Environmental Defense Fund

RIFS POTSDAM

Controlling Emissions in Germany's Future Hydrogen Economy

Entry-Points for Policy Action

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RIFS Study
Potsdam
October 2024

Acknowledgements

This study was partially funded by the Environmental Defense Fund (EDF) and was developed in cooperation between the Research Institute for Sustainability (RIFS) and EDF.

The research team would like to acknowledge the valuable inputs and feedback provided by the EDF team. Furthermore, the team would like to thank the following experts for their support and insights during the preparation of the study: Dr. Sofia Esquivel Elizondo, Envionmental Defense Fund; Nils Bruch, Technische Universität Darmstadt; Charlotte Große, DBI-Gruppe; Marco Henel, DBI-Gruppe; Roman Mendelevitch, Öko-Institut; Jenny Sammüller, DBI-Gruppe; Rüdiger Schwarze, TU Bergakademie Freiberg; Martin Wietschel, Fraunhofer Institute for Systems and Innovation Research (ISI).

Executive Summary

Hydrogen has taken on an outsized role in our collective imagination as an energy carrier that will help the world reach a net-zero future, and this is increasingly reflected in concrete policies, plans, and actions. This enthusiasm is based on the hope that hydrogen can become a carbon neutral alternative to fossil fuels, given that hydrogen combustion does not produce carbon dioxide (CO_2). **In the German context, hydrogen is an integral part of its national climate strategy to reach net zero in 2045. It is often seen as the only viable solution for decarbonizing industrial sectors like steel and chemical production.**

To date, the political debate in Germany has concentrated on how to enable a rapid ramp-up of renewable – or 'green' – hydrogen production and to build up the necessary infrastructure, both in Germany and abroad, to secure a sufficient hydrogen supply. Little attention has been paid to the fact that hydrogen, as an indirect greenhouse gas (GHG), contributes to climate change when released into the atmosphere. While the underlying science is well understood, there have been few studies that have systematically assessed the potential climate impact of hydrogen emissions within net-zero scenarios. **With this study, we take a first step towards closing this gap by evaluating the potential warming impact of hydrogen emissions in a future hydrogen economy for Germany, one of the major frontrunners in the sector. Building on our estimates of these impacts, we then identify policy levers at the national, European, and international level to minimize these impacts.** Our results show that hydrogen emissions from an all-green hydrogen value chain in 2045 would amount to 10.8 Mt CO_2e (GWP100). To put this into perspective, this is equivalent to approximately 17% of Germany's projected residual GHG emissions in 2045 in its net zero scenarios.

Reviewing the role of hydrogen as an indirect greenhouse gas

The study begins with a brief review of the underlying climate science, outlining the role of hydrogen as an indirect GHG. That is, hydrogen does not act itself as a GHG, but its chemical reactions in the atmosphere lead to an increase in the abundance of other GHGs, namely methane, tropospheric ozone, and stratospheric water vapor. Taking these reactions into account, a recent multi-model study calculated that the global warming potential of hydrogen over 100 years (GWP100) – the most common metric for evaluating the climate impact of molecules in the atmosphere – is 11.6 ± 2.8. This means that on a per-kg basis, hydrogen is over 11 times more effective in warming than CO_2 on a 100-year timescale (Sand et al., 2023). On a 20-year timescale, hydrogen is even more potent, with a GWP20 value of GWP20 of 37.3 ± 15.1. We use these values to calculate the CO_2-equivalence (CO_2e) of hydrogen emissions in our study.

Estimating hydrogen emissions along the hydrogen value chain

We next describe the hydrogen emissions that can be expected to occur along the hydrogen value chain during production, conversion, transport, and storage. We evaluate the expected magnitude of these emissions based on current knowledge in the field, as well as assumptions regarding technology and policy development. We then choose a range of emission rates for a low ('min') and high ('max') case to be used in our calculations. In addition, we consider CO_2 and CH_4 emissions from fossil-based hydrogen with carbon capture and storage (CCS) – or 'blue hydrogen' – and quantify a range of expected emission rates. These ranges are applied to calculate additional scenarios where blue hydrogen is also part of Germany's hydrogen supply.

Green and blue hydrogen in Germany's net-zero plans

In Section 3 we briefly present Germany's plans for a hydrogen economy, with Germany's National Hydrogen Strategy and the government's net-zero scenarios ('Langfristszenarien') as the centrepieces. These are part of Germany's broader strategy to achieve its climate target of net-zero GHG emissions by 2045. In its updated National Hydrogen Strategy, the federal government expects that Germany will need between 95 and 130 TWh of hydrogen and its derivatives (e.g., ammonia and methanol) by 2030. This includes the existing hydrogen demand of 55 TWh (currently covered by 'grey', natural gas-based hydrogen) as well as a newly-emerging demand of 40 - 75 TW. This new demand for hydrogen is expected to come in large part from industry, most notably from the steel and chemical sectors. Maritime shipping, aviation, and heavy-duty transport are also expected to play a role. Germany aims to produce 30 - 50% (i.e., 30 - 56 TWh) of its hydrogen supply domestically by 2030, focusing on green hydrogen produced from renewable energy sources. To meet the remainder of Germany's projected hydrogen demand, Germany will need to depend on hydrogen imports.

Although direct financial support for hydrogen production is limited to green hydrogen, the updated National Hydrogen Strategy also promotes blue hydrogen, which is planned to be imported in the short- to mid-term. The German government has already entered into co-operation agreements with Norway and the United Arab Emirates (UAE) to facilitate the import of blue hydrogen and its derivatives from these countries to Germany.

Scenarios for estimating the climate impact of Germany's hydrogen plans

With these policy documents as a basis, we develop a range of illustrative scenarios for a German hydrogen economy in 2045. Each scenario represents a potential hydrogen future with assumptions about the amount and type of hydrogen produced, the location of its production and associated transport modes and distances. In all cases, we assume domestic hydrogen production will be green. For imports, we also consider scenarios with shares of imported blue hydrogen. Based on these scenarios, we quantify the expected hydrogen (H_2), methane (CH_4), and carbon dioxide (CO_2) emissions of our scenarios and their global warming potential. In order to highlight a plausible range of emissions intensities (and resulting total emissions), for each scenario we perform a calculation using low ('min') and high ('max') emission rates, as defined in Section 2. For scenarios that include blue hydrogen we perform an additional calculation ('EU-max'), where we assume that imported blue hydrogen will meet (but not exceed) the EU standard for low-carbon hydrogen (with an emissions intensity of 3.38 kg CO_2e per kg of hydrogen).

Significant climate impacts from unmitigated hydrogen emissions

Our results show that hydrogen emissions from an all-green hydrogen value chain in 2045 have the potential to be significant. Under assumptions of high emission rates ('max') in a high hydrogen demand scenario, we find that total hydrogen (H_2) emissions would amount to 10.8 Mt CO_2e (GWP100). To put this into perspective, this is equivalent to approximately 17% of Germany's projected residual GHG emissions in 2045 in its net zero scenarios. Importantly, 64% of the total hydrogen emissions would be 'imported' from a German standpoint, since only a part of the required hydrogen supply would be produced domestically. This means they would not count against Germany's domestic net-zero target. Nonetheless, they represent a significant impact on global climate and point towards the need for action to minimize hydrogen emissions.

Hydrogen emissions from production: large potential impact, large potential for emission reduction

Furthermore, our results show that, under assumption of high ('max') emission rates, production-related losses are the main contributor to hydrogen emissions along the green hydrogen value chain, accounting for over 75% of the total in an all-green scenario. Importantly, the high emission rates during production assume the intentional release of gases during electrolysis (based on current practices of venting from electrodes and during purification). These emission rates can be reduced significantly by capturing the vented hydrogen and recombining it with oxygen to form water. In other words, the main determinant of the emissions footprint of green hydrogen production is an operational practice that could be adapted. This suggests that minimizing the hydrogen emissions during electrolysis would be both technically feasible and effective. Indeed, if hydrogen emissions are minimized along the entire value chain, they can be reduced from 17% to less than 2% of projected residual emissions in 2045, as illustrated by our calculations using low emissions rates ('min').

Furthermore, in a future energy system that assumes less total demand for hydrogen (relying more on direct electrification), hydrogen emissions are significantly decreased, equivalent to about half of the emissions calculated for the high demand scenario. This underlines the benefits of electrification with renewable energy in meeting Germany's energy needs in 2045.

Emissions from blue hydrogen imports: equivalent of 15% of Germany's current GHG emissions in an "all blue" import scenario

Compared to an all-green scenario, the GHG footprint of a German hydrogen economy would look quite different if it included blue hydrogen imports, which yield significant additional emissions of methane and CO_2. While blue hydrogen production generates fewer hydrogen emissions compared to electrolysis, methane as well as CO_2 emissions increase the total emissions significantly. In a scenario where blue hydrogen accounts for 1/3 of total imports, total emissions are 40 Mt CO_2e (GWP100), assuming high emission rates ('max') across the value chain. This is equivalent to 64% of the residual GHG emissions projected in Germany's net-zero scenarios. For comparison: assuming that all hydrogen imports are blue results in nearly 100 Mt CO_2e (GWP100) in emissions. Not only would this be 1.5 times the projected residual emissions in Germany's net-zero scenarios for 2045; it is also equivalent to nearly 15% of Germany's current GHG emissions. This highlights the importance of ensuring low methane leakage rates and high CCS efficiency for blue hydrogen production.

If we alternately assume that imported blue hydrogen would meet the EU definition for low-carbon hydrogen (calculating the CH_4+CO_2 emissions based on the threshold emissions intensity of 3.38 kg CO_2e per kg of hydrogen), we see a significant reduction in the total GHG emissions for blue hydrogen compared to the calculations using our maximum assumed emission rates ('max). That is, assuming high emission intensities for blue hydrogen ('max') - a reasonable representation of current practices - blue hydrogen would not qualify as 'low-carbon'. Even assuming low emission rates ('min') for blue hydrogen - which represent substantial emission reductions compared to the current standard for low-carbon hydrogen - a significant amount of GHG emissions would remain 'embedded' in blue hydrogen imports. In sum, the positive climate impact of green hydrogen clearly outweighs that of blue hydrogen, even assuming that emissions of methane and CO_2 from blue hydrogen are minimized.

Controlling emissions in a hydrogen economy: a review of the regulatory landscape

As a basis for developing policy recommendations based on our calculations, Section 4 provides an overview of relevant regulations of GHG emissions along the hydrogen value chain, both at the national (German) and European level. A distinction is made between regulations that a) set targets, thresholds and methodologies, b) price CO_2 and c) prescriptively control and limit emissions. Of particular importance is the recently adopted Hydrogen and Decarbonized Gas Market Package (HDGMP), which is the first EU regulation to recognize the climate impact of hydrogen emissions. Accordingly, the package stipulates that the methodology for the emission savings of low-carbon hydrogen, which is to be adopted by August 2025, should address the climate impact of hydrogen emissions. Nonetheless, the draft methodology published by the European Commission on September 27th, 2024 for consultation, does not consider hydrogen emissions, citing the need for additional scientific evidence to determine hydrogen's precise global warming potential.

Apart from the standard for low-carbon hydrogen, the HDGMP contains tentative steps for the limitation of hydrogen emissions during transport and storage. Transport and storage operators will be required to measure and report hydrogen emissions more accurately and take initial measures to minimize them. Moreover, the European Commission is tasked with the compilation of a report to assess the risk of climate-damaging hydrogen emissions and to submit legislation to control hydrogen emissions 'if appropriate'.

Hydrogen emissions from the production of hydrogen are regulated by the Industrial Emissions Directive at the EU-level as well as the German National Immission Control Act (BImSchG), which offers more detailed specifications in this regard. However, neither explicitly considers the climate impact of hydrogen emissions. Consequently, existing provisions of the BImSchG only address safety-related requirements. Finally, the EU Methane Regulation contains provisions for minimizing upstream methane emissions, which affects the production of blue hydrogen with natural gas and CCS within the EU. However, the regulation only applies to the import of gas, oil and coal; hence, the upstream emissions of imported blue hydrogen are not covered by the EU Methane Regulation.

Entry-points for policy action at the national, European and international level

Based on the calculations presented in Section 3 and the regulatory landscape and its shortcomings outlined in Section 4, we recommend the following measures at the 1) national, 2) European, and 3) international level:

Make every effort to meet Germany's hydrogen demand with green hydrogen in 2045 and prioritize direct electrification

As shown in our scenarios, blue hydrogen is associated with significantly higher GHG emissions than green hydrogen – even if it meets the EU low-carbon threshold. This necessitates prioritizing green hydrogen in domestic production and imports. To do so, limiting overall hydrogen demand by prioritizing direct electrification wherever possible represents an important no-regret measure.

Swiftly transpose the EU Hydrogen and Decarbonized Gas Market Package (HDGMP) into German law and define maximum H_2 emissions rates for electrolysers

An important first step for addressing hydrogen emissions will be the swift transposition of the HDGMP into national law and its subsequent implementation. In addition, German policymakers should define maximum emission rates for electrolysers and prescribe the implementation of best available techniques (BAT) for emission reduction in the Federal Immission Control Act (BImSchG). This is of particular importance since hydrogen production is responsible for the bulk of emissions from the hydrogen value chain (over 75% of total emissions in our only-green, high demand scenario) and emissions can be reduced cost-effectively. An important point of reference is the guidance for hydrogen production by electrolysis of water which was recently published by the UK government and includes specific provisions for the minimization of hydrogen emissions.

Furthermore, the government should work with network and storage operators to support the implementation of available measures to reduce downstream hydrogen emissions (e.g., tightening of valves and seals, use of laminated gaskets and welded joints, etc.). It should also support further research for the development of market-ready hydrogen leak detection technologies to detect climate-relevant emissions that are not controlled for by safety regulations.

Ensure consideration of H_2 and methane emissions in methodology for calculating GHG savings of low-carbon hydrogen

At the European level, Germany should advocate for the inclusion of hydrogen (H_2) emissions in the draft methodology for low-carbon emission savings. Subsequently, it should promote a corresponding update of the methodology for Renewable Fuels of Non-Biological Origin (RFNBOs) (DR 2023/1185) and the EU taxonomy for sustainable investments. Initially, emission rates can be included on the basis of standard values, but as technology and data improve, these should be replaced by measured and verified emission rates.

Increase GHG savings rate for renewable and low-carbon hydrogen over time and add blue hydrogen to list of imported goods covered by the EU Methane Regulation

Furthermore, the current emissions saving threshold of 70% (3.38 kg CO_2e per kg of hydrogen) for renewable and low-carbon hydrogen (applicable to green and blue hydrogen, respectively) should be increased over time to meet German and the European climate targets. Germany can act as a frontrunner by implementing national legislation that anticipates such a ratcheting-up mechanism at the EU level. Moreover, the EU Methane Regulation (2024/1787) applies only to the import of gas, oil and coal but not that of hydrogen. Adding hydrogen to the list of regulated goods would help minimize methane emissions for all fossil-based hydrogen entering the EU, whether in compliance with the standard for low-carbon hydrogen or not. The planned review of the Methane Regulation in 2028 offers a suitable opportunity for implementing this amendment.

Promote increasingly stringent regulation of H_2 emissions at EU level

Complementing more stringent national regulation to control hydrogen emissions, Germany should promote the regulation of hydrogen emissions from production in the EU’s Industrial Emissions Directive by requiring the implementation of best-available technologies and setting maximum hydrogen emission rates. To underpin effective implementation, policymakers should mandate comprehensive monitoring of hydrogen emissions by the European Environmental Agency and the German Environmental Protection Agency.

To promote formal recognition of hydrogen's impact as an indirect GHG, review and update the value of its GWP100 to reflect the latest science in the next IPCC report

Internationally, Germany should promote greater awareness of hydrogen as an indirect GHG and support including an updated Global Warming Potential (GWP) for hydrogen in the IPCC's upcoming seventh assessment report. This will create a clear reference point that researchers and policy-makers can draw on to quantify the climate impact of hydrogen in future research and regulatory standards, such as the methodology for calculating GHG savings for low-carbon hydrogen.

Incorporate best-in-class provisions regarding methane emissions, CO_2 capture rates and overall transparency when importing blue hydrogen

Additionally, Germany should incorporate best-in-class provisions on methane leakage, CCS efficiency and require high levels of transparency when engaging with partners for the import of blue hydrogen. In the absence of such provisions, Germany risks largely displacing rather than significantly reducing total GHG emissions. In support of this, international certification schemes, which will be crucial to monitor and verify emission rates when importing blue hydrogen, should consider hydrogen's climate-warming impact as an indirect GHG.

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1 Introduction

Hydrogen is an integral part of Germany's climate strategy to reach net zero. We have seen a surge in attention for hydrogen during the last five years, triggered by the hope that it can become a carbon neutral alternative to fossil fuels. Many industrial sectors have started to bet on the widespread of hydrogen and that hydrogen will play an important role in our future low-carbon economy.

Hydrogen is particularly relevant for heavy industries such as iron and steel, for chemical plants and for ammonia production. Hydrogen-based fuels are also an alternative in cases where renewable energies cannot simply replace fossil fuels from an economic or technical perspective. While the political debate has concentrated on how to make (green) hydrogen available as fast as possible and to build up the necessary infrastructure in Germany and abroad, there is an important aspect notably missing from the discussion: hydrogen has the potential to lead to significant climate warming impacts.

