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MSc Max Schönfisch

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Referent: Prof. Dr. Marc Oliver Bettzüge
Korreferent: Jun.-Prof. Dr. Oliver Ruhnau
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1. Introduction

Hydrogen is increasingly seen as one of the key building blocks of a low-emission energy system. As of mid 2023, 41 governments (and the European Commission) have published hydrogen strategies, placing low-carbon hydrogen at the heart of their decarbonisation strategies. This includes many European countries, as well as economic heavyweights like the United States, China, India and Japan (IEA, 2023). On the global stage, hydrogen was a key focus of Japan's G20 presidency in 2019 (IEA, 2019c), and the G7 reaffirmed their commitment to low-carbon and renewable hydrogen as a tool for cross-sectoral decarbonisation in April 2023 (METI, 2023).

At present, hydrogen is used overwhelmingly in industry, typically as an intermediate product in multi-step production processes, such as oil refining or ammonia production (IEA, 2019c). As a result, it is generally produced on-site, close to the point of consumption, mostly using unabated fossil fuels, making it emissions-intensive. The International Energy Agency (IEA) estimates that in 2022, 62% of global hydrogen was produced using unabated natural gas, 21% from coal and 16% as a by-product of naphtha reforming in refineries. Low-carbon hydrogen, by contrast, accounted for less than one percent (IEA, 2023).

Nonetheless, policy support and a growing pipeline of announced projects is creating momentum for a scaling up of low-carbon hydrogen production over the next five to ten years, with the fuel expected to start displacing conventional hydrogen in existing applications and finding new uses, such as in the production of low-carbon steel or as a fuel for heavy-duty road transport (IEA, 2023).

Low-carbon hydrogen can be produced through the electrolysis of water using electricity from a low-emission source, such as renewables or nuclear. It can also be derived from fossil fuels, either by capturing and storing the carbon dioxide (CO_2) that is emitted by existing processes such as natural gas reforming or coal gasification, or novel processes that do not generate CO_2 as a waste product, such as natural gas pyrolysis (IEA, 2019c, 2023). Large-scale low-carbon hydrogen production will therefore create additional linkages between different energy markets, most importantly the electricity and natural gas markets, with potential effects on all these markets.

Unlike today, when hydrogen is almost always produced and consumed on-site, the projected increase of low-carbon hydrogen production and use, including in new applications, implies that low-carbon hydrogen will become an energy commodity in its own right. Growth in off-site (merchant) production and trade, potentially over large distances such as between countries or even continents, will lead to the development of a market with increasing numbers of buyers and suppliers. However, the spatial structure of this market is still uncertain: will it become a truly global market, or will we witness the emergence of regional markets that are only indirectly connected with each other?

Drawing on a detailed, country-level assessment of potential low-carbon hydrogen production and transportation costs, this thesis aims to provide insights into potential development pathways of the emerging market for low-carbon hydrogen. It focuses on two broad questions:

- How could technology choices, transportation costs, the distribution of global hydrogen demand and regional differences in the availability and cost of key inputs for low-carbon hydrogen production (electricity from renewable energy sources and natural gas) shape the spatial structure of the market or markets for low-carbon hydrogen?
- What is the potential impact of the growth of low-carbon hydrogen production on the established markets for natural gas, liquefied natural gas (LNG) and electricity?

Each chapter is based on an article to which all authors contributed in equal parts:

- Chapter 2: Estimating Long-Term Global Supply Costs for Low-Carbon Hydrogen, based on Brändle et al. (2021).
- Chapter 3: Charting the Development of a Global Market for Low-Carbon Hydrogen, based on Schönfisch (2022).
- Chapter 4: The Emerging Hydrogen Economy and its Impact on LNG, based on Al-Kuwari and Schönfisch (2022).

- Chapter 5: Analysing the Impact of a Renewable Hydrogen Quota on the European Electricity and Natural Gas Markets, based on Schlund and Schönfisch (2021).

Detailed summaries are provided in the next section, followed by an overview of the methodologies underpinning the analysis presented in this thesis.

1.1. Outline of the Thesis

Chapter 2 presents a comprehensive approach for estimating the development of global production and supply costs of low-carbon hydrogen from renewable energy sources (RES) (onshore wind, offshore wind and solar photovoltaics) and natural gas (natural gas reforming (NGR) with carbon capture, utilisation and/or storage (CCUS) and natural gas pyrolysis) until 2050. The analysis also assesses the costs associated with the transportation of hydrogen by ship or pipeline. The combination of production and transportation costs yields a ranking of cost-optimal supply sources for individual countries.

Estimation results suggest that NGR with CCUS will be the most cost-efficient low-carbon hydrogen production pathway in the medium term (2020-2030). Production of hydrogen from RES could become competitive in the long run (2030-2050) if capital costs decrease significantly. Until 2050, minimum production costs for hydrogen from RES could fall to \$1.6/kg under central assumptions and to below \$1/kg under optimistic assumptions in some regions.

The cost-optimal long-term hydrogen supply depends on regional characteristics, such as renewable energy potentials and gas prices. Imports of hydrogen from RES are cost-effective where the domestic RES-based hydrogen production potential is small or cost-intensive. Additionally, good import conditions exist for countries which are connected to prospective low-cost exporters via existing natural gas pipelines that can be retrofitted to transport hydrogen. Due to the high cost of seaborne transport, it can be concluded that hydrogen trade will most likely develop regionally along pipeline networks.

Chapter 3 analyses the impact of supply technology choices and costs on structures and prices on the emerging low-carbon hydrogen market using a novel, integrated natural gas and hydrogen market model, integrating the global low-carbon hydrogen supply cost and supply potential projections derived through the analysis presented in Chapter 2. The model-based analysis shows that natural gas-based low-carbon hydrogen production pathways predominate in technology-neutral scenarios in 2050. In scenarios where hydrogen production is gas-based, hydrogen is produced close to the point of consumption. Natural gas prices determine local hydrogen prices.

In scenarios characterised by high shares of RES-based low-carbon hydrogen production, long-distance, cross-border trade in pure hydrogen becomes an economically viable proposition due to the heterogeneous distribution of low-cost RES potentials and significant hydrogen price spreads between countries with high hydrogen demand but poor RES potentials, and countries that are well endowed with cost-competitive RES. Trade is conducted almost exclusively via pipeline. The analysis finds the most significant potential for cross-border trade in and around Europe. It suggests that it would be economical for Europe to import substantial quantities of low-carbon hydrogen from North Africa.

Chapter 4 examines synergies and linkages between the hydrogen and LNG values chains and quantifies the impact of increased low-carbon hydrogen production and consumption on global natural gas demand and LNG flows. The analysis is conducted through interviews with LNG industry stakeholders, a review of secondary literature on the LNG/hydrogen nexus and a scenario-based analysis of the potential development of global low-carbon hydrogen production, natural gas consumption and LNG trade until 2050 using the natural gas and hydrogen market model presented in Chapter 3.

The model-based analysis shows that low-carbon hydrogen production could become a major user of natural gas and thus stabilise global LNG demand. Only in scenarios where RES-based hydrogen becomes the dominant pathway globally, LNG demand starts to decline significantly after 2040.

Furthermore, commercial and operational links exist that could provide the LNG industry with a competitive edge in developing a value chain around natural gas-based low-carbon hydrogen. Accordingly, LNG industry participants acknowledged the growing importance role of low-carbon hydrogen in decarbonising systems and identified hydrogen as both an opportunity and a threat in the long term.

Chapter 5 assesses impact of a renewable hydrogen quota on EU gas and electricity markets through a model-based analysis. By comparing a scenario in which a renewable hydrogen quota with tradable certificates is imposed on final gas consumption in the sectors of the economy outside the EU emissions trading system with a reference scenario without a quota, price, quantity and welfare effects are analysed.

The model simulations show that the hydrogen quota leads to a significant expansion in renewable electricity generating capacity to produce renewable hydrogen and synthetic methane with power-to-gas technologies. On the electricity market, the price increases substantially, rising by up to 12%—mostly due to increasing emission allowance prices—leading to a higher surplus for power producers. The quota's primary beneficiaries in the power sector are renewable energy producers. On the gas market, the quota leads to a small decrease in prices (by a maximum of -3%) and gas producer surpluses. Quota obliged gas consumers, mainly households, commercial and small industrial consumers, carry the largest part of the burden associated with the obligation. Overall, the quota leads to the redistribution of welfare from these consumers to renewable electricity generators and power-to-gas producers and a significant decline in total welfare.

1.2. Methodology

This section provides a general overview of the methodologies applied in Chapters 2 to 5. More detailed and comprehensive descriptions can be found inside each individual chapter.

In **Chapter 2**, global production and supply costs of low-carbon hydrogen from renewable energy sources (onshore wind, offshore wind and solar photovoltaics) and natural gas (natural gas reforming with carbon capture and storage and natural gas pyrolysis) are estimated for 89 countries for the period from 2020 to 2050. The analysis also assesses the costs associated with the transportation of hydrogen by ship or pipeline. The combination of production and transportation costs is used to determine a ranking of cost-optimal supply sources for selected countries.

In **Chapter 3**, the potential impact of technology costs and choices on the ramp-up of a global market for low-carbon hydrogen is quantified through a scenario analysis using a partial equilibrium model of the global markets for natural gas and low-carbon hydrogen, covering 97 countries. To capture the impact of natural gas-based hydrogen production on the price of natural gas and vice versa, the model fully represents the up- and midstream segments of the global natural gas value chain. It is formulated as a mixed complementarity problem (MCP). Spatially, it is defined by a set of nodes that are connected through arcs. Nodes are divided into natural gas and hydrogen production, liquefaction, regasification and consumption nodes, and the arcs connecting them represent pipelines and LNG/liquid hydrogen. The model is populated by different profit-maximising agents: exporters, producers, transmission system operators (TSOs), liquefiers, regasifiers and shippers. Subject to various constraints, they maximise their profits by making optimal decisions with respect to the production, sale and transport of natural gas or hydrogen; and through optimal investments into production and transportation infrastructure. Four scenarios describing different supply side technology development pathways for the global low-carbon hydrogen market to 2050 are simulated and compared. Both hydrogen and natural gas demand are treated as inelastic, while the markets for both commodities are assumed to be perfectly competitive.

In **Chapter 4**, the model described in the previous chapter is applied to analyse the impact of different low-carbon hydrogen market development scenarios on the LNG market. Here too, four scenarios describing different technology development pathways for the global low-carbon hydrogen supply are simulated and compared. Both hydrogen and natural gas demand are treated as inelastic, while markets are assumed to be perfectly competitive. Furthermore, to gain additional insights into synergies and linkages between the hydrogen and LNG values chains, the analysis is supplemented by qualitative interviews with LNG market stakeholders and a comprehensive review of relevant literature.

In **Chapter 5**, two partial equilibrium models of the European electricity and natural gas markets are iteratively linked to assess the impact of a renewable hydrogen quota on both markets. Sectoral gas demand, temporal gas demand profiles, PtG capacities and PtG injection volumes are passed from the electricity to the gas market model. The gas market model's simulated gas price is then returned to the electricity market model to initiate the next iteration. The iteration process is stopped once the annual difference in each of the exchanged parameters between two subsequent iterations is less than 5%.

The electricity market model is an investment model covering electricity production and consumption in 28 countries in Europe[1]. Initially developed as a standalone electricity market model by Richter (2011), to better replicate future energy systems in which final energy consumption is increasingly electrified, it has since been extended to cover additional end-use sectors, conversion technologies and electricity-derived energy carriers. The model is run in an hourly resolution for 16 typical days, which, combined, are representative for a single year (Helgeson and Peter, 2020). It endogenously models electricity production, cross-border power flows and electricity-based hydrogen and synthetic methane production. Final electricity and natural gas demand are treated as exogenous inputs. Both are assumed to be inelastic. The electricity market is assumed to be perfectly competitive, allowing the model to be formulated as a constrained linear optimisation problem.

Furthermore, a European natural gas infrastructure model is expanded and used to assess the impact of hydrogen and synthetic methane injection on natural gas flows and prices. The model was initially developed by Lochner (2011b) and is formulated as a linear optimisation problem that minimises the total cost of natural gas supply in Europe, subject to infrastructure and production constraints. Implicit in this setup is the assumption that European natural gas markets are perfectly competitive[2]. The model considers commodity as well as dispatch cost. It covers most of European natural gas transmission infrastructure, consisting of pipelines, gas storage and LNG terminals. All European countries connected to the transmission grid[3] and major exporting countries (Russia, Algeria, Libya and the Southern Gas Corridor) are included with their corresponding annual gas demand and production capacities. The model is run in monthly resolution.

[1] Austria, Belgium, Bulgaria, Croatia, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Netherlands, Norway, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden, Switzerland and the United Kingdom.

[2] This assumption is supported by recent market monitoring reports of the European Union Agency for the Cooperation of Energy Regulators (ACER). They show that gas hub prices converged significantly over the last years (ACER, 2019), indicating an increasingly competitive market. Moreover, market interconnectivity and liquidity is expected to further improve in the future (Schulte and Weiser, 2019a).

[3] Concerning the EU, all EU member states except for Malta and Cyprus are included in the model.

2. Estimating Long-Term Global Supply Costs for Low-Carbon Hydrogen

2.1. Introduction

Hydrogen is a versatile energy carrier and presents an attractive option for the substitution of fossil energy sources. Unlike electricity, it can be stored on a large scale over a long time and can be transported via pipeline or ship (IEA, 2019e). It can also be blended into existing natural gas networks (Speirs et al., 2018). Additionally, there are no direct carbon emissions when it is converted into power or heat. Therefore, hydrogen will likely play a central role in achieving greenhouse gas neutrality in energy-consuming sectors such as industry and transportation (IEA, 2019e).

For the purposes of this analysis, hydrogen is treated as low-carbon when the production process releases minimal or no CO_2 into the atmosphere. Two pathways to produce low-carbon hydrogen currently receive the most attention, both in academia (Parkinson et al., 2017, Schmidt et al., 2017) as well as in (supra-)national hydrogen strategies (for example, European Commission, 2020b, METI, 2020): the production of hydrogen from the electrolysis of water driven by electricity from renewable energy sources (RES) and the production of hydrogen from natural gas, primarily through natural gas reforming (NGR) with carbon capture, utilisation and storage (CCUS) or alternatively natural gas pyrolysis.

Other options commonly suggested to produce low-carbon hydrogen include electrolysis using nuclear electricity, coal gasification with CCUS and the gasification of biomass (IEA, 2020a). However, limited potentials and a large number of competing uses for biomass in a decarbonised economy will likely constrain the sustainable low-carbon hydrogen production potential from biomass. Coal gasification with CCUS may play an important role in some countries, such as China (IEA, 2019e), and nuclear electricity may be used in a limited number of countries that rely heavily on nuclear energy today, such as France. Nevertheless, projections such as IEA (2019d, 2020a) suggest that across the globe, the future production of low-carbon hydrogen will be based overwhelmingly on either electrolysis using RES electricity or the processing of natural gas. Therefore, the comparative global analysis presented by this study focuses on the following production pathways:

1. Hydrogen from the electrolysis of water driven by electricity from RES. This kind of hydrogen is also commonly known as *green hydrogen* (Velazquez Abad and Dodds, 2020). The RES considered for electrolysis are solar photovoltaics (PV) and wind power (onshore and offshore).

2. Hydrogen from NGR with CCUS, also referred to as *blue hydrogen*. Most of the CO_2 produced in the process is captured, transported away and stored in permanent repositories to prevent it from escaping into the atmosphere.

3. Hydrogen from the pyrolysis of natural gas, which is also known as *turquoise hydrogen*. Natural gas (methane) is cracked into hydrogen and solid carbon in the absence of oxygen and under high temperature. The process itself produces no CO_2.

The transportation of hydrogen is challenging due to its low volumetric energy density, in particular when using pipelines is not feasible (IEA, 2019e). Therefore, various solutions are being investigated as potential hydrogen energy carriers for the long-distance transportation of hydrogen by sea, the most prominent being ammonia (Yüksel Alpaydin et al., 2021), methanol (Garcia et al., 2021), liquid organic hydrogen carriers (LOHC) (Brigljević et al., 2020) and liquid hydrogen (LH_2) (Wijayanta et al., 2019). A final assessment of which energy carrier will be the most cost-efficient solution for hydrogen transportation in the long-term is not yet possible; this also depends on the final form of use.

First studies on hydrogen energy were conducted in the 1970s (Dell and Bridger, 1975, Veziroglu et al., 1976), as a response to the first signs of impending environmental disruption, exhaustion of hydrocarbon fuels (Meadows et al., 1972), and a global energy crisis (Goltsov, 2001). After the oil crisis of 1973 subsided, low fuel prices and high technology costs led to a reduction in interest in the hydrogen topic, and only few studies were published. The situation began to change in the early 2000s. Since then, the number of economic studies on hydrogen has sharply increased due to a rise in environmental concerns around fossil fuels and the growing maturity of hydrogen technologies (El-Emam and Özcan, 2019).

Techno-economic assessments examine the technological feasibility and costs of different low-carbon hydrogen production routes (Kalamaras and Efstathiou, 2013, Machhammer et al., 2016, Timmerberg et al., 2020). In an early analysis, Mueller-Langer et al. (2007) assess different hydrogen production processes and suggest that hydrogen production from electrolysis is unlikely to be competitive, mostly due to high electricity prices. Instead, applying carbon capture technologies could enable a low-carbon hydrogen production from fossil fuels.

Many conditions have changed since then. Most notably, the cost of renewable energy has fallen rapidly, a trend that major projections expect to continue (BNEF, 2019, IEA, 2019e, IRENA, 2020a).

Glenk and Reichelstein (2019) assess the economics of operating an electrolysis system with grid electricity and find that renewable hydrogen is already cost-competitive in some niche applications. El-Emam and Özcan (2019) carry out a comprehensive review of studies on the techno-economics of sustainable large-scale low-carbon hydrogen production. Their findings suggest that fossil-based carbon-intensive hydrogen production is currently more cost-effective than low-carbon production. However, according to their assessment, a medium-term transition towards low-carbon hydrogen looks possible as alternative routes, such as nuclear-driven electrolysis represent promising and potentially competitive production pathways. A study of Ram et al. (2019), which focuses on a path towards an energy system based on 100% renewable energy, expects that the cost of RES-derived hydrogen will continue to decline and become cost-competitive with fossil-based hydrogen by 2050. The International Energy Agency (IEA) states that low-carbon hydrogen from electrolysis "could become competitive in the long-term if large-scale deployment brings down costs" (IEA, 2020a, p. 144). According to the IEA's projections, demand for low-carbon hydrogen could, therefore, be covered in the long-term by a combination of both production routes, whereby electrolysis could become the dominant technology by 2050 (IEA, 2020a, p. 110).

A supply chain infrastructure that connects production and consumption is needed to facilitate the large-scale utilisation of hydrogen. This infrastructure must be newly built (Gerwen et al., 2019), or alternatively, based on the conversion of existing assets. Converting existing natural gas pipelines is potentially the most economical way to establish an infrastructure to transport hydrogen across continental distances (Wang et al., 2020). Timmerberg and Kaltschmitt (2019) discuss a low-cost opportunity, wherein hydrogen is blended into existing gas pipelines. Wang et al. (2020) describe a potential future European transportation network for hydrogen, whereby parts of the infrastructure have to be newly built, retrofitting former gas pipelines can substantially reduce costs. Gaseous hydrogen has a low volumetric energy density; transportation and storage in a medium with limited space (ships, tanks) is expensive and inefficient. Alternative energy carriers for long-distance (overseas) transportation and storage are discussed, wherein hydrogen is liquefied or incorporated into other molecules with higher energy density (IEA, 2019c). Kojima (2019) assesses the materials most suitable for mixing with hydrogen to ensure efficient transportation storage and finds ammonia to be an attractive hydrogen carrier. Wijayanta et al. (2019) review different hydrogen carriers and conduct a long-term cost comparison. According to the study, ammonia with direct utilisation has the potential for massive adoption. If pure hydrogen[1] is required as the end use product, liquid hydrogen (LH_2) looks promising as a carrier in the long run. Mizuno et al. (2017) present a cost analysis of different hydrogen energy carriers as part of an international supply chain by shipping for 2030 and 2050. They find only negligible cost differences between ammonia and LH_2 and identify many essential points for research and development that could significantly decrease transportation costs.

So-called liquid organic hydrogen carriers (LOHC) are also examined as transportation options. These are substances that can absorb and release hydrogen by chemical reaction. Abánades et al. (2013) and Aakko-Saksa et al. (2018) review and discuss the suitability of LOHC for transportation and storage.

Another literature stream deals with potential structures of hydrogen trade and supply. Results from techno-economic assessments of production and transportation often serve as a basis for these analyses. Case studies discuss the development of a hydrogen economy and possible sources of hydrogen imports for selected countries.

Heuser et al. (2020) model a global hydrogen supply scheme. They estimate supply costs for selected countries in 2050 and only consider production and trade of hydrogen from RES. Hydrogen provision is determined by a cost-optimal allocation approach where regions with a strong output of wind and solar energy export to different demand regions. Their results suggest that trading will mostly take place within continental regions.

[1] As defined by ISO 14687 (ISO, 2019).

A range of specific case studies can be found for Japan and Germany, as both countries have set ambitious targets for the hydrogen economy and will likely have to import at least part of their demand (BMWi, 2020, METI, 2020). Jensterle et al. (2019) analyse the role of clean hydrogen in Japan and Germany's future energy systems and investigate potential supply chains. In a subsequent study, Jensterle et al. (2020) evaluate international cooperation potentials for Germany to import hydrogen from RES and include soft criteria such as socio-political stability or existing know-how.

Case studies for Japan often focus on hydrogen imports by ship due to the country's geographical location as an island. Watanabe et al. (2010) estimate costs for hydrogen from overseas wind energy. Fúnez Guerra et al. (2020) discuss the case of providing Japan with renewable ammonia from Chile. A similar study comes from Heuser et al. (2019) who investigate the elements of a hydrogen supply chain linking Patagonia and Japan.

There are also hydrogen case studies for other countries that analyse the potential of domestic production or imports, for example, for Argentina (Rodríguez et al., 2010), Hong Kong (Shu et al., 2015), or South Korea (Stangarone, 2020).

Expanding on to the existing literature, this article presents a comprehensive global assessment of low-carbon hydrogen production and supply costs. To our knowledge, it is the first work to compare different RES- and natural gas-based hydrogen production technologies and transportation options on a country-by-country basis.

Efficient hydrogen supply pathways are examined by estimating cost developments for different production and transportation options. Hydrogen from RES as well as hydrogen from natural gas are considered. For the analysis of hydrogen from RES, data on global PV and wind energy potentials is clustered into multiple resource classes that make a cost distinction possible also within a country. Each resource class can be combined with a low- or high-temperature electrolyser to produce hydrogen. A linear optimisation model determines optimal ratios of installed RES-to-electrolyser capacity to minimise hydrogen costs individually for each RES and electrolyser combination. Concerning hydrogen from natural gas, this study considers NGR with CCUS as a medium-term and production via pyrolysis as a long-term[2]

[2]In this chapter, *long-term* refers to the time after 2040

production route. Pyrolysis is currently not market-ready, but if feasible, its advantage is that the carbon by-product is solid. Capture and storage of CO_2 can thus be avoided. The analysis assesses hydrogen transportation by pipelines or by liquid hydrogen tankers. Based on global production costs and cost-minimising transportation routes, potential supply structures at a country level are discussed in exemplary case studies for Germany and Japan[3].

The remainder of this chapter is structured as follows: Section 2.2 lays out the methodology of the analysis. Data and assumptions are presented in Section 2.3. Key results are presented and discussed in Sections 2.4. Section 2.5 concludes the analysis.

2.2. Methodology

The objective of this analysis is to estimate long-term production and supply costs of different low-carbon hydrogen technologies. Production costs are estimated for low-carbon hydrogen derived from the electrolysis of water, using renewable energy sources (solar PV, onshore and offshore wind) to drive the process, and from natural gas (NGR with CCUS and pyrolysis). Estimations are performed individually for each year (2020-2050), country and technology. We derive the levelised cost of hydrogen (LCOH), which is the average net present cost of hydrogen produced by a technology over its whole lifetime.[4]

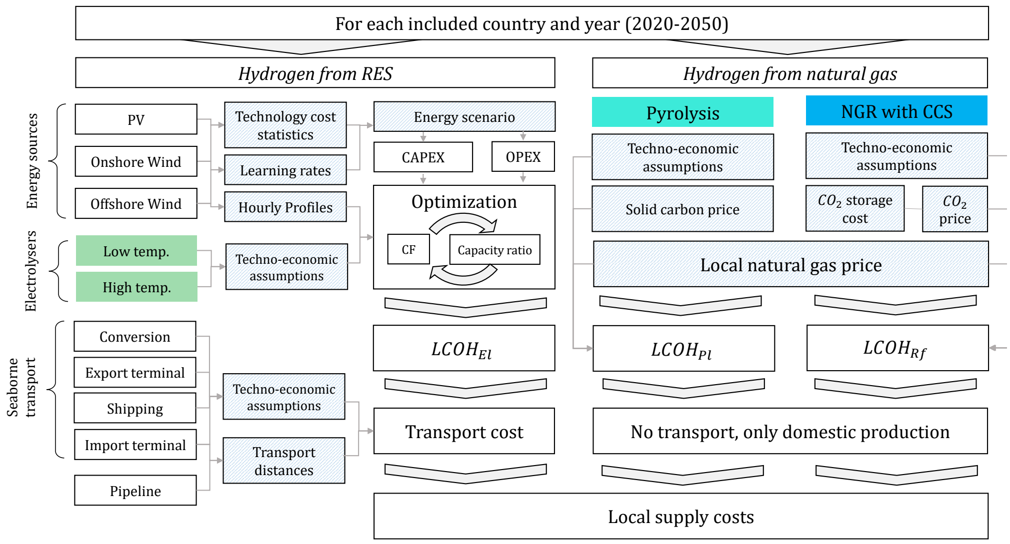
Since production costs alone have no significance for local supply costs, international transport costs for hydrogen are estimated. We assume that only hydrogen from RES will be transported internationally (over long distances); hydrogen from natural gas is always produced domestically, so that the local gas price determines local supply costs.[5]

[3] A third case study on the United States can be found in A.3.3

[4] The LCOH (in \$/kg) is derived by dividing the discounted total costs by the sum of hydrogen produced over the economic lifetime of asset.

[5] The transportation of natural gas, whether by pipeline or ship, is always cheaper than the transportation of hydrogen. Therefore, importing hydrogen produced elsewhere from natural gas would always be more costly than domestic hydrogen production using imported natural gas. This is likely the case even when the long-term storage of CO_2 is not possible locally and it has to be transported over large distances to suitable storage sites, thereby substantially increasing the cost of CO_2 disposal. As we show in Section 2.5, the LCOH of hydrogen from NGR with CCUS exhibits a very low sensitivity to variations in CO_2 disposal costs. The costs of supplying natural gas to a specific country are already included in the local gas price.

Figure 2.1.: Methodology for long-term supply cost estimation



Techno-economic assumptions include lifetime, efficiency, availability, capital expenditures (CAPEX) and operating costs (OPEX). Exogenous inputs are blue-hashed. Weighted average costs of capital (WACC) are assumed to be equal over countries and time and therefore excluded in this figure for simplicity.

Hydrogen costs from electrolysis, pyrolysis and NGR with CCUS are first analysed individually and then compared with each other afterwards. Figure 2.1 provides a detailed overview of the methodology, key inputs and assumptions. A detailed description of each individual step can be found in Appendix A.1.

2.3. Data and Assumptions

We assess 94 countries on six continents (except Antarctica).[6] The years considered are 2020 to 2050. A uniform WACC of $r = 8\%$ is assumed for all investments.[7]

From the perspective of this analysis, a prerequisite for strong growth in global demand for low-carbon hydrogen is an ambitious decarbonisation of the entire economy, and the power sector in particular. Our analysis is therefore embedded in a scenario framework that reflects such a transition. In line with

[6] A detailed list of countries and regions can be found in Appendix A.2

[7] This assumption is in line with major techno-economic assessments of energy investments, such as IEA (2019d) or IRENA (2019c).

IEA (2019d), we assume a carbon price is imposed on all uncaptured emissions from the hydrogen production process (see A.2.6 for details). In addition to that, we assume an aggressive deployment of renewables in the power sector, as outlined in the IRENA REmap scenario (IRENA, 2019a). The cumulative, technology-specific RES build-out projected by this scenario is to estimate the development of RES CAPEX and operating costs (OPEX) by applying learning rates (described in more detail below).[8]

2.3.1. Hydrogen from RES

Techno-economic forecasts for RES and electrolyser CAPEX differ very strongly. In order to consider this in our analysis, we developed two separate cost scenarios[9]:

- A scenario with baseline assumptions close to mean values of cost projections from literature,
- a scenario with optimistic assumptions from the lower end of cost projections,
- an explicit optimisation and consideration of a scenario with pessimistic assumptions is left out for simplicity. If costs decrease less than under baseline assumptions or even remain constant, the LCOH from more recent years of the baseline assumptions scenario can represent this possibility.

There is a large body of literature on learning rates (LR) for wind and solar PV. The assumptions on learning rates in this analysis are based on a literature review of recent learning rate estimates. A detailed overview of the surveyed literature can be found in A.2.2. Only estimates from the last five years are considered since older projections have mostly underestimated RES cost reductions and are, in some cases, already incorrect today (Krey et al., 2019).

The selected learning rates and other key techno-economic assumptions are presented in Table 2.1. CAPEX and OPEX figures for PV, onshore wind and shallow-water (<25m) offshore wind were obtained from DNV GL (2019) for

[8]The cumulative, technology-specific RES capacity additions assumed by the IRENA REmap scenario are displayed in Table A.2 in Appendix A.2.

[9]The difference in CAPEX between the baseline and optimistic scenarios is a function of both better technology and greater scale, with the optimistic case representing larger, more advanced systems.

the year 2018. DNV-GL differentiates costs by region,[10] so each country we consider is assigned to the corresponding region. For offshore wind turbines sited in deeper waters (25m to 55m), we used projections from NREL (2020, TRG 5) since offshore CAPEX varies considerably with water depth and distance to shore (Myhr et al., 2014).[11] Cost differences between countries for the deep-water class are assumed to be the same as those of the shallow-water offshore class, as provided by DNV GL (2019).[12]

Table 2.1.: Techno-economic assumptions on RES

	PV	**Onshore wind**	**Offshore wind**
Lifetime n (years)	25	25	25
$OPEX$ (% of CAPEX/a)	2	2.5	2.5
LR baseline (%)	30	18	16
LR optimistic (%)	40	23	20
Cum. installed capacity x_y^{res} (reference)	IRENA (2019a)	IRENA (2019a)	IRENA (2019a)
Capacity factor (reference)	Pietzcker et al. (2014)	Bosch et al. (2017)	Bosch et al. (2019)

Assumptions for lifetime and $OPEX$ from IEA (2019e). A full overview on calculations of accumulated installed capacities can be found in Appendix A.2.

The capacity factor is a ratio between 0-1 that indicates how much energy a RES produces in relation to its installed capacity (1) over a given period of time, usually a year. Areas with higher solar irradiance or higher mean wind speeds allow for higher capacity factors and thus yield *ceteris paribus* a lower levelised cost of electricity (LCOE) and thus potentially lower LCOH. To assess a country's RES-based hydrogen production potential, and to take into account in-country variations in the quality of the RES resource, we cluster PV and onshore wind potentials based on capacity factor ranges. As explained above, offshore wind potentials are clustered based on water depth instead, as CAPEX rise significantly when moving into deeper waters.

Each resource class has a theoretical potential, which states how much total capacity (measured in GW_{el}) can be installed within a given resource class in a given country.

[10]Statistics compiled by (IRENA, 2020c) show that RES CAPEX varies between countries. This is due to, among other factors, differences in labour costs and the prevailing exchange rates.

[11]CAPEX for PV and onshore wind also vary depending on location and terrain, although to a much lesser extent. For the purpose of simplification, in-country variations in the CAPEX/OPEX of PV and onshore wind are not considered for this analysis.

[12]Costs for connecting an offshore wind park to the coast are already included in the CAPEX for offshore wind (see NREL (2020) for an exact list of the cost components). We therefore assume that hydrogen from offshore wind electricity is produced onshore.

We exclude potentials with capacity factors below certain thresholds from the analysis, as hydrogen production would be prohibitively expensive in such areas. Furthermore, resource classes with a potential of less than 1 GW_{el} are also excluded.

Country-level data on PV capacity factors and potentials is taken from Pietzcker et al. (2014). The data is already clustered into resource classes based on capacity factor ranges. PV potentials are clustered into four classes with capacity factors ranging from >0.22 (1), 0.21 to 0.22 (2), 0.21 to 0.2 (3) and 0.2 to 0.125 (4).[13][14]

Capacity factors and potentials for onshore and offshore wind are taken from Bosch et al. (2017) and Bosch et al. (2019). As with PV, the potentials of the analysed countries are clustered into classes based on capacity factors. For onshore wind, capacity factor classes range from >0.4 (1), 0.4 to 0.3 (2) and 0.3 to 0.2 (3). Potential sites with capacity factors below 0.2 are excluded.

As explained above, offshore wind CAPEX are strongly dependent on water depth. Simply categorising offshore wind potentials by capacity factor would bias the results and give a relative advantage to potentials in deep waters. For this reason, we chose to define offshore wind resource classes based on water depth, not capacity factor. Classes 1 and 2 correspond to water depths of <25m and 25-55m respectively.

For each resource class of PV, onshore, and offshore wind, we construct a synthetic hourly capacity factor profile for a full year. More details on this procedure can be found in A.1.5. The estimated hourly profiles are then fed into

[13] Pietzcker et al. (2014) subtract another 10% from all results to account for additional losses, e.g. due to the accumulation of dust on modules. The 10% is added again for our analysis; otherwise, the absolute capacity factor decrease would be higher for good potentials, leading to a slight convergence of global PV capacity factors. The author also excludes all areas with a distance of >100 km from the closest settlement since development costs increase with the distance from existing infrastructure. However, there are not many countries with a relevant amount of space more than 100 km away from existing infrastructure. Countries in which this is the case (the United States, some countries in Africa, South America, and China) have such extensive solar potentials (Pietzcker et al., 2014, p. 712), that more distant areas with higher development costs will most likely never need to be developed.

[14] It should be noted that for Spain, potentials with a capacity factor in excess of 0.21 (the maximum value for the Iberian Peninsula according to (Solargis, 2020) were excluded, since they are located on the Canary Islands. For this analysis, only the Spanish mainland is considered, so that it is possible to assume uniform transportation costs. Furthermore, the Canary Islands are remote and lack the area potentials required for large-scale hydrogen production.

the optimisation model that computes the optimal RES-to-electrolyser ratio for the given resource class.

The assumptions on CAPEX, OPEX and capacity factors are used to compute the LCOE for each combination of country, technology and resource class. For a comparison of our estimates with those in the literature, refer to Table A.3 in Appendix A.2.

We distinguish between low and high temperature electrolysers. Unlike for RES, no country or region-specific cost data is available for electrolysers.[15] Therefore, a globally uniform cost for electrolysers is assumed, as is common in the literature to date. The techno-economic assumptions chosen for our analysis are based on IEA (2019c) and presented in Table 2.2.

Table 2.2.: Techno-economic assumptions for electrolysers

		2020	2030	2040	2050
Low temperature					
	$CAPEX$ base / optimistic (\$/kW)	950 / 500	625 / 400	537.5 / 300	450 / 200
	$OPEX$ (%CAPEX/a)	2	2	2	2
	Efficiency η (%)	66.5	68	71.5	75
	Operating pressure (bar)	30			
	Operating temperature (°C)	50-80			
	Lifetime (years)	25	25	25	25
High temperature					
	$CAPEX$ base / optimistic (\$/kW)	4000 / 2400	1800 /800	1275 / 650	750 / 500
	$OPEX$ (%CAPEX/a)	2	2	2	2
	Efficiency η (%)	77.5	80.5	82	83.5
	Operating pressure (bar)	30			
	Operating temperature (°C)	650-1000			
	Lifetime (years)	25	25	25	25

2.3.2. Hydrogen from natural gas

In contrast to hydrogen from RES, system CAPEX are not a dominant factor in LCOH from natural gas-based systems. Therefore, only one set of assumptions is made for the techno-economic parameters.[16]

We model both NGR with CCUS and pyrolysis as options for the production of low-carbon hydrogen from natural gas. Assumptions for NGR with CCUS

[15] There is a cost distinction in BNEF (2019), but only between China and the rest of the world. Furthermore, the study assumes costs in the rest of the world will converge with China by 2030.

[16] A sensitivity analysis for CAPEX is performed in Section 2.5.

Table 2.3.: Techno-economic assumptions for NGR and pyrolysis plants

	NGR with CCUS	**Pyrolysis (H_2-fired)**
Lifetime n (years)	25	25
$CAPEX$ 2020 / 2030 / 2050 (\$/kWH$_2$)	1627 / 1360 / 1280	- / - / 457
$OPEX$ (% of CAPEX/a)	3%	5%
Efficiency η (%)	69%	52%
CO_2 capture rate (%)	90%	-
Total emissions (kgCO_2/kgH_2)	9.7	-
Captured emissions CE (kgCO_2/kgH_2)	8.7	-
Uncaptured emissions UE (kgCO_2/kgH_2)	1	-
Carbon yield CB (kgC/kgH_2)	-	3
Availability CF (%)	95%	95%

are based on IEA (2019c); expected improvements in carbon capture technology translate into a CAPEX and OPEX decline over time. Table 2.3 gives an overview of all relevant techno-economic parameters. For the hydrogen from NGR with CCUS to be low-CO_2, the CO_2 captured in the carbon capture facility must be transported away and stored permanently to prevent it from escaping into the atmosphere. The long-term storage of CO_2 can take place in geological formations called saline aquifers, or in depleted oil and gas fields. Currently, storing CO_2 underground is restricted by law in many regions, e.g., in Germany. In some countries, there is significant public opposition to underground CO_2 storage. Therefore, based on Hendriks et al. (2004), we consider two carbon storage scenarios: In a restricted scenario, CO_2 storage is only allowed offshore; in an unrestricted scenario, CO_2 can also be stored onshore. Costs for CO_2 transportation and storage range from between \$6 and \$18 per tonne of CO_2 in the unrestricted scenario and \$8 to \$40 per tonne when only offshore storage is permitted.

No CO_2 is produced in the methane pyrolysis process. There are cost estimates for large-scale pyrolysis plants in the literature, but no projections of how costs will develop once the technology is deployed at scale. This is mainly due to the low technology readiness level (TRL), which is also why it is uncertain if and when the technology will be ready for the market. A German research group (Bode, 2019) plans to construct the first commercial plant by 2030; Ausfelder et al. (2019) expect pyrolysis to be ready for use by 2040.[17] For the analysis at hand, it is assumed that commercial-scale pyrolysis for hydrogen production will be available from 2035 onwards. There are multiple sub-categories of pyrolysis

[17] Monolith Materials (Monolith Materials, 2019) already have a pyrolysis plant in operation. However, this plant is designed to produce solid carbon; hydrogen is only a by-product.

plants which differ mainly on the technologies used to provide the heat needed to drive the pyrolysis process. An overview can be found in Schneider et al. (2020) and Timmerberg et al. (2020). For this analysis, we selected the molten metals pyrolysis reactor from Parkinson et al. (2017) with hydrogen combustion as a heat source. This has some advantages:

- In contrast to a natural gas-fired pyrolysis system, no CO_2 is produced in the heating process, making a hydrogen-fired unit more suitable for the purpose of our analysis - examining low-carbon hydrogen production.
- H_2-fired pyrolysis systems are generally able to produce hydrogen at lower LCOH than systems that use electricity to drive the process (e.g. plasma plants), except when gas prices are high and grid electricity is cheap.[18]
- As no additional electricity is required, this simplifies the computational process and obviates the need to make assumptions about the CO_2 intensity of electricity supply from the grid or RES potentials, capacity factors and costs.
- All relevant techno-economic assumptions adopted for our analysis are presented in Parkinson et al. (2017) and shown in Table 2.3.

Parkinson et al. (2017) estimate Pyrolysis CAPEX through process modelling of a large-scale plant and by multiplying the individual plant cost components with the *Lang factor*, which is widely used in chemical engineering, to calculate total installation costs of plants (Sinnot, 1999). To determine total CAPEX from the total cost of equipment, a multiplier is set based on the maturity level of a technology.[19] Parkinson et al. (2017) apply a Lang factor of 10, which corresponds to a *first-of-a-kind* plant. To account for the techno-economic progress and decreasing CAPEX with an increasing number of plants, we gradually decrease the Lang factor over the years 2035-2050 to a value of 6 (*nth-of-a-kind*), which is the current maturity level of SMR technology.[20] A

[18] Exemplary calculations show that for a gas price of $20/MWh, an electricity price of below $20/MWh would be necessary for a plasma system to yield lower LCOH than a H_2-fired system.

[19] A cost estimation with with a scalar like the Lang factor is characterised by high uncertainty. However, an alternative cost estimate is infeasible as no dedicated large-scale systems have been constructed yet. To reflect the high level of uncertainty in CAPEX estimations, we conduct a sensitivity in Figure 2.5. The results suggest that CAPEX is not a major cost driver for hydrogen from pyrolysis.

[20] If pyrolysis is market-ready and cost-competitive, market shares of hydrogen from pyrolysis could rise rapidly with many pyrolysis plants being built. Therefore, a fast market ramp-up with decreasing CAPEX appears likely in such a scenario.

critical factor for production costs of hydrogen from pyrolysis is the price of the solid carbon by-product. The exact structure of the carbon produced in the process depends on specific process characteristics. The most prominent carbon by-product of pyrolysis is carbon black, where market prices range between 400 and 2000 $/t (Keipi et al., 2016a,b). The current market size of carbon black is 16.4 Mt/a (Parkinson et al., 2019), which would correspond to a hydrogen production of 5.5 Mt/a under the assumptions of this analysis (see Table 2.3). This corresponds to 7.5% of the global hydrogen demand in 2018 (IEA, 2019c). Considering a future large-scale production of hydrogen from pyrolysis, the current carbon market size would quickly be exceeded, and solid carbon prices would likely fall towards zero. If new applications or markets are found, prices for carbon products could be positive. Alternatively, if there is no use for the material and it has to be disposed of, there would be a cost, which would be equivalent to a negative solid carbon price. A solid carbon price of 0 is assumed for this analysis. The impact of a price change is considered as sensitivity in Section 2.5.

2.3.3. Hydrogen transportation

We consider both pipelines and oceangoing ships as modes for the long-distance transportation of hydrogen.

Cost estimates for pipeline-bound hydrogen transportation vary substantially from study to study. They can be significantly reduced if - instead of building new hydrogen pipelines from scratch - existing natural gas pipelines are retrofitted to carry hydrogen. For our analysis, both estimates of IEA (2019c) and Wang et al. (2020) are considered as an upper and lower bound in order to reflect the entire cost spectrum as a sensitivity for pipeline transportation costs. Since hydrogen pipelines are an established technology (IEA, 2019c, p. 75), we assume costs to remain flat over time. We also assume hydrogen production facilities to operate in the same pressure range as the pipelines, avoiding the need for an additional compression of the hydrogen prior to its injection into a pipeline.[21] Table 2.4 gives an overview of the assumptions.

Table 2.4.: Techno-economic assumptions on hydrogen pipelines

	High cost	**Low cost**	**Retrofit**
Technical lifetime (years)	40	40	40
CAPEX ($/tpa/km)	3.56	1.33	0.73
OPEX & fuel (% of CAPEX/a)	5	5	5
Utilisation (%)	75	75	75
Cost of pipeline transport ($/1000km/kg H_2)	0.64	0.24	0.13

Pipeline costs are assumed to be constant over time. Assumptions for **high cost** pipelines are based on IEA (2019e). Assumptions for **low cost** and **retrofitted** natural gas pipelines are based on central cost estimates from Wang et al. (2020).

Transporting gaseous hydrogen over long distances by ship would be prohibitively expensive due to its low volumetric energy density. For sea-based transportation, it is more efficient to liquefy the hydrogen or incorporate it into carrier molecules with a higher energy density. However, hydrogen liquefaction or conversion are very energy-intensive and expensive, increasing hydrogen supply costs by 50-150%, depending on transportation technology and distance (IEA, 2019e, p. 608). The three most widely studied technologies are liquid hydrogen (LH_2), ammonia (NH_3) and liquid organic hydrogen carriers (LOHCs).

