transport) makes the second largest contribution to the carbon footprint.<br><br>• Decarbonizing the electricity supply is therefore very important;<br>• Increase energy efficiency of the ASU;<br>• Potential to use biomethane as for other forms of blue hydrogen;<br>• O POx technology allows for the use of a wide range of feedstock, e.g., heavier hydrocarbons up to vacuum residue. The carbon footprint of the different feedstocks varies. Consequently, the total carbon footprint of POx can be different when using another type of feedstock. However, using waste feedstock could reduce emissions |

| | | |
|---|---|---|
| | | associated with natural gas production and transportation. |
| **Reforming biomethane + CCS**[65] | Up to -5.3 with ATR + gas heater reformer (GHR) + CCS, biomethane with 96% capture | Note that there are many conditions for biomethane to be sustainable, as it needs to not result in land-use change, come from waste feedstock (hence does not generate additional pressure on food crops) and have leaks monitored and kept to a minimum. In addition, the emissions depend on the counterfactual, i.e., what would have happened to the feedstock otherwise.<br><br>Availability of sustainable biomethane could be an issue. |
| **Gasification of municipal solid waste, reforming with CCS**[66] | -8 with the assumption of 65% biogenic content<br><br>Up to -13 for the gasification of fully biogenic waste | This pathway already presents the greatest potential for negative emissions – up to a maximum of nearly 13 kg/kg for the gasification of fully biogenic waste + CCS.<br><br>The carbon intensity depends on the biogenic fraction in the feedstock used and counterfactual waste. |

Technologies that are marginal today, such as electrolysis powered by nuclear, methane pyrolysis, partial oxidation and the reforming of biomethane, could all play a role in producing hydrogen with low to negative carbon intensities, either on their own or in combination with the more established routes for hydrogen production. However, their implementation at scale could be challenging for different reasons: investment and public support required for nuclear power development or the availability and sustainability of feedstock for biomethane.

# 7. Project vs portfolio (or country) average

Public and private sector organizations can use the approach we have defined to map the carbon intensity of a particular hydrogen project through time and how it could reach net-zero emissions by 2050 for a portfolio of projects, for example, at a company (in line with the SBTi methodology) or regional level. When looking at an aggregate level, the average carbon intensity should remain in line with the IEA net-zero curve, meaning that projects well-below the curve could balance projects that may be individually or temporarily (slightly) above the curve. This would provide some flexibility in managing existing assets, for example, but would not justify investing in new projects far above the curve.
When used in the investment decision process, this could help ensure that a company shifts assets to a 1.5°C-aligned future. Equally, policymakers could use the approach at the regional or national level to understand how to design support mechanisms (for example, through subsidies, contracts for difference or others). The goal would be to preferentially reward the projects that are 1.5°C-aligned and result in a net-zero future in 2050, thus maximizing the decarbonization potential using hydrogen.

# 8. Conclusion

We aim to help companies, investors and policymakers alike to understand the implications of how the various hydrogen production pathways may fit in a 1.5°C scenario or what it would take for them to do so.

While it is foreseen that in 2050, most hydrogen will come from electrolysis powered by renewable electricity, it is essential to understand in what circumstances other technologies may help meet the forecasted demand increase. This should not be done to the detriment of green hydrogen and renewable electricity but as an additional source of hydrogen that helps accelerate the shift to lower carbon and eventually net-zero carbon sources of energy.

Normative scenarios, such as IEA's Net Zero Emissions or IRENA's 1.5°C pathway, indicate what is possible. Unfortunately, the reality on the ground is not yet catching up with the urgency that the climate and energy crises require. We call for that gap to close, which is why we have defined guidelines for investment decisions that the following questions can drive:

- What measures should businesses and governments implement to keep the carbon intensity of the hydrogen project under the IEA Net Zero Emissions curve and to reach net-zero emissions in 2050?
- Is the project making efficient use of hydrogen to help decarbonize other sectors?
- Can the project respect the energy transition redlines of no new fossil exploration and the phasing out of fossil fuels subsidies?

We invite companies and investors to include those questions in their framework for investment decisions and policymakers to consider them in creating supportive policies and incentives for hydrogen projects and infrastructure on their journey to net-zero emissions energy systems in 2050. Equally, we invite hydrogen users to ask these questions when sourcing hydrogen.
It is crucial that companies purposefully direct investments to solutions aligned with a 1.5°C pathway and net-zero emissions in 2050 or sooner. When it comes to existing hydrogen, some pathways can help decarbonize it and therefore avoid the nearly 1 Gt of $CO_2$e currently emitted yearly. And as for the growth of decarbonized hydrogen, it is significant in almost all 1.5°C scenarios: some estimates67 show that by 2050, it could contribute to avoiding a cumulative 50 Gt of $CO_2$e.

Let's make these numbers a reality.

