Hydrogen's Role in the Global Energy Transition

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Abstract

This paper investigates the role of hydrogen in achieving a decarbonized global energy system. Utilizing a global system dynamics model for the energy transition to 2050, we evaluate the potential of hydrogen across various production methods, its integration within different sectors, and the infrastructural developments required for its adoption. The analysis is bifurcated into a most-likely future scenario and a pathway to net-zero (PNZ) scenario. Our findings underscore hydrogen as a pivotal energy carrier by 2050, contributing to 5% of the global energy mix under the most-likely scenario, with significant advancements in low-carbon production methods such as carbon capture and storage (CCS) and electrolysis powered by renewable sources. The transport sector emerges as a key beneficiary, with hydrogen and its derivatives playing crucial roles in decarbonizing maritime and heavy-duty road transport. Under the PNZ scenario, hydrogen's share surges to 12-15%, underscoring its indispensability in achieving net-zero emissions. This scenario highlights a substantial increase in electrolysis capacity, spearheaded by solar and wind cost reductions. This paper contributes to the literature by providing a system dynamics analysis of hydrogen's evolving role in the context of global energy transition, explicitly accounting for endogenous interactions between regions and between hydrogen and other energy carriers.

Keywords: hydrogen, energy transition, green hydrogen, decarbonization pathways. Sector coupling

1 Introduction

Hydrogen has traditionally been used as a raw material in the production of chemicals, fertilizers, and refinery processes. Despite its potential, its adoption as an energy carrier remains limited due to the high costs associated with emission-free production methods essential for decarbonizing the energy system.

To harness hydrogen as a sustainable energy source or fuel, it must be extracted from oxygen or hydrocarbons. Although hydrogen is the simplest element, producing it in its pure form is complex and energy-intensive, leading to substantial energy losses, costs, and possible carbon emissions. The motivation behind expanding hydrogen usage is to minimize the carbon footprint of those sectors of the energy system that cannot be directly electrified, highlighting the necessity for low-emission or emission-free production and transportation methods, efficient water use, and effective byproduct management.

Interest in hydrogen within the energy sector is significant, yet the development and funding of related projects remain modest (Marouani et al 2023). Innovation continues, with numerous studies evaluating existing technologies and startups proposing innovative solutions. Direct use of hydrogen as energy faces challenges in cost, complexity, efficiency, and safety, making it less attractive than electricity for many applications. Nonetheless, in sectors where direct electrification is unfeasible, hydrogen and its derivatives like ammonia, methanol, and e-kerosene emerge as vital low-carbon alternatives.

Consensus is growing on the role of low-carbon and renewable hydrogen in achieving a carbon-neutral energy system, though the extent of its importance varies. Estimates suggest hydrogen could account for 10 to 20% of global energy consumption in a future low-carbon energy landscape (Buli, 2021). However, increasing hydrogen utilization encounters hurdles such as availability, cost, public acceptance, safety, efficiency, and purity. Despite the urgency for more hydrogen use to meet the Paris Agreement goals, progress lags, especially compared to advancements in renewable energy, power grids, and battery storage.

Many papers have investigated the role of hydrogen in the future, using system dynamics. Yusaf et al. (2022) delves into the critical role of hydrogen in transitioning towards a decarbonized energy sector. It leverages system thinking and dynamics models to predict hydrogen energy demand growth, considering environmental impacts, particularly NOx emissions from combustion processes. The study forecasts a significant rise in global hydrogen demand, ranging from 73 to 568 Mt by 2050, under various scenarios.

Shafiei et al (2015) presents a system dynamics model integrating the entire energy system, not just the hydrogen sector, to simulate the transition towards alternative fuel markets, emphasizing feedback loops, endogenous factors, and interactions across energy supply, demand, and infrastructure. The model, applied to Iceland's transition path, demonstrates the potential of system dynamics to offer policy insights by effectively capturing the dynamic equilibrium of supply and demand, illustrating a comprehensive method to forecast the scale of the hydrogen economy and its pivotal role in a sustainable energy transition.

Yang et al. (2023) study employs a system dynamics model to predict the development scale of the green hydrogen production industry in China, focusing on government subsidy policies' impact under different demand scenarios. The model comprehensively covers the entire energy system, incorporating feedback-driven mechanisms and endogenous factors such as investment willingness, production demand, and policy influences. Their analysis concludes that without appropriate policy combinations, the green hydrogen production capacity cannot meet the varying demand scenarios, emphasizing the critical need for tailored policy support to foster the industry's growth.

However, these studies often have geographical or scope limitations, restricting their ability to capture global interactions or the integration of hydrogen with other energy carriers. This paper utilizes the Energy Transition Model, a system dynamics model designed for global, comprehensive analysis of the energy transition, including interactions between regions and the roles of different energy carriers. This model aims to overcome the limitations of previous studies by including mechanisms for cost reduction through learning and the interplay between energy supply chains without relying on external assumptions.

In the following sections, we introduce the Energy Transition Model, detail the hydrogen sector's structure within the model, and present our findings for both a likely future scenario and a net-zero emissions scenario.

2 The Energy Transition Outlook Model

The Energy Transition Outlook (ETO) model offers a framework for examining the global shift in energy usage, focusing on how energy demand, supply, and emissions interact within the broader system. Unlike models that prioritize optimization or precise predictions, the ETO model highlights the dynamics and feedback mechanisms of the energy sector over time.

The model is built on assumptions that treat economic and demographic developments as external influences, thereby zooming in on the internal workings of the energy sector. It maintains an annual equilibrium between energy demand and supply, facilitating in-depth analysis by region and energy type. This level of detail sheds light on the varying trajectories of different areas and energy carriers throughout the transition.

Central to the model are its extensive database, which encompasses both historical data and projections, and its ability to simulate the impact of technological progress, policy measures, and market trends. These elements are vital for exploring possible routes to a sustainable, low-emission energy future.

The ETO model's projection of the long-term energy scenario makes it an invaluable tool for decision-makers, industry participants, and scholars. It supports the discovery of strategic opportunities, highlights transition challenges, and assesses the effects of potential energy policies and innovations. This sophisticated modelling tool emphasizes the significance of system dynamics analysis in formulating strategies to steer the global transition toward renewable energy.

The model comprises several interconnected modules that illustrate the intricate relationship between energy demand and supply, enhancing its analytical capabilities.
Each sector of the energy system (see Figure 1) is modelled by modules representing:

— final energy demand (buildings, manufacturing, transport, non-energy, and other)

— energy supply (coal, gas, and oil production)

— transformations (power generation, oil refineries, hydrogen production)

— and other relevant developments (economy, grids, CCS, energy markets, trade volumes, emissions)

These modules exchange information regarding demand, cost, trade volumes, and other parameters to provide a coherent forecast.

As the main focus of this paper is the power hydrogen, we will not go into the details of other model sectors. Nonetheless, the following paragraphs provide a broad overview of these sectors.

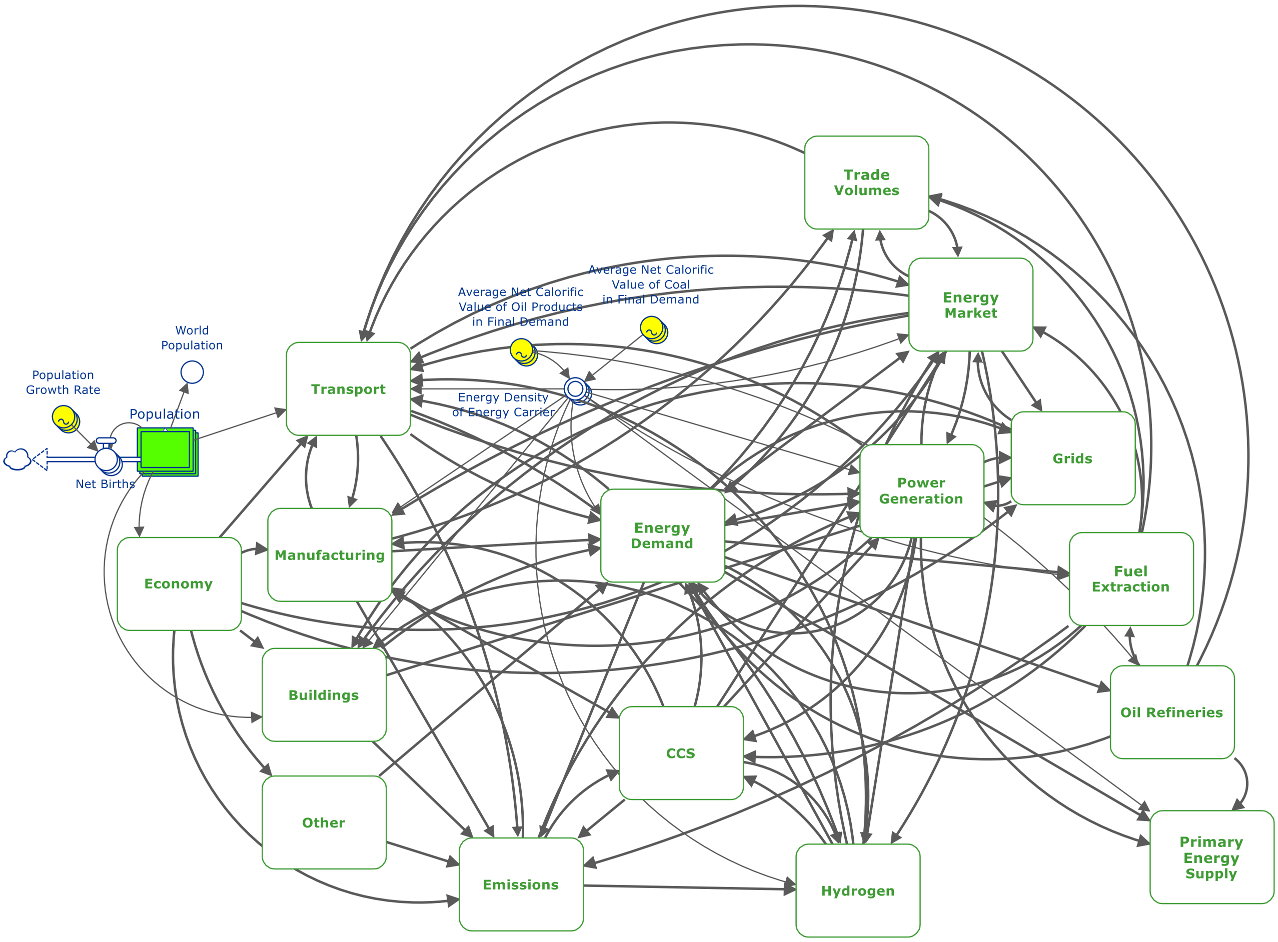

Figure 1. Model structure

GEOGRAPHICAL SCALE

The spatial resolution of the model is limited to 10 world regions (Figure 2). Regions interact directly, through trade in energy carriers, and, indirectly, by affecting and being influenced by global parameters, such as the cost of wind turbines, which is a function of global capacity additions.