Transporting hydrogen in the form of ammonia is considered to be cheaper than LH_2 transport in the medium term, despite the high costs for conversion and reconversion. According to a detailed analysis by the IEA (2019c, pp. 76), ammonia-based seaborne transport is cost-efficient in 2030 for all shipping distances. However, since the technological maturity of large-scale hydrogen liquefaction and shipping is currently low (IEA, 2019c, p.75), substantial cost reductions can be expected if the technology is used more widely in the future (ERIA, 2019). According to Wijayanta et al. (2019), while ammonia transportation would remain the most efficient solution in the long term if the

[21] If the output pressure of the production process is lower than the pipeline system's suction pressure, the additional cost of compression increases overall transportation costs. The relationship between compression costs and the width of the pressure gap is positive and nonlinear (Wang et al., 2020). Wang et al. (2020, p. 13) propose a pipeline suction pressure of 30-40 bar. NGR and pyrolysis plants, as well as low- and high-temperature electrolysers, can all be designed to operate in this pressure range: see Muradov and Veziroglu (2005) for NGR with CCUS; Parkinson et al. (2017) for pyrolysis and Mathiesen et al. (2013) for electrolysers.

ammonia is used directly, and not reconverted back to hydrogen, if pure hydrogen is needed, LH_2 has the potential to become the cheapest shipping method in the long term. Ammonia (re-)conversion is associated with high energy losses, which increase with the purity of the hydrogen required. Fuel cells, for example, require hydrogen of high purity, which makes ammonia reconversion and thus the entire transportation chain more expensive (IEA, 2019c). Since we explicitly estimate the long-term costs of pure hydrogen, in line with other long-term studies (Heuser et al., 2019, Kamiya et al., 2015), LH_2 is chosen as the preferred technology for ship-based hydrogen transportation. Table A.6 displays the techno-economic assumptions on the individual components of the liquid hydrogen transport infrastructure. The cost of the electricity required for the operation of the infrastructure (mainly the liquefaction of hydrogen) is taken from DNV GL (2019) projections.

In order to calculate shipping costs, we obtained port-to-port distances between countries from the CERDI sea distance database (Bertoli et al., 2016). Pipeline distances are based on own calculations, using existing natural gas pipeline routes as a baseline.

2.4. Results and Discussion

This section presents the key results of this study. The full range of results on production, transportation, and supply costs is provided in a supplementary spreadsheet.[22] It should be noted that RES-to-electrolyser ratios are optimised. Therefore, RES capacity factors do not translate directly to electrolyser capacity factors, as the optimisation model trades RES curtailment for a higher annual utilisation of the electrolyser. Additional information on the effect of the optimisation of the electrolyser-to-RES ratio on the LCOH of the combined system are presented in A.3.1.

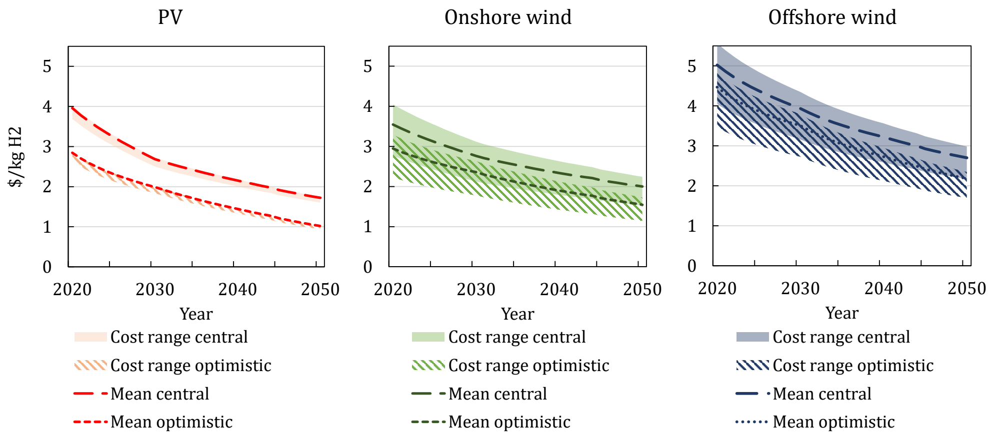
2.4.1. Hydrogen from RES

Figure 2.2 shows cost ranges and mean LCOH for the 20 best RES resource classes globally under baseline and optimistic assumptions.

The mean values for the LCOH in Figure 2.2 tend to be located at the upper end of the respective cost ranges, which shows that the lowest cost potentials are

[22]The spreadsheet can be downloaded here.

Figure 2.2.: LCOH range and mean values of the 20 lowest-cost resources classes for each RES-electrolyser combination



generally smaller than those with higher costs. The cost range for PV is relatively narrow, as solar irradiation and thus the LCOH varies less among the best areas.

A slightly different picture emerges for onshore wind, which has a broader cost range. The variation in wind capacity factors is larger than for PV. Often, there are small areas with low costs and more extensive areas with higher costs. For baseline assumptions, onshore wind has the lowest minimum LCOH of \$2.7/kg in 2020 and \$2.1/kg in 2030. The lowest LCOH for PV is \$3.75/kg in 2020 and \$2.5/kg in 2030. Costs for PV decrease faster compared to onshore wind so that PV is catching up in the long run. In 2050 the most favourable potentials of both RES have minimum hydrogen production costs of \$1.6/kg. The mean LCOH under baseline assumptions is \$2.7/kg in 2030, decreasing to \$1.7/kg by 2050 for PV and \$2.6/kg in 2030 decreasing to \$2/kg in 2050 for onshore wind. For offshore wind-based systems, the minimum LCOH is \$4.5/kg in 2020, decreasing to \$2.2/kg in 2050. However, the range between is quite large, as capacity factors vary substantially within the top 20 offshore resource classes considered here. Across the top 20, the mean LCOH decreases from \$5.05/kg in 2020 to \$2.76/kg in 2050.

Under optimistic assumptions, cost reductions are most substantial for PV, making it the potentially cheapest source of RES-based hydrogen from 2033 on. By 2050, minimum hydrogen production costs could fall below \$1/kg for PV. Onshore wind remains the most competitive source in the short term with a mean LCOH of \$2.2/kg in 2030, decreasing to \$1.5/kg by 2050. Minimum Onshore wind

LCOH is \$1.75/kg in 2030 decreasing further to \$1.2/kg by 2050. The minimum LCOH for offshore wind is \$2.7/kg in 2030 and \$1.7/kg in 2050, the mean LCOH declines from \$4.32/kg in 2020 to \$2.04/kg in 2050.

There are particularly well-suited regions for each renewable energy technology, with costs close or equal to the global minima shown in Figure 2.2. Regions with low LCOH for PV-based systems are the Middle East and North Africa, Central America, and the United States. Besides, China, parts of India, Pakistan, and Southeast Asia also have good potentials for PV. There, the LCOH is further depressed by the lower expected CAPEX for PV, when compared to the global average. Low production costs for hydrogen from onshore wind can be found in Central and South America, Northern Europe, the United States, and China (again favoured by comparably low wind turbine CAPEX in China). The lowest costs for hydrogen from offshore wind can be found along the coasts of South America and North-Western Europe. The offshore resource class 1 with $<$25m water depth generally yields a lower LCOH. This is due to the lower CAPEX associated with building offshore wind turbines in shallower waters, which more than compensates for the on average only slight decrease in capacity factor closer to the coastline.

Regarding hybrid systems[23], we found that combining a wind turbine, PV array and electrolyser (to decrease the intermittency of the combined system and increase the load factor of the electrolyser) can result in a lower overall LCOH. However, this is only the case when very good wind and solar potentials overlap geographically and even in such cases, the cost advantage is small over a pure PV- or wind-based system. In most cases, however, an optimised system relying on only one type of RES yields a lower LCOH because of its lower capital intensity, in particular in the optimistic case with its substantial decline in RES and electrolyser CAPEX. We therefore chose to exclude hybrid systems from the cost comparison, given that they have (small) cost advantages only in specific geographies and only when very specific conditions are met. The issue is explained in more detail in A.3.2.

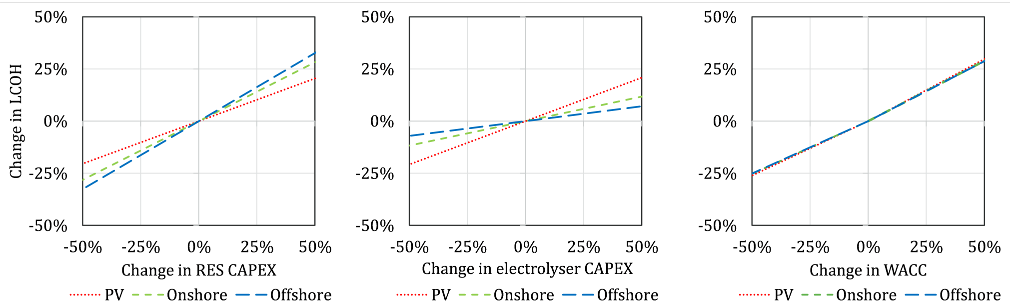
Apart from the exact costs for individual technologies, some general insights on the cost structure of hydrogen from RES can be derived from the results:

[23] The term *hybrid* denotes a system consisting of an electrolyser and at least two (different) RES. Hybrids are typically formed by pairing an electrolyser with a PV array and an onshore wind turbine (Mazzeo et al., 2020).

- As RES CAPEX vary between regions, some regions have fundamental cost advantages in hydrogen production. A particular advantage exists for China. With the lowest global CAPEX for PV, onshore, and offshore wind, China has better starting conditions for hydrogen production than countries with higher CAPEX. The results reflect this; hydrogen production costs are close to the global minimum in China for both PV- and onshore wind-based hydrogen production.
- Comparing low and high temperature electrolysis, low temperature is the cheaper electrolysis technology in the short and medium term. In the long run, however, high temperature electrolysers could become cost-competitive for RES potentials with high capacity factors, allowing for a high annual utilisation of the electrolyser. The advantage of a high temperature electrolyser is its higher efficiency; the disadvantage are higher system costs, which are currently reinforced by a low technological maturity. With maturity increasing over time, CAPEX and LCOH decrease more significantly for hydrogen production based on high temperature electrolysis, making it more cost-competitive. Under baseline assumptions, a high temperature electrolyser becomes the more cost-efficient option in the long-run for utilisation rates >0.7. Our results suggest that RES capacity factors that make high temperature electrolysers cost-efficient exist for some offshore potentials, such as Chile, United Kingdom, Germany, and France. Under optimistic assumptions, the combination of PV, onshore wind or offshore wind with low temperature electrolysis is always superior to high temperature electrolysis in the long run. This is largely due to the CAPEX for low temperature electrolysers decreasing by a larger proportion (-125% in 2050) than the CAPEX for high temperature electrolysers (-50%) when comparing baseline to optimistic assumptions.
- Offshore wind is not competitive in terms of the global minimum LCOH. Although it yields the best RES capacity factors with values of over 0.6, hydrogen production costs from offshore wind electricity are relatively high. This is due to the high CAPEX, which cannot be offset by the higher capacity factors relative to onshore wind and PV. However, there is an advantage for offshore wind concerning the area potential. Large, high quality PV and onshore wind potentials are concentrated on specific regions around the world (e.g. MENA for PV or the US Midwest for onshore wind).

The vast offshore wind potentials could therefore be particularly interesting for regions with limited onshore and unsuitable PV potential (e.g. Northern Europe or East Asia). The case studies in Section 2.4.3 take a closer look at these regions.

Figure 2.3.: Sensitivity analysis for production cost of hydrogen from RES in 2050



A low temperature electrolyser with CAPEX of 450$/kW is assumed for the sensitivity analysis. Standard WACC are 8%. The PV sensitivity analysis is conducted for India PV resource class 1, the Onshore sensitivity analysis for China resource class 1 and the Offshore sensitivity analysis for Chile resource class 1. Chosen countries and resource classes represent the respective global minima of production costs for each type of RES. While changing input factors for LCOH changes the optimum S^* for installed RES-to-electrolyser ratios, ratios are held constant to simplify the sensitivity analysis. Re-optimising for changes in RES CAPEX, WACC and electrolyser CAPEX would reduce the magnitude of the effects shown by the sensitivities somewhat; however, the fundamental insights would stay the same.

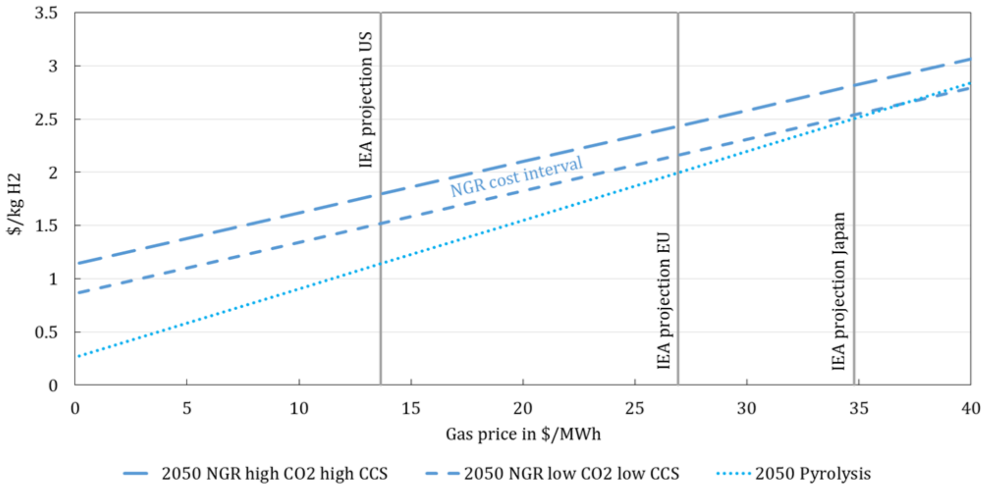
Figure 2.3 displays sensitivities for the LCOH of PV, onshore, and offshore wind in 2050 under baseline assumptions. The sensitivity of the LCOH to RES CAPEX is lowest for PV and highest for offshore wind. CAPEX make up 41% of the total LCOH for PV, 56% for onshore, and 65% for offshore wind. The effects are exactly reversed for sensitivities to electrolyser CAPEX. Since PV has the lowest RES CAPEX, electrolyser CAPEX make up a larger portion of the total cost, and the LCOH is thus more sensitive to it changing. The effect of a WACC change on the LCOH is approximately the same for all RES. The LCOH is quite sensitive to a WACC change; a decrease of WACC from 8 to 4% would reduce the LCOH by 25%. This finding is particularly interesting because the WACC can vary between countries, significantly affecting hydrogen production costs.[24]

[24] According to Vartiainen et al. (2020), the WACC can be as low as 2.5%, reported for utility-scale PV in Germany.

2.4.2. Hydrogen from natural gas

Estimates for the production cost of hydrogen from NGR and pyrolysis are not as heterogeneous as those for RES-based hydrogen. Globally uniform CAPEX and a uniform utilisation of plants are assumed. Thus, cost differences between years arise only from a variation in gas prices and changes in CAPEX and CO_2 prices over time. Consequently, the LCOH does not change much over the years; instead, it varies significantly with natural gas prices. Therefore, Figure 2.4 displays a static cost estimate for hydrogen from natural gas in 2050 as a function of the gas price. The vertical lines indicate gas prices as projected by the IEA (2019d). Accordingly, the hydrogen production costs for pyrolysis in the US would be \$1.1/kg, while costs for NGR with CCUS would range between \$1.5-\$1.75/kg of hydrogen. Due to the higher projected gas prices, hydrogen production cost from pyrolysis would be \$2/kg in the EU and \$2.5/kg in Japan. In gas exporting countries, costs could be lower still. Taking the upstream and

Figure 2.4.: Hydrogen production cost for NGR with CCUS and pyrolysis in relation to the gas price in 2050

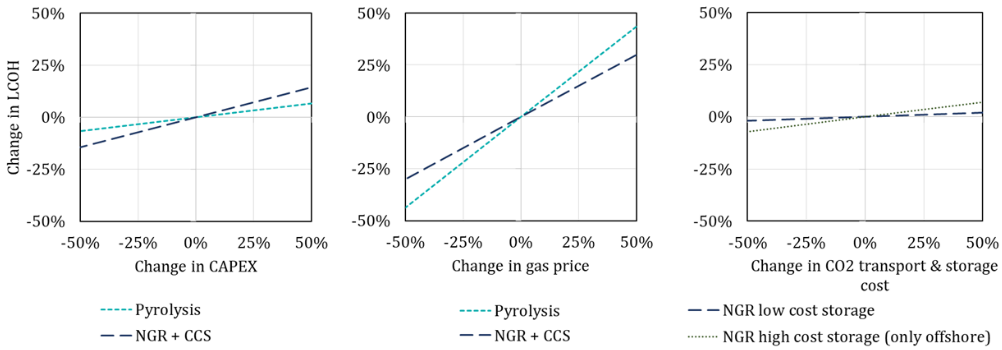


IEA gas price projections refer to IEA (2019d). High CO_2 high CCUS refers to a CO_2 price of \$160/t and CCUS cost of \$40/t while low CO_2 low CCUS refers to a CO_2 price of \$145/t and CCUS cost of \$10/t. The two lines mark the upper and lower limits of the possible cost interval for NGR with CCUS. A solid carbon price of 0 is assumed for pyrolysis.

in-country transportation costs for natural gas given by the IEA (2018, p. 195) for Qatar and Russia – two of the most important natural gas producers – in 2025, gas input prices for hydrogen production could be as low as \$2/MWh in the latter and \$5/MWh in the former. These gas prices would yield hydrogen production costs of \$0.4/kg for pyrolysis and \$0.95/kg for NGR with CCUS in Qatar, and \$0.6/kg for pyrolysis and \$1.2/kg NGR with CCUS in Russia.

Under standard assumptions (see description of Figure 2.5), plant CAPEX account for 22% of the LCOH for NGR and 9% of the LCOH for pyrolysis. Hydrogen production costs are thus not very sensitive to plant CAPEX, especially when compared to hydrogen from RES. Consequently, a change in the WACC is also not particularly significant; changing the WACC rate by ±50% changes the LCOH by ±7% for NGR and ±3% for pyrolysis. Instead, production costs are highly sensitive to the gas price. The feed gas price makes up 60% of LCOH for NGR with CCUS. For pyrolysis, the gas price is even more significant, accounting for up to 87% of the LCOH. A high dependence of the LCOH on the gas price is typical for all different pyrolysis plant types.[25] Nevertheless, the choice of a H_2-fired pyrolysis system for our analysis leads to a particularly high sensitivity to the natural gas price: It uses recovered hydrogen for heating and therefore has a lower energy efficiency than, for example, a plasma (electricity)-based pyrolysis plant.

Figure 2.5.: Sensitivity analysis for hydrogen from natural gas



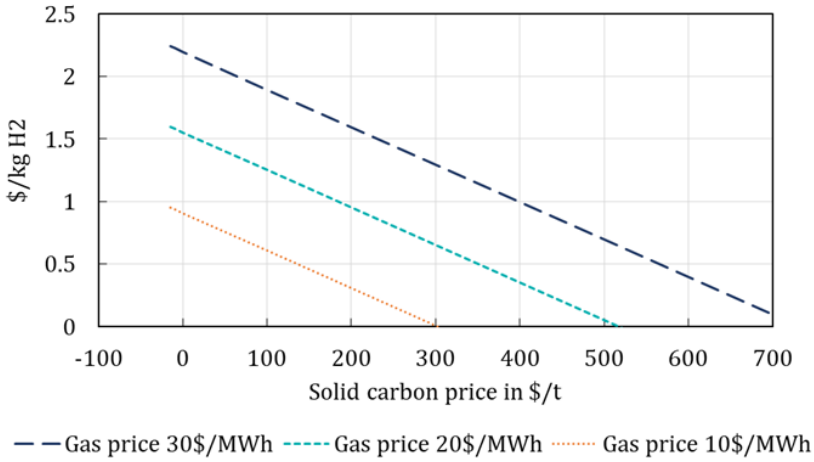
The baseline for sensitivity analysis is a Western European country (e.g. Germany) in the year 2050. Standard assumptions are CAPEX of 1280\$/kW for NGR and 457\$/kW for pyrolysis, a gas price of \$26/MWh taken from IEA (2019c) as projected for European countries, a CO_2 price of \$160/t (advanced economy assumption for 2050), low CO_2 transportation and storage cost of \$10/t, high CO_2 transportation and storage cost of \$40/t, WACC of 8%.

Sensitivities to CO_2 transportation and storage costs, which are illustrated on the right side in Figure 2.5, only play a role in LCOH of NGR with CCUS. It is evident that production costs for hydrogen from NGR are not very sensitive to changes in CO_2 transportation and storage costs. For the high-cost storage

[25] A sensitivity comparison of different pyrolysis systems can be found in Timmerberg et al. (2020).

scenario (\$40/t CO_2), a cost increase of 50% to \$60/t CO_2 changes the LCOH by +7%.[26]

Figure 2.6.: Sensitivity analysis for solid carbon price



Hydrogen costs are illustrated as a function of solid carbon prices for three different gas prices. Functions are based on CAPEX of 547\$/kW and WACC of 8%.

Figure 2.6 displays hydrogen production costs from pyrolysis as a function of a potentially positive price for the solid carbon by-product for three different gas prices of \$10, \$20 and \$30/MWh. A small change of the solid carbon price has little effect on the LCOH of pyrolysis. However, current market prices for carbon black range between \$400 and \$2000/t (Keipi et al., 2016b), providing an indication why pyrolysis plants that are already in operation today have focused primarily on the production of carbon black (Monolith Materials, 2019). For example, a carbon black price of \$500/t leads to such high revenues that the hydrogen by-product could essentially be given away for free, assuming a gas price of \$20/MWh. If solid carbon prices remain at current levels despite a significant scale-up of pyrolysis for hydrogen production, for instance because new markets are developed (Muradov and Veziroglu, 2005), both products – hydrogen and solid carbon – could potentially be sold at a profit. In that case, pyrolysis would most likely become the most cost-effective method to produce hydrogen in all the countries considered for this analysis. However, the inverse could occur as well: if large amounts of hydrogen are produced using pyrolysis, and new markets for solid carbon do not develop, it could be treated as waste that has to be disposed of at a cost, even though this cost is likely to be small.[27]

[26] A similar observation can be made for the sensitivity to the CO_2 price, which is even lower when the capture rate exceeds 50%.

[27] Solid carbon is a stable, non-toxic element that can be disposed of in landfills.

When considering the sensitivity analysis and the high uncertainty with respect to future solid carbon prices, it can be stated that the natural gas price is the main factor determining the production costs of low-carbon hydrogen from natural gas. Plant CAPEX, as well as the cost of CO_2 transportation and storage, play a less significant role. If, for example, pyrolysis CAPEX is higher than projected by our analysis, or if CO_2 storage is initially more expensive due to small scales or legal restrictions, these cost changes would have a relatively low impact on the LCOH of natural-gas based low carbon hydrogen.

2.4.3. Long-term supply costs of hydrogen

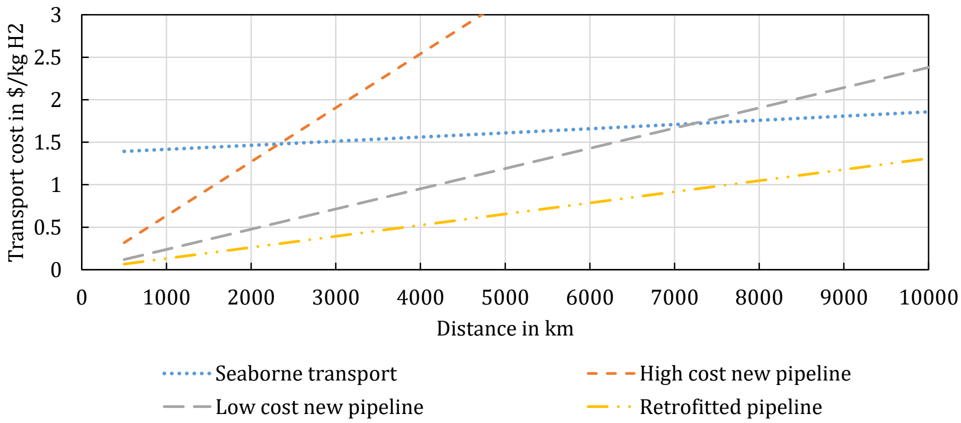
This section illustrates how the costs associated with the long-distance transportation of hydrogen affect the order of the most cost-efficient hydrogen supply sources for different countries. We define supply costs as the sum of production and transportation costs. Figure 2.7 provides an overview of hydrogen transportation costs as a function of technology and distance. Assuming high costs for new hydrogen pipelines, transportation by ship would be more cost-effective than pipelines for distances of around 2000km. However, if hydrogen pipelines can be built and operated at lower costs, liquefaction and LH_2 transportation by ship would be more cost-efficient only for distances of over 7000km. The least costly option for hydrogen transportation would be in converted natural gas pipelines, with costs of around 13ct to transport a kilogram of hydrogen over a distance of 1000km.

Low-carbon hydrogen production costs, transportation costs and thus supply costs vary from country to country. The following sections compare different supply cost scenarios using Germany and Japan as case studies.[28]. Both countries are at the forefront of promoting the use of hydrogen in their respective energy transitions and have recently published their own hydrogen strategies (BMWi, 2020, METI, 2020).

Looking at medium term (2030) costs can provide information on how the development of low-carbon hydrogen supplies might proceed most efficiently. However, large-scale international trade of hydrogen will likely only emerge in the long term, if at all. Therefore, in addition to medium term trends, supply costs for the year 2050 are compared as well.

[28] A third case study looking at the United States can be found in A.3.3.

Figure 2.7.: Comparison of options for long-distance hydrogen transportation



Seaborne transportation costs include the liquefaction OPEX (including electricity), export terminal CAPEX, shipping CAPEX and OPEX and import terminal CAPEX and OPEX. Pipeline transportation costs include CAPEX and OPEX and are assumed to be uniform across countries. Seaborne transportation cost are also dependent on the price of the electricity used to liquefy the cargo. The cost shown here assumes liquefaction in Saudi Arabia.

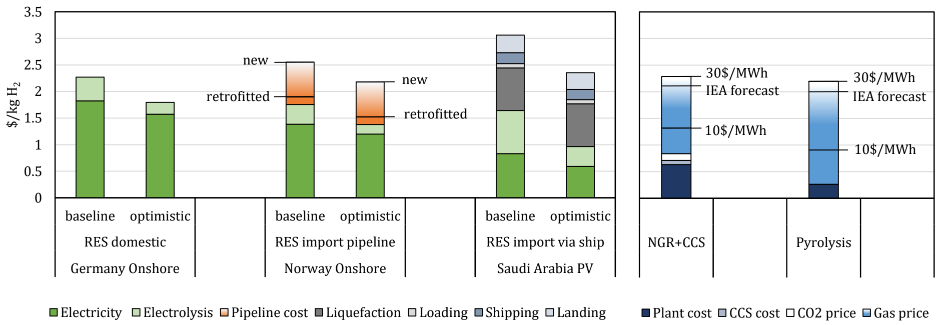
Germany

With its central location on the continent, Germany is well integrated into the European natural gas pipeline network. It is therefore not necessary to build an entirely new infrastructure for hydrogen transport; instead, parts of the gas network could be repurposed to carry hydrogen, which is a lower-cost option than building new, dedicated hydrogen pipelines (Wang et al., 2020). Nevertheless, despite the potentially relatively low import costs when using converted natural gas pipelines, hydrogen from RES is likely not competitive with hydrogen from NGR in the medium term (2030). Even under optimistic assumptions, the costs of renewable energy and electrolysis are too high; cost parity with gas-based hydrogen could be reached in 2030 only for gas prices exceeding $25/MWh.[29] These results suggest that for the short- and medium-term development of a hydrogen economy, it is more efficient to use NGR with CCUS under the given assumptions, at least as a transitional technology. In the long term however, while costs for NGR could roughly stay the same, there is still a considerable cost reduction potential for hydrogen from RES.

[29]Figure A.7 in A.3 shows a comparison of hydrogen supply costs in Germany for the year 2030.

The results also show that imports by ship are not competitive in Germany's case, as very large RES potentials can be reached more cost-efficiently through both retrofitted natural gas and new dedicated hydrogen pipelines.

Figure 2.8.: Comparison of hydrogen supply costs to Germany in 2050



The horizontal black lines for RES imports via pipeline indicate cost levels for different types of pipeline transportation; a retrofitted natural gas pipeline as the lower bound and a high cost new pipeline as the upper bound. The same applies for hydrogen from natural gas, where black lines indicate costs at different gas price levels. Figure A.7 in Appendix A.3 displays the same comparison for 2030.

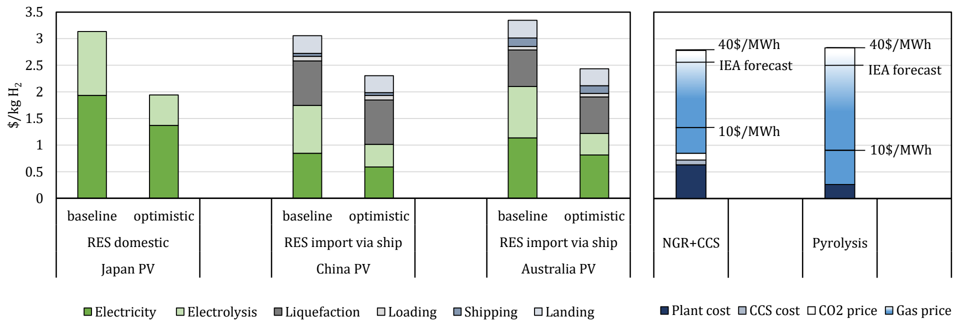
Figure 2.8 compares long-run costs for domestic and imported hydrogen from RES as well as hydrogen from natural gas. Norway is chosen as an example for pipeline imports since it is the cheapest source of pipeline supplies with significant production potential. Saudi Arabia serves as an example for countries with low hydrogen production costs that could become large-scale hydrogen exporters but are not directly connected to Germany, e.g. via pipeline. Costs of hydrogen from natural gas are illustrated as a range, with the black lines indicating the LCOH for different gas price levels.

Comparing the costs of hydrogen from RES and natural gas, it is unclear which production pathway will be more cost-effective for Germany in the long run. At gas prices below \$10/MWh, NGR with CCUS and pyrolysis would remain more cost-efficient than hydrogen from RES in the long run. However, such low natural gas prices have been rare in Europe in the past. Taking the gas price assumption from the IEA (2019d) hydrogen report for Europe in 2050, which is \$27/MWh, hydrogen from RES could become cost-competitive under baseline assumptions when transported in retrofitted pipelines. Under optimistic assumptions, RES would be a cheaper hydrogen source than natural gas under IEA (2019c) price projections. Production based on domestic wind and electrolysis could also decrease to \$1.8/kg.

Japan

Japan's basic economic structure is similar to that of Germany in many respects: Both are highly industrialised countries that are densely populated, both are heavily dependent on energy imports (IEA, 2019e), and both want to assume a pioneering role in the development of a hydrogen economy (BMWi, 2020, METI, 2020). However, the geographical conditions of Japan differ fundamentally from those of Germany. As an island, Japan is difficult to reach and has no existing transmission lines or pipeline connections to other countries, in contrast to Germany, which is integrated into the European natural gas grid. This limits the options Japan has for sourcing RES-based low-carbon hydrogen: The country itself does not have particularly good wind or PV conditions, but as imported hydrogen has to be transported by ship, costs are so high that imports are often not worthwhile. Natural gas prices are also traditionally high in Japan, as the country relies on LNG for 100% of its supplies (IEA, 2019a). Consequently, this is reflected in a higher LCOH for hydrogen derived from natural gas. However, despite the comparatively high domestic natural gas prices, hydrogen from NGR with CCUS is by far the cheapest form of production in the medium term, with a LCOH of approximately \$2.5/kg for the gas price level projected by the IEA (2019d) for 2030.[30] By comparison, minimum supply costs of hydrogen from RES under baseline assumptions are \$4.9/kg for domestic production and \$4.8/kg for imports.

Figure 2.9.: Comparison of hydrogen supply costs in Japan 2050



Black lines for hydrogen from natural gas indicate costs at different gas price levels. Figure A.8 in Appendix A.3 shows a cost comparison for 2030.

[30]For a visual comparison, see Figure A.8 in Appendix A.3

In the Japanese case, due to the high transportation costs and the relatively poor conditions for domestic production, hydrogen from RES will probably only be competitive in the long run under optimistic assumptions. Under baseline assumptions, natural gas remains the cheaper feedstock; the LCOH of hydrogen derived from pyrolysis and NGR with CCUS are at approximately the same level for IEA (2019d) natural gas prices, namely at $2.5/kg. For gas prices greater than $35/MWh, due to the lower process efficiency, pyrolysis-derived hydrogen becomes more expensive than hydrogen produced from NGR with CCUS. If future natural gas prices remain high, NGR would be and probably remain the most cost-competitive path to produce hydrogen from natural gas in Japan.

2.4.4. Discussion

Supply cost estimates alone are not sufficient to predict the structure of the emerging market for low-carbon hydrogen. Still, some general conclusions can be drawn from our analysis. Above all, our results suggest a mix of production pathways would likely emerge in the low-carbon hydrogen market, where hydrogen from RES as well as hydrogen from natural gas will each serve parts of global demand.[31] The relative contribution by natural gas and RES in individual countries could differ substantially between countries and compared to the global average. Policy choices favouring the early development of one technology over the other will matter too in this respect.

A country's local natural gas price will likely determine whether hydrogen from natural gas will retain a cost advantage in the long run. From a cost perspective, imports of hydrogen produced from RES will only become competitive where low production costs go hand in hand with low transportation costs. The supply cost analysis shows that shipping in particular increases hydrogen costs. Therefore, it seems likely that markets for low-carbon hydrogen will be regional first and foremost, with hydrogen pipeline networks as the most essential transportation infrastructure. Regions that are already well integrated through existing natural gas pipeline networks, such as Europe and North Africa or North America, have obvious advantages here.

[31] Hydrogen from coal gasification with CCUS or nuclear energy could also play a role. However, costs for these technologies are not estimated here.

While we did not explicitly model a pessimistic cost development trajectory for RES and electrolysers, there are conclusions that can be drawn with respect to such a scenario. Some analyses show that the energy return on energy invested (EROI) of the global energy system will fall as energy dense fossil fuels are phased out in favour of less energy dense renewables. A fall in the EROI would result in an increase in the materials intensity of the global economy, as more infrastructure is needed to harvest the energy required (Capellán-Pérez et al., 2019). A consequence of such a shift could be a smaller decline in RES CAPEX than currently anticipated, or a tapering off of the ongoing cost decline, followed by a subsequent increase. Looking at the near-term baseline assumptions, a more pessimistic cost trajectory for RES would preserve the cost advantage which natural-gas based hydrogen production pathways currently enjoy in all of the major economies.

However, there are several limitations to the analysis presented in this chapter, providing openings for further research.

Firstly, we treat hydrogen production as a closed system, a necessary assumption to simplify cost estimates for the large number of countries considered. In reality however, hydrogen production is integrated into the overall energy market. An obvious opportunity cost of producing hydrogen with renewable electricity is the profit associated with the alternative of feeding the electricity into the grid. In our analysis, RES do not interact with the power sector, whereas in reality, a link between hydrogen production from RES and the power sector will likely exist in many cases[32]. When the renewable electricity source is also connected to the grid, market prices for electricity and hydrogen would determine the optimal ratio between hydrogen and electricity production.

The fact that renewable electricity would have to supply both the power sector and hydrogen production also creates a rival-use problem. The low-carbon hydrogen production potentials shown in this chapter are theoretical and do not consider competing use. In reality, hydrogen electrolysis directly competes for renewable electricity with alternative decarbonisation options, such as the electrification of the industrial, transport, or heating sectors. Due to the rising demand for electricity in these sectors, renewable electricity demand could increase despite the efficiency gains in end-use applications. In the

[32]Unless the hydrogen production facility is sited in a remote location that makes a connection to the power grid prohibitively expensive.

transition to decarbonisation, renewable electricity could therefore become scarce.

According to Dickel (2020), decarbonisation of the electricity sector should be prioritised over hydrogen production, since the direct use of electricity leads to smaller efficiency losses. Therefore, in the medium term, there is a possibility that in some regions, not enough surplus RES capacity will be available to serve the hydrogen market. If ambitious targets for renewable power and hydrogen were to be maintained or set regardless, hydrogen from natural gas would be an obvious medium-term substitution option.

Secondly, we do not consider in-country transportation costs. This may be an issue for seaborne exporters, where good renewable energy potentials are located inland, but terminals have to be sited along the coast. As shown in Section 2.4.3, China is such a case. As a result, the hydrogen supply costs of such exporters are likely underestimated in our analysis. Furthermore, we do not consider costs associated with the storage and distribution of hydrogen to end users in the receiving country. This, however, is an issue for both imports and local production, and should not greatly affect the relative cost differentials between the two.

Lastly, depending on the end-use, it may not always make sense to transport pure hydrogen. Demand for low-carbon hydrogen will also consist of various hydrogen-based energy carriers, such as synthetic gases or fuels. For some of these energy carriers, such as ammonia, there is already a significant demand; for others, demand could rise rapidly in the future (IEA, 2019c). Areas with the lowest production costs are roughly the same for hydrogen and hydrogen-based energy carriers since the feedstocks remain the same. Nevertheless, transportation costs and end-use locations could change, which would impact investment decisions and affect market structures. For example, in Saudi Arabia, an investment decision for a plant that produces ammonia directly from renewable energy has recently been made (Di Paola, 2020). If ammonia is used directly, transportation in the form of the latter is cheaper than in the form of LH_2.

Some of these limitations could be addressed through the following extensions to our analysis:

- A more sophisticated geospatial analysis of each of the 96 countries considered in this chapter, linking renewable energy potentials to elements of a hydrogen production, transmission and distribution infrastructure in a cost-efficient manner, could result in more detailed and robust cost estimates for RES-based hydrogen.

- Integrating the supply cost curves derived in this analysis into an integrated global model of the natural gas and hydrogen markets, which would allow for the derivation of more robust insights on future hydrogen prices, infrastructure developments, exporters and market structures, as well as shed light on the potential interaction between natural gas-based hydrogen production and the global natural gas market.
- Explicitly modelling demand, production and transportation options for hydrogen derivatives (ammonia, methanol etc.) on top of pure hydrogen would allow for a more comprehensive assessment of cost and supply structures.

2.5. Conclusions

In this chapter, we estimate long-term production and supply costs of low-carbon hydrogen from renewable energy sources and natural gas. Costs for hydrogen from renewable energy sources are derived using clustered, country-level data on wind and solar potentials (resource classes), combined with capital cost projections for renewables and low- as well as high-temnperature electrolysers. A linear optimisation model is used to determine optimal combinations of renewable energy sources and electrolyser technologies; the cost-minimising utilisation of the electrolyser is calculated based on country- and renewable energy-specific hourly capacity factor profiles. As an alternative to electrolysis, we also consider the production of hydrogen via natural gas reforming with carbon capture and storage or natural gas pyrolysis. After defining potential transport routes, long-term supply costs of all potential production possibilities are compared in case studies for Germany and Japan to approximate cost-optimal provision schemes. The central findings of the analysis are as follows:

- In terms of production cost, hydrogen from natural gas will most likely have a cost advantage in the medium term, making it the most cost-efficient supply route for the ramp-up of a low-carbon hydrogen market.

- In the long run, the production of hydrogen from renewable electricity could become cost-competitive if renewables and electrolyser capital costs decrease significantly. Under optimistic assumptions, minimum production costs could fall to below $\$1/\mathrm{kg}_{H_2}$ in some regions.
- Country-level supply costs vary significantly between regions. Optimal long-term hydrogen supply choices depend primarily on local conditions, such as domestic renewables potentials, the availability of pipeline infrastructure that can be converted to hydrogen, or local natural gas prices.
- Where possible, retrofitted natural gas pipelines could provide a low-cost opportunity for hydrogen transport, increasing the feasibility of hydrogen trade. Due to the high cost of transporting hydrogen by ship, hydrogen trade will most likely be pipeline-based and thus concentrated regionally.
- The results are sensitive to several assumptions. The most sensitive factors for the levelised cost of hydrogen from renewable electricity are financing costs (weighted average cost of capital) and the investment costs of electrolysers and renewable energy sources. The levelised cost for hydrogen from natural gas is determined mainly by the price of the natural gas feedstock. For natural gas pyrolysis, the potential to sell the solid carbon by-product at a price could further reduce hydrogen production costs.

3. Charting the Development of a Global Market for Low-Carbon Hydrogen

3.1. Introduction

Hydrogen is an essential industrial feedstock produced almost exclusively from fossil fuels today. According to the International Energy Agency (IEA), roughly 75% of global hydrogen production is natural gas-based. The remainder is produced mainly from coal, while less than one per cent is produced through the electrolysis of water. The reliance on unabated fossil fuels makes the production of hydrogen very emission-intensive (IEA, 2019c). At the same time, hydrogen is almost always produced at or very close to the point of consumption, often as an intermediate or by-product of refining or chemical synthesis processes. Therefore, as of today, no true market exists for hydrogen as a commodity.

However, this may change over the next three decades: low-carbon hydrogen—hydrogen the production of which releases little or no CO_2 into the atmosphere—is projected to take on an increasingly important role in a decarbonising global economy, both as an alternative energy carrier and as a feedstock for the production of synthetic fuels and various other industries. Major reports examining decarbonisation pathways for the global energy system (e.g. IRENA (2019b), BP (2020), Shell (2020), IEA (2020a,b, 2021b,c)) all foresee the emergence of substantial demand for low-carbon hydrogen by 2050.

The low-carbon hydrogen production pathways currently seen as most relevant on a global scale are water electrolysis powered by electricity from renewable energy sources (RES) and natural gas reforming (NGR) in combination with carbon capture and utilisation/storage (CCUS) (Brändle et al., 2021, IEA, 2019c, 2020a,b, 2021c).[1] The evolution of the future market for low-carbon hydrogen will thus likely be shaped by the competition between RES- and natural gas-based

[1]Coal gasification with CCUS is also expected to play a role, but at significant scale only in China (IEA, 2019c).

production pathways, as well as the interaction of the latter with the natural gas market.

This chapter addresses the following research question: what role do technology costs and technology choices play in shaping the potential evolution of a future market for low-carbon hydrogen based on natural gas- and RES-based hydrogen production pathways, both spatially and over time?

Methodologically, it applies a new, integrated, partial equilibrium model of the global natural gas and hydrogen markets. A review of the existing, peer-reviewed literature suggests that this model is the first partial equilibrium model in which both the natural gas market and the emerging market for low-carbon hydrogen are simulated together. This is important because it allows for an explicit consideration of the link between the natural gas and the hydrogen market when hydrogen production is natural gas based.

This work joins two distinct literature streams. The first stream is concerned with analysing future supply costs of low-carbon hydrogen based on different production chains, most notably electrolysis using renewable electricity and natural gas reforming (NGR), and the analysis of long-distance trade in hydrogen using pipelines or ships. The second stream involves modelling global energy markets, most notably for natural gas, using partial equilibrium models. Such models commonly comprise a spatially disaggregated representation of the individual players in the upstream (production), midstream (transportation) and downstream (distribution and consumption) segments of the market. They are typically used to analyse market structures, commodity flows and prices.

Several recent publications have assessed low-carbon hydrogen supply costs and potentials on a global scale.

Brändle et al. (2021) estimate production costs of hydrogen from RES and natural gas for 89 countries until 2050, as well as the costs associated with the transport of hydrogen by ship or pipeline from each of these countries to Germany, Japan and the United States. They produce a ranking of suppliers by cost, considering both domestic production and imports. They find that NGR, in combination with carbon capture and storage (CCS), will be the most cost-efficient low-carbon hydrogen production technology in the medium term (2020-2030). However, hydrogen production from RES could become competitive in the long run (2030-2050) if RES and electrolyser investment costs decrease significantly. The cost-optimal long-term hydrogen supply of each country depends on regional characteristics, such as RES potentials and gas prices. Imports are cost-effective where the domestic production potential is small or cost-intensive. Due to the high cost of seaborne transport, hydrogen trade will most likely develop regionally along pipeline networks.