Hydrogen (H_2) emissions are released into the atmosphere at all stages of the hydrogen value chain: production, conversion, transport, storage, and end-use. Although hydrogen itself is not a greenhouse gas (GHG), its chemical reactions in the atmosphere lead to increasing concentrations of the GHGs methane (CH_4), tropospheric ozone and stratospheric water vapor. These H_2 emissions occur for all types of hydrogen and are often not accounted for – e.g., in Life Cycle Assessments or climate benefit calculations – despite their climate warming impact. Moreover, it is often taken for granted that 'green' hydrogen, produced by electrolysis using renewable energy, is climate-neutral and that 'blue' hydrogen is 'low-carbon' if its production, based on reforming natural gas, is combined with the removal of the direct CO_2 emissions using carbon capture and storage (CCS). In this study we demonstrate that without attention to developing policies and practices that minimize hydrogen and as well as methane and CO_2 emissions along the hydrogen value chain, we run the risk of counteracting the promised benefits of a hydrogen economy.

The goal of this study is to evaluate the climate impacts of plausible future hydrogen production and deployment pathways (a future 'hydrogen economy') for Germany and to identify policy levers on national, European, and international levels that could minimize these impacts. In Section 2 we provide an overview of the potential climate impact of a future hydrogen economy, explaining hydrogen's role as an indirect GHG and providing an overview of where hydrogen emissions can occur along the hydrogen value chain, using a range of expected emission rates for these different steps. We further consider CO_2 and CH_4 emissions from blue hydrogen and discuss the potential climate impacts of emissions of hydrogen derivatives (particularly ammonia). In Section 3 we focus on Germany's plans for a hydrogen economy. With Germany's National Hydrogen Strategy as a starting point, we develop several illustrative scenarios for domestic and imported green and blue hydrogen, and, based on the emission rates in Section 2, quantify the expected indirect and direct GHG emissions and their global warming potential. Section 4 considers entry points for policy to reduce or avoid these emissions, providing an overview of the current German and EU regulatory landscape relevant for the hydrogen sector. Finally, Section 5 provides recommendations for how to account for and control these emissions along the hydrogen value chain in order to realize the climate benefits of a future hydrogen economy.

2 Warming Impacts of a Future Hydrogen Economy

Hydrogen has taken an outsized role in current scenarios of how the world will reach a net-zero future. In this chapter we provide an overview of the risks posed by hydrogen (H_2) emissions due to their role as an indirect GHG. We use estimates from the literature to assess the amount of hydrogen emissions that can be expected at different points along the value chain; these emission rates are then applied in our analysis in Section 3. We also consider the additional impact of CH_4 and CO_2 emissions from blue hydrogen, to evaluate whether it can be expected to earn its 'low carbon' moniker. While our primary focus is on hydrogen emissions, we also discuss potential emissions of hydrogen derivatives, focusing on ammonia (NH_3), and their impacts. Although not considered in this study, they are also important for understanding the full picture of the environmental impacts of a hydrogen economy.

This study is not an exhaustive analysis of all possible hydrogen futures. Instead, we focus on a range of desirable and plausible scenarios for Germany in 2045, guided by Germany's National Hydrogen strategy and the government's net-zero scenarios. For this reason, we consider only green and blue hydrogen. Nonetheless, it can be expected that all hydrogen production technologies will lead to hydrogen emissions, so many of our findings will still be relevant. When considering hydrogen emissions along the value chain, we do not consider different end-uses of hydrogen, in part because for many of the proposed end-uses it is highly uncertain if hydrogen as an energy source will truly be implemented. Furthermore, emission rates of many end-uses are extremely uncertain due to a lack of measurement data (Fan et al., 2022). Finally, we do not undertake a full lifecycle assessment in this study; emissions from the production of equipment necessary for a hydrogen economy (e.g., electrolysers, solar panels) are not considered.

2.1 Warming impact of hydrogen emissions

To evaluate the potential warming impact of hydrogen emissions in a future hydrogen economy, it is essential to know two things: how much hydrogen we can expect to emit and what the warming impact of these hydrogen emissions are. Hydrogen itself is not a GHG, but its chemical reactions in the atmosphere lead to an increase in the abundance of GHGs, namely methane, tropospheric ozone, and stratospheric water vapor, contributing to climate warming.

Taking into account these reactions, a recent multi-model study by Sand et al. (2023) calculated that the GWP100 for hydrogen is 11.6 ± 2.8. That is, on a per-kg basis, hydrogen is 11.6 times more effective in warming than CO_2. The largest contribution to this warming effect is due to hydrogen-induced changes in methane (44%), followed by tropospheric ozone (38%), and stratospheric water vapor (18%).

The results of Sand et al. (2023) are consistent with two other recent studies which evaluated the GWP100 for hydrogen as 12 ± 6 (Warwick et al., 2023) and 12.8 ± 5.2 (Hauglustaine et al., 2022). Importantly, the uncertainty associated with the calculation of Sand et al. (2023) (one standard deviation is ± 2.8) is in line with uncertainties in the global warming potential for other greenhouse gases. For example, in the latest IPCC report the GWP100 for fossil CH_4 is reported as 29.8 ± 11, and for N_2O 273 ± 130 (Forster et al., 2021). We use the value of GWP100 from Sand et al. (2023) to calculate the CO_2-equivalence of hydrogen emissions in our study (Section 3.3).

Notably, methane and tropospheric ozone are classified as short-lived climate forcers, because their atmospheric lifetimes (ca. 12 years and a few weeks in the troposphere, respectively) are short in comparison to long-lived GHGs such as CO_2, which remains in the atmosphere for centuries to millennia. Hydrogen itself has an atmospheric lifetime of around two years (Sand et al., 2023), which means it is also short-lived. As a consequence, hydrogen acts as a more potent warmer over shorter timescales, which can be better represented by a short-term metric such as GWP20, the global warming potential over a 20-year time period. Sand et al. (2023) calculated that the GWP20 of H_2 is 37.3 ± 15.1, considerably higher than its GWP100. While considering warming impacts over a 20-year timescale (e.g., via GWP20) is arguably equally important as considering a 100-year timescale (as represented by GWP100) (Ocko et al., 2017) – among other things for limiting peak warming and achieving of the UN Sustainable Development Goals – GWP100 remains the standard metric for reporting under the UNFCCC. For this reason, not all GHG emissions benchmarks used in future-looking scenarios are expressed in CO_2 equivalents (CO_2e) calculated with GWP20. We nonetheless use the value GWP20 from Sand et al. (2023), in addition to their GWP100 value, to report the impact of our calculated hydrogen emissions over 20-year and 100-year timescales.

2.2 Emissions of hydrogen along the value chain

In this section we provide an overview of the sources of hydrogen (H_2) emissions along the hydrogen value chain (see Figure 1). We briefly explain the origin of these emissions and discuss their expected magnitude based on current knowledge in the field. The emission rates used for input into our calculations are explained in the relevant subsections and summarized in Figure 2.

In October 2024, a first-ever study reporting the direct detection hydrogen emission rates in situ - at a chemical park in the Netherlands comprising an electrolyser, a hydrogen fuelling station and chemical production plants - was published (Westra et al., 2024). The authors derived aggregated H_2 emissions of up to 4.2% of the production volume, with the daily median being significantly lower, between 0.1 and just over 1%. Note that Westra et al. (2024) could not attribute the emissions to specific elements of the plant (e.g., production vs. storage). The study of Westra et al. (2024) complements a range of studies that estimate hydrogen emission rates at different steps along the hydrogen value chain, often based on assumptions, calculations via proxies, laboratory experiments, or simulations (Esquivel-Elizondo et al., 2023). In the following, we take a closer look at these studies and consider emissions from individual steps along the hydrogen value chain, namely production, conversion, transport and storage.

While the emission rates applied in this study are valuable for orientation, it is not yet possible to precisely quantify (future) hydrogen emissions, although high-precision sensors are under development and will soon become available. The hydrogen value chain can be very complex and variable; beyond the lack of empirical measurements from existing infrastructure, much of the hydrogen infrastructure that will be used in the future is not yet in place.

2.2.1 Hydrogen emissions during production

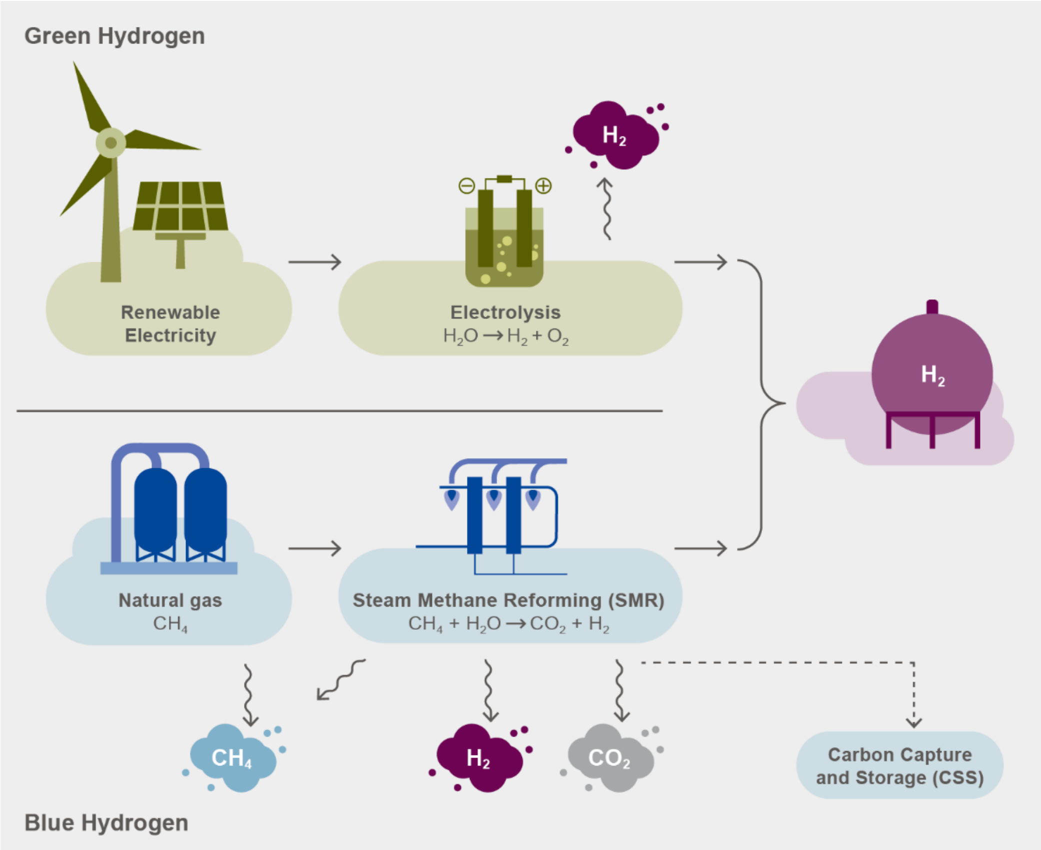
Green hydrogen

One method of generating hydrogen is by electrolysis, which uses electricity to split water into its components: hydrogen (H_2) and oxygen (O_2). If the electricity comes from renewable energy sources, the product is known as 'green hydrogen'. There are several points during the production of green hydrogen in which gases are intentionally released for safety or process reasons, including venting during startup and shutdown and purging during the purification process. These can lead to potentially significant emissions of hydrogen. However, many of these emissions can be avoided by capturing the emitted gases and recombining the H_2 and O_2 to make water. A study by the Frazer-Nash Consultancy (2022) estimates hydrogen emission rates from the production of green hydrogen between 3.32% and 9.20% if venting and purging occur and 0.24% to 0.52% if hydrogen from purging and crossover venting is fully recombined. Consistent with these estimates, a study by Cooper et al. (2022) estimates that future green hydrogen production will lead to hydrogen emissions in the range of 0.1% to 4% of the hydrogen produced by considering a range of technological and regulatory measures that might be implemented by 2045. For the calculations in this study, we apply the range from Cooper et al. (2022) as the lower and upper emission rates for production of green hydrogen (Figure 2).

Blue hydrogen

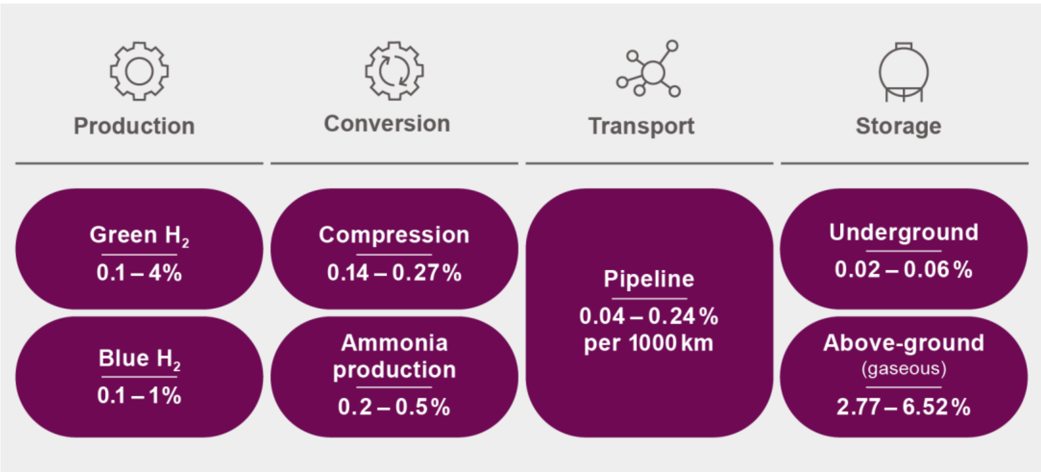
At present, the most widely used method for producing hydrogen is steam methane reforming (SMR), in which methane from natural gas is heated with steam to produce hydrogen and carbon dioxide (CO_2). If the CO_2 produced by SMR is captured and permanently stored, the hydrogen produced is referred to as 'blue' (for a discussion of methane and CO_2 emissions from blue hydrogen, see Section 2.3 below). Due to process differences between SMR and electrolysis, hydrogen emissions from the production of blue hydrogen are expected to be somewhat lower than for green hydrogen. For our calculations we take the lower and upper emission rates from the study of Cooper et al. (2022), who estimate that 0.1% to 1% of the total blue hydrogen produced will be released to the atmosphere.

FIGURE 1. SCHEMATIC DIAGRAM SHOWING PRODUCTION OF GREEN AND BLUE HYDROGEN AND ASSOCIATED EMISSIONS OF HYDROGEN (H_2), METHANE (CH_4), AND CARBON DIOXIDE (CO_2).



Source: Authors.

FIGURE 2. EMISSION RATES OF HYDROGEN (H_2) ALONG THE VALUE CHAIN.

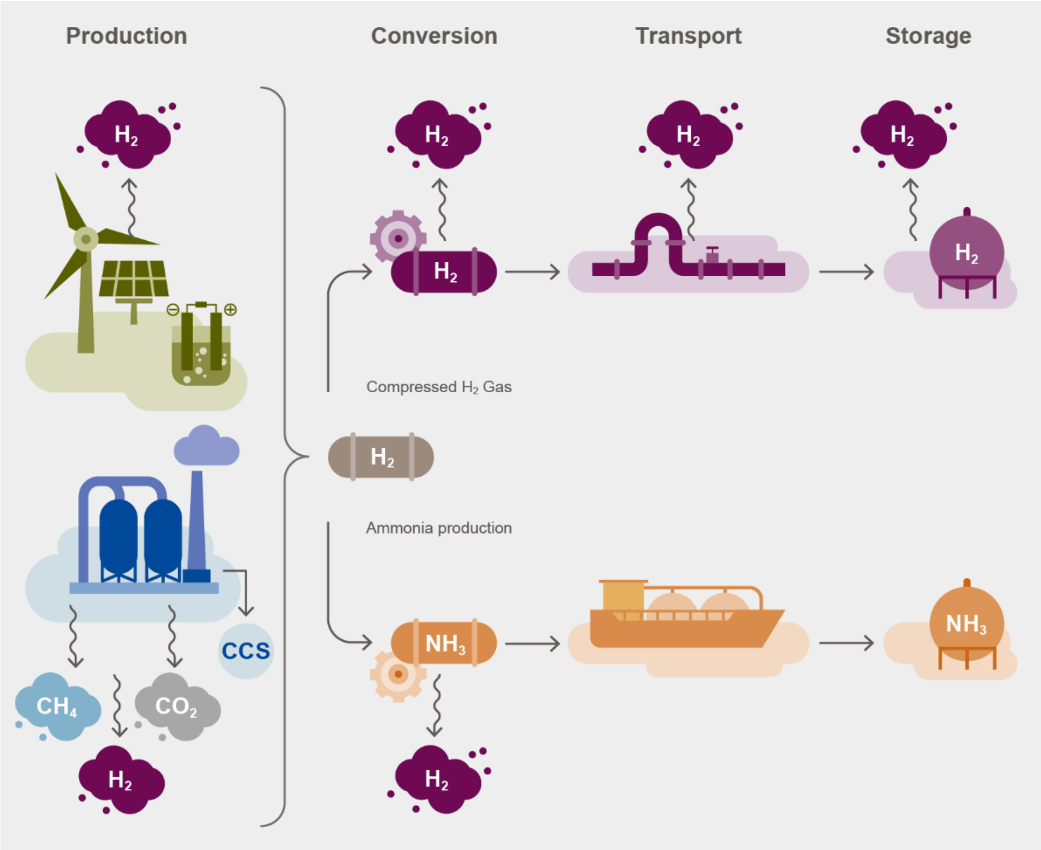


Source: Authors. Note: Percentages apply to the amount of hydrogen produced, converted, transported, or stored. The emission rate for storage represents an average over different storage conditions, including the storage time.