# Appendix 1: Definitions and background information

| Terms | Definitions |
|---|---|
| **Aligned with a 1.5°C scenario** | In this report, this means limiting global warming to 1.5°C above the pre-industrial level. More details are available in section 2. |
| **Auto thermal reforming (ATR)** | A relatively recent technology to produce hydrogen from methane. |
| **Carbon capture and storage (CCS)** | Process of capturing carbon dioxide ($CO_2$) before it enters the atmosphere, transporting it and storing it. |
| **Carbon intensity (CI)** | The amount of $CO_2$ equivalent emissions released per unit. |
| **Intervention accounting** | This approach (also known as consequential approach) is used to estimate the GHG impacts of actions/products relative to counterfactual baseline scenarios or other performance standards. Several regulations/jurisdictions use intervention accounting methods to promote low-carbon fuels, including biomethane. For example, they estimate the carbon intensity of biomethane in relation to counterfactual scenarios. |
| **Inventory accounting** | Provides a complete assessment of product life-cycle emissions. This is compliant with the GHG Protocol corporate and Scope 3 standard. |
| **Gas heater reformer (GHR)** | A technology often used in conjunction with ATR. |
| **Greenhouse gas (GHG) reductions** | Actions reducing the quantity of GHGs attributable to an entity vis-à-vis a baseline. Examples: replacing fossil-burning power with renewable energy, reducing consumption of emissions-intensive products or inputs, avoiding damage to ecological carbon sinks, carbon capture and storage (CCS), avoided emissions from the deployment of renewable energy.[68] |
| **Greenhouse gas (GHG) removals** | Actions that remove greenhouse gases from the atmosphere relative to a baseline. Examples: afforestation and reforestation, soil carbon enhancement, bioenergy with CCS, direct air capture and storage, mineralization, biochar or enhanced weathering. |
| **Hydrogen leaks or leakages** | In the case of fossil fuel-based hydrogen, the life cycle includes upstream production including methane leakages. In the case of green hydrogen, it includes infrastructure emissions from the generating assets (e.g., the solar parks and wind turbines), which are most of the emissions for this type of hydrogen.<br><br>At this stage, there remains uncertainty as to the GWP of hydrogen itself and there is little information available about leak rates during production, distribution, storage and use. Hydrogen is an indirect greenhouse gas (half of its GWP comes from increasing the atmospheric lifetime of methane) with, like methane, a higher GWP on a 20-year basis (central estimate from a recent survey is 33) than a 100-year basis (central estimate from same survey is 11), the commonly used timeframe for GHG calculations in $CO_2$ equivalent. While it is already clear that hydrogen leaks will have to be closely monitored and kept to a minimum, they are not yet included in data available for life-cycle carbon intensity calculations and we therefore omit them from this report. |
| **Life-cycle carbon intensity** | There is currently no specific standard to calculate life-cycle carbon intensity specifically for hydrogen. However, using ISO 14044:2006, ISO 14067:2018, and GHG Protocol standards as a reference, we include all significant emissions, on a cradle-to-grave (well-to-wake) basis (including CAPEX – infrastructure – emissions, production, transport and storage, and use), of all relevant and material United |

| | |
|---|---|
| | Nations Framework Convention on Climate Change (UNFCCC) and Kyoto GHGs, using the most recent GWP-100 values as per international reporting standards.[69] We therefore make several assumptions in any life-cycle emissions calculation, especially when they relate to future projects. Thus, those numbers are to be taken as best estimates.<br><br>This means that we consider the full Scope 1, 2, and 3 emissions[70] because most WBCSD members are committing to reach net-zero emissions along the value chain (i.e., full life cycle). This differs from numerous jurisdictions and standards bodies, which do not include infrastructure emissions for green hydrogen or renewable electricity. The main reason for excluding those infrastructure emissions is that there is a lot of uncertainty in determining them. However, we do expect companies to try to understand those embodied emissions as they work to achieve their net-zero commitments.<br><br>In this report, we use kg $CO_2e$/kg $H_2$ for convenience. However, detailed carbon intensity calculations are usually expressed in g $CO_2e$/MJ lower heating value (LHV). For reference, 1 kg $CO_2e$/kg $H_{2\ LHV}$ = 8.3 g $CO_2e$/MJ $_{LHV}$.<br><br>In the case of hydrogen made from (fossil or biological) methane, upstream methane emissions significantly impact the overall life-cycle carbon intensity. This is even more significant[71] when using a 20-year GWP for methane rather than the 100-year GWP used in the standard calculations (e.g., GHG Protocol). While in this report we have focused on current standards (using 100-year GWP), we recommend that companies and decision-makers run a sensitivity analysis using the 20-year GWP for methane as well. Methane has a more acute effect in the short term and limiting climate change in the next few decades is crucial.<br><br>As previously explained in other reports[72] in which we define a few applicable thresholds based on hydrogen's full life-cycle carbon intensity, **we advocate for deploying hydrogen of the lowest possible carbon intensity**, meaning no threshold is satisfactory in the long term unless it is "net zero". |
| **Net-negative emissions** | This term refers to when a particular technology removes more GHG than what is emitted to the atmosphere, based on a life-cycle analysis. |
| **Net-zero emissions** | The Intergovernmental Panel on Climate Change (IPPC) defines net zero as when anthropogenic removals of GHGs from the atmosphere balance anthropogenic emissions over a specified period.<br><br>Race to Zero considers individual actors to have reached a state of net zero when an actor reduces its emissions following science-based pathways, with any remaining GHG emissions attributable to that actor being fully neutralized by like-for-like removals (e.g., permanent removals for fossil carbon emissions) exclusively claimed by that actor, either with the value chain or through the purchase of valid offset credits.[73]<br><br>SBTi states[74] that a company that has achieved its long-term science-based target is considered net zero. Most companies are required to have long-term targets with emissions reductions of at least 90-95% by 2050. At that point, a company must use carbon removals to neutralize any limited emissions that it cannot yet eliminate.<br><br>In this report, we mean "net-zero" when like-for-like removals neutralize the residual emissions associated with a specific project or activity (e.g., the entire hydrogen value chain). According to the GHG Protocol, a company should report any credits bought in its inventory accounting (to avoid double counting). |
| **Offsetting** | According to the Race to Zero: "Reducing GHG emissions (including through avoided emissions) or increasing GHG removals through activities external to an |

