

## RESEARCH ARTICLE OPEN ACCESS

## Decarbonizing the Chemical Industry Through Sustainable Hydrogen Production Pathway

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## ABSTRACT

Hydrogen is key to decarbonizing the chemical industry. This study compares future hydrogen production scenarios for 2030 and 2045. Global warming potential from emerging technologies is quantified using prospective life cycle assessments. The Annuity Method is used to calculate the levelized cost of hydrogen. By 2030, electrolysis can reduce greenhouse gas emissions by over 50%, though costs rise drastically. By 2045, combining electrolysis with hydrogen derivatives may reduce emissions, but hydrogen costs remain high. Electricity and CO<sub>2</sub> emissions costs are major factors. Our findings indicate that a sustainable hydrogen production pathway for the chemical industry requires support from policymakers by adapting legislative frameworks and initiating global purchase agreements.

## 1 | Introduction

On July 23, 2025, the International Court of Justice (ICJ) issued a unanimous advisory opinion setting the access to a clean, healthy, and sustainable environment as a human right [1, Para. 393]. The ICJ confirmed that states have legal obligations to mitigate climate change and set the 1.5°C global warming limit above pre-industrial levels as the benchmark for all climate policies [1, Para. 224]. To achieve this climate goal, economic decarbonization is necessary [2]. The chemical sector, identified as “hard to abate” [3], relies heavily on hydrogen for producing ammonia, methanol, and further basic chemical compounds [4]. Therefore, reducing greenhouse gas (GHG) emissions from hydrogen production is

critical to helping the chemical industry meet its decarbonization targets and contribute to the global climate objective.

Currently, the dominant method for hydrogen production is steam methane reforming (SMR) of natural gas, a process associated with significant GHG emissions. However, a suite of emerging technologies offers alternative pathways for hydrogen production using diverse energy sources, including natural gas, biogas, and electricity. Additionally, hydrogen derivatives, such as low-carbon ammonia and liquid organic hydrogen carriers (LOHCs), present promising options, particularly when produced in regions with abundant renewable energy resources. These emerging technologies for hydrogen production currently have

**Abbreviations:** AEL, alkaline electrolysis; ATR, autothermal reforming; CAPEX, capital expenditure; fixOPEX, fixe operating expenditure; GHG, greenhouse gas; GWP (100), global warming potential over 100 years; IAM, integrated assessment model; IJC, International Court of Justice; LCA, life cycle assessment; LCOH, levelized cost of hydrogen; LOHC, liquid organic hydrogen carrier; OPEX, operational expenditure; PEM, proton-exchange-membrane electrolysis; pLCA, prospective LCA; REMIND, Regional Model of Investments and Development; SMR, steam methane reforming of natural gas; SMR Bio, steam methane reforming of biogas; SOEC, solid oxide electrolysis cell; TRL, technology readiness level; varOPEX, variable operating expenditure.

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different technology readiness levels (TRLs). This concept was originally developed by NASA and is a method used for assessing the maturity level of a technology [5]. There are nine TRLs: TRL 1 is the lowest (basic principles) and TRL 9 the highest (commercial stage).

As highlighted in the recent review by Wilkinson et al., interest in the environmental assessment of hydrogen production pathways has increased substantially in recent years, resulting in a growing body of literature addressing the sustainability of hydrogen supply systems [6]. However, most studies have focused on specific production technologies, individual energy sources, or selected hydrogen import routes, such as hydrogen carriers or dedicated transport pathways [7–16]. In parallel, techno-economic assessments (TEA) have generally been conducted for a limited set of technologies. For example, Oni et al. and Salkuyeh et al. primarily investigated hydrogen production routes based on natural gas [17, 18], whereas Koj et al. focused on electrolysis technologies [19]. Consequently, existing studies often examine only a subset of available hydrogen production options and frequently separate economic and environmental performance assessments.

Several recent reviews have further emphasized the difficulty of comparing results across studies because of differences in methodological assumptions, system boundaries, functional units, economic parameters, and environmental assessment approaches [6, 20–22]. These methodological inconsistencies limit the identification of robust conclusions regarding the relative performance of alternative hydrogen pathways.

To address these gaps, this study presents an integrated techno-economic and environmental assessment of eight hydrogen pathways encompassing electricity-based, imported, biogenic, and fossil-based production routes within a harmonized evaluation framework contextualized in the chemical industry. The assessment simultaneously considers the levelized cost of hydrogen (LCOH) and the global warming potential (GWP), thereby enabling a systematic evaluation of cost-emission trade-offs across complete hydrogen supply chains rather than focusing solely on production technologies. Furthermore, the study includes a reference scenario considering hydrogen production through conventional natural-gas-based SMR, an inland scenario considering three electrolysis technologies, biogas-based SMR and autothermal reforming (ATR), and an import scenario hydrogen import via LOHCs and ammonia. By combining these diverse supply options under consistent methodological assumptions, the analysis provides a comprehensive cross-pathway comparison that is currently lacking in the literature and supports the identification of economically and environment-favorable hydrogen transition strategies for the chemical industry.

The assessment is situated within a European context and specifically considers the decarbonization strategy of the German chemical industry, which aims to achieve climate neutrality by 2045. To provide a realistic basis for the analysis, a case study of a medium-scale chemical plant in Germany with an annual hydrogen demand of 5000 t was considered. This case study enables the evaluation of the technical, economic, and environmental performance of the investigated hydrogen supply pathways under representative industrial conditions.

The research is guided by two central questions:

1. To what extent can the environmental impact of hydrogen production be reduced in the future, and at what cost, thereby contributing to a more sustainable chemical industry?
2. How can policy frameworks support the chemical industry in accelerating the transition to low-emission hydrogen production?

To answer these questions, the study evaluates the GWP and LCOH for the different hydrogen production technologies.

## 2 | Methods

This study employs a harmonized and prospective methodological framework to evaluate the environmental and economic performance of emerging hydrogen production technologies. The approach integrates a prospective life cycle assessment (pLCA) with a techno-economic analysis using the Annuity Method. The analysis is conducted for two future time horizons—2030 and 2045.

### 2.1 | Technology Scope and Readiness

A comprehensive set of hydrogen production technologies is evaluated, classified in different production scenario.

The reference scenario considers the SMR of natural gas.

The inland production scenario assesses the following technologies:

- Biogas-based: SMR from Biogas (SMR Bio) and ATR
- Electricity-based: Alkaline electrolysis (AEL), proton exchange membrane electrolysis (PEM), and solid oxide electrolysis cells (SOEC)

The import scenario investigates the import of following hydrogen derivatives low-carbon ammonia ( $\text{NH}_3$ ) and LOHCs. The selected technologies represent different stages of technological maturity and reflect the main pathways currently discussed for industrial-scale low-carbon hydrogen supply.

Figure 1 summarizes the considered hydrogen production technologies, including inputs and outputs.