Hydrogen emissions during conversion

Transporting hydrogen poses significant challenges due to its extremely low energy density by volume under normal temperature and pressure conditions. For this reason, gaseous hydrogen is typically converted into another form for storage and transport. There are several different options for this; here we consider conversion to compressed hydrogen gas at high pressures as well as the chemical conversion to ammonia. These options (and associated further steps along the hydrogen value chain) are shown in Figure 3.

FIGURE 3. SCHEMATIC DIAGRAM SHOWING THE STEPS ALONG THE HYDROGEN VALUE CHAIN AND THEIR ASSOCIATED EMISSIONS OF H_2, CH_4, AND CO_2, AS CONSIDERED IN THIS STUDY.



Source: Authors

Compression
For hydrogen to be transported via long-distance pipeline, it needs to be converted to compressed hydrogen gas. During the compression process, it is expected that hydrogen emissions will primarily result from pipework and equipment leakage due to the high pressures involved (compressed hydrogen is typically stored at pressures between 300 and 700 bar). In this study, we have taken the range of hydrogen emission rates during compression of 0.14% to 0.27% from Cooper et al. (2022).

Conversion to ammonia
Ammonia (NH_3) is an attractive choice of hydrogen carrier due to several favourable properties. The energy required for conversion from hydrogen is relatively low, and ammonia can be stored as a liquid or as a gas at more reasonable conditions (e.g., as a liquid at -33°C and standard pressure or a gas at 10 bar and room temperature) (Bertagni et al., 2023). Ammonia can also be burned directly as a fuel in many end-uses.

The conversion of hydrogen to ammonia is achieved via the Haber-Bosch process ($N_2 + 3H_2 \rightarrow 2\ NH_3$). This process is also expected to lead to some hydrogen emissions, but there are no published studies that estimate an emission rate. Here we use an emission rate of 0.2% to 0.5% based on the study of Fan et al. (2022), who based their estimate on a comparison to similar technologies for the production of chemical synthetic fuels.

Infobox 1 Ammonia emissions and their climate and environmental impact

There is the potential for emissions of ammonia to occur during its production, transport and storage, and also further down the ammonia value chain (e.g., use via direct combustion or re-conversion to hydrogen). Since ammonia is toxic to humans and ecosystems, it is expected that significant emission rates will not be tolerated, with some safety regulations already in place. There is little data on emissions of ammonia, and we have not quantified them in this study.

If usage of ammonia increases as part of the growth of a hydrogen economy, it will be important to ensure that emissions are minimized – and not only because of their directly toxic effects. Ammonia also indirectly impacts the climate. First, on short timescales, it forms atmospheric aerosol particles, which reflect sunlight and have a cooling effect. Second, over longer timescales, ammonia gets oxidized to nitrous oxide (N_2O) (Bertagni et al., 2023). This can happen via several pathways, including atmospheric deposition followed by microbial oxidation. Nitrous oxide is a long-lived GHG with a global warming potential (GWP100) of 273 (IPCC, 2021). Ammonia's net impact on climate – weighing the cooling and warming effect on different timescales – has not yet been quantified.

2.2.2 Hydrogen emissions during transport

Infrastructure for the transport of hydrogen will take multiple forms. Here we consider two primary modes of long-distance transport: transport of gaseous hydrogen via pipeline and transport of ammonia via (international) shipping (see also Section 3.3.1). For regional and domestic distribution – i.e., the 'last mile' of transport which gets the hydrogen to the point of end-use (e.g., to a fuelling station) – both distribution pipelines and various forms of truck transport (e.g., high-pressure tube trailers) could be used. In general, it can be assumed that the majority of hydrogen emissions from gaseous hydrogen transport will result from the long-distance rather than local transport, both due to higher pressures (for pipelines) and the longer distances involved (Mendelevitch & Heinemann, 2024).

Transport via pipeline

For transport over long distances, a significant fraction will be sent via pipeline – using both existing (retrofitted) natural gas transmission pipelines and dedicated hydrogen pipelines. In both cases, the hydrogen is transported through the pipelines as compressed gaseous hydrogen at high pressures. Pipelines designed for regional and domestic distribution would operate with lower hydrogen pressures (Hormaza Mejia et al., 2020). Hydrogen can be emitted via pipework leakage, diffusion and venting (Cooper et al., 2022).

For our study, we estimate the hydrogen emission rate due to transport via pipeline based on a study by the Öko-Institut, taking low and high values of 0.04 per 1000 km to 0.24% per 1000 km, respectively (Mendelevitch & Heinemann, 2024). We apply these emission rates to both the international and domestic transport distances (Table A2).

Transport via ship

For our scenarios, we have assumed that hydrogen transported via long-distance shipping will be shipped in the form of ammonia (see also Section 3.3.1). While we account for emissions of hydrogen during the conversion to ammonia (Section 2.2.2), transport of liquid ammonia will not result in any direct hydrogen emissions. However, ammonia emissions can impact the climate (Infobox 1; Bertagni et al., 2023).

2.2.3 Hydrogen emissions from storage

There are many options for storing hydrogen, including in the form of a derivative like ammonia. Since our aim is to quantify emissions of (molecular) hydrogen (H_2), we consider storage options for H_2 (and not for derivatives) here.

Underground storage facilities

Longer-term underground storage of hydrogen can take place in geological formations such as salt caverns, depleted oil and gas reservoirs, and aquifers (Al-Shafi et al., 2023). The more commonly used salt caverns are assumed for this study. The main source of hydrogen emissions from underground storage is expected to occur at the surface processing plant. Releases of hydrogen gas can occur during plant shutdown (planned or emergency) and maintenance activities. We use a range of emission rates of 0.02% to 0.06% based on the estimates of the Frazer-Nash Consultancy (2022).

Above-ground storage facilities
Hydrogen can also be stored in compressed tanks for balancing fluctuations in gas supply and demand, or for example for truck transport or at hydrogen filling stations. Leakage rates are dependent on the storage pressure, storage time, cylinder and valve material, and cylinder size. Assuming the storage of compressed gaseous hydrogen, we take the minimum and maximum leakage rates of 2.77% and 6.52% of total hydrogen stored from the Frazer-Nash Consultancy (2022); these emission rates were derived assuming an average over a variety of end uses and storage conditions.

2.3 Additional GHG emissions from the production of blue hydrogen

In contrast to green hydrogen, production of blue hydrogen also results in emissions of the GHGs methane (CH_4) and carbon dioxide (CO_2), which we consider below.

2.3.1 Methane

In SMR, methane from natural gas is the feedstock used to produce hydrogen. Methane is a potent GHG with a global warming potential nearly 30 times greater than CO_2 over a 100-year timescale.[1] Methane emissions from the natural gas supply chain (referred to as up- and midstream methane emissions) are responsible for a significant fraction of blue hydrogen's carbon footprint. These up- and midstream emissions are expected to be significantly higher than the methane emissions from the SMR production process itself; in our calculations we don't treat methane emissions from production separately. That is, we assume that the total methane emissions from the natural gas supply chain plus SMR production are covered by the range of emission rates we use (see Figures 2 and 4 and discussion below).

Methane emissions from the natural gas supply chain are currently poorly quantified, in part due to lack of measurements and poor data availability as well as large variations in emission intensities depending on factors such as well location and use (or not) of practices like venting and flaring. Satellites are being increasingly used to quantify methane, including the newly-launched MethaneSat, which will quantify methane emissions from the global down to the local scale (https://www.methanesat.org/).

In this study, methane emission intensities for blue hydrogen production are assumed for a low and a high case. For the low case, we assume a methane emission rate of 0.2%, corresponding to the Oil and Gas Climate Initiative's target for 2025 (Barry, 2023). For the high emissions case, we assume an emission rate of 4% of the total methane input into the blue hydrogen production process (Lin et al., 2021).

2.3.2 Carbon dioxide

In the SMR process, CH_4 reacts with water, producing hydrogen and carbon monoxide ($CH_4 + H_2O \rightarrow CO + 3H_2$). The carbon monoxide (CO) then reacts with water to produce CO_2 and additional hydrogen ($CO + H_2O \rightarrow CO_2 + H_2$). Thus, the SMR process itself produces carbon dioxide as 'process emissions.' In addition, the energy to power the SMR process is generally generated by combustion of fossil fuels, producing CO_2 emissions.

The production of blue hydrogen assumes the application of carbon capture and storage (CCS) to the SMR process. Currently, capture rates of operating CCS plants coupled to hydrogen production are only 50-60% overall (Collodi et al., 2017). This low rate of capture is mainly due to the fact that only the CO_2 from the process emissions (syngas) is captured, and not from the combustion emissions. Carbon capture rates of 90% have been demonstrated for setups where CO_2 from both gas streams is captured (Office of Fossil Energy and Carbon Management, 2024). However, this technique has not yet been applied for the production of hydrogen with SMR. In this study, we assume a CCS efficiency of 60% in a low case (representing today's capture rates) and 90% in a high case (see Figure 4).

Notably, there is increasing interest in alternate technologies for hydrogen production such as air-fed autothermal reforming (ATR). For ATR it is expected that CCS would be more cost effective because carbon dioxide emissions from the ATR process are nearly entirely confined to the process gas stream and are more highly concentrated (Gorski et al., 2021). However, using ATR is currently only common for the production of ammonia and methanol, and not yet for the industrial production of blue hydrogen (Gorski et al., 2021).

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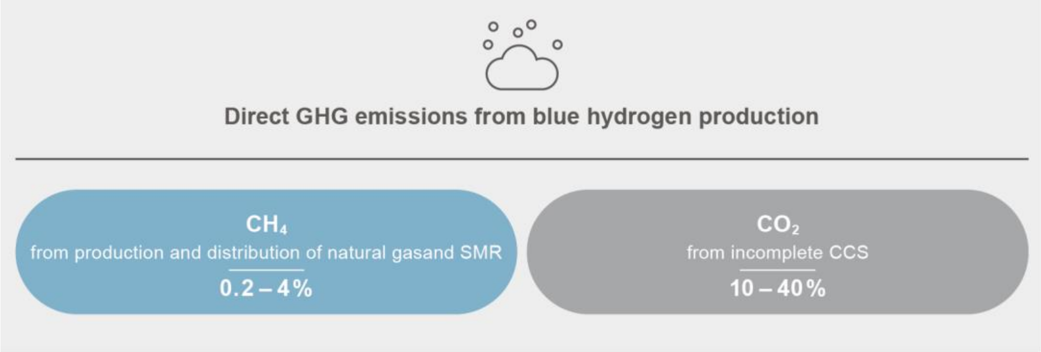
[1] The GWP100 of methane was assessed as 27.9 in the IPCC Sixth Assessment Report (Smith et al., 2021). Over a 20-year timescale the impact is even greater: the GWP20 of methane is 81.2 (Smith et al., 2021).

FIGURE 4. EMISSION RATES OF METHANE (CH_4) AND CARBON DIOXIDE (CO_2) FROM BLUE HYDROGEN PRODUCTION USED IN OUR SCENARIOS.



Source: Authors.

2.4 Emissions for blue hydrogen based on the EU definition of 'low-carbon' hydrogen

In Sections 2.2 and 2.3, we provide a process-based view of direct and indirect GHG emissions along the hydrogen value chain, considering production, conversion, transport, and storage. Based on current data and expectations regarding the future development of technology and regulations, we have selected high and low emission rates for each step, which we then use to calculate emissions in our study. For simplicity, the calculations using the high and low emission rates throughout are labelled ‘max’ and ‘min’, respectively. Note that they reflect the maximum and minimum of the values used in the context of this study rather than maxima and minima of all existing estimates on emission rates.

For blue hydrogen, the methane and CO_2 emissions resulting from ‘max’ emission rates (and resulting total emissions) are quite high. Although these high emissions rates are in many cases a realistic representation of current practices (particularly the low capture rates for CO_2), it is likely that future blue hydrogen imports by Germany (see discussion in Section 3.3.2) will meet the EU standard for ‘low-carbon’ hydrogen as recently defined in the Hydrogen and Decarbonized Gas Market Package (HDGMP). The definition specifies that there must be a 70% reduction in GHGs compared to fossil fuels, which translates into a maximum emission intensity of 3.38 kg CO_2e per kg of hydrogen produced (see also Sections 4.1 and 4.3). Although the HDGMP indicated that the methodology for calculating GHG emissions savings for low-carbon hydrogen should consider emissions due to the leakage of hydrogen, the recently-published draft methodology does not consider H_2 emissions, citing an insufficient level of precision for hydrogen's global warming potential (GWP100).

Based on these developments, we use a third approach for calculating emissions in our scenarios that include blue hydrogen: namely, instead of applying process-based leakage rates, we assume the blue hydrogen value chain will emit CH_4+CO_2 at a rate of 3.38 kg CO_2e per kg of hydrogen, so that it (just) meets the definition for low-carbon hydrogen. We refer to these calculations as 'EU-max,' as they can be considered an alternate 'maximum' level of emissions in Germany’s future hydrogen economy in 2045. Following the methodology for renewable fuels of non-biological origin (RFNBOs; see Section 4.1), we apply the threshold emissions intensity (i.e., 3.38 kg CO_2e per kg of hydrogen). In our 'EU-max' calculations, hydrogen emissions resulting from the production of blue hydrogen as well as emissions from green hydrogen along its value chain are based on the high (max) emission rates as described in Section 2.2 and Figure 1.

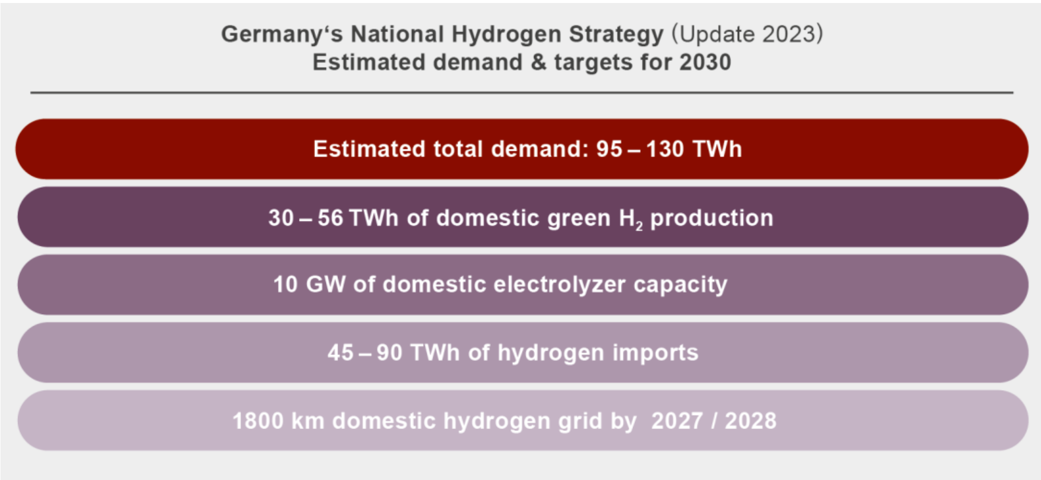
3 Germany's Future Hydrogen Economy: What is its potential GHG footprint?

This chapter explores Germany's future hydrogen economy and its potential contribution to GHG emissions, both direct and indirect. Section 3.1 outlines the National Hydrogen Strategy (updated in 2023), highlighting key targets for domestic production, infrastructure, transport and storage, as well as import pathways. Section 3.2 briefly discusses the government's 'Langfristszenarien' (long-term scenarios) for carbon neutrality by 2045. Against this backdrop, Section 3.3 quantifies potential hydrogen (H_2) and hydrogen-related (i.e., CH_4 and CO_2) emissions across different illustrative scenarios for Germany's hydrogen economy in 2045. The analysis includes both emissions along the domestic supply chain as well as from hydrogen imports, thus quantifying potential residual emissions not accounted for in the German government's net-zero scenarios.

3.1 Germany's National Hydrogen Strategy: a short overview

Germany's National Hydrogen Strategy, initially adopted in 2020 and updated in 2023, is part of the government's wider climate protection goal,[2] which aims to reduce GHGs by 65% by 2030 and 88 percent by 2040 (compared to 1990 levels) and achieve net zero GHGs by 2045 (BMWK, 2023a). The updated hydrogen strategy is divided into four fields of action in the period until 2030: ensuring hydrogen availability, building an efficient infrastructure, implementing hydrogen applications, and creating effective framework conditions (BMWK, 2023b). Against this backdrop, Germany plans to develop its future hydrogen economy in two phases: the first focuses on building a domestic market, while the second phase foresees increased import of European and international hydrogen resources. Figure 5 provides an overview of the key projections and targets of the updated strategy.