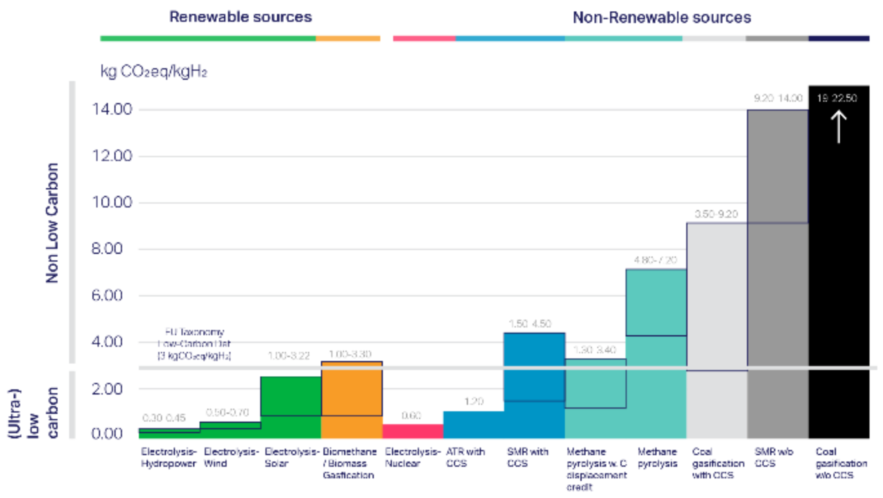
| | |
|---|---|
| | actor in order to compensate for GHG emissions, such that an actor's net contribution to global emissions is reduced. Offsetting is typically arranged through marketplace for carbon credits or other exchange mechanisms. Offsetting claims are only valid through a rigorous set of conditions, including that the reductions/removals involved are additional, not over-estimated, and exclusively claimed. Further, offsetting can only be used to claim net zero status to the extent is it 'like for like' with any residual emissions."[75]<br><br>This report extends the concept of neutralization offsets to a particular project or sector. As such, companies can conceptually understand the neutralization offsets required by a specific project to become net zero, even though methodologically (e.g., SBTi), net zero cannot be claimed for one particular product or activity and only applies at the whole corporate/actor level. |
| **Steam methane reforming (SMR)** | The prevalent technology to produce hydrogen today from methane. |

# Appendix 2: Hydrogen colors and their carbon intensity

The various production pathways (colors) of hydrogen and their carbon intensity[76]