Natural gas- and biogas-based hydrogen production

SMR is currently the dominant industrial process for hydrogen production and has reached full commercial maturity (TRL 9) [23, 24]. In this process, methane reacts with steam at temperatures of approximately 800°C and pressures up to 3.5 MPa over a nickel-based catalyst to produce synthesis gas consisting primarily of hydrogen and carbon monoxide (Equation 1) [7, 24]. The synthesis gas subsequently undergoes a water–gas shift reaction (Equation 2), increasing hydrogen yield while converting carbon monoxide into carbon dioxide. Hydrogen is finally purified

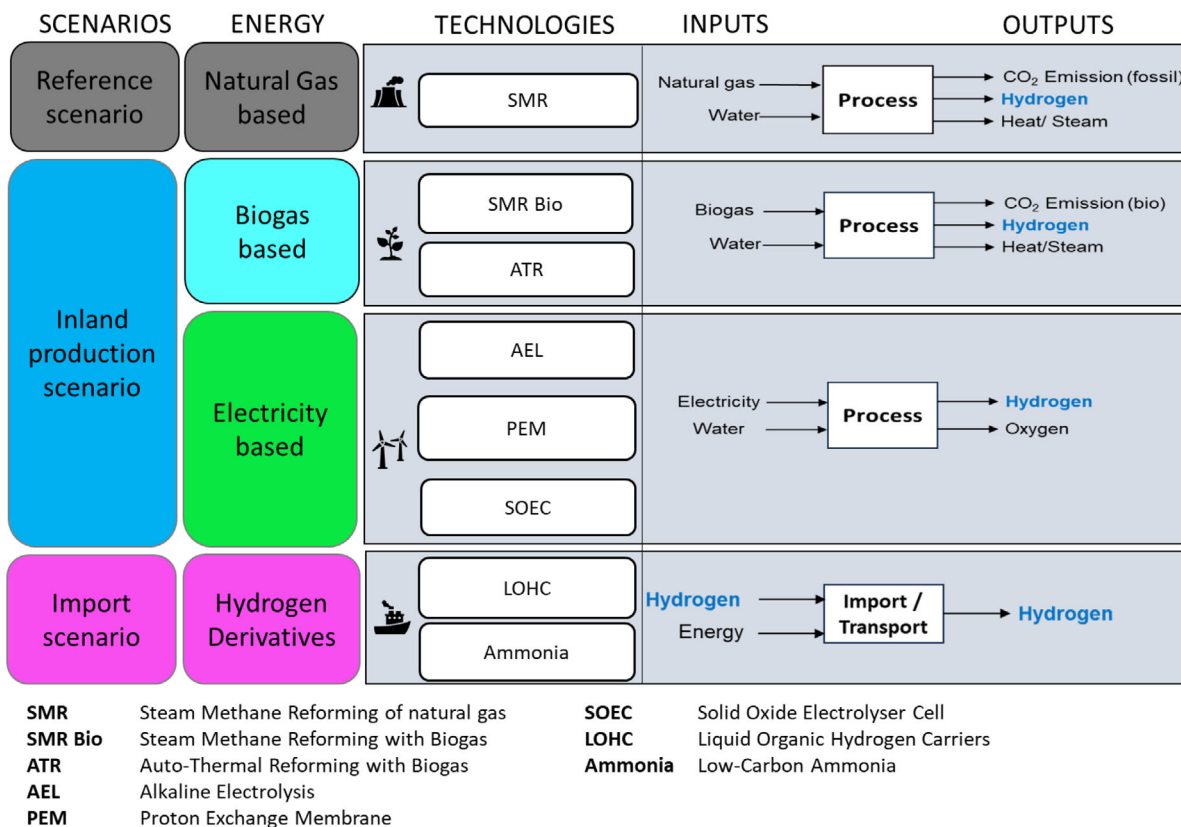
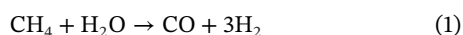


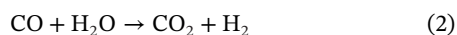
**FIGURE 1** | Overview of the evaluated technologies, including inputs and outputs, each of the considered technologies is subsequently presented as follows: natural gas- and biogas-based hydrogen production.

through pressure swing adsorption [25], resulting in the overall reaction shown in Equation (3).

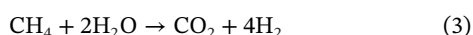
Steam reforming reaction



Water-gas shift reaction



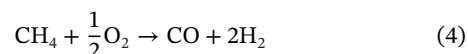
Net reaction of the SMR Process



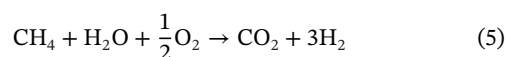
Biogas-based pathways follow similar reforming principles but differ in feedstock origin and pre-treatment requirements. Prior to reforming, raw biogas is upgraded to biomethane through membrane separation, possibly using the commercially established SEPURAN technology (TRL 9) [26]. Once purified, biomethane can either be processed in a conventional steam reformer (SMR-Bio), which exhibits technological characteristics largely identical to natural-gas SMR, or converted through ATR. Unlike SMR, ATR combines partial oxidation and steam reforming within a single reactor, whereby the exothermic oxidation reaction supplies the heat required for the endothermic reforming reactions [17] according to Equations (4) and (5). The overall reaction is according to Equation (5). Following reforming, the product gas undergoes a water-gas shift reaction and hydrogen purification.

Although SMR-Bio has already reached commercial maturity, ATR is currently at TRL 7 and is expected to reach commercial deployment by 2040 [17, 25].

Partial oxidation reaction

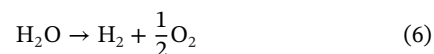


Overall reaction



Electricity-based hydrogen production

Electricity-based hydrogen production relies on water electrolysis, in which electrical energy is used to split water into hydrogen and oxygen [7] according to the following equation:



Among the available electrolysis technologies, AEL and PEM electrolyses are the most mature options, both having reached TRL 9 [27, 28]. Although both technologies perform the same electrochemical conversion, they differ in electrolyte configuration and operating conditions. AEL employs a liquid alkaline electrolyte and porous diaphragm, whereas PEM utilizes a solid proton-conducting membrane and typically requires noble-metal catalysts, such as platinum, iridium, and ruthenium, because of

the acidic conditions and high cell potential [7, 28]. The operation conditions for the AEL are between 70°C and 90°C and 1–30 bar, whereas PEM requires temperatures between 50°C and 80°C and operating pressures below 70 bar [27]. Their commercial maturity and increasing deployment have established both technologies as key candidates for large-scale renewable hydrogen production.

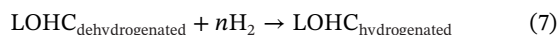
In contrast, SOECs operate at temperatures above 800°C and pressure of 1 bar [27, 29]. This technology uses steam rather than liquid water as the feedstock. By integrating external heat sources, SOEC systems can achieve higher electrical efficiencies and facilitate sector coupling with industrial processes. Although SOEC technology remains less mature than AEL and PEM, it has already reached TRL 8 and is expected to benefit from significant technological improvements in the coming decades [28, 30].

## Hydrogen Derivatives

Hydrogen derivative systems can be used to enable long-distance transport of hydrogen. Two systems were considered in the import scenario: LOHC and ammonia (NH<sub>3</sub>). Both pathways involve the chemical conversion of hydrogen into a transportable form at the production site, followed by hydrogen recovery at the point of use.

LOHCs are the chemical compounds capable of reversible hydrogenation and dehydrogenation, enabling efficient hydrogen storage and transport. In this study, the benzyltoluene/perhydrobenzyltoluene system was chosen as the representative LOHC owing to its advanced state of technological development and favorable operational characteristics [31]. During hydrogenation, renewable hydrogen is chemically bound to the carrier molecule in an exothermic process that releases heat at approximately 150°C, whereas hydrogen recovery takes place through endothermic dehydrogenation at temperatures of about 300°C [31–33] according to Equations (7) and (8). Owing to its favorable safety characteristics and successful demonstration at pilot and industrial scale, the benzyltoluene/perhydrobenzyltoluene system represents one of the most advanced LOHC concepts currently under development. The technology has reached TRL 8 and is expected to achieve commercial maturity by 2035 [31].

### Hydrogenation reaction



### Dehydrogenation reaction



Ammonia represents an alternative hydrogen carrier characterized by a high volumetric hydrogen density and well-established transport infrastructure [34]. In this pathway, renewable hydrogen produced by PEM electrolysis is combined with nitrogen obtained through cryogenic air separation and subsequently converted into ammonia via the Haber–Bosch process [35, 36]. At the destination, hydrogen is recovered through ammonia cracking over ruthenium-based catalysts under low-pressure conditions and at temperatures exceeding 300°C (Equation 9) [37]. Similar to the LOHC pathway, low-carbon ammonia is currently assessed at TRL 8, with commercial deployment anticipated by 2035 [38].