FIGURE 5. KEY TARGETS OF THE GERMAN NATIONAL HYDROGEN STRATEGY, UPDATE 2023.



Source: Authors.

3.1.1 Expected hydrogen demand by 2030

In its updated hydrogen strategy, the federal government expects that Germany will need between 95 and 130 TWh of hydrogen and its derivatives (e.g., ammonia and methanol) by 2030, with a potential increase depending on price and market developments in the coming years (BMWK, 2023b). This includes the existing hydrogen demand of 55 TWh (currently covered by 'grey', natural gas-based hydrogen) as well as a newly emerging

[2] Adopted under the German Climate Protection Act in 2019.

demand of 40 to 75 TWh, as projected in various energy scenarios[3] (BMWK, 2023b). The new demand for hydrogen is expected to come in large part from industry, most notably from the steel and chemical sectors; maritime shipping, aviation, and heavy-duty transport are also expected to play a role. Some use is also expected in the electricity sector to ensure back-up capacity in times of scarce renewable resources. However, the predicted demand for hydrogen and its synthesis products varies significantly across different GHG reduction scenarios and studies (Wietschel et al., 2021).

3.1.2 Hydrogen supply

Germany aims to produce 30 - 50% (i.e., 30 - 56 TWh) of its hydrogen supply domestically by 2030, focusing on 'green' hydrogen produced from renewable energy sources. Through a mix of policy instruments, electrolysers with a capacity of up to 10 gigawatts (GW) are planned to be installed by 2030 for domestic hydrogen production (BMWK, 2023b). The majority of electrolysers will be located in the Northern parts of Germany due to the relative abundance of renewable (primarily wind) energy and proximity to potential hydrogen storage locations (Wietschel, 2021; 2023).

Due to limited domestic production capacities, Germany will be heavily dependent on future hydrogen imports (Westphal et al., 2020; Quitzow et al., 2024). In its strategy, the government estimates that 50 - 70% (i.e., 45 - 90 TWh) of the projected demand for 2030 will have to be covered by imports from European and non-European countries in the form of hydrogen and hydrogen derivatives (BMWK, 2023b). In line with projected market and price developments after 2030, a separate hydrogen import strategy, published in July 2024, projects that demand for imports will increase to 360 - 500 TWh of molecular hydrogen, and about 200 TWh of hydrogen derivatives (e.g. ammonia, methanol) and other synthetic hydrocarbons by 2045 (BMWK, 2024c).

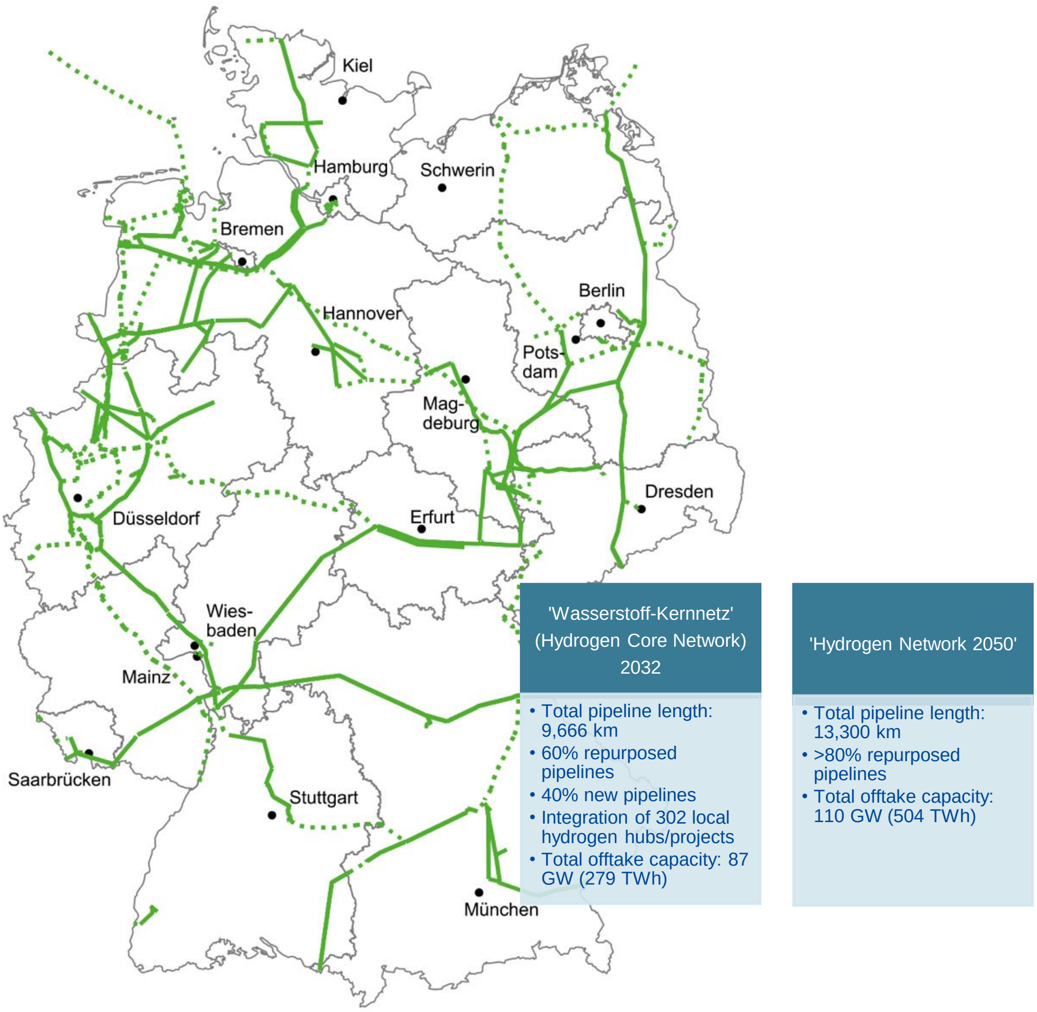
Although direct financial support for hydrogen production is limited to green hydrogen, the updated hydrogen strategy also promotes low-carbon ('blue') hydrogen based on natural gas combined with carbon capture and storage (CCS), which is planned to be imported in the short- to mid-term. The German government has already entered into cooperation agreements with Norway and the United Arab Emirates (UAE) to facilitate the import of blue hydrogen and its derivatives from these countries to Germany (BMWK, 2022; BMWK, 2023c). To ensure a positive climate balance when using this energy carrier, the national hydrogen strategy advocates for the development of 'ambitious' emission standards for the production of blue hydrogen. There are no explicit targets or estimates of the amount of blue hydrogen imports the government expects.

3.1.3 Transport, distribution and storage

The updated hydrogen strategy further includes plans for creating an initial domestic hydrogen grid by 2027-2028, comprising 1,800 km of new and refurbished pipelines. Expanding this initial infrastructure plan, a law establishing the legal framework for integrating the German 'Kernnetz' (core network) into a network development plan for hydrogen and natural gas was passed in April 2024 (BMWK, 2024a). This 'Wasserstoff-Kernnetz' (hydrogen core network), which will connect large consumer and producer regions in Germany, will be put into operation between 2025 and 2032 (see Figure 6) (FNB Gas e.V., 2024a). The final plan for the 9,666 km hydrogen core network was submitted to the Federal Network Agency in July 2024 and is also integrated into the European Hydrogen Backbone to accelerate the development of a trans-European hydrogen infrastructure (BMWK, 2024b). In the long-term, the core network will be expanded into a 'Hydrogen Network 2050' with a targeted offtake capacity of over 500 TWh of hydrogen (FNB Gas e. V., 2024b). The BMWK announced a separate strategy for the storage of hydrogen to be published at the end of 2024 (BMWK, 2024c).

3 This refers to projections made in the government's 'Langfristszenarien' (long-term scenarios) for Germany's energy system in 2045, which is discussed in more detail below.

FIGURE 6. DRAFT MAP AND KEY PARAMETERS OF THE GERMAN HYDROGEN INFRASTRUCTURE PLAN. SOLID LINE: REPURPOSED PIPELINE. DOTTED LINE: NEW PIPELINE.



Source: FNB Gas e. V. (2024a)

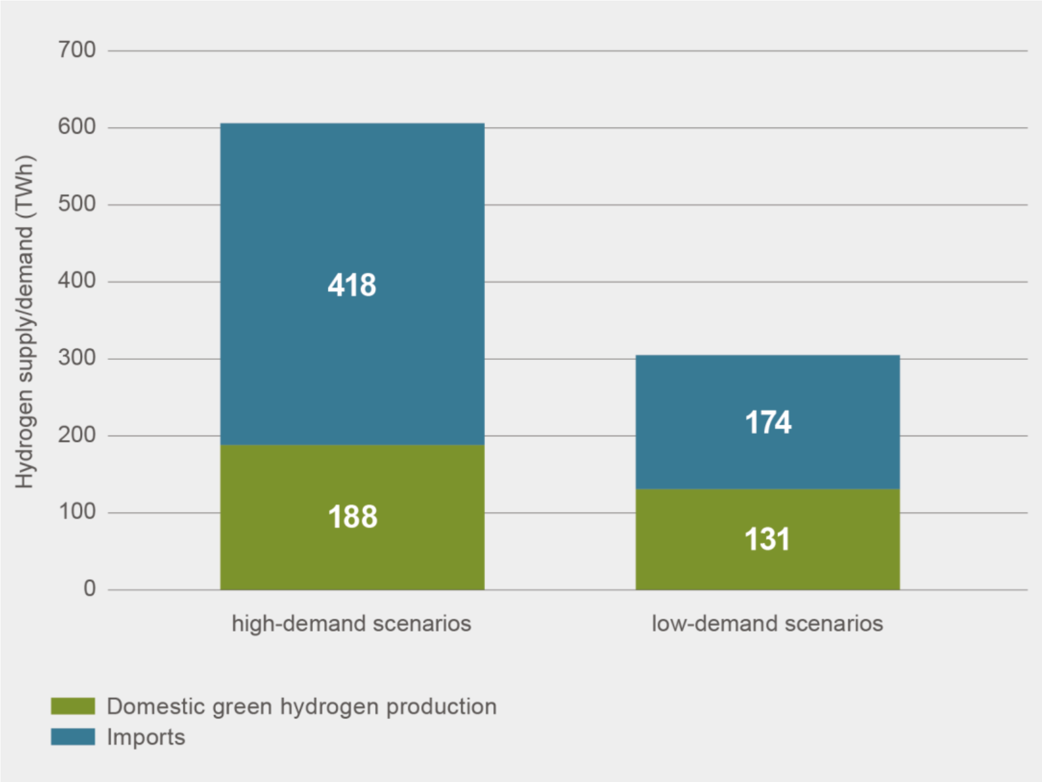
Regarding international transport routes, the government plans the parallel development of pipelines (for imports from Europe and neighbouring countries) and import terminals (for international ship-based imports). Currently planned onshore LNG terminals are being built 'H_2-ready' so that they can be retrofitted for hydrogen at no more than 10-15% of the investment cost. Pipeline development initially focusses on the North-Sea region, with the first pipeline to be built between Germany and Denmark, starting operation in 2028; from 2030 onwards, further pipeline imports are planned from Norway, the Netherlands and Belgium. Additionally, the German government is advancing infrastructure projects along designated import corridors from non-European countries. These include the South-West and Southern Corridor, where new and repurposed pipelines are planned to enable imports from Spain, Portugal and possibly Morocco via France to Germany ('H2Med' and 'Hy-FEN') as well as from Algeria and Tunisia via Italy, Austria and possibly Switzerland ('SouthH2') (BMWK, 2024c). Moreover, a Central European Hydrogen Corridor was initiated in 2021 to develop hydrogen transport infrastructure from Ukraine via Slovakia and Czech Republic to Germany (CEHC, 2024). While most imports are expected to be pipeline-based by 2045, ships will remain significant for derivative imports.

3.2 Long-term scenarios for a climate-neutral energy system in 2045

While the hydrogen supply and demand forecasts at the core of the national hydrogen strategy are limited to projections for 2030, the government has also commissioned the development of long-term net-zero scenarios that model possible pathways to reaching carbon neutrality by 2045. They encompass the entire energy system, including generation of electricity, heat, and hydrogen, as well as the future demand for hydrogen across the industry, transportation, buildings and appliances sectors. Hydrogen infrastructures and future import-export flows are also modelled (Senßfuß et al., 2021 and updates[4]). Due to their longer time horizon and regular updates, these scenarios differ from the national hydrogen strategy in their estimates and projections for a hydrogen-based future German energy system.

This report draws on two recently developed long-term scenarios as the basis for quantifying a low- and a high-demand case for hydrogen in our subsequent analysis: the first case prioritizes direct electrification and relies less on the use of hydrogen (referred to as 'Low Demand' in this report), while the second case relies more heavily on hydrogen with less direct use of electricity (referred to as 'High Demand' in this report).[5] Figure 7 provides an overview of the estimated quantities of domestic hydrogen production as well hydrogen imports in the two cases.

FIGURE 7. PROJECTIONS FOR GERMAN HYDROGEN SUPPLY/DEMAND IN 2045.



Source: Authors, based on the Langfristszenarien (Senßfuß et al., 2021 and updates).

3.3 Estimating GHG emissions in Germany's future hydrogen economy

3.3.1 Technical assumptions, parameters and scenarios

While research on the GHG emissions implications of Germany's hydrogen plans is expanding, precise assessments are challenging as many components along the supply chain remain uncertain (see Riemer et al., 2022; Heneka & Mörs, 2022; Agora Industry & TU Hamburg, 2023; Guidehouse, 2024; Gatzen et al., 2024; Mendelevitch & Heinemann, 2024). Germany's net-zero strategy and the government's long-term scenarios for 2045 are modelled based on an emissions reduction target of at least 95% compared to current levels and only include electricity-based hydrogen. The projected residual emissions in these net-zero scenarios (63 Mt CO_2e, GWP100) represent the total domestic GHG emissions that Germany will not have eliminated by 2045 and will thus require offsetting through carbon dioxide removal (CDR) to achieve Germany's net zero target. Importantly, these residual emissions do not include any hydrogen emissions from the value chain.

We build and expand upon previous studies' contributions by assessing direct and indirect GHG emissions in different scenarios for a German hydrogen supply chain in 2045. In

4 Updated scenarios, used in our analysis, are available at https://langfristszenarien.de/enertile-explorer-de/dokumente/.
5 In the original 'Langfristszenarien' (long-term scenarios), the 'High Demand' scenario is labeled as 'O45-H2' and the 'Low Demand' scenario is labeled as 'O45-Electricity' (Senßfuß et al., 2021 and updates).

addition to hydrogen emissions in the domestic green hydrogen supply chain, we also quantify upstream hydrogen emissions of green hydrogen imports as well as additional methane and CO_2 emissions of imported blue hydrogen. Even though these emissions are not generated in Germany itself but in the exporting countries, they nevertheless play an important role for the overall GHG footprint contribution of Germany's future hydrogen economy[6]. Our analysis therefore sheds light on potential direct and indirect GHG emissions not accounted for in the German government's net-zero scenarios for 2045, as well as differences in emissions intensity of alternative import options and pathways.