| Hydrogen color | Production method | Production life-cycle carbon intensity[77] (kg $CO_2e$/kg $H_2$) |
|---|---|---|
| **Green** | Water electrolysis powered by renewable electricity (wind, solar, hydro) | 0.3 (hydro); 0.6 (wind); 1-3+ (solar)<br><br>Note: Most of the emissions are due to fossil fuel use to power the manufacturing of equipment, which will decrease over time as society moves to renewable power. For example, estimates for solar-powered electrolysis today are usually around 3 but are expected to reach about 1 in 2030. |
| **Blue** | Reforming methane with carbon capture and storage | Best case: 1.2 (ATR with 98% capture in Norway) and potentially a lot more depending on upstream methane leakage.<br><br>SMR with 60% capture: best case around 5 and potentially more. For example, Alberta, Canada,[78] SMR with 54% capture: 8.2; with 85% capture: 6.7 |
| **Turquoise** | Methane pyrolysis | 0.8 (with carbon displacement credit, but rules for that could change in the future) to 8 |
| **Pink** (also called purple or yellow, depending on the energy source) | Water electrolysis powered by nuclear | 0.6 |
| **Yellow** | Water electrolysis powered by a mix of generation on the grid | Current global grid mix: 25; expected in 2030: 11; France: 2.77; Norway: 0.9<br>Coal-based grid: 35 |
| **Grey** | Reforming of fossil methane without mitigation | c. 11, more depending on upstream gas GHG intensity |
| **Brown and black** | From lignite and coal gasification | c. 22 |
| **White** | Naturally occuring | Unknown |
| **Other undefined** (sometimes referred to as gold for their potential for negative emissions; the most significant reduction numbers include counterfactuals and therefore rely on intervention or consequential accounting) | Biomethane ATR + CCS<br><br>Wood gasification + CCS<br><br>Waste gasification + CCS | c. -4.8 to -12<br><br>c. -19<br><br>c. -3.5 to -6.5<br><br>Numbers taken from E4tech survey for BEIS[79] but dependent on process, source of energy (e.g., wide variations if the grid is used) and counterfactual (e.g., what would have happened to the feedstock if not transformed), which could evolve in time |

**Figure 11: Example of solar-based green hydrogen project carbon intensity and decarbonization**




**Figures and ranges include 2020 baselines and 2030 projections**

Note the 3.22 intensity for solar (source: Ademe) is the estimated carbon intensity for hydrogen production by solar-powered electrolysis today; and it is estimated that by 2030 this number would decrease to 1 kg/kg (source: Hydrogen Council).

**Source:** numbers taken from litterature review, including publications from the Hydrogen Council, IEA, IRENA, CertifHy, Ademe, DLR, Bellona

**Figure 12: Hydrogen carbon intensity by origin – by grid mix type**


**Source:** numbers taken from litterature review, including publications from the Hydrogen Council, IEA, IRENA, CertifHy, Ademe, DLR, Bellona

# Appendix 3: KBC detailed analysis

Here is an example from an existing SMR unit being retrofitted with post combustion CCS (capturing 95% of process emissions). Using the same base case as in the main body of the report:

- Base case in 2022:
  - Upstream gas with a CI of 0.47 kg $CO_2e$/kg $H_2$ (corresponding to about 1.35[80] $CO_2e$/kg $H_2$) with 0.73% methane leak rate (UK gas mix i.e. a realistic and not best case assumption; however, methane leaks could also be higher).
  - SMR unit in the UK with a CI of 10.3 [81]kg $CO_2e$/kg $H_2$ [82]
  - No emissions from distribution (the grey hydrogen is used on a site in a refinery / fertilizer plant for example)
  - Starting intensity = 10.1 kg $CO_2$/kg $H_2$

- The following CI reductions measures are applied (dates are notional)
  - Reduction of methane leakages from 0.73 to 0.36% (0.3 reduction in hydrogen CI) in 2025 (in reality this would occur gradually over a period of time as leaks are identified and controlled, rather than at a specific date). Again this is a realistic and not best case assumption for methane leaks (some companies are claiming to achieve significantly lower levels than this).
  - Implementation of a hypothetical project in 2030, to close 25% of the gap to best technology: CI reduction of 0.4 kg $CO_2$/kg $H_2$.
  - Implementation of pre-combustion capture CCS in 2028 (95% capture of process emissions, note that stack emissions are not captured, thus overall percentage of carbon capture is 60%), reaching a total CI of 4.9 kg $CO_2$/ kg $H_2$ (including upstream emissions).
  - Introduction of biomethane (with intensity of 17 g $CO_2$/MJ) in the feedstock, starting in 2031, increasing linearly to 69 % in case of pre-combustion in 2050. Gradual CI reduction of up to 4.7
  - Net-zero emissions achieved in 2050

For the purpose of section 3 of this report, KBC has considered a best technology SMR hydrogen unit to have the following process parameters:

| Process parameter | Units | BAT |
|---|---|---|
| **Feed natural gas composition** | %wt | 100 |
| **Reforming steam: carbon ratio** | mole/mole | 2.0 |
| **Process effluent cooler inlet temperature** | °C | 100 |
| **Reforming furnace flue gas excess O2** | %vol | 1.8 |
| **Reforming furnace bridgewall temperature** | °C | 1000 |
| **Reforming furnace stack temperature** | °C | 150 |

| | | |
|---|---|---|
| **PSA percentage $CO_2$ recovery** | % | 90 |
| **Recycle: hydrogen/carbon ratio** | mole/mole | 0.051 |

- Heat integration within the unit battery limit is maximized, process steam export is minimized.
- As the focus of the work was to decarbonize existing grey hydrogen units, using an ATR or other technology that differs largely from conventional steam-methane reforming was not considered as part of the best technology definition.

# Endnotes

[1] Estimates from 1.5°C scenarios range from 5% (DNV) to 22% (Hydrogen Council), with the International Energy Agency (IEA) at 13% and the International Renewable Energy Agency (IRENA) at 12%.