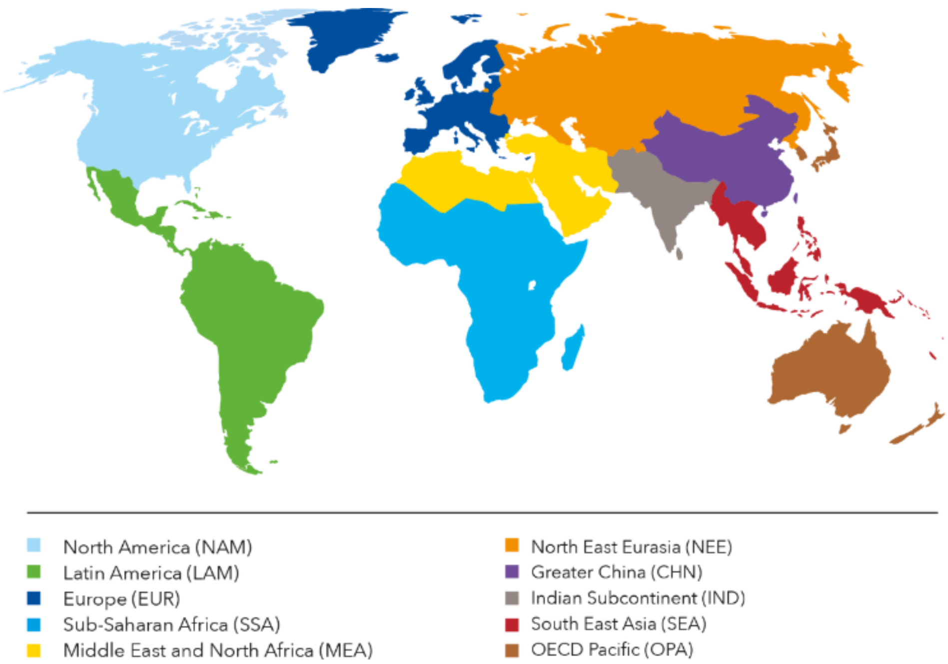

Figure 2. Ten regions used in our model

ENERGY DEMAND

We use policy and behavioural effects, either explicitly, as in the effect of increased recycling on plastics demand, or implicitly, such as the impact of expected electricity prices on electrification of heating. Generally, we estimate sectoral energy demand in two stages. First, we estimate the energy services provided, such as passenger-kilometres of transport, tonnes of manufacturing, and useful heat for water heating. Then we use parameters on energy efficiency and energy-mix dynamics to forecast the final energy demand by sector and by energy carrier.

We use non-linear econometric models to estimate regional demand for energy services. Population and GDP per capita are the main drivers, but we also incorporate other technological, economic, social, and natural drivers as necessary.

The choice of energy carrier is based on levelized costs in manufacturing and EV uptake. For the energy mix of other end-uses and for energy efficiency, our forecasts are derived from extrapolating past-usage trends into the future. These trends have been subject to expert judgement in our workshops, and adjustments have been made where deemed appropriate.

ENERGY CARRIERS

Among the 10 energy carriers that we model, seven are also primary energy sources; i.e., they can be used without any conversion or transformation process. The others are secondary forms of energy obtained from primary sources. Primary energy sources are *coal* (including peat and derived fuels), *oil*, *natural gas* (including ethane, propane, and butane), *geothermal*, *biomass* (including wood, charcoal, waste, biogases, and biofuels), *solar thermal* (thermal energy from solar water heaters), and *off-grid PV* (electricity from solar panels not connected to the grid). Secondary energy sources are *electricity*, *direct heat* (thermal energy produced by power stations), and *hydrogen*.

FOSSIL-FUEL EXTRACTION

When it comes to the supply of energy from primary sources, the ETOM focuses on the production of *oil*, *natural gas*, and *coal*. For oil and gas, we use a cost-based approach to determine regional production dynamics. Coal production is modelled by distinguishing between hard coal and brown coal. Each region’s hard-coal supply reflects its mining capacity, which expands as demand increases and is limited by its geologically-available reserves.

3 Hydrogen Sector

The hydrogen sector in the Energy Transition Outlook (ETO) model is a detailed component reflecting the complex dynamics and future potential of hydrogen as an energy carrier and feedstock. This sector bifurcates hydrogen into two main types: merchant and captive. Merchant hydrogen is sold as a commodity for energy or feedstock purposes, while captive hydrogen is produced for on-site consumption, primarily in ammonia or methanol production. The model incorporates these distinctions due to their differing roles and dynamics within the energy system.

Hydrogen demand in the model is driven by its competitiveness across various applications, acknowledging that almost all current hydrogen production serves non-energy purposes. The ETO model aggregates all sources of hydrogen demand, offering a comprehensive view of the sector's evolving landscape. Hydrogen supply modelling focuses on merchant hydrogen, addressing its cost structure meticulously. The levelized cost of hydrogen includes feedstock, energy, carbon, and CCS costs, reflecting the diverse pathways of hydrogen production, including fossil-based routes with or without carbon capture and storage (CCS) and electrolysis.

The model calculates hydrogen production CAPEX, considering global learning rates for technology advancements. Electrolysis, pivotal for producing green hydrogen, is modelled with detailed cost breakdowns, including the effects of regional differences, efficiency improvements over time, and the influence of policy factors on hydrogen economics. Operational considerations, such as annual operating hours for electrolysis, are dynamically modelled to reflect the shifting economics of hydrogen production technologies.

Hydrogen storage, a critical aspect of its market integration, is addressed through cost models that consider the type and availability of storage options. The model simulates the economics of hydrogen transport and distribution, crucial for understanding its role in a future energy system. The interplay between technology costs, market demand, and policy incentives is intricately modelled to project hydrogen's contribution to decarbonizing various sectors, including industry, transport, and power generation.

3.1 Hydrogen Demand

Currently, the world's annual hydrogen production amounts to approximately 90 Mt/yr, primarily used for non-energy purposes such as sulfur removal in refineries, ammonia and methanol production, and the direct reduction of iron in steel manufacturing, according to the International Energy Agency (IEA, 2021). An additional 30 Mt/yr of hydrogen, derived as a byproduct from industrial processes, is not included in this analysis of hydrogen demand. Future hydrogen demand is categorized into three main areas:

1. Decarbonization of existing hydrogen uses by replacing high-emission fossil fuels with cleaner alternatives.

2. Transitioning to hydrogen and its derivatives through retrofitting existing infrastructure.

3. Development of new applications requiring new infrastructure.

Hydrogen serves as a key input in several sectors, including oil refining, ammonia production, methanol and other chemicals manufacturing, direct reduced iron production, and the creation of ammonia and e-fuels like e-methanol and e-kerosene for energy purposes. The latter two categories are emerging demands.

In oil refineries, hydrogen is primarily used to desulfurize diesel and fuel oils. A third of a refinery's hydrogen needs are typically met by on-site by-product hydrogen, with the remainder supplied by on-site production (40% globally) or external suppliers (25%). Demand in refineries is influenced by crude oil demand, the sulfur content of crude oil, and regulatory limits on sulfur content in fuel products. Although developed countries already enforce low sulfur limits in vehicle fuels, reductions in sulfur content are anticipated in international shipping and in developing countries. The IEA (2019) notes a decrease in the average sulfur content of crude oil, largely due to increased production of US tight oil.

Figure 3 illustrates the relationship between the amount of crude oil processed in refineries and the demand for hydrogen, indicating an upward trend across all regions.

Global ammonia production, crucial for fertilizer manufacturing, has grown steadily with population increases. The IEA (2019) forecasts a 1.7% annual increase in ammonia demand for current uses between 2018 and 2030, with a continued rise expected thereafter. The demand for ammonia in industrial applications is predicted to grow faster during this period, while demand for nitrogen-based fertilizers may plateau or decline in some regions after 2030.

This analysis adopts a straightforward method, assuming that ammonia demand will rise linearly with population growth (18.869 kgN/person/yr), the impacts of increased industrial use and decreasing fertilizer demand will balance out, and 0.24 kg of hydrogen will be required per kg of nitrogen for ammonia production, based on 2019 data of 35.8 MtH_2/yr for 150.3 MtN/yr of ammonia production.

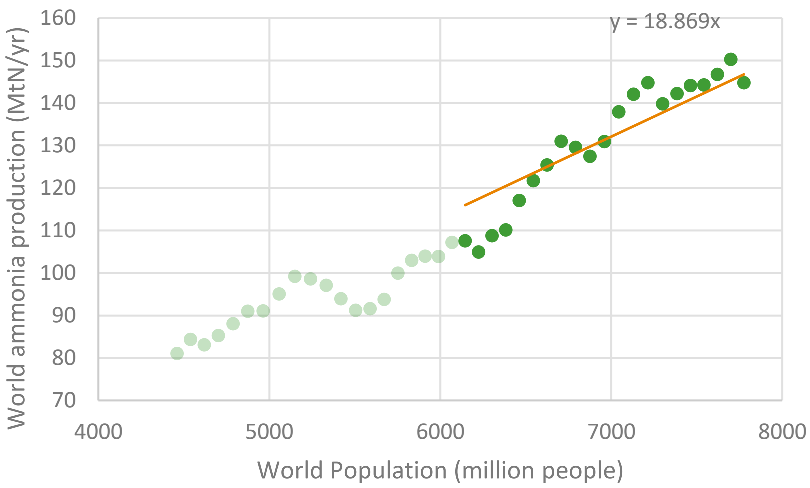

Figure 3. Population vs Ammonia Production

This leads to a continued increase in world ammonia production and corresponding hydrogen demand.

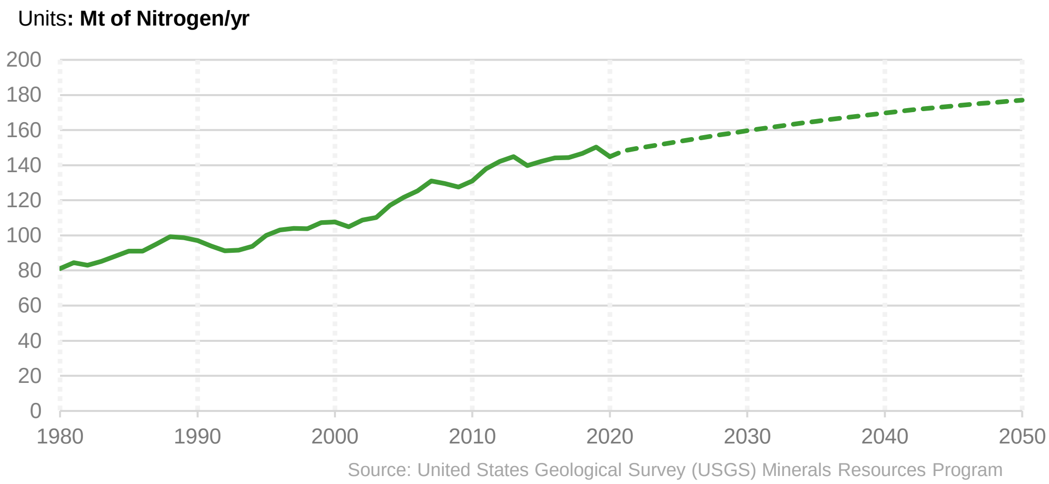

Figure 4. World Ammonia Production

The allocation of regional shares to meet demand is influenced by the cost competitiveness between local producers and exporters. This competition is modelled using a multinomial probit model, where the preference for a technology or import source is based on the inverse Levelized Cost, assumed to follow a normal distribution with a predefined standard deviation.

Hydrogen adoption in various sectors hinges on its availability and price competitiveness. Prices are projected on a regional basis to capture the economic, infrastructural, and regulatory diversity across different parts of the world. Such granularity ensures the model accurately reflects the varying dynamics of hydrogen supply and demand, the state of infrastructure, and the influence of regional policies on the hydrogen market. By incorporating these regional differences, the model offers detailed forecasts on how hydrogen prices might change in specific markets, providing valuable insights for developing strategies and policies that are adapted to the local contexts of each region.