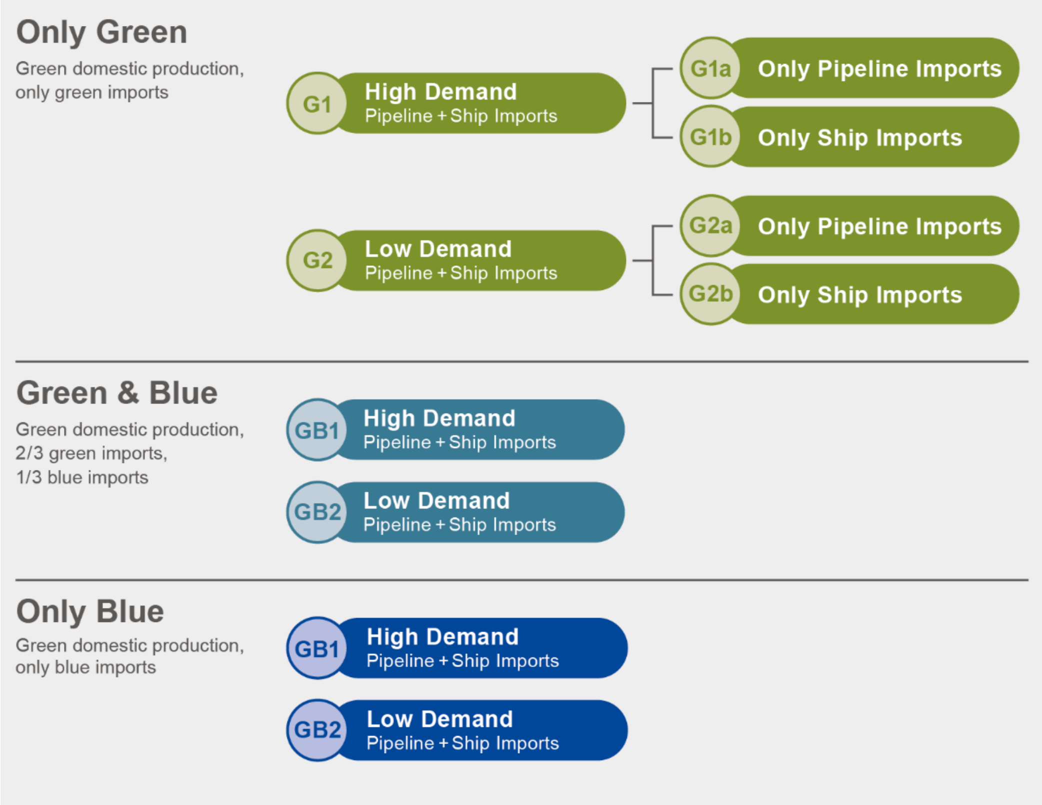
While we adopt the parameters for domestic production and import quantities of the long-term scenarios ('High Demand' and 'Low Demand' case), other assumptions such as the ratio of ship-based vs. pipeline-based transport, green vs. blue hydrogen imports as well as average international and domestic transport distances reflect illustrative estimates based on the government's hydrogen strategy as well as previous studies' calculations. In addition, background conversations with several experts in Germany were held to validate our assumptions and key findings. For simplification and illustration, we make several baseline assumptions (see Tables A2 and A3 in Appendix for further information):

- First, we assume that only green hydrogen will be produced domestically in Germany in 2045, in line with the policy framework of the national hydrogen strategy; if blue hydrogen is used, it will be imported.
- Second, we assume that molecular hydrogen is imported exclusively by pipeline and derivatives exclusively by ship. For derivatives we focus on ammonia as it is already shipped internationally in significant volumes, and major terminal projects are currently under development in Northern Germany, with estimated completion by 2030 (BMWK, 2024c).
- Third, for pipeline imports of hydrogen, we assume an illustrative distance of 3,300 km for imports from North Africa (e.g., Algeria, Morocco, Tunisia), and a representative distance of 1,200 km for imports from within Europe (e.g., Norway, Denmark, Netherlands), in order to have two broadly representative values of the government's current pipeline plans (BMWK, 2024c; 2024d). For simplification, we distribute pipeline imports evenly across both regions (half from within Europe, and half from North Africa).
- Fourth, for domestic hydrogen transport and distribution, we assume an average distance of 350 km, which serves as a simplified but illustrative distance between major industry clusters (where hydrogen demand will be highest) and hydrogen import/storage facilities in the Northern parts of Germany (Wietschel, 2023).
- Fifth, estimates for storage capacity reflect only values for gaseous (pipeline-transported) hydrogen storage.
- Sixth, blue hydrogen is assumed to be produced (in the exporting country) through SMR in combination with CCS.

We then develop three illustrative scenarios for a German hydrogen supply chain in 2045 with variations in total demand as well as the type of imported hydrogen: only green imports ('G' scenarios), green and blue imports ('GB' scenarios), and only blue imports ('B' scenarios) (see Table A3). As part of the 'G' scenarios (only green H_2 imports), which reflect an exclusively green hydrogen supply chain in 2045, we also vary the means of transport (pipeline or ship) in order to highlight the implications of different import pathways for total emissions. In the 'GB' scenarios (green and blue H_2 imports), we illustrate the role of additional upstream emissions – specifically the impact of methane and CO_2 – assuming that one third of all imported hydrogen in 2045 will be blue. Finally, the 'B' scenarios (only blue H_2 imports) serve as an illustration of additional upstream emissions from methane and CO_2 production assuming all imported hydrogen will be blue. Taken together, these scenarios allow us to illustrate the potential magnitude of hydrogen emissions within a green hydrogen supply chain that are not accounted for in the net-zero scenarios, and to shed light on relevant upstream GHG emissions if Germany was to also import (a share of) blue hydrogen in 2045.

6 Only GHG emissions occurring on German territory are counted towards the national climate balance; emissions from imported hydrogen are attributed to the country where these emissions occur and would reflect imported or 'embedded' emissions which officially are not accounted for.

FIGURE 8. ILLUSTRATIVE SCENARIOS FOR HYDROGEN ECONOMY IN GERMANY IN 2045 USED IN OUR CALCULATIONS.



Source: Authors.

3.3.2 Results and discussion

Our assessment of hydrogen (H_2), methane (CH_4), and carbon dioxide (CO_2) emissions across different hydrogen supply scenarios for Germany in 2045 highlights the range of potential emissions of hydrogen, methane, and CO_2 resulting from hydrogen production, conversion, transport, and storage. The main results of our calculations are summarized in Table 1 below, which comprises a selection of scenarios for ease of comparison. Table A1 in the Appendix includes a full summary of our scenario results. Each scenario represents a potential hydrogen future with assumptions about the amount and type of hydrogen produced, the location of its production and associated transport modes and distances (Figure 1, Table A3). To highlight a plausible range of expected emissions intensities (and resulting total emissions) depending on assumptions regarding technology and policy development (see Sections 2.2 and 2.3), we perform two calculations based on the low and high emission rates discussed in Section 2 (referred to as 'min' and 'max' respectively) for each scenario. For scenarios that include blue hydrogen we perform an additional calculation ('EU-max') applying an alternate approach for calculating the 'maximum' emissions from blue hydrogen, where we assume that imported blue hydrogen will meet the EU standard for low-carbon hydrogen and apply the associated threshold for emissions intensity (3.38 kg CO_2e per kg of hydrogen, see Section 2.4).

Table 1 presents our calculation of H_2, CH_4, and CO_2 emissions for our scenarios, shown in units of Mt CO_2e calculated using both GWP100 and GWP20. For most scenarios, we see that the total emissions in Mt CO_2e are significantly higher if CO_2 equivalence (CO_2e) is calculated on the basis of GWP20; this is because both hydrogen and methane emissions are more potent on shorter timescales (see discussion in Section 2.1). For scenarios that are dominated by CO_2 emissions (e.g., B1 using 'min' emission rates), the difference between using GWP100 and GWP20 is smaller.

For interpreting our results, one benchmark we use is the projected residual emissions assumed in Germany's net zero scenarios in 2045: 63 Mt CO_2e, calculated using GWP100. This serves as a point of reference to evaluate whether emissions calculated for the hydrogen value chain are comparatively large or small. Note that a gas-by-gas breakdown of the projected 63 MtCO2e of residual emissions is not available, and it is thus not possible to convert these residual emissions to MtCO_2e based on GWP20.

TABLE 1. OVERVIEW OF EMISSIONS ALONG THE HYDROGEN VALUE CHAIN FOR SELECTED SCENARIOS.

<table>
<tr><th rowspan="2">Scenario</th><th rowspan="2">Emission rates</th><th rowspan="2">Total emissions (Mt CO_2e) [GWP100]</th><th rowspan="2">Total emissions (Mt CO_2e) [GWP20]</th><th rowspan="2">Equivalent % of residual emissions in 2045 [GWP100]</th><th colspan="3">Split into emitted gases (Mt CO_2e) [GWP100]</th></tr>
<tr><th>H_2</th><th>CH_4</th><th>CO_2</th></tr>
<tr><td rowspan="2">G1</td><td>Min</td><td>1.04</td><td>3.36</td><td>1.7 %</td><td>1.04</td><td>0.00</td><td>0.00</td></tr>
<tr><td>Max</td><td>10.80</td><td>34.72</td><td>17.1 %</td><td>10.80</td><td>0.00</td><td>0.00</td></tr>
<tr><td rowspan="2">G2</td><td>Min</td><td>0.71</td><td>2.29</td><td>1.1 %</td><td>0.71</td><td>0.00</td><td>0.00</td></tr>
<tr><td>Max</td><td>5.84</td><td>18.78</td><td>9.3 %</td><td>5.84</td><td>0.00</td><td>0.00</td></tr>
<tr><td rowspan="3">GB1</td><td>Min</td><td>5.74</td><td>9.38</td><td>9.1 %</td><td>1.04</td><td>0.75</td><td>3.94</td></tr>
<tr><td>Max</td><td>40.15</td><td>87.46</td><td>63.7 %</td><td>9.33</td><td>15.06</td><td>15.75</td></tr>
<tr><td>Max-EU</td><td>23.57</td><td>*</td><td>37.41 %</td><td>9.33</td><td colspan="2">14.24</td></tr>
<tr><td rowspan="3">GB2</td><td>Min</td><td>2.67</td><td>4.80</td><td>4.2 %</td><td>0.71</td><td>0.31</td><td>1.64</td></tr>
<tr><td>Max</td><td>18.09</td><td>40.79</td><td>28.7 %</td><td>5.23</td><td>6.29</td><td>6.57</td></tr>
<tr><td>Max-EU</td><td>11.17</td><td>*</td><td>17.73 %</td><td>5.23</td><td colspan="2">5.94</td></tr>
<tr><td rowspan="3">B1</td><td>Min</td><td>15.15</td><td>21.47</td><td>24.1 %</td><td>1.04</td><td>2.26</td><td>11.84</td></tr>
<tr><td>Max</td><td>99.06</td><td>193.32</td><td>157.2 %</td><td>6.39</td><td>45.30</td><td>47.37</td></tr>
<tr><td>Max-EU</td><td>49.20</td><td>*</td><td>78.10 %</td><td>6.39</td><td colspan="2">42.81</td></tr>
<tr><td rowspan="3">B2</td><td>Min</td><td>6.58</td><td>9.83</td><td>10.5 %</td><td>0.71</td><td>0.94</td><td>4.93</td></tr>
<tr><td>Max</td><td>42.58</td><td>84.80</td><td>67.6 %</td><td>4.01</td><td>18.86</td><td>19.72</td></tr>
<tr><td>Max-EU</td><td>21.83</td><td>*</td><td>34.65 %</td><td>4.01</td><td colspan="2">17.82</td></tr>
</table>

*Since the EU emissions intensity threshold is for aggregated GHG emissions and defined based on GWP100, it is not possible to present results using GWP20.

In Table 2 we show which of our calculated emissions are produced domestically (i.e., in Germany); the remainder of the emissions are produced outside of Germany and are therefore considered 'imported' or 'embedded' from a German standpoint. This is politically relevant because only domestic emissions are required to be considered within Germany's national climate accounting – i.e., only domestically-produced residual emissions need to be compensated to reach Germany's net zero goal for 2045.[7] In the 'G' scenarios that consider exclusively green hydrogen, roughly 30-70% of the (hydrogen) emissions produced are domestic. In scenarios that include blue hydrogen, the proportion of international emissions is significantly higher. This is because these scenarios assume that any blue hydrogen in Germany's hydrogen mix would be imported, with the overall warming impact being primarily driven by the CO_2 and CH_4 emissions associated with blue hydrogen production. While these emissions are extremely relevant for the global climate, they would not be counted towards Germany's national climate balance.

7 And as of now, hydrogen is not officially recognized as an indirect GHG and is excluded.

TABLE 2. OVERVIEW OF THE SHARE OF DOMESTIC (VS IMPORTED) EMISSIONS ALONG THE HYDROGEN VALUE CHAIN FOR SELECTED SCENARIOS.

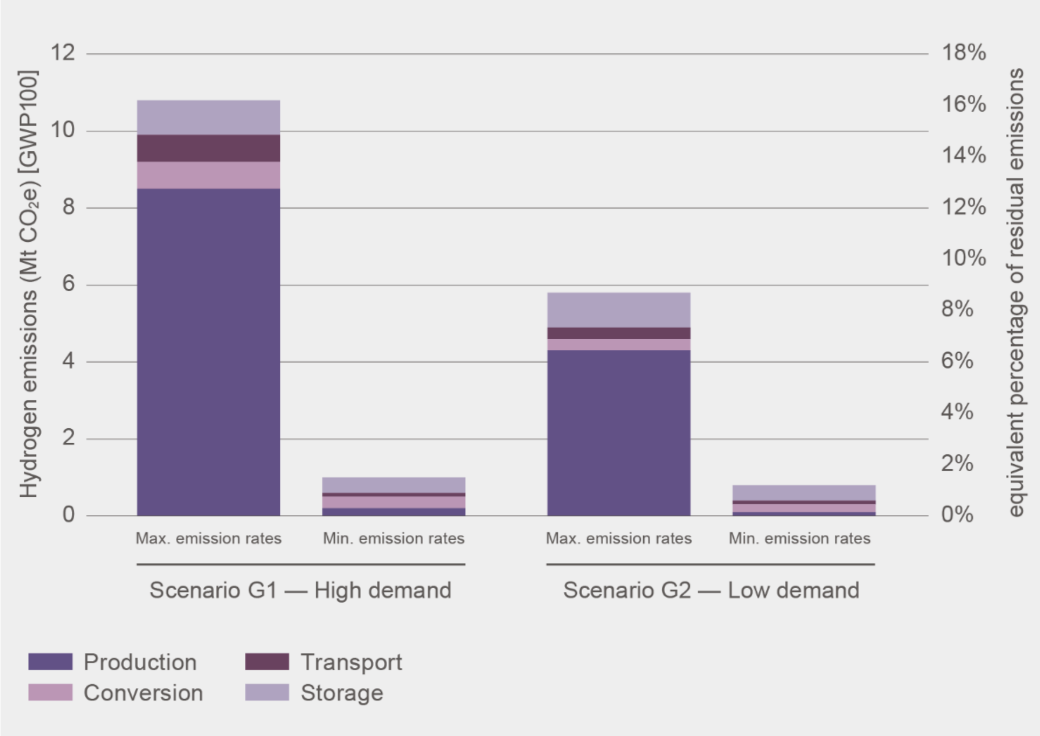
Scenario	Emission rates	Total emissions (Mt CO_2e) [GWP100]	Domestic emissions (Mt CO_2e) [GWP100]	Total emissions (Mt CO_2e) [GWP20]	Domestic emissions (Mt CO_2e) [GWP20]
G1	Min	1.04	0.57 (55 %)	3.36	1.85 (55 %)
	Max	10.80	3.88 (36 %)	34.72	12.47 (36 %)
G2	Min	0.71	0.52 (72 %)	2.29	1.70 (74 %)
	Max	5.84	2.96 (51 %)	18.78	9.51 (51 %)
GB1	Min	5.74	0.57 (10 %)	9.38	1.85 (20 %)
	Max	40.15	3.88 (10 %)	87.46	12.47 (14 %)
	Max-EU	23.57	-	-	-
GB2	Min	2.67	0.52 (19 %)	4.80	1.66 (35 %)
	Max	18.09	2.96 (16 %)	40.79	9.51 (23 %)
	Max-EU	11.17	-	-	-
B1	Min	15.15	0.57 (4 %)	21.47	1.85 (9 %)
	Max	99.06	3.88 (4 %)	193.32	12.47 (6 %)
	Max-EU	49.60	-	-	-
B2	Min	6.58	0.52 (8 %)	9.83	1.66 (17 %)
	Max	42.58	2.96 (7 %)	84.80	9.51 (11 %)
	Max-EU	21.83	-	-	-

*The Max-EU calculation for the blue hydrogen imports apply the threshold emissions intensity assuming it covers the whole value chain, so the emissions cannot be separated into domestic vs. imported. Furthermore, since the EU emissions intensity threshold is for aggregated GHG emissions and defined based on GWP100, it is not possible to present results using GWP20.

Green hydrogen: Indirect greenhouse gas effect of hydrogen emissions

First, looking at the all-green hydrogen scenarios for Germany's future energy system (G1 and G2), the impact of hydrogen emissions varies significantly depending on emission rates (see also Section 2.2 and Table 1). Under assumptions of high ('max') emission rates, we calculate that the total emissions would amount to almost 11 Mt CO_2e in a high-demand scenario (G1). To put this into perspective: this value represents approximately 17% of Germany's projected residual GHG emissions in 2045 under its net-zero scenario. By contrast, assuming low ('min') emission rates, the climate impact would be significantly smaller, equivalent to less than 2% of the projected residual GHG emissions for 2045. Notably, the maximum hydrogen emissions in a future energy system that relies less on green hydrogen and more on electrification (G2) are only about half of those compared to the high-demand scenario (G1) (Table 1 and Figure 9). This points to the important role of electrification with renewable energy in meeting a share of Germany's clean energy needs in 2045, and hence in reducing indirect GHG emissions from hydrogen.

FIGURE 9. HYDROGEN EMISSIONS RESULTING FROM SCENARIOS USING ALL GREEN HYDROGEN (G1 & G2).