**TABLE 1** | Technologies readiness level.

| Technology | TRL 2030 | TRL 2045 | Sources  |
|------------|----------|----------|----------|
| SMR        | 9        | 9        | [17, 39] |
| SMR bio    | 9        | 9        | [17]     |
| ATR        | 7        | 9        | [17]     |
| PEM        | 9        | 9        | [28]     |
| AEL        | 9        | 9        | [28]     |
| SOEC       | 8        | 9        | [28]     |
| LOHC       | 8        | 9        | [40, 41] |
| Ammonia    | 8        | 9        | [38]     |

Abbreviations: AEL, alkaline electrolysis; ATR, autothermal reforming; LOHC, liquid organic hydrogen carrier; PEM, proton exchange membrane; SMR, steam methane reforming; SOEC, solid oxide electrolysis cell; TRL, technology readiness level.

### Ammonia cracking reaction



Table 1 summarizes the TRL for each technology considered in this study. Each technology is assessed in this study at its projected commercial maturity (TRL 9).

## 2.2 | Environmental Assessment: pLCA

The environmental evaluation is based on the ISO 14040 and 14044 standards [42, 43] for life cycle assessment (LCA), adapted to a prospective context. The pLCA methodology models the environmental impacts of technologies at future points in time, accounting for both technological advancements (foreground system) and systemic changes in the broader economy (background system). Arvidsson et al. defined the term pLCA as “LCA that models the product system at a future point in time relative to the time at which the study is conducted” [44].

### 2.2.1 | Goal and Scope Definition

The primary goal of the pLCA is to assess the GWP of hydrogen production technologies in 2030 and 2045. The functional unit is defined as 1 kg of hydrogen at 30 bar delivered/available in Germany. The system boundary is defined as cradle-to-gate, encompassing the life cycle stages of hydrogen production from raw material extraction, through facility construction, to the operational phase of hydrogen generation. Figure 2 illustrates the hydrogen production routes investigated in this study for the different scenarios. For both the reference and inland scenarios, production is assumed to occur within Germany, utilizing a customized German electricity mix as described in the Supporting Information S1. In contrast, the import scenario involves hydrogen production abroad based on renewable energy sources, followed by transportation to Germany and subsequent hydrogen disposal using the same customized German electricity mix.

Coproducts, such as heat or steam, are allocated on the basis of energy content. For electrolysis, no allocation is attributed to

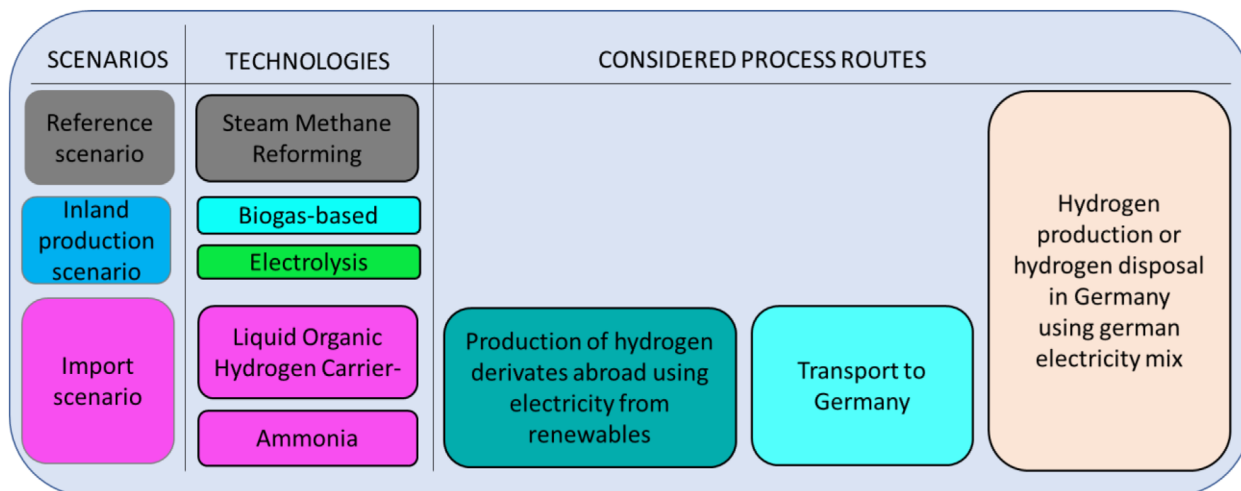


**FIGURE 2** | Overview of the considered process routes for the different scenarios and technologies.

oxygen as it is not further utilized within the system boundaries of this study.

### 2.2.2 | Foreground System Modeling

The foreground system includes the specific hydrogen production technologies under evaluation. Input and output flows—such as energy, materials, emissions, and waste—are derived from a combination of primary data, process simulations, and scientific literature. These data are extrapolated to reflect the technologies' performance at commercial maturity (TRL 9) in the target years. Mass and energy balances are documented in Tables S2–S8.

### 2.2.3 | Background System Modeling

The background system represents the broader economic and energy context in which the technologies operate. To model this system, the Premise framework [45] was used. This framework couples integrated assessment models (IAMs) with unit processes from the ecoinvent 3.9 cutoff database [46], enabling the representation of future developments in the background system. In this study, the prospective background scenario corresponds to the Shared Socioeconomic Pathway 2 (SSP2) [47] using the Regional Model of Investments and Development (REMIND) IAM [48]. The background scenario used is Remind-SSP2-PeakBudget1150, which limits cumulative GHG emissions to 1150 Gt CO<sub>2</sub> by 2100, consistent with a 2°C warming target.

A custom German electricity mix is developed for each time horizon on the basis of projections from the German Federal Ministry for Economic Affairs and Climate Action (BMWK) [49] and is documented in Table S1. This mix is integrated into the background system using a superstructure approach, enabling consistent modeling across scenarios [50].

### 2.2.4 | Impact Assessment Method

The Environmental Footprint 3.1 method is used for impact assessment, focusing on the GWP over a 100-year time horizon

[51]. This impact category is prioritized due to its relevance for climate policy and its methodological robustness. It is classified as a Level I recommendation by the International Life Cycle Data System (ILCD). All models are developed using the Activity Browser LCA software [52].

## 2.3 | Economic Assessment: LCOH

The economic analysis employs the Annuity Method, standardized by VDI 6025 [53] and VDI 2067 [54], to calculate the LCOH. The Annuity Method annualizes capital expenditures (CAPEX), operational expenditures (OPEX), and revenues over the lifetime of the hydrogen production facility.

CAPEX refer to the investment costs associated with the establishment of the facilities. OPEX are categorized into fixed and variable costs, where fixed operating costs (fixOPEX) primarily encompass maintenance, personnel, administration, and insurance expenses, whereas variable operating costs (varOPEX) include expenditures related to energy, water consumption, and costs for GHG emissions according to European Union Emissions Trading System (EU-ETS). Indeed, for gas-based technologies emitting GHG, emission permits have to be purchased from EU-ETS. Costs for the emission permits are based in this study on Germany's long-term energy scenarios [49] and Schmid et al. [55] assuming to reach €300 t CO<sub>2</sub><sup>-1</sup> in 2045. Details on electricity, natural gas, water, and biogas prices, as well as the costs of imported hydrogen derivatives and emission permits, are provided in Table S7. Information regarding cost and revenue associated with heat and steam is also included therein.

The LCOH represents the cost of producing 1 kg of hydrogen and is calculated on the basis of annualized CAPEX, fix and variable OPEX, and revenues for coupled-product like heat and steam for a yearly capacity of 5000 t H<sub>2</sub> over the considered lifetime. Interested rate was set by 7.9% on the basis of the weighted average cost of capital for the chemical and pharmaceutical industry [56].