3.2 Hydrogen production routes

In the evolving landscape of hydrogen production, our analysis encompasses a comprehensive suite of technologies, each with its distinct characteristics and implications for the energy transition. This paper delineates the various hydrogen production routes modelled, providing a structured comparison to inform both policy and technological development.

Our modelling framework includes both traditional and emerging hydrogen production pathways. Initially, we address **coal gasification and oil-based processes**. This category amalgamates hydrogen production from coal or oil, with an emphasis on coal gasification due to its prevalent parameterisation in the literature. Such methods, while established, pose significant environmental challenges due to their carbon-intensive nature.

Methane reforming, commonly referred to as 'grey hydrogen', represents another conventional route. It underscores the current dominance of fossil fuel-based hydrogen production but similarly raises concerns over carbon emissions.

Recognising the imperative for carbon mitigation, we extend our analysis to carbon capture and storage (CCS) variants of the aforementioned processes: **coal gasification or oil-based with CCS** and **methane reforming with CCS.** These pathways offer a transitional approach by substantially reducing the carbon footprint of traditional hydrogen production methods.

Parallelly, our study delves into **grid-connected electrolysis**, a technique that, depending on the grid's carbon intensity, has variable environmental impacts. The shift towards renewable energy sources introduces several **dedicated renewable electrolysis** methods, each harnessing distinct renewable resources:

- **Dedicated solar PV electrolysis** capitalises on photovoltaic technology to directly convert solar energy into hydrogen, presenting a clean, albeit intermittently available, hydrogen source.

- **Dedicated solar+storage electrolysis** builds upon the previous method by integrating energy storage solutions, thus mitigating issues related to solar energy's variability.

- **Dedicated onshore wind electrolysis**, **dedicated fixed offshore wind electrolysis**, and **dedicated floating offshore wind electrolysis** each utilise wind energy, albeit in different settings, to produce hydrogen. These methods highlight the potential of wind energy's varying capacities and the technological nuances in exploiting these resources.

- Lastly, **dedicated nuclear electrolysis** offers a low-carbon alternative, leveraging the consistent output of nuclear power plants to facilitate hydrogen production.

Each of these pathways embodies distinct trade-offs between technological maturity, economic viability, environmental impact, and scalability. Our comparative analysis aims to elucidate these factors, thereby guiding stakeholders in navigating the complex landscape of hydrogen production towards a sustainable energy future.

3.3 Hydrogen production cost

Our analysis of the economic aspects of hydrogen production routes is segmented into several cost categories, reflecting the complexity and variability inherent in these technologies. This structured approach allows for a nuanced understanding of the financial implications associated with each production pathway. The cost categories modelled encompass both capital expenditures (CAPEX) and operational expenditures (OPEX) across different technologies, outlined as follows:

Hydrogen Production CAPEX: This category includes the initial capital investment required to establish hydrogen production facilities. It is a critical cost component for all production routes, including fossil-based processes, fossil with carbon capture and storage (CCS), grid-based electrolysis, and dedicated power station electrolysis. The investment covers the construction of production plants and the installation of necessary equipment.

Hydrogen Production OPEX: Operational expenditures for hydrogen production span across all routes. These costs are recurrent and include maintenance, labour, and other day-to-day expenses necessary for the continuous operation of hydrogen production plants.

Power Station CAPEX: This cost category is unique to hydrogen production methods that involve dedicated power stations, such as dedicated renewable electrolysis (solar, wind, nuclear). It accounts for the capital required to build the power generation facilities that supply electricity exclusively for hydrogen production.

Power Station OPEX: Similarly, this operational expenditure is specific to dedicated power stations. It encompasses the ongoing costs associated with running these power generation facilities, including maintenance, labour, fuel (where applicable), and other operational costs.

Feedstock Costs: For hydrogen production methods that rely on fossil fuels (either with or without CCS), feedstock costs constitute a significant expense. This includes the cost of acquiring coal, oil, or natural gas used in the hydrogen production process.

Energy Costs: Energy expenses are relevant to all hydrogen production methods, accounting for the cost of electricity or other forms of energy required during the hydrogen production process. This includes grid-based electrolysis and dedicated power station routes.

Carbon Emission Costs: Applicable to fossil-based and fossil with CCS hydrogen production routes, these costs reflect the financial implications of carbon emissions, including taxes or carbon trading expenses.

C**CS Non-CAPEX Costs**: For processes that incorporate CCS, this category covers operational costs associated with carbon capture and storage that are not included in the initial capital investment. This may involve expenses related to the operation of CCS facilities, transportation of captured CO_2, and its sequestration.

Short-Term Storage and Transport Costs: These costs are universal across all hydrogen production methods, addressing the expenses related to the short-term storage of hydrogen post-production and its subsequent transportation to the point of use or further storage facilities. This category is crucial for understanding the logistics and infrastructure requirements associated with the hydrogen supply chain.

3.3.1 Hydrogen production capex

In our economic analysis of hydrogen production technologies, Capital Expenditures (CAPEX) are meticulously assessed across three primary technology groups, each with distinct infrastructural and technological demands:

Electrolysis: The CAPEX for electrolysis-based hydrogen production encompasses the investment required for the installation and setup of electrolysis equipment. This includes the costs associated with the electrolyzers themselves, as well as any necessary infrastructure for water supply, purification, and the electrical connections needed to power the process.

Methane Reforming: For methane reforming technologies, the CAPEX includes the costs of constructing steam methane reforming (SMR) or autothermal reforming (ATR) facilities. This also covers the expenses related to the setup of reformers, heat exchangers, and other necessary components for converting natural gas into hydrogen.

Coal Gasification: The capital expenditure for coal gasification involves the construction of gasification plants where coal is converted into syngas, a mixture of hydrogen, carbon monoxide, and carbon dioxide, followed by a water-gas shift reaction to increase hydrogen yield. This category accounts for the costs of gasifiers, cleanup systems, and other infrastructure required for the process.

Technologies such as pyrolysis, thermolysis, and photolysis are not modelled in this paper, focusing the analysis on the more established and commercially viable routes for hydrogen production. This distinction allows for a focused examination of the capital investments necessary to deploy these technologies at scale, facilitating a clearer understanding of the economic barriers and opportunities in advancing towards a hydrogen economy.

3.3.1.1 Electrolysis

In the domain of hydrogen production, electrolysis stands out due to its diverse technological pathways and evolving cost structures. Our model differentiates between several competing electrolysis technologies, namely Alkaline, Proton Exchange Membrane (PEM), Solid Oxide Electrolysis, and Anion Exchange Membrane. Among these, Alkaline and PEM technologies emerge as the most mature, each securing a niche depending on their application size and use case. Alkaline electrolysis, celebrated for its longstanding history, commands approximately 65% of the market despite its lower operational flexibility compared to pressured alternatives, with a cost of $800/kW_electrical. Conversely, PEM technology, notable for its rapid operational dynamics, carries a higher price tag of $1000/kW_electrical and depends on rare earth elements for its functionality.

To account for the comprehensive costs associated with establishing electrolysis infrastructure, our analysis incorporates an additional 35% on top of the baseline for engineering, procurement, and construction (EPC) expenses. Anticipating a convergence in the cost disparities among technologies within the next decade, we adopt a unified modelling approach for future electrolyser expenses, positing a reference cost of $870/kW. This projection is underpinned by a learning rate of 14.75%, an average derived from Alkaline (12%) (IRENA, 2020) and PEM (17.5%) (Böhm et al, 2019), which indicates a 5.6% cost reduction for each doubling of cumulative capacity, starting from a baseline of 31.2 GW (30 GW Alkaline, 1.2 GW PEM) as reported by Schmidt et al. (2017).

Another significant CAPEX consideration is the electrolyser stack replacement, which incurs 35% of the unit CAPEX. The stack's lifespan is expected to improve from approximately 72,000 hours in 2020 to 80,500 hours by 2050, attributed partly to the shift towards PEM technology. This evolution in lifespan is critical for financial modelling over the operational timeline of the electrolysis plants.

Furthermore, our model acknowledges the presence of lower-cost alternatives in China, where electrolysers are priced as low as $300/kW according to Bloomberg New Energy Finance (BNEF, 2019). However, these units exhibit lesser efficiency and reduced operational lifetimes. We, therefore, assume a baseline cost of $350/kW for these Chinese electrolysers, without factoring in learning rate improvements. Additionally, a 25% efficiency penalty is applied to these units, projected to decrease to 15% by 2050, to account for the quality and performance disparity.

This nuanced CAPEX analysis provides a comprehensive understanding of the financial dynamics influencing the deployment of electrolysis-based hydrogen production technologies, laying the groundwork for informed investment and policy decisions in the hydrogen economy.

3.3.1.2 Coal gasification

Coal gasification for hydrogen production, specifically through the partial oxidation (POX) method, involves burning coal with oxygen under pressure to produce hydrogen. This process stands as a significant component of the global hydrogen production landscape, with approximately 85% of the world's coal gasification plants located in China, highlighting the country's dominance in this technology.

The capital expenditure (CAPEX) for coal gasification-based hydrogen production is quantified at approximately $3300 per kilogram of hydrogen produced per day, as indicated by the International Energy Agency (IEA). When incorporating carbon capture and storage (CCS) technology to mitigate the environmental impact, the unit CAPEX rises by 20%, reflecting the additional complexity and equipment required for capturing and storing CO_2 emissions effectively.

Furthermore, our model accounts for an additional 35% in costs attributed to engineering, procurement, and construction (EPC) for both coal gasification with and without CCS. This addition is essential for a comprehensive understanding of the total investment required to establish and commission a coal gasification hydrogen production facility.

It's important to note that our financial modelling assumes no learning rate for coal gasification technology. This assumption is predicated on the maturity of the technology and the current market dynamics, especially in regions like China where coal gasification is extensively deployed. The absence of a learning curve in our model reflects a conservative approach to cost projections, ensuring that our analysis remains robust against potential fluctuations in technological advancements and market conditions.

3.3.1.3 Methane reforming

In the realm of hydrogen production via methane reforming, two principal technologies emerge: steam methane reforming (SMR) and autothermal reforming (ATR). SMR, the incumbent technology, involves the reaction of steam and methane in a reactor, heated externally by a furnace. ATR, although less mature, distinguishes itself by using pure oxygen instead of air—eliminating the need for nitrogen separation—and incorporating internal heat generation, thereby obviating the requirement for an external furnace. This process utilises over 90% of natural gas as feedstock, compared to 65% for SMR, resulting in a higher CO_2 concentration that potentially reduces the cost implications for carbon capture and storage (CCS).

The capital expenditures (CAPEX) for methane reforming technologies vary significantly between merchant (standalone) and captive (integrated into ammonia or methanol production) operations, without making a distinction between SMR and ATR for baseline cost calculations; however, reference costs are primarily based on SMR. For merchant units, the reference CAPEX is averaged at $700 per kilogram of hydrogen produced per day, drawing from sources such as the International Energy Agency (IEA) and the Fuel Cells and Hydrogen Joint Undertaking (FCHJU), plus an additional 35% for engineering, procurement, and construction (EPC). Captive units, on the other hand, exhibit a lower reference CAPEX of $550 per kilogram of hydrogen per day (sourced from the IEA), also subject to the same 35% EPC markup.

When considering the integration of CCS, particularly relevant given the CO_2 intensity of these processes, it's assumed that ATR will be the preferred choice due to its higher CO_2 concentration output and, consequently, more cost-effective CCS implementation. The additional CAPEX for carbon capture is modelled at 100% of the SMR CAPEX for merchant units, according to Oni et al. (2022), and 20% of SMR CAPEX for captive operations, as indicated by the IEA.