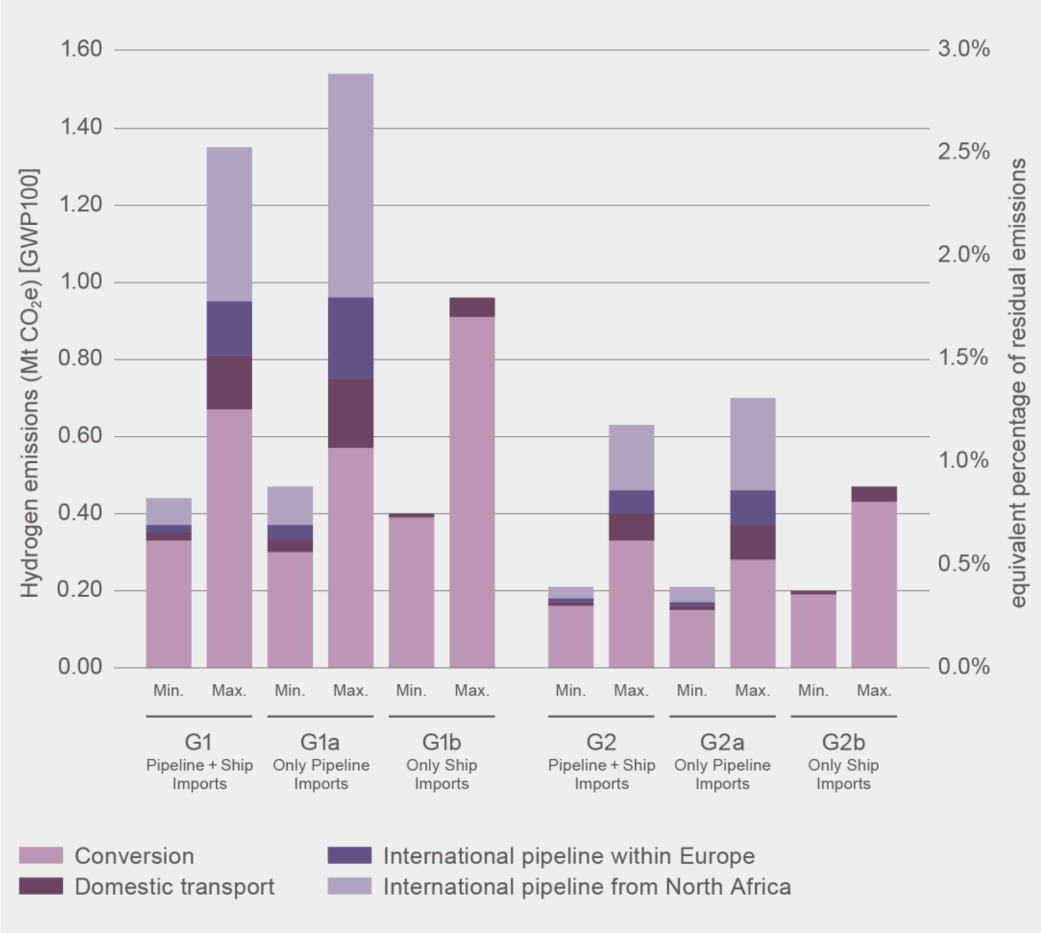


Source: Authors.

Furthermore, our results show that under assumption of high emission rates, production by electrolysis emerges as the primary source of hydrogen emissions along the value chain for green hydrogen (Figure 9). Importantly, the maximum emission rate assumes the intentional release of gases due to the practices of venting and purging of hydrogen from the electrodes, and during the purification step (commonly referred to as 'hydrogen venting'). By contrast, the minimum emissions rate assumes that such gas release is minimized by capturing the vented hydrogen and recombining it with oxygen to form water, thereby reducing emissions. Consequently, the main determinant of the emissions footprint during hydrogen production is the operational practice employed. If minimum emission rates are assumed, the contribution of electrolysis to hydrogen emissions decreases significantly and emissions resulting from conversion and storage play a larger role. Hydrogen emissions from transport are comparably low.

Given the high share of hydrogen emissions during electrolysis (under assumptions of high emission rates), green hydrogen imports to Germany would already carry substantial 'embedded' emissions from production. In addition to these, a smaller amount of hydrogen emissions would also result from compression and transport via pipeline to (and within) Germany. Here, our results highlight that particularly the distance transported via pipeline plays a role: total hydrogen emissions from transport within Europe would be significantly less than those of transport from North Africa (Figure 10). By contrast, in the case of ship-based imports of ammonia, hydrogen emissions would result only from the conversion process and not from transport to Germany, thus making shipping the 'least' hydrogen emissions-intense import mode in our scenarios. Instead, the transport via ship could lead to potentially significant emissions from ammonia leakage, which are not quantified in this study (see Infobox 1 in Section 2.2).

FIGURE 10. COMPARISON OF HYDROGEN EMISSIONS FOR DIFFERENT TRANSPORT MODES.



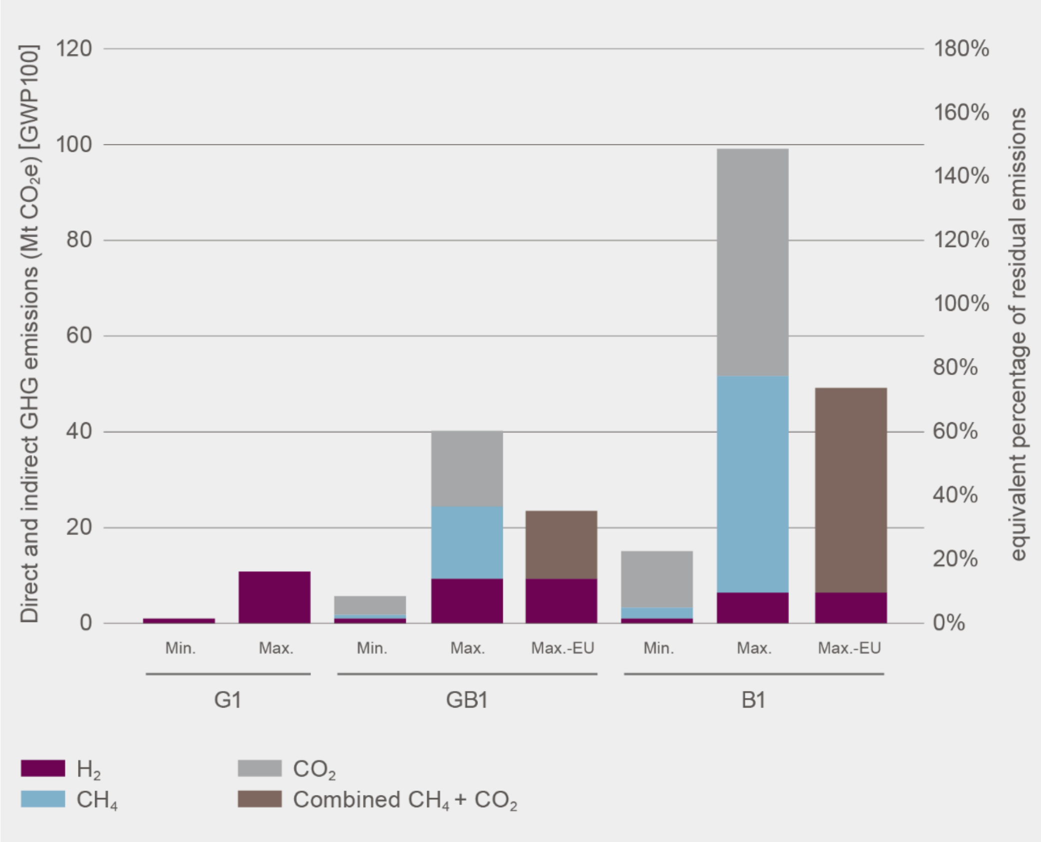
Source: Authors.

Blue hydrogen: Direct greenhouse gas effect from methane and CO_2 emissions
Compared to an all-green scenario, the GHG footprint of a German hydrogen economy would look quite different if it included blue hydrogen imports. If one third of all imported hydrogen in 2045 were blue (GB1), Germany's supply chain would yield significant additional upstream emissions of methane and CO_2 (Figure 11). While blue hydrogen production generates fewer hydrogen emissions compared to electrolysis, CH_4 as well as CO_2 emissions would increase the total emissions of blue imports to approx. 40 Mt CO_2e [GWP100], assuming max. emission rates. This is equivalent to 64% of the residual GHG emissions projected in Germany's net-zero scenarios (Table 1).

Hence, compared to a high-demand scenario in which only green hydrogen is imported (G1), the import of blue hydrogen (representing 1/3 of total hydrogen imports) in GB1 results in significant additional emissions of methane and CO_2. For comparison: assuming that all hydrogen imports are blue (B1) results in nearly 100 Mt CO_2e [GWP100] in emissions, assuming max. emission rates. Not only would this be 1.5 times the projected residual emissions in Germany's net-zero scenarios for 2045; it is also equivalent to nearly 15% of Germany's current GHG emissions (673 Mt CO_2e in 2023[8]).

8 Data from the German Umweltbundesamt, see https://www.umweltbundesamt.de/en/press/pressinformation/climate-emissions-fall-101-per-cent-in-2023-biggest#:~:text=In%20total%2C%20around%20673%20million,further%20action%20on%20climate%20protection

FIGURE 11. COMPARISON OF EMISSIONS IN HIGH-DEMAND SCENARIOS UNDER THREE DIFFERENT ASSUMPTIONS REGARDING EMISSION RATES.



Source: Authors.

The large quantities of methane and CO_2 emissions highlights the importance of methane leakage rates and CCS efficiency in countries that plan to export blue hydrogen. High CCS efficiency and low methane leakage (as targeted for example by Norway) would significantly reduce the upstream emissions of Germany's blue hydrogen imports. For blue hydrogen, we also calculate total CH_4 + CO_2 emissions assuming that the imported blue hydrogen would meet the EU definition for low-carbon hydrogen ('max-EU' calculations). We see in Figure 11 and Table 1 that applying the EU threshold for low-carbon hydrogen to the blue hydrogen imports ('max-EU') significantly reduces the total emissions in comparison to the calculations using our maximum assumed emission rates ('max'). That is, assuming 'max' emission intensities for blue hydrogen (which are a reasonable representation of current practices and emission rates), the blue hydrogen would not qualify as 'low-carbon'.

On the other hand, assuming low ('min') emission rates results in less emissions than applying the threshold emission intensity for low-carbon hydrogen. However, even assuming 'min' emission rates for blue hydrogen (which would qualify as low-carbon hydrogen), a significant amount of GHG emissions would remain 'embedded' in blue hydrogen imports. In sum, the positive climate impact of green hydrogen clearly outweighs that of blue hydrogen, even assuming that emissions of methane and CO_2 from blue hydrogen are minimized. Moreover, since information on individual countries' upstream leakage rates and emissions management is not readily available, there remains significant uncertainty about precise accounts of emissions resulting from future blue hydrogen imports to Germany.

To conclude, our results highlight the role of unaccounted-for domestic hydrogen emissions as well as 'embedded' emissions from imports for the GHG emissions profile of a German hydrogen supply chain in 2045. Even though the internationally emitted fraction of emissions from imported hydrogen are not attributed towards Germany's national GHG balance, they present a significant risk for global warming that needs to be accounted for when it comes to hydrogen's contribution to a global net-zero economy. While green hydrogen clearly offers a lower emissions footprint compared to blue hydrogen, uncertainties regarding total demand, emission rates and choice of transport pathway could impact the effectiveness of Germany's hydrogen strategy in meeting climate targets. Furthermore, our analysis does not fully account for lifecycle emissions, such as those associated with the production of equipment used for green hydrogen production; however, these factors play a crucial role in the broader debate about hydrogen's environmental impact (see e.g., Terlouw et al., 2024).

4 Existing Regulatory Landscape for Hydrogen Emissions and other Hydrogen-related GHG Emissions

The existing regulation of GHG emissions along the hydrogen value chain in Germany is primarily determined at the European level. A distinction can be made between legislation that defines political targets, definitions and thresholds along with related methodologies for assessing compliance (Section 4.1), instruments of carbon pricing (Section 4.2) and directives and regulations aimed at controlling emissions by prescribing compliance with environmental, health and safety standards (Section 4.3). In each case, different stages of the hydrogen value chain and different types of emissions are included. Collectively, they provide the framework for controlling GHG and hydrogen emissions (see the following Figure 12 for an overview). In the following, the main elements of these policies and regulations are outlined and remaining gaps are identified.

4.1 Targets, definitions and thresholds

The European Union's strategic (though non-binding) targets for the hydrogen ramp-up are defined in the EU hydrogen strategy (COM/2020/301) and the REPowerEU plan (COM(2022)230), which aim for the production of up to 10 million tons of renewable hydrogen within the EU and up to 10 million tons to be imported from outside the EU. The Renewable Energy Directive (RED) III (2023/2413) is the EU's central policy for defining and promoting hydrogen from renewable energy but does not consider hydrogen emissions.[9] In the transport sector, RED III requires that at least 1 % of fuel demand is covered by so-called renewable fuels of non-biological origin (RFNBOs), encompassing renewable hydrogen and its derivatives. For industry, it requires that 42% of industrial gases come from renewable sources by 2030 and 60% by 2035.[10] Finally, it defines RFNBOs as liquid and gaseous fuels the energy content of which is derived from renewable sources other than biomass. To be recognized as RFNBOs, these fuels have to be produced with electricity that meets the EU criteria for renewable energy and achieve a 70% reduction of GHG emissions compared to fossil fuels (EP & Council, 2023a).

The methodology for calculating the GHG savings of RFNBOs has been laid out in a delegated regulation (DR) supplementing the RED (EC, 2023a). DR 2023/1185 sets out the methodology for calculating the emissions saved from RFNBOs compared to the fossil comparative value of 94 g CO_2e per MJ (resulting in the 70% threshold of 28.2 g CO_2e per MJ, equivalent to 3.38 kg CO_2e per kg of hydrogen).[11] In principle, the methodology attempts to include the entire value chain except the manufacturing of the machinery and equipment used. However, the methodology only records carbon dioxide (CO_2), nitrogen oxide (N_2O) and methane (CH_4) emissions from the supply of rigid and elastic inputs,[12] from processing, from transport and distribution and from the combustion of fuel in its end-use. Possible emission savings from carbon capture and geological storage are deducted (EC, 2023b). Since the DR only covers CO2, N2O, and CH4, it does not account for hydrogen emissions.

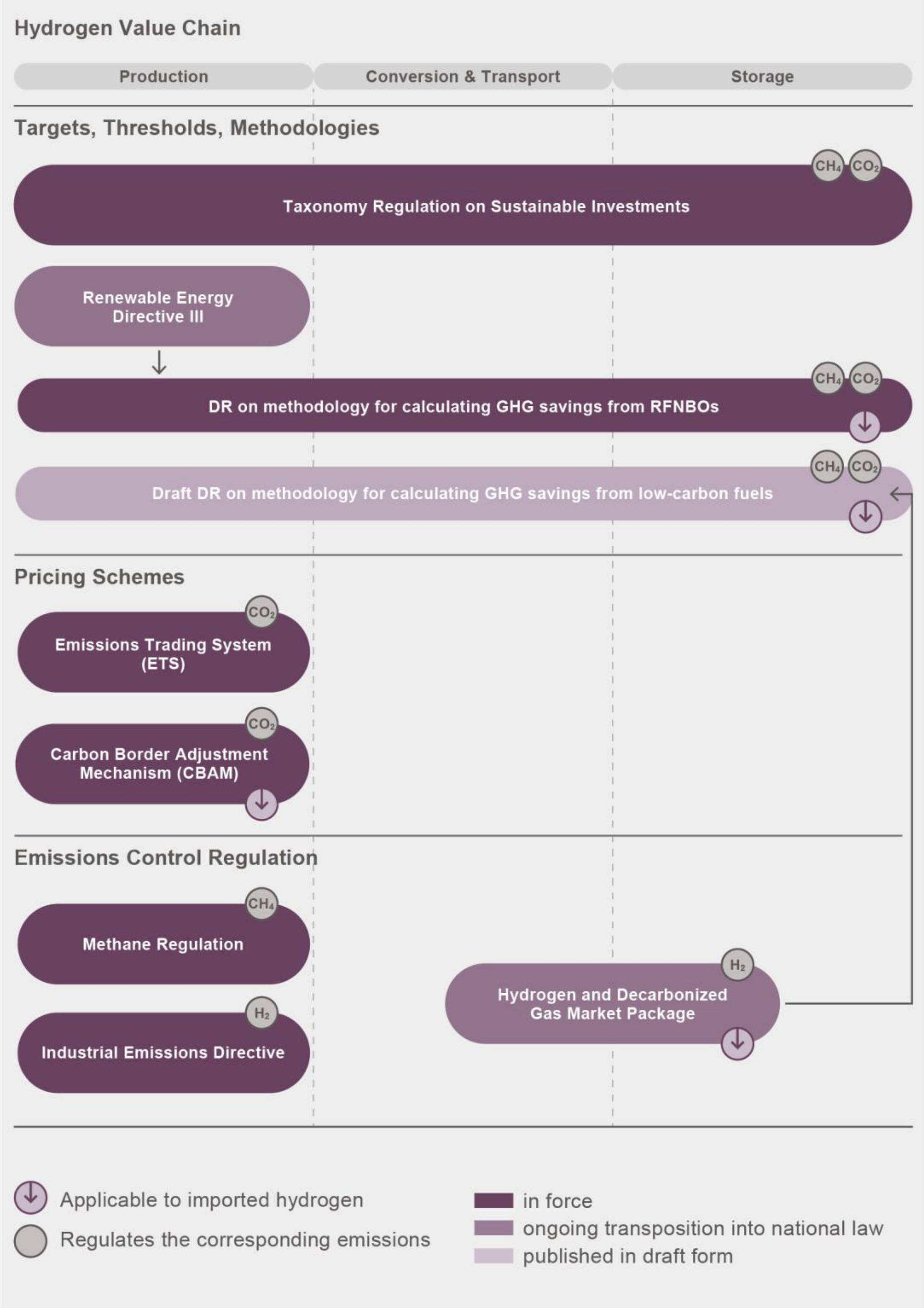
9 Currently, most of the RED II provisions are still in force since member states have an 18-month period (starting from 20 November 2023) to transpose most of the RED III provisions into national law, with a shorter deadline, of July 2024 for some provisions related to permitting for renewables (EP & Council, 2023a).