The CAPEX values used for the calculation of LCOH for the different technologies are based on literature reviews and

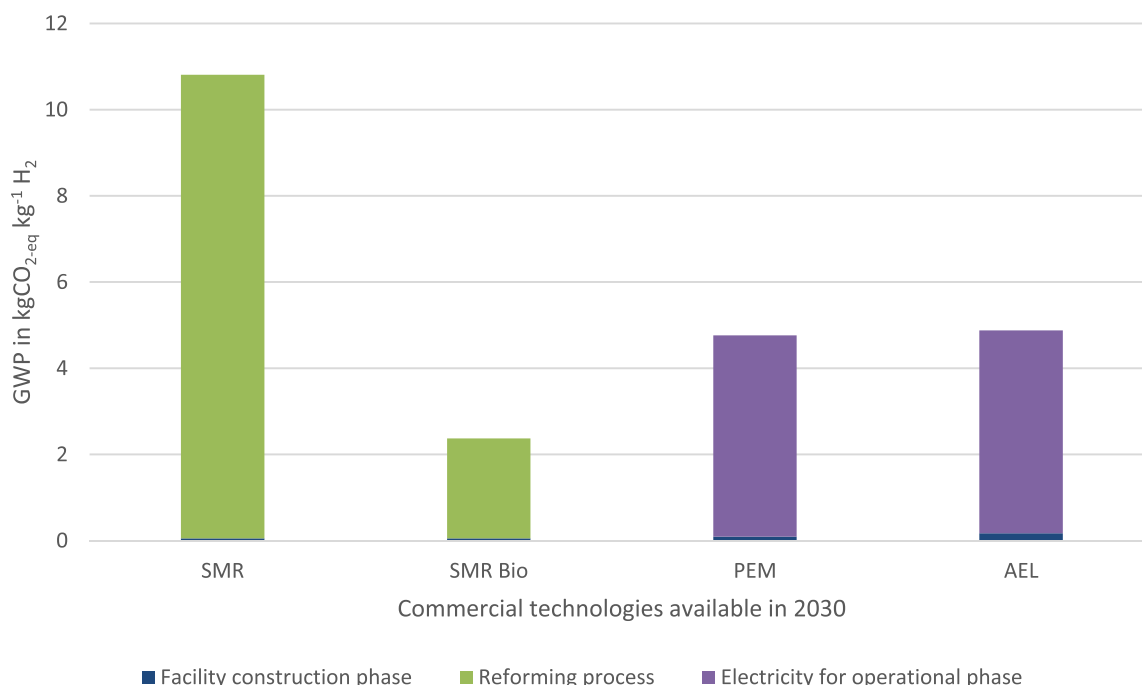


**FIGURE 3** | Global warming potential for 1 kg hydrogen produced/available in 2030, including contribution analysis. AEL, alkaline electrolysis; PEM, proton exchange membrane; SMR, steam methane reforming.

discussion with experts. These values are adapted considering scaling factors [57] for a yearly capacity of 5000 t H<sub>2</sub>, that is, 571 kg H<sub>2</sub> h<sup>-1</sup>, future cost development, and specific technology lifetime. Assumed CAPEX values are considered up to the point where the technology has reached commercial maturity (TRL 9) based on Table 1 and is documented in Table S10.

The fix OPEX is defined for all technologies as 3% of the CAPEX [39, 58], except for the LOHCs where it is defined as 4% [59]. Storage for hydrogen derivatives is considered as 2% of CAPEX [59].

The variable OPEX and revenues are calculated by combining the mass and energy balances with the defined costs and prices assumptions for material and energy inputs, imported energy derivatives, and coupled-products [49, 60–62]. Data are available in Table S7.

### 3 | Results

The results of this study provide a comparative analysis of the environmental and economic performance of emerging hydrogen production technologies in the years 2030 and 2045, using the harmonized framework described in Section 2.

#### 3.1 | Environmental Impact: GWP

##### 3.1.1 | GWP in 2030

In 2030, only a subset of the evaluated technologies is expected to be commercially available (TRL 9). These include SMR from natural gas, SMR from Biogas (SMR Bio), PEM Electrolysis, and AEL.

Figure 3 illustrates the GWP associated with the production of 1 kg of hydrogen for technologies expected to be commercially available by 2030. The results indicate that the construction phase contributes only marginally to the overall GWP ( $\leq 3\%$ ), whereas the operational phase of hydrogen production represents the dominant source of environmental impacts. The contribution analysis further reveals that, for gas-based and biogas-based technologies, GHG emissions generated during the reforming process are the primary contributor to the overall GWP. In contrast, for the electrolysis technologies AEL and PEM, the environmental performance is predominantly determined by the electricity consumed during the electrolysis process. These findings are consistent with previous studies reported in the literature [7, 8].

Among the technologies, as depicted in Figure 4, SMR from Biogas achieves the highest GHG savings, reducing emissions by 78% compared to conventional SMR. PEM Electrolysis and AEL Electrolysis reduce emissions by 56% and 55%, respectively. The analysis assumes the German electricity grid mix projected for 2030, comprising approximately 82% renewable sources, alongside 8% natural gas and 7% oil [49]. The associated GWP are estimated at 0.92 kg CO<sub>2</sub>-eq kWh<sup>-1</sup> for natural gas and 0.46 kg CO<sub>2</sub>-eq kWh<sup>-1</sup> for oil, whereas photovoltaic electricity is assumed to have a GWP of 0.03 kg CO<sub>2</sub>-eq kWh<sup>-1</sup>. Although electrolysis technologies benefit from grid decarbonization, the GWP of hydrogen produced via electrolysis is reduced by only 55%, due to the residual fossil-based share in the electricity mix.

##### 3.1.2 | GWP in 2045

By 2045, all technologies are assumed to have reached commercial maturity. As depicted in Figure 4, the most substantial

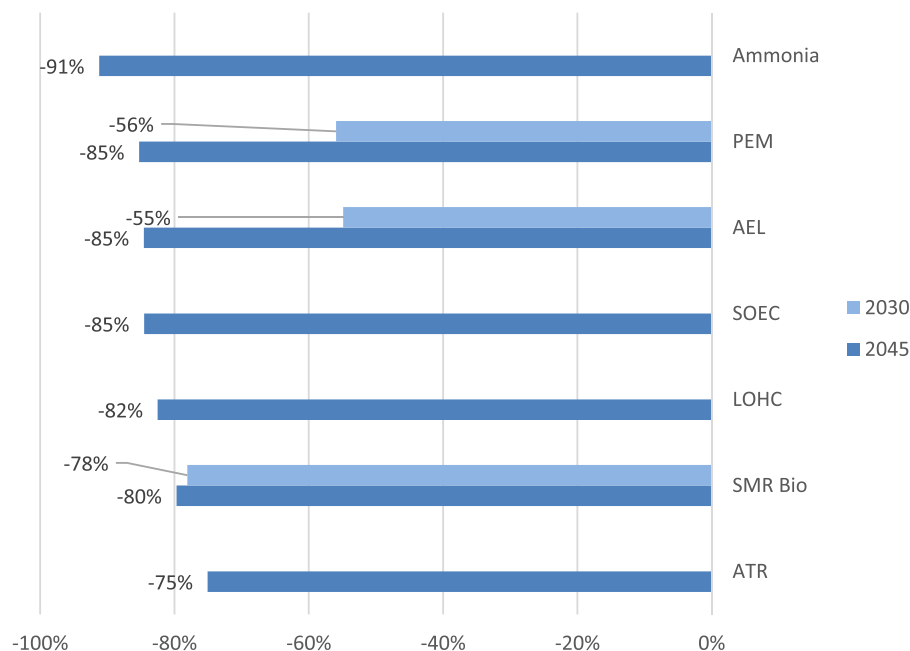


**FIGURE 4** | GHG-emissions reduction for 1 kg produced hydrogen in 2030 and 2045, compared to steam methane reforming from natural gas. AEL, alkaline electrolysis; ATR, autothermal reforming; LOHC, liquid organic hydrogen carrier; PEM, proton exchange membrane; SMR, steam methane reforming; SOEC, solid oxide electrolysis cell.

GHG emission reductions are achieved through the import of low-carbon ammonia, which results in a 91% decrease in GHG emissions relative to the reference scenario considering SMR of natural gas. Electrolysis-based hydrogen production and LOHC imports also demonstrate significant mitigation potentials, with GHG reductions of 85% and 82%, respectively. Biogas-derived technologies, including ATR and SMR Bio based on biogas, yield GHG emission reductions ranging from 75% to 80%.