Heuser et al. (2020) perform a techno-economic analysis of a global supply system for RES-based hydrogen. They estimate hydrogen production costs and potentials for selected countries and regions in 2050 and the potential global demand for hydrogen, broken down by region. Production and consumption regions are linked by an infrastructure consisting of pipelines and liquefied hydrogen (LH_2) carriers. The authors also conclude that trade will occur primarily within regional clusters due to the high cost of transporting hydrogen.

Other studies have examined individual supply chains in more detail: Heuser et al. (2019) conceptualise and analyse a potential supply chain for wind-based hydrogen linking Patagonia and Japan using LH_2 carriers. Timmerberg and Kaltschmitt (2019) analyse the possibility of producing RES-based hydrogen in North Africa and blending it into natural gas pipelines to facilitate the early development of hydrogen production in the region and reduce the carbon footprint of Europe's natural gas supply.

Partial equilibrium models of global energy markets are generally used to tackle questions related to the structure of the respective markets, most notably the impact of supply disruptions or the strategic behaviour of suppliers on prices and trade volumes. More recently, such models have also been used to assess the impact of decarbonisation policies on individual commodity markets.

The following papers showcase how partial equilibrium models are applied to analyse market structures, trade flows and price effects on global commodity markets.

Berk and Çam (2020) use a partial equilibrium model to analyse the structure of the global crude oil market for the 2013-2017 period, concluding that while an oligopolistic setup generates model results that are closest to actual market outcomes, low prices point to a reduction in the market power potential of the Organisation of Petroleum Exporting Countries (OPEC), a cartel of 13 oil-exporting countries, in the latter part of the period under investigation.

Schulte and Weiser (2019b) apply a partial equilibrium model of the global gas market to analyse the potential of Turkey to exercise market power as a gas transit hub of the European Union (EU)'s Southern Gas Corridor. Looking ahead to 2030, they find that if the European market is characterised by oligopolistic competition, Turkey will be able to influence European gas market prices by restricting gas transits. If the market is competitive, however, less gas flows along the Southern Gas Corridor in general, limiting the potential of Turkey to exercise market power.

Growitsch et al. (2014) use the same model to study the price and quantity effects of supply shocks on the global natural gas market. Using the potential disruption of LNG flows through the Straits of Hormuz as an example, they find that Japan— entirely dependent on LNG—would be most affected by the price spike, while Europe—more reliant on pipeline gas—would be less affected. They also find that the high interconnectedness of the European pipeline system limits the ability of individual suppliers to increase prices by exercising market power.

Mendelevitch (2018) employs a partial equilibrium model of the global steam coal market to analyse the impact of supply-side measures designed to reduce coal production and consumption.

This chapter integrates the data on the potential future cost of low-carbon hydrogen production and transport published by Brändle et al. (2021) into a partial-equilibrium model of the global natural gas and hydrogen markets. The model, scenarios and key assumptions are presented in Section 3.2. Section 3.3 presents the main results of the model-based analysis, which are discussed in Section 3.4. Section 3.5 concludes the chapter.

3.2. Methodology

The chapter at hand quantifies the potential impact of technology costs and choices on the ramp-up of a global market for low-carbon hydrogen through a scenario analysis using a detailed partial equilibrium model of the global markets for natural gas and low-carbon hydrogen, covering 97 countries. To capture the impact of natural gas-based hydrogen production on the price of natural gas and vice versa, the model fully represents the up- and midstream segments of the global natural gas value chain. It is adapted from COLUMBUS, a partial equilibrium model of the global natural gas market, developed by Hecking and Panke (2012), and subsequently applied in analyses by Growitsch et al. (2014) and Schulte and Weiser (2019b).

3.2.1. Model description

The extended model covers the following stages of natural gas and hydrogen value chains: production, transportation, storage, and consumption. It is formulated as a mixed complementarity problem (MCP).

The time structure of the model is given by a set $t \subset T$ of points in time. For this analysis, an annual resolution was chosen. Spatially, the model is defined by nodes $n \subset N$ connected through arcs $n \rightarrow n1$. Nodes are divided into natural gas and hydrogen production, liquefaction, regasification, and consumption nodes, and the arcs connecting them represent pipelines and LNG/LH$_2$ shipping routes.

The model is populated by different profit-maximising agents: exporters, producers, transmission system operators (TSOs), liquefiers, regasifiers and shippers. Subject to various constraints, they maximise their profits by making optimal decisions with respect to the production, sale and transport of natural gas or hydrogen; and through optimal investments into production and transportation infrastructure.

The respective optimisation problems of the individual agents situated along the natural gas and hydrogen value chains and their corresponding first-order optimality conditions are outlined in the following subsections. The partial equilibrium model is formed by combining the first-order optimality conditions with the market clearing conditions of the respective markets.

The exporter's problem

Exporters $e \in E$ sell natural gas and/or hydrogen $f \in F = \{H_2, NG\}$ to consumers. They are affiliated with at least one natural gas or hydrogen production node $p \in P$. They purchase fuel from associated production nodes and sell ($sell_{e,f,d,t}$) it to consumers located in consumption nodes $d \in D$. The exporter's payoff function is the following:

$$\begin{aligned}
&\max_{sell_{e,f,d,t}} \prod_{eI}(sell_{e,f,d,t}) \\
&= \sum_t \sum_d \Big((1 - cv_e) * \beta_{f,d,t} + cv_e * \beta_{f,d,t}(\sum_e sell_{e,f,d,t}) - \lambda_{e,f,d,t}\Big) * sell_{e,f,d,t}, \\
&sell_{e,f,d,t} \geq 0
\end{aligned} \tag{3.1}$$

where $\lambda_{e,f,d,t}$ corresponds to the cost associated with production and delivery of the respective fuel f to a consumption node d and $\beta_{f,d,t}$ is the market price for fuel f at consumption node d. The conjectural variation parameter cv_e determines whether an exporter can exert market power or behaves as a price taker. If $cv_e = 1$, the exporter faces a linear inverse demand function and thus implicitly considers the impact of its own sales and those of others on the market price $\beta_{f,d,t}$. Otherwise, if $cv_e = 0$, it observes market price directly and behaves as a price taker.

Long-term contracts (LTCs) play an important role in determining trade flows in the natural gas market. They are modelled as a constraint, which ensures that an exporter's sales to consumers with which a long-term contract is in place are always equal or greater than the contractually defined minimum delivery obligation ($mdo_{e,f,d,t}$):

$$\sum_t sell_{e,f,d,t} - mdo_{e,f,d,t} \geq 0 \qquad \forall\ e, f, d, t \qquad (\chi_{e,f,d,t}) \tag{3.2}$$

The first-order optimality condition of the exporter's profit maximisation problem is defined by the first partial derivative of the Lagrangian $\mathcal{L}_{eI}$ with respect to the variable $sell_{e,f,d,t}$:

$$\begin{aligned} -\beta_{f,d,t} + (cv_e + 1) * \text{slope}_{f,d,t} * sell_{e,f,d,t} - \chi_{e,f,d,t} + \lambda_{e,f,d,t} \geq 0 \\ \perp \quad sell_{e,f,d,t} \geq 0 \qquad \forall\ e, f, d, t. \end{aligned} \tag{3.3}$$

Sales have to be matched by actual physical deliveries of natural gas or hydrogen. This is modelled as a separate optimisation problem:

$$\begin{aligned} &\max_{flow_{e,f,n,n1,t}} \prod_{eII}(flow_{e,f,n,n1,t}) \\ &= \sum_t (\lambda_{e,f,n1,t} - \lambda_{e,f,n,t} - varcost^{tra}_{f,n,n1,t} - varcost^{tra}_{f,r,t}) * flow_{e,f,n,n1,t} \end{aligned} \tag{3.4}$$

Exporters choose the least-cost supply route ($flow_{e,f,n,n1,t}$) to fulfil their delivery obligation, where $\lambda_{e,f,n,t}$ is the marginal cost of gas supplied by exporter s to node n and $\lambda_{e,f,n1,t}$ is the marginal cost of gas or hydrogen delivered by s to node $n1$. $varcost^{tra}_{f,r,t}$ is the cost of regasifying a unit of natural gas or hydrogen if n is a regasification node $[r(n)]$, while $varcost^{tra}_{f,n,n1,t}$ is the short-run marginal cost of transporting natural gas or hydrogen from node n to node $n1$. If $n1$ is a liquefaction node $[l(n1)]$, $varcost^{tra}_{f,n,l,t}$ is equivalent to the short-run marginal cost of liquefying the commodity. If n and $n1$ are connected by pipeline, $varcost^{tra}_{f,n,n1,t}$ denotes the short-run marginal cost of pipeline deliveries. Finally, if the node pair are a liquefaction node $[l(n)]$ and a regasification node $[r(n1)]$, $varcost^{tra}_{f,l,r,t}$ expresses the short-run marginal cost of transporting the respective commodity f by tanker.

The transportation problem expressed in Equation 3.4 is subject to physical capacity constraints. Equation 3.5 describes the pipeline capacity constraint, with total pipeline capacity given by the sum of exogenous capacity ($cap^{pipe}_{f,n,n1,t}$) and additional, endogenous investments ($inv^{pipe}_{f,n,n1,t}$):

$$cap^{pipe}_{f,n,n1,t} + inv^{pipe}_{f,n,n1,t} - \sum_{e} flow_{e,f,n,n1,t} \geq 0 \qquad \forall\ f, n, n1, t \qquad (\phi_{f,n,n1,t}) \tag{3.5}$$

Equations 3.6, 3.7 and 3.8 outline the liquefaction, regasification and shipping capacity constraints, respectively. The maximum available shipping capacity on a given route is derived taking into account the average capacity of an LNG or LH_2 tanker (cap^{ship}_{f}), the number of vessels invested in ($inv^{ship}_{f,t}$), their average speed in km/h ($speed$) and the round-trip distance ($dist_{l,r}$).

$$cap^{liq}_{f,l,t} + inv^{liq}_{f,l,t} - \sum_{e}\sum_{n} flow_{e,f,n,l,t} \geq 0 \qquad \forall\ f, l, t \qquad (\zeta_{f,l,t}) \tag{3.6}$$

$$cap^{reg}_{f,r,t} + inv^{reg}_{f,r,t} - \sum_{e}\sum_{d} flow_{e,f,r,d,t} \geq 0 \qquad \forall\ f, r, t \qquad (\gamma_{f,r,t}) \tag{3.7}$$

$$\begin{aligned} &\left(cap^{ship}_{f} * inv^{ship}_{f,t}\right) * 8760/12 * speed \\ &- \sum_{e}\sum_{l}\sum_{r} 2 * (flow_{e,f,l,r,t} * dist_{l,r}) \geq 0 \qquad \forall\ f, t \qquad (\iota_{f,t}) \end{aligned} \tag{3.8}$$

The associated first-order condition of the transportation problem defined in Equation 3.4 is derived by taking the first partial derivative of the Lagrangian $\mathcal{L}_{eII}$ with respect to the variable $flow_{e,f,n,n1,t}$:

$$\begin{aligned}
&-\lambda_{e,f,n1,t} + \lambda_{e,f,n,t} + varcost^{tra}_{f,n,n1,t} + varcost^{tra}_{f,r,t} + \phi_{f,n,n1,t} \\
&+ \zeta_{f,l,t} + \gamma_{f,r,t} + \iota_{f,t} * 2 * dist_{l,r} \geq 0 \quad \perp \quad flow_{e,f,n,n1,t} \geq 0 \qquad \forall \; e, f, n, n1, t.
\end{aligned} \tag{3.9}$$

The producer's problem

Producers operate a single production node $p \in P$ and maximise their profits by selling natural gas or hydrogen to their affiliated exporter e. They act as price takers, which means that, in essence, a producer and an exporter together behave like a single, vertically integrated firm. The producer payoff functions differ slightly depending on the fuel that is produced and—in the case of hydrogen—the production pathway that is chosen.

Natural gas production is modelled as a piecewise linear supply function with $c \subset C$ cost steps, which reflects the short-run marginal cost of existing production and the long-run marginal cost of prospective developments. The producer payoff function for natural gas is given by Equation 3.10, where $\lambda_{e,NG,p,t}$ is the marginal value of gas in production node p, $prod_{NG,c,p,t}$ is the production volume of natural gas and $varcost^{prod}_{NG,p,c,t}$ the marginal production cost:

$$\begin{aligned}
&\max_{prod_{NG,p,c,t}} \prod_{pI} (prod_{NG,p,c,t}) \\
&= \sum_{t} \sum_{c} (\lambda_{e,NG,p,t} * prod_{NG,c,p,t} - varcost^{prod}_{NG,p,c,t} * prod_{NG,p,c,t})
\end{aligned} \tag{3.10}$$

Equation 3.11 describes the payoff function of hydrogen producers. The model considers both RES- and natural gas-based low-carbon hydrogen production pathways. For hydrogen, investment decisions are modelled explicitly. Producers can therefore invest into additional production capacity ($inv^{prod}_{H2,p,c,t}$), incurring investment costs ($invcost^{prod}_{H2,p,c,t}$). Here, $c \subset C$ stands for different hydrogen production pathways. The term $purch_{p,t} * \beta_{NG,p,t}$ is specific to natural gas-based hydrogen production and expresses the opportunity cost of purchasing natural gas for hydrogen production, with $\beta_{NG,p,t}$ denoting the price of natural gas in the respective production node:

$$
\begin{aligned}
&\max_{\substack{prod_{H2,p,c,t}\\ inv^{prod}_{H2,p,c,t}}} \prod_{pII}(prod_{H2,p,c,t}, inv^{prod}_{H2,p,c,t})\\
&= \sum_t \sum_c (\lambda_{e,H2,p,t} * prod_{H2,c,p,t} - varcost^{prod}_{H2,p,c,t}\\
&* prod_{H2,p,c,t} - purch_{p,t} * \beta_{NG,p,t})\\
&+ \sum_t \sum_c (invcost^{prod}_{H2,p,c,t} * inv^{prod}_{H2,p,c,t})
\end{aligned}
\tag{3.11}
$$

The producers are subject to capacity and—in the case of RES-based hydrogen—availability constraints. Natural gas production is limited to the maximum production capacity ($cap^{prod}_{NG,p,c,t}$) of the respective cost step c (Equation 3.12).

$$
cap^{prod}_{NG,p,c,t} - prod_{NG,c,p,t} \geq 0 \qquad \forall\ p, c, t \qquad (\mu_{NG,p,c,t}) \tag{3.12}
$$

Hydrogen production is limited by the installed capacity, including endogenous investments ($cap^{prod}_{NG,p,c,t} + inv^{prod}_{H2,p,c,t}$). RES-based hydrogen production is further constrained by the capacity factor ($cf^{prod}_{H2,c,p,t}$) of the respective renewable energy source (Equation 3.13). The capacity factors are calculated for cost-optimal combinations of a renewable energy source and an electrolyser, taking into account the full cost of both components and differences in the quality and variability of the RES in the 89 countries covered by the model. A detailed description of the underlying methodology and estimates is provided in Brändle et al. (2021).

$$
(cap^{prod}_{H2,p,c,t} + inv^{prod}_{H2,p,c,t}) * cf^{prod}_{H2,c,p,t} - prod_{H2,c,p,t} \geq 0 \qquad \forall\ p, c, t \qquad (\mu_{H2,p,c,t}) \tag{3.13}
$$

As shown in Equation 3.14, natural gas-based hydrogen production technologies [$ngb(c)$] are further constrained by the amount of natural gas purchased for hydrogen production ($purch_{p,ngb,t}$) in the respective production node p, which must be equal or greater than the amount of hydrogen produced ($prod_{H2,p,ngb,t}$), divided by the process efficiency ($eff^{prod}_{H2,p,ngb,t}$).

$$purch_{p,ngb,t} - \frac{prod_{H2,p,ngb,t}}{eff^{prod}_{H2,p,ngb,t}} \geq 0 \qquad \forall \ p, ngb \subset C, t \qquad (\omega_{p,ngb,t}) \tag{3.14}$$

The first-order optimality condition of the natural gas producer's maximisation problem (Equation 3.10) is given by the partial derivative of the Lagrangian $\mathcal{L}_{pI}$ with respect to the variable $prod_{NG,p,c,t}$:

$$-\lambda_{e,NG,p,t} + varcost^{prod}_{NG,p,c,t} + \mu_{NG,p,c,t} \geq 0 \quad \perp \quad prod_{NG,p,c,t} \geq 0 \qquad \forall \ f, p, c, t \tag{3.15}$$

Finally, the first-order conditions of the hydrogen producer's maximisation problem (Equation 3.11) are derived by taking the partial derivatives of the Lagrangian $\mathcal{L}_{pI}$ with respect to the variables $prod_{H2,p,c,t}$, $purch_{p,t}$ and $inv^{prod}_{H2,p,c,t}$:

$$\begin{aligned} -\lambda_{e,H2,p,t} + varcost^{prod}_{H2,p,c,t} + \mu_{H2,p,c,t} + \omega_{p,t} \geq 0 \\ \perp \quad prod_{H2,p,c,t} \geq 0 \qquad \forall \ f, p, c, t \end{aligned} \tag{3.16}$$

$$-\omega_{p,ngb,t} + \beta_{NG,p,t} \geq 0 \quad \perp \quad purch_{p,ngb,t} \geq 0 \qquad \forall \ f, p, t \tag{3.17}$$

$$invcost^{prod}_{H2,p,c,t} - \mu_{H2,p,c,t} \geq 0 \quad \perp \quad inv^{prod}_{H2,p,c,t} \geq 0 \qquad \forall \ p, c, y \tag{3.18}$$

The transmission system operator's problem

TSOs are players that control pipeline arcs ($n \rightarrow n1$). They allocate transmission capacity to exporters and are in turn compensated for the short-run marginal cost of transmission ($varcost^{tra}_{f,n,n1,t}$)[2] and the congestion rent ($\phi_{f,n,n1,t}$), which is determined by the transmission capacity constraint (Equation 3.5). TSOs invest in additional pipeline capacity if the long-run marginal cost of transmission expansion is less than the congestion rent. Their payoff function is as follows:

[2]Which thus cancels out in the payoff function.

$$\max_{inv^{pipe}_{f,n,n1,t}} \prod_{TSO}(inv^{pipe}_{f,n,n1,t}) = \sum_t \left[\phi_{f,n,n1,t} * (cap^{pipe}_{f,n,n1,t} + inv^{pipe}_{f,n,n1,t})\right] - inv^{pipe}_{f,n,n1,t} * invcost^{pipe}_{f,n,n1,t} \tag{3.19}$$

Taking the partial derivative of the Lagrangian $\mathcal{L}_{TSO}$ with respect to the variable $inv^{pipe}_{f,n,n1,t}$ yields the first-order optimality condition:

$$invcost^{pipe}_{f,n,n1,t} - \phi_{f,n,n1,t} \geq 0 \quad \perp \quad inv^{pipe}_{f,n,n1,t} \geq 0 \qquad \forall\ f,n,n1,t. \tag{3.20}$$

The liquefier's problem

Liquefiers (l) receive natural gas or hydrogen and liquefy it. They allocate liquefaction capacity to exporters and in exchange for the short-run liquefaction cost ($varcost^{tra}_{f,n,l,t}$) and the congestion rent ($\zeta_{f,l,t}$). The congestion rent is determined by the liquefaction capacity constraint (Equation 3.6). They maximise their payoff in accordance with Equation 3.21:

$$\max_{inv^{liq}_{f,l,t}} \prod_l(inv^{liq}_{f,l,t}) = \sum_t \left[\zeta_{f,l,t} * (cap^{liq}_{f,l,t} + inv^{liq}_{f,l,t})\right] - inv^{liq}_{f,l,t} * invcost^{liq}_{f,l,t} \tag{3.21}$$

Their first-order optimality condition is:

$$invcost^{liq}_{f,l,t} - \zeta_{f,l,t} \geq 0 \quad \perp \quad inv^{liq}_{f,l,t} \geq 0 \qquad \forall\ f,l,t. \tag{3.22}$$

The regasifier's problem

Regasifiers (r) receive LNG or LH_2 and regasify it. They allocate regasification capacity to exporters, who pay for the short-run regasification cost ($varcost^{tra}_{f,r,t}$) and the congestion rent ($\gamma_{f,r,t}$). The congestion rent is determined by the regasification capacity constraint (Equation 3.7). Their payoff function is described by Equation 3.23:

$$\max_{inv^{reg}_{f,r,t}} \prod_r (inv^{reg}_{f,r,t}) = \sum_t \left[\gamma_{f,r,t} * (cap^{reg}_{f,r,t} + inv^{reg}_{f,r,t}) \right] - inv^{reg}_{f,r,t} * invcost^{reg}_{f,r,t} \quad (3.23)$$

Their first-order optimality condition is:

$$invcost^{reg}_{f,r,t} - \gamma_{f,r,t} \geq 0 \quad \perp \quad inv^{reg}_{f,r,t} \geq 0 \qquad \forall \ f, r, t. \quad (3.24)$$

The shipper's problem

The market for LNG or LH_2 shipping capacity is modelled as a single player (the shipper) who behaves competitively. The shipper allocates shipping capacity to exporters, passing on operating costs ($varcost^{tra}_{f,l,r,t}$) and congestion rent ($\iota_{f,t}$). The shipper invests into additional shipping capacity until the associated long-run marginal cost exceeds the congestion rent, which is determined by the shipping capacity constraint (Equation 3.8). Its payoff function is given by Equation 3.25:

$$\begin{aligned} &\max_{inv^{ship}_{f,t}} \prod_{LNG} (inv^{ship}_{f,t}) \\ &= \sum_t \left[\iota_{f,t} * 8760/12 * speed * (cap^{ship}_f * inv^{ship}_{f,t}) \right] - inv^{ship}_{f,t} * invcost^{ship}_{f,t} \end{aligned} \quad (3.25)$$

The first-order optimality condition is derived by taking the partial derivative of Lagrangian $\mathcal{L}_{LNG}$ with respect to $inv^{ship}_{f,t}$:

$$invcost^{ship}_{f,t} - \iota_{f,t} * 8760/12 * speed \geq 0 \quad \perp \quad inv^{ship}_{f,t} \geq 0 \qquad \forall \ f, t. \quad (3.26)$$

Market clearing conditions

The first-order optimality conditions of the individual optimisation problems described above and the following market-clearing conditions comprise the partial equilibrium model.

Equation 3.27 ensures that trades ($sell_{e,f,d,t}$) are matched by production and/or net inflows:

$$\sum_{c} prod_{f,p,c,t} - sell_{e,f,d,t} + \sum_{n1 \in (n1,n)} flow_{e,f,n1,n,t} - \sum_{n1 \in (n,n1)} flow_{e,f,n,n1,t} = 0$$
$$\perp \quad \lambda_{e,f,n,t} \quad \text{free} \qquad \forall \; e,f,n,t. \tag{3.27}$$

Equations 3.28 (for natural gas) and 3.29 (for hydrogen) assure that aggregate sales ($sell_{e,f,n,t}$) match demand ($dem_{f,d,t}$) and, in the case of natural gas, gas purchases for hydrogen production ($purch_{p,t}$). The dual variable ($\beta_{f,n,t}$) can be interpreted as the market price of the respective fuel:

$$\sum_{e} sell_{e,NG,d,t} - dem_{NG,d,t} - \sum_{ngb \in (C)} purch_{p,ngb,t} = 0$$
$$\perp \quad \beta_{NG,d,t} \quad \text{free} \qquad \forall \; f,d,t. \tag{3.28}$$

$$\sum_{e} sell_{e,H2,d,t} - dem_{H2,d,t} = 0 \quad \perp \quad \beta_{H2,d,t} \quad \text{free} \qquad \forall \; f,d,t. \tag{3.29}$$

3.2.2. Scenarios and assumptions

The scenarios underpinning the analysis are adapted from the IEA's Sustainable Development Scenario (SDS) (IEA, 2019e, 2020a,b), supplemented by additional assumptions on the distribution of the aggregated natural gas and hydrogen demand estimates provided by the IEA to the individual countries covered by the model. The SDS's natural gas and hydrogen demand trajectories postulate rapid decarbonisation of the global economy, reaching net-zero emissions globally by 2070.

The model simulates RES-, natural gas-, and coal-based low-carbon hydrogen production pathways: electrolysis using electricity from either onshore wind, offshore wind, or solar PV (RES-based), NGR+CCUS (natural gas-based) and coal gasification (CG)+CCUS (coal-based).[3] CG+CCUS is considered as an

[3]Pyrolysis, an alternative natural gas-based low-carbon hydrogen production technology, is not considered because of the high uncertainty surrounding cost estimates and expected availability at scale compared to NGR+CCUS. Furthermore, this analysis focuses on evaluating the impact of the fundamental choice between RES-based or natural gas-based hydrogen in general, rather than comparing individual, natural gas-based processes.

option for China specifically[4], which operates more than 80% of the world's coal gasification capacity today, making it by far the world's largest producer of hydrogen from coal (IEA, 2019c).

Four scenarios are simulated, analysed, and compared to assess the impact of supply technology choices and costs on structures and prices on the emerging market for low-carbon hydrogen.

In the first two scenarios (labelled *open transition* [OPT]), the different hydrogen production technologies compete solely based on their levelised cost of production in all modelled regions. In the *OPT (central)* scenario, the future decline in RES and electrolyser investment costs follows the central trajectory presented in Brändle et al. (2021)[5], while in the *OPT (optimistic)* scenario, the assumed cost decline corresponds to the optimistic projection. Investment costs and efficiencies for NGR+CCUS and CG+CCUS do not vary between the scenarios.

In the third and fourth scenario, a so-called green transition (GRT), where RES-based production technologies dominate the global low-carbon hydrogen supply mix from the beginning as a matter of policy choice, is modelled. In the *GRT (central)* scenario, the future decline in RES and electrolyser investment costs follows the central trajectory, while in the *GRT (optimistic)* scenario, the assumed cost decline corresponds to the optimistic projection.

In all scenarios, natural gas and hydrogen markets are assumed to be perfectly competitive.

The four scenarios represent extreme cases, and either one is highly unlikely to describe how the global low-carbon hydrogen market will develop in reality. The purpose of the scenarios is not to sketch out "best estimate" development pathways that consider regional political and commercial specificities but to

[4]In the future, China is likely to keep using the technology—with the addition of CCUS—to meet some of its future low-carbon hydrogen requirements, while coal production is projected to decline substantially or be phased-out entirely in most other parts of the world (IEA, 2020a,b).

[5]Brändle et al. (2021) provide detailed, disaggregated information on RES potentials and costs for the countries represented in the model. There are two cost cases for RES-based hydrogen: in the central case, RES and electrolyser costs decline. In locations with above-average onshore wind or PV conditions, the levelised cost of hydrogen drops to around \$2/kg by 2050. In the optimistic case, higher RES investment cost reductions are achieved, in particular for solar PV, and levelised hydrogen production costs dip to \$1/kg in locations with good solar potentials.

assess the impact of technology costs and fundamental choices regarding production pathways on the nascent market for low-carbon hydrogen.

The key differences between the scenarios are summarised in Table 3.1.

Table 3.1.: Scenarios

	OPT (central)	**OPT (optimistic)**	**GRT (central)**	**GRT (optimistic)**
RES/electrolyser cost case	central	optimistic	central	optimistic
NGR+CCUS	available	available	unavailable	unavailable
CG+CCUS	available	available	unavailable	unavailable

Identical low-carbon hydrogen demand, natural gas demand and CO_2 price trajectories are assumed for all four scenarios. The consumption pathways are based on the IEA SDS and, therefore, consistent with a global transition to net-zero emissions by 2070 (IEA, 2020a,b).

Global natural gas demand (excluding consumption to produce low-carbon hydrogen, which is determined endogenously by the model) continues to grow to 3945 bcm in 2030 before declining to 3285 bcm in 2040 and 2534 bcm in 2050 as a result of the pressure to decarbonise.

Global demand for low-carbon hydrogen is projected to rise from 35 Mt in 2030 to 102 Mt in 2040 and 258 Mt in 2050. In 2050, 37% of the low-carbon hydrogen is consumed in the transport sector[6] 34% in industry[7] and 10% in buildings. The remaining 19% are consumed in other sectors, in particular, the power sector, where hydrogen provides an essential source of backup power for intermittent RES (IEA, 2020a).

Figure 3.1 shows the assumed development of the global demand for low-carbon hydrogen, broken down by region.

Detailed information on the data used and the assumptions made to derive the aforementioned low-carbon hydrogen and natural gas demand trajectories is provided in B.1.

As mentioned above, data on current and future investment costs, operating costs, and the conversion efficiencies of RES- and natural gas-based hydrogen production technologies is taken from a comprehensive global assessment of low-carbon hydrogen production costs published by Brändle et al. (2021). Investment

[6]Including hydrogen used for the production of synthetic fuels.
[7]Including hydrogen used in refining and for the production of low-carbon ammonia.

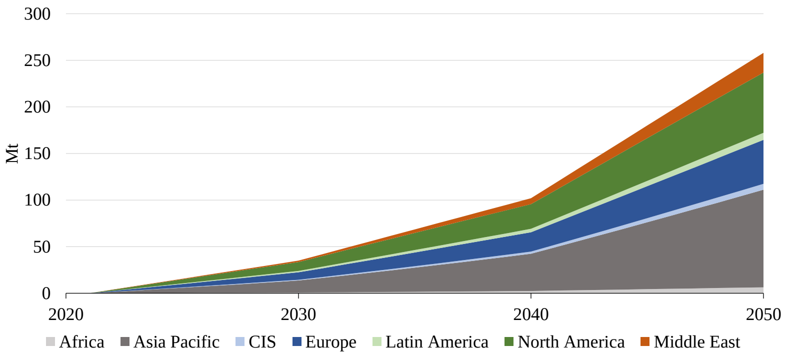


Figure 3.1.: Assumed annual demand for low-carbon hydrogen

costs, operating costs and conversion efficiencies for CG+CCUS in China are obtained from IEA (2019c, p. 51).[8]

For NGR+CCUS and CG+CCUS, the cost of transporting and storing CO_2 underground is an important cost component. Country-level CO_2 storage cost assumptions (see Table B.1) are based on CO_2 transport costs and reservoir-specific storage costs provided by Roussanaly et al. (2014) and Rubin et al. (2015b).[9]. NGR+CCUS and CG+CCUS are assumed to have a CO_2 capture efficiency of 90%. The residual emissions are subject to the local CO_2 price.[10]

The direct decarbonisation of the power sector generally represents a more cost-efficient use of RES-based electricity than hydrogen production (Dickel, 2020). For this analysis, it is assumed that the highest quality RES potentials are developed first and employed to decarbonise the direct use of electricity,

[8]The weighted average cost of capital (WACC) plays an important role in shaping the economics of capital-intensive production technologies. A WACC of 8% is assumed to apply to investments into hydrogen production and liquefaction infrastructure. A WACC of 5% is assumed to apply to investments into hydrogen regasification and transmission (pipeline) infrastructure.

[9]Potential limitations to the underground storage of CO_2 in certain areas are not considered. In some cases, nearby reservoirs may not be readily available, and the CO_2 would have to be transported over greater distances to suitable disposal sites, increasing the associated cost. However, as shown by Brändle et al. (2021), the impact of an escalation in the cost of CO_2 transport and storage on the levelised cost of hydrogen produced by NGR+CCUS is relatively low.

[10]In reality, CO_2 prices would likely vary from scenario to scenario, in particular, if hydrogen or hydrogen-based technologies are the marginal abatement option. However, since this link cannot be captured by the partial equilibrium model used for this study, an exogenous global CO_2 price, based on IEA (2019c) and IEA (2020b), is assumed instead. It increases from \$89/tCO_2 in 2030 to \$165/tCO_2 in 2050 in advanced economies and \$70/tCO_2 in 2030 to \$145/tCO_2 in 2050 in less advanced economies in all four scenarios.

which is itself projected to increase substantially in the SDS (IEA, 2020b). This reduces the potential available for hydrogen production.

The scale of RES expansion in a given country thus becomes an important constraint on the potential domestic supply of RES-based hydrogen. IEA (2020b) and IEA (2019b) provide installed PV and wind energy capacities for regions and selected countries in the SDS until 2040. For the 2040 to 2050 period, a continuation of the linear trend observed between 2030 and 2040 is assumed. Unless provided directly, regional figures are allocated to individual countries based on their 2018 share in the respective region's total RES capacity (IRENA, 2020b). To determine the residual RES potentials available for hydrogen production in the model, the 2050 capacities thus derived are deducted from the theoretical, country-level RES capacity potentials found in (Brändle et al., 2021), assuming that the best potentials are generally developed first.[11]

For NGR+CCUS and CG+CCUS, the cost of transporting and storing CO_2 underground is an important cost component. Since geological formations that permit the large-scale storage of CO_2 underground are ubiquitous and dispersed globally (Baines et al., 2020, Consoli, 2016), it is assumed that suitable reservoirs (depleted oil and gas fields and/or saline aquifers) are available in all countries represented in the model. Country-level costs associated with the transportation and storage of CO_2 captured when producing low-carbon hydrogen via natural gas reforming are estimated based on Roussanaly et al. (2014) and Rubin et al. (2015b), taking country specificities into account. These include the availability of depleted oil/gas fields and whether suitable storage sites are located onshore or offshore. More details can be found in B.1.

For the land-based transport of hydrogen, pipelines are considered the lowest cost technology to transport significant volumes of hydrogen over large distances. Projected investment and operating costs for new, dedicated hydrogen pipelines are sourced from Brändle et al. (2021).[12]

[11] This represents a conservative assessment of the available potential since some of the RES capacity assumed to be installed by 2050 in the IEA SDS is already for hydrogen production.

[12] Brändle et al. (2021) assume the specific cost for the transmission of hydrogen through new, large-scale, dedicated hydrogen pipelines to fall to \$240 per tonne of H_2 per 1000 km by 2030.

Seaborne transport is assumed to be based on liquid hydrogen, as it could potentially be the lowest-cost shipping solution in the long run if the desired end product is pure hydrogen.[13]

For the seaborne transport of hydrogen, we model an infrastructure consisting of hydrogen liquefaction terminals, liquid hydrogen (LH_2) tankers and regasification terminals, with projected investment and operating costs of all three elements sourced from Brändle et al. (2021).

Natural gas production is modelled as a piecewise linear supply function. Country-specific natural gas supply curves are built from granular, field-level cost and capacity data provided by Rystad Energy (2020).

Existing cross-border natural gas pipeline capacities are obtained from an in-house database maintained by the Institute of Energy Economics at the University of Cologne. LNG liquefaction/regasification capacities (existing and sanctioned) are sourced from IGU (2021). Current long-term contracts (LTCs) for pipeline gas and LNG are also modelled, with contract volumes and durations obtained from Rystad Energy (2020). Existing LTCs are assumed not to be renewed after expiry. Investment costs for natural gas pipelines and LNG infrastructure come from various sources, including company reports and publications by the Oxford Institute for Energy Studies (Songhurst, 2018, Steuer, 2020).

3.3. Results

The main results of the model-based analysis of the four scenarios, focusing on the global hydrogen supply technology mix, the market's spatial structure, and the resulting price levels, are presented below.

3.3.1. Global hydrogen supply mix

In the *OPT (central)* scenario, where RES and electrolyser investment costs follow the central trajectory described in Brändle et al. (2021) and hydrogen production

[13] In the medium term, the conversion to ammonia is likely to be the cheapest way of transporting hydrogen by sea, in particular, because existing port infrastructure and LPG tankers could be used for this purpose. However, expenditures and energy losses associated with the process of cracking ammonia to obtain hydrogen impose additional costs (IEA, 2019c). Some studies show LH_2 to potentially yield a lower cost in the long run, provided the technology improves further and economies of scale are harnessed (Brändle et al., 2021).

technologies compete only based on cost, fossil fuel-based hydrogen production remains the dominant pathway to 2050 (Figure 3.2). Since hydrogen production is overwhelmingly natural gas-based, it becomes a significant consumer of natural gas relative to other sectors, accounting for 10% of global natural gas consumption in 2030 and 30% in 2050 (Figure B.3 in B.2). Nevertheless, total natural gas demand stagnates due to declining consumption in other sectors of the economy, and natural gas prices are low by historical standards in most major consumption regions (Figure B.4 in B.2). The low gas price environment explains the persistent competitive edge of natural gas over RES-based hydrogen production in this scenario.

In the *OPT (optimistic)* scenario, RES and electrolyser investment costs follow the optimistic trajectory set out in Brändle et al. (2021). In this scenario, RES and electrolyser costs decline sufficiently to make the production of low-carbon hydrogen using electrolysis—especially when paired with solar PV—the most economical choice in several regions, especially after 2040. In 2050, more than a third of global hydrogen production is RES-based (Figure 3.2). Figure 3.3 displays the share of RES-based hydrogen production in the hydrogen production technology mix of each modelled country in the year 2050. It shows that RES-based hydrogen production is concentrated in regions with good solar energy potentials, such as the Middle East and North Africa, southern Europe and South America. RES-based low-carbon hydrogen also plays a role in regions with comparatively high gas prices, including China and Southeast Asia. In other regions, however, low natural gas prices, less favourable available RES potentials or a combination of both allow natural gas-based hydrogen production to retain its competitiveness even in the long run. The upshot is that even in this scenario, natural gas-based hydrogen production is a major user of natural gas, accounting for 22% of global gas consumption in 2050 (Figure B.3).

In the *GRT (central)* and *GRT (optimistic)* scenarios, the development of global low-carbon hydrogen production is fully RES-based from the beginning due to an assumed global preference for RES-based hydrogen. In both the central and the optimistic cost cases, electrolysis powered by PV-based electricity becomes the dominant production pathway, accounting for, respectively, 90% and 95% of global low-carbon hydrogen production in 2050. In the central cost case, by comparison, the share of hydrogen production based on wind energy is slightly greater since it is cost-competitive in regions with good wind but poor solar resources, such as northwestern Europe.[14]

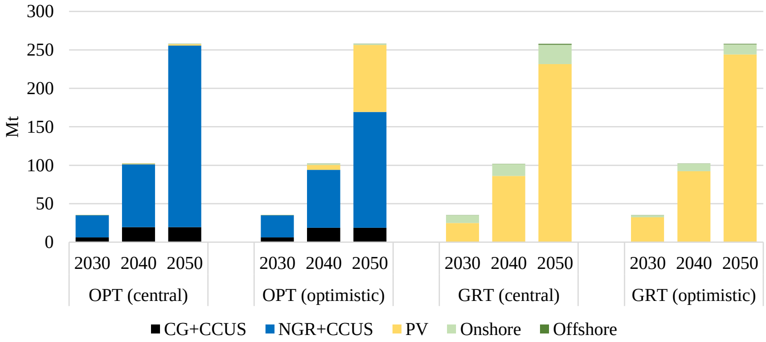


Figure 3.2.: Global low-carbon hydrogen production by pathway

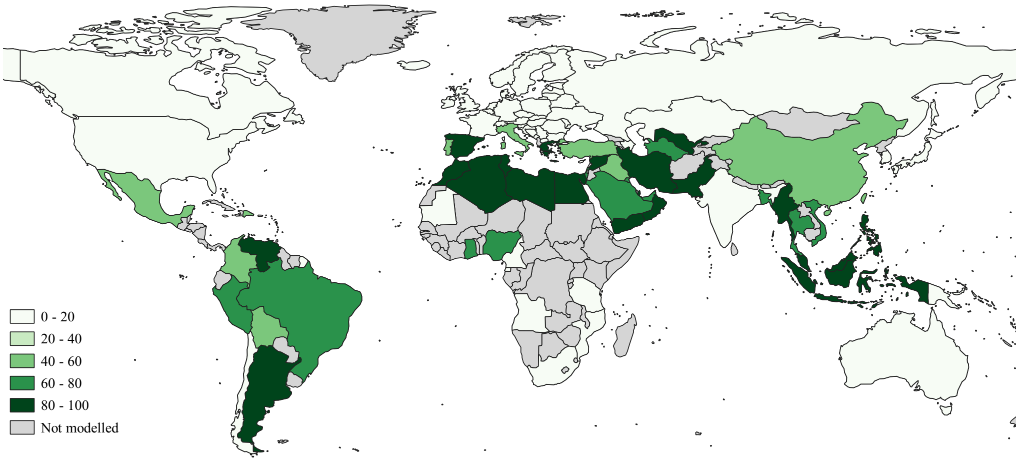


Figure 3.3.: Share of RES-based hydrogen production in the OPT (optimistic) scenario in 2050, by country (in %)

A comparison of the scenarios illustrates the potential impact of a substantial increase in natural gas-based low-carbon hydrogen production on the natural gas market. Figure B.4 displays the modelled natural gas prices for major consumers by scenario. It shows that the additional demand from natural gas-based hydrogen production contributes to a stabilisation of gas prices over the 2030-2050 period in the *OPT (central)* and *OPT (optimistic)* scenarios. In

[14]The strong performance of PV-based hydrogen relative to wind after 2030 is due to the assumed investment cost reduction trajectories for solar PV and onshore/offshore wind energy. A less pronounced decline in PV investment costs, or a steeper fall in the cost of onshore or offshore wind energy, would lead to higher shares of wind-based hydrogen production in the global supply mix.

GRT scenarios by contrast, natural gas demand declines more steeply (see Figure B.3), causing prices to fall further as well.

3.3.2. Spatial structure of the market

The low-carbon hydrogen market simulated in the *OPT (central)* and, to a lesser degree, the *OPT (optimistic)* scenarios, is essentially an adjunct to the natural gas market. Due to a higher volumetric energy density and existing infrastructure, natural gas is less costly to transport than hydrogen. As a result, natural gas-based low-carbon hydrogen is always produced in the country where it is also consumed.

In the *OPT (optimistic)* scenario, around 33% of global hydrogen production is RES-based in 2050. Differences in the quality of RES potentials between countries and regions are significant enough to make the long-distance transmission of RES-based hydrogen an economically viable option in several cases. In 2050, 4% of the hydrogen produced is traded across international borders, all of it via pipeline.

In the *GRT (central)* and *GRT (optimistic)* scenarios, by contrast, a significant fraction of the low-carbon hydrogen produced is traded across international borders, since production cost gaps between countries with low-cost RES potentials and countries with less favourable RES potentials located in the same general region are wide enough to make trade economical.

Trade is based almost exclusively on hydrogen pipelines. Although the model permits the seaborne transportation of liquid hydrogen in all scenarios, due to its high cost, it is only relevant in the *GRT (central)* and *GRT (optimistic)* scenarios, and only in the case of Japan.[15]

Most of the cross-border trade in hydrogen takes place in Europe. Cross-border flows into and inside Europe account for 98% of the total international trade in pure hydrogen in 2050 in the *GRT (central)* and 94% in the *GRT (optimistic)* scenario. Figure 3.4 displays the modelled hydrogen pipeline flows and national hydrogen prices in Europe and the vicinity in the *GRT (central)* scenario. 78% of the pure hydrogen consumed in Europe in 2050 is imported from outside the region, with 20.7 Mt supplied by Morocco, 12.1 Mt by Algeria and 2.4 Mt

[15]Due to the high cost of domestic RES-based hydrogen production and the lack of pipeline-based import options, Japan sources 64% of the hydrogen it consumes in the form of liquid hydrogen imports from Oman in 2050 in the *GRT (central)* scenario. The production cost gap between Japan and Oman is wide enough to offset the cost of liquefying, shipping and regasifying the hydrogen plus the associated infrastructure cost.

sourced from Iran. Within Europe, hydrogen flows from south to north, with Spain, France and Italy transiting substantial volumes destined for northwestern Europe. Hydrogen production in Europe itself amounts to only 10.4 Mt in the *GRT (central)* scenario, consisting mainly of PV-based production in Spain and Onshore wind-based production in Scandinavia.

Countries are mostly self-sufficient in hydrogen in the rest of the world, even in the GTR scenarios. However, there is substantial long-distance pipeline transmission in large countries such as China, Russia or the United States that are modelled as multiple nodes. The pipelines link more remote areas with good RES potentials, such as Western China, Southwestern Russia or the Southwestern United States, to consumption centres in the same countries.