10 The precise methodology for calculating the quota as well as possible reductions are stipulated in EC (2024b).

11 Recycled carbon fuels are also regulated by DR 2023/1185 but will not be addressed in this report.

12 Rigid inputs are inputs where 'supply cannot be expanded to meet extra demand'. Elastic inputs are inputs where 'supply can be increased to meet extra demand', such as hydrogen, electricity and petroleum (Heinemann et al., 2023a).

FIGURE 12. OVERVIEW OF EXISTING EU REGULATIONS ALONG THE HYDROGEN VALUE CHAIN.



Source: Authors.

Moreover, the recently adopted Hydrogen and Decarbonized Gas Market Package (HDGMP) defines low-carbon hydrogen. Low-carbon hydrogen can be produced from non-renewable energy sources but has to meet the same 70% emissions saving threshold as RFNBOs (EP & Council, 2024a, Article 2 (11)). In addition, §9 (5) announces a delegated act (DA) to establish a methodology for calculating the emissions saved. A first draft for consultation was published on September 27th, 2024 and does not include hydrogen emissions (see more detailed discussion in 4.3.1).

In addition to the RED, the EU taxonomy for sustainable activities (2020/852) and the supplementary DR (2021/2139) contain criteria for considering hydrogen and related activities as contributing to climate change mitigation which qualifies hydrogen activities for subsidies and administrative exemptions. Included here are the production of hydrogen, the chemical storage of electricity in the form of hydrogen and the deployment of transmission and distribution networks for renewable and low-carbon gases. The central criterion is an emissions saving threshold of 73.4% for hydrogen and 70% for hydrogen-based synthetic fuels. Since the taxonomy regulation builds on DR 2023/1185, hydrogen emissions are also not considered for the purpose of greenhouse gas accounting (EP & Council, 2020; EC, 2021).

Finally, to verify compliance with the sustainability and greenhouse saving criteria described above, §30 of RED III provides for the establishment of a mass balance certification system (EP & Council, 2023a).[13] Mass balance systems are distinguished from book-and-claim models by the fact that they link the certificate to the delivery of the respective physical product. Hence, they require the physical tracking of certified hydrogen along the supply chain (Seebach, 2023). While the EU does not provide for the establishment of a corresponding certification scheme, §30 and the Implementing Regulation 2022/996 on rules to verify sustainability and greenhouse gas emissions saving criteria lay down standards and principles that must be met by voluntary national and international schemes to be recognized by EU. The standards make provisions regarding the governance structure of voluntary schemes (§3), the internal monitoring (§5), the selection of independent audit and verification bodies by the scheme (§11) and the audit process itself, which requires that economic operators successfully pass an initial audit before allowing them to participate in the scheme (§10). Furthermore, specific rules are set for the audits of mass balance systems and their implementation (§15, §19) and recycled carbon fuels and renewable fuels of non-biological origin (§22) (EC, 2022). The RED, §30(3), states that these obligations shall apply regardless of whether renewable fuels and recycled carbon fuels are produced within or are imported into the Union. As of September 2024, three voluntary and national certification schemes have been pre-certified (i.e., had their technical programme approved) to validate RFNBOs and are now waiting to be formally recognized by the EC (EC, 2024a).[14]

4.2 Carbon pricing: the EU ETS and CBAM

The EU's Emissions Trading System (ETS) (2003/87/EC) requires companies to hold ETS allowances for CO_2 emissions but no other direct or indirect GHG emissions in the energy, industry, and parts of the transport sector, including the production of hydrogen. In 2023 the EU introduced the Carbon Border Adjustment Mechanism (CBAM), which targets imports to the EU and obliges companies that import a number of energy-intensive products to the EU to purchase certificates equivalent to EU ETS allowances. Until 2025, CBAM operates in a transitional period, during which importers of hydrogen, ammonia or steel (as energy-intensive goods) are subject to monitoring and reporting obligations. From 2026 onwards, certificates for direct emissions[15] must be purchased for hydrogen, ammonia and steel. Both ETS and CBAM are limited by the fact that they only address CO_2 but not hydrogen emissions or other non-CO_2 emissions and include only emissions from production (EP & Council, 2024b; EP & Council, 2023b).[16]

4.3 Emissions control regulations

4.3.1 Regulating transport and storage of hydrogen: the Hydrogen and Decarbonized Gas Market Package

The recently adopted Hydrogen and Decarbonised Gas Market Package (HDGMP), consisting of a Directive (2024/1788) and a Regulation (2024/1789), aims to update the rules of the European gas market to account for a growing share of renewable and low-carbon gases. While the package has a broad scope, it also contains provisions specifically designed to minimize hydrogen emissions during transport and storage. As outlined above (see Section 4.1), it also defines a GHG savings threshold for so-called low-carbon hydrogen (EP & Council, 2024a; 2024c).

In principle, the package represents an important step forward for the regulation of hydrogen emissions. The package not only addresses GHG emissions associated with the hydrogen value chain but also acknowledges the warming impacts of hydrogen. The wording is clear: 'Methane and hydrogen contribute to global warming. Their leakage from the natural gas and hydrogen system should thus be avoided in line with the energy efficiency first principle and in order to minimize their climate impact' (EP & Council, 2024a,

13 While schemes have to comply with the criteria and threshold set out above, they are free to go beyond these.

14 However, the recognition by the EC is not a requirement for EU countries to recognize certification schemes.

15 'To calculate direct emissions, all processes occurring in the installation directly or indirectly linked to hydrogen production and all fuels used in the production of hydrogen irrespective of their energetic or non-energetic use are covered'. (Graichen et al., 2023).

16 CBAM also covers indirect emissions linked to the electricity that is used in the production process. Moreover, from 2026 onwards methane and other emissions will be included in an additional shipping ETS.

preamble). In concrete terms, this is expressed in §9(5), which requires the development of a 'Methodology on greenhouse gas emissions savings from low-carbon fuels', which is to be adopted by August 2025, must be consistent with DR 2023/1185 for RFNBOs, applying the same 70% GHG emissions savings rate, and address hydrogen and methane emissions:

'That methodology shall be consistent with the methodology for assessing greenhouse gas emissions savings from renewable liquid and gaseous transport fuels of non-biological origin and from recycled carbon fuels, including the treatment of emissions due to the leakage of hydrogen, and take into account methane upstream emissions and actual carbon capture rates.' (§9).

In addition, §9(4) states that the obligations also apply regardless of whether low-carbon fuels are produced within the EU or imported.

Despite the reference to hydrogen emissions in the directive, the draft methodology, published for consultation on September 27th, 2024, does not require operators to consider hydrogen emissions along the value chain when calculating their GHG savings. This is justified by the fact that hydrogen's global warming potential has not been determined with the required level of precision. Instead, it states that hydrogen emissions will be included once the required scientific evidence is available (Draft Methodology, Preamble, Paragraph 5).

Apart from the GHG savings threshold, the directive refers to a number of monitoring and reporting requirements related to hydrogen emissions, which could later translate into more clearly defined requirements for operators. §9(6) refers to a report to evaluate hydrogen leakage, including environmental and climate risks, technical specificities and adequate maximum hydrogen leakage rates which the EC is tasked to submit 'where appropriate'. Based on this report, the Commission should, 'if appropriate', submit a legislative proposal to minimize possible risks of hydrogen leakage, set maximum hydrogen leakage rates and establish compliance mechanisms. It remains unclear, however, under what conditions such a report that could lead to further legislative measures must be compiled.

In addition, §50(1) on the tasks of the hydrogen network, storage and terminal operators defines responsibilities of the operators to reduce hydrogen emissions. It states that these shall take 'all reasonable measures available to prevent and minimize hydrogen emissions in their operations and carrying out, at regular intervals, a hydrogen leak detection and repair survey of all relevant components under the operator responsibility' (ibid., §50). It leaves open, however, what 'all reasonable measures' would entail. The operators are tasked to submit a hydrogen leak detection report and, if necessary, a repair or replacement programme to the competent authorities. The directive also requires that they publish statistical information on hydrogen leak detection and repair (LDAR) yearly. To ensure the enforcement of these obligations, the HDGMP grants regulatory authorities the ability to penalize operators who do not comply with requirements to minimize hydrogen leakage. According to §78(4) regulatory authorities are granted the power to impose (or propose to a competent court) penalties of up to 10% of the annual turnover of the transmission system operator or hydrogen network operator. Complementing this, §59 of Regulation 2024/1789 provides for the establishment of the European Network of Network Operators for Hydrogen (ENNOH). One of the tasks of this new body will be the development of best practices for the detection, monitoring and reduction of hydrogen leaks.[17]

4.3.2 Regulating hydrogen production: the Federal Immission Control Act and the Industrial Emissions Directive

In Germany, the Federal Immission Control Act (BImSchG) aims to limit emissions from industrial plants but does not adequately control direct hydrogen emissions. Its implementing regulation requires that harmful environmental impacts and other dangers are avoided and related precautions are taken (BImSchG, Section 5, Paragraph 1, 4). Crucially, however, no threshold value for the emission of hydrogen from electrolysers exists. This means that emissions through leakage, venting and purging are not effectively regulated in Germany. It is also important to note that existing safety regulations, namely Germany's Technical Rules for Hazardous Substances (TRGS) on hazardous explosive mixtures (in particular TRGS 720 – 723), also do not effectively regulate hydrogen emissions as they treat hydrogen exclusively as an explosive and hence safety-relevant substance, but not as an indirect GHG. For example, the blowing out of hydrogen remains a permissible practice; measures are only taken to prevent the accumulation of explosive gas concentrations.

17 In a position paper on HDGMP, ENTSOG criticizes the creation of the ENNOH and argues that it could lead to a fragmentation of the energy system and a disintegration of gas and hydrogen modelling and planning activities (ENTSOG, 2022).

More broadly, smaller leaks that may not be safety-relevant but can have aggregate significant climate effects are not addressed.

At the EU-level, the Industrial Emissions Directive (2010/75/EU) addresses emissions generated during industrial production. Its effect on limiting hydrogen emissions during the stage of production is limited for two reasons, however. Firstly, it only covers larger production units with a capacity of at least 50 tonnes of hydrogen production per day. Secondly, hydrogen is not listed as a pollutant in Annex II but only falls under general emissions, Obligations for general emissions are laid down in §12 on applications for permits, which requires that the application for a permit includes a description of the sources of emissions from the installation, the proposed technology and other techniques for preventing or, where this is possible, reducing emissions from the installation and measures planned to monitor emissions into the environment. For enforcement, §23 requires a system of environmental inspections to examine the emissions of the respective installation (EP & Council, 2011). It is important to note that countries may implement regulations that are more ambitious than EU-level requirements and Germany's Federal Immission Control Act already allows for more stringent controls of hydrogen emissions at the national level. Nevertheless, the Industrial Emissions Directive is crucial for ensuring a harmonized European approach.

4.3.3 Regulating Methane Emissions: the EU's Methane Regulation

In the case of blue hydrogen that is produced within the EU, the EU Methane Regulation (2024/1787) applies indirectly as it contains key provisions for the measurement, quantification and reduction of upstream emissions from methane leakages that contribute to the global warming footprint of blue hydrogen.[18] However, with respect to imports from outside of the EU, the Methane Regulation only applies to coal, gas and oil and therefore does not include the upstream methane emissions of imported, fossil-based hydrogen.

Within the EU, §12 of the Methane Regulation requires operators of relevant installations to submit a report on near-source methane emissions estimated by August 2025. For this, they must use at least generic emission factors for all sources including the information specified in §12(4). In addition, operators are required to take all appropriate measures to prevent and minimize methane emissions in their operations (§13) and to submit a LDAR programme to the competent authorities by May 2025 for existing installations and within six months of commissioning new installations (§14). In addition, §15 provides for restrictions on venting and purging, with venting and flaring to be generally prohibited except in emergencies (EP & Council, 2024d).

With respect to imports, Articles 27 – 29 lay out the gradually increasing requirements for importers of crude oil, natural gas or coal produced outside the EU. By May 2025, importers must provide a list of information, including the country of origin, to the competent authorities (§27); by January 2027 importers must demonstrate that import contracts concluded or renewed after 4 August 2024 cover only imports subject to monitoring, reporting and verification measures that are equivalent to those set out in this Regulation (§28). Moreover, by August 2027, the Commission shall set out a methodology for calculating, at the level of the producer, the methane intensity of the production of crude oil, natural gas and coal placed on the Union market in a delegated act (§29(4)). Based on this methodology, by August 2028, methane intensities of imported products must be reported (§29(1) and by August 2030, these intensities must be below the maximum methane intensity threshold which will be set out in a further delegated act (§29(6)) (EP & Council, 2024d). However, as these provisions only apply to the import of oil, gas and coal, upstream emissions related to the import of fossil-based hydrogen are not covered by the Methane Regulation.

18 Neither Germany nor the EU is planning for significant blue hydrogen production within Europe. However, Norway, for example, which plans to produce and export blue hydrogen in large quantities, is also affected by the regulations as a member of the European Economic Area (EEA).

5 Recommendations for Policymakers in Europe and Germany

Despite some tentative steps towards regulating hydrogen emissions, direct hydrogen emissions remain insufficiently addressed in the existing regulatory framework. Further action at various levels is required to ensure the adequate control of emissions of direct and indirect GHGs in a future hydrogen economy. As the calculations in Section 3 demonstrate, the range of possible hydrogen emissions remains large, varying between 0.7 Mt to 10.8 Mt of CO_2e (see Table 1). This corresponds to 1.1% and 17.1% of equivalent residual emissions in the government's net-zero scenarios and 0.1% and close to 2% of GHG emissions in Germany in 2023. In other words, controlling hydrogen emissions plays a significant role in climate mitigation efforts. Moreover, the results show that emissions from production account for the largest share of the total emissions, ranging from 20.4% to 78.9%,[19] and are therefore of particular importance.

Additionally, imports of blue hydrogen could also generate very sizable emissions. Assuming a scenario where one third of imported hydrogen is produced from natural gas with CCS and meets but not does not exceed the required GHG savings for low-carbon hydrogen in the EU, this would generate direct and indirect GHG emissions equivalent to 33% of residual emissions in a high-demand scenario or 3% of GHG emissions in 2023.

These results not only show that the potential impact of Germany's hydrogen plans is substantial, they also indicate a number of entry-points for mitigating these impacts. The following chapter outlines a set of specific recommendations for German policymakers to take action to control direct and indirect GHG emissions from the hydrogen sector.

5.1 National Level: Act at home

5.1.1 Make every effort to meet Germany's hydrogen demand with green hydrogen by 2045 and prioritize direct electrification

As indicated, the utilization of imported blue hydrogen to meet part of Germany's hydrogen demand significantly increases total GHG emissions from the sector, albeit mainly in the country of hydrogen production. Significantly higher GHG emissions in the Green and Blue Scenarios (equivalent to 4.2% to 63.7% share of residual emissions in the German net-zero scenario) compared to the 'only green' scenarios (equivalent to 1.1% to 17.1% share of residual emissions) show that Germany should make every effort to enable sufficient quantities of green hydrogen to meet its hydrogen demand by 2045. If imported blue hydrogen meets the EU's standard for low-carbon hydrogen, estimated GHG emissions from hydrogen are equivalent to 37.4% of residual emissions, still more than double those in an Only Green scenario with 'maximum' levels of hydrogen emissions (according to the assumptions in this report).

Notably, meeting hydrogen demand with green hydrogen does not only mean promoting sufficient green hydrogen production and imports. It also means taking measures to reduce overall hydrogen demand wherever possible and prioritizing direct electrification. In other words, hydrogen should mainly be used in the industrial sector (production of steel and chemicals) as well as for the production of synthetic fuels for the aviation and maritime shipping sector, for which direct electrification is not feasible.

5.1.2 Swiftly transpose Directive 2024/1788 of the HDGMP into national law

Member states are obliged to transpose Directive 2024/1788 of the HDGMP (4.3.1) into national law by mid-2026 (EP & Council, 2024a). National legislators should address the implementation in a timely manner and ideally bring about implementation before the deadline. At the same time, contact should be sought with hydrogen operators as soon as possible so that they can, in their own interest and depending on their technical capabilities, already take first measures for the detection and repair of hydrogen leakage before the directive is implemented. Such measures include the tightening of valves and seals, the

[19] Based on considering min. and max. emission rates for Scenario G1, which assumes all-green hydrogen production.

use of laminated gaskets and welded joints as well as the reduction of operating pressure and/or the minimisation of points of pressurisation and depressurisation (EDF, 2023). The significantly higher energy density of hydrogen may prove to be productive here, as it entails that limiting leakage has more significant economic advantages than in the case of natural gas (Arrigoni & Bravo Diaz, 2022).