The financial model incorporates a learning rate of 11%, which reflects not only improvements in cost efficiency but also a gradual transition from SMR to ATR technologies. This shift is considered alongside the projection of reference cumulative capacity additions, estimated at 210 million tonnes of hydrogen per year.

3.3.2 H_2 Production OPEX

For methane reforming with CCS, the fixed OPEX is calculated at 3.3% per annum of the capital expenditure (CAPEX). This slightly higher operational cost reflects the added complexity and maintenance requirements associated with integrating CCS technology into the methane reforming process. The CCS component necessitates additional monitoring, maintenance, and operational management to ensure the effective capture and sequestration of carbon dioxide, thereby incurring higher annual operational costs relative to other production methods.

In contrast, all other hydrogen production routes are characterised by a fixed OPEX of 3% per annum of CAPEX. This category encompasses a broad spectrum of technologies, including coal gasification, various forms of electrolysis, and methane reforming without CCS. The slightly lower fixed OPEX percentage for these technologies suggests a general operational efficiency and potentially less complex maintenance and operational management compared to systems that incorporate CCS.

3.3.3 Power station costs

Figure 5 delineates the relationship between the energy output from solar photovoltaic (PV) sources, the energy input into the electrolyser, and the resulting hydrogen output over time, measured in hours. It is intended to inform the optimal sizing of an electrolyser to maximise its utilisation and efficiency when paired with a dedicated power source.

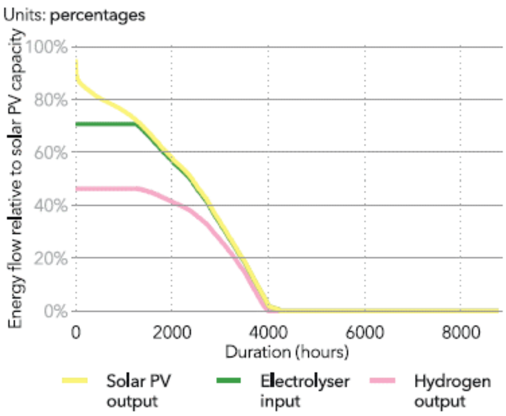

Figure 5. Optimal sizing of an electrolyser

In addressing the costs associated with power station capacity, our model adopts a tailored approach to electrolyser sizing based on the type of dedicated power station. For wind and nuclear power sources, a one-to-one ratio is used, implying that 1 megaw0att (MW) of power station capacity is matched with an electrolyser of equivalent capacity. Conversely, for solar power stations, a 0.7 MW capacity electrolyser is deemed optimal per 1 MW of solar capacity to accommodate the variable nature of solar energy and to enhance electrolyser utilisation.

To ascertain the correct utilisation rates, Normalized Load Duration Curves (NLDCs) are calculated for each type of power station and geographical region. These curves are essential in evaluating how often and to what extent the electrolysers can operate relative to their maximum capacity, based on the availability of power from the respective energy sources.

NLDCs serve as a foundational tool for informing the infrastructural investment decisions related to the deployment of dedicated power stations for hydrogen production. This methodological rigour ensures that the sizing of electrolysers is aligned with the temporal patterns of energy availability, thereby optimising capital efficiency and operational performance.

3.3.4 CCS and carbon cost

The assumptions surrounding carbon capture and storage (CCS) and the associated carbon costs form an integral part of our economic model for hydrogen production. The model presumes a 90% capture rate for CCS technologies, aligning with the efficiency levels commonly cited in CCS literature. This high rate of capture is essential to ensure that the carbon emissions from hydrogen production are significantly mitigated, thereby enabling a cleaner hydrogen economy.

Capital expenditures (CAPEX) for carbon capture technology are incorporated within the broader Hydrogen Production CAPEX category. This inclusion is critical as it reflects the upfront investment necessary to integrate CCS into hydrogen production facilities, particularly for fossil fuel-based processes like methane reforming.

Beyond the initial capital outlay, the non-CAPEX costs for CCS are comprehensive, encompassing operational expenditures (OPEX), which include energy costs intrinsic to the operation of CCS technology, and expenses related to the transport and storage of the captured CO_2. These aspects are discussed in detail within the CCS sector-specific analysis and have significant bearing on the overall economics of hydrogen production when CCS is employed.

For emission intensities, we assume values based on the feedstock's calorific value: 66.1 $kgCO_2/GJ$ of natural gas for conventional methane reforming (SMR) and 57.3 $kgCO_2/GJ$ for methane reforming with CCS (ATR). These figures provide a basis for estimating the total carbon emissions associated with each process and are pivotal in calculating the carbon cost.

The carbon cost itself is a dynamic component, scaling with the regional carbon price. It is applied not only to the CCS sector but also more broadly to the hydrogen production sector. By tying the carbon cost directly to regional carbon pricing mechanisms, our model remains sensitive to policy changes and market-driven price variations, allowing for a more accurate and responsive economic assessment of hydrogen production routes in different geographical contexts.

3.3.5 Feedstock and energy intensity

Figure 6 traces the trajectory of fuel usage efficiency across different hydrogen production technologies over time. The metrics provide insight into the energy requirements specific to each method, measured in megajoules per kilogram of hydrogen (MJ/kgH_2).

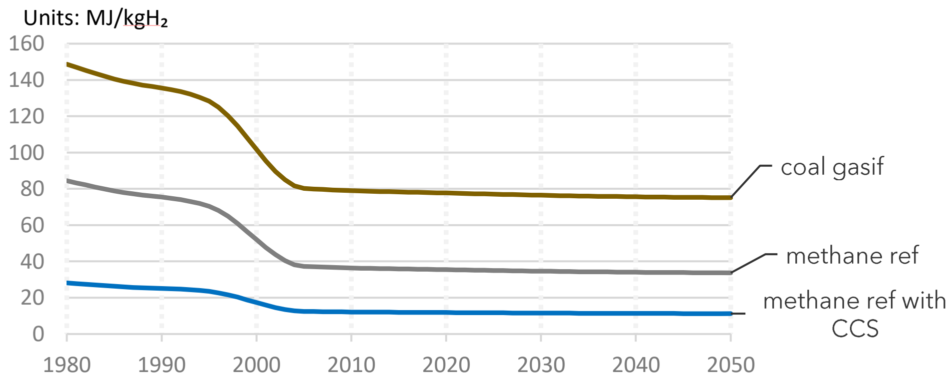

Figure 6. Specific Fuel Intensity of New H_2 Production Capacity

For coal gasification, indicated by 'coal gasif' on the chart, the specific fuel intensity starts significantly higher than other methods but shows a declining trend, particularly before the 2000s, indicating improvements in efficiency over time. However, the graph suggests that there is a plateau in recent years, with little scope for further enhancement, stabilising around the 60 MJ/kgH_2 mark.

The 'methane ref' line represents the traditional steam methane reforming (SMR) process, which also shows a decrease over time but appears to level out, reflecting a mature technology with limited potential for future efficiency gains. The introduction of carbon capture and storage (CCS) in methane reforming, denoted as 'methane ref with CCS', exhibits a slightly higher energy intensity due to the additional energy requirements for capturing and storing CO_2.

The feedstock intensity for these processes remains constant over time: 104.8 MJ/kgH_2 for coal gasification, 118.2 MJ/kgH_2 for methane reforming (SMR), and 145.3 MJ/kgH_2 for methane reforming with CCS (ATR). These values underscore the relative energy requirements for producing hydrogen from different feedstocks.

In addition to feedstock intensity, a small amount of electricity is used in the SMR process, estimated at around 1 MJ/kgH_2. For ATR and coal gasification, which involves an air separation unit, this electricity requirement is higher, at approximately 5 MJ/kgH_2.

Focusing on the electricity intensity of electrolysis, there's an anticipated decline from 185.5 MJ/kgH_2 in 2020 to 173.2 MJ/kgH_2 in 2050, correlating with an efficiency improvement from 65% to 69%. This projection is based on a weighted average between Alkaline and PEM electrolysis technologies, with a noted industry shift from 65% Alkaline in 2020 towards a 50% share by 2050.

3.3.6 Fuel cost

In the context of hydrogen production, both the cost and availability of feedstocks are essential factors in determining the economic viability of various hydrogen production methods. For coal gasification, the price of coal is assumed to match that of the industrial sector's coal price. Similarly, the cost of natural gas utilised for methane reforming is equated to the industrial sector's natural gas price. For both these processes, the electricity price is presumed to be in line with the industrial electricity rates.

When it comes to grid-connected electrolysers, a critical factor influencing their operational economics is the electricity price, which varies depending on when the electrolysers are run. The model assumes that electrolysers do not have fixed-price electricity purchase agreements, implying that their operation is subject to fluctuations in the electricity market.

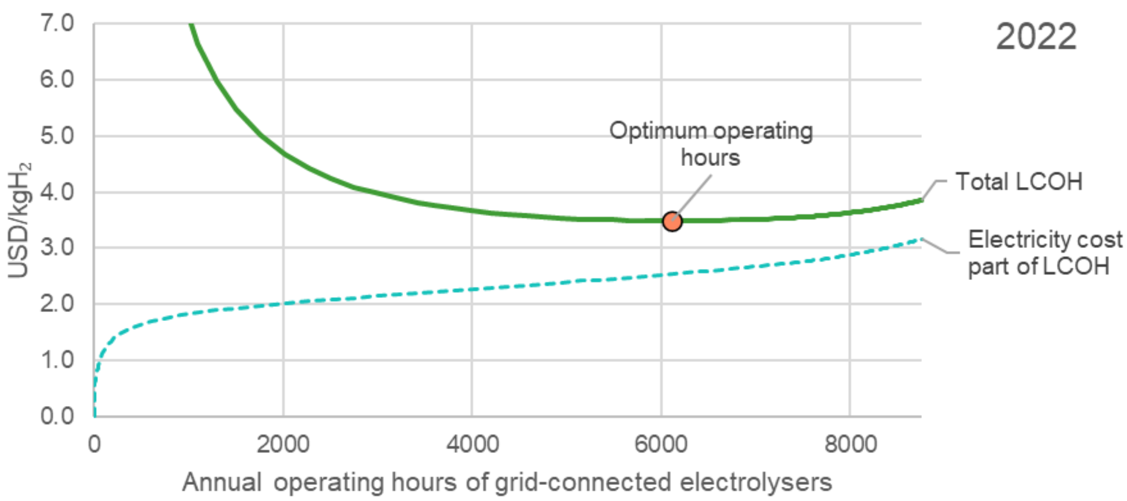

Figure 7. Calculation of grid-connected electrolyser operating hours in 2022

Under the current scenario, without a common market for hydrogen producers, electrolysers are operated to minimize their total cost. They run as long as it is economically viable without the constraint of competing with other hydrogen production sources. This situation is reflected in the Figure 7 where the total LCOH decreases as the annual operating hours increase, emphasizing the economic benefit of extended operation.