[2] For example: Under European Union taxonomy, "low-carbon" hydrogen is 3 kg $CO_2e$/kg $H_2$ on full life-cycle basis; in the US "clean" is at 2 kg $CO_2e$/kg $H_2$ for production installation only; in the UK, it is 20 g $CO_2$/MJ (c. 2.4 kg $CO_2e$/kg $H_2$); and in China "low-carbon" is <14.51 kg $CO_2e$/kg $H_2$ and "clean hydrogen" is <4.9 kg $CO_2e$/kg $H_2$.

[3] From cradle to grave, meaning including capital expenditure (capex) emissions – i.e., infrastructure emissions, production, transport and storage, and use. See more details in the definition of life-cycle carbon intensity in Appendix 1.

[4] Emissions that occur during the manufacturing and installation of assets.

[5] To be clear, this relates only to existing grey hydrogen. There should be no new hydrogen made with unbated emissions from fossil natural gas use.

[6] Hydrogen Council and McKinsey & Company (2021). *Hydrogen for Net-Zero: A critical cost-competitive energy vector*. Available at https://hydrogencouncil.com/en/hydrogen-for-net-zero/.

[7] International Energy Agency (IEA) (2021). *Net Zero by 2050: A Roadmap for the Global Energy Sector*. Available at https://iea.blob.core.windows.net/assets/deebef5d-0c34-4539-9d0c-10b13d840027/NetZeroby2050-ARoadmapfortheGlobalEnergySector_CORR.pdf.

[8] As per the International Energy Agency's *Net Zero by 2050: A Roadmap for the Global Energy Sector* scenario: *"No fossil fuel exploration is required in the NZE as no new oil and natural gas fields are required beyond those that have already been approved for development" [as of 2021]*. Available at https://iea.blob.core.windows.net/assets/deebef5d-0c34-4539-9d0c-10b13d840027/NetZeroby2050-ARoadmapfortheGlobalEnergySector_CORR.pdf.

[9] Estimates from 1.5°C scenarios range from 5% (DNV) to 22% (Hydrogen Council), with the IEA at 13% and IRENA at 12%.

[10]

[11] It is worth noting that today's hydrogen production is around 100 million tons per annum (mtpa) and emits c. 2% of global emissions).

[12] Being net-zero means that any residual emissions (which should be as low as possible) would need equivalent removals ("neutralization offsets").

[13] International Energy Agency (2021). *Net Zero by 2050: A Roadmap for the Global Energy Sector*. Available at https://www.iea.org/reports/net-zero-by-2050.

[14] International Renewable Energy Agency (IRENA) (2021). *World Energy Transitions Outlook: 1.5°C Pathway*. Available at https://irena.org/publications/2021/Jun/World-Energy-Transitions-Outlook.

[15] Principles for Responsible Investment (2021). "The Inevitable Policy Response 2021: Forecast Policy Scenario and 1.5C Required Policy Scenario". Available at https://www.unpri.org/inevitable-policy-response/the-inevitable-policy-response-2021-forecast-policy-scenario-and-15c-required-policy-scenario/8726.article.

[16] International Energy Agency (IEA) (2021). *Net Zero by 2050: A Roadmap for the Global Energy Sector*. Available at https://iea.blob.core.windows.net/assets/deebef5d-0c34-4539-9d0c-10b13d840027/NetZeroby2050-ARoadmapfortheGlobalEnergySector_CORR.pdf.

[17] Level of energy demand: 13% for IEA and 12% for IRENA, requiring a mix of technologies to achieve the volumes required (IEA: 60% green and about 40% blue; IRENA 2/3 green and 1/3 blue).

[18] Science Based Target initiative (SBTi) (2021). *The Net-Zero Standard*
Available at https://sciencebasedtargets.org/resources/files/Net-Zero-Standard.pdf

[19] As per IEA NZE scenario: "No fossil fuel exploration is required in the NZE as no new oil and natural gas fields are required beyond those that have already been approved for development" [as of 2021]. https://www.iea.org/reports/net-zero-by-2050.

[20] International Energy Agency (IEA) (2021). *Net Zero by 2050: A Roadmap for the Global Energy Sector*. Available at https://iea.blob.core.windows.net/assets/deebef5d-0c34-4539-9d0c-10b13d840027/NetZeroby2050-ARoadmapfortheGlobalEnergySector_CORR.pdf.

[21] Note this is our own approach here and the carbon intensities that we use are not necessarily equal to those the IEA models in its scenario.

[22] From cradle to grave, meaning including capital expenditure (CAPEX) emissions – i.e., infrastructure emissions, production, transport and storage, and use. See more details on life-cycle carbon intensity in Appendix 2.

[23] For comparison, SBTi requires the use of offsets only after reducing 90-95% of emissions, which is a useful reference point.