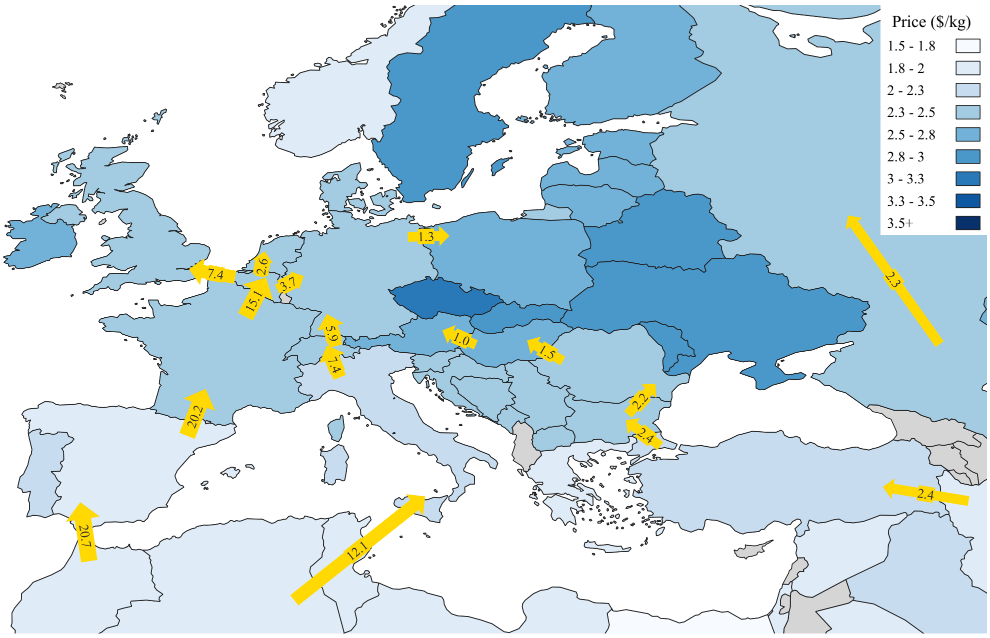


Figure 3.4.: Hydrogen pipeline flows (in Mt/a) and hydrogen prices (in $/kg) in Europe and the vicinity in the GRT (central) scenario

3.3.3. Hydrogen prices

Figure 3.5 displays consumption-weighted average local hydrogen prices in four important hydrogen consumption regions (China, Europe, Japan and the US). Taken together, they account for 64% of global low-carbon hydrogen demand in 2050.

In the OPT scenarios, the availability of natural gas-based low-carbon hydrogen, leveraging comparably low natural gas prices, keeps prices below \$2/kg in all regions for the 2030 to 2050 period. By contrast, in the GRT scenarios, prices are high early on and fall over time due to the assumed decline in RES and electrolyser investment costs.

From the large hydrogen consumers shown in Figure 3.5 the US exhibits the lowest prices overall in both the OPT and the GRT scenarios since it combines large, high-quality renewable energy potentials with low natural gas prices due to an abundance of low-cost supply.

The highest prices are found in Japan. In the OPT scenarios, the country relies entirely on more expensive LNG to produce natural gas-based low-carbon hydrogen. In the GRT scenarios, owing to its insularity and high-cost RES potentials, Japan imports liquid hydrogen, its marginal cost setting the local hydrogen price.

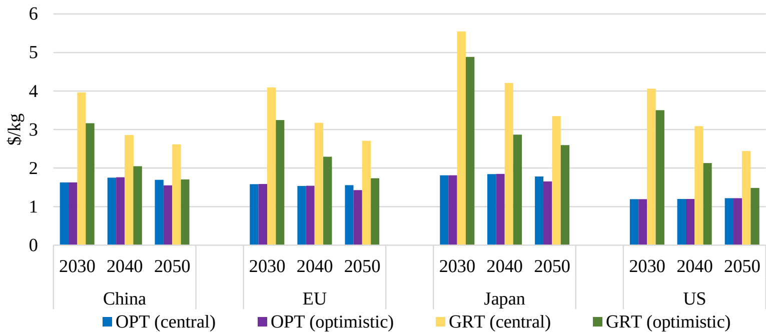


Figure 3.5.: Estimated hydrogen prices for major consumers by scenario

Table 3.2 displays the mean, country-level global hydrogen price, its standard deviation and the volume-weighted mean global hydrogen price, by scenario and year. It illustrates that when RES-based hydrogen production is the dominant pathway globally (*GRT (central)* and *GRT (optimistic)* scenario), mean price levels are higher. Standard deviations are greater, meaning price differentials between different countries and regions are larger. The latter is due to the spatial heterogeneity of RES potentials, resulting in more significant differences in hydrogen production costs between countries well-endowed in RES and RES-poor countries.

Maps depicting country-level hydrogen prices calculated by the model for the year 2050 can be found in B.2 (Figures B.5 to B.8).

Table 3.2.: Mean price ($\overline{x}_p$), standard deviation (σ_p) and volume-weighted mean price ($\overline{x}_{p,weighted}$)

	OPT (central)			OPT (optimistic)			GRT (central)			GRT (optimistic)		
	2030	**2040**	**2050**	**2030**	**2040**	**2050**	**2030**	**2040**	**2050**	**2030**	**2040**	**2050**
$\overline{x}_p$	1.4	1.5	1.5	1.4	1.4	1.2	3.5	2.7	2.3	3.1	1.9	1.5
σ_p	0.4	0.4	0.4	0.5	0.4	0.4	1.3	1.5	1.5	1.8	1.3	1.3
$\overline{x}_{p,weighted}$	1.5	1.6	1.5	1.5	1.5	1.3	3.8	2.8	2.3	3.2	1.9	1.5

3.4. Discussion

Although the four scenarios presented in the previous section are unlikely to represent how the global low-carbon hydrogen market will develop in reality, they yield important insights on the impact of technology costs and technology choices on the potential structure and evolution of the market for low-carbon hydrogen.

3.4.1. Key findings and implications

RES potentials and access to low-cost natural gas determine a country's or region's position in the global low-carbon hydrogen supply curve.

Notable is the general resilience of natural gas-based hydrogen production. The OPT scenarios illustrate that if low-carbon hydrogen production is predominantly natural gas-based, the hydrogen market is essentially an adjunct to the natural gas market. Natural gas is transported over large distances, and hydrogen is produced chiefly close to the point of consumption. There are two primary reasons for this: First, due to its lower volumetric energy density, hydrogen is more costly to transport than natural gas, in particular by ship. Secondly, there already is an extensive infrastructure for the transportation of natural gas, which can be leveraged to support the development of natural gas-based hydrogen production. The OPT scenarios also show that natural gas-based low-carbon hydrogen production is not merely a bridge towards a RES-based future, but a potential long-term solution for many countries, especially if global natural gas prices trend downwards as the world decarbonises and the demand for natural gas in other sectors decreases. This finding is robust even if electrolyser and RES investment costs continue to decrease substantially, following an optimistic cost trend.[16]

The analysis shows that long-distance trade in pure hydrogen is unlikely to occur on a relevant scale until RES-based low-carbon hydrogen production makes up a substantial share of the global supply mix. Countries with substantial hydrogen demand but poor RES potentials face higher prices than countries well endowed with cost-competitive RES. As a result, a long-distance, cross-border trade in hydrogen becomes an economically viable proposition under some circumstances. The scenario analysis shows that the greater the share of RES-based production in the global low-carbon hydrogen supply mix, the greater the amount of hydrogen traded across borders. The model-based analysis confirms the hypothesis of Brändle et al. (2021) that the comparably high cost of transporting pure hydrogen would lead to the emergence of regional rather than a global market for low-carbon hydrogen. These regional markets are organised around hydrogen pipeline networks. Seaborne trade based on the far more energy-intensive liquefaction of hydrogen, on the other hand, was shown not to be economical in the long run, except for cases like Japan, which combine limited, relatively high-cost domestic production potentials with a geographic location that makes importing hydrogen via pipeline infeasible. However, it should be emphasised that this finding pertains strictly to pure hydrogen. Other analyses (e.g., Hampp et al., 2021, Hank et al., 2020, Moritz et al., 2022) suggest that when the desired end product is a synthetic, hydrogen-based energy commodity, such as ammonia or methanol, producing the commodity in countries with low-cost RES and then shipping it to the destination may be cost competitive.

The high cost of transporting pure hydrogen over long distances means that scenarios with high shares of RES-based hydrogen production feature greater price differentials between countries than when production is primarily natural gas-based. Existing natural gas pipeline networks and LNG ensure that the global gas market exhibits a significant degree of price convergence, which feeds through into the production cost of, and thus price for, natural gas-based hydrogen. In scenarios where RES-based hydrogen production pathways predominate, the highest hydrogen prices are found in RES-poor regions, such

[16] While a pessimistic cost trajectory for RES and electrolysers was not explicitly considered in the analysis presented above, the results of the *OPT (central)* scenario, where the global supply mix is almost entirely natural gas-based even in 2050, suggest that such an outcome would further reinforce the competitive edge of natural gas-based hydrogen production technologies.

as Central and Eastern Europe and parts of East Asia. If production is mainly natural gas-based, hydrogen prices are effectively set by the local prices for natural gas, which are highest in East Asia. In scenarios dominated by natural gas-based hydrogen production pathways and in scenarios dominated by RES-based pathways, some of the lowest hydrogen prices are found in North America, particularly the United States. The region combines a large natural gas resource base with high-quality PV and Onshore wind potentials located not too far from prospective hydrogen consumption centres along the West Coast and the Eastern Seaboard.

The model-based analysis further suggests that imports may play an important role in the European hydrogen supply mix if strong demand for RES-based low-carbon hydrogen develops, indicating that it would be economical for the region to import significant quantities of hydrogen from North Africa, primarily Algeria and Morocco. The high reliance on imports is mainly driven by the lower availability and increased competition for low-cost RES in Europe. The potential dependence on a limited number of large suppliers raises issues around diversification and security of supply that are already familiar with natural gas, albeit on a smaller scale and involving different actors.

Generally, the results presented above confirm the inference of Brändle et al. (2021) on the global low-carbon hydrogen supply curve and the structure of the market: natural gas-based hydrogen appears to be a broadly competitive option even in the long-run, while the high cost of transporting pure hydrogen, in particular by sea, leads to the emergence of regional markets organised around pipeline networks.

3.4.2. Limitations and opportunities for further research

There are limitations to the analysis presented in this chapter, creating opportunities for future research.

Firstly, the emerging market for low-carbon hydrogen and the global market for natural gas is assumed to be perfectly competitive. However, in reality, this may not be the case. On the natural gas market, individual suppliers have at times been in a position to exercise market power (Growitsch et al., 2014, Schulte and Weiser, 2019b). Furthermore, policy choices, strategic objectives and geoeconomic considerations will also shape the future evolution of the low-carbon hydrogen market (see, e.g., Van de Graaf et al., 2020).

The model developed for this analysis is able to simulate potential strategic behaviour of market participants (Cournot competition) and thus lends itself to future extensions of this work in that direction. Furthermore, additional scenarios considering country-specific policy choices and strategic objectives could be defined to gain a deeper understanding of plausible market development pathways.

Secondly, the production and consumption of hydrogen-based synthetic energy commodities, such as ammonia or methanol, is treated as exogenous to the model. These energy commodities are likely to increase in relevance as economies decarbonise, and separate markets for them may thus emerge. As mentioned above, once produced, these energy commodities are less costly to transport over large distances than pure hydrogen, in particular by ship. It is thus not inconceivable to potentially see more robust price convergence and market integration for these commodities than for pure hydrogen. Production of these commodities would likely be concentrated in regions with low-cost renewable energy potentials that are otherwise not well-positioned geographically to export pure hydrogen to major consumers, for example, because the establishment of pipelines is infeasible. Future research could thus entail an extension of the model presented in this chapter to cover hydrogen-based energy commodities.

Thirdly, the potential impact of higher energy costs implicit in the scenario setup used for this analysis on economic growth and energy consumption is not considered since it is a partial equilibrium analysis focusing on the impact of hydrogen supply technology choices and costs on the global market for low-carbon hydrogen.

Low-carbon hydrogen demand is treated as inelastic and assumed not to vary between scenarios, even though the analysis shows that hydrogen prices can differ significantly between countries, particularly in scenarios with high shares of RES-based low-carbon hydrogen production. Future research to estimate the expected price-responsiveness of hydrogen demand, for example, using large-scale, global energy system models, would therefore be necessary to derive additional insights on the impact of supply technology choices on hydrogen demand itself.

Furthermore, the link between energy costs and the cost of energy technologies is not modelled. Investment costs are exogenous to the model, and potential variations are captured through scenarios representing a central and optimistic cost trend for RES and electrolysers. However, some analyses predict a decline in the energy return on energy invested (EROI) of the global energy system when comparably energy-dense fossil fuels are phased out in favour of less energy-dense renewables. This would increase the materials intensity of the world economy (see, e.g. Capellán-Pérez et al., 2019, Jackson and Jackson, 2021, Sers and Victor, 2018), which could, in turn, translate into higher than anticipated investment costs for energy technologies such as solar panels and electrolysers. Future research into the interaction between falling energy yields, increasing investment requirements and energy costs in a decarbonising global economy would be helpful to project better the evolution of the total cost of different low-carbon hydrogen production pathways, allowing for further refinement of the assumptions underpinning hydrogen market models such as the one presented in this chapter.

3.5. Conclusions

This chapter analyses the impact of supply technology choices and costs on structures and prices on the emerging low-carbon hydrogen market using a novel, integrated natural gas and hydrogen market model. Four scenarios are simulated, analysed, and compared to assess the impact of supply technology choices and costs on the potential evolution of the emerging global market for low-carbon hydrogen until 2050, focusing on the supply technology mix, the spatial structure of the market and market prices. The scenarios are based on the IEA's Sustainable Development Scenario and assume a deep decarbonisation of the global economy until 2050.

The model-based analysis shows that natural gas-based low-carbon hydrogen production pathways predominate in technology-neutral scenarios in 2050, even when the decline in RES and electrolyser investment costs follows an optimistic trend. The strong economic performance of natural gas-based technologies is supported by natural gas prices that are low by historical standards in most regions. The low natural gas price environment results from an assumed decline in natural gas consumption in sectors other than hydrogen production as major economies decarbonise. In scenarios where hydrogen production is mostly gas-based, the hydrogen market is effectively an adjunct to the natural gas market. Pure hydrogen is more costly to transport than natural gas. Therefore, the latter is transported over large distances and the former is mainly produced close to the point of consumption. Natural gas prices thus determine local hydrogen prices.

In scenarios characterised by high shares of RES-based low-carbon hydrogen production, long-distance, cross-border trade in hydrogen becomes an economically viable proposition. This is due to the heterogeneous distribution of low-cost RES potentials, which widens hydrogen price spreads between countries with substantial hydrogen demand but poor RES potentials and countries well endowed with cost-competitive RES. However, due to the high cost of transporting pure hydrogen, trade is regional rather than global and organised around hydrogen pipeline networks. Seaborne trade based on liquid hydrogen was shown not to be economical in most cases. The analysis finds the most significant potential for cross-border trade in and around Europe. It suggests that it would be economical for Europe to import significant quantities of hydrogen from North Africa.

4. The Emerging Hydrogen Economy and its Impact on LNG

4.1. Introduction

The global market for liquefied natural gas (LNG) has grown significantly in recent years. Global LNG trade increased to a record 484 billion cubic metres (bcm) of natural gas in 2020, despite the COVID-19 pandemic. There is currently 616 bcm of liquefaction capacity in operation and nearly 190 bcm financially approved or under construction. The three largest exporters—Australia, Qatar and the United States—account for half the world's operational capacity. With the potential addition of Canada and Mozambique, there will be 23 exporting countries in the coming years (IGU, 2021). LNG essentially restructured the global natural gas industry and is expected to continue to play a crucial role in its development and potential growth. It is credited to have changed the role of natural gas in the world, moving it towards a type of globalised commodity (Colombo et al., 2016). The industry's outlook, however, could change rapidly due to the dynamic supply and demand situation globally related to the evolution of the current energy transition, particularly concerning the competitiveness of rival fuels and international decarbonisation policies. Longer-term, given that the LNG supply is due to increase at the same time as major economies adopt decarbonisation targets in line with the Paris Agreement (UNFCCC, 2015), LNG exporters must consider ways to reduce greenhouse gas emissions along the value chain, which can account for up to 20% of the total well-to-smokestack emissions resulting from the combustion of the transported gas (IGU, 2015, Roman-White et al., 2019). However, the vast majority of greenhouse gas emissions in the LNG chain are emitted at the end-use point, placing part of the responsibility on LNG importers. There are two principal ways to address these emissions: by employing carbon capture, utilisation and storage (CCUS) technology to capture and permanently store the resulting CO_2, or by switching to alternative, carbon-neutral energy carriers, such as hydrogen.

Today, hydrogen production is very localised, with 85% produced and consumed on-site, mostly at refineries (Van de Graaf et al., 2020). However, with the projected growth in demand for low-carbon hydrogen, this is likely to change as centralising production is one of the most effective ways to achieve scale. With natural gas-based low-carbon hydrogen production, natural gas will likely continue to be transformed into hydrogen locally, eliminating the need to transport hydrogen over large distances, which is more expensive than transporting natural gas (Abánades, 2018).

In a series of reports published by the Oxford Institute for Energy Studies, Stern (2017, 2019a,b, 2020) explores the future role of natural gas, the natural gas value chain, and the LNG industry in the context of decarbonisation. The author highlights that the natural gas industry must move forward from the coal-to-gas switching narrative of the recent decade and respond rapidly to market requirements regarding decarbonisation, mainly in Europe. Therefore, LNG exporters must address the issue of methane emissions and increase transparency in the short term, while moving towards full decarbonisation in the medium to long term, for example by using LNG to produce natural gas-based low-carbon hydrogen.

Accordingly, recent reports examining decarbonisation pathways for the global energy system (e.g. IRENA (2019b), BP (2020), Shell (2020), IEA (2020a,b, 2021b)) all predict growing importance of low-carbon hydrogen as an alternative energy carrier, with a substantial market for the commodity developing by 2050. At the same time, all projections expect global natural gas consumption to peak and then fall as decarbonisation deepens (see Table 4.1).

Table 4.1.: Projected global demand for hydrogen and natural gas in major decarbonisation scenarios

		2030		**2040**		**2050**	
Source	**Scenario**	**Hydrogen** *(Mt)*	**Gas** *(Mtoe)*	**Hydrogen** *(Mt)*	**Gas** *(Mtoe)*	**Hydrogen** *(Mt)*	**Gas** *(Mtoe)*
IEA (2020a)	ETP SDS	35	-	102	3056	258	2384[1]
IEA (2020b)	WEO SDS	18	3312	75	2943	164	-
IEA (2021b)	Net Zero	149	3081	353	1791	520	1433
BP (2020)	Rapid	5	3941	64	3774	199	3392
	Net Zero	6	3368	162	2508	483	2173
Shell (2020)	Sky	4	3750	18	3607	73	2747
IRENA (2019b)	REMap	-	3057	-	2484	242	1767

[1]The 2050 value for the ETP SDS scenario was derived by linearly interpolating between the 2040 and a 2070 estimate (2048 Mtoe) given by the source. Mt = Million tonnes. Mtoe = Million tonnes of oil equivalent.

Many studies have identified and compared technical pathways for the natural gas-based production of low-carbon hydrogen (Bollen et al., 2010, Brändle et al., 2021, CE Delft, 2018, Khan et al., 2021, Maggio and Nicita, 2021, Parkinson et al., 2018, Salkuyeh et al., 2017, Voldsund et al., 2016). As the fastest-growing segment within natural gas, LNG could play a key role in delivering natural gas to markets that can then be used to produce hydrogen.

The choice of pathway depends on the actors involved, whose decisions will be influenced by market conditions, price signals, regulatory environments, technology risk, existing infrastructure, and potential future infrastructure (Hanley et al., 2015).

In the emerging market for low-carbon hydrogen, natural gas-based technologies such as natural gas reforming (NGR)[1]+CCUS or methane pyrolysis are likely to compete against electrolysis using electricity derived from renewable energy sources (RES) as the primary means of hydrogen production (Brändle et al., 2021).

The degree to which each technology contributes to the supply mix depends on policy choices, especially in the short to medium term. As the market for low-carbon hydrogen matures, however, technologies with significant cost advantages over others are likely to come to dominate the supply mix.

As shown by Brändle et al. (2021), natural gas-based technologies are likely the most economical choice to produce low-carbon hydrogen in the short to medium term. However, in the long term, RES-based hydrogen could become competitive in countries with good renewable resources if RES and electrolyser investment costs decline substantially and natural gas prices increase (Brändle et al., 2021, Espegren et al., 2021, IEA, 2019c, Lambert and Schulte, 2021). Significant research and development investment, coupled with the recognition by major countries that low-carbon hydrogen is a potentially viable economic and environmental solution, could accelerate the development of competitive RES-based hydrogen (Kovac et al., 2021). Amongst the natural gas-based technologies, NGR+CCUS could be supplemented by methane pyrolysis if it becomes mature enough to be deployed at scale for hydrogen production. The pyrolysis process itself generates no CO_2 emissions, leaving only a solid carbon by-product which is easier to manage and store than gaseous CO_2. The

[1] in this Chapter, *natural gas reforming* refers to the production of hydrogen from natural gas using steam methane reforming (SMR), autothermal reforming (ATR) or partial oxidation (POX).

technology has the potential to produce low-carbon hydrogen at a very low cost when feed gas costs are low. However, when and at what scale and cost pyrolysis will become available is uncertain.

Depending on how the global low-carbon hydrogen supply technology mix and the associated market structure develop, there are significant implications for natural gas producers and the LNG market. Suppose low-carbon hydrogen production is primarily natural gas-based. In that case, it could potentially act as a brake on the long-term decline of global natural gas consumption that is otherwise projected to occur in a deep-decarbonisation scenario.

Furthermore, the LNG industry may leverage technical or commercial synergies when it comes to producing, shipping, and marketing low-carbon hydrogen. Transferable know-how could play a role in developing technology and methods based on delivering and handling large amounts of gas over long distances. In addition, the development of an international market for low-carbon hydrogen may mirror that of the LNG market, where large producers and customers underpinned the early stages of market development, supported by strategic government support that eventually led to a dynamic near-commodity type market. However, whether exports of RES-based hydrogen are a viable alternative for some of the current LNG producers is an open question that hinges on the technology and economics of exporting hydrogen, particularly by ship. It depends on the cost of shipping hydrogen, the proximity to export markets and other factors, such as the integration into potential regional hydrogen pipeline networks. The issues described above can be distilled into two main research questions, which this Chapter will address:

- What impact could increasing demand for low-carbon hydrogen have on the global LNG market?
- Do potential synergies exist between the LNG and hydrogen industry value chains—commercial and technical—that LNG producers could leverage?

We perform a model-based scenario analysis to quantify the impact of different global low-carbon hydrogen development pathways on LNG exporters using a novel, integrated natural gas and hydrogen market model. The chosen pathways are based on recent projections by the International Energy Agency (IEA) and consistent with a deep decarbonisation of the global energy system by 2050.

The scenario analysis is supplemented by interviews with LNG industry stakeholders and a review of secondary literature to derive further insights. The interviewees represent a range of actors, including market experts, traders, consultants, traders and producers (see Appendix C.1).

4.2. Model-Based Analysis

The model-based scenario analysis is conducted using a model of the global markets for natural gas and low-carbon hydrogen. It covers several stages of natural gas and hydrogen value chains (production, transport, storage and consumption) across 90 countries globally and is formulated as a mixed complementarity problem (MCP).

For this analysis, the model is run in an annual resolution. Spatially, it is defined by a set of nodes that are connected through arcs. Nodes are divided into natural gas and hydrogen production, liquefaction, regasification and consumption nodes, and the arcs connecting them represent pipelines and LNG/liquid hydrogen (LH_2)[2] shipping routes.

The model is populated by different profit-maximising agents: exporters, producers, transmission system operators (TSOs), liquefiers, regasifiers and shippers. Subject to various constraints, they maximise their profits by making optimal decisions with respect to the production, sale and transport of natural gas or hydrogen and through optimal investments into production and transport infrastructure.

The partial equilibrium model is formed by combining the first-order optimality conditions of the respective optimisation problems of the individual agents situated along the natural gas and hydrogen value chains with the market clearing conditions of the respective markets.

A detailed mathematical description of the model is provided in Chapter 3.

4.2.1. Scenarios

To quantify the impact of technology choices on the ramp-up of a global market for low-carbon hydrogen, the natural gas market more broadly, and LNG in

[2]While converting hydrogen to ammonia for shipping represents the lowest-cost option of transporting hydrogen by sea today—since existing infrastructure (liquefied petroleum gas tankers and port facilities) can be leveraged—LH_2 has the potential to become the lowest-cost technology in the long run, if pure hydrogen is the desired end product and LH_2 shipping is deployed at scale (Brändle et al., 2021).

particular, we base our analysis on four transition scenarios. They are loosely adapted from the IEA's Sustainable Development Scenario (SDS) (IEA, 2019e, 2020a,b), supplemented by own assumptions on the distribution of the aggregated natural gas and hydrogen demand estimates provided by the IEA to the individual countries covered by the model. The SDS's natural gas and hydrogen demand trajectories are consistent with a rapid decarbonisation of the global economy.

The scenarios represent different possible trajectories for the evolution of the low-carbon hydrogen production technology mix. We consider RES-, natural gas- and coal-based low-carbon hydrogen production pathways. The modelled RES-based pathways rely on the electrolysis of water using electricity from onshore wind, offshore wind, or solar PV. The natural gas-based technologies are NGR+CCUS and methane pyrolysis, as described in Brändle et al. (2021). RES- and natural gas-based technologies are assumed to be available globally, while coal gasification (CG) is modelled as an additional option specifically for China. It is by far the world's largest producer of hydrogen from coal today, being home to more than 80% of the world's coal gasification capacity (IEA, 2019c). It is assumed that the country is likely to keep using the technology—with the addition of CCUS—to meet some of its future low-carbon hydrogen requirements, while coal production is projected to decline substantially or be phased-out entirely in most other parts of the world (IEA, 2020a,b).

The first three scenarios (collectively labelled open transition [OPT]) represent a world in which hydrogen production technologies compete solely based on their levelised cost of production.

To assess the impact of different future RES and electrolyser costs, we compare a scenario in which RES and electrolyser cost reductions follow a baseline trend with a scenario in which costs fall further (low-cost). Pyrolysis is currently not a mature technology deployed at scale for the purposes of hydrogen production. To account for the uncertainty around its eventual application and to assess its potential impact on hydrogen production and natural gas consumption, we model a separate scenario in which pyrolysis becomes available after 2030 in a setting with low RES and electrolyser costs (OPT [low cost/pyrolysis]). In the other two scenarios (OPT [baseline] and OPT [low-cost]), pyrolysis is assumed not to be available, making NGR+CCUS the default option when it comes to natural gas-based low-carbon hydrogen production.

Finally, as a special case, we simulate the so-called green transition (GRT) scenario, where RES-based production technologies dominate the global low-carbon hydrogen supply mix as a matter of policy choice.

Broadly speaking, the four scenarios are differentiated along two dimensions: the RES/electrolyser cost case (baseline vs low cost) and the availability of fossil fuel-based low-carbon hydrogen production technologies (Table 4.2).

Table 4.2.: Overview of scenarios

	OPT (baseline)	**OPT (low cost)**	**OPT (low cost/pyrolysis)**	**GRT**
RES cost case	baseline	low cost	low cost	baseline
Pyrolysis	unavailable	unavailable	available	unavailable
NGR+CCUS	available	available	available	unavailable
CG+CCUS	available	available	available	unavailable

The four scenarios are not to be taken as predictions. Instead, they are designed to provide benchmarks regarding the impact of low-carbon hydrogen production on the natural gas sector. In reality, developments may be less clear-cut than predicted by the model, as technological choices are likely to be shaped as much by policy choices in different regions as they are by economics.

The scenarios are assessed with respect to overall production and consumption trends, the size of the LNG and hydrogen markets, and the impact on LNG and hydrogen trade flows. We analyse and present results for the years 2030, 2040 and 2050.

4.2.2. Data and assumptions

This section outlines key assumptions made for the model-based scenario analysis of the markets for natural gas and low-carbon hydrogen.

Natural gas and hydrogen demand

All four scenarios assume the same underlying natural gas and hydrogen demand trajectories (see Table 4.3). The consumption pathways are based on the IEA SDS and therefore consistent with a global transition to net-zero emissions by 2070 (IEA, 2020a,b). The demand assumptions are identical to those presented in Chapter 3, where a more detailed description is provided.

Global natural gas demand (excluding consumption to produce low-carbon hydrogen, which is determined endogenously by the model) continues to grow to 3945 bcm in 2030, with demand growth in the Asia Pacific offsetting a decline in consumption in other regions, in particular Europe and North America. After 2040, the pressure to decarbonise leads to demand falling in Asia as well. Global consumption then declines to 3285 bcm in 2040 and 2534 bcm in 2050.

Table 4.3.: Assumed development of global demand for low-carbon hydrogen and natural gas

	2030	2040	2050
Low-carbon hydrogen	35 Mt	102 Mt	258 Mt
Natural gas*	3945 bcm	3285 bcm	2534 bcm

* Excluding for the production of low-carbon hydrogen.

The IEA (2020a) projects global demand for low-carbon hydrogen to increase sharply after 2030, rising from 35 Mt to 258 Mt until 2050. In 2050, 37% is consumed in the transport sector[3] 34% in industry[4] and 10% in the buildings sector. The remaining 19% are consumed in other sectors, most notably the power sector, where hydrogen provides an important source of backup power for intermittent RES, displacing natural gas (IEA, 2020a). Since the agency does not provide a country-level breakdown of its consumption estimates, it is allocated based on projected GDP (OECD, 2018) (for industrial and transport sector hydrogen consumption) and natural gas consumption (for buildings and other sectors). It is further assumed that in 2050, most of the hydrogen (80%) is still consumed in the high-income economies[5] and China, the likely front runners when it comes to decarbonisation. According to this distribution, more than 40% of the hydrogen is consumed in the Asia Pacific region in 2050, followed by North America (25%) and Europe (18%) (see Figure 4.1).

It should be noted that we assume both the natural gas and the emerging market for low-carbon hydrogen to be perfectly competitive. Historically, large natural gas producers like Russia were at times in a position to exert market power in certain regions, such as Europe. However, in recent years, the market has become much more competitive, not least because of the increasing role LNG plays in providing liquidity and linking the hitherto segmented markets of North

[3]Including hydrogen used for the production of synthetic fuels.
[4]Including hydrogen used in refining and for the production of low-carbon ammonia.
[5]As defined by the World Bank.

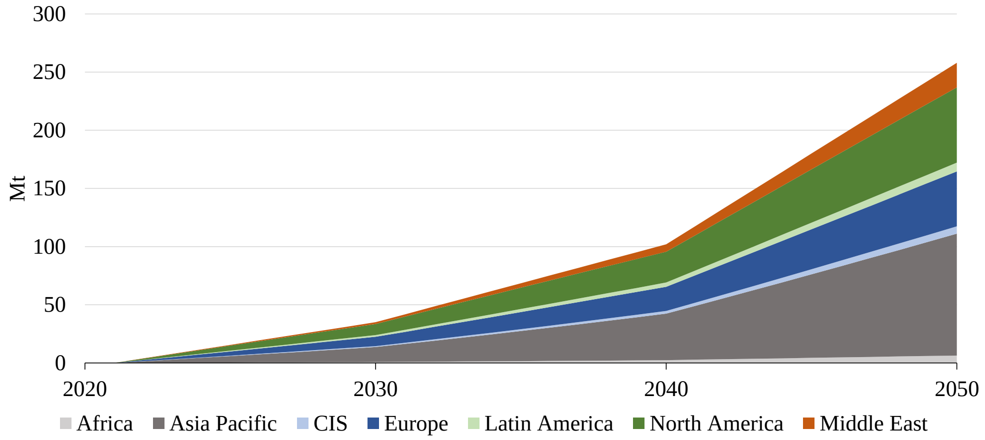


Figure 4.1.: Assumed distribution of global demand for low-carbon hydrogen

America, Europe, and East Asia (Growitsch et al., 2014, Schulte and Weiser, 2019b).

Natural gas and hydrogen supply costs and potentials

Country-level natural gas supply cost curves are built from proprietary field-level cost and capacity projections provided by Rystad Energy (2020).

Data on current and future investment costs, operating costs, and the conversion efficiencies of RES- and natural gas-based hydrogen production technologies are taken from a comprehensive global assessment of low-carbon hydrogen production costs published by Brändle et al. (2021). Cost-optimal RES-to-electrolyser ratios for different renewable energy potentials of varying quality in the individual countries covered by the model are taken from the same source. Investment costs, operating costs and conversion efficiencies for CG+CCUS in China are obtained from IEA (2019c).[6]

For NGR+CCUS and CG+CCUS, the cost of transporting and storing CO_2 underground is an important cost component. Country-level CO_2 storage costs (see Table C.1) are estimated using data on CO_2 transport costs and reservoir-specific storage costs provided by Roussanaly et al. (2014) and Rubin

[6]Investment costs for all hydrogen production technologies included in the model are assumed to decline over time. This is a function of both technological improvements and increases in scale as the market for low-carbon hydrogen grows in size.

et al. (2015b).[7] Both NGR+CCUS and CG+CCUS are assumed to have a CO_2 capture efficiency of 90%. The residual emissions are subject to the local CO_2 price[8]. Unlike NGR+CCUS, pyrolysis produces a solid carbon byproduct, which is chemically stable at ambient temperatures. While there is a market for solid carbon and the product is valuable in itself, a large-scale deployment of pyrolysis of hydrogen production would likely result in production far in excess of current demand. As a result, solid carbon prices would then tend towards zero. However, if new uses are found, prices could again rise. Alternatively, if the solid carbon can only be disposed of, there would be a cost. Due to this uncertainty, a solid carbon price of zero is assumed by Brändle et al. (2021) and for this analysis as well. Brändle et al. (2021) also provide detailed, disaggregated information on RES potentials and costs for the countries represented in the model. There are two cost cases for RES-based hydrogen: in the baseline case, RES and electrolyser costs decline so that in locations with above average onshore wind or PV conditions, the levelised cost of hydrogen drops to around \$2/kg by 2050. In the low-cost case, higher RES investment cost reductions are achieved, in particular for solar PV, and levelised hydrogen production costs dip to \$1/kg in locations with good solar potentials.

To take account of variations in investment risk and financial conditions between countries, all investments are discounted using country-specific weighted average cost of capital estimates (see Table C.1).

Natural gas and hydrogen transport

Data on existing cross-border natural gas pipeline capacities is obtained from an in-house database maintained by the Institute of Energy Economics at the University of Cologne. LNG liquefaction/regasification capacities (existing and sanctioned) are sourced from IGU (2021). Current long-term contracts (LTCs) for pipeline gas and LNG are modelled as well, with contract volumes and

[7]Potential limitations to the underground storage of CO_2 in certain areas are not considered. In some cases, nearby reservoirs may not be readily available, and the CO_2 would have to be transported over greater distances to suitable disposal sites, increasing the associated cost. However, as shown by Brändle et al. (2021), the impact of an escalation in the cost of CO_2 transport and storage on the levelised cost of hydrogen produced by NGR+CCUS is relatively low.

[8]It should be noted that in reality, CO_2 prices would likely vary from scenario to scenario, in particular if hydrogen or hydrogen-based technologies—for which we model different cost trajectories—are the marginal abatement option. However, we are unable to model this link in the partial equilibrium model used for this study. As in Chapter 3, we therefore assume an exogenous global CO_2 price, based on IEA (2019c) and IEA (2020b), which increases from \$89/tCO_2 in 2030 to \$165/tCO_2 in 2050 in advanced economies and \$70/tCO_2 in 2030 to \$145/tCO_2 in 2050 in less advanced economies in all scenarios.

durations obtained from Rystad Energy (2020). Existing LTCs are assumed not to be renewed after expiry. Investment costs for natural gas pipelines and LNG infrastructure come from various sources, including company reports and publications by the Oxford Institute for Energy Studies (Songhurst, 2018, Steuer, 2020).

For the seaborne transport of hydrogen, an infrastructure consisting of hydrogen liquefaction terminals, liquid hydrogen (LH_2) tankers and regasification terminals is modelled, with projected investment and operating costs of all three elements sourced from Brändle et al. (2021).

For land-based transport, pipelines are the lowest cost technology to transport significant volumes of hydrogen over large distances. In line with Brändle et al. (2021), the specific cost for the transmission of hydrogen through new, large-scale, dedicated hydrogen pipelines is assumed to fall to \$240 per tonne of H_2 per 1000 km by 2030.

4.3. Results and Discussion

4.3.1. Model results

The model simulations show (Figure 4.2) that in the open transition (*OPT*) scenarios—where the different low-carbon hydrogen production technologies compete based on cost—the initial development of the hydrogen market in 2030 is supported almost exclusively by NGR+CCUS. This applies to both the baseline (*OPT (baseline)*) and low RES/electrolyser (*OPT (low cost)*) cost cases. However, with a more aggressive decline in the cost of RES and electrolysis, RES-based hydrogen production becomes competitive with NGR+CCUS, particularly in regions with good PV potentials. In the *OPT (low cost)* scenario, roughly a third of global low-carbon hydrogen production in 2050 is RES-based. The calculations also show that coal gasification, combined with CCUS, remains the mainstay of hydrogen production in China.

In the *OPT (low cost/pyrolysis)* scenario, natural gas pyrolysis is available as an alternative for the natural gas-based production of hydrogen. Since it does not require CCUS equipment, the associated investment costs are projected to be lower than for NGR+CCUS. Consequently, it becomes the lowest-cost natural gas-based hydrogen production technology once available, despite its lower efficiency and, therefore, higher natural gas consumption. The *OPT (low* *cost/pyrolysis)* scenario also shows that the cost differential between RES- and natural gas-based technologies is relatively narrow even in regions with good RES potentials: the cost reduction associated with the use of pyrolysis in this scenario is enough to make it the dominant technology in almost all modelled countries once it becomes available.

Generally, the strong performance of natural gas-based hydrogen is the result of persistently low natural gas prices in all major consumption regions (see Figure 4.4 below), triggered by a levelling off and decline of global natural gas consumption (see Figure 4.3 below).

In the green transition (*GRT*) scenario, an assumed global preference for RES-based hydrogen ensures that low-carbon hydrogen is produced exclusively from RES in all countries. Furthermore, the scenario shows an increase in the relative importance of PV-based hydrogen in the supply mix as production scales up since the cost of PV-based electricity is projected to decline more than from onshore or offshore wind turbines.

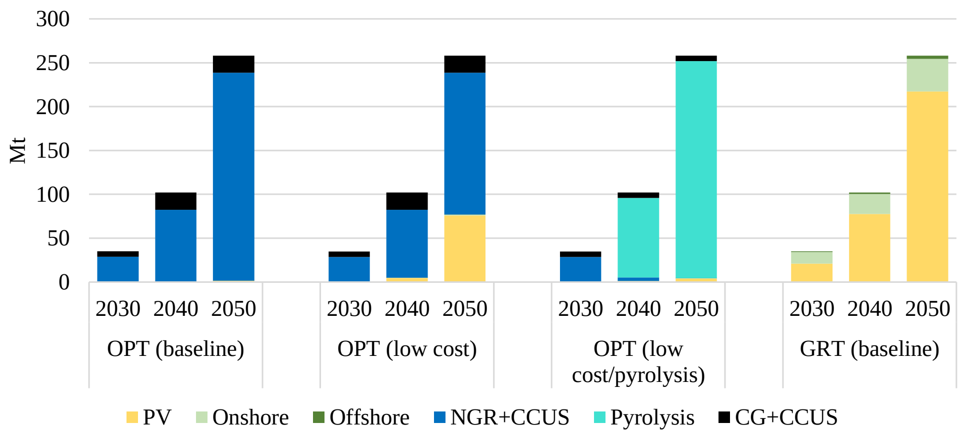


Figure 4.2.: Evolution of global low-carbon hydrogen production

Comparing the four scenarios illustrates significant differences concerning the spatial structure of the emerging hydrogen market. In the OPT scenarios, hydrogen production is overwhelmingly based on natural gas and generally occurs close to where the hydrogen is consumed. In the case of NGR+CCUS, the resulting CO_2 is stored locally. Furthermore, due to the lower associated cost, international trade is overwhelmingly in the form of natural gas and LNG, rather than gaseous or liquid hydrogen.

However, as the share of RES-based hydrogen increases, so does the importance of cross-border trade, linking countries/regions with low production costs to countries with high demand but less favourable conditions to produce hydrogen from RES. The simulations reveal that pure hydrogen is generally traded in regional clusters via pipeline, forming several regional rather than a global market. Due to the high cost of shipping hydrogen compared to pipelines, hydrogen is generally not traded by sea. The notable exception is Japan, which in the GRT scenario imports LH_2 from the Middle East.

As shown in Figure 4.3, the substantial increase in natural gas-based hydrogen production in the *OPT (baseline)* and *OPT (low cost/pyrolysis)* scenarios supports global natural gas demand, slowing down or reversing the decline in natural gas consumption between 2030 and 2050. In some regions with a strong decline in natural gas demand before 2040, such as Europe, the substantial rise in local natural gas-based hydrogen production leads to a rebound in demand between 2040 and 2050. In the OPT (low cost) scenario, the higher reliance on RES-based hydrogen production leads to a general decline in global natural gas consumption, which is even more pronounced in the *GRT* scenario, where all hydrogen is produced from RES.

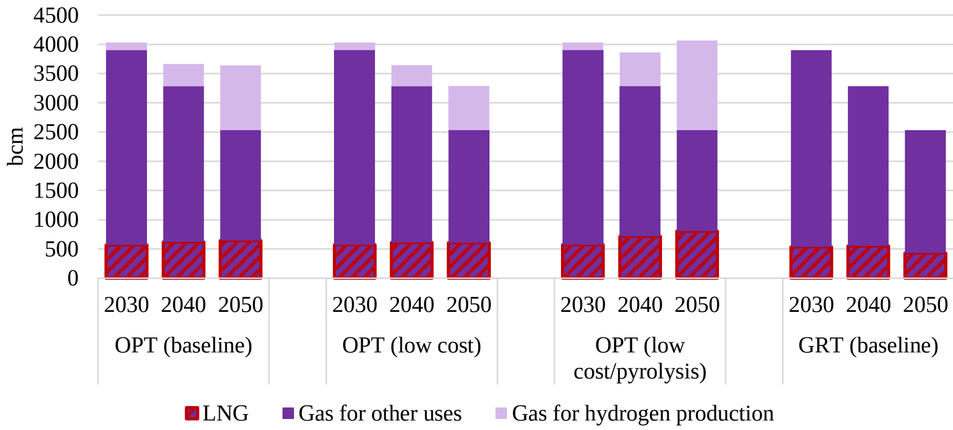


Figure 4.3.: Development of global natural gas consumption and the share of LNG

In contrast to the gas market as a whole, the LNG market continues to grow until 2050 in the *OPT (baseline)* and *OPT (low cost/pyrolysis)* scenarios, since a significant share of the additional hydrogen production takes place in the large economies of the Asia Pacific region, which are significantly more reliant on LNG imports than, for example, countries in Europe or North America. In the *OPT (baseline)* scenario, the LNG market in 2050 is approximately 33% bigger than in 2020[9]. In the *OPT (low cost/pyrolysis)* it even grows by 66% over the same time period.

In the *OPT (low cost)* scenario, by contrast, the increasing share of RES-based hydrogen production in 2040 and 2050 and the smaller associated demand for natural gas affect the LNG market. Since most of the early decline in natural gas consumption is in North America and Europe, while consumption in the Asia Pacific region increases until 2040, the LNG market will continue to grow until 2040, albeit more slowly, with demand peaking in 2040 and then declining slightly until 2050. The post-2040 decline is even more pronounced in the *GRT* scenario, where low-carbon hydrogen production is exclusively RES-based. Consequently, the global LNG market is 12% smaller in 2050 than it was in 2020.