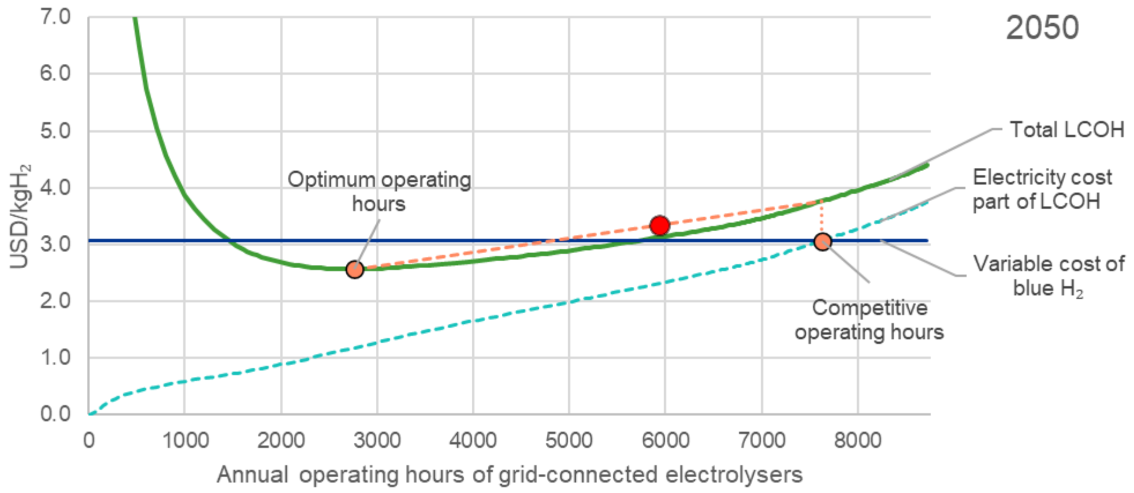

Figure 8. Calculation of grid-connected electrolyser operating hours in 2050

Looking towards the future, it is anticipated that a portion of the grid-connected electrolysers, specifically those serving the merchant market, will need to compete with methane reforming that includes CCS (termed 'blue hydrogen'). By 2050, it is expected that two-thirds of electrolysers will operate in such competitive markets across all regions. For these electrolysers to be economically productive, they will need to generate hydrogen at a cost that is lower than the variable cost of producing blue hydrogen. This competitive dynamic is illustrated in Figure 8, where the LCOH for grid-connected electrolysers intersects with the variable cost of blue hydrogen, indicating the maximum feasible operating hours for electrolysers to remain cost-competitive.

Moreover, it is assumed that around 25% of grid-connected electrolysers will be subject to grid charges, akin to standalone operations purchasing grid electricity. The rest will have the advantage of paying wholesale electricity prices, like those directly associated with grid-connected power stations.

3.3.7 Short-term storage and transportation cost

Short-term storage and transportation costs are integral to the economics of hydrogen production, covering on-site hydrogen storage and delivery to the transmission grid. Costs associated with transmission and distribution are accounted for separately. Systems reliant on dedicated solar and wind for electrolysis require more extensive on-site storage, incurring higher costs. Conversely, captive hydrogen production, typically consumed on-site, necessitates minimal storage, reducing this cost component.

As the production site density increases and hydrogen-utilising industries relocate closer to these sites, we anticipate a general decrease in short-term storage and transport costs. However, an exception is noted for grid-connected electrolysers: as they shift towards more variable operations due to the integration of solar and wind, their storage requirements—and consequently, costs—are expected to increase in the future.

3.4 Cost calculations and supply mix

Central to our model is the concept of the levelized cost of hydrogen (LCOH), which serves as a linchpin connecting various facets of hydrogen production. The LCOH is not a static figure but a product of numerous variables that interact within the energy market. These include the capital expenditures (CAPEX) and operational expenditures (OPEX) associated with hydrogen production, the efficiency of different production technologies, and the feedstock and energy costs, which are subject to variations in market prices.

The model considers the CO_2 emissions resultant from hydrogen production methods, acknowledging the weighty influence of carbon pricing mechanisms on the LCOH. This influence underscores the economic drive towards low-carbon technologies, such as electrolysis powered by renewable energy, and technologies coupled with carbon capture and storage (CCS).

The market dynamics depicted within the model capture the competition between grey hydrogen (from fossil fuels without CCS), blue hydrogen (from fossil fuels with CCS), and green hydrogen (from electrolysis using renewable energy). Each production route's competitiveness is influenced by factors such as feedstock price, technology maturity, and regulatory frameworks, including carbon taxation and incentives for renewable energy.

Looking towards grid-connected electrolysers, a pivotal element of our analysis, their economic viability is dictated by the electricity cost. This cost is variable, contingent upon the operating hours and the electricity market fluctuations. Grid-connected electrolysers must remain cost-competitive against alternative hydrogen sources, an aspect that will grow in significance as these electrolysers increasingly enter competitive markets.

By 2050, it is envisaged that a considerable segment of electrolysers will operate in such competitive environments. This projection has been incorporated into the model, with assumptions about the proportion of electrolysers that will need to contend with the variable cost of blue hydrogen to remain commercially viable.

In the competitive landscape of merchant hydrogen production, the viability of various technologies and import options hinges upon their levelized cost of hydrogen (LCOH). To determine the distribution of market share across different hydrogen production capacities and import methods, we employ a multinomial logistic probability model. This model is predicated on the notion that each technology's utility is inversely proportional to its LCOH and assumes a normally distributed utility with a predefined standard deviation.

Within this model, the probability that any given technology *i* will be less expensive than the cheapest alternative technology is calculated through an integration process. This calculation considers all potential costs *c*, multiplying the probability that technology *i* costs *c* by the product of the probabilities that all other technologies have costs exceeding *c*. Integrating across all values of *c* allows for the accumulation of the total probability that technology *i* is the least costly option, thus informing its likelihood of selection for capacity addition.

$$P\{X_i < \min_j X_j\} = \int_{-\infty}^{\infty} P\{X_i = c\} \cdot \prod_{j,\, j \neq i} P\{X_j > c\}\, dc$$

The model operates under the assumption that a switch in technology does not occur prior to the end of each technology's technical lifespan. An exception to this rule is made for the transition from grey to blue hydrogen, where adding CCS is considered a technology switch rather than a complete replacement.

In the context of hydrogen use within the transport sector as a direct fuel, the model restricts the option to hydrogen produced via electrolysis. This is due to the high purity requirements of hydrogen fuel cells, which are more readily met through the electrolysis process.

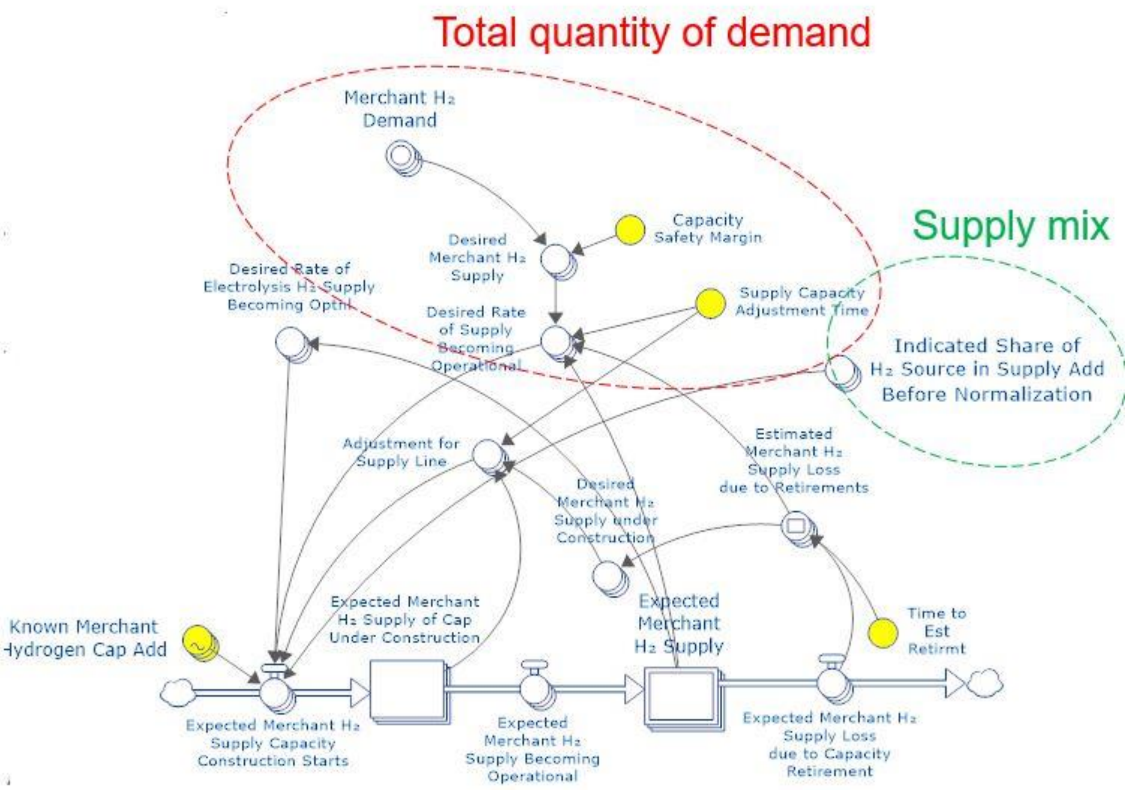

Figure 9. Model structure related to hydrogen capacity

In this model, the total quantity of demand for merchant hydrogen is driven bythe competitiveness of hydrogen against alternatives in the demand sectors. Merchant hydrogen demand is addressed alongside a capacity safety margin, set at 0.2 in this instance, to ensure supply resilience. The 'Desired Merchant H_2 Supply' emerges as a critical factor that must account for this safety margin, thereby dictating the necessary scale of hydrogen production capacity.

To maintain an adequate supply, the model considers the need for new capacity additions. These additions are informed by the anticipated retirements of existing capacity and the timeframe required to bring new capacity online. This is where the 'Expected Merchant H_2 Capacity' becomes operational, integrating the 'Desired Merchant H_2 Supply' with the practical considerations of capacity construction and retirement.

This framework also integrates data from the IEA Hydrogen Projects Database, identifying 'Known Merchant Hydrogen Capacity Additions'. These data points provide a tangible grounding to the model, ensuring that projections for capacity additions are anchored in existing developments within the industry before a demand and cost driven logic takes over.

The model then proceeds to the 'Supply mix', where the 'Indicated Share of H_2 Source in Supply Add Before Normalization' is factored into the overall scheme. This mix reflects the variety of hydrogen sources that contribute to meeting the merchant demand, encompassing all local supply technologies, and potentially imported hydrogen through sea or pipelines.

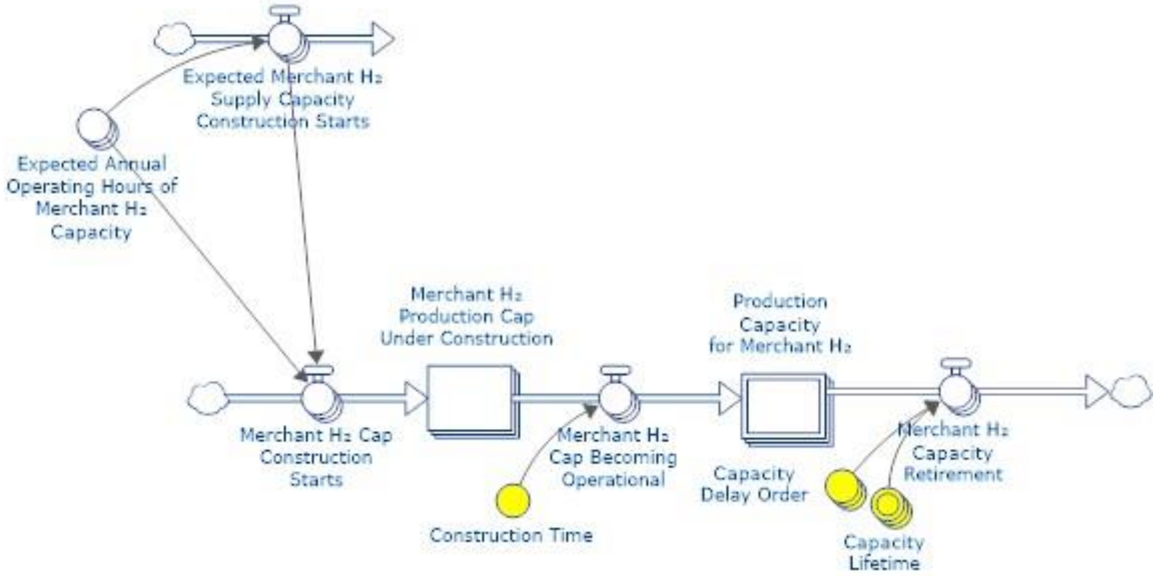

Figure 10

As our system dynamics model elaborates on the nuanced operational phase of hydrogen production, the tracking of actual production capacity is brought to the fore alongside the expected supply (Figure 10).