[24] See Michael Liebreich's hydrogen ladder of uses, for example: "The Clean Hydrogen Ladder [Now updated to V4.1]". Available at https://www.linkedin.com/pulse/clean-hydrogen-ladder-v40-michael-liebreich/.

[25] International Energy Agency (IEA) (2021). *Net Zero by 2050: A Roadmap for the Global Energy Sector*. Available at https://iea.blob.core.windows.net/assets/deebef5d-0c34-4539-9d0c-10b13d840027/NetZeroby2050-ARoadmapfortheGlobalEnergySector_CORR.pdf.

[26] Source: Rocky Mountain Institute (RMI) (2020). *Hydrogen's decarbonization impact for industry*. Available at https://rmi.org/wp-content/uploads/2020/01/hydrogen_insight_brief.pdf.

[27] International Energy Agency (IEA) (2021). *Net Zero by 2050: A Roadmap for the Global Energy Sector*. Available at https://iea.blob.core.windows.net/assets/deebef5d-0c34-4539-9d0c-10b13d840027/NetZeroby2050-ARoadmapfortheGlobalEnergySector_CORR.pdf.

[28] WBCSD (2021). *Vision 2050: Time to Transform*. Available at https://www.wbcsd.org/Overview/About-us/Vision-2050-Time-to-Transform.

[29] From International Energy Agency (IEA) (2021). *Global Hydrogen Review*. Available at https://iea.blob.core.windows.net/assets/e57fd1ee-aac7-494d-a351-f2a4024909b4/GlobalHydrogenReview2021.pdf.

[30] Note that life-cycle figures in principle include all emissions, from cradle to grave. As per the ISO 14040/44 standard, we use cut-off criteria to define the system boundary and scope of the study. If the contribution of a particular element to total GHG emissions is below a certain threshold (typically 1-2%), we consider it negligible and no further calculations to include those contributions are necessary. One-time GHG emissions from fossil fuel

asset construction and infrastructure are normally below this threshold due to the amortization of GHGs over large energy output and long production lifetimes. Therefore, we exclude them from the life-cycle results shown here.

[31] From Element Energy, adapted from Zemo (2021). *Low Carbon Hydrogen Well-to-Tank Pathways Study – Full Report*. Available at http://www.element-energy.co.uk/wordpress/wp-content/uploads/2021/08/Zemo-Low-Carbon-Hydrogen-WTT-Pathways-full-report.pdf.

[32] More details in Appendix 3.
[33] For example, member companies from the Oil and Gas Climate Initiative achieved their target of 0.25% in 2018, 0.20% in 2020 and are aiming to further reduce to "near zero". This includes WBCSD member companies bp, Shell and TotalEnergies, among others.

[34] From IEAGHG (2019). "The Carbon Capture Project at Air Products' Port Arthur Hydrogen Production Facility", 2018/05, December 2018. Available at http://documents.ieaghg.org/index.php/s/4hyafrmhu2bobOs.

[35] This corresponds to biomethane made from a mixed feedstock of food waste, municipal organic waste, sewage sludge and wet manure.

[36] See bp (2020). "bp and Ørsted to create renewable hydrogen partnership in Germany". Available at https://www.bp.com/en/global/corporate/news-and-insights/press-releases/bp-and-orsted-to-create-renewable-hydrogen-partnership-in-germany.html.

[37] See Shell (2021). "Shell starts up Europe's largest PEM green hydrogen electrolyser". Available at https://www.shell.com/media/news-and-media-releases/2021/shell-starts-up-europes-largest-pem-green-hydrogen-electrolyser.html.

[38] See Shell (2022). "Shell to start building Europe's largest renewable hydrogen plant". https://www.shell.com/media/news-and-media-releases/2022/shell-to-start-building-europes-largest-renewable-hydrogen-plant.html.

[39] See Iberdrola (n.d.). "Puertollano green hydrogen plant – Iberdrola commissions the largest green hydrogen plant for industrial use in Europe". Available at https://www.iberdrola.com/about-us/lines-business/flagship-projects/puertollano-green-hydrogen-plant.

[40] corresponding to upstream emissions with a range between 3.9 kg $CO_2e$/kg $H_2$ to date, down to 3.4 kg $CO_2e$/kg $H_2$ by 2050

[41] Usually in the range 1.3 – 1.8 kg $CO_2e$/kg $H_2$

[42] Feedstock assumption: 80% methane and 20% naphtha – furnace fuel assumed to be methane; credit for steam export = -2.3 so gross CI= 11.

[43] More details in Appendix 3.

[44] Bringing net carbon intensity to 4.8 including CCS amine regeneration emissions and upstream gas intensity.

[45] It is unlikely that all of today's existing units will be in operation by 2050 as many will reach their end of life before then. However, considering that many new SMR units are currently being installed, we use this as a working and likely conservative assumption.