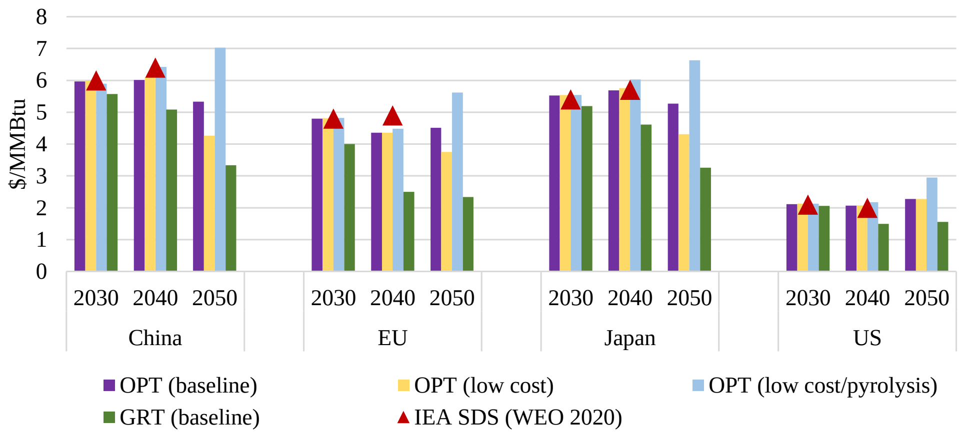


Figure 4.4.: Development of natural gas prices in selected regions

The simulations reveal that the growth of the LNG market in the *OPT (baseline)* and *OPT (low cost/pyrolysis)* scenarios is driven primarily by rising demand in the Asia Pacific and, to a lesser degree, Africa. Compared to today, market shares in the large East Asian LNG market shift: exports from the Commonwealth of Independent States (CIS) and North America to Asia increase significantly. Exports from the Middle East to the Asia Pacific increase as well, with India and later Southeast Asia becoming the two largest off-takers for cargoes from the region. European LNG imports decline substantially from today's levels. For Europe, shipments from the United States increase in importance, compared to a reduction in imports from the Middle East. Low-cost suppliers of LNG are less affected by constrained demand. High-cost

[9]According to IGU (2021), 484 bcm of LNG were shipped in 2020.

producers, on the other hand, located mainly in the Asia Pacific and North America are—by virtue of their higher relative cost base—much more sensitive to differences in LNG demand resulting from different hydrogen pathways. They act as "swing suppliers" and primarily make up for the differences in volumes between the four scenarios.

A detailed overview of the LNG trade flows calculated for each scenario is presented in Table C.2 in C.3.

4.3.2. Discussion

Impact on the LNG Market

The scenario analysis presented in the previous section shows that hydrogen production could become a significant user of natural gas by 2040, provided that the ramp-up of the growing market for low-carbon hydrogen is supported mainly by natural gas-based technologies. As a result, it could stabilise global natural gas demand, compensating for the decline in natural gas consumption by other sectors that accompanies the global economy's progressive decarbonisation. LNG producers would be the primary beneficiaries of such a development since the lion's share of low-carbon hydrogen is likely to be consumed in the advanced economies of the Asia Pacific region—due to their size and overall energy demand. On average, these economies rely more on LNG imports than on domestic natural gas production or imports via pipeline.

The strong performance of natural gas-based hydrogen production in the model-based analysis confirms industry expectations: in the interviews conducted for this study, it was noted that the cost and complexity of developing RES-based hydrogen would lead to more natural gas-based hydrogen introduced to energy systems in the short to medium term than projected by many experts and forecasters, even in regions such as Europe that are primarily supporting the development of electrolysis using RES electricity. The overwhelming view of participants was that the need to make progress towards net-zero would push countries to embrace an "all of the above" approach to hydrogen.

Several interviewees remarked that an early ramp-up using natural gas-based hydrogen in the short to medium term, followed by an increase in RES-based hydrogen production in the long run, is likely to reflect how the energy system will develop. It was noted that the development of a technology mix, taking advantage of supply economics, regulatory support, and technological improvements, is what is likely to unfold. From the modelled scenarios, the *OPT (low cost)* scenario, where natural gas-based hydrogen becomes the dominant pathway in some regions and RES-based hydrogen in others, is the closest approximation of such an outcome. The calculations reveal that in this scenario—which assumes a substantial decline in RES and electrolyser investment costs over the coming decades—the cost margin between natural-gas based and RES-based hydrogen is relatively narrow in several regions in 2050. As a result, small differences in the gas price can significantly impact the relative competitiveness of both production pathways, leading to large differences in hydrogen-related natural gas consumption.

All four modelled scenarios postulate an aggressive decarbonisation of the global economy. In this context, the outlook for the LNG market itself could potentially still be robust until 2050, provided low-carbon hydrogen production is overwhelmingly natural gas-based. However, in scenarios where RES-based hydrogen production predominates, slow growth until 2040 followed by a shallow decline until 2050. This outcome aligns with the perception of the interviewed LNG industry stakeholders, who identified RES-based hydrogen as a downside risk to the LNG industry in the long term. Several interviewees noted that resource holders could take major strategic decisions to leverage their asset base subject to the availability of low-carbon resources, but that a long term future based primarily on RES-based hydrogen would be very disruptive to LNG. An energy expert concluded that it would be very tough to see a viable path for LNG under a RES-based hydrogen pathway, stating that "definitely blue all the way through" needs to be the approach for the industry.

Strategic implications

Within the broader context of decarbonisation in general, interviewees representing different parts of the LNG industry identified several key opportunities in the coming decades. First, there is still significant scope to support coal-to-gas switching in many parts of the world, mainly Asia, and at the same time support the continued deployment of renewables by providing large-scale backup capacity, mainly in developing economies. LNG represents an easy "bolt-on strategy that can be implemented right away" supported by a mature market and developed logistical value chain, especially when compared to more unproven technologies that require significant support to develop. Second, several interviewees highlighted that industrial clusters could represent an opportunity to leverage LNG import facilities for hydrogen development. A cluster strategy focusing on on-site NGR with CCUS or pyrolysis and access to RES, which can eventually be used to produce hydrogen, would introduce the possibility of a phased decarbonisation of large energy consumers in Europe initially and subsequently in other parts of the world as well. In addition, transferable skills related to the operation of cryogenic liquids and the management of complex long-distance supply chains were identified as potential areas of synergy between hydrogen and LNG.

Cluster strategies have also received treatment in the literature. According to IEA (2019c) industrial clusters where LNG import terminals are located could provide an opportunity for LNG to be imported and low-carbon hydrogen to be produced at the same location. Coastal industrial clusters with large dependable industrial customers represent one of the main near-term opportunities where existing gas infrastructure can support the scale-up of low-carbon hydrogen production and consumption (BNEF, 2020a, IEA, 2019c, 2021a). Furthermore, blending natural gas with low-carbon hydrogen in pipelines is often proposed to support the introduction of hydrogen as an energy carrier while reducing the emissions attributed to natural gas (Hanley et al., 2015, Speirs et al., 2018). However, the direct use of hydrogen is much more economical than blending in the short to medium term (Schlund and Schönfisch, 2021).

In terms of threats, several interviewees highlighted an increasing risk that specific energy systems might skip the traditional evolution from coal to natural gas to renewables for power generation, mainly due to rapid cost reductions of renewables, which could expedite the development of RES-based hydrogen. It was broadly agreed that although China and India will be the key markets for LNG's potential growth in the coming decades—something that is also shown by the model-based scenario analysis conducted in this Chapter—other important markets in Asia, South American and Africa are important, yet at the same time have some characteristics that could limit LNG's bridging role, such as domestic coal and rich renewables resources. Overall, the greenhouse gas emissions of LNG are perceived as a risk for the industry, partly due to growing anti-fossil fuel sentiment in key export markets, but also partly because of the resulting dependence on CCUS as a technology that has yet to be deployed at scale, with doubts expressed on the long-term impact of carbon-neutral cargoes.

While natural gas-based low-carbon hydrogen production may play a major role in supporting LNG exports, the model-based scenario analysis also shows that directly exporting pure hydrogen does not appear to be a viable option for most LNG producers. If natural gas-based hydrogen production technologies dominate, transporting gas instead of hydrogen is the more economical option, with hydrogen production generally taking place close to where it is consumed. If hydrogen production is mainly RES-based, more hydrogen is traded internationally, but mainly via pipeline, with the market divided into regional clusters. Due to the higher relative cost vis-à-vis pipelines, ship-based imports of hydrogen are only relevant for Japan, which lacks suitable amounts of low-cost renewables to produce all of the hydrogen it needs domestically and is—for geographic reasons—dependent on additional seaborne imports.

While not explicitly covered by the model-based analysis presented in this Chapter, producing and exporting low-carbon ammonia and synfuels may present an additional opportunity for exporters since they are less costly to ship than pure hydrogen. In the IEA SDS, for example, ammonia and synfuels production accounts for 17% of global hydrogen-related final energy demand in 2040 and roughly 30% in 2070 (IEA, 2020a). Currently, ammonia production generally takes place close to where it is consumed and where natural gas is available, and refined fuels are similarly produced locally from imported crude oil. However, if hydrogen production is predominantly RES-based, it may be more economical to locate ammonia and synfuel production facilities in regions with low-cost renewable energy potentials and export the commodities. Existing infrastructure could potentially be leveraged to support such exports. The LNG chain, for example, could handle synthetic methane as well. Nevertheless, if pure hydrogen is the required end-product, it is likely to be more economical to produce, transport and consume the hydrogen directly, thereby avoiding the costs associated with the conversion into a hydrogen-based energy carrier, followed by a reconversion to hydrogen (Brändle et al., 2021).

Several studies have explored potential technical and operational synergies between LH_2 and LNG, focusing on production methods, shipping, utilisation and storage (Abe et al., 1998, Bang et al., 2011, Hanley et al., 2015, Lloyd's Register and UMAS, 2019, Musharavati et al., 2020). However, hydrogen requires significantly colder temperatures to become a cryogenic liquid (-253 degrees Celsius compared to -161 degrees Celsius for LNG). Liquefying hydrogen would consume between 25%-35% of the energy contained in the hydrogen, compared to 10% for natural gas (IEA, 2019c). In terms of shipping, LNG bunkering infrastructure is unlikely to be suited for LH_2. Retrofitting could be as expensive as building new infrastructure (different cooling equipment and insulation are required), even though both LH_2 and LNG require cryogenic treatment.

However, there are commercial synergies to explore. Several major potential future importers of hydrogen are already significant LNG importers with established links to LNG exporters, such as Japan and Korea, which possess transferable commercial and value chain management knowledge (ARENA, 2018, Noussan et al., 2021). The hydrogen industry could develop similarly to the LNG industry, through the initial establishment of a hydrogen market based on long-term bilateral contracts, supported by government-to-government agreements, and take or pay commitments to support and underpin investment into hydrogen production, storage and transport assets (Bruce et al., 2018, Van de Graaf et al., 2020). Initial supply agreements could also benefit from negotiating favourable trade tariffs, supported by joint ventures that leverage current commercial relationships and share risk through a vertically integrated approach (Bruce et al., 2018).

Australia is an example of an important LNG exporter that looks to leverage its LNG position and expertise to support its hydrogen export plans. It has developed a national hydrogen roadmap and strategy, focusing initially on electrolysis and then at a later stage the large scale production of hydrogen utilising brown coal (Bruce et al., 2018, Van de Graaf et al., 2020). The roadmap developed by the Commonwealth Scientific and Industrial Research Organisation (CSIRO), Australia's national science research agency states that "lessons learnt from the LNG industry" include mimicking the origins of LNG market development leaning on government-to-government agreements to support long term off-take contracts to secure stable and sufficient financing (Bruce et al., 2018, p. 53).

Generally, the hydrogen industry was characterised as still in an early stage by interviewees. While low-carbon hydrogen was accepted as technically viable and a component of the future energy system, the current lack of infrastructure and its high overall cost mean that hydrogen will require substantial government support, similar in scale to that of renewables in Europe over the past several decades, which could translate to slower adaptation rates than many forecasts predict. Technical challenges linked to transport and the current overall fragmentation of the hydrogen chain were also identified as hurdles. However, it was also acknowledged that the narrative around hydrogen is evolving positively and rapidly, with RES-based hydrogen especially seen as a key tool to reach net-zero emissions.

Within the LNG industry, different actors will respond to hydrogen development differently. 2040 and 2050 are beyond the average life of current LNG projects, the life of ship leases and other related facilities. This may even be the case for projects that will be financed and developed in the coming five years. However, for resource owners, especially in countries where gas revenue represents a significant source of income, the slow but then rapid development of hydrogen demand presents a potential long-term risk for their natural gas exports. Increasing investment into natural gas-based hydrogen production and CCUS technology and expanding LNG import terminals to explore synergies with industrial clusters are measures that can be taken to ensure that future strategies are in line with deep decarbonisation policies. In addition, steps to "clean up" the LNG value chain (fugitive emissions, liquefaction-related emissions) should be taken in order to meet the more stringent emission reduction criteria associated with a progressive decarbonisation of the energy system. A long-term low-carbon strategy provides an opportunity for LNG resource owners to support their host governments' diversification plans by increasing the ability to monetise their natural gas reserves while maintaining access to high-value markets.

As the hydrogen industry develops while the LNG industry continues to play a significant role in the global energy system, the link between the two is important. As Hanley et al. (2015, p. 56) conclude, "it is evident that the links between natural gas and hydrogen are very long standing and are likely to grow, not diminish, in the coming years."

Table 4.4 summarises and expands on the wider set of strategic choices pertaining to low-carbon hydrogen discussed in this Chapter and outlines their consequences for LNG exporters.

Table 4.4.: Impact of strategic choices with respect to hydrogen on LNG exporters

Strategic choices			**Impact on LNG exporters**
Value chain options	**Natural gas**	**Renewable energy**	
Production technology	Natural gas reforming or pyrolysis.	Electrolysis.	• NGR+CCUS and/or pyrolysis in the importing country could present upside for natural gas demand; LNG exporters can play a direct role by delivering the natural gas feedstock needed. • RES-based hydrogen would be a downside for natural gas demand, minimal opportunities for LNG exporters in green pathways.
Production location	Domestic gas to be converted to hydrogen.	Hydrogen produced via renewable energy and electrolysers domestically.	• LNG exporters could convert natural gas into hydrogen at LNG receiving terminal, subject to CCUS access or methane pyrolysis technology. • For hydrogen import-based strategies, limited direct role for LNG; exporters can potentially leverage know-how and commercial links, potentially retrofitting export terminal and some facilities. • For pure non-import strategies, there is no role for LNG exporters.
	LNG to be imported and converted to hydrogen near LNG importing terminal.	RES-based hydrogen imported via liquid hydrogen, liquid organic hydrogen carriers, ammonia (or other derivatives).	
Hydrogen transport (pure hydrogen vs derivatives)	Natural gas can be converted to pure hydrogen with NGR+CCUS, or pyrolysis.	Pure hydrogen produced via low-carbon renewable energy.	• Utilising current LNG infrastructure and import terminal allows for LNG to be shipped and converted into hydrogen at importing countries. • Pure hydrogen, and all other derivatives except synthetic methane have separate technical requirements for liquefaction/loading, shipping, and receiving infrastructure, limited scope for LNG exporters.
	Natural gas-based hydrogen could be converted into synthetic methanol, methane, Fischer-Tropsch liquid hydrocarbons, ammonia, etc.	RES-based hydrogen could be converted into synthetic methanol, methane, Fischer-Tropsch liquid. hydrocarbons, ammonia, etc.	
Hydrogen end-use (targeted vs economy-wide)	Natural gas-based hydrogen to target applications, such as chemical feedstock, oil refining, steel production, ammonia production; initially replace current / potential hydrogen demand.	RES-based hydrogen to target applications such as chemical feedstock, oil refining, steel production, ammonia production; initially replace current hydrogen demand. In the long run, it is likely that processes will relocate to areas with high-RES demand.	• LNG terminals located near industrial clusters present an opportunity to take advantage of technical and commercial synergies. • For wide-scale hydrogen adoption, importers could leverage existing gas infrastructure by blending and other measure in the medium term. LNG exporters long term role will depend on the ability to manage CO_2 (CCUS or pyrolysis), and favourable government policy. • Countries may take political decisions to utilise only RES-based hydrogen, which would limit LNG exporters' role drastically.
	Natural gas-based hydrogen's role in large scale hydrogen adoption will depend on technical characteristics, economics, and government policy.	RES-based hydrogen's role in large scale hydrogen adoption will depend on available renewable resources, economics, and government policy.	
Hydrogen role (exports vs domestic use)	Natural gas-based hydrogen supports exports to sectors and countries with increasing hydrogen demand.	RES-based hydrogen allows for countries with rich renewable energy resources the ability to export a new commodity, subject to geographical location and technological improvements.	• LNG exporters could continue to export to end-users with aggressive decarbonisation targets. • Longer term, LNG exporters who are resource owners may consider shifting to exporting hydrogen derivatives (reforming natural gas and managing carbon domestically), altering entire value chain.
	Natural gas-based hydrogen could decarbonise current domestic hydrogen and other derivatives demand.	RES-based hydrogen could decarbonise current domestic hydrogen and other derivatives demand.	

Source: interviews and own analysis, table adapted from Van de Graaf et al. (2020).

4.3.3. Limitations and further research

It should be noted that there are some limitations to the model-based analysis presented in this Chapter. Firstly, we do not explicitly model the production, transportation and consumption of hydrogen-based synthetic fuels and feedstocks such as ammonia or methanol separately from hydrogen. As mentioned above, producing and exporting such energy carriers might be an opportunity for producers with low-cost RES in scenarios where hydrogen production is predominantly RES-based.

Furthermore, existing commercial relationships, strategic considerations and policy choices may play an important role in shaping the evolution of the market for low-carbon hydrogen as well, which are not easily represented in models such as the one used in this Chapter. This was highlighted by interviewees, who noted that the development of a technology mix, taking advantage of supply economics, regulatory support, and technological improvements, is what is likely to unfold. In addition, the fragmented nature of hydrogen with complex supply chains that can be structured in a variety of derivatives and end-uses, coupled by the different approaches of the prominent energy players, likely will lead to different routes being developed, and therefore different technology combinations. As an industry participant concluded: "different places will get different solutions."

This opens avenues for further research. For example, a more detailed representation of other relevant hydrogen-derived energy carriers in a global model could be used to explore potential alternative business models based on the production and export of such energy carriers rather than hydrogen.

Additionally, future research may look at the actual implementation of export-oriented business models centred on hydrogen, for example, potential contractual frameworks required to establish such a business.

Finally, expanding the outlook to the period beyond 2050 may provide further insight into the economic implications of increased hydrogen use on LNG exporting countries in a net-zero emissions economy (i.e. potential for stranded assets).

4.4. Conclusions

We perform a model-based scenario analysis to quantify the impact of different global low-carbon hydrogen development pathways on LNG exporters using a novel, integrated natural gas and hydrogen market model. The scenarios are based on recent projections by the International Energy Agency (IEA) and consistent with a deep decarbonisation of the global energy system by 2050.

We find that low-carbon hydrogen production has the potential to become a significant user of natural gas by 2040, stabilising global natural gas consumption within a framework of global decarbonisation. In scenarios where different low-carbon hydrogen production technologies compete on cost, natural gas-based pathways predominate. The exception is regions with very good RES potentials in scenarios where RES and electrolyser investment costs decline substantially compared to the baseline. However, even in such cases, the cost margin between natural gas- and RES-based low-carbon hydrogen production technologies is relatively narrow. This is an effect of natural gas prices remaining at comparably low levels due to overall stagnation in global natural gas demand. The development of pyrolysis as a potentially less costly alternative to NGR with CCUS could further reinforce the economic advantage of natural-gas based hydrogen production in such a low gas price environment. In scenarios with high shares of natural gas-based hydrogen production, LNG demand continues to grow to 2050. In scenarios where RES-based hydrogen becomes the dominant pathway globally, LNG demand grows until 2040 and then declines. In conclusion, LNG demand is generally resilient in technology-agnostic scenarios, even as global demand for natural gas decreases.

The results suggest that for LNG exporters, encouraging the adoption of natural-gas based low-carbon hydrogen in import markets appears to be a viable strategy to safeguard export revenues. LNG industry participants interviewed for this analysis acknowledged the growing importance of low-carbon hydrogen and identified hydrogen as both an opportunity and a threat in the long term. Furthermore, the LNG industry is perceived to be well-positioned in terms of skills and resources to play a role in developing low-carbon hydrogen, mainly due to its large-scale engineering and project management capabilities. Rather than technical, the most relevant synergies between LNG and low-carbon hydrogen appear to be commercial. The LNG industry has decades of experience developing specialised infrastructure and supply chains, with associated high investment risks and high capital requirements. The initial development of LNG-based low-carbon hydrogen supply chains could be modelled on the LNG market, with long-term off-take agreements centred on industrial clusters built around LNG import terminals.

5. Analysing the Impact of a Renewable Hydrogen Quota on the European Electricity and Natural Gas Markets

5.1. Introduction

In 2018, the member states of the European Union (EU)—excluding the United Kingdom (UK)[1]—consumed around 3775 TWh of natural gas, with the fuel accounting for approximately 22% of the EU's total energy consumption (Eurostat, 2020a). However, to achieve ambitious CO_2 mitigation targets, such as reducing EU net emissions to zero by 2050 (European Commission, 2020a), conventional natural gas as an energy carrier must progressively be phased-out in the long-term (Scharf et al., 2021). While electrification presents an option to replace natural gas in some of the end-uses it currently dominates, full electrification may neither be technically feasible in the time frame considered for decarbonisation nor the most economical choice (Ioannis et al., 2020), in particular in sectors that are seen as hard to decarbonise. In space heating, for instance, there is a strong path dependence and high degree of technological lock-in (Gross and Hanna, 2019). The pace of the shift towards alternative heating technologies would have to increase substantially to be consistent with a full decarbonisation of the sector by 2050.

To be consistent with the net-zero objective, the gas supply would thus have to be decarbonised (Speirs et al., 2018). One way to decarbonise the gas supply is to substitute biomethane for fossil natural gas. Estimated theoretical production potentials for the EU and the UK range from 160 TWh (manure only) to 1510 TWh (all potential feedstocks) (Scarlat et al., 2018a,b).

While the latter is equivalent to more than a third of the block's present-day natural gas consumption, it is likely that actual future production potentials will be more constrained. Biogas production from energy crops, rather than organic waste streams, is increasingly challenged on sustainability grounds and reined in

[1]The UK left the EU on February 1st, 2020, reducing the number of member states from 28 to 27.

by national as well as EU regulation (Scarlat et al., 2018a). Also, competition for the available biomass will greatly increase in a carbon-constrained world, since it can also be used as a feedstock for the production of liquid fuels, or combusted directly to produce electricity and heat. This limits the potential of biomethane as a drop-in replacement for natural gas.

An alternative option is the injection of low carbon hydrogen or hydrogen-derived synthetic methane[2] into the gas grid. Low-carbon hydrogen and gases derived from it can be produced in a multitude of ways, for instance, from biomass, from fossil fuels (in combination with carbon capture and storage/utilisation (CCS/U)) or from the electrolysis of water (through so-called Power-to-Gas (PtG) technologies), provided the electricity used in the process itself comes from a low carbon power source (IEA, 2019c). Supplementing the individual national hydrogen strategies of several member states (Lambert, 2020), the EU published its own hydrogen strategy in 2020, stating a clear political preference for electrolysis-based renewable hydrogen (European Commission, 2020b).

However, technologies to produce renewable hydrogen are not mature enough to compete with conventional energy sources (Moraga et al., 2019, Speirs et al., 2018, Van Leeuwen and Mulder, 2018), particularly at today's carbon price levels. Therefore, additional instruments are often proposed to incentivise the production and uptake of low carbon hydrogen and its derivatives (Moraga et al., 2019). These include, e.g., direct subsidies, tax breaks, loan guarantees (Dolci et al., 2019), state-backed offtake guarantees or carbon contracts for difference (Chiappinelli and Neuhoff, 2020). To encourage the injection of renewable hydrogen or synthetic methane into the natural gas grid, instruments that have been introduced to promote the deployment of renewable energy source (RES) in the power sector, such as feed-in tariffs or quotas with tradable certificates[3] (Menanteau et al., 2003) could conceivably be adapted for this purpose as well.

Against this background, in this paper, we assess and quantify the distributional effects of a renewable hydrogen quota on the electricity and natural gas markets in the EU. The assumed quota is imposed on final gas consumption outside the EU Emission Trading System (EU ETS) in order to

[2]Hydrogen (H_2) and carbon dioxide (CO_2) can be used to produce synthetic methane (CH_4).

[3]Quotas with tradable certificates are or have been used in several countries to promote the adoption of RES in the electricity sector. In Europe, these include, for example, Belgium, Ireland, Sweden and the United Kingdom (CEER, 2018).

act both as an instrument to facilitate the large-scale deployment of PtG technologies and to reduce emissions from sectors currently not subject to mandatory capping.

A renewable hydrogen quota (alternatively referred to as a renewable hydrogen obligation) is a policy instrument designed to promote renewable hydrogen and its derivatives and to contribute to the decarbonisation of the gas supply. Our definition of renewable hydrogen is based on the European hydrogen strategy. It refers to hydrogen that is "produced through the electrolysis of water [...] with the electricity stemming from renewable sources." (European Commission, 2020b, p. 3). We further include synthetic methane but exclude biogas, biohydrogen or biomethane as renewable gases to better isolate the effects of PtG on the gas and electricity markets. Furthermore, any other low-carbon hydrogen source, particularly fossil fuel-derived hydrogen with CCS, is not considered. The quota would be imposed on the demand side and requires consumers to source a minimum share of their gas-based energy from renewable hydrogen or hydrogen-derived synthetic methane (Finon et al., 2003). Quotas are a part of the toolbox of policy instruments proposed in the European hydrogen strategy. The strategy suggests the introduction of "minimum shares or quotas of renewable hydrogen or its derivatives in specific end-use sectors" (European Commission, 2020b, p. 11), such as the chemical industry or the transport sector (European Commission, 2020b). Analogous to a renewable energy obligation with tradable green certificates, a renewable hydrogen quota could in practice be based on a system of tradable certificates: once a unit of hydrogen or hydrogen-derived gas is injected into the gas grid by a PtG producer, a renewable hydrogen certificate is generated. This certificate can then be sold to a consumer, who needs to purchase enough certificates to demonstrate its compliance with the quota obligation to the regulator. A quota designed in such a manner decouples the financial from the physical hydrogen flows, allowing for "virtual blending" (European Commission, 2020b, p. 11), i.e. a variation in the injection and thus the hydrogen share in different gas grids and potentially across member states, increasing economic efficiency (Haas et al., 2004).

Under a quota with tradable certificates, PtG producers have two income sources: from selling hydrogen to gas consumers at the natural gas price and from selling renewable hydrogen certificates to quota obliged consumers. They receive the equilibrium price on the certificate market (Finon et al., 2003).

Assuming the certificate market is perfectly competitive, producers are incentivised to offer certificates at their long-run marginal cost of production, which consists of the price for renewable electricity, fixed and variable operations and maintenance costs, annualised investment costs, and—if the hydrogen is converted into synthetic methane—the cost of the CO_2 feedstock required, less the natural gas price. As a result, the PtG producers with the lowest marginal cost will satisfy the demand for renewable hydrogen (Kildegaard, 2008) and the trading of certificates guarantees that the quota is met in a cost-efficient manner (Finon et al., 2003, Menanteau et al., 2003).

As mentioned above, injecting renewable hydrogen or synthetic methane into gas networks is an option for both PtG integration and gas sector decarbonisation (Quarton and Samsatli, 2018, Speirs et al., 2018, Timmerberg and Kaltschmitt, 2019). While synthetic methane is of natural gas quality and can be injected into natural gas pipelines unrestrictedly, hydrogen can be blended with natural gas only up to a specific limit (Moraga et al., 2019), which varies from country to country and is currently 10 vol-% in Germany, 6% in France and 4% in Austria, for example (Hydrogen Europe, 2018). Injecting too much hydrogen into natural gas pipelines may damage some existing transportation, metering and end-use equipment (de Vries et al., 2017). The level at which the injection takes place also plays a role. Hydrogen injection into gas distribution pipelines is mostly considered as less of a concern than injection into gas transmission grids (Haeseldonckx and D'haeseleer, 2007, Quarton and Samsatli, 2018).

From a market perspective, blending renewable hydrogen and synthetic methane with natural gas creates another link between the electricity and the natural gas markets. So far, gas-fired power plants are the only interface between the power and gas systems (Ordoudis et al., 2017). Several studies have assessed the interaction between gas and power markets using market models (e.g. Dueñas et al. (2013), Ordoudis et al. (2019), Yang et al. (2015)). The interaction between both markets is typically simulated by providing the natural gas demand of gas-fired power plants as an input to the gas market model and, in turn, the gas prices/gas supply availability derived using the gas market model as an input to the electricity market model. Yang et al. (2015) iteratively simulate gas and power systems in order to assess the interaction between the sectors on both a physical and an economic level. Market and system interdependence are evaluated by analysing physical (e.g. transmission limits, load variation) and economic parameters to better understand system and market reactions (e.g. market prices, outages).

A renewable hydrogen quota will lead to an expansion of PtG capacity and production. The integration of PtG into the electricity and natural gas systems increases both markets' interdependence and gives rise to additional interactions. Helgeson and Peter (2020) investigate the coupling of the European electricity and road transport sectors through—among other technologies—hydrogen and hydrogen-derived fuels (including PtG) using a multi-sector energy market model. They show that an increase in the production of hydrogen and hydrogen-derived fuels leads to a rise in marginal electricity generation costs. Vandewalle et al. (2015) present a stylised model implemented as a mixed-integer linear programme to analyse the interaction of natural gas, electricity and carbon emissions markets. They assume that PtG plants produce synthetic methane using only excess electricity from solar photovoltaics (PV) and wind turbines that would otherwise be curtailed, finding that PtG integration increases the market value of RES and triggers a decline in gas market prices. Similarly, Roach and Meeus (2020) use a stylised deterministic model formulated as a mixed complementary problem (MCP) to investigate the price and welfare effects of PtG on the gas and electricity markets. They assume that the gas and electricity market clear separately but are coupled by PtG plants. They show that electricity consumers benefit from PtG integration because it decreases RES premia. Gas consumers profit from lower gas prices, as PtG injection replaces natural gas production. Lynch et al. (2019) study portfolio effects of PtG by developing and applying a stylised, stochastic MCP with profit-maximising firms and cost-minimising consumers. Firms can endogenously invest in electricity and PtG generation capacities, whereby generation from RES receive a feed-in premium. Their results indicate that investment in PtG becomes attractive with wind penetration above approximately 50%, leading to a transfer of rents from consumers to wind power. Focusing on decarbonisation of natural gas demand, Horschig et al. (2018) use a method of system dynamics to gain insights into the effect of policy instruments on energy demand, investments, energy availability and capacity development. The method is an iterative procedure and is applied on assessing the effect of different policy measures on biomethane, natural gas and bio-synthetic methane supply in Germany. Koirala et al. (2021) develop an integrated energy system model covering the electricity, gas, and hydrogen systems to and analyse the interaction between the subsystems. The model is formulated as a linear program and minimises the total cost of operating the system. The subsystems are linked by different assets, e.g., PtG links power and hydrogen systems, whereas gas power plants link the gas and power systems. Model outputs comprise system dispatch and marginal cost. The model is simulated in a case study for the Netherlands until 2050.

Previous work focused mostly on either the technical impact of injecting hydrogen or synthetic methane into existing gas infrastructure or assessing gas and electricity markets' interaction using numerical models, but mostly with highly stylised system layouts. We add to the existing body of knowledge by analysing the effects and interactions associated with the integration of PtG in natural gas and electricity markets. Whereas the existing literature on the subject applies simplified models, we significantly extend the scope of the analysis by linking two large-scale, data and technology-rich models of the European natural gas and electricity markets, which are run in iterations. To isolate the impact of PtG and the renewable hydrogen quota on both markets, we compare a reference scenario with an alternative scenario in which a progressively rising renewable hydrogen quota is imposed on final gas consumption. We show how cost-optimal generation capacities change over time and how renewable hydrogen and synthetic methane injection impact natural gas prices. In addition to that, we quantify the distributional effects and the changes in rents among different producer and consumer groups on both markets.

We assume that the uptake of PtG in the EU is driven by a uniform renewable hydrogen quota on final gas consumption in sectors of the energy system not subject to the EU ETS. The EU ETS covers the power sector, large industrial emitters and aviation.

The remainder of this paper is structured as follows: Section 5.2 describes the gas and electricity market models, the input data used, and the assumptions made for this analysis. Section 5.3 presents the results of the scenario simulations and shows the price, quantity and welfare effects. Section 5.4 interprets and discusses the results, shows the limitations of our work and highlights openings for further research. Section 5.5 concludes the research paper.

5.2. Methodology

In order to assess the impact of a renewable hydrogen quota on both markets, we iteratively link two partial equilibrium models of the European electricity and natural gas markets (see Figure 5.1). Sectoral gas demand, temporal gas demand profiles, PtG capacities and PtG injection volumes are passed from the electricity to the gas market model. The gas market model's simulated gas price is then returned to the electricity market model to initiate the next iteration. The iteration process is stopped once the annual difference in each of the exchanged parameters between two subsequent iterations is less than 5%.[4]

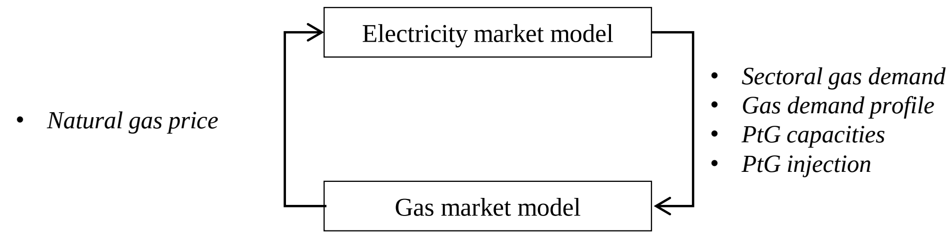


Figure 5.1.: Applied simulation framework

5.2.1. Model descriptions

The electricity market model is an investment model covering electricity production and consumption in 28 countries in Europe[5]. Initially developed as a standalone electricity market model by Richter (2011), to better replicate future energy systems in which final energy consumption is increasingly electrified, it has since been extended to cover additional end-use sectors, conversion technologies and electricity-derived energy carriers. The model is run in an hourly resolution for 16 typical days, which, combined, are representative for a single year (Helgeson and Peter, 2020).

[4]The electricity and gas market models employed are large-scale, data-rich models, making iterations a time-intensive process. The selected stopping criterion represents a trade-off between model convergence and the time required to achieve convergence, i.e. the number of iterations of both models. Since model convergence proceeds exponentially, we found that below 5%, the number of iterations required to achieve further measurable convergence increases substantially.

[5]Austria, Belgium, Bulgaria, Croatia, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Netherlands, Norway, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden, Switzerland and the United Kingdom.

We endogenously model electricity production, cross-border power flows and electricity-based hydrogen and synthetic methane production. Final electricity and natural gas demand are treated as exogenous inputs. Both are assumed to be inelastic. The electricity market is assumed to be perfectly competitive, allowing the model to be formulated as a constrained linear optimisation problem.

Furthermore, we use and extend a European natural gas infrastructure model to assess the impact of hydrogen and synthetic methane injection on natural gas flows and prices. The model was initially developed by Lochner (2011b) and is formulated as a linear optimisation problem that minimises the total cost of natural gas supply in Europe, subject to infrastructure and production constraints. Hence, it is assumed that European natural gas markets are perfectly competitive[6]. The model considers commodity as well as dispatch cost. It covers most of European natural gas transmission infrastructure, consisting of pipelines, gas storage and LNG terminals. All European countries connected to the transmission grid[7] and major exporting countries (Russia, Algeria, Libya and the Southern Gas Corridor) are included with their corresponding annual gas demand and production capacities. The model is run in monthly resolution. Further details on the model can be found in, e.g., Dieckhöner et al. (2013), Lochner (2007), and Lochner (2011a).

A detailed description of the main equations governing both the electricity and the gas market model is provided in Appendix D.1.

5.2.2. Data and assumptions

To quantify the impact of a renewable hydrogen quota on final gas consumption in the sectors outside the EU ETS, we compare a reference scenario (REF) with a scenario in which a quota is imposed (EUQ). Other than the quota, assumptions for both scenarios are identical.

EU electricity and natural gas demand projections are based on the POTEnCIA Central scenario of the EU Joint Research Centre. The scenario describes the possible evolution of the EU energy system based solely on

[6]This assumption is supported by recent market monitoring reports of the European Union Agency for the Cooperation of Energy Regulators (ACER). They show that gas hub prices converged significantly over the last years (ACER, 2019), indicating an increasingly competitive market. Moreover, market interconnectivity and liquidity is expected to further improve in the future (Schulte and Weiser, 2019a).

[7]Concerning the EU, all EU member states except for Malta and Cyprus are included in the model.

policies and measures introduced until 2017. The POTEnCIA Central scenario was explicitly designed to serve as a benchmark against which alternative pathways can be compared. Consequently, it assumes a substantial decline in CO_2 emissions in the sectors regulated by the EU ETS, most notably heavy industry and power generation. In branches of the energy system not regulated by the ETS, fossil fuel consumption and thus CO_2 emissions are assumed to decline more gradually (Mantzos et al., 2019). To increase the pace of reductions in these sectors, additional policy measures—such as a renewable hydrogen quota—would be required.

The allocation of the gas demand projections from the POTEnCIA Central scenario (classified according to NACE Rev. 2) to the EU ETS, non-EU ETS, transmission system-level and distribution-system level consumption sectors used in this paper is based on the POTEnCIA Central scenario and further own assumptions. Further details on the natural gas demand allocation are provided in Appendix D.1.

We represent the EU ETS using a simplified approximation integrated into the electricity market model, in which only the power sector abates endogenously. Emissions from industry and aviation follow an exogenous path taken from the POTEnCIA Central scenario report (Mantzos et al., 2019). The assumption implicit in this setup is that marginal abatement always occurs in the power sector.

Minimum capacity targets for the technology-specific RES build-out in the power sector are taken from the *National Trends* scenario of the draft ENTSOG/ENTSO-E Ten-Year Network Development Plan (TYNDP) 2020, which reflect the latest targets of the individual member states for the development of RES in the power sector (ENTSOG/ENTSO-E, 2020). The initial installed capacities of other generating technologies are taken from Mantzos et al. (2019).

The gas market model computes natural gas prices. Price projections for steam coal and oil are taken from the IEA World Energy Outlook 2020's Sustainable Development Scenario (IEA, 2020b).

Gas infrastructure data is based on the gas market model's historical database, which is updated using recent, publicly available data. Cross-border pipeline capacities are retrieved from the ENTSO-G Transmission Capacity Map (ENTSOG, 2019), LNG regasification capacities from the GIE LNG Map

(GIE, 2019) and storage capacities from the GIE Storage Map (GIE, 2018). Entry and exit tariffs from/into market areas are set to values published by the ACER market monitoring report 2018 (ACER, 2019). If not otherwise stated in the data sources, capacities and tariffs are assumed to remain fixed over time. Regarding the future expansion of the European gas transmission system, only projects with 'final investment decision' status in the TYNDP 2018 are considered (ENTSOG, 2018).

Commodity costs, i.e. break-even prices of natural gas supply, are derived from a commercial database that covers all domestic European gas production and that of the relevant exporters of pipeline gas and LNG in a high resolution (Rystad Energy, 2020). Expected changes in gas production capacities and the corresponding break-even prices out to the year 2040 are reflected in the dataset and the decreasing gas production of European countries, such as the Netherlands or UK, as well as the increasing gas production by exporting countries, e.g. Russian pipeline exports and aggregated LNG, are thus considered in the model. A visualisation of the gas supply merit order can be found in Appendix D.1 (Figure D.1).

Technical injection limits of hydrogen into distribution grids vary between countries, and it is as yet unclear what injection limits will be feasible with only minor technical modifications. Currently, 10-20 vol-% are generally considered as the maximum acceptable (Melaina et al., 2013, Müller-Syring and Henel, 2014). Although limits currently differ from member state to member state, for reasons of simplification, moving forward, we assume a fixed injection limit (in vol-%) across the EU (see Table 5.1), which increases over time. Hence, individual injection limits due to local specificities (e.g. CNG filling stations, sensitive industrial consumers (IEA, 2019d)) are not explicitly considered.

The quota is imposed on final gas demand sectors, which are not part of the EU ETS. The rationale for excluding the EU ETS is that inside it, a renewable hydrogen quota would not lead to a decline in overall CO_2 emissions, as the reduction in emission allowances required by gas consumers would free up allowances to be used elsewhere. Outside the EU ETS, emissions are not capped, and the substitution of renewable hydrogen or synthetic methane for natural gas would reduce total emissions. We further assume that the quota is based on a system of tradable renewable hydrogen certificates, which are valid for one year and can be traded across the EU, and that PtG producers have to obtain their electricity from RES located in the same market area and generating electricity in the same hour. This ensures that there is a temporal and spatial correlation between PtG electricity consumption and RES electricity production. Assumed hydrogen injection limits and the quota obligations are shown in Table 5.1[8].

Table 5.1.: Assumed injection limits in gas demand end-use sectors in vol-% and renewable hydrogen quotas in TWh-% (own assumption based on IEA (2019d), Melaina et al. (2013), Moraga et al. (2019), Müller-Syring and Henel (2014))

	year							
	quota [TWh-%]				limit [vol-%]			
Demand sector	2025	2030	2035	2040	2025	2030	2035	2040
Residential and commercial	5	10	15	20	5	10	15	20
Non EU ETS industry	5	10	15	20	5	10	15	20
EU ETS industry	0	0	0	0	0	0	0	0
Power sector	0	0	0	0	0	0	0	0
Others	5	10	15	20	5	10	15	20

5.3. Results

The results of the scenario simulations are summarised in this section.[9] The quantity effects (Section 5.3.2), price effects (Section 5.3.3) and distributional effects (Section 5.3.4) of the renewable hydrogen quota are assessed by analysing the difference between the quota scenario (EUQ) and the reference scenario (REF).

The results were generated through an iterative procedure. The electricity and gas market models were parameterised with the data and assumptions presented in Section 5.2.2. The models were run in iterations, exchanging gas prices, gas consumption and PtG production volumes, until the convergence criterion[10] was met.

[8] Note that the renewable hydrogen quota refers to per cent of gas demand (in TWh) and can be complied with hydrogen and synthetic methane, whereas the injection limit only refers to pure hydrogen and refers to vol-%.

[9] Summary tables can be found in D.2.

[10] We defined a less than 5% difference in annual results between two subsequent model runs as our convergence criterion.

5.3.1. Reference scenario

In the REF scenario, EU final electricity consumption increases by 0.6% per year on average, growing from 3054 TWh in 2025 to 3444 TWh in 2040. The development of the supply mix is illustrated in Figure 5.2. National renewable energy targets and rising prices in the EU ETS ensure that electricity production becomes significantly less carbon-intensive over time. RES account for 47% of EU net electricity generation in 2025 and 77% in 2040. Coal and lignite are mostly phased-out until 2040. The rapid expansion of wind and solar power between 2025 and 2030 also cuts into gas use in the power sector, depressing the load factors of gas-fired power stations. However, gas power generation stays broadly flat thereafter, with gas-fired capacity providing an essential backup power source for intermittent RES.

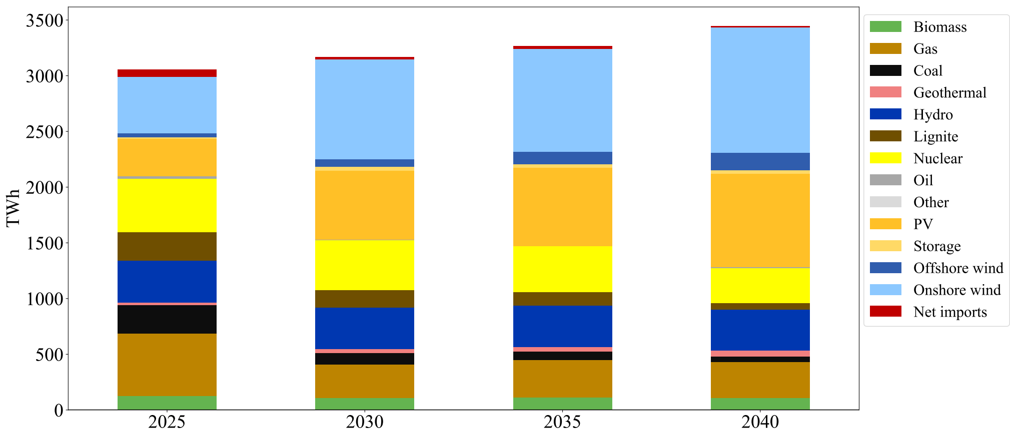


Figure 5.2.: EU electricity generation in the REF scenario

Mainly due to the lower consumption of the power sector, EU natural gas demand drops by 354 TWh/a between 2025 and 2030 and then levels off at around 3290 to 3350 TWh/a until 2040 (see Table D.6 in Appendix D.2). No hydrogen and synthetic methane are produced for gas grid injection in the REF scenario.[11] EU indigenous gas production declines from around 340 TWh in 2025 to 300 TWh in 2040, but due to decreasing natural gas demand, the import share remains stable at around 90%. The most important suppliers are Russia, Norway and the LNG market, whereby Russian and LNG imports increase, and gas supply from Norway decreases over time.