The expected annual operating hours for merchant hydrogen capacity form a crux of this part of the model. For grid-connected electrolysers, these hours are contingent upon grid electricity availability, which, as we previously discussed, fluctuates with the intermittency of renewable sources. Dedicated power stations, linked to the direct supply from renewable sources, have their expected operating hours grounded in the inherent availability of these energy sources. In contrast, fossil-based sources boast a higher assumed availability of 90%, reflecting their less intermittent nature and greater control over production rates.

A common assumption within the model is a 25-year capacity lifetime for all hydrogen production types. This is a standard practice within the industry, providing a consistent baseline for modelling the turnover of infrastructure and enabling clear comparisons across different technology types.

The model delineates the lifespan of hydrogen production, starting with 'Merchant H_2 Cap Construction Starts', signalling the initiation of new capacity builds. As these projects progress, they move into 'Merchant H_2 Production Cap Under Construction', and then transition into the 'Merchant H_2 Cap Becoming Operational' phase once completed. This sequence captures the inherent delay represented by the 'Capacity Delay Order', which is indicative of the time lag between the initial decision to build and the actual start of construction.

Upon becoming operational, the 'Production Capacity for Merchant H_2' needs to be closely monitored for its effective operational lifetime until it culminates in the 'Merchant H_2 Capacity Retirement' phase. This end-of-life stage is critical to ensure that the model accurately represents the phasing out of outdated or exhausted capacity, maintaining a realistic forecast of production capabilities over time.

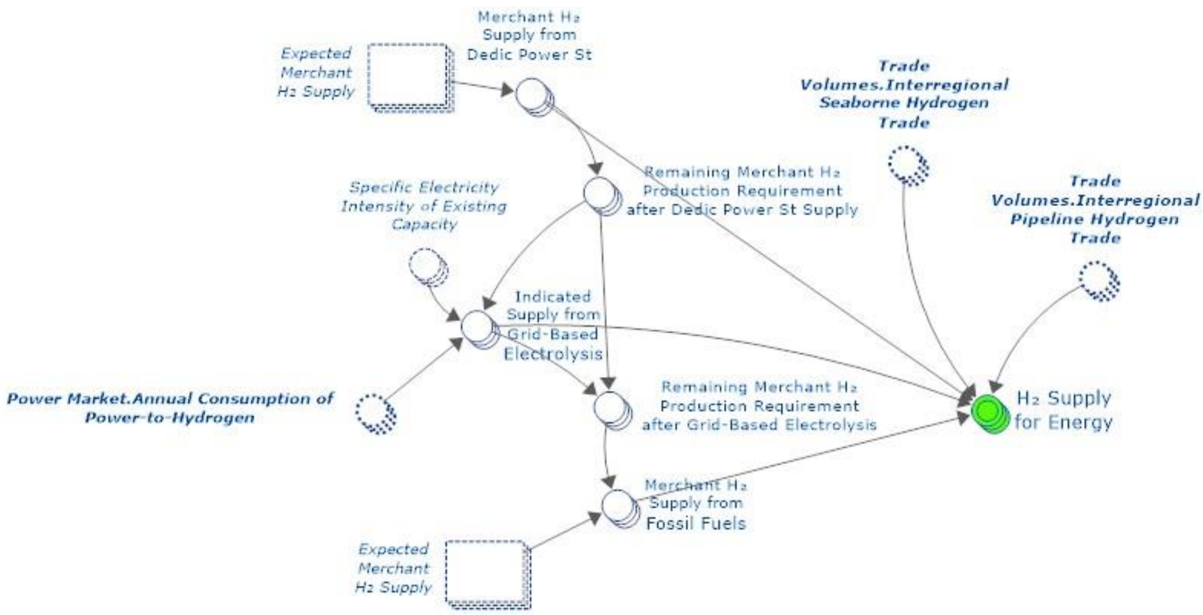

Figure 11. Supply adjustment structure

In the case of an oversupply within the hydrogen market, our model specifies a hierarchy in utilising the excess production (Figure 11). The prioritisation sequence for consuming this oversupply is as follows:

Hydrogen from dedicated power stations is utilised first. These stations, typically aligned with renewable energy sources, represent the most sustainable and preferable option within the hierarchy, reflecting the increasing focus on green energy within global energy policies. **Grid-based electrolysers** come next. While these are also aligned with renewable energy, their operation may be more variable due to their dependence on the grid's fluctuating supply, which may not always be sourced from renewables. **Fossil-based hydrogen supply** is used last. As the least sustainable option due to the associated carbon emissions, this supply is considered the fallback option within the oversupply scenario.

This stratified approach towards managing oversupply aligns with global efforts to transition towards more sustainable energy systems, where the utilisation of green and renewable energy sources is prioritised to minimise carbon footprints and combat climate change. The model effectively accounts for trade-offs between sustainability and supply availability, ensuring that even in times of excess production, the utilisation of hydrogen aligns with broader environmental objectives.

In the context of the wider system dynamics, the 'H_2 Supply for Energy' node serves as the convergence point for these supplies, indicating the total hydrogen that is available for energy use after accounting for the existing market mechanisms, such as trade volumes in interregional seaborne and pipeline hydrogen trade. The model's architecture ensures that the supply is responsive to market conditions, dynamically adjusting to changes in production and demand to maintain equilibrium within the hydrogen economy.

3.5 Learning process

Figure 12 encapsulates the relationship between capacity additions and the resultant cost reductions—a fundamental aspect that hinges on the principle of learning rates.

The model, through its global scope, is uniquely equipped to generate endogenous trajectories for the cost of electrolysers. In this schema, we observe that for every cumulative doubling of capacity additions, there is a corresponding fractional reduction in the cost of electrolysers. This relationship is underpinned by the 'learning-by-doing' hypothesis, widely accepted in industrial economics, which posits that production costs decline as a function of cumulative production experience.

This effect of cumulative capacity on learning rates is a pivotal component of our model, illustrating that as more countries and companies invest in electrolyser technology, the more cost-effective it becomes. The learning rate itself is a function of technological improvements, economies of scale, and enhanced production efficiencies, which collectively contribute to the decreasing cost curve depicted in the figure.

The relationship shown in Figure 12 corroborates the global nature of the learning effect; as such, any regional advancements in electrolyser technology contribute to the global reduction in costs. This synergistic effect underscores the importance of international collaboration and investment in driving the hydrogen transition, making the case for coordinated policy measures and shared R&D initiatives.

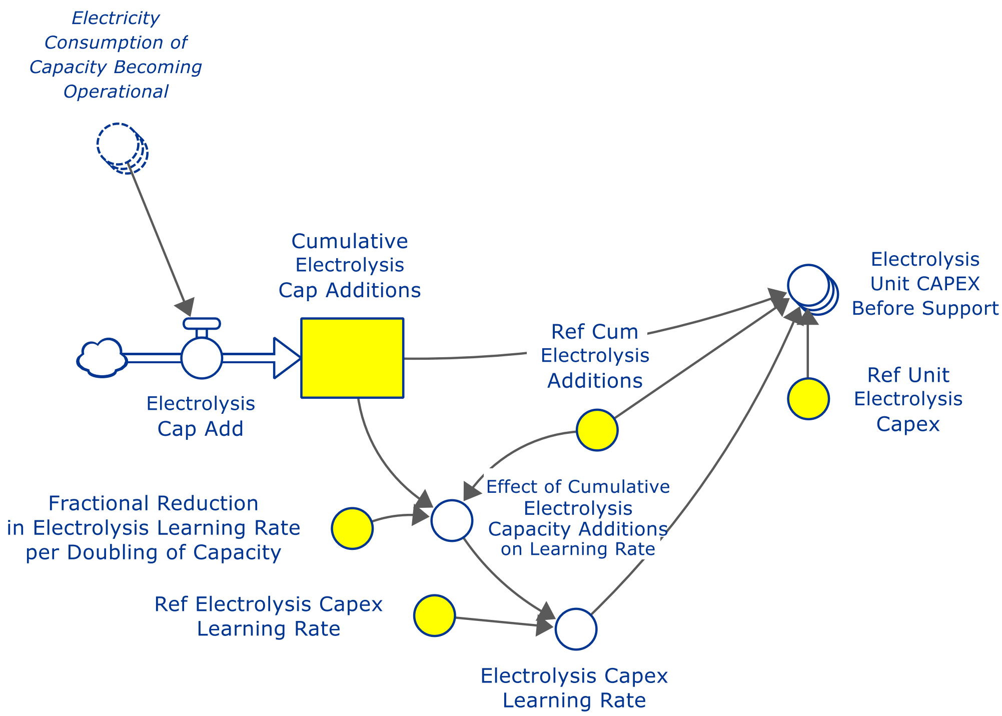

Figure 12. Model structure that creates the feedback loop between the capacity additions and cost

3.6 Hydrogen prices and its end-use competitiveness

The transport cost of hydrogen is a key determinant of its final market price and competitive positioning. Our model estimates these costs based on the total expenditure on pipelines designed specifically for hydrogen. For smaller volumes, hydrogen is mixed with methane, and a proportionate share of the total methane pipeline cost is allocated to hydrogen. For larger volumes, the costs are calculated based on the dedicated hydrogen pipelines, with both investment and operating costs factored into the pipeline sector of our model.

Transport costs vary with the volume of hydrogen moved; no transport translates to no cost, which can skew the perceived price of hydrogen. To counter this and provide a baseline for comparison, a default transport cost of $2/kg by truck is introduced, applicable when there is no demand. Additionally, storage costs are modelled to be 25% of the transport cost.

The 'Cost of H_2 Supply' within the model is derived from a weighted average of production and import costs, focusing exclusively on low-carbon hydrogen sources.

In terms of end-use, hydrogen prices fluctuate by sector. We assume that around half of the manufacturers either produce hydrogen onsite, purchase it from adjacent facilities, or are hydrogen producers utilizing excess hydrogen for power generation. Consequently, these manufacturers avoid additional storage and transport costs. This nuanced pricing mechanism ensures that hydrogen's competitiveness is accurately reflected across various end-use sectors.

Next section shows the results of hydrogen uptake as a result of its competitiveness against other alternatives.

4 Results

4.1 Hydrogen price

In the current landscape, the most economical low-carbon hydrogen production method on a global scale is identified as methane reforming with carbon capture and storage (CCS), or blue hydrogen, with an average cost slightly under USD 3/kgH_2 in 2020 (Figure 13). This cost estimation is more aligned with regions having access to inexpensive natural gas, such as North America and North East Eurasia, and does not take into account the surge in gas prices post-2020. Due to the increase in gas prices, estimates suggest that the levelized cost of methane reforming with CCS escalated by 20-30% in gas-producing areas and by 60-400% in gas-importing regions from 2020 to 2022. Although gas prices are expected to decrease by the 2030s, blue hydrogen faces several challenges including the developmental stage of CCS technology, uncertainties surrounding long-term storage solutions, future costs, and the limited benefits derived from economies of scale. Additionally, the CO_2 capture rate's inefficiency beyond 90% and the resultant direct CO_2 emissions in the supply chain could lead to reduced policy support for blue hydrogen compared to other low-carbon alternatives.