5.1.3 Set maximum emission rates for hydrogen from electrolysers in the Federal Immission Control Act

As pointed out in this report, hydrogen emissions at the stage of production account for the largest share of hydrogen emissions in the presented scenarios. Moreover, research suggests that hydrogen emissions at the point of production can be reduced at significantly lower cost than at other stages of the hydrogen value chain. Notably, this includes operational measures that minimize ‘intentional’ leakage through purging and venting as opposed to ‘unintentional’ leakage during transport or storage. By recombining the hydrogen that was purged during the purification phases and vented during operation back to water, a large share of hydrogen emissions during production can be avoided. As electrolyser installations gain in size, the cost-effectiveness of these and other measures is likely to increase further (Frazer-Nash Consultancy, 2022).

However, it is precisely this part of the process chain that remains largely unaddressed. The HDGMP - the only regulatory package that explicitly addresses hydrogen emissions – only regulates leakage in the ‘hydrogen network, storage and terminal operators’, whose obligations relate to ‘all relevant components under the operator responsibility’ (EP & Council, 2024a, §50). This is consistent with its focus on transport and storage infrastructure for hydrogen and other gases.

As described in 4.3.2, in Germany, the operation of electrolysers is currently regulated by the Industrial Emissions Directive (2010/75/EU) and the Federal Immission Control Act, both of which do not recognize hydrogen as an indirect GHG. This regulatory gap should swiftly be closed by including specific provisions for the minimization of hydrogen emissions in electrolysers, including maximum hydrogen emissions per unit of hydrogen production. To do so at the national level, no further legislative action is required as §7(2) of the Federal Immission Control Act already empowers the federal government to set out a) technical requirements as well as b) maximum emission rates that installations must meet. An important point of reference is the guidance for hydrogen production by electrolysis of water, which was recently published by the UK government and includes specific provisions for the minimization of hydrogen emissions (Environment Agency, 2024).

5.1.4 Support the systematic monitoring of hydrogen emissions and the further development of hydrogen leak detection technology

Another important step towards controlling hydrogen emissions should be the systematic collection of data on hydrogen emissions throughout the hydrogen value chain, including hydrogen production. The EC has recognized this with the establishment of the obligations of hydrogen network operators to collect leakage data and the task of ENNNOH to compile best practices. In recognition of hydrogen as an indirect GHG, the European Environment Agency and the German Environmental Protection Agency should also receive the mandate to ensure comprehensive monitoring of hydrogen emissions. This should build on but should not be limited to the work of network operators, to ensure that data is also collected and reported at the point of hydrogen production.

To do so effectively, additional investments in technology for leak detection are needed. Existing technologies are designed for large safety-relevant leaks and are inadequate for small climate-relevant leaks (EDF, 2023). First calls for funding to develop adequate technologies have recently been published in the EU and a call for research into actual hydrogen emission rates along the value chain was launched (Horizon Europe, 2022; 2023). However, as confirmed by researchers in the field, there is still important scope for further technology and knowledge development. Given Germany’s central role in promoting the hydrogen sector, this warrants additional national level research funding. Technology could be tested in pilot networks like H2-Infra[20] or H2-Direkt[21] as well as the networks of AirLiquide and Linde in Germany.

5.1.5 Further advance research to quantify ammonia emissions and their impact on climate

Ammonia (NH_3) is a widely-used derivative of hydrogen whose climate impacts are very uncertain. There is the potential for ammonia emissions to occur during its production, transport, storage, and use, however there is very little data on the magnitude of these emissions. Moreover, the net climate impact ammonia once released into the atmosphere

[20] https://www.dbi-gruppe.de/leistungen-projekte/leuchtturmprojekte/h2infra/
[21] https://www.esb.de/h2direkt

is highly uncertain: in the short-term in forms reflective aerosols which have a net cooling effect, but over longer timescales it gets oxidized to nitrous oxide (N_2O), a powerful greenhouse gas. Since use of ammonia will likely increase in a future hydrogen economy, it is crucial to close this knowledge gap by advancing research to quantify ammonia emissions and their climate impact.

5.2 European Level: Lead in Europe

5.2.1 Include hydrogen emissions in the methodology for low-carbon emission savings and update DR 2023/1185 and the EU taxonomy

Another key entry-point for addressing hydrogen emissions is the low-carbon emission savings methodology. For this, the draft methodology, published on September 27, 2024, should be amended so that hydrogen emissions are covered alongside CO_2 and methane. Since production accounts for the largest share of emissions, particular attention should be devoted to this part of the value chain. Initially, emission rates can be included on the basis of technology-specific emission factors, but as technology and data improve, these should be replaced by actually measured and verified leakage rates (see also Agora Energiewende & Agora Industrie, 2024). The same applies to upstream methane leakage emissions of low-carbon hydrogen. Thanks to recent regulatory and technology developments, including the adoption of the EU Methane Regulation and the availability of new satellite data, a significant increase of available data can be expected (see Section 4.3.3).

In order to ensure regulatory coherence, corresponding provisions should also be made in the RFNBO methodology (DR 2023/1185) and in the EU taxonomy for activities that contribute to climate change mitigation.

5.2.2 Increase the GHG emissions savings threshold for low-carbon as well as renewable hydrogen over time

In addition, emissions from blue hydrogen can be reduced over time by increasing the required GHG emissions savings threshold over time. For the moment, the GHG saving threshold of 70% (3.38kg of CO_2e per kg of hydrogen) for low-carbon and renewable hydrogen in the various EU regulations (i.e., HDGMP, RED and the Taxonomy Regulation) is fixed, though provisions for reviewing and amending threshold values and methodologies are in place. To meet the 2045 and 2050 net-zero targets in Germany and the EU, it will be crucial to continuously reduce remaining emissions in the hydrogen sector. To achieve this and to incentivize the needed investments in technological innovation, the GHG savings rate required by the various EU regulations should be increased over time. This recommendation aligns with a report by Agora Energiewende which proposes a dynamic decrease of the maximum greenhouse gas threshold for low-carbon fuels to 3kg by 2030, 2kg by 2040 and 1kg by 2050 (Agora Energiewende & Agora Industrie, 2024). Germany can act as a frontrunner in this regard by implementing national legislation that anticipates such a ratcheting-up mechanism at the EU level.

5.2.3 Regulate the upstream methane emissions of imported blue hydrogen in the methane regulation

Currently, the EU Methane Regulation (2024/1787) applies only to the import of gas, oil and coal but not that of hydrogen (see Section 4.3.3). Adding hydrogen to the list of regulated good would help minimize methane emissions for all fossil-based hydrogen entering the EU, whether in compliance with the standard for low-carbon hydrogen or not. The planned review of the Methane Regulation in 2028 offers a suitable opportunity for implementing this amendment.

5.2.4 Regulate hydrogen emissions during production in the Industrial Emissions Directive

Apart from amending the Federal Immission Control Act to minimize hydrogen emissions from electrolysers (see Section 5.1.4), German policymakers should also work towards implementing equivalent provisions at the EU level in the Industrial Emissions Directive. This is particularly important as Germany is expected to import parts of its green hydrogen from European countries. As long as no coherent regulatory EU framework for the minimization of hydrogen emissions from electrolysers exists, Germany risks ‘importing’ the emissions from other countries.

5.2.5 Ratchet-up the obligations of hydrogen infrastructure operators in the HDGMP by defining maximum emission rates

The existing obligations for hydrogen infrastructure operators in the HDGMP should be further specified as additional data on hydrogen emission becomes available. This should include an obligation to employ best available techniques (BAT) for hydrogen leakage control, provisions for regular inspections, specific time intervals for LDAR surveys, and, crucially, the definition of maximum leakage rates. For the latter, Article 9 of the HDGMP already provides the mandate (see Section 4.3.1), while the Methane Regulation 2024/1787 can provide an important point of reference (see Section 3.3.3) (EP & Council, 2024d).

5.3 Global Level: Engage internationally

5.3.1 Increase international awareness of hydrogen as an indirect GHG and promote formal recognition by updating its GWP100 in the next IPCC report

To create a regulatory framework for the monitoring and control of hydrogen emissions, it must be recognized as an indirect GHG. At the international level, it is crucial for the IPCC to review and update hydrogen's GWP100 (last reported as 5.8 in AR4) to reflect the latest science (Sand et al., 2023, Warwick et al., 2023; Hauglustaine et al., 2022) when it publishes its 7th Assessment Report (AR7). This will create a clear reference point that researchers and policy makers can draw on to quantify the climate impact of hydrogen in their future research and development of political methodologies and regulations, including the EU’s methodologies for calculating GHG savings from hydrogen.

Moreover, a targeted communication effort should be launched to raise awareness of hydrogen’s role as an indirect GHG without discrediting its important contribution to decarbonizing hard-to-abate sectors. A particular focus should be on highlighting the importance of reducing hydrogen emissions at the point of production. The institutions described in 5.2.5 for the monitoring of hydrogen emissions should play an important role in this effort.

5.3.2 Incorporate best-in-class provisions on transparency and CCS efficiencies when engaging with partners for the import of blue hydrogen

The basis for cooperating with partners for securing imports of blue hydrogen should be the adherence to stringent transparency criteria to enable the systematic monitoring and verification of direct and indirect GHG emissions, including CO_2, methane and hydrogen emissions, throughout the hydrogen sector in the respective country. In the absence of strict monitoring of GHG emissions from the sector, there is a significant risk that the reduction of GHG emissions in Germany will go hand in hand with an increase in GHG emissions in partner countries. Depending on the specific hydrogen use and the amounts of hydrogen required for the avoidance of a unit of CO_2 equivalents, there is even a risk of largely displacing rather than significantly reducing total GHG emissions. Both methane emissions in the natural gas value chain and precise control of CCS efficiency are crucial. If the current EU standard value (9.7 g CO2e per MJ) is assumed for upstream emissions, CCS efficiency must be close to 90% in order to fulfil the current threshold for low-carbon hydrogen (Agora Energiewende & Agora Industrie, 2024). To avoid the displacement of GHG emissions to hydrogen-producing countries, the import of blue hydrogen should be conditional not only on the compliance with the EU’s threshold for GHG savings as specified in the HDGMP for low-carbon hydrogen. The GHG savings should also be subject to independent monitoring and verification. For this, international certification schemes should also incorporate hydrogen emissions (see the following recommendation).

5.3.3 Consider indirect impacts of hydrogen emissions on GHG emissions in relevant standards and certification schemes

Currently, there is no standard or certification system for climate-friendly hydrogen whose methodology includes hydrogen emissions. This should be changed to account for the indirect impact of hydrogen on GHG emissions. A starting point should be the methodology of the International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE) and the first international standard under development at the International Organisation for Standardisation (IOS) for calculating the GHG emissions of hydrogen, which is based on the IPHE methodology. This would represent an important step towards widespread consideration of hydrogen emissions across relevant schemes, as the IPHE methodology is already used by relevant organisations like the International Energy Agency (IEA) (IEA, 2023b) and forms the basis for the Global Green Hydrogen Standard sponsored by the Green Hydrogen Organisation (GH2) (Heinemann et al., 2023b). These standards and certifications will be crucial for controlling emissions from imported hydrogen.

6 Appendix

TABLE A1. APPENDIX - SUMMARY OF CALCULATIONS.

Scenario Code	Scenario Description	Emission rates	Total emissions [Mt CO_2e] (GWP100)	Total emissions [Mt CO_2e] (GWP20)	H_2 emissions [Mt CO_2e] (GWP100)	CH_4 emissions [Mt CO_2e] (GWP100)	CO_2 emissions [Mt CO_2e] (GWP100)	CH_4 and CO_2 emissions [Mt CO_2e] (GWP100)	Equivalent % of residual emissions
G1	High Demand, Only Green H_2 Imports, Pipeline & Ship	Min	1.04	3.36	1.04	0.00	0.00	0.00	1.66 %
		Max	10.80	34.72	10.80	0.00	0.00	0.00	17.14 %
G1a	High Demand, Only Green H_2 Imports, Only Pipeline	Min	1.07	3.43	1.07	0.00	0.00	0.00	1.69 %
		Max	10.98	35.31	10.98	0.00	0.00	0.00	17.43 %
G1b	High Demand, Only Green H_2 Imports, Only Ship	Min	1.00	3.22	1.00	0.00	0.00	0.00	1.59 %
		Max	10.41	33.46	10.41	0.00	0.00	0.00	16.52 %
G2	Low Demand, Only Green H_2 Imports, Pipeline & Ship	Min	0.71	2.29	0.71	0.00	0.00	0.00	1.13 %
		Max	5.84	18.78	5.84	0.00	0.00	0.00	9.27 %
G2a	Low Demand, Only Green H_2 Imports, Only Pipeline	Min	0.72	2.31	0.72	0.00	0.00	0.00	1.14 %
		Max	5.92	19.02	5.92	0.00	0.00	0.00	9.39 %
G2b	Low, Demand, Only Green H_2 Imports, Only Ship	Min	0.69	2.23	0.69	0.00	0.00	0.00	1.10 %
		Max	5.68	18.25	5.68	0.00	0.00	0.00	9.01 %
GB1	High Demand, Green & Blue H_2 Imports, Pipeline & Ship	Min	5.74	9.38	1.04	0.75	3.94	4.69	9.11 %
		Max	40.15	87.46	9.33	15.06	15.75	30.82	63.73 %
		Max-EU	23.57	-	9.33	-	-	14.24	37.41
GB2	Low Demand, Green & Blue H_2 Imports, Pipeline & Ship	Min	2.67	4.80	0.71	0.31	1.64	1.96	4.24 %
		Max	18.09	40.79	5.23	6.29	6.57	12.86	28.71 %
		Max-EU	11.17	-	5.23	-	-	5.94	17.73
B1	High Demand, Only Blue H_2 Imports, Pipeline & Ship	Min	15.15	21.47	1.04	2.26	11.84	14.11	24.05 %
		Max	99.06	193.32	6.39	45.30	47.37	92.67	157.24 %
		Max-EU	49.20	-	6.39	-	-	42.81	78.10
B2	Low Demand, Only Blue H_2 Imports, Pipeline & Ship	Min	6.58	9.83	0.71	0.94	4.93	5.87	10.45 %
		Max	42.58	84.80	4.01	18.86	19.72	38.58	67.59 %
		Max-EU	21.83	-	4.01	-	-	17.82	34.65

TABLE A2. APPENDIX - TECHNICAL PARAMETERS AND ASSUMPTIONS FOR SCENARIOS.

Parameter	Unit	2045	Source
International Transport: Pipeline			
Average distance for European imports	km	1200	Own estimate based on BMWK (2024c)
Average distance of North African imports	km	3300	Own estimate based on BMWK (2024d)
Domestic Transport / Distribution			
Total Length	km	350	Own estimate based on Wietschel (2023)
Storage			
Total storage capacity	TWh	80	Senßfuß et al. (2021)
Salt caverns	TWh	40	Guidehouse (2024)
Other	TWh	40	Guidehouse (2024)

TABLE A3. APPENDIX - SUMMARY OF SCENARIOS AND PARAMETERS FOR CALCULATIONS.

Scenarios	Domestic Production [TWh]*	Import [TWh]**					Total Demand [TWh]*
		Share Green vs. Blue Imports		Pipeline		Ship	
		Green	Blue	Europe	North Africa		
Scenario G: Only Green Hydrogen Imports							
High Demand, Pipeline & Ship (G1)	188	418	0	143	143	132	606
Only Pipeline (G1a)	188	418	0	209	209	0	606
Only Ship (G1b)	188	418	0	0	0	418	606
Low Demand, Pipeline & Ship (G2)	131	174	0	60	60	54	305
Only Pipeline (G2a)	131	174	0	87	87	0	305
Only Ship (G2b)	131	174	0	0	0	174	305
Scenario GB: Green & Blue Hydrogen Imports							
High Demand, Pipeline & Ship (GB1)	188	279	139***	143	143	132	606
Low Demand, Pipeline & Ship (GB2)	131	116	58	60	60	54	305
Scenario B: Only Blue Hydrogen Imports							
High Demand, Pipeline & Ship (B1)	188	0	418	143	143	132	606
Low Demand, Pipeline & Ship (B2)	131	0	174	60	60	54	305

* Source: 'Langfristszenarien' by BMWK, https://langfristszenarien.de/enertile-explorer-de/. ** Share of pipeline vs. ship-based imports (69% to 31%, respectively) adjusted from ratio in BMWK's import strategy, see BMWK (2024c). *** Own assumption (one third of total imports).

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The Research Institute for Sustainability (RIFS) conducts research with the aim of investigating, identifying, and advancing development pathways for transformation processes towards sustainability in Germany and abroad. The Institute was founded in 2009 as the Institute for Advanced Sustainability Studies (IASS) and has been affiliated with the Helmholtz Centre Potsdam - GFZ German Research Centre for Geosciences under its new name since 1 January 2023 and is thus part of the Helmholtz Association. Its research approach is transdisciplinary, transformative, and co-creative. RIFS cooperates with partners in science, political and administrative institutions, the business community, and civil society to develop solutions that enjoy broad support. Its central research topics include the energy transition, climate change and socio-technical transformations, as well as sustainable governance and participation. A strong network of national and international partners and a Fellow Programme support the work of the Institute.

RIFS Study
October 2024

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ViSdP:
Prof. Dr Mark G. Lawrence,
Scientific Director, Speaker

Editor:
Harrison, Damian

DOI: 10.48481/rifs.2024.016

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