[11] In the REF scenario, around 10 GW of electrolysers are installed EU-wide by 2040 to feed a small but increasing demand for renewable hydrogen in the industrial sector. This demand is exogenous to the model and based on POTEnCIA Central Scenario assumptions (Mantzos et al., 2019).

5.3.2. Quantity effects of a quota

In the EUQ scenario, a progressively increasing renewable hydrogen quota is imposed on final gas consumption in sectors not regulated by the EU ETS, rising from 5% in 2025 to 20% in 2040 (see Table 5.1).

Since the quota is assumed to apply to the EU as a whole, the actual production and injection of renewable hydrogen or synthetic methane varies significantly from member state to member state.

Consequently, there is noticeable growth in electricity consumption for hydrogen production: it rises from 200 TWh in 2025 to 805 TWh in 2040. PtG production is a significant consumer of RES-based electricity: in 2025, 13% of RES electricity is already consumed—on balance—for the production of hydrogen, with the share rising to 26% in 2040.

The rise in electricity demand associated with an EU-wide renewable hydrogen quota induces changes in the electricity mix (see Figure 5.3). Most of the additional electricity is provided by intermittent RES, in particular solar PV and onshore wind. The additional electricity required for electrolysis also leads to a rise in gas-fired electricity production. Some of it displaces coal and lignite. This is due to the cap on CO_2 emissions imposed by the EU ETS: in the EUQ scenario, power sector emissions are the same as in REF. At the same time, there is an increasing competition for RES-based electricity as some of the RES electricity that would have otherwise been used by other consumers is now diverted to PtG. This leads to an increase in demand for emission allowances and a rising price[12] (see Section 5.3.3 below), precipitating a coal-to-gas switch. Since gas-fired electricity production is less emission-intensive than coal or lignite, more electricity can be produced for the same absolute level of emissions by using gas.

Furthermore, the EUQ scenario also sees a relative increase in net electricity imports from outside the EU and slightly higher utilisation of nuclear generating capacity.

In the EUQ scenario, hydrogen and synthetic methane injection into the gas grid steadily increases, from 103 TWh in 2025 to 452 TWh in 2040. PtG production capacity rises from 26 GW to 117 GW over the same time.

[12]Since we use a simplified approximation of the EU ETS with exogenous emission reduction pathways for aviation and industry, we implicitly assume that marginal abatement occurs only in the power sector.

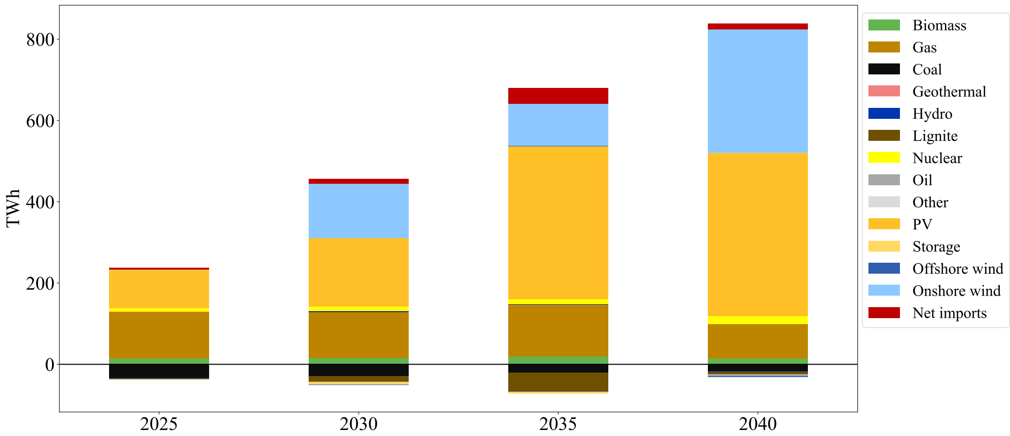


Figure 5.3.: Additional electricity generation in the EUQ scenario

Since the renewable hydrogen quota has to be fulfilled across the EU as a whole, rather than individually in each member state, hydrogen and synthetic methane production and injection vary significantly from country to country, both in absolute terms as well as as a percentage of gas consumption. Owing to the low volumetric energy density of hydrogen and the injection limits in the gas grid, the quota can not be fulfilled by injecting raw hydrogen alone. The level of PtG production in individual member states correlates with two main determinants: overall gas consumption and the availability of cost-competitive RES. Gas consumption determines how much hydrogen and synthetic methane can be absorbed by a country's gas networks. The larger the distribution-grid level gas consumption, the more hydrogen can be injected in absolute terms. Likewise, the higher the gas grid's capacity as a whole, the more synthetic methane can be absorbed by it. The production and injection of raw hydrogen into the distribution grid is maximised up to the volumetric limit in all member states since it is always more economical to produce and inject hydrogen instead of synthetic methane. Even in countries with the lowest-cost RES electricity, such as Spain, synthetic methane production, which is not subject to technical injection limits, is more costly than the production of raw hydrogen in the member states with the highest-cost RES electricity.

Figure 5.4 illustrates the distribution of hydrogen/synthetic methane production and its relationship to overall country-level gas demand. Measured in terms of energy, France and Spain produce slightly more synthetic gas than Germany, despite the latter's much more sizeable gas consumption. However, while in Germany, roughly half of the gas produced in energy terms is pure hydrogen, in France and Spain, most of the hydrogen produced is converted into synthetic methane since the production volumes exceed the assumed capacity of their respective distribution systems to absorb hydrogen. In the EUQ scenario, in 2025 and 2030, Denmark, Estonia, Finland, Greece, Ireland, Portugal, Spain and Sweden generate a surplus (net export) of renewable hydrogen certificates relative to the other member states. In 2040, France, Lithuania and Romania become net exporters as well, while Greece becomes a net importer.

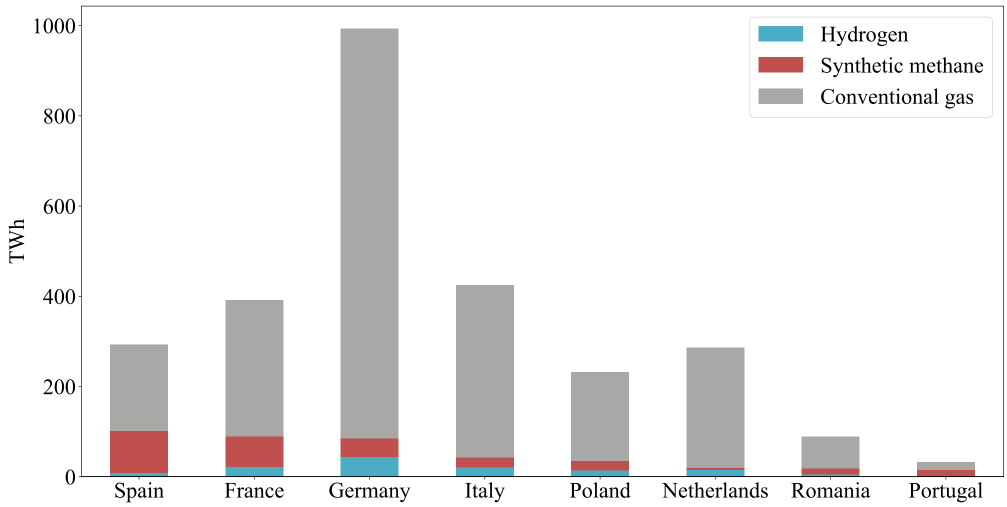


Figure 5.4.: Conventional gas, hydrogen and synthetic methane consumption of the eighth largest gas consumers in the EUQ scenario in 2040

Total natural gas demand is slightly higher in EUQ compared to REF due to higher gas-fired power generation[13]. The difference is greatest in 2030 and 2035, where the relative gas demand in the EU is around 6% higher in the EUQ than the REF scenario. In absolute terms, the increase in demand for natural gas is between 154 TWh (2040) and up to 216 TWh (2035) (see Table D.9 in Appendix D.2).

While the quota has a noticeable effect on the demand side of the natural gas market, conventional production is only affected in the long term when significant amounts of natural gas are replaced by hydrogen and synthetic methane (see Table D.9 in Appendix D.2). Until 2035, natural gas production hardly differs between the scenarios. Only in 2040 does gas production decrease noticeably compared to the REF scenario, by around 5.8% or 298 TWh/a over

[13] Note that only power sector gas consumption is derived endogenously. The remaining gas consumption from other end-use sectors is based on the POTEnCIA Central Scenario (Mantzos et al., 2019) and thus unchanged compared to the REF scenario.

all countries that produce gas in or export gas to the EU. Most of the reduction in natural gas production occurs in gas exporting countries, with the UK and LNG experiencing the most significant decrease in relative terms (22% and 15% in 2040). In absolute terms, LNG and Russian gas imports decline the most (105 TWh/a and 103 TWh/a in 2040) relative to the REF scenario. Lower imports from gas exporting countries in the EUQ scenario lead to marked shifts in gas flows in the European gas transmission system (see Figure 5.5). A noteworthy observation is that the EU's indigenous natural gas production is only 7.3 TWh/a lower in the EUQ scenario. Hence, the replacement of natural gas by hydrogen and synthetic methane mostly affects the gas exporting countries that supply gas to the EU.

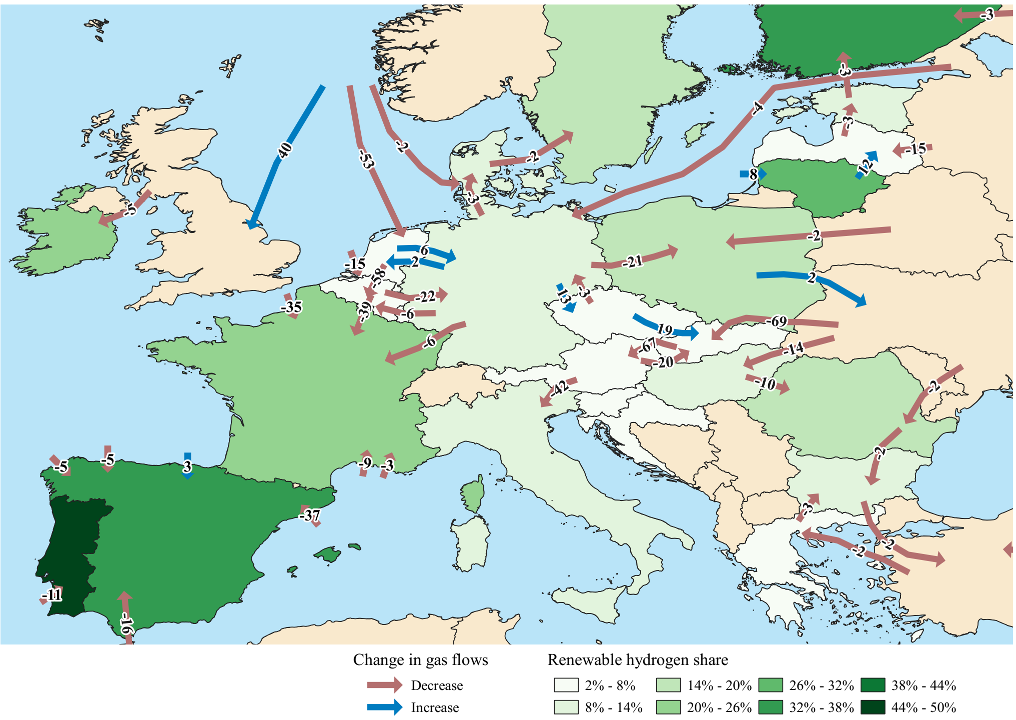


Figure 5.5.: Renewable gas shares of total gas demand in EU countries and absolute gas flow differences between REF and EUQ in 2040 (in TWh)

5.3.3. Price effects of a quota

A strong relative increase in electricity and EU ETS prices can be observed (see Figure D.2 in Appendix D.2). The substantial relative increase in electricity demand in the EUQ scenario when compared to the REF scenario, combined with the price increase in the EU ETS and the resulting coal-to-gas switch, leads to higher prices on the electricity market.[14]

In the long run, the large-scale injection of hydrogen and synthetic methane leads to a slight gas price decrease in Europe. Until 2030, gas prices change little since the elevated consumption of natural gas in the power sector cancels out the reduction in conventional natural gas demand resulting from the quota obligation. However, the price effect becomes more significant as the share of substitute gas increases. In 2040 gas prices in the EU are on average 3% lower than in the REF scenario (see Table D.9 in Appendix D.2).

As defined in this chapter, the renewable hydrogen quota applies to the final gas consumption of sectors outside the EU ETS. However, as shown above, it results in substantially higher electricity consumption. Most of the increase in power generation comes from RES. However, some of the RES-based electricity consumed by other sectors in the REF scenario is diverted to PtG production in the EUQ scenario, leading to increased gas-fired power generation and a rise in the demand for emission allowances from the power sector. This leads to a higher price for EU ETS allowances in the EUQ scenario, with the increase rising from 29% in 2030 to 34% in 2040.

The renewable hydrogen quota itself is assumed to be implemented based on tradable renewable hydrogen certificates that gas supply companies purchase to demonstrate their compliance with the quota. We assume that certificates are valid for one year and tradable across the EU on a competitive market. Due to the assumed decline in RES and electrolyser investment costs, the gap between the cost of production and the revenue PtG producers generate through sales on the gas market shrinks over time. Accordingly, the renewable hydrogen certificate price[15] drops from 213 EUR/MWh in 2025 to 119 EUR/MWh in 2040.

As a result, non-quota obliged consumers pay up to 3% less for natural gas on the wholesale market. Quota obliged consumers—mostly households, commercial, and small industrial consumers—pay up to 114% more for a unit of

[14] At the same time, there is no detectable correlation between the amount of hydrogen produced in a country and the price on its national electricity market, since most of the additional electricity is provided by zero marginal cost RES and gas-fired generators are usually setting the price.

[15] The certificate price is derived from the shadow variable of the renewable hydrogen constraint, reflecting the marginal cost of producing and injecting an additional unit of renewable hydrogen or synthetic methane. The variable can be interpreted as the market-clearing renewable hydrogen certificate price.

gas, since they have to purchase certificates to demonstrate compliance with the quota.

5.3.4. Welfare effects of a quota

We assess the welfare impact of a quota on both the electricity and gas market by determining the difference in the average[16] producer and consumer surpluses between the REF and the EUQ scenario:

$$\Delta_a(\overline{W}_a^{EUQ} - \overline{W}_a^{REF}) = \sum_{c \in C} W_{a,c}^{EUQ} * \frac{q_{a,c}^{EUQ}}{\sum_c q_{a,c}^{EUQ}} - \sum_{c \in C} W_{a,c}^{REF} * \frac{q_{a,c}^{REF}}{\sum_c q_{a,c}^{REF}} \quad (5.1)$$

The difference in average surplus is calculated separately for each group of market participants a (i.e. producers and consumers) by subtracting their average surplus $\overline{W}^{REF}$ in the REF scenario from their average surplus $\overline{W}^{EUQ}$ in the EUQ scenario. The EU-wide average surpluses are defined as the quantity (q) -weighted sum of each countries' c average surpluses. The PtG producer's surplus includes the renewable hydrogen certificate price.

As shown by Figure 5.6 the primary beneficiaries of a renewable hydrogen quota on the electricity market are RES producers, who benefit from the additional payments made by PtG producers for certifiable renewable electricity.

In the longer term, operators of conventional power plants benefit as well. As explained in Section 5.3.2, gas-fired power stations in particular produce more electricity in the EUQ scenario. However, spark spreads are lower in 2025 because emission allowances are marginally more expensive and wholesale gas prices slightly higher. After 2025, the overall increase in the electricity market price compensates for the additional marginal cost.

On the gas market, the quota increases total gas demand due to increased generation by gas-fired power plants but reduces conventional natural gas demand because of its partial substitution with hydrogen and synthetic methane. Changes in the average surpluses of producers and consumers on the gas market are shown by Figure 5.7. In 2025, the increased gas demand in the EUQ scenario has a small positive welfare effect on conventional natural gas producers due to the increased gas price. However, from 2030 to 2040, the increasing replacement of natural gas

[16] Expressed in Euros per unit of energy produced or consumed.

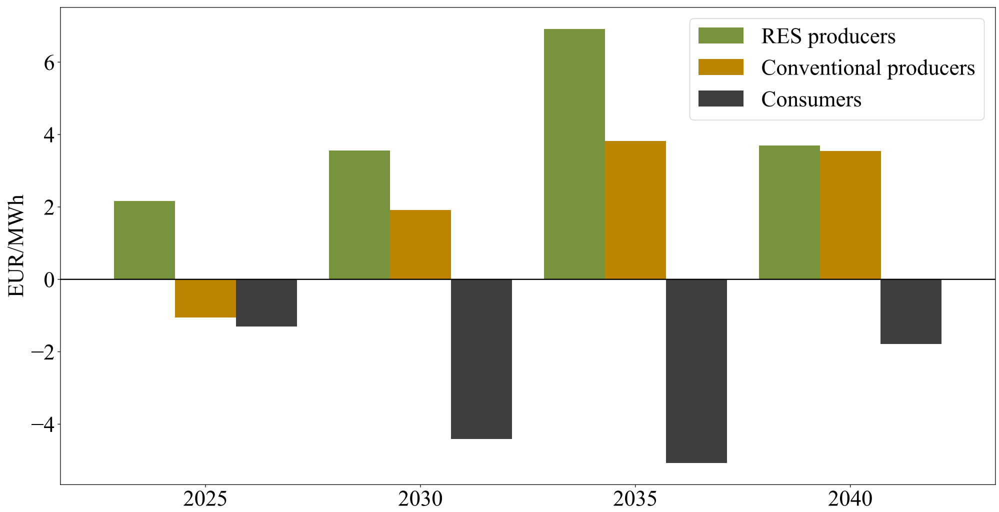


Figure 5.6.: Change in RES producer surplus, conventional producer surplus and consumer surplus on the electricity market

with hydrogen and synthetic methane leads to lower prices and lower natural gas production in the EUQ scenario, lowering producer profit margins. Compared to conventional natural gas producers, PtG producers have an additional source of income: first, they sell hydrogen and synthetic methane to gas consumers at the natural gas price and second, they are qualified to issue and sell renewable hydrogen certificates to quota obliged gas consumers. The average surplus of PtG producers in the EUQ scenario ranges from 32 EUR/MWh in 2025 to 18 EUR/MWh in 2030.

The average surplus of non-quota obliged gas consumers depends only on the natural gas price[17]. Hence, a higher gas price in 2025 in the EUQ scenario decreases the average surplus of non-quota consumers and increases their surplus after 2025 due to lower gas prices in the EUQ scenario. Quota obliged gas consumers pay the gas price for each consumed unit of gas. Additionally, they are required to purchase renewable gas certificates in the EUQ scenario. As a consequence, quota obliged consumer's average surplus differs strongly to the REF scenario and is 10.9 EUR/MWh lower in 2025 and 23.1 EUR/MWh lower in 2040.

[17] Buyers of EU ETS certificates face a higher carbon price. This results in higher costs for the operators of conventional, fossil-fuel-fired power stations. Since the analysis at hand focuses on the electricity and gas markets, we do not quantify the cost impact of this on consumers regulated by the EU ETS that are not part of the power sector.

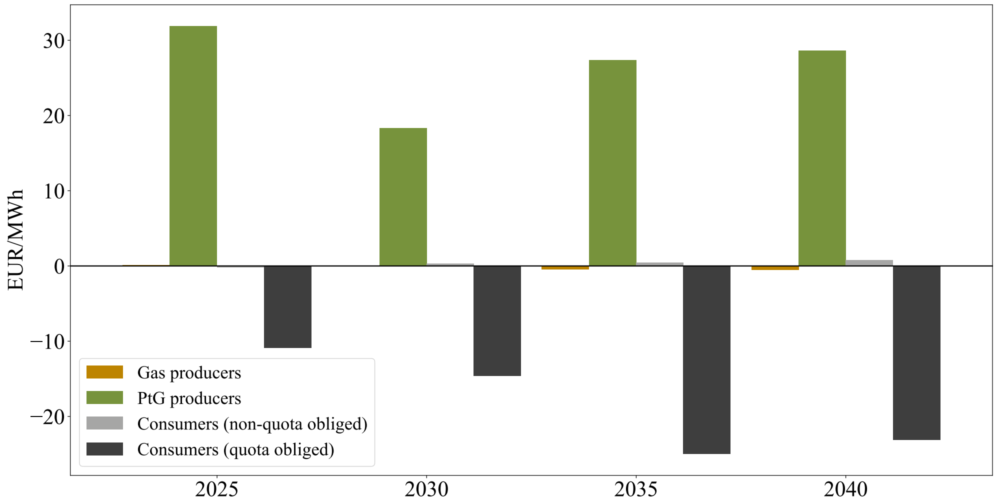


Figure 5.7.: Change in gas producer surplus, PtG producer surplus and consumer surplus on the gas market

Taken together across both markets, the quota has a welfare-diminishing effect (see Figure 5.8). There is a small net benefit for producers—mostly RES and PtG—while consumers face significant losses. Considering this, it should be highlighted that we do not consider the external benefit associated with reducing emissions through the use of renewable hydrogen. However, by dividing the additional cost of the quota by the resulting reduction in emissions, we are able to derive the emission abatement cost associated with the policy measure. Since the quota applies to consumption not regulated by the EU ETS, there is no waterbed effect, i.e. the emissions that would otherwise have been produced from the combustion of the displaced natural gas are fully avoided and not merely shifted to other sectors.

The direct emission reduction in the EU amounts to 21 million tCO_2 per year in 2025 and 90 million tCO_2 per year in 2040, while the additional cost associated with the quota increases from 15 billion EUR per year in 2025 to 43 billion EUR per year in 2040. Accordingly, we derive average marginal abatement costs of 736 EUR/tCO_2 in 2025 and 473 EUR/tCO_2 in 2040.

5.4. Discussion

The results of the simulations show that different producer and consumer groups are affected differently by sector-specific renewable hydrogen quotas.

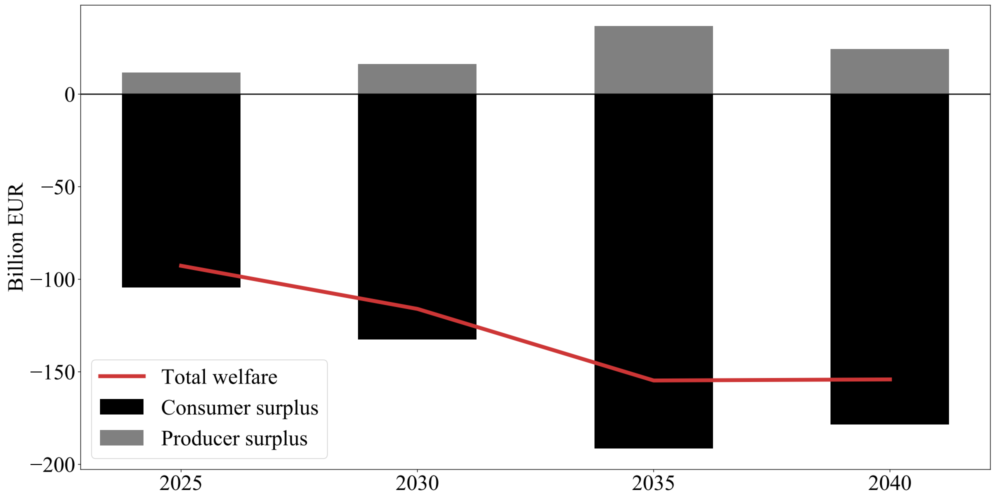


Figure 5.8.: Change in consumer surplus, producer surplus and total welfare

The majority of the cost burden is carried by quota obliged gas consumers, who subsidise the production and injection of renewable hydrogen through the purchase of renewable gas certificates emitted by the producers. The primary beneficiaries are both PtG producers and the producers of renewable electricity, since the former are required to purchase the power needed for the production of hydrogen from the latter.

On the electricity market, the increase in the price also leads to a decline in consumer welfare. As a consequence, quota obliged consumers which consume both electricity and gas would face both higher wholesale electricity prices and higher end consumer gas prices. Considering the composition of non-EU ETS gas consumption in general, the quota would therefore mostly affect households, the commercial sector and smaller, less energy intensive industries.

The quota design as suggested here could release the pressure on RES costs and they could earn additional profits and might ultimately lead to a decrease in public support for RES generation. Simultaneously, the burden would be carried by gas consumers. In our analysis, we assumed exogenous gas consumption in all sectors except the power sector. Most probably, the increasing end consumer gas price could lead to a phase out of gas utilisation in these sectors, e.g. by electrification. A decreasing gas consumption would reduce the utilisation of gas infrastructure and lead to a decrease in gas network charges. Ultimately, an upward cost cycle could be initiated, leading to a shrinking attractiveness of gas as an energy carrier.

Ultimately, quota obliged gas consumers shoulder most of the additional cost associated with the RES and PtG capacity expansion by purchasing the renewable hydrogen certificates emitted by the producers in order to demonstrate compliance with the quota.[18] Quota obliged gas consumers pay up to 25 EUR/MWh more in the quota scenario (EUQ) compared to the reference scenario (REF). As a comparison, in the first half of 2020 EU household consumers paid on average 65.6 EUR/MWh and non-household consumers 31.5 EUR/MWh for natural gas respectively (Eurostat, 2020b).

The primary beneficiaries are both PtG and RES producers since the former are required to purchase the power needed to produce hydrogen from the latter. RES producers earn up to 6.9 EUR/MWh more in the EUQ scenario. Average wholesale electricity prices in European countries in 2019 range from approximately 37 EUR/MWh to 64 EUR/MWh (ACER, 2021). Effectively, the renewable hydrogen quota thus constitutes an additional, indirect subsidy mechanism for RES.

While the substitution of natural gas consumption outside the EU ETS leads to the full equivalent reduction in total emissions, the quota constitutes a very costly emission abatement option. The derived average marginal abatement costs of 736 EUR/tCO_2 in 2025 and 473 EUR/tCO_2 in 2040 are high compared to those of alternative GHG mitigation measures.[19]

However, it is effective in stimulating the deployment of electrolysers, an EU industrial policy objective. The block's hydrogen strategy proposes installing at least 40 GW of electrolyser capacity in the EU by 2030[20] (European Commission, 2020b). With a quota as modelled in this chapter, cumulative installations would reach 52 GW by 2030, exceeding the EU capacity target. The rapid expansion could potentially contribute to a reduction in the unit cost of electrolysers through scale and learning effects. Policymakers must be aware that such technology support is nearly entirely paid for by a small group of energy consumers - which

[18]In practice, the burden of proof would likely rest with retail gas suppliers, rather than gas consumers directly. Retailers would have to demonstrate compliance by purchasing certificates and have an incentive to pass the associated cost on to consumers through the retail tariffs.

[19]For example, emission abatement cost in the power sector range from 22 EUR/tCO_2 (onshore wind or natural gas combined cycle replacing coal) to 119 EUR/tCO_2 (solar thermal replacing coal). A gasoline tax (16-42 EUR/tCO_2), wind energy subsidies (2-234 EUR/tCO_2) or electric vehicle subsidies (315-576 EUR/tCO_2) also comprise less costly abatement measures (Gillingham and Stock, 2018).

[20]An additional 40 GW is planned abroad for hydrogen imports into the EU.

might not necessarily be the same as those who benefit from a possible decline in technology costs.

While renewable hydrogen injection is maximised up to the volumetric limits in all member states, synthetic methane production is not equally distributed. The EU-wide quota and tradable certificates allow for an efficient allocation of PtG production across the participating countries, and synthetic methane is produced primarily in countries that combine good RES potentials with a high capacity gas grid, such as Spain. As a consequence, these countries become net exporters of renewable hydrogen certificates.

Finally, it should be noted that the general price and welfare effects described in this analysis would also occur if the hydrogen were not physically blended into the gas grid, but consumed directly. While the effects on the natural gas market are contingent on hydrogen displacing natural gas, the price/quantity effects on the electricity market are independent of the fuel substituted for hydrogen, provided it is consumed in non-EU ETS end-use sectors. However, as soon as the hydrogen demand of the quota obliged consumers and other new hydrogen consumers, e.g., industry, mobility and transport, exceeds a certain amount, repurposing gas networks to carry pure hydrogen may become more efficient economically than blending.

To our knowledge, this paper presents the first assessment of a renewable hydrogen quota using a combination of gas and electricity market models approximating real-world systems. However, there are some limitations to our analysis that provide opportunities for future research.

The first is that cost assumptions, particularly regarding current and future RES and electrolyser technology costs, are based on current projections (see Appendix D.1). We do not endogenously model technological learning, and the exogenous cost trajectory is a significant driver of the results presented in this paper. However, it should be pointed out that unless the full cost of consuming renewable hydrogen falls below that of natural gas, the *direction* of the welfare effects of a quota that forces consumers to use a more expensive fuel—hydrogen—should remain the same.[21]

[21] In terms of overall efficiency, the economic impact of a renewable hydrogen quota in our setting is similar to that of a low carbon fuel standard. Holland et al. (2009), for example, show that a low carbon fuel standard always lowers economic efficiency unless it is non-binding.

Secondly, we assumed most consumers to have an inelastic demand. Due to the iterative coupling of the electricity and gas market model, we are able to capture the price-responsiveness of power sector gas demand, but not that of other consumption sectors. The same applies to the electricity demand of all consumers other than PtG producers. In reality, one would expect to observe long-run adjustments on the demand side, particularly in the sectors that see an increase in gas supply costs due to the quota. The increase in the cost of gas could accelerate the shift towards other energy carriers in sectors covered by the quota. Decreasing gas consumption would reduce gas infrastructure utilisation and lead to a decrease in gas network charges. Ultimately, an upward cost cycle could be initiated, further contributing to a shrinking attractiveness of gas as an energy carrier. Furthermore, in reality gas and electricity markets are characterised by imperfections, which differ from the perfect competition assumptions of the proposed models.

However, while considering these dynamics might affect the size of the estimates presented in this chapter, qualitatively, the overall direction and distribution of the cost, price, quantity, and welfare effects would likely not change fundamentally.

5.5. Conclusions

In this chapter, we study the impact of a large-scale injection of renewable hydrogen and synthetic methane into gas grids on the European Union (EU) gas and electricity markets. By taking a renewable hydrogen quota on final gas consumption that is not subject to the EU emission trading system as an example, we analyse the resulting price, quantity and welfare effects. The analysis is conducted by comparing two numerical scenario simulations of European gas and electricity markets by linking two linear optimisation models.

Our model simulations show that the renewable hydrogen quota leads to significant expansion of renewable electricity production since power-to-gas producers are obliged to source their electricity from renewables simultaneously generating in the same market area. The remaining electricity demand on the market may be served either by conventional or by renewable power sources. However, since the CO_2 emissions of the power sector are capped, the increased electricity demand results in a higher emission allowance price, which triggers in an accelerated coal-to-gas-switch in the quota scenario[22]. The result is a higher electricity price in the quota scenario. The quota's primary beneficiaries in the power sector are renewable electricity producers. Since they are the exclusive suppliers for power-to-gas plants, their average profit margins rise significantly. However, conventional power producers also benefit from the increase in the market price, while the same effect leads to a decline in the surplus of power consumers.

On the gas market, the large scale injection of renewable hydrogen and synthetic methane leads—on balance—to a slight decline in gas prices. power-to-gas producers enter the gas market as a must-run capacity and sell their output at the gas market price. Hydrogen and synthetic methane partially displace conventional natural gas, which leads to lower gas production and imports and a slight decline in the natural gas price. The rents of natural gas producers decline accordingly. Ultimately, quota obliged gas consumers carry most of the additional cost associated with the renewable electricity generation and power-to-gas capacity expansion through purchasing the renewable hydrogen certificates needed to demonstrate compliance with the quota.

The simulations show that different producer and consumer groups are affected differently by sector-specific renewable hydrogen quotas. Whereas power producers benefit from increased electricity prices and power-to-gas producers enter the market with a positive welfare, quota obliged gas consumers as well as power consumers suffer from decreased welfare due to the quota obligation.

In summary, the quota's additional cost would be covered overwhelmingly by households, commercial and small industrial gas consumers. Beneficiaries are mostly renewable electricity and conventional power producers, and power-to-gas operators. Hence, the quota leads to a significant welfare redistribution from consumers to producers.

[22] In order to simplify the model, we assume that within the EU emission trading system, marginal abatement occurs in the power sector.

A. Supplementary Material for Chapter 2

A.1. Methodology

This section provides a detailed description of the methodological approach underpinning the analysis presented in Chapter 2. The analysis was conducted in five consecutive steps:

- Set a framework of general assumptions
  First, central assumptions are made. This includes a global electricity production scenario, a carbon price projection, as well as countries, years, available technologies and a uniform weighted average cost of capital (WACC).

- Estimate production costs for hydrogen from RES
  A RES investment cost (CAPEX) projection is constructed based on global one-factor experience curves for each renewable energy technology, using a scenario on the development of cumulative global RES capacity as the foundation. One-factor experience curves are widely used to project future RES costs (Alberth, 2008, Rubin et al., 2015c) and indicates a log-linear relationship between technology cost and cumulative installed capacity (McDonald and Schrattenholzer, 2001). Global RES potentials are clustered into resource classes that differ in the quality of their capacity factors. For each country, resource class, RES, electrolyser and year, cost-minimising ratios for RES-to-electrolyser capacity are determined using a linear optimisation model (see equations A.3 to A.9 in Appendix A.1.2). Individual production costs for hydrogen from RES are calculated based on the optimum ratios.[1]

- Estimate production costs for hydrogen from natural gas
  Techno-economic assumptions are combined with a natural gas price

[1] We also modelled hybrid systems (combinations of more than one type of intermittent RES with an electrolyser). More details on the potential advantages of hybrid systems can be found in A.3.2.

projection to obtain the LCOH from pyrolysis and natural gas reforming. Country-specific CO_2 transportation and storage cost assumptions are considered in the estimation of the LCOH from natural gas reforming with CCS.

- Estimate transportation costs for hydrogen
  Pipelines and seaborne transportation with liquid hydrogen tankers are considered as options. Distance-based transportation costs are determined based on existing natural gas pipeline routes and selected port-to-port distances.

- Compare costs for selected countries, years and technologies
  Supply costs at a country level are compared under varying assumptions to obtain robust insights on what the most cost-efficient hydrogen supply structure could look like depending on country characteristics, such as the natural gas price, domestic RES conditions, distance from potential exporters and the potential availability of pipeline connections.

A.1.1. Estimation of hydrogen production costs

The LCOH is estimated for countries $n \in N$, years $y \in Y$ and electrolysis technologies $el = \{\text{low temperature, high temperature}\}$ from renewable energy sources $res = \{\text{PV, onshore, offshore}\}$, pyrolysis ($pl$) and natural gas reforming (rf). A central factor for LCOH of every technology is financing costs. They are expressed via an $amortisationfactor$ that includes the weighted average cost of capital (WACC) and the financing time and is assumed to be constant over time. The amortisation factor a for a technology is calculated as

$$a = \frac{i * (1 + i/100)^l}{(1 + i/100)^{l-1}}, \tag{A.1}$$

where i is the interest rate or WACC in %, l is the economic lifetime and amortisation period of the corresponding technology in years.

A.1.2. Cost estimation for hydrogen from RES

A RES cost projection is constructed based on global one-factor experience curves for each renewable energy technology.[2] The one-factor experience curve is widely used to project future RES costs (Alberth, 2008, Rubin et al., 2015c) and indicates a log-linear relationship between technology cost and cumulative installed capacity (McDonald and Schrattenholzer, 2001). Technology production costs decline over time where the rate of decline is driven by the total installed capacity of a technology: The learning rate (LR) determines the per cent decrease in cost for every doubling in accumulated installed capacity. Capital expenditure $CAPEX$ for renewable energy source res in country n and year y is calculated as

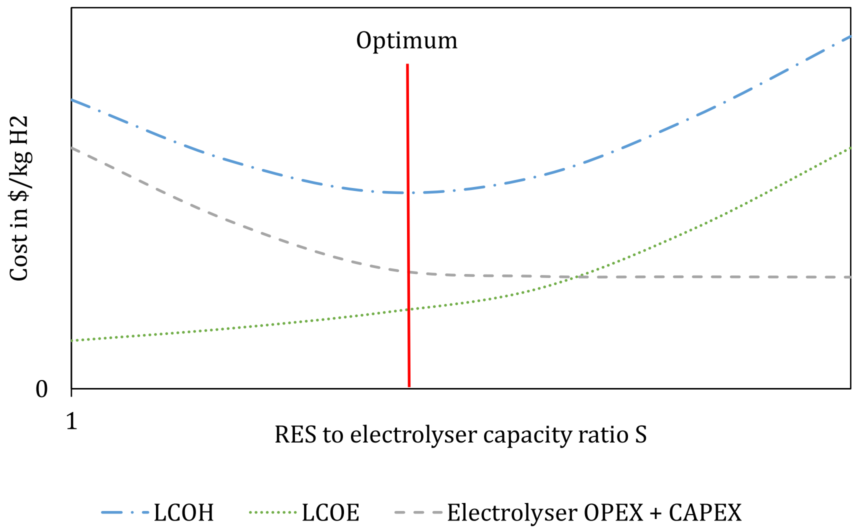
$$CAPEX_{n,y}^{res}(x_y^{res}) = CAPEX_{n,0}^{res}(x_0^{res})\left(\frac{x_y^{res}}{x_0^{res}}\right)^{-LR^{res}}, \tag{A.2}$$

where x_y^{res} and x_0^{res} are global cumulative installed capacities of renewable energy source res in year y and the baseline year 0, respectively. In line with other major electricity cost assessments (IEA, 2019e), operating expenditures (OPEX) are calculated as % of CAPEX and thus change over time in parallel to CAPEX. In addition to CAPEX and OPEX, the capacity factor of a renewable energy source is a determining factor for electricity and thus hydrogen costs. It is expressed as a unit-less parameter in an interval between zero and one and indicates the proportion of time the installed capacity of the corresponding RES is fully utilised. The higher the capacity factor, the higher the utilisation and the lower the electricity costs of a renewable energy source. The capacity factor depends on the natural conditions for sun and wind and therefore varies greatly depending on the location. In order to adequately reflect this variation, which can also occur within a country, all considered renewable energy sources are additionally clustered into resource classes for each country, which combine different intervals of capacity factors. A detailed explanation of the clustering approach can be found in Section 2.3.1.

[2] Using this approach instead of taking costs directly from existing literature has the advantage that consistent cost scenarios can be constructed based on assumptions on learning rates and the global expansion of RES. Furthermore, these assumptions can be changed and updated flexibly.

Renewable electricity sources, such as wind and PV, are generally characterised by intermittency and a low utilisation – usually below a capacity factor of 50% for wind and below 25% for PV – even in the most favourable locations. Hours where a generator produces at close to full capacity, are relatively rare. Electrolysers are capital-intensive pieces of equipment and should therefore experience a high utilisation to be as economical as possible. Consequently, combining an electrolyser with a low capacity factor RES such as a wind turbine, a 1:1 pairing of electrolyser to generator capacity is likely not to result in the lowest possible LCOH for the combined system. Instead, it may be more advantageous to install an electrolyser with a capacity lower than that of the paired RES. The electrolyser could then be operated at a higher annual capacity factor, while some of the peak output of the RES would have to be curtailed.[3]

Figure A.1.: Optimization of LCOH as trade-off between levelised cost of electricity (LCOE) and electrolyser CAPEX & OPEX



The ratio of electrolyser-to-RES capacity that yields the lowest LCOH is dependent on the capital cost of the electrolyser, the capital cost of the RES, as well as the load profile and capacity factor of the RES. Since all these factors are variable, calculating the optimal ratio between electrolyser and RES

[3] It could also be fed into the grid; however, the interaction with the electricity sector is neglected in this study due to its complexity, and the fact for some of the more remote RES resources, in particular, a connection to the (far away) power grid may not always be a cost-efficient option.

capacity is not a trivial problem. Furthermore, both RES and electrolyser capital costs are assumed to decline over time, but at different rates; RES capital costs are assumed to vary between countries. Similarly, RES capacity factors and hourly load profiles differ from location to location. In order to derive optimal RES-to-electrolyser capacity ratios for all combinations of electrolyser technologies, RES, countries, and RES resource classes covered by this study, a linear optimisation model is developed, as described in equations A.3 to A.7. Figure A.1 illustrates the optimisation process.

$$\min_{C^{el}_{n,r,y},C^{res}_{n,r,y}} TC^{el,res}_{n,r,y} \tag{A.3}$$

s.t.

$$TC^{el,res}_{n,r,y} = (CAPEX^{el}_{y} * a^{el} + OPEX^{el}_{y}) * C^{el}_{n,r,y} + (CAPEX^{res}_{n,y} * a^{res}_{n} + OPEX^{res}_{n,y}) * C^{res}_{n,r,y} \tag{A.4}$$

$$Q^{res,el}_{n,r,y,h} \leq C^{res}_{n,r,y} * CF^{res}_{n,r,h} * \eta^{el}_{y} \tag{A.5}$$

$$Q^{res,el}_{n,r,y,h} \leq C^{el}_{n,r,y} * \eta^{el}_{y} \tag{A.6}$$

$$\sum_{n=h}^{8760} Q^{res,el}_{n,r,y,h} = D^{res,el}_{n,r,y} \tag{A.7}$$

where

$TC^{el,res}_{n,r,y}$ is the total cost of hydrogen production by the combination of electrolyser el and RES technology res in year y, country n and resource class r,

$C^{el}_{n,r,y}$ is the installed el capacity in year y, country n and resource class r (expressed in kW-electric),

$C^{res}_{n,r,y}$ is the installed res capacity in year y, country n and resource class r (expressed in kW-electric),

η^{el}_{y} is the efficiency of electrolyser el in year y in %,

$CF^{res}_{n,r,h}$ is the capacity factor of res in hour h, country n and resource class r, with $h = \{1, 2, ..., 8760\}$, the generation of hourly profiles is explained in A.1.5

$Q^{res,el}_{n,r,y,h}$ is the H_2 production of the respective combination of res, and el in country n, resource class r, year y and hour h.

$D^{res,el}_{n,r,y}$ is the exogenous volume of H_2 that has to be produced by the respective combination of res, and el in country n, resource class r, year y and hour h.

The optimal ratio of RES-to-electrolyser capacity $S^{*el,res}_{n,r,y}$ that yields the lowest levelised cost of hydrogen ($LCOH^{*el,res}_{n,r,y}$) for a combination of res and el in country i, resource class r and year y is given as

$$S^{*el,res}_{n,r,y} = \frac{C^{*res}_{n,r,y}}{C^{*el}_{n,r,y}}, \tag{A.8}$$

where $C^{*el}_{n,r,y}$ is the optimal installed el capacity in year y, country n and resource class r and $C^{*res}_{n,r,y}$ is the optimal installed res capacity in year y, country n and resource class r. The $LCOH^{*el,res}_{n,r,y}$, expressed in \$/kg of hydrogen, is computed as

$$LCOH^{*el,res}_{n,r,y} = LHV * \frac{TC^{*el,res}_{n,r,y}}{\sum_{n=h}^{8760} Q^{*res,el}_{n,r,y,h}} \tag{A.9}$$

where LHV is the lower heating value of hydrogen (33.33 kWh/kg). The optimisation

Due to the optimisation, electrolysers experience increased utilisation and have a higher capacity factor than the associated RES system. The optimal mean yearly capacity factors of electrolyser el is obtained by

$$CF^{*el}_{n,r} = \frac{\sum_{n=h}^{8760} Q^{*res,el}_{n,r,y,h}}{C^{*el}_{n,r,y} * 8760} \tag{A.10}$$

Some factors potentially influencing the LCOH from RES are disregarded. This includes

1. interactions of RES and local electricity markets. We assume that the installed RES produces electricity only for electrolysis. Potential revenue from feeding excess electricity to the grid is thus disregarded. Instead, hydrogen production is considered a closed system. Hydrogen is assumed to be produced directly on-site and transported from there (see Section 2.3.3).
2. costs of water supply. Electrolysis needs large amounts of demineralised water,[4] which may have to be transported to the hydrogen production site. However, other studies found the impact of water supply costs on the LCOH to be insignificantly small (Caldera et al., 2017, Caldera and Breyer, 2017, Jensterle et al., 2020). As a simplification, we exclude the cost of water supply in this study.