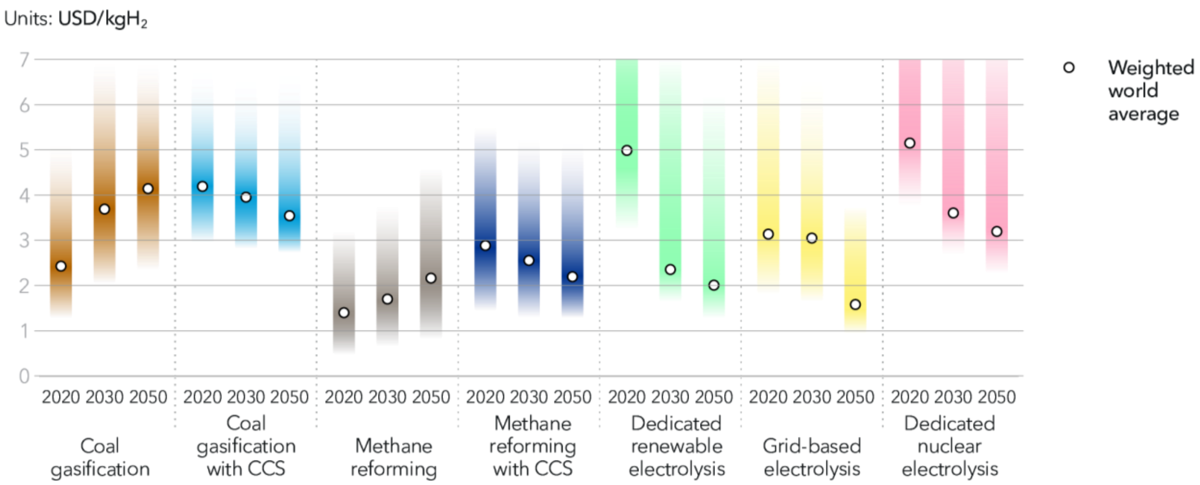

Figure 13. Ranges of levelized cost of hydrogen by production route

Conversely, the initial cost of hydrogen production via dedicated renewable-based electrolysis was prohibitively high at USD 5/kgH_2 in 2020. However, a significant decrease in this cost is anticipated over the next decade, aiming towards an average cost of USD 2/kgH_2, driven primarily by a 40% reduction in solar panel costs and a 27% decrease in turbine costs. Improvements in technology and increased operational hours will further contribute to this trend. Additionally, a 25-30% reduction in the cost of capital for electrolysers is expected as financial risks diminish.

Electrolysers powered by dedicated nuclear stations, offering continuous electricity supply, face the challenge of high electricity costs despite a predicted 35% reduction in nuclear CAPEX by 2050. This method is projected to constitute a mere 1% of the global hydrogen supply by 2050, predominantly in China.

The cost of electricity significantly influences the economics of grid-connected electrolysers, with the price of electricity and the penetration of variable renewable energy sources (VRES) in power systems being pivotal. Prior to 2030, the limited penetration of VRES is unlikely to significantly impact electricity price distribution. Post-2030, an increase in VRES penetration is expected to result in more hours of very cheap or even free electricity, affecting the cost competitiveness of grid-connected electrolysers, especially against blue hydrogen. The competition among hydrogen production methods is anticipated to intensify, with the operating hours of grid-connected electrolysers adjusting according to market dynamics and the cost of electricity compared to the cost of gas for blue hydrogen production.

4.2 Hydrogen demand

Figure 14, depicting the projection of hydrogen demand by sector, underscores the significant role that hydrogen is anticipated to play in the global energy mix. The trajectory outlined in the graph suggests a rapid ascent in demand across several sectors, with manufacturing taking the lead.

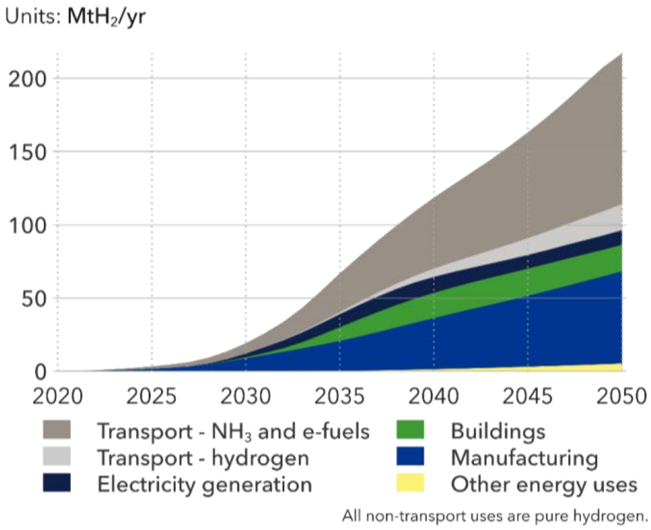

Figure 14. World demand for hydrogen and its derivatives as energy carrier by sector

Despite a modest start, with only 0.5% of energy demand met by hydrogen in 2030 and projections of reaching 5% by 2050, the regional variations could be substantial. In certain areas, hydrogen is expected to constitute a notably higher percentage of the energy mix, potentially doubling the global average.

While hydrogen's overall contribution may seem incremental relative to the entire global energy demand, its absolute growth is substantial. This marks the emergence of hydrogen as a new pivotal energy source, accounting for a significant fraction of energy consumption. The financial implications of this transition are profound, with projected global expenditure on hydrogen production for energy reaching USD 6.8 trillion by 2050, complemented by substantial investments in infrastructure, including pipelines and ammonia terminals.

By 2050, the demand for hydrogen as an energy carrier is expected to exceed 238 million tonnes per annum, reflecting a robust upward trend. The sector-wise breakdown reveals manufacturing as the primary consumer, accounting for 61% of the demand. This is followed by the transport sector, which includes both hydrogen direct use and its derivatives like ammonia and e-fuels, representing 17%, and then by the buildings sector at 14%. The residual demand will cater to electricity generation and a miscellany of other energy uses.

The steep increase in demand portrayed in the graph indicates not just an energy transition, but a transformation with implications across industries and energy markets. The advent of hydrogen stands to revolutionize the way energy is produced, distributed, and consumed, positioning it as a cornerstone in the quest for a sustainable and low-carbon future.

Hydrogen is poised to play a pivotal role in decarbonizing sectors like shipping, aviation, road transport, and manufacturing, and will be essential in meeting Paris Agreement goals. However, it currently falls short of the necessary global energy share, projected at only 5% by 2050, with significant regional variations.

In maritime transport, hydrogen-based fuels are set to dominate, with e-methanol and ammonia as leading contenders. E-methanol is expected to reach 19% of the shipping fuel mix by 2050, while ammonia will likely scale up later, achieving 36% share. Aviation will see a rise in e-fuels, predicted to constitute 12% of energy use by 2050, with hydrogen limited to medium-haul flights due to design and cost constraints.

Road transport will primarily be dominated by Battery Electric Vehicles (BEVs), capturing 95% of new passenger vehicle sales by 2050, with hydrogen Fuel Cell Electric Vehicles (FCEVs) making up a marginal 0.2%. However, hydrogen is projected to carve a niche in heavy-duty, long-distance trucking, accounting for 3% of the road transport energy demand, heavily influenced by policy support in regions like Greater China, Europe, and North America.

In manufacturing, hydrogen will increasingly replace fossil fuels for high-temperature heat, particularly in steel production, expected to consume 37% of hydrogen demand in this sector. By 2050, hydrogen use in manufacturing will make up 6% of the sector's energy demand, corresponding to 75 million tonnes per year (MtH_2/yr).

Building sector uptake of hydrogen will be minimal, reaching about 1.3% of its energy demand by 2050, focused on heating applications. This modest share reflects the comparative efficiency and cost advantages of electric alternatives.

Power generation and seasonal storage will also leverage hydrogen, especially in VRES-rich regions, to manage peak demand, with OECD Pacific, Europe, Greater China, and later North America, leading the way. By 2050, these regions will use approximately 10 Mt of hydrogen annually for power.

Lastly, hydrogen's role as a feedstock is currently significant in oil refineries and fertilizer production but is set to shift towards e-fuels and ammonia for energy, which will exceed traditional feedstock uses by 2050. Environmentally friendly hydrogen production methods are expected to replace CO_2-intensive ones, favouring CCS, grid-connected electrolysis, and renewable-powered electrolysis.

4.3 Hydrogen supply

The trajectory of hydrogen supply is poised to evolve under the influence of its burgeoning role as an energy carrier and the transition towards production methods with a smaller environmental footprint. Forecasts show that by 2030, a third of global hydrogen production will pivot to low-carbon sources. This includes 14% from methane reforming with CCS and 13% via electrolysis. By 2050, an emphatic shift will see 85% of hydrogen being produced through low-carbon processes: methane reforming with CCS at 28%, grid-connected electrolysis at 15%, solar-based electrolysis at 28%, wind-based electrolysis at 7%, and nuclear-based electrolysis at 2%.

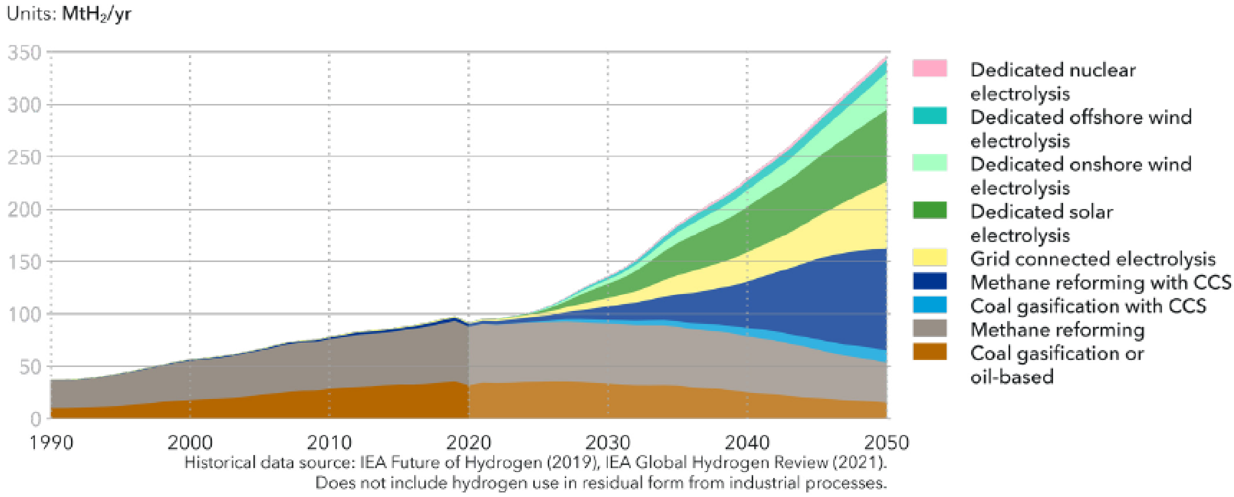

Figure 15. World hydrogen production by production route

In the current landscape, blue hydrogen, primarily produced via methane reforming with CCS, emerges as the most economical low-carbon hydrogen source. Challenges for blue hydrogen include evolving CCS technologies, storage uncertainties, and capture rates that economically do not exceed 90%, making it less competitive in the long run compared to other renewable options.