### 3.2 | Economic Impact: LCOH

Figure 5 presents a comparative analysis of the LCOH for various production technologies relative to the reference process—SMR of natural gas. By 2030, hydrogen production via SMR of biogas and commercially available electrolysis technologies (PEM and AEL) is significantly more expensive than the reference process, with cost premiums of +104% for SMR using biogas, and +85% and +81% for PEM and AEL electrolysis, respectively.

In contrast, projections for 2045 indicate a shift in cost competitiveness. Electrolysis technologies are projected to be marginally less expensive than conventional SMR.

However, hydrogen derivatives remain costlier than the reference process, with an estimated increase of +16%–+19%. Technologies based on biogas continue to exhibit higher costs, ranging from +23% to +53% above the benchmark.

Detailed costs and revenues distribution are presented exemplarily for SMR of natural gas as natural gas-based technology, PEM-electrolysis as electricity-based technology, SMR Bio as biogas-based technology for 2030 and 2045 in Figure 6. The variable operating costs comprise expenditures for natural gas and biogas, costs associated with CO<sub>2</sub> emission permits (in cases where

GHGs are emitted through the combustion of natural gas), and electricity-related costs. In 2030, the LCOH for SMR is primarily driven by natural gas costs and CO<sub>2</sub> permit costs, accounting respectively for 43% and 49% of the LCOH. By 2045, the share of emission permits costs increases substantially to 74%, whereas the contribution of natural gas declines to 19%. Electricity cost has a high impact of electricity-based technologies. For PEM electrolysis, electricity-related costs constitute the dominant component of the LCOH, accounting for 83% in 2030 and 85% in 2045. For SMR Bio, biogas-related costs constitute the predominant component of the LCOH, accounting for 90% in 2030 and 91% in 2045.

To evaluate the robustness of the economic assessment and account for uncertainties associated with future market developments, a scenario analysis was conducted for the electricity-based technologies and hydrogen derivatives to calculate the LCOH considering the baseline electricity price from €0.055 kWh<sup>-1</sup>, a low-price scenario of €0.03 kWh<sup>-1</sup>, and a high-price scenario of €0.135 kWh<sup>-1</sup> based on the assumptions reported by Fleiter and Fraunhofer [63].

Figure 7 illustrates the impact of varying electricity price assumptions on LCOH from electrolysis technologies and hydrogen derivatives. Compared with the baseline scenario, the low electricity price scenario reduces the LCOH of all electrolysis technologies by approximately 40%, whereas the corresponding reductions amount to only 6% and 4% for the LOHC and ammonia pathways, respectively. Conversely, the high electricity price scenario increases the LCOH of electrolysis-based hydrogen production by around 120%, whereas the costs of the LOHC and ammonia pathways rise by approximately 20% and 14%, respectively. These results highlight the strong dependence of electrolysis technologies on electricity prices, whereas hydrogen derivative pathways are comparatively less sensitive to changes in electricity prices.

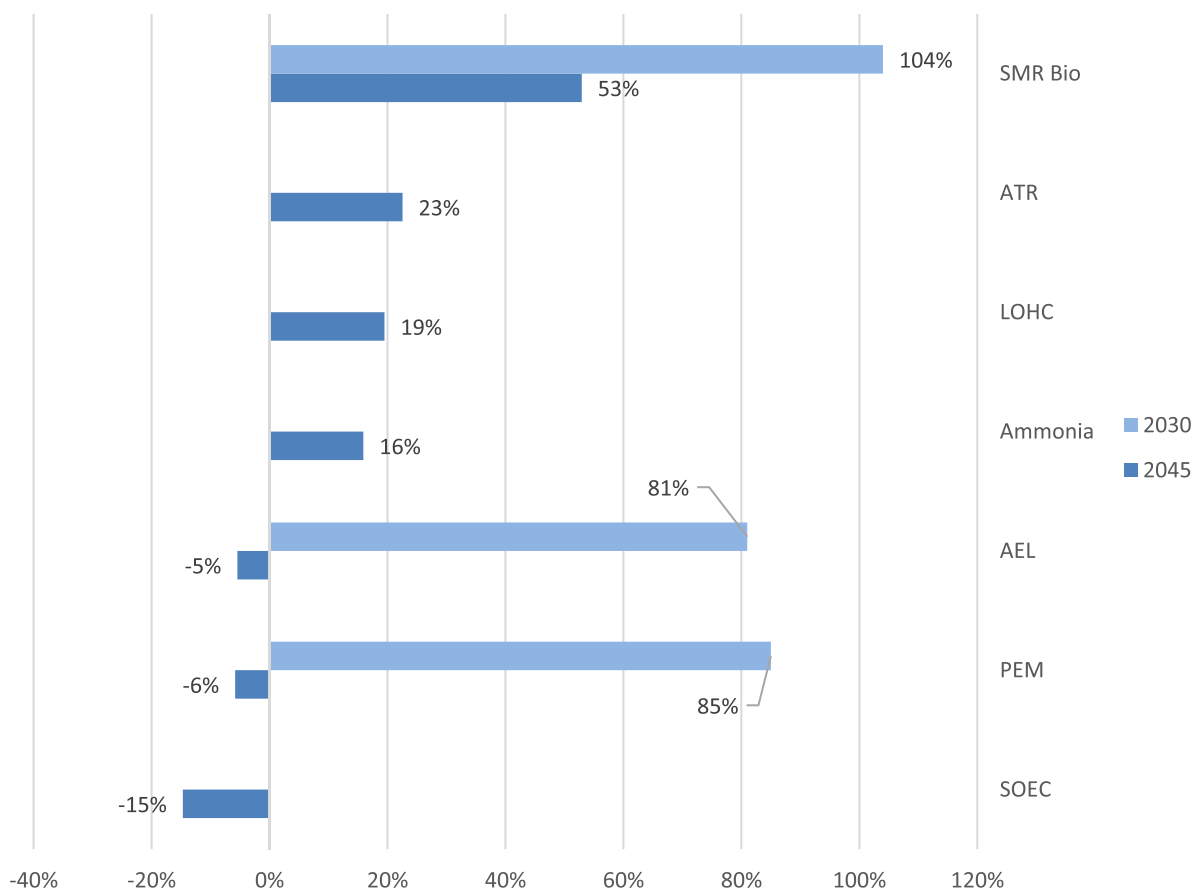


**FIGURE 5** | Levelized cost of hydrogen in € for 1 kg of produced/available hydrogen 2030 and 2045 compared to steam methane reforming of natural gas. AEL, alkaline electrolysis; ATR, autothermal reforming; LOHC, liquid organic hydrogen carrier; PEM, proton exchange membrane; SMR, steam methane reforming; SOEC, solid oxide electrolysis cell.