[46] International Energy Agency (IEA) (2020). *Outlook for biogas and biomethane: Prospects for organic growth – World Energy Outlook Special Report*. Available at https://iea.blob.core.windows.net/assets/03aeb10c-c38c-4d10-bcec-de92e9ab815f/Outlook_for_biogas_and_biomethane.pdf.

[47] National Grid ESO (2022). *Future Energy Scenarios*. Available at https://www.nationalgrideso.com/document/264421/download.

[48] About 10 $MtCO_2e$ or more than 10%.

[49] International Energy Agency (IEA) (2020). *Outlook for biogas and biomethane*.

[50] Hydrogen Council (2021). *Hydrogen Decarbonization Pathways*. Available at https://hydrogencouncil.com/wp-content/uploads/2021/01/Hydrogen-Council-Report_Decarbonization-Pathways_Part-1-Lifecycle-Assessment.pdf.

[51] For example: Under European Union taxonomy, "low-carbon" hydrogen is 3 kg $CO_2e$/kg $H_2$ on full life-cycle basis; in the US "clean" is at 2 kg $CO_2e$/kg $H_2$ for production installation only; in the UK, it is 20 g $CO_2$/MJ (c. 2.4 kg $CO_2e$/kg $H_2$); and in China "low-carbon" is <14.51 kg $CO_2e$/kg $H_2$ and "clean hydrogen" is <4.9 kg $CO_2e$/kg $H_2$.

[52] Numbers provided by Element Energy, adapted from Zemo (2021). *Low Carbon Hydrogen Well-to-Tank Pathways Study – Full Report*. Available at http://www.element-energy.co.uk/wordpress/wp-content/uploads/2021/08/Zemo-Low-Carbon-Hydrogen-WTT-Pathways-full-report.pdf.

[53] Note that life-cycle figures in principle include all emissions from cradle to grave. As per the ISO 14040/44 standard, cut-off criteria is used to define the system boundary and scope of the study. If the contribution of a particular element to total GHG emissions is below a certain threshold (typically 1-2%), it is considered negligible and no further calculations to include those contributions are required. One-time GHG emissions from fossil fuel asset construction and infrastructure are normally below this threshold due to GHGs being amortized over large energy output and long production lifetimes. Therefore, we exclude them from the life-cycle results shown here.

[54] Recent survey from Oni A.O. et al. (2022). "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*. Volume 254, 15 February 2022, 115245. Available at https://www.sciencedirect.com/science/article/pii/S0196890422000413.

[55] From Hydrogen Council (2021). *Hydrogen Decarbonization Pathways*. Available at https://hydrogencouncil.com/wp-content/uploads/2021/01/Hydrogen-Council-Report_Decarbonization-Pathways_Part-1-Lifecycle-Assessment.pdf.

[56] For example, members of the Oil and Gas Climate Initiative achieved their target of 0.25% in 2018, 0.20% in 2020 and are aiming to further reduce to "near zero". This includes WBCSD member companies bp, Shell and TotalEnergies, among others.

[57] Climate Group (2022). "Major businesses commit to 100% net zero steel". Available at https://www.theclimategroup.org/our-work/press/major-businesses-commit-100-net-zero-steel.

[58] For a study comparing the life-cycle carbon intensity of various electricity sources, see United Nations Economic Commission for Europe (UNECE) (2022). *Carbon Neutrality in the UNECE Region: Integrated Life-cycle Assessment of Electricity Sources*. https://unece.org/sites/default/files/2022-04/LCA_3_FINAL%20March%202022.pdf.

[59] Hydrogen Council (2021). *Hydrogen Decarbonization Pathways*. Available at https://hydrogencouncil.com/wp-content/uploads/2021/01/Hydrogen-Council-Report_Decarbonization-Pathways_Part-1-Lifecycle-Assessment.pdf.

Ghandehariun, S. & Kumar, A.(2016). "Life cycle of wind based hydrogen production in western Canada". *International Journal of Hydrogen Energy*. 41(22). Available at https://www.researchgate.net/publication/303097783_Life_cycle_assessment_of_wind-based_hydrogen_production_in_Western_Canada.

[60] Tenhumberg, N. & Büker, K. (2020) "Ecological and Economic Evaluation of Hydrogen Production by Different Water Electrolysis Technologies". *Chemie Ingenieur Technik*. Available at https://onlinelibrary.wiley.com/doi/full/10.1002/cite.202000090

**[61] Yadav, D. & Banerjee, R. (2020). "Net energy and carbon footprint analysis of solar hydrogen production from the high-temperature electrolysis process". *Applied Energy*. Available at https://www.sciencedirect.com/science/article/abs/pii/S0306261920300155.**

[62] Solar Power Europe. "The average PV energy yield in the EU is in the range of 1,100 – 1,200 kWh/kWp, but if the PV system is build to produce green hydrogen, it would most likely be built in a better location (e.g. Spain) where the yield is more likely in the range of 1,600 kWh/kWp or more.
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World Nuclear News (2022). "EDF study confirms very low carbon nature of nuclear". Available at https://www.world-nuclear-news.org/Articles/EDF-study-confirms-very-low-carbon-nature-of-nucle.