Despite these hurdles, the progressive reduction in methane reforming and CCS capital costs, combined with increasing carbon prices, will likely bolster blue hydrogen's market presence, especially in ammonia and methanol production. By 2050, it's anticipated that blue hydrogen will represent 28% of global hydrogen supply, equating to 97 MtH_2/yr.

Green hydrogen is expected to see substantial cost reductions, leading to a sizable market share towards mid-century despite the lack of ability to operate continuously.

Grid-connected green hydrogen is predicted to acquire a market share comparable to blue hydrogen, with nearly 130 MtH_2/yr expected from dedicated renewables by 2050, which will account for over a third of global hydrogen demand.

4.4 Hydrogen transport

Transport methodologies are anticipated to be selective and pragmatic, governed by distance and volume considerations. Pipeline transportation is posited as the method of choice for medium-range distribution within and across national borders, rather than for intercontinental transit. Ammonia's favourable transport properties, particularly for maritime shipment, are forecasted to command a 59% share of the energy-related ammonia trade by 2050.

Economic efficiency will be a key driver in hydrogen infrastructure development, with over half of the anticipated hydrogen pipelines being retrofitted from the existing natural gas network. In specific areas, the repurposing could extend to 80% of the infrastructure, leveraged by the relatively low costs—just 10-35% of new pipeline construction expenses.

Pure hydrogen's role in interregional transportation is predicted to remain limited due to the logistical advantages of pipelines for large-scale, medium-distance transfers. Conversely, ammonia is likely to become the carrier of choice for shorter distances and smaller volumes, utilising truck and rail modalities. Maritime hydrogen transport will generally be less favoured, burdened by high liquefaction and regasification costs that could inflate prices by USD 1.5-2/kgH_2. We estimate that by mid-century, a mere fraction of global hydrogen—under 2%—will be moved via sea, with only about 4% traversing through interregional pipelines.

Ammonia stands out as the preferred medium for hydrogen's seaborne movement, anticipated to see a significant uptick from the 2030s to 2050. We envisage a sharp rise, with a twenty-fold increase in ammonia maritime transport during this period, eventually accounting for 95% of all hydrogen trade in 2050, with total shipping volumes reaching 150 million tonnes.

4.5 Sensitivity analysis

4.5.1 Policy levers

Our net zero scenario, centred on hydrogen's role, leverages a suite of policy levers across multiple sectors to stimulate the shift towards a low-carbon economy:

- In the road sector, EV purchases are subsidized, while ICE vehicles are discouraged through regional bans, stricter standards, and additional taxes on fossil fuels. Investment in public infrastructure and battery R&D is crucial, along with support for converting manufacturing capacities.
- Aviation will see mandates for fuel economy and emissions, along with blending mandates and requirements for electric short-haul flights. Rising fees and taxes on traditional fuels will steer the industry towards hydrogen and e-fuels.
- Maritime transport's move to low-carbon fuels is supported by technical requirements on emissions, carbon pricing, and mandated uptake of carbon-neutral fuels. Infrastructure investment support is pivotal to enable the distribution and refuelling of these fuels.
- In the building sector, a focus on limiting fossil-fuel heating options, coupled with support for advanced heating technologies, will drive the transition. Efficiency regulations for building insulation are also key.
- For industries like iron and steel, a carbon price, energy taxation favourable to hydrogen, and support for direct reduced iron-electric arc furnace (DRI-EAF) plants are essential. Recycling and construction mandates will facilitate a faster move away from carbon-intensive processes.
- In cement production, regulations promoting low-carbon alternatives, efficiency standards, and increased fossil fuel taxation will spur the adoption of cleaner practices.
- Petrochemicals will see a push for recycling, bans on single-use plastics, and support for low-carbon hydrogen production, which is vital for ammonia synthesis.
- The power sector's transition involves retiring oil and coal-fired capacities, bolstering carbon prices, and extending the life of nuclear plants. Investment is channelled towards renewable energy, grid enhancements, and market redesigns to support VRES integration.
- For hydrogen demand, energy taxation will favour hydrogen, with mandates accelerating the shift in fuel mix and emissions trajectories. CAPEX support for integrated renewable projects and subsidies for steel production to transition to hydrogen are critical.
- Hydrogen R&D will benefit from incentives aimed at decreasing technology costs, while CCS and DAC will rely on infrastructure support, higher carbon prices, and government subsidies to boost adoption, particularly in high GDP regions.

4.5.2 Net zero trajectory

As a result of changes in the policies as described above, in our Pathway to Net Zero (PNZ) scenario, hydrogen's share in final energy demand undergoes a dramatic increase from a mere 0.02% in 2022 to 12% by 2050, or 15% when accounting for hydrogen derivatives. Hydrogen emerges as a crucial element in the net-zero strategies of numerous countries, addressing the decarbonization challenge in sectors where electrification is less viable.

The projected upsurge in hydrogen demand necessitates a robust inter-regional trade network, leveraging existing shipping and pipeline technologies. Over a quarter of the global demand for hydrogen and synthetic fuels by 2050 is expected to serve industrial heating needs, with hydrogen supplying 28 EJ/yr or 22% of manufacturing energy demand.

In road transport, hydrogen fulfils 7% of the sector's energy needs by 2050 in our PNZ, despite extensive subsidies. This is a testament to the competitiveness of battery-electric vehicles across all segments. However, maritime transport presents a different narrative, where the lack of substantial battery-electric solutions paves the way for hydrogen derivatives to meet 72% of fuel needs by 2050.

Aviation also sees a sizeable inclusion of hydrogen and its derivatives, anticipated to account for 40% of the fuel mix. Electrolysis, particularly through dedicated off-grid capacities primarily from solar PV, is set to dominate hydrogen production by mid-century, constituting 74% of the supply, with Greater China and Europe at the helm.

Our PNZ outlines a significant scale-up in global hydrogen production, with electrolysis capacity targets of 0.4 TW by 2030, 1.9 TW by 2040, and 3.8 TW by 2050. Grid-based electrolysis is expected to expand similarly, reaching nearly 2 TW by 2050, predominantly driven by North America and Europe. This scale of production sees hydrogen output, including that for feedstock, reaching 820 Mt/yr by 2050 compared to the 350 Mt/yr forecasted by the base scenario for the same period.

Around 15% of this hydrogen production will be directed towards creating hydrogen derivatives for fuel by 2050. Notably, 'blue ammonia'—ammonia produced via methane reforming with CCS—becomes the method of choice for ammonia production due to the efficiency of integrating carbon capture with the current manufacturing processes.

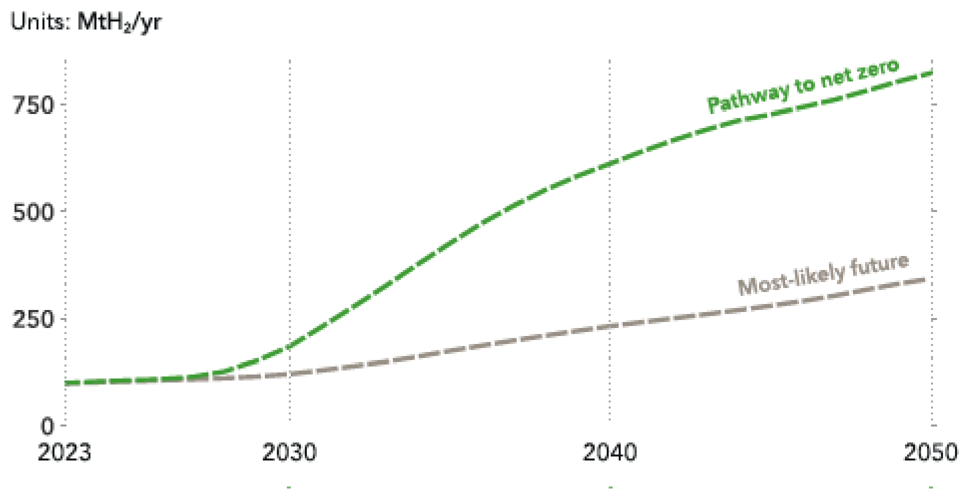

Figure 16. World hydrogen production in PNZ versus the most likely future

5 Conclusion

In this paper, we have investigated the multifaceted role of hydrogen within the context of a most-likely future energy scenario, extending our investigation to a pathway to net-zero (PNZ) scenario as a sensitivity analysis. The core of our research underscores hydrogen's evolving position in the energy transition, its production pathways, the economic implications of its adoption, and the infrastructural transformations necessary to facilitate its widespread use.

The Most-Likely Future of Hydrogen

Our results indicate that, by 2050, hydrogen is set to contribute 5% to the global energy mix, with significant regional disparities. Hydrogen's production is expected to pivot predominantly toward low-carbon methods, reflecting the industry's trajectory toward sustainability. With the increasing viability of carbon capture and storage (CCS), 'blue hydrogen' emerges as a key transitional energy source. Meanwhile, electrolysis powered by renewable sources, though currently cost-prohibitive, is forecasted to see a substantial decrease in costs due to technological advancements and economies of scale.

The transportation sector's shift towards hydrogen, particularly in maritime and heavy-duty road transport, reveals a pragmatic approach to decarbonization, with a strategic focus on sectors where electrification faces challenges. Hydrogen derivatives, such as ammonia for shipping and e-fuels for aviation, are expected to garner significant shares in their respective sectors, reflecting the specialized energy needs of these modes of transport.

Pathway to Net Zero (PNZ) Scenario

In our PNZ sensitivity analysis, hydrogen is envisioned as an indispensable component of the net-zero equation. Hydrogen's share in the energy mix jumps to 12%, or 15% if including derivatives, by 2050. This scenario delineates an urgent and expansive role for hydrogen in decarbonizing sectors traditionally reliant on fossil fuels. Industrial heating, predominantly in the iron and steel sectors, is forecasted to be a major hydrogen consumer, demanding proactive policy frameworks and considerable capital investment in new technologies.

The PNZ scenario envisions significant infrastructural developments, including the repurposing of existing natural gas pipelines for hydrogen transport and a massive expansion in electrolysis capacity, spearheaded by solar and wind initiatives. By mid-century, a diversified, predominantly green hydrogen production landscape emerges, signalling a decisive break from nearly exclusive reliance on fossil-based sources.

Policy and Market Implications

Our exploration has underscored the necessity of strategic policy interventions and market shifts to foster the growth of hydrogen. In the road sector, subsidies for electric vehicles (EVs), differentiated ICE bans, and tighter fuel economy standards are essential. For aviation and maritime transport, blending mandates and low-carbon fuel requirements set the course for a sustainable transformation.

In the manufacturing realm, particularly for iron, steel, and cement, carbon pricing and energy taxation favourable to hydrogen adoption emerge as crucial levers. The building sector will also require stringent regulations and support for hydrogen heating technologies to facilitate the switch from fossil fuels.

Concluding Thoughts

In summary, while our most-likely scenario portrays a gradual and regionally variable integration of hydrogen into the energy mix, our PNZ sensitivity analysis reveals a more aggressive trajectory in line with global net-zero aspirations. Both scenarios elucidate hydrogen’s crucial role, with the PNZ offering an intensified outlook on the decarbonization potential of hydrogen across various sectors.

To actualize these futures, a synergy of technological innovation, supportive policies, and robust investments is required. The transition to a hydrogen-inclusive energy system is not only about the introduction of a new energy carrier but about reconfiguring the very infrastructure and market dynamics that define our energy landscape. The forthcoming decades will be pivotal, as stakeholders across the globe navigate the challenges and opportunities presented by hydrogen, reshaping the energy narrative towards a more sustainable and resilient future.

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