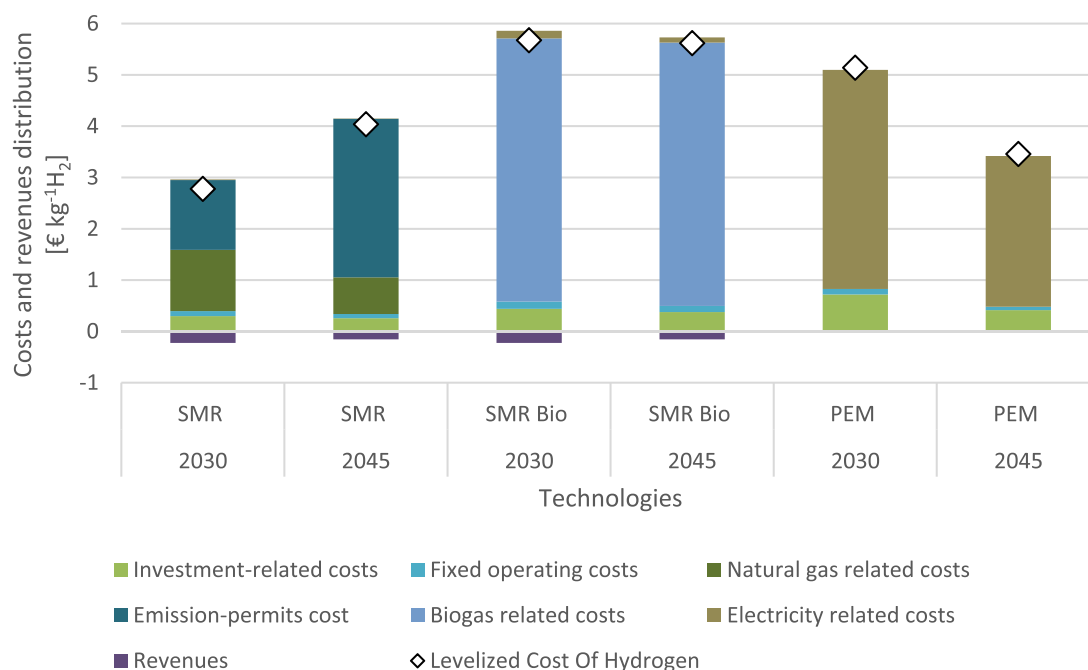


**FIGURE 6** | Comparison of cost and revenues distribution for steam methane reforming of natural gas (SMR) and biogas (SMR Bio) and PEM-electrolysis in 2030 and 2045. PEM, proton exchange membrane.

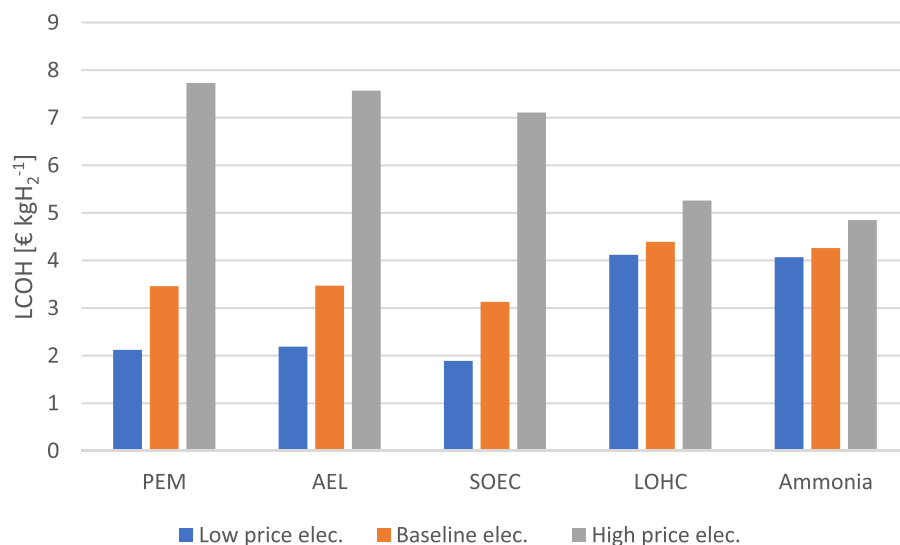


**FIGURE 7** | LCOH in € kg H<sub>2</sub><sup>-1</sup> for the electrolysis technologies and hydrogen derivatives considering a low-price electricity scenario (blue), a baseline electricity scenario (orange) and a high-price electricity scenario (gray) in 2045. AEL, alkaline electrolysis; LCOH, levelized cost of hydrogen; LOHC, liquid organic hydrogen carrier; PEM, proton exchange membrane; SOEC, solid oxide electrolysis cell.

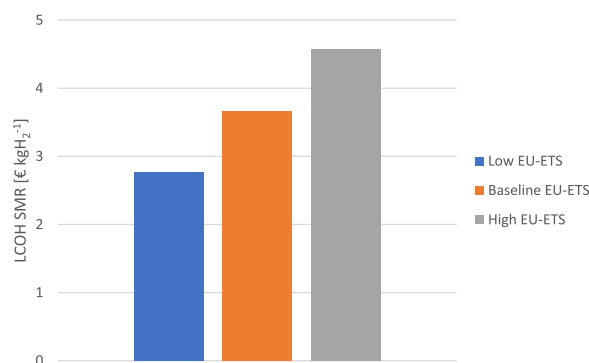


**FIGURE 8** | LCOH for SMR under variation of EU-ETS price scenario low (blue), baseline (orange), and high (gray) in € kg H<sub>2</sub><sup>-1</sup> in 2045. EU-ETS, European Union Emissions Trading System; LCOH, levelized cost of hydrogen; SMR, steam methane reforming.

As the EU-ETS carbon price represents the dominant cost component of SMR-based hydrogen production, an additional scenario analysis was conducted to assess its influence on the economic results. Three EU-ETS price scenarios were considered: a low-price scenario of €200 t CO<sub>2</sub><sup>-1</sup>, a baseline scenario of €300 t CO<sub>2</sub><sup>-1</sup>, and a high-price scenario of €400 t CO<sub>2</sub><sup>-1</sup>.

Figure 8 demonstrates the influence of EU-ETS carbon prices on the LCOH of hydrogen produced via SMR. Compared with the baseline scenario, the low EU-ETS price scenario results in a 24% reduction in LCOH, whereas the high EU-ETS price scenario increases the LCOH by approximately 24%.

The results of both scenario analyses further indicate that, under a high electricity price assumption of €0.135 kWh<sup>-1</sup> in 2045, hydrogen produced via electrolysis may become more expensive than SMR-based hydrogen when the EU-ETS price is limited to €200 t CO<sub>2</sub><sup>-1</sup>.

To further assess the competitiveness of both production pathways, Figure 9 presents the break-even points exemplarily between PEM electrolysis and SMR. The figure illustrates the combinations of electricity prices and EU-ETS carbon prices at which either technology becomes economically preferable. This analysis provides a transparent representation of the economic conditions under which the cost advantage shifts from SMR to electrolysis, or vice versa. The break-even point at which SMR becomes economically more competitive than PEM electrolysis depends on both the electricity price and the EU-ETS carbon price. Specifically, SMR becomes the lower cost option when the electricity price exceeds approximately €0.04 kWh<sup>-1</sup> at an EU-ETS price of €200 t CO<sub>2</sub><sup>-1</sup>, €0.06 kWh<sup>-1</sup> at €300 t CO<sub>2</sub><sup>-1</sup>, and €0.08 kWh<sup>-1</sup> at €400 t CO<sub>2</sub><sup>-1</sup>. These results indicate that higher carbon prices increase the electricity price threshold at which SMR retains a cost advantage over PEM electrolysis.

### 3.3 | Environmental–Economic Analysis

In this section, we combine the environmental and the economic results.

#### 3.3.1 | Results for 2030

As depicted in Figure 10, SMR from Biogas has the lowest GWP but is 104% more expensive than conventional SMR of natural gas. PEM and AEL Electrolysis reduce GHG emissions by 50%–60%, but LCOH increases by more than 80%.

This cost burden poses a challenge for short-term competitiveness in the chemical industry.

#### 3.3.2 | Results for 2045

Illustrated in Figure 11, assuming an EU-ETS cost of €300 t CO<sub>2</sub>-eq<sup>-1</sup> in 2045 [49], electrolysis and hydrogen derivatives achieve 80% GHG reduction with LCOH comparable to SMR.