[64] Numbers from Element Energy Blue Hydrogen study.

[65] From Element Energy, adapted from Zemo (2021). *Low Carbon Hydrogen Well-to-Tank Pathways Study – Full Report*. Available at http://www.element-energy.co.uk/wordpress/wp-content/uploads/2021/08/Zemo-Low-Carbon-Hydrogen-WTT-Pathways-full-report.pdf.

[66] From Element Energy, adapted from Zemo (2021). *Low Carbon Hydrogen Well-to-Tank Pathways Study – Full Report*. Available at http://www.element-energy.co.uk/wordpress/wp-content/uploads/2021/08/Zemo-Low-Carbon-Hydrogen-WTT-Pathways-full-report.pdf.

[67] Hydrogen Council (2021). *Hydrogen Decarbonization Pathways*. Available at https://hydrogencouncil.com/wp-content/uploads/2021/01/Hydrogen-Council-Report_Decarbonization-Pathways_Part-1-Lifecycle-Assessment.pdf.

[68] Race to Zero. *Race to Zero Lexicon*. Available at https://racetozero.unfccc.int/wp-content/uploads/2021/04/Race-to-Zero-Lexicon.pdf.

[69] We do, however, recommend that companies also run sensitivity analysis on their life cycle using the 20-year GWP.

[70] Scope 1: direct emissions from company owned and controlled resources (including fuel use); Scope 2: indirect emissions from the generation of purchased energy (electricity, heat, steam or cooling); Scope 3: all other indirect emissions that occur in the value chain of the reporting company.

[71] A recent survey from Bauer et al. highlights the impact of methane leakage and CCS capture rates for blue hydrogen. Bauer et al. (2021). "On the climate impacts of blue hydrogen production". Pre-print version. Available at https://chemrxiv.org/engage/api-gateway/chemrxiv/assets/orp/resource/item/6141926f27d906e30288cff1/original/on-the-climate-impacts-of-blue-hydrogen-production.pdf.

[72] Our policy recommendations for hydrogen, published in September 2021, define reduced carbon hydrogen at 6 kg $CO_2e$/kg $H_2$ (only applicable to existing grey hydrogen as an interim decarbonization step), low-carbon hydrogen at 3 kg $CO_2e$/kg $H_2$ and ultra-low carbon hydrogen below 1 kg $CO_2e$/kg $H_2$. WBCSD (2021). *Policy Recommendations to Accelerate Hydrogen Deployment for a 1.5°C Scenario*. Available at https://www.wbcsd.org/Programs/Climate-and-Energy/Energy/New-Energy-Solutions/Resources/Policy-Recommendations-to-Accelerate-Hydrogen-Deployment-for-a-1.5-C-Scenario.

[73] Race to Zero. *Race to Zero Lexicon*. Available at https://racetozero.unfccc.int/wp-content/uploads/2021/04/Race-to-Zero-Lexicon.pdf.

[74] Science Based Targets initiative (SBTi). "The Net-Zero Standard". Available at https://sciencebasedtargets.org/net-zero.

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[76] Sources include reports from the Hydrogen Council, IRENA, IEA, CertifHy, Ademe, DLR, Bellona.

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[77] These numbers do not take into account additional emissions from the storage and distribution of hydrogen.

[78] Recent survey from Oni, A.O. et al. (2022). "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*. Volume 254, 15 February 2022, 115245. Available at https://www.sciencedirect.com/science/article/pii/S0196890422000413.

[79] United Kingdom Department for Business, Energy & Industrial Strategy (BEIS) (2021). *Options for a UK low carbon hydrogen standard*. Available at https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1024173/Options_for_a_UK_low_carbon_hydrogen_standard_report.pdf.

[80] This value ranges from 1.3 and 1.8 kg $CO_2e$/kg $H_2$.

[81] This figure is obtained from the following computation:

> Gross emissions (13.0 kg $CO_2e$/kg $H_2$) (i.e., stack emissions (11.0 kg $CO_2e$/kg $H_2$) + upstream (2.0 kg $CO_2e$/kg $H_2$) – steam bonus (2.7 kg $CO_2e$/kg $H_2$).

Taking into account the steam bonus, the "corrected stack" amounts to 8.75 kg $CO_2e$/kg $H_2$.

[82] Feedstock assumption: 80% methane and 20% naphtha – furnace fuel assumed to be methane; credit for steam export = -2.7, so gross CI = 11.

**Disclaimer**

This publication has been developed in the name of WBCSD. Like other WBCSD publications, it is the result of a collaborative effort by members of the secretariat and representatives from member companies. A wide range of members reviewed drafts, thereby ensuring that the document broadly represents the perspective of the WBCSD membership. Input and feedback from members was incorporated in a balanced way. This does not mean, however, that every member company agrees with every word.

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