A.1.3. Cost estimation for hydrogen from natural gas

Natural gas reforming with CCS captures a large part of the CO_2 emissions caused in the process. These emissions have to be transported and stored, which is reflected in the LCOH. In order not to ignore emissions that have not been caught, they are assigned a CO_2 price. The $LCOH$ from NGR with CCS (rf) are calculated as

$$\begin{aligned} LCOH^{rf}_{n,y} = LHV * \left(\frac{a^{rf} * CAPEX^{rf}_y + OPEX^{rf}_y}{CF^{rf} * 8760} + \frac{P^{NG}_{n,y}}{\eta^{rf}} \right) \\ + \frac{Q^{ce} * P^{CCS}_n + Q^{ue} * P^{CO_2}_{n,y}}{1000}, \end{aligned} \tag{A.11}$$

where

a^{rf} is the amortisation factor,
$OPEX^{rf}_y$ are operating expenditures in $\$/kW/a$,
$CAPEX^{rf}_y$ are capital expenditures in $\$/kW\ H_2$,
CF^{rf} is the plant's availability in %,
$P^{NG}_{n,y}$ is the natural gas price in country n and year y in $\$/kW$,
η^{rf} is the plant efficiency,
Q^{ce} is the quantity of captured CO_2 emissions in $(kg\ CO_2)/(kg\ H_2)$,
P^{CCS}_n is the cost of transporting and storing CO_2 for country n in $\$/ton$,

[4]One kg of hydrogen needs about nine litres of water.

Q^{ue} is the quantity of uncaptured CO_2 emissions in $(kg\ CO_2)/(kg\ H_2)$,
and $P^{CO_2}_{n,y}$ is the CO_2 price for country n in year y in $\$/ton$.

The production of hydrogen by pyrolysis does not produce CO_2, but solid carbon as a by-product, which can potentially be sold for extra revenue. The $LCOH$ from pyrolysis of natural gas are calculated as

$$LCOH^{pl}_{n,y} = LHV * \left(\frac{a^{pl} * CAPEX^{pl}_y + OPEX^{pl}_y}{CF^{pl} * 8760} + \frac{P^{NG}}{\eta^{pl}} \right) - Q^{sc} * P^{sc}, \tag{A.12}$$

where Q^{sc} is the solid carbon yield in $(kg\ C)/(kg\ H_2)$ and P^{CB} is the price for carbon in $\$/kg$. All other variables are used equivalently to equation A.11.

Estimation of transportation costs

Transport distance is defined as distance from external border to external border, transport distances within a country are disregarded for simplicity. The transport cost of hydrogen in $\$/kg$ to country n from country m is calculated as a minimisation of costs of three possible transport routes, via pipeline (1), ship (2), or a combination of pipeline and ship (3) in equation A.13. If a direct route by pipeline or ship is unfeasible for a combination of two countries, then $d^{pipe}_{n,m} = \{\}$ or $d^{sea}_{n,m} = \{\}$.

$$TraC_{n,m,y} = \min \begin{cases} (1)\ TraC^{pipe}_{n,m} & \forall\ d^{pipe}_{n,m} \neq \{\} \\ (2)\ TraC^{sea}_{n,m,y} & \forall\ d^{sea}_{n,m} \neq \{\} \\ (3)\ TraC^{combined}_{n,m,y} & \end{cases} \tag{A.13}$$

where

$TraC^{pipe}_{n,m}$ are transport costs via pipeline (constant) in $\$/kg\ H_2$,
$d^{pipe}_{n,m}$ is the length of a direct pipeline route between country m and n
$TraC^{sea}_{n,m,y}$ are transport costs for overseas transport,
$d^{sea}_{n,m}$ is the direct sea distance between country m and n

$TraC^{combined}_{n,m,y}$ are transport cost of a combination of pipeline and ship transport, if a single mode of transport is not applicable or efficient.

Transport costs via pipeline are assumed to be constant over time; a cost distinction is made between offshore and onshore sections as shown in equation A.14.

$$\begin{aligned} TraC^{pipe}_{n,m} = & \underbrace{(a^{on} * CAPEX^{on} + OPEX^{on}) * d^{on}_{n,m}}_{\text{Onshore pipeline}} \\ & + \underbrace{(a^{off} * CAPEX^{off} + OPEX^{off}) * d^{off}_{n,m}}_{\text{Offshore pipeline}}, \end{aligned} \tag{A.14}$$

For both pipeline types, a is the amortisation factor, $OPEX$ are operating expenditures in $\$/km/a$, $CAPEX$ are given in $\$/km$, and $d_{n,m}$ is the length of the respective pipeline section in km. For overseas transport, hydrogen is liquefied and transported by ship[5]. Total seaborne transport cost is made up of the individual components of the shipping supply chain as shown in equation A.15, superscripts for the hydrogen production technologies res, el, rf, pl are dropped for simplicity. Since, in contrast to pipeline technology, significant cost reductions are still expected for the transport of hydrogen by ship, the costs of the individual components decrease over time.

$$TraC^{sea}_{n,m,y} = LC_{m,y} + EC_{m,y} + SC_{m,y} + IC_{n,y}, \tag{A.15}$$

where $LC_{m,y}$ are liquefaction cost, $EC_{m,y}$ are export terminal costs, $SC_{m,y}$ are shipping costs and $IC_{n,y}$ are costs of the import terminal. The calculation of the individual components is explained below. Variables $a, CAPEX$ and $OPEX$ represent the amortisation factor, capital expenditures and operating expenditures of the corresponding supply chain element. Liquefaction plant costs of exporting country m and year y in $\$/kg\ H_2$ are calculated as

$$LC_{n,y} = (a^{liq} * CAPEX^{liq}_{y} + OPEX^{liq}) + el^{liq}_{y} * p^{el}_{m,y}, \tag{A.16}$$

[5] A detailed justification for the choice of the transport medium can be found in section 2.3.3.

where el_y^{liq} is the electricity needed for the liquefaction in $kWh/kg\ H_2$ and $p_{m,y}^{el}$ is the price of electricity in exporting country m and year y in $\$/kWh$. Export terminal costs in $\$/kg\ H_2$ are

$$EC_{m,y}^{tech} = (a^{et} * CAPEX_y^{et} + OPEX^{et}) + el_y^{et} * p_{m,y}^{el} + b^{et} * t^{et} * LCOH_{m,y}, \tag{A.17}$$

where

el_y^{et} and $p_{m,y}^{el}$ are electricity amount and price,
b^{et} is the boil-off, that means the share of hydrogen that escapes and is lost in $\%/h$,
t^{et} is the average storage time in the export terminal storage tanks in hours,
$LCOH_{m,y}$ is the cost of the transported hydrogen in $\$/kg\ H_2$.

Shipping costs to importing country n from country m in year y are also given in $\$/kg\ H_2$ and are calculated as

$$\begin{aligned} SC_{n,m,y}^{tech} = & \underbrace{(a^{ship} * CAPEX_y^{ship} + OPEX^{ship})}_{\text{Yearly CAPEX per kg of transport capacity}} / \underbrace{\frac{8760}{2 * (\frac{d_{n,m}}{v^{ship}} + h^{ship})}}_{\text{Loads per year}} \\ & / \underbrace{\left(1 - (b^{ship} * \frac{d_{n,m}^{sea}}{v^{ship}}) - (f^{ship} * d_{n,m}^{sea})\right)}_{\text{Share of load left after shipping}} \\ & + \underbrace{(b^{ship} * \frac{d_{ij}^{sea}}{v^{ship}} + f^{ship} * d_{n,m}^{sea}) * LCOH_{m,y}}_{\text{Cost of boil-off}}, \end{aligned} \tag{A.18}$$

where

$d_{n,m}^{sea}$ is the distance between country i and j via ship in km,
v^{ship} is the ship speed in km/h,
h^{ship} is the time a ship spends in a harbour for loading or unloading, also called berthing time, in hours,
b^{ship} is the ship's boil-off in $\%/h$,
f^{ship} is the fuel need of a ship in $kg\ H_2/km$, [6]
$LCOH_{m,y}$ is the cost of the transported hydrogen in $\$/kg\ H_2$.

[6] It is assumed that the ship uses hydrogen as fuel. On the outward journey, the vessel can use some of the boiled-off hydrogen cargo as fuel. The boil-off is generally higher than the ship's fuel requirements. On the way back, the ship still needs sufficient residual hydrogen in its tanks to cover the fuel required for the return journey. Therefore, the fuel requirement is only calculated for one route (the return journey).

$$IC_{n,m,y} = (a^{it} * CAPEX_t^{it} + OPEX^{it}) + el_y^{it} * p_{n,y}^{el} + b^{it} * t^{it} * LCOH_{m,y} \tag{A.19}$$

where

el_y^{it} and $p_{n,y}^{el}$ are electricity need (constant) and price in importing country i and year y,
b^{et} is the import terminal's boil-off in $\%/h$,
t^{et} is the average storage time in the import terminal's tanks in hours,
$LCOH_{m,y}$ is the cost of hydrogen that has been transported from m to n in $\$/kg\ H_2$.

Finally, transport costs of a route that combines pipeline and overseas transport are the sum of the costs of the individual segments:

$$TraC_{n,m,y}^{combined} = TraC_{n,m}^{pipe} + TraC_{n,m,y}^{sea} \tag{A.20}$$

A.1.4. Calculation of total hydrogen supply costs

The LCOH from equations A.9, A.11 and A.12 gives the production costs for an investment made in a respective year y. The local hydrogen supply costs $HSC_{n,m,y}$ in year y are the sum of the production costs in country m and the transportation costs from country m to country n (equation A.21):

$$HSC_{n,m,y} = LCOH_{m,y} + TraC_{n,m,y} \tag{A.21}$$

The minimum of equation A.21 is the most efficient pathway to supply hydrogen to country n. Local production cost results and suitable supply options for specific case study countries are discussed in Section 2.4.3.

A.1.5. Generation of synthetic hourly RES profiles

Capacity factors for RES are taken from peer-reviewed assessments of global wind (Bosch et al., 2017, 2019) and solar energy (Pietzcker et al., 2014) potentials (a detailed description of the datasets used is provided in Section 2.3.1). However, these data sets do not provide the hourly capacity factors required for the optimisation of RES-to-electrolyser capacity.

Therefore, we generate synthetic hourly RES production profiles which correspond to the average annual capacity factors given by Bosch et al. (2017, 2019) and Pietzcker et al. (2014) for the respective resource class. They are adapted from actual hourly profiles for a full year, which are obtained from renewables.ninja (Pfenninger and Staffell, 2016, Staffell and Pfenninger, 2016), one for each country and renewable energy source.[7] In order to generate synthetic hourly RES production profiles for each technology, country and resource class, an exponential scaling parameter is then applied to the original hourly profile $HP^{res}_{n,h}$. The hourly profile is scaled using the exponential scaling factor $\sigma^{res}_{n,r}$, so that the sum of the hourly RES capacity factors $CF^{res}_{n,r,h}$ of the resulting profile, divided by the number of hours per year (8760) is equal to the annual capacity factor $CF^{res}_{n,r,y}$ for a particular resource class in a particular country:

$$(HP^{res}_{n,h})^{\sigma^{res}_{n,r}} = CF^{res}_{n,r,h} \tag{A.22}$$

$$\frac{\sum_{n=h}^{8760} CF^{res}_{n,r,h}}{8760} = CF^{res}_{n,r,y} \tag{A.23}$$

where

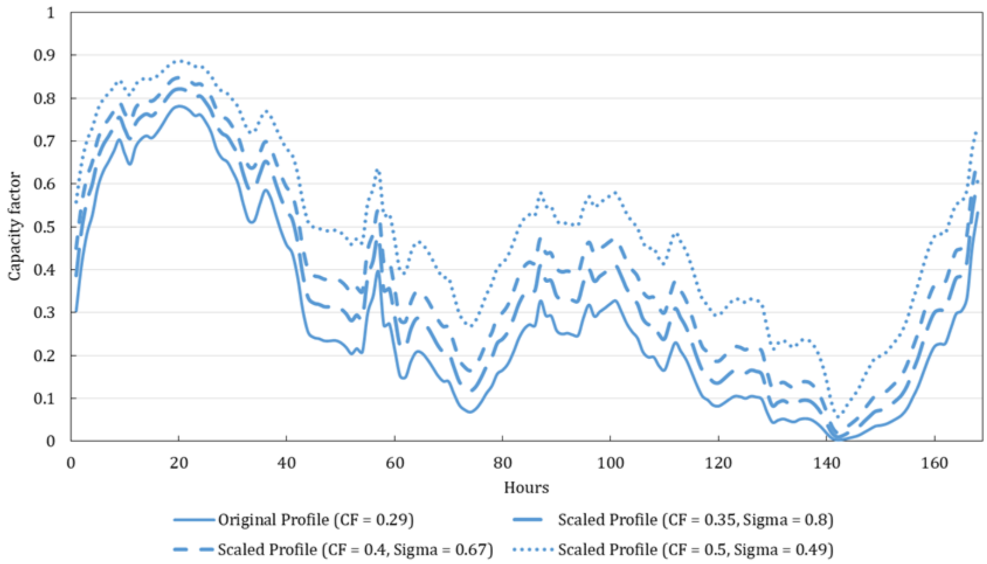
$HP^{res}_{n,h}$ is the unscaled hourly profile of res in country n, with $HP^{res}_{n,h} = [0,1]$,
$CF^{res}_{n,r,h}$ is the scaled hourly capacity factor of res in country n and resource class r, with $CF^{res}_{n,r,h} = [0,1]$,
$CF^{res}_{n,r,y}$ is the annual capacity factor of res in country n and resource class r, with $CF^{res}_{n,r,y} = [0,1]$,

Figure A.2 illustrates the exponential scaling from the original capacity factor to three different higher capacity factors. To obtain a profile that is more representative of the true variability in single locations, rather than averaging

[7] The coordinates of the point each profile was extracted for can be found in Table A.4.

over the entire area of the country or resource class, a single point is chosen to represent the hourly profile for a corresponding country. Using an exponential scaling factor has the advantage that the peaks and troughs of the original profile are preserved, while the overall distribution becomes smoother when scaled up to a higher capacity factor and more variable when scaled down to a lower capacity factor.

Figure A.2.: Illustrative scaling of hourly capacity factor profile



Original profile for 168 hours of onshore wind in Berlin from January 1-7.

For PV and Onshore Wind, the hourly capacity factor is the 2019 profile for selected points in each of the countries considered in this study, obtained from renewables.ninja (Pfenninger and Staffell, 2016). Table A.4 gives an overview of all point coordinates. The individual exponential scaling factors $\sigma_{res,n,r}$ for all combinations of res, countries n and resource classes r were derived through the application of a non-linear, numerical optimisation model. The model determines the optimal scaling parameter $sigma_{n,r}^{res}$ by minimising the objective value OBJ, subject to the constraint given in equation A.26, which ensures that the algorithm chooses the correct $sigma_{n,r}^{res}$ to scale the original profile $HP_{n,h}^{res}$ to the desired annual capacity factor.

$$\min OBJ \tag{A.24}$$

s.t.

$$OBJ = slack_{up} + slack_{down} \tag{A.25}$$

$$CF^{res}_{n,r,y} = \frac{\sum_{n=h}^{8760} HP^{res}_{n,h} \sigma^{res}_{n,r}}{8760} + slack_{up} - slack_{down} \tag{A.26}$$

where OBJ is the objective, $slack_{up}$ is a positive slack variable, with $slack_{up} \geq 0$ and $slack_{down}$ is a negative slack variable, with $slack_{up} \geq 0$.

A.2. Data and Assumptions

This section provides a detailed description of the data and assumptions underpinning the analysis presented in Chapter 2.

A.2.1. Countries and assumptions

Regions Regional clustering is applied in line with DNV GL (2019). Abbreviations in the region column stand for NAM: North America; LAM: Latin America; EUR: Europe; MEA: Middle East and North Africa; NEE: North East Eurasia; SSA: Sub-Saharan Africa; CHN: Greater China; IND: Indian Subcontinent; SEA: South East Asia; OPA: OECD Pacific.

Hourly profiles Profiles are taken from renewables ninja (Pfenninger and Staffell, 2016, Staffell and Pfenninger, 2016) for point coordinates indicated in Table A.4

Costs of CO_2 transport and storage A weighted average is applied to calculate costs from Hendriks et al. (2004). Unrestricted storage includes all forms of storage, onshore and offshore. Original values are converted to $ and adjusted to 2018$.

A.2.2. RES learning rates in the literature

Table A.1.: Overview of the recent literature on learning rates

RES	Reference	Learning rate	Description
PV			
	Comello et al. (2018)	20%	Module costs between 1979 and 2010
	ETIP-PV (2019)	30%	Expected LR for module prices in the next decade
	Fraunhofer ISE (2020)	25%	Module price LR in last 40 years
	IRENA (2020c)	40%	Utility scale solar PV installed cost LR forecast
	ITRPV (2020)	23.5%	LR from long-term module sales prices
	Mauleón (2016)	>27%	PV cost LR above 27% with a 95% probability
	Reichelstein and Sahoo (2018)	34%	long-run marginal costs LR
	Sivaram and Kann (2016)	18%	Historical LR until 2015
	Vartiainen et al. (2020)	20/30/40%	LRs for slow/best case/fast price decrease projection
General wind			
	Mauleón (2019)	12%	Project cost for wind parks
	Rubin et al. (2015a)	12%	Offshore & Onshore technology cost
	Wiser et al. (2016)	16-20%	Implicit LCOE LRs for cumulative wind until 2030
	Williams et al. (2017)	9%	LR on LCOE
Onshore wind			
	IRENA (2020c)	23-29%	Onshore LCOE LR from 2010-2021
	Junginger et al. (2020a)	11.4%	Historical LR on onshore LCOE since 1990
	Wiser et al. (2016)	18.6%	Historical global LCOE learning rate
	Wiser et al. (2016)	14-18%	Implicit LR projection for onshore LCOE
Offshore wind			
	Costa (2019)	12.4%	LR on offshore LCOE 2011-2017
	IRENA (2020c)	10%	Offshore LCOE LR for projects 2010-2023
	Junginger et al. (2020b)	27%	CAPEX for wind parks with >250 MW & >20m water depth
	NREL (2020) ATB (moderate)	20%	Calculated from offshore CAPEX & IRENA REmap capacity
	Wiser et al. (2016)	8%	Estimated LCOE LR until 2030

Table A.2.: Cumulative global RES capacity additions

	2020	**2030**	**2040**	**2050**
PV installed (GW)	1113	3151	5761	8519
PV cumulative (GW)	1113	3151	5982	10651
Onshore wind installed (GW)	988	2309	3790	5044
Onshore cumulative (GW)	988	2309	4195	6693
Offshore installed (GW)	72	216	540	999
Offshore cumulative (GW)	72	216	552	1143

Because RES have to be decommissioned and replaced after 25 years of assumed lifetime, decommissioned capacities are added to obtain the cumulative installed capacities for wind and PV.

A.2.3. Cumulative RES capacity additions in the IRENA REmap scenario

A.2.4. Comparison of RES cost estimates with the literature

Table A.3.: Comparison of major CAPEX and LCOE projections with own estimations

Reference		**PV**			**Onshore**			**Offshore**		
		2030	2040	2050	2030	2040	2050	2030	2040	2050
Literature										
IRENA (2019a)	CAPEX ($/kW)	340-834	-	165-481	800-1350	-	650-1000	1700-3200	-	1400-2800
	LCOE ($/kWh)	0.02-0.08	-	0.014-0.05	0.03-0.05	-	0.02-0.03	0.05-0.09	-	0.03-0.07
IEA (2019e)	CAPEX ($/kW)	-	430-830	-	-	1160-1760	-	-	1460-2580	-
	LCOE ($/kWh)	-	0.03-0.065	-	-	0.05-0.085	-	-	0.045-0.075	-
BNEF (2019)	CAPEX ($/kW)									
	LCOE ($/kWh)	~0.045	-	~0.025	~0.037	-	~0.03	~0.037	-	~0.03
Pregger et al. (2019)	CAPEX ($/kW)	730	560	470	1510	1450	1400	3190	2830	2610
	LCOE ($/kWh)	-	-	-	-	-	-	-	-	-
DNV GL (2019)	CAPEX ($/kW)	507-815	456-731	431-689	941-1495	879-1359	839-1272	2292-2914	2208-2785	2154-2702
	LCOE ($/kWh)	0.037-0.07	0.03-0.056	0.025-0.055	0.037-0.084	0.034-0.071	0.032-0.068	0.061-0.1	0.057-0.08	0.055-0.076
Total range	CAPEX ($/kW)	340-834		165-689	800-1510		650-1400	1700-3200		1400-2800
	LCOE ($/kWh)	0.02-0.08		0.014-0.055	0.03-0.084		0.02-0.068	0.037-0.1		0.03-0.076
This study										
Base LR	CAPEX ($/kW)	384-626	322-524	266-434	838-1400	753-1257	692-1156	1877-2482	1615-2136	1438-1902
	LCOE ($/kWh)	0.023-0.06	0.019-0.05	0.016-0.04	0.028-0.09	0.025-0.08	0.023-0.073	0.05-0.32	0.045-0.27	0.04-0.24
Optimistic LR	CAPEX ($/kW)	318-518	251-410	195-318	780-1301	680-1135	610-1019	1717-2271	1424-1883	1231-1627
	LCOE ($/kWh)	0.02-0.05	0.015-0.04	0.012-0.03	0.026-0.082	0.023-0.072	0.02-0.064	0.047-0.29	0.039-0.24	0.034-0.21

A.2.5. Country and RES profile information

Table A.4.: Full country information

Country	Region	Onshore & PV coordinates		Offshore coordinates		CCS cost ($/t)	
		Longitude	Latitude	Longitude	Latitude	Unrestricted	Offshore only
Algeria	MEA	3.086472	36.737232	2.764252	36.891593	6.08	8.07
Angola	SSA	13.234444	-8.838333	13.683006	-11.274237	6.08	8.07
Argentina	LAM	-57.969559	-34.920345	-65.112497	-44.396911	9.93	10.42
Australia	OPA	149.128998	-35.282001	146.720189	-38.916195	12.43	12.12
Austria	EUR	16.363449	48.210033	-	-	8.45	8.90
Azerbaijan	NEE	49.867092	40.409264	50.497842	40.416625	21.07	34.22
Bahrain	MEA	50.606998	26.201001	50.774686	26.360307	10.93	35.57
Bangladesh	IND	90.399452	23.777176	91.736779	22.064911	11.26	10.92
Belarus	NEE	27.567444	53.893009	-	-	21.07	34.22
Belgium	EUR	4.351711	50.850339	2.974966	51.512907	8.45	8.90
Bolivia	LAM	-65.261963	-19.019585	-	-	6.83	8.71
Brazil	LAM	-47.882778	-15.793889	-40.793754	-21.761496	6.83	8.71
Brunei darussalam	MEA	114.939453	4.889694	114.481567	4.937166	11.42	12.63
Bulgaria	EUR	23.319941	42.698334	28.072589	42.821415	9.48	19.37
Cameroon	SSA	11.501346	3.844119	9.617127	2.736100	9.93	10.42
Canada	NAM	-75.695001	45.424721	-131.500513	53.851515	10.55	12.87
Chile	LAM	-70.673676	-33.447487	-71.452426	-29.831955	6.83	8.71
China	CHN	11.733017	40.846333	122.259134	30.909732	11.34	11.73
Colombia	LAM	-74.063644	4.624335	-77.552557	4.738221	6.83	8.71
Croatia	EUR	15.966568	45.815399	15.762576	43.419435	21.07	34.22
Czech Republic	EUR	14.418541	50.073658	-	-	9.48	19.37
Denmark	EUR	12.568337	55.676098	7.529094	55.656649	8.45	8.90
Dominican Republic	LAM	-69.929611	18.483402	-70.046872	18.214019	8.89	10.36
Egypt	MEA	31.233334	30.033333	30.334033	31.678836	6.08	8.07
Equatorial Guinea	SSA	8.781663	3.755781	9.576795	1.735380	9.93	10.42
Estonia	EUR	24.753574	59.436962	20.722967	55.728118	21.07	34.22
Finland	EUR	24.945831	60.192059	23.976852	59.851824	8.45	8.90
France	EUR	2.349014	48.864716	-2.742391	47.202829	8.45	8.90
Georgia	NEE	44.783333	41.716667	41.465224	42.163747	21.07	34.22
Germany	EUR	13.404954	52.520008	7.409051	53.916902	8.45	8.90
Ghana	SSA	-0.196901	5.556025	-0.471426	5.251925	9.93	10.42
Greece	EUR	23.727539	37.982813	25.486830	36.541305	9.48	19.37
Hungary	EUR	19.040236	47.497913	-	-	9.48	19.37
Iceland	EUR	-21.827774	64.128288	-16.992288	63.619733	8.45	8.90
India	IND	77.216721	28.644795	72.677288	18.757909	11.26	10.92
Indonesia	SEA	106.816666	-6.199987	101.556228	-3.493006	11.42	12.63
Iran	MEA	51.404343	35.715298	51.882292	27.675845	10.93	35.57
Iraq	MEA	44.361488	33.312805	48.625098	29.836197	10.93	35.57
Ireland	EUR	-6.266155	53.349996	-7.252736	52.028595	8.45	8.90
Israel	MEA	35.217018	31.771959	34.809070	32.624223	10.93	35.57
Italy	EUR	12.496366	41.902782	12.768698	44.149726	8.45	8.90
Japan	OPA	139.839478	35.652832	141.167345	37.295460	10.86	10.86
Kazakhstan	NEE	71.449074	51.169392	51.482481	46.934975	21.07	34.22

Country	Region	Onshore & PV coordinates		Offshore coordinates		CCS cost ($/t)	
		Longitude	Latitude	Longitude	Latitude	Unrestricted	Offshore only
Kuwait	MEA	47.990341	29.378586	48.305813	29.196934	10.93	35.57
Libya	MEA	13.180161	32.885353	14.120382	32.880662	6.08	8.07
Malaysia	SEA	101.693207	3.140853	103.578921	3.637505	11.42	12.63
Mexico	LAM	-99.133209	19.432608	-105.970908	22.496933	8.89	10.36
Moldova	NEE	28.907087	47.003671	-	-	21.07	34.22
Morocco	MEA	-6.841648	34.020882	-7.360148	33.888460	6.08	8.07
Mozambique	SSA	32.588711	-25.953724	35.707949	-19.534613	10.04	10.04
Myanmar	SEA	96.129720	19.745000	94.312807	17.313531	11.42	12.63
Netherlands	EUR	4.895168	52.370216	4.264626	52.627737	8.45	8.90
Nigeria	SSA	7.491302	9.072264	3.575211	6.204284	9.93	10.42
Norway	EUR	10.757933	59.911491	4.856371	59.095572	8.45	8.90
Oman	MEA	58.545284	23.614328	59.159880	23.424497	10.93	35.57
Pakistan	IND	73.084488	33.438045	66.628908	24.706976	11.26	10.92
Papua New Guinea	SEA	147.150890	-9.477230	147.698683	-7.561372	12.43	12.12
Peru	LAM	-77.042793	-12.046374	-76.990071	-12.501116	6.83	8.71
Philippines	SEA	120.984222	14.995120	126.663693	8.078208	11.42	12.63
Poland	EUR	21.017532	52.237049	17.384011	54.991130	9.48	19.37
Portugal	EUR	-9.142685	38.736946	-9.109244	41.682254	8.45	8.90
Qatar	MEA	51.534817	25.286106	51.842368	25.119592	10.93	35.57
Republic of Korea	OPA	127.024612	37.532602	125.943429	34.513116	11.34	11.73
Romania	EUR	26.096306	44.439663	29.064786	44.416690	9.48	19.37
Russian Federation	NEE	37.618423	55.751244	29.333282	60.062179	21.07	34.22
Saudi Arabia	MEA	46.738586	24.774265	39.467980	20.312128	10.93	35.57
Singapore	SEA	103.851959	1.290270	103.621874	1.077362	11.42	12.63
Slovakia	EUR	17.107748	48.148598	-	-	9.48	19.37
Slovenia	EUR	14.505751	46.056946	13.351036	45.542545	9.48	19.37
South Africa	SSA	-33.431441	21.052866	18.903624	-34.488003	9.93	10.42
Spain	EUR	3.703791	40.416775	-2.875886	43.509849	8.45	8.90
Sweden	EUR	18.063240	59.334591	17.632432	61.184636	8.45	8.90
Switzerland	EUR	7.451123	46.947456	-	-	8.45	8.90
Syria	MEA	36.278336	33.510414	35.633162	35.241458	10.93	35.57
Taiwan	CHN	121.597366	25.105497	120.783397	24.709394	11.34	11.73
Thailand	SEA	100.523186	13.736717	100.152647	8.861925	11.42	12.63
Trinidad and Tobago	LAM	-61.521206	10.671067	-60.790541	10.456449	6.83	8.71
Tunisia	MEA	10.181667	36.806389	10.128552	37.430981	6.08	8.07
Turkey	MEA	32.866287	39.925533	29.402782	35.974174	10.93	35.57
Turkmenistan	NEE	58.383330	37.950000	52.362964	40.353905	21.07	34.22
Ukraine	NEE	30.517023	50.431759	30.798417	46.166125	21.07	34.22
United Arab Emirates	MEA	54.366669	24.466667	54.443660	25.044579	10.93	35.57
United Kingdom	EUR	-0.118092	51.509865	1.120625	51.581845	8.45	8.90
United States	NAM	-95.358421	29.749907	-120.920998	34.376985	13.43	16.33
Uzbekistan	NEE	69.240562	41.311081	-	-	21.07	34.22
Venezuela	LAM	-66.916664	10.500000	-66.130320	10.814753	6.83	8.71
Vietnam	SEA	105.804817	21.028511	105.735775	9.027149	11.42	12.63
Yemen	MEA	44.191006	15.369445	45.434282	12.960379	10.93	35.57

The point coordinates in the table designate the location of the 2019 hourly profile obtained from renewables.ninja (Pfenninger and Staffell, 2016, Staffell and Pfenninger, 2016) that serves as the starting point for the estimation of the RES resource class-specific synthetic hourly profiles described in A.1.5.

A.2.6. Carbon price

Advanced Economies: Australia, Austria, Belgium, Bulgaria, Canada, Chile, Croatia, Cyprus, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Israel, Italy, Japan, Korea, Latvia, Lithuania, Luxembourg, Malta, Mexico, Netherlands, New Zealand, Norway, Poland, Portugal, Romania, Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Turkey, United Kingdom and United States.

Emerging Economies: All other.

Table A.5.: Assumptions on global CO_2 prices

Region	**2020**	**2030**	**2050**
Advanced economies ($\$/t_{CO_2}$)	28	100	160
Emerging economies ($\$/t_{CO_2}$)	16	75	145

A.2.7. Full assumptions on transport infrastructure

Table A.6.: Techno-economic assumptions for transport infrastructure

		2020	**2030**	**2040**	**2050**
Pipeline	Lifetime (years)	40	40	40	40
	CAPEX ($/tpa/km)	4	4	4	4
	OPEX (%CAPEX/a)	5	5	5	5
	Utilization (%)	75	75	75	75
Ship	Lifetime (years)	30	30	30	30
	CAPEX ($/t)	37,455	33,709	25,282	16,855
	OPEX (%CAPEX/a)	4	4	4	4
	Speed (km/h)	30	30	30	30
	Berthing time (h)	48	48	48	48
	Fuel use (MJ H_2/km)	1,487	1,487	1,487	1,487
	Boil off (%/day)	0.2	0.2	0.2	0.2
Export Terminal	Lifetime (years)	30	30	30	30
	CAPEX ($/tpa)	747	672	504	336
	OPEX (%CAPEX/a)	4	4	4	4
	Electricity use (kW/kg H_2)	0.61	0.61	0.61	0.61
	Boil-off (%/day)	0.1	0.1	0.1	0.1
Import Terminal	Lifetime (years)	30	30	30	30
	CAPEX ($/tpa)	4,939	4,445	3,334	2,223
	OPEX (%CAPEX/a)	4	4	4	4
	Electricity use (kW/kg H_2)	0.2	0.2	0.2	0.2
	Boil-off (%/day)	0.1	0.1	0.1	0.1
Liquefaction	Lifetime (years)	30	30	30	30
	CAPEX ($/tpa)	5,385	4,846	4,362	3,877
	OPEX (%CAPEX/a)	4	4	4	4
	Electricity use (kWh/kg H_2)	6.1	6.1	6.1	6.1
	Availability (%)	90	90	90	90

Offshore pipeline costs are assumed to be 25% higher than onshore pipeline costs (Gerwen et al., 2019). Assumptions for ships and terminals are based on IEA (2019d), cost reductions are calculated based on projections of Wijayanta et al. (2019, Table 7), who project a 20% cost reduction for liquefaction cost, a 50% reduction for shipping cost and a 45-55% cost reduction for import and export terminals from 2030 to 2050. A storage length of 3 days for export terminals and 20 days for import terminals is assumed (Mizuno et al., 2017). Additionally, a 10% cost reduction from 2020 to 2030 is assumed for every technology in the seaborne transport supply chain.

A.3. Supplementary Results

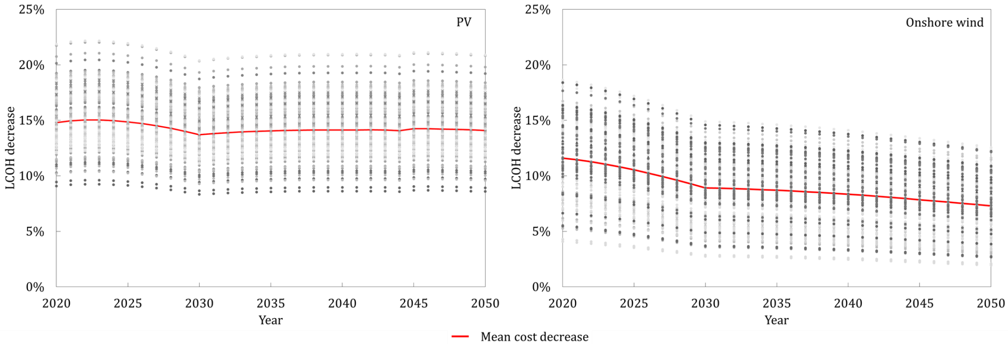
A.3.1. Effects of RES-to-electrolyser capacity ratio optimisation on LCOH

The general optimisation principle is that the ratio of installed electrolysis to RES capacity is adjusted to minimise the LCOH of the whole system. The optimisation essentially trades RES curtailment against a higher annual utilisation of the installed electrolyser capacity. The optimal RES-to-electrolyser ratio is given by the variable $S*$. Optimising RES-to-electrolyser capacities decreases the LCOH of all RES-electrolyser combinations. Figure A.3 shows the relative decrease in LCOH through optimisation compared to a system in which the installed capacity of the RES and the electrolyser are the same. Cost reductions through the optimisation are higher for PV than for wind. PV capacity factors are generally lower, resulting in a lower electrolyser utilisation, making electrolysis costs more significant per kg of hydrogen. The optimisation increases electrolyser utilisation and decreases the share of electrolyser costs in the total LCOH. As a consequence, the disadvantage of low PV capacity factors is partially diminished, leading to higher relative LCOH decreases.[8] Optimising capacity ratios decreases electrolyser costs and increases the cost of electricity (LCOE) per kg of hydrogen. The mean LCOE increase is roughly constant for PV, at 9-10%. A slight decrease in additional LCOE is observable over time for wind, from 6% in 2020 to 4% in 2050 for onshore, and from 5% in 2020 to 4% in 2050 for offshore wind.

Figure A.4 displays the optimal ratios of the respective RES to low-temperature electrolysers under baseline assumptions. The grey dots visualise time series for each country and resource class covered in this study. The optimal ratio depends on the local hourly electricity generation profile of the wind or PV generator. The distribution of optimal capacity ratios is wider for onshore wind than for PV. This is because globally, the range of possible capacity factors for wind is higher than for PV, leading to a greater interval of optimal ratios, between 2.5 and 1.3. The mean optimal RES-to-electrolyser capacity ratio for PV stays constant at 1.6, while for onshore wind, it decreases from 1.8 in 2020 to 1.6 in 2050.

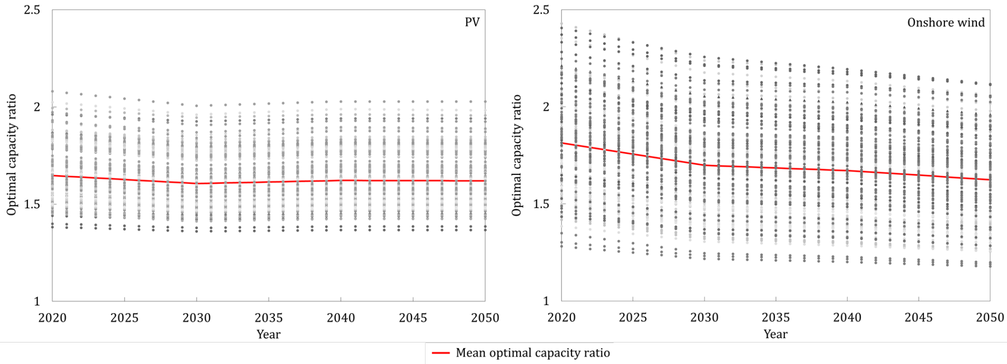
[8] The slight kink in the curve in the year 2030 are based on assumptions about the development of electrolyser CAPEX. The electrolyser CAPEX curve changes its slope at 2030, which is also reflected in the relative cost improvement through optimisation.

Figure A.3.: Relative PV and onshore wind LCOH reduction through optimisation compared to the case without optimisation



The relative decrease is calculated by comparing LCOH for a 1:1 ratio of RES and electrolyser capacity to the LCOH for an optimised ratio and utilisation. Grey dots indicate the relative LCOH decreases for all individual resource classes and years of PV (left) and onshore wind (right). Results are presented for low-temperature electrolysers and baseline cost assumptions.

Figure A.4.: Optimal RES-to-electrolyser capacity ratio for PV and onshore wind



Grey dots indicate results for optimal RES-to-electrolyser ratios for all individual resource classes of PV (left) and onshore wind (right). Results are based on baseline assumptions and low-temperature electrolysis.

This is mainly due to the different development of relative RES-to-electrolyser cost ratios in both technology combinations. The ratio of electrolyser cost to PV cost per kW and year, and consequently also the optimal capacity ratio, remains roughly constant over the years. As learning rates for onshore wind are lower, electrolysis CAPEX decrease faster relative to onshore wind CAPEX, making the electrolysis component relatively cheaper. As a result, achieving high utilisation of the electrolysis system becomes less important over time, leading to a lower optimal ratio and a lower optimal electrolyser utilisation. Relative cost improvements through optimisation also decrease for onshore wind from 12% in 2020 to 7% in 2050, as shown in Figure A.3. LCOH improvements roughly stay constant for PV at a mean of 15%.

A.3.2. On the potential cost advantage of hybrid systems

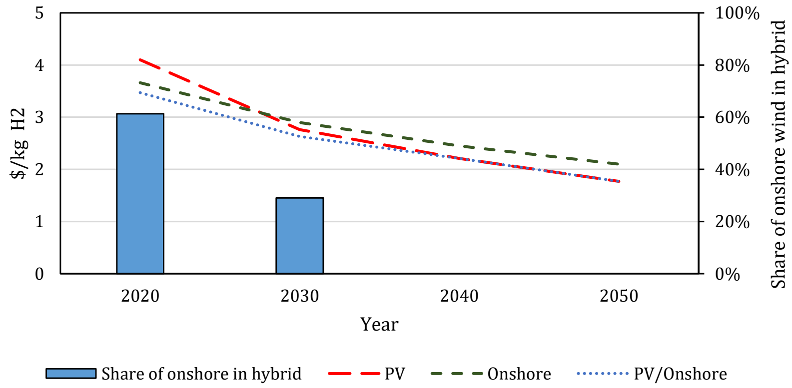
Some studies consider RES-based hydrogen production from hybrids (Fasihi et al., 2016, Fasihi and Breyer, 2020, Jensterle et al., 2020, Niepelt and Brendel, 2020, Ram et al., 2019). In a hybrid system, e.g., a combination of onshore wind and PV is coupled to an electrolyser (Mazzeo et al., 2020), allowing for a higher utilisation of the installed electrolyser capacity by reducing the overall intermittency of the electricity supply. This may—in the right circumstances—give a hybrid system a cost advantage over pure wind- or PV-based systems. The decisive factor is the percentage overlap or balance between the hourly production profiles of the wind and solar components. Estimates for overlap hours of PV and wind range between 5%–25% (Breyer, 2012, pp. 386). The smaller the number of overlap hours, the better both RES complement each other and the higher the possible annual utilisation of the electrolyser. In a hybrid system, the savings associated with the higher utilisation of the electrolyser are traded against the increase in CAPEX/OPEX associated with having to install two different RES technologies.

Simulated runs of the optimisation model used in this study, allowing for a pairing of wind and PV capacity, show that hybrid systems do lead to a lower LCOH in some cases only. Generally, this is the case if the best potentials of PV and onshore wind of a country are combined in a hypothetical hybrid system[9] and electrolyser CAPEX are high. However, since we assume a progressive reduction in electrolyser CAPEX over time, the optimisation shows that even when a country's best wind and PV potentials are combined in a hypothetical hybrid system, single RES systems, in particular those based on a combination of an electrolyser with solar PV, become the least-cost solution in almost all countries. This is shown by Figure A.5 for the case of Morocco as an illustrative example. It shows that from 2030 onwards, it is more cost-effective to produce hydrogen using the cheaper RES technology, rather than a hybrid system existing of more than one technology. The big advantage of a hybrid system in other studies without capacity optimisation is a higher installed

[9] For this, it is necessary to assume that the best wind and PV potentials overlap geographically, which may not be the case in reality. Furthermore, the sources used to determine and classify country-level RES potentials in this study (Bosch et al., 2017, 2019, Pietzcker et al., 2014) do not provide information on the spatial overlap of wind/PV potentials, making it impossible to determine the volumes of hydrogen that could be produced from a given combination of wind/PV resource classes. That would require a new and very detailed geospatial analysis of global RES potentials, which is beyond the scope of this study.

RES-to-electrolyser capacity ratio,[10] which increases the electrolyser's utilisation. But as soon as the RES-to-electrolyser capacity ratio is optimised in general, electrolysers are run at an optimal level, and the relative advantage of hybrid systems is lost in most cases.

Figure A.5.: Illustrative comparison of hybrid with single RES system



This chart compares the LCOH of a hybrid—an optimal pairing of an electrolyser with two RES (onshore wind and PV)—with the LCOH of a single-RES-system—an optimal pairing of an electrolyser with a single RES (either onshore wind or PV)—for Morocco as an illustrative example. The LCOH of the respective systems is plotted on the left axis, while the share of onshore wind in the total electrical capacity of the hybrid system is given by the right axis.

A.3.3. Hydrogen supply cost case study: United States

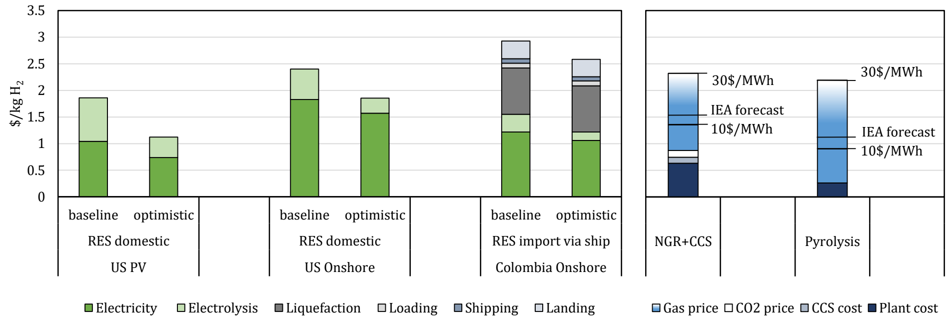
In contrast to Japan, the United States has excellent conditions for low cost domestic low-carbon hydrogen production. The country is the world's largest natural gas producer and therefore has access to inexpensive natural gas (IEA, 2019a). There are also large areas with very favourable conditions for both onshore wind and solar PV. However, the United States is a large country, and good RES potentials are often located far from where energy is consumed. Thus, supply costs for domestically produced hydrogen in consumption centres, in particular, if it is RES-based, could be slightly higher than presented here, as the hydrogen would potentially need to be transmitted over substantial distances.