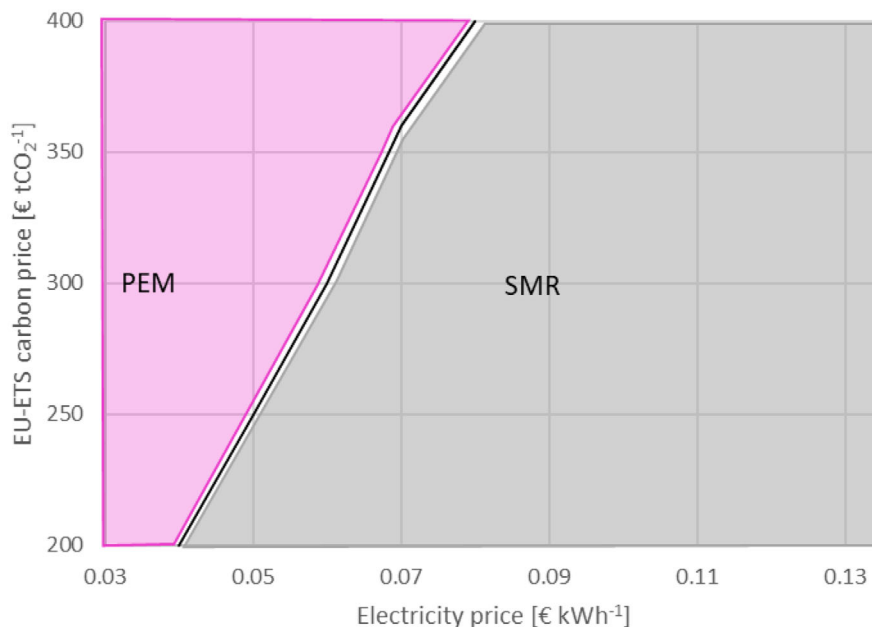


**FIGURE 9** | Technology ranking map in 2045 demonstrating under which EU-ETS carbon prices and electricity prices assumptions SMR and PEM are most economically advantageous. The black line denotes the break-even boundary between both technologies. The pink region indicates the parameter space in which PEM electrolysis achieves lower hydrogen production costs, whereas the gray region represents the conditions under which SMR remains the more cost-competitive option. EU-ETS, European Union Emissions Trading System; PEM, proton exchange membrane; SMR, steam methane reforming.

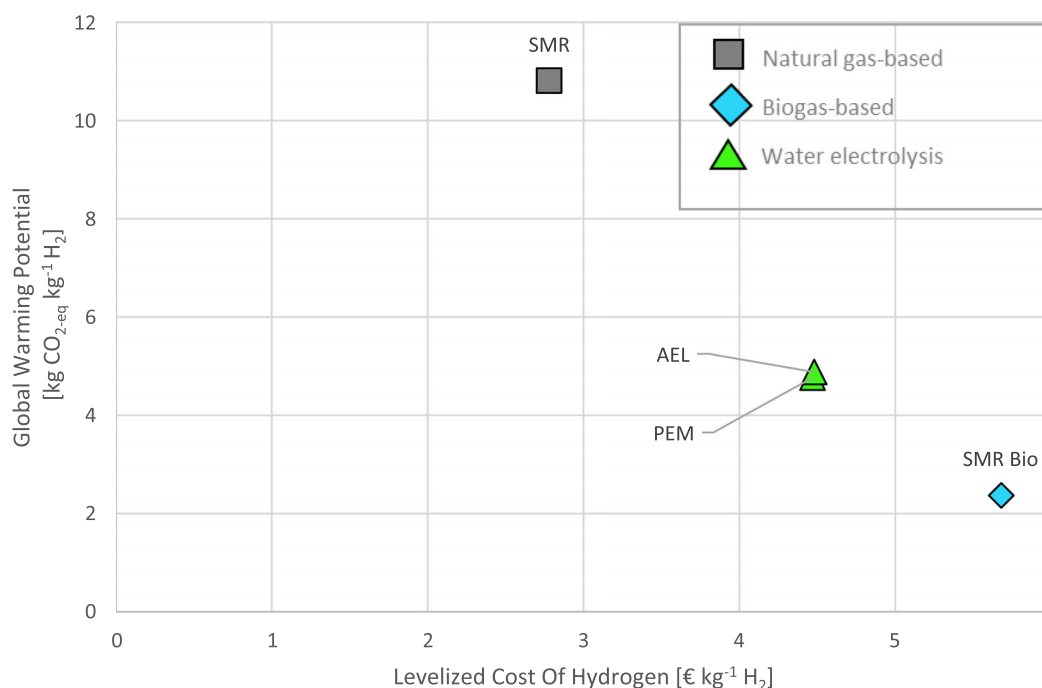


**FIGURE 10** | Global warming potential vs. levelized cost of hydrogen from commercially available hydrogen technologies in 2030.

Biogas technologies offer GHG reduction between 80% and 85% but are 22%–53% more expensive than SMR.

The LCOH values obtained in this study for both electrolysis and SMR are slightly lower than the mid-century cost projections reported by the IEA and IRENA [64, 65]. This difference can be largely attributed to the underlying assumptions, as the IEA and

IRENA estimates are based on global datasets and broad international market conditions, whereas the present study relies on assumptions specific to the German and European energy markets. In particular, region-specific assumptions regarding future electricity prices, carbon pricing mechanisms, and market conditions influence the resulting hydrogen production costs. Furthermore, global projections may not fully reflect the impact of

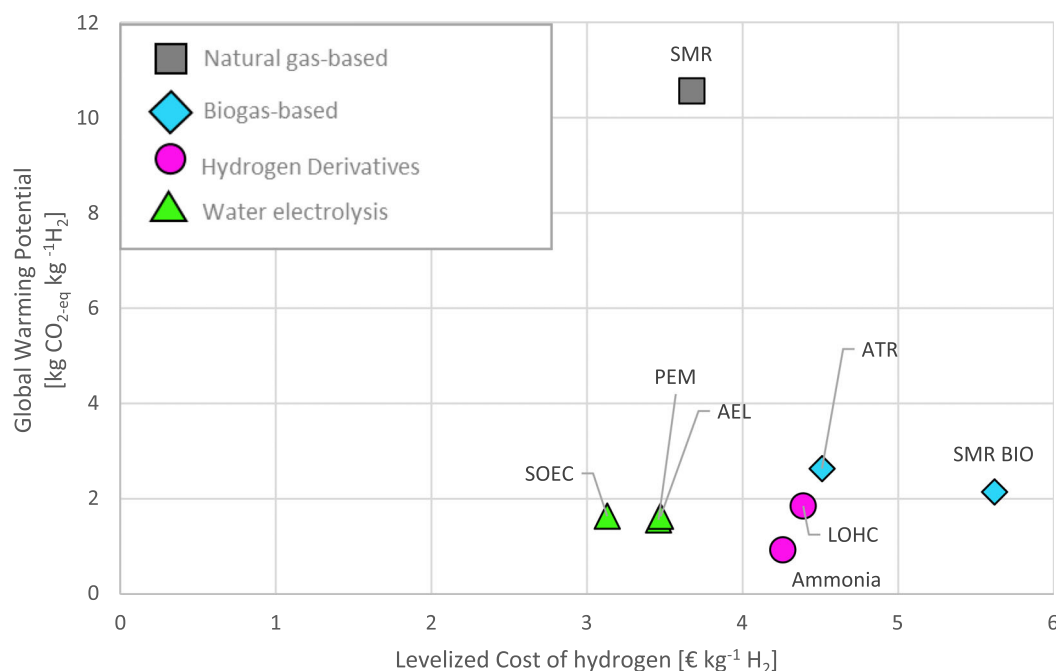


**FIGURE 11** | Global warming potential vs. levelized cost of hydrogen from hydrogen technologies in 2045.

the EU-ETS on the competitiveness of fossil-based hydrogen pathways. When compared with the German study by Matthes et al. [66], which applies a similar framework and comparable assumptions regarding electricity and carbon prices, the LCOH values determined in this work fall within the projected cost range, thereby supporting the plausibility and consistency of the results.

## 4 | Discussion

The findings of this study underscore the complex interplay between environmental performance, economic feasibility, and technological maturity in the future landscape of hydrogen production. The harmonized prospective framework employed in this research enables a robust comparison of diverse hydrogen technologies production under consistent assumptions, offering valuable insights for both industry stakeholders and policymakers.

### 4.1 | Environmental Performance

The study demonstrates that emerging hydrogen production technologies can significantly reduce GHG emissions compared to the current benchmark—SMR from natural gas. In particular, electrolysis technologies (PEM, AEL, and SOEC) and hydrogen derivatives (LOHC, low-carbon ammonia) offer substantial GHG reductions (up to ~80% in 2045).

The environmental performance of gas- and biogas-based pathways is predominantly influenced by direct GHG emissions associated with the reforming process, whereas the environmental performance of electricity-based hydrogen production technologies and their derivatives is strongly dependent on the carbon intensity of the electricity supply.

### 4.2 | Economic Competitiveness and Cost Barriers

The economic analysis reveals that most emerging technologies are currently not cost-competitive with conventional SMR. In 2030, electrolysis technologies are more than 80% more expensive than SMR, despite offering significant GHG reductions.

By 2045, the cost gap narrows. Electrolysis is projected to have comparable LCOH to SMR. Hydrogen derivatives are 19% more expensive than SMR. However, biogas-based technologies remain 22%–53% more expensive.

The scenario analyses demonstrated that assumptions regarding electricity and carbon prices have a substantial influence on the economic competitiveness of electrolysis- and SMR-based hydrogen production pathways. The results indicate that the competitiveness of SMR is highly sensitive to future carbon pricing, with lower EU-ETS carbon prices significantly reducing hydrogen production costs. In contrast, electrolysis technologies are primarily affected by electricity prices, as electricity constitutes their dominant operating cost. Consequently, lower electricity prices improve the economic performance of electrolysis pathways, whereas lower carbon prices favorize SMR-based hydrogen production.

These findings highlight the pivotal role of future energy market developments and climate policy frameworks in bridging the gap between improving environmental performance and economic feasibility. Although technological progress and decarbonization are expected to enhance the environmental benefits of hydrogen production pathways, their large-scale deployment will depend on whether economic competitiveness can be achieved, especially for technologies associated with high operating costs.

### 4.3 | Limitations

As electricity price and EU-ETS carbon prices were identified as the dominant drivers of economic performance for SMR and electrolysis technologies, the conclusions are most applicable to regions with similar energy system characteristics. In regions with substantially different electricity costs and where EU-ETS is not applicable, the absolute values reported in this study may vary significantly. Although the relative trends observed are expected to remain valid, future work should investigate a broader range of regional conditions and perform uncertainty analyses to evaluate the robustness of the conclusions under different techno-economic and environmental boundary conditions.

For the assessment of the import of hydrogen derivatives, it should be noted, however, that both the choice of export region and the assumed transport distance may influence the economic and environmental performance. Previous studies have shown that the GHG intensity of the electricity used for hydrogen production is a key determinant of the overall environmental performance of ammonia and LOHC supply chains [67]. Similarly, transport distance directly affects transportation-related costs and emissions. Export regions characterized by higher electricity-related GHG emissions would result in increased life cycle impacts of the imported hydrogen derivatives [68]. Therefore, the results presented in this study for the hydrogen derivatives should be interpreted as representative of the selected intra-European supply corridor and may differ quantitatively under alternative geographical sourcing scenarios.

Another limitation of this study is that the environmental assessment is limited to the evaluation of GWP. Although GWP is a key indicator for assessing climate change impacts, it does not capture other relevant environmental burdens that may arise along the hydrogen supply chain. Future research should therefore extend the assessment to additional impact categories, such as water scarcity, mineral resource depletion, land use, acidification, eutrophication, and human toxicity. Considering a broader set of environmental indicators would provide a more comprehensive evaluation of the sustainability performance of the investigated pathways and help identify potential trade-offs and burden-shifting effects between different environmental impact categories.

### 4.4 | Role of Policy and Market Design

The study emphasizes the pivotal role of policy in enabling the transition to low-emission hydrogen in the chemical industry: Without targeted policy support, industries may be reluctant to adopt emerging technologies due to the associated financial risks.

An increase in EU-ETS carbon prices could enhance the cost competitiveness of emerging technologies. In contrast, for hydrogen produced via PEM-electrolysis, electricity costs constitute 85% of the LCOH in 2045. This highlights the importance of reducing renewable electricity costs to improve the economic viability of electrolysis-based hydrogen production.

Furthermore, international collaboration is essential given the global nature of industrial competition. Policy dialogues should be established at a worldwide level to ensure coherent and coordinated strategies. For example, long-term purchase agreements with renewable-rich countries (e.g., Spain) can facilitate the import of hydrogen derivatives, while ensuring supply security and price stability.

### 4.5 | Strategic Recommendations

On the basis of the findings, the study offers several strategic recommendations for a sustainable hydrogen production pathway: In the near term, by 2030, it is essential to prioritize the deployment of electrolysis technologies in Germany. To address the economic disparity between low-emission hydrogen and conventional fossil-based hydrogen, governments should implement policy instruments, such as electricity subsidies and carbon contracts, to limit the cost penalties to industry pioneers.

By 2045, efforts should focus on scaling up the production of hydrogen through electrolysis and the import of hydrogen derivatives. The development of international hydrogen import agreement will be crucial for enabling the global supply chains.

## 5 | Conclusion

This study presents the first harmonized, prospective evaluation of emerging hydrogen production technologies, integrating environmental and economic assessments within a unified framework considering hydrogen production for the chemical industry. By modeling the GWP and LCOH for a wide range of technologies across two future time horizons—2030 and 2045—the research provides a comprehensive foundation for strategic decision-making in the chemical sector.

The key conclusions are as follows: First, regarding the environmental potential, emerging technologies can significantly reduce the carbon footprint of hydrogen production. In particular, electrolysis powered by renewable electricity and sustainably sources hydrogen derivatives offer GHG reductions of up to 80% by 2045.

Then, considering the economic trade-offs, despite their environmental benefits, most emerging technologies are not yet cost-competitive with conventional SMR. In 2030, electrolysis technologies are projected to be 80% more expensive. By 2045, the cost gap narrows, and electrolysis and hydrogen derivatives become economically viable under a high CO<sub>2</sub> price scenario.

Hence, policy interventions play a pivotal role in closing the cost gap between emerging hydrogen and conventional production pathways. Several strategies can be implemented to address these challenges. First, taking into account international competitive landscape, strengthening carbon pricing mechanisms—such as increasing the price of CO<sub>2</sub> emissions within emissions trading systems—can improve the relative cost position of low-carbon hydrogen by penalizing fossil-based alternatives. Second, reducing electricity costs for electrolysis through market reforms and

renewable energy integration is essential, as electricity constitutes the dominant cost component for electrolytic hydrogen production. Finally, establishing international agreements for hydrogen imports can facilitate global supply chain.

Additionally, concerning the strategic sustainable pathway for the chemical industry in Germany and similar contexts, the recommended transformation pathway involves: on short-term investment in electrolysis projects and on medium-term scaling of electrolysis and hydrogen derivative imports.

In conclusion, this research provides a robust analytical foundation for guiding the sustainable transformation of hydrogen production. It highlights the need for coordinated action across technology development, policy design, and international cooperation. Future research should expand the scope of environmental impact categories and explore alternative transport modes for hydrogen derivatives.

## Nomenclature

### Symbols

|              |                                                                                                  |
|--------------|--------------------------------------------------------------------------------------------------|
| $C_L$        | investment cost for a specific technology from the literature, € kg <sup>-1</sup> H <sub>2</sub> |
| $C_S$        | investment cost for a specific technology in this study, € kg <sup>-1</sup> H <sub>2</sub>       |
| $S_L$        | capacity from the literature, t H <sub>2</sub> a <sup>-1</sup>                                   |
| $S_S$        | capacity for this study, t H <sub>2</sub> a <sup>-1</sup>                                        |
| $sf$         | scaling factor, –                                                                                |
| $\eta_{k,s}$ | isentropic efficiency, %                                                                         |

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## Conflicts of Interest

The authors declare no conflicts of interest.

## Data Availability Statement

The data that support the findings of this study are available in the Supporting Information of this article.

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## Supporting Information

Additional supporting information can be found online in the Supporting Information section.

This section includes additional references to primary literature relevant for this research [69–72].

**Supporting File:** ceat70329-sup-0001-SuppMat.docx.