However, despite low costs for hydrogen from RES, the conversion of natural gas to hydrogen will probably be the cheapest solution in the United States in

[10]Usually, a ratio of one is installed. For hybrid plants, wind and PV are paired to an electrolyser, leading to a capacity ratio of two.

the long term. Under optimistic assumptions, domestic hydrogen costs could fall to \$1.2/kg in the long run. At the natural gas prices projected by the IEA (2019d), pyrolysis could be an even cheaper option (\$1.14/kg). If upstream costs for domestic gas production were taken as inputs, costs for hydrogen from NGR+CCS and pyrolysis could be lower still.

Figure A.6.: Comparison of hydrogen supply costs in the United States 2050



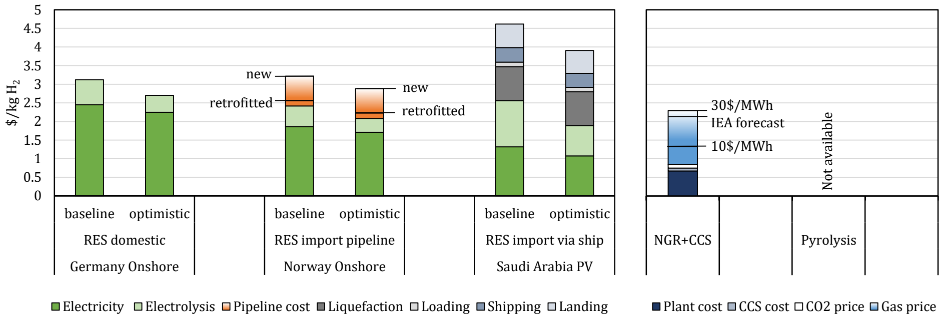
Black lines for hydrogen from natural gas indicate hydrogen costs for different gas prices. Figure A.9 shows a cost comparison for 2030.

For the United States, the following conclusions can be drawn:

- As large potentials for cheap renewable electricity exist, importing hydrogen from RES is probably not competitive. Instead, the US could potentially become a hydrogen exporter.
- Despite low costs for domestic RES, hydrogen from natural gas, especially from pyrolysis, will probably be the cheapest form of low-carbon hydrogen production in the medium and long term.
- Gas prices and favourable RES conditions lead to particularly low hydrogen costs that could fall to \$1/kg by 2050.

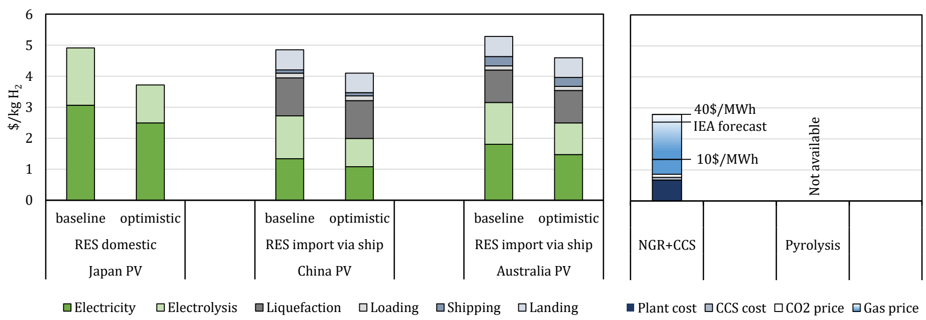
A.3.4. Additional hydrogen supply cost case study figures for 2030

Figure A.7.: Comparison of hydrogen supply costs in Germany 2030



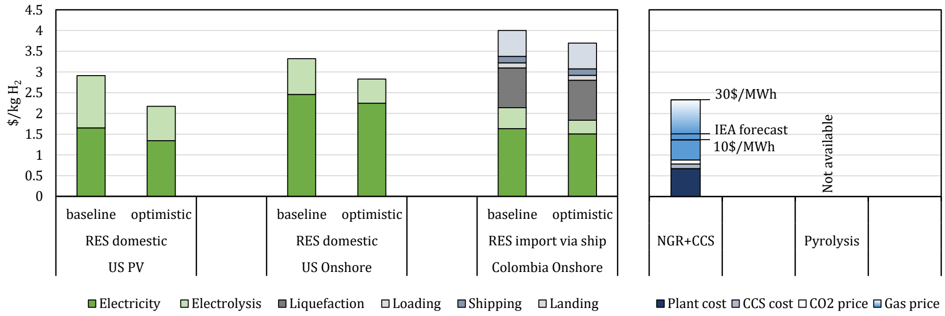
Black lines for RES import via pipeline indicate cost levels for different types of pipeline transport, spanning from a retrofitted natural gas pipeline to a high cost new pipeline. For hydrogen from natural gas, black lines indicate costs for different gas prices.

Figure A.8.: Comparison of hydrogen supply costs in Japan 2030



Black lines indicate costs for different gas prices.

Figure A.9.: Comparison of hydrogen supply costs in the US 2030



Black lines indicate costs for different gas prices.

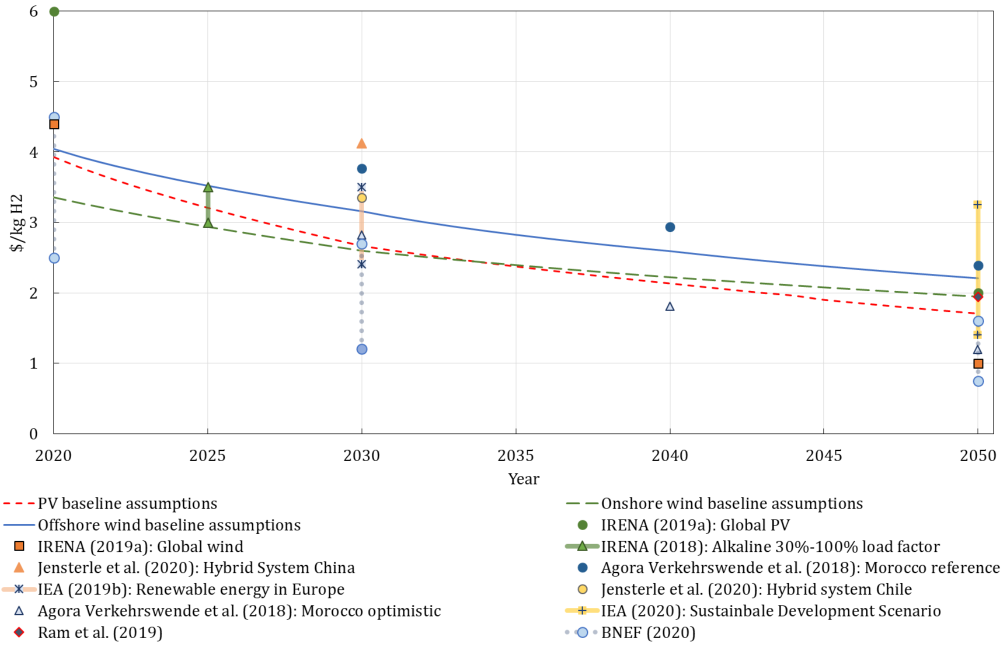
This section compares our estimates for low-carbon hydrogen production and supply costs to those in other literature. The comparison focuses mainly on hydrogen from RES because it is the focus of more studies, and there is a higher number of cost estimates than for hydrogen from natural gas.

A.3.5. Hydrogen from RES: comparison to literature estimates

A comparison of production cost results from this study and recent estimates from the literature is shown in Figure A.10 for hydrogen from RES. There is a wide scattering of cost estimates from the literature; production costs of hydrogen from RES vary for different WACC and CAPEX assumptions. Cost estimates derived in this study under baseline assumptions are located within the interval of literature estimates.

The LCOH projection from BNEF (2020b) is significantly lower than estimates from other studies because lower assumptions are made for capital expenditures, especially for electrolysers. According to BNEF (2019), alkaline electrolysers could cost \$115/kW in 2030, sliding further to \$80/kW until 2050. These CAPEX assumptions are substantially lower than in the other studies and also significantly lower than the optimistic assumption in this study. If BNEF is considered a downward outlier, cost results in the literature for the short and medium term are higher than the results obtained by this study (Section 2.4.1). This changes in the long run, where some studies project even lower costs.

Figure A.10.: Classification of results for hydrogen from RES under baseline assumptions



Results shown for this study are mean values of the 20 lowest-cost resources classes for each RES-electrolyser combination, as elaborated in Section 2.4.1. For studies where a cost interval is given, the upper and lower limits are marked as points and connected by a line.

IRENA (2019c) estimates current hydrogen costs of \$6/kg for PV and \$4.4/kg for wind and expects costs to decrease to an average of \$2/kg for PV and \$1/kg for wind. Thus, IRENA projects a higher relative cost reduction than the analysis presented in Chapter 2. Its projected long-term production costs are roughly at the level of this study's optimistic case. The poor performance of PV compared to onshore wind is partly due to IRENA assuming a 1:1 ratio of RES to electrolyser capacity, leading to correspondingly low utilisation of electrolysers paired with PV due to the lower capacity factors of the latter. In this study, by contrast, the optimisation of RES-to-electrolyser ratios reduces PV's relative disadvantage, making it the cheapest source for hydrogen from RES in the long run.

Perner et al. (2018) provide hydrogen production costs for PV in Morocco for 2050 and report \$2.39/kg in a reference and 1.19%/kg in an optimistic scenario. This study's results are slightly lower with \$1.77-\$2/kg under baseline assumptions and \$1.04-\$1.18/kg under optimistic assumptions. Just like IRENA (2019c) however, Perner et al. (2018) also assume electrolyser utilisation in line with the capacity factor of the PV plant. The optimisation of the RES-to-electrolyser ratio can therefore explain the lower LCOH derived in Chapter 2.

In projections from the IEA (2020a), production costs for hydrogen from electrolysis start from a minimum of \$1.4/kg in 2050. This result is very close to this study, where \$1.5/kg is the minimum production cost under baseline assumptions.

A.3.6. Hydrogen supply cost: comparison to literature estimates

It is challenging to compare the supply cost estimates derived by this study to other studies as all make different assumptions relating to the transportation, storage or distribution of low-carbon hydrogen. Nevertheless, the following section compares this study's results to other projections provided in the literature. The primary purpose is to identify the different approaches used to estimate supply costs for a given country.

According to BNEF (2020b), low-carbon hydrogen supply costs as low as \$2/kg in 2030 and \$1/kg in 2050 may be achievable in many parts of the world. Again, BNEF project much lower costs than other studies, which is mainly due to the very low assumed CAPEX (Figure A.10) for electrolysis.

Jensterle et al. (2020) analyse import potentials for Germany, with the lowest-cost hydrogen in 2030 imported from Norway with a border price of \$5.47/kg. These estimates are substantially higher than the estimates in this study due to higher assumed production costs, which Jensterle et al. (2020) expect to be \$4.84/kg in Norway in 2030.

Pfennig et al. (2017) analyse the import of hydrogen via LH_2 tanker from Morocco to Germany and derive costs of \$5.17/kg for2030 and \$4.19/kg for 2050. This analysis, by contrast, finds that LH_2 imports are not cost-efficient, especially for Germany. Instead, hydrogen from Morocco would best be transported through retrofitted natural gas pipelines. However, this study's estimates for LH_2 imports from Morocco are broadly in line with Pfennig et al. (2017) for 2030 (\$5.14/kg) and slightly lower for 2050 (\$3.45/kg). The main reason for the difference in the 2050 estimate is that Pfennig et al. (2017) project electricity generation costs (LCOE) in Morocco to fall less than assumed by the analysis presented in Chapter 2.

According to the IEA (2019c), low-carbon hydrogen from Australia could be delivered to Japan at a cost of \$5.5/kg in 2030, which corresponds almost exactly to the results of this analysis. However, the IEA estimate is for ammonia, whereas LH_2 transport, as assumed in this study, would cost \$7/kg. The difference is mainly due to higher electricity prices assumed by IEA (2019c) compared to our study, which results in higher liquefaction costs.

Heuser et al. (2020) assess a global provision scheme for low-carbon hydrogen and estimate \$4/kg for hydrogen supplied to Germany and the US and \$4.5/kg for hydrogen supplied to Japan. This study's finds significantly lower costs, about \$2/kg for domestic hydrogen in the US, slightly above \$2/kg for pipeline-based supplies to Germany, and \$3.3/kg for Japan. Differences in the research focus can mainly explain the discrepancy: Heuser et al. (2020) only consider the production and trade of hydrogen from RES. Furthermore, they pre-select hydrogen production regions and include domestic hydrogen transportation costs. In this work, by contrast, hydrogen production is not limited ex-ante to specific areas. Additionally, this analysis considers hydrogen from natural gas as an alternative production route to hydrogen from RES. Our results suggest that, for example, the United States could probably produce low-carbon hydrogen more cost-effectively from natural gas than from RES.[11]. Above all, the United States are unlikely to need to import hydrogen. Heuser et al. (2020), on the other hand, assumes that domestic RES potentials are not sufficiently competitive for hydrogen production.

To summarise the points made above, supply cost estimates for countries vary from study to study due to differences in assumptions. LCOH projections depend on techno-economic assumptions; different initial inputs inevitably lead to different results. Furthermore, including or excluding different pathways for transport may potentially have a large impact on import costs. Shipping especially is costly: if tankers are used to transport hydrogen, overall supply costs increase substantially. Another key feature of many previous studies is that production regions are pre-selected. Consequently, hydrogen production is limited to these regions, a predetermined structure that also affects the results. The advantage of the analysis presented in Chapter 2 is that it covers a large number of countries and thus avoids a high degree of pre-selection. Thus, it

[11] This depends mainly on the future gas price since supply costs for hydrogen from natural gas are very sensitive to changes in gas price. In IEA (2020a), the cost of hydrogen produced by SMR with CCS ranges from \$1.1-\$2.1/kg in 2050 for gas prices of \$6-\$25/MWh, which is also roughly the result in this study.

provides a broader basis for the projection of low-carbon hydrogen production costs globally, with many countries considered as potential exporters.

B. Supplementary Material for Chapter 3

B.1. Assumptions

B.1.1. Demand for low-carbon hydrogen

Projections for the future development of global demand for natural gas and low-carbon hydrogen used in the paper at hand are based on the Sustainable Development Scenario (SDS) of the International Energy Agency (IEA). The SDS describes a scenario in which international climate and energy access goals are met and the world is on track to achieve net-zero greenhouse gas emissions by 2070 (IEA, 2020a).

The IEA (2020a) projects global demand for low-carbon hydrogen to increase sharply after 2030, rising from 35 Mt to 258 Mt until 2050. In 2050, 37% is consumed in the transport sector[1] 34% in industry[2] and 10% in the buildings sector. The remaining 19% are consumed in other sectors, where hydrogen provides an important source of backup power for intermittent RES (IEA, 2020a).

IEA (2020a,b) do not provide a breakdown of low-carbon hydrogen demand by country or region. In order to derive the country-level estimates required for this analysis, additional assumptions have to be made.

Firstly, due to its higher cost relative to other, albeit more carbon-intensive fuels, hydrogen is likely to be used in high-income economies first. As a simple approximation, it is therefore assumed that 80% of global low-carbon hydrogen is consumed by high-income economies[3] plus China and the remaining 20% by other medium- and low-income countries.

Secondly, industrial and transport sector hydrogen demand is allocated to individual countries based on their share in the projected combined GDP

[1] Including hydrogen used for the production of synthetic fuels.
[2] Including hydrogen used in refining and for the production of low-carbon ammonia.
[3] As per the current World Bank classification (World Bank, 2021).

(OECD, 2018) of all of countries in their respective income group. The underlying rationale is that since higher absolute GDP tends to correlate with higher absolute industrial output and transportation demand and thus energy consumption, sectoral hydrogen demand can be distributed accordingly as well. Hydrogen consumed in other sectors, most importantly buildings, on the other hand, is mainly used for heating. Some of it is also blended into natural gas grids (IEA, 2020a,b). In sectors other than transport and industry, the spatial distribution of low-carbon hydrogen demand within an income group is assumed to mirror that of natural gas, its direct substitute.

The assumed regional distribution of low-carbon hydrogen demand is shown in Figure 3.1 in Section 3.2.2.

B.1.2. Demand for natural gas

In the SDS, global natural gas demand peaks around 2025 at 4166 bcm and then declines to 3554 bcm in 2040 (IEA, 2020b, p. 339). However, demand trends differ between regions: a rapid decline in Europe and North America is contrasted by growth in the Asia Pacific, primarily China and India (IEA, 2020b, p. 48). After 2040, consumption in Asia peaks as well, and global natural gas demand declines to 3195 bcm[4] by 2050.

Since the demand projections in IEA (2020b) are only provided for regional groupings and large countries, the residual regional gas demand is distributed to the remaining countries covered by the model based on their share in the respective region's 2018 residual natural gas consumption, obtained from IEA (2019a). Gas demand projections for selected African countries come from IEA (2019e).

It should be noted that a part of the natural gas consumption presented above is associated with the natural gas-based production of low-carbon hydrogen. However, since the level of gas-based hydrogen production is an outcome of the model, hydrogen-related natural gas consumption as projected by the IEA has to be deducted from the total natural gas demand presented above to arrive at a consistent estimate of the residual, non-hydrogen-related

[4]Since neither IEA (2020a) nor IEA (2020b) provide an estimate for global gas demand in 2050, this value was interpolated between the 2040 projection given in IEA (2020b) (3554 bcm) and a 2070 estimate provided in IEA (2020a) (2048 Mtoe). The latter was converted to bcm by dividing it by the energy density ($\frac{Mtoe}{bcm}$) of global gas demand in 2040 (0.828) (IEA, 2020b).

natural gas demand. Since this information is not provided directly by IEA (2020b), further assumptions have to be made. According to IEA (2020a), approximately 50% of the low-carbon hydrogen consumed in the SDS is produced from fossil fuels with CCS—mostly natural gas. Therefore, by taking half of the low-carbon hydrogen demand presented above and dividing by the efficiency of a natural gas reformer with carbon capture and storage (CCS) technology (69%) (Brändle et al., 2021), it is possible to derive a rough estimate of hydrogen-related natural gas consumption in the SDS, which is deducted from the total natural gas consumption given by (IEA, 2020b) to estimate global non-hydrogen-related natural gas consumption. The resulting distribution of the global demand for natural gas, broken down by region, is shown in Figure B.1: After peaking in the mid-2020s, non-hydrogen-related natural gas demand declines to 3945 bcm in 2030 and 2534 bcm in 2050.

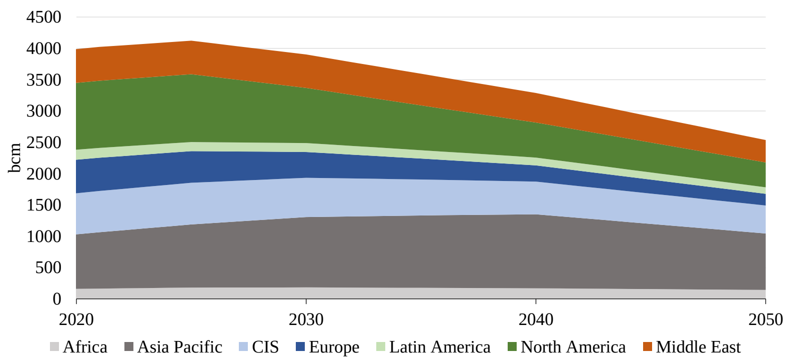


Figure B.1.: Assumed annual demand for natural gas (excluding for hydrogen production)

Table B.1.: Country-specific CO_2 storage cost used in the model

Country	**CO_2 storage assumptions** Formation	Location	Cost ($/t$CO_2$)
Algeria	Depleted oil & gas field	Onshore	17.6
Angola	Depleted oil & gas field	Offshore	23.3
Egypt	Depleted oil & gas field	Onshore	17.6
Equatorial Guinea	Depleted oil & gas field	Offshore	23.3
Libya	Depleted oil & gas field	Onshore	17.6
Nigeria	Depleted oil & gas field	Onshore	17.6
Ghana	Depleted oil & gas field	Offshore	23.3
Morocco	Saline formations	Onshore	23.4
Tunisia	Depleted oil & gas field	Onshore	17.6
Mozambique	Depleted oil & gas field	Offshore	23.3
Australia	Depleted oil & gas field	Onshore	17.6

Brunei Darussalam	Depleted oil & gas field	Offshore	23.3
Indonesia	Depleted oil & gas field	Onshore	17.6
Malaysia	Depleted oil & gas field	Offshore	23.3
Myanmar	Depleted oil & gas field	Offshore	23.3
Bangladesh	Depleted oil & gas field	Offshore	23.3
China	Saline formations	Onshore	23.4
India	Depleted oil & gas field	Onshore	17.6
Japan	Saline formations	Offshore	36.2
Korea	Saline formations	Onshore	23.4
Philippines	Depleted oil & gas field	Offshore	23.3
Pakistan	Depleted oil & gas field	Onshore	17.6
Singapore	Depleted oil & gas field	Offshore	23.3
Thailand	Depleted oil & gas field	Offshore	23.3
Taiwan	Saline formations	Offshore	36.2
Vietnam	Depleted oil & gas field	Offshore	23.3
Azerbaijan	Depleted oil & gas field	Offshore	23.3
Kazakhstan	Depleted oil & gas field	Onshore	17.6
Russian Federation	Depleted oil & gas field	Onshore	17.6
Turkmenistan	Depleted oil & gas field	Onshore	17.6
Uzbekistan	Depleted oil & gas field	Onshore	17.6
Ukraine	Saline formations	Onshore	23.4
Georgia	Saline formations	Onshore	23.4
Denmark	Depleted oil & gas field	Offshore	23.3
Netherlands	Depleted oil & gas field	Offshore	23.3
Norway	Depleted oil & gas field	Offshore	23.3
United Kingdom	Depleted oil & gas field	Offshore	23.3
Austria	Saline formations	Onshore	23.4
Baltic States	Saline formations	Onshore	23.4
Belgium	Saline formations	Onshore	23.4
Bulgaria	Depleted oil & gas field	Offshore	23.3
Belarus	Saline formations	Onshore	23.4
Switzerland	Saline formations	Onshore	23.4
Czech Republic	Saline formations	Onshore	23.4
Germany	Depleted oil & gas field	Offshore	23.3
Spain	Saline formations	Onshore	23.4
Finland	Saline formations	Onshore	23.4
France	Saline formations	Onshore	23.4
Greece	Saline formations	Onshore	23.4
Hungary	Saline formations	Onshore	23.4
Ireland	Saline formations	Onshore	23.4
Italy	Saline formations	Onshore	23.4
Poland	Saline formations	Onshore	23.4
Portugal	Saline formations	Onshore	23.4
Romania	Depleted oil & gas field	Offshore	23.3
Sweden	Saline formations	Onshore	23.4

Slovenia	Saline formations	Onshore	23.4
Slovakia	Saline formations	Onshore	23.4
Turkey	Depleted oil & gas field	Offshore	23.3
Moldova	Depleted oil & gas field	Offshore	23.3
Yugoslavia	Saline formations	Onshore	23.4
Argentina	Depleted oil & gas field	Onshore	17.6
Bolivia	Depleted oil & gas field	Onshore	17.6
Peru	Depleted oil & gas field	Onshore	17.6
Trinidad and Tobago	Depleted oil & gas field	Offshore	23.3
Venezuela	Depleted oil & gas field	Offshore	23.3
Brazil	Depleted oil & gas field	Onshore	17.6
Chile	Saline formations	Onshore	23.4
Colombia	Depleted oil & gas field	Onshore	17.6
Caribbean	Depleted oil & gas field	Offshore	23.3
Iran	Depleted oil & gas field	Offshore	23.3
Iraq	Depleted oil & gas field	Onshore	17.6
Oman	Depleted oil & gas field	Onshore	17.6
Qatar	Depleted oil & gas field	Offshore	23.3
Saudi Arabia	Depleted oil & gas field	Onshore	17.6
United Arab Emirates	Depleted oil & gas field	Onshore	17.6
Yemen	Depleted oil & gas field	Onshore	17.6
Bahrain	Depleted oil & gas field	Onshore	17.6
Kuwait	Depleted oil & gas field	Onshore	17.6
Syria	Depleted oil & gas field	Onshore	17.6
Near East	Depleted oil & gas field	Offshore	23.3
Canada	Depleted oil & gas field	Onshore	17.6
United States	Depleted oil & gas field	Onshore	17.6
Mexico	Depleted oil & gas field	Onshore	17.6
South Africa	Saline formations	Onshore	23.4
Iceland	Saline formations	Onshore	23.4
Papua New Guinea	Depleted oil & gas field	Onshore	17.6
Cameroon	Depleted oil & gas field	Offshore	23.3

CO_2 storage costs are calculated based on Roussanaly et al. (2014) and Rubin et al. (2015b). An average distance of 200 km between production sites and storage reservoirs and a connection by CO_2 pipeline is assumed.

B.2. Supplementary Results

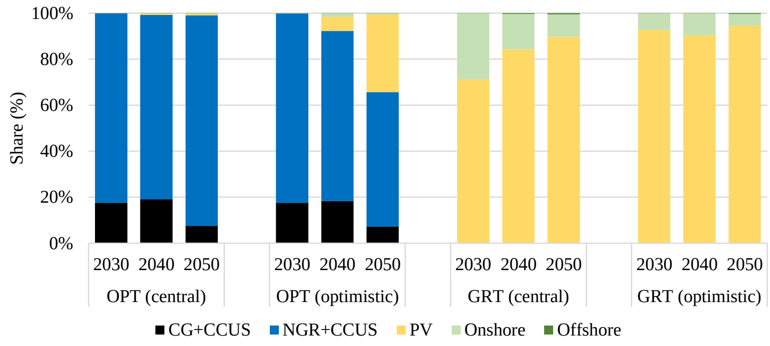


Figure B.2.: Share of low-carbon hydrogen production by pathway

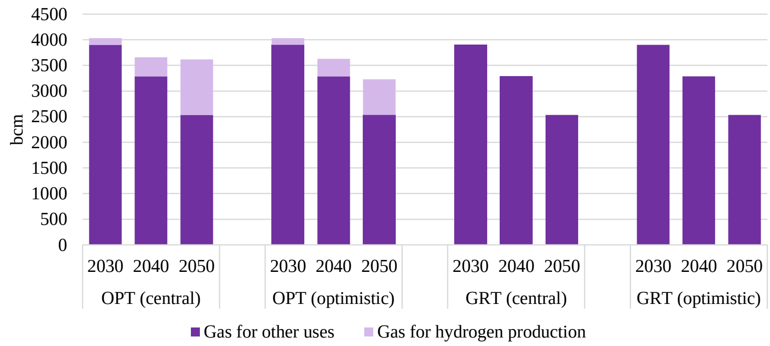


Figure B.3.: Global natural gas consumption

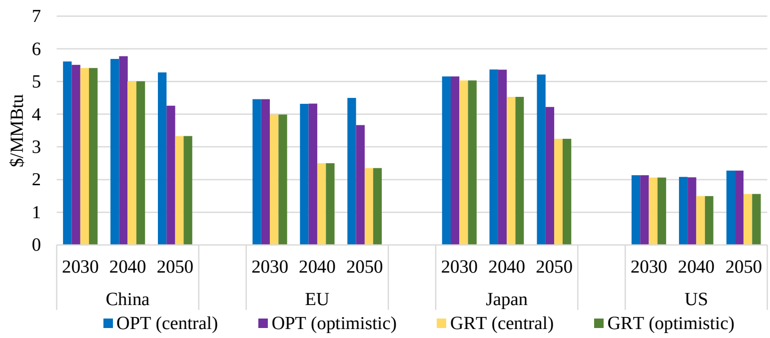


Figure B.4.: Estimated natural gas prices for major consumers by scenario

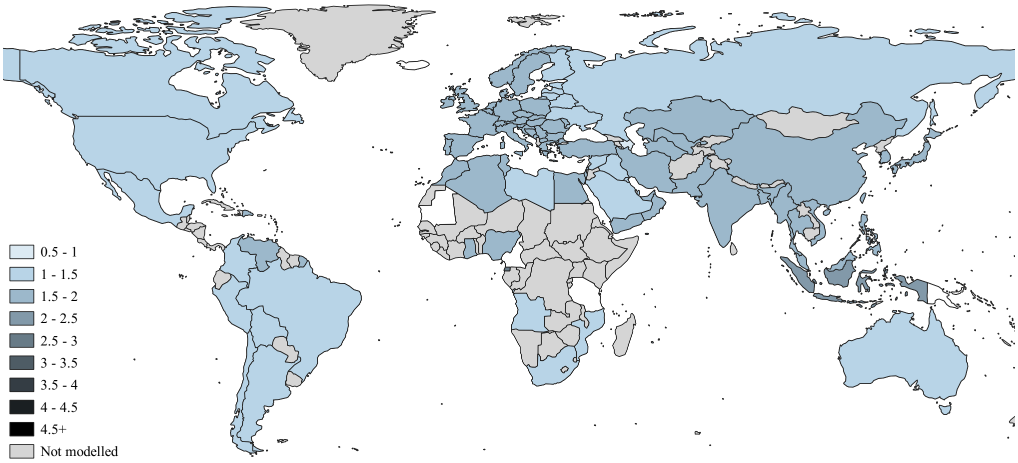


Figure B.5.: Hydrogen prices in the OPT (central) scenario in 2050, by country (in \$/kg)

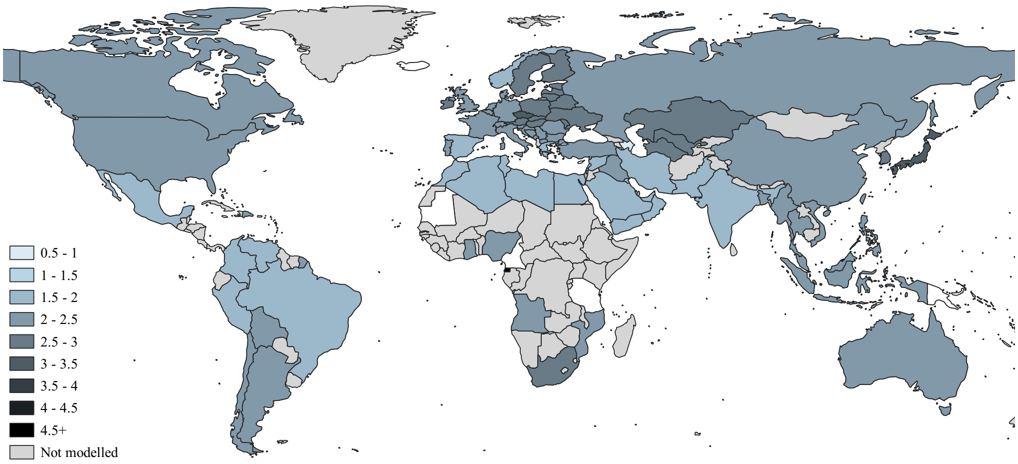


Figure B.6.: Hydrogen prices in the GRT (central) scenario in 2050, by country (in \$/kg)

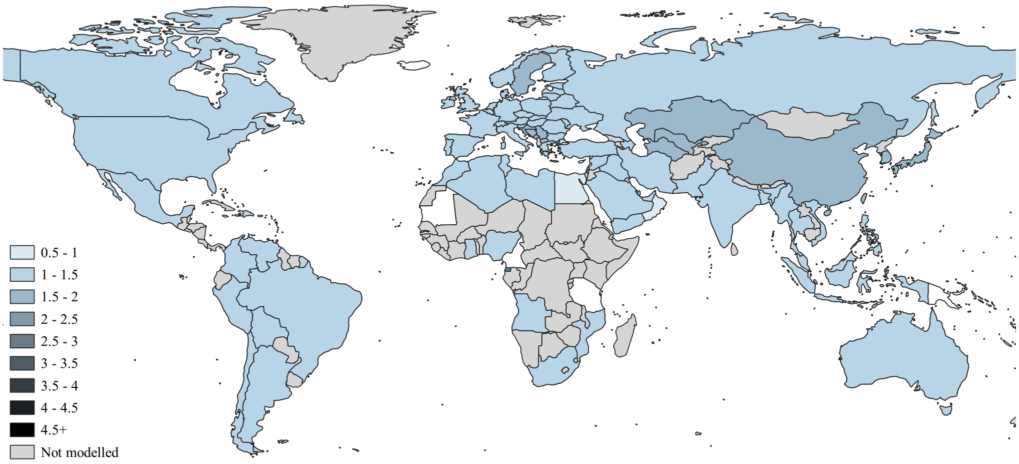


Figure B.7.: Hydrogen prices in the OPT (optimistic) scenario in 2050, by country (in \$/kg)

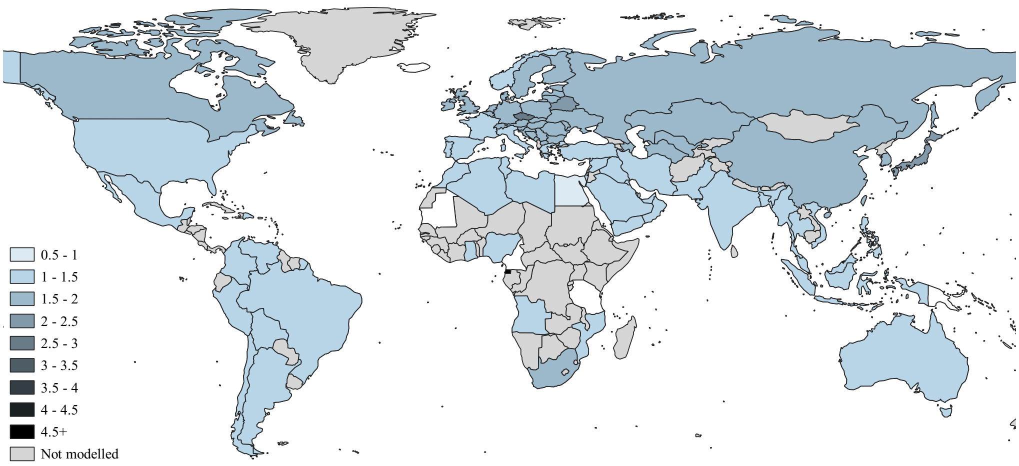


Figure B.8.: Hydrogen prices in the GRT (optimistic) scenario in 2050, by country (in \$/kg)

C. Supplementary Material for Chapter 4

C.1. Interviews

Questions:

- How do you think the evolution of hydrogen will impact the LNG industry?

  Short and long term?

  Regionally?

- Is hydrogen development a threat or opportunity for LNG?
- What options exist for the LNG industry in natural gas-based (blue) and RES-based (green) hydrogen pathways?
- Focusing on Qatar LNG and Australian LNG, how do you see hydrogen market evolution impacting them specifically?

Interviewees:

1. Executive – International oil company, major LNG player
2. Executive – International oil company, major LNG player
3. Analyst – Major international organisation
4. Senior Analyst – Major international organisation
5. Partner – Management consultancy
6. Executive – LNG and decarbonisation expert
7. Executive – LNG marketing, production and trading
8. Executive – LNG marketing, trading

C.2. Additional Assumptions

Table C.1.: Country-specific CO_2 storage cost and WACC used in the model

Country	CO_2 storage assumptions			WACC
	Formation	Location	Cost ($/t$CO_2$)	
Algeria	Depleted oil & gas field	Onshore	17.6	12.8%
Angola	Depleted oil & gas field	Offshore	23.3	11.3%
Egypt	Depleted oil & gas field	Onshore	17.6	16.1%
Equatorial Guinea	Depleted oil & gas field	Offshore	23.3	10.8%
Libya	Depleted oil & gas field	Onshore	17.6	12.8%
Nigeria	Depleted oil & gas field	Onshore	17.6	10.8%
Ghana	Depleted oil & gas field	Offshore	23.3	12.9%
Morocco	Saline formations	Onshore	23.4	9.4%
Tunisia	Depleted oil & gas field	Onshore	17.6	10.7%
Mozambique	Depleted oil & gas field	Offshore	23.3	11.7%
Australia	Depleted oil & gas field	Onshore	17.6	8.4%
Brunei Darussalam	Depleted oil & gas field	Offshore	23.3	9.5%
Indonesia	Depleted oil & gas field	Onshore	17.6	10.4%
Malaysia	Depleted oil & gas field	Offshore	23.3	9.5%
Myanmar	Depleted oil & gas field	Offshore	23.3	11.7%
Bangladesh	Depleted oil & gas field	Offshore	23.3	11.7%
China	Saline formations	Onshore	23.4	9.0%
India	Depleted oil & gas field	Onshore	17.6	10.7%
Japan	Saline formations	Offshore	36.2	8.6%
Korea	Saline formations	Onshore	23.4	8.8%
Philippines	Depleted oil & gas field	Offshore	23.3	10.0%
Pakistan	Depleted oil & gas field	Onshore	17.6	15.7%
Singapore	Depleted oil & gas field	Offshore	23.3	8.6%
Thailand	Depleted oil & gas field	Offshore	23.3	9.7%
Taiwan	Saline formations	Offshore	36.2	9.0%
Vietnam	Depleted oil & gas field	Offshore	23.3	12.1%
Azerbaijan	Depleted oil & gas field	Offshore	23.3	9.1%
Kazakhstan	Depleted oil & gas field	Onshore	17.6	10.2%
Russian Federation	Depleted oil & gas field	Onshore	17.6	10.2%
Turkmenistan	Depleted oil & gas field	Onshore	17.6	10.2%
Uzbekistan	Depleted oil & gas field	Onshore	17.6	10.2%
Ukraine	Saline formations	Onshore	23.4	14.8%
Georgia	Saline formations	Onshore	23.4	9.8%
Denmark	Depleted oil & gas field	Offshore	23.3	7.1%
Netherlands	Depleted oil & gas field	Offshore	23.3	7.3%
Norway	Depleted oil & gas field	Offshore	23.3	7.2%
United Kingdom	Depleted oil & gas field	Offshore	23.3	8.4%
Austria	Saline formations	Onshore	23.4	7.2%
Baltic States	Saline formations	Onshore	23.4	7.9%

Belgium	Saline formations	Onshore	23.4	7.8%
Bulgaria	Depleted oil & gas field	Offshore	23.3	8.6%
Belarus	Saline formations	Onshore	23.4	16.2%
Switzerland	Saline formations	Onshore	23.4	7.2%
Czech Republic	Saline formations	Onshore	23.4	7.8%
Germany	Depleted oil & gas field	Offshore	23.3	7.1%
Spain	Saline formations	Onshore	23.4	8.7%
Finland	Saline formations	Onshore	23.4	7.3%
France	Saline formations	Onshore	23.4	7.4%
Greece	Saline formations	Onshore	23.4	13.3%
Hungary	Saline formations	Onshore	23.4	9.1%
Ireland	Saline formations	Onshore	23.4	8.5%
Italy	Saline formations	Onshore	23.4	8.6%
Poland	Saline formations	Onshore	23.4	8.0%
Portugal	Saline formations	Onshore	23.4	9.3%
Romania	Depleted oil & gas field	Offshore	23.3	9.0%
Sweden	Saline formations	Onshore	23.4	7.1%
Slovenia	Saline formations	Onshore	23.4	9.2%
Slovakia	Saline formations	Onshore	23.4	8.0%
Turkey	Depleted oil & gas field	Offshore	23.3	9.2%
Moldova	Depleted oil & gas field	Offshore	23.3	13.2%
Yugoslavia	Saline formations	Onshore	23.4	9.2%
Argentina	Depleted oil & gas field	Onshore	17.6	16.1%
Bolivia	Depleted oil & gas field	Onshore	17.6	11.5%
Peru	Depleted oil & gas field	Onshore	17.6	9.5%
Trinidad and Tobago	Depleted oil & gas field	Offshore	23.3	11.5%
Venezuela	Depleted oil & gas field	Offshore	23.3	20.5%
Brazil	Depleted oil & gas field	Onshore	17.6	10.1%
Chile	Saline formations	Onshore	23.4	9.0%
Colombia	Depleted oil & gas field	Onshore	17.6	9.7%
Caribbean	Depleted oil & gas field	Offshore	23.3	8.3%
Iran	Depleted oil & gas field	Offshore	23.3	9.2%
Iraq	Depleted oil & gas field	Onshore	17.6	10.2%
Oman	Depleted oil & gas field	Onshore	17.6	9.1%
Qatar	Depleted oil & gas field	Offshore	23.3	8.4%
Saudi Arabia	Depleted oil & gas field	Onshore	17.6	9.2%
United Arab Emirates	Depleted oil & gas field	Onshore	17.6	8.4%
Yemen	Depleted oil & gas field	Onshore	17.6	20.5%
Bahrain	Depleted oil & gas field	Onshore	17.6	8.4%
Kuwait	Depleted oil & gas field	Onshore	17.6	8.9%
Syria	Depleted oil & gas field	Onshore	17.6	20.5%
Near East	Depleted oil & gas field	Offshore	23.3	12.8%
Canada	Depleted oil & gas field	Onshore	17.6	8.3%
United States	Depleted oil & gas field	Onshore	17.6	8.1%
Mexico	Depleted oil & gas field	Onshore	17.6	9.4%

South Africa	Saline formations	Onshore	23.4	10.0%
Iceland	Saline formations	Onshore	23.4	8.5%
Papua New Guinea	Depleted oil & gas field	Onshore	17.6	11.8%
Cameroon	Depleted oil & gas field	Offshore	23.3	11.6%

CO_2 storage costs are calculated based on Roussanaly et al. (2014) and Rubin et al. (2015b). We assume an average distance of 200 km between production sites and storage reservoirs and a connection by CO_2 pipeline.

WACC = weighted average cost of capital. Country-specific WACC figures (corresponding to oil & gas sector risk-return profiles) are taken from Finance 3.1 (2021), supplemented by own assumptions.

C.3. Supplementary Model Results

Table C.2.: Projected annual trade flows on the LNG market (in bcm)

FROM/TO	Scenario	Africa			Asia Pacific			CIS			Europe			Middle East			Latin America			North America			Total		
		2030	**2040**	**2050**	**2030**	**2040**	**2050**	**2030**	**2040**	**2050**	**2030**	**2040**	**2050**	**2030**	**2040**	**2050**	**2030**	**2040**	**2050**	**2030**	**2040**	**2050**	**2030**	**2040**	**2050**
Africa	OPT (baseline)	0	24	21	44	16	18	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	45	41	40
	OPT (low cost)	0	24	26	45	20	12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	45	44	38
	OPT (low cost/pyrolysis)	0	34	49	44	19	55	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	45	53	104
	GRT (baseline)	0	10	23	46	32	13	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	46	42	36
Asia Pacific	OPT (baseline)	0	0	0	134	147	132	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	134	147	132
	OPT (low cost)	0	0	0	134	148	120	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	134	148	120
	OPT (low cost/pyrolysis)	0	0	0	136	147	136	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	136	147	136
	GRT (baseline)	0	0	0	137	147	60	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	137	147	60
CIS	OPT (baseline)	0	0	0	48	65	68	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	48	65	68
	OPT (low cost)	0	0	0	49	65	66	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	49	65	66
	OPT (low cost/pyrolysis)	0	0	0	48	73	79	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	48	73	79
	GRT (baseline)	0	0	0	63	64	63	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	63	64	63
Europe	OPT (baseline)	0	0	0	0	0	0	0	0	0	6	6	6	0	0	0	0	0	0	0	0	0	6	6	6
	OPT (low cost)	0	0	0	0	0	0	0	0	0	6	6	6	0	0	0	0	0	0	0	0	0	6	6	6
	OPT (low cost/pyrolysis)	0	0	0	0	0	0	0	0	0	6	6	6	0	0	0	0	0	0	0	0	0	6	6	6
	GRT (baseline)	0	0	0	0	0	0	0	0	0	6	5	4	0	0	0	0	0	0	0	0	0	6	5	4
L. America	OPT (baseline)	0	0	0	5	5	4	0	0	0	2	1	0	0	0	0	0	0	0	0	0	0	7	6	4
	OPT (low cost)	0	0	0	5	5	0	0	0	0	2	1	0	0	0	0	0	0	0	0	0	0	7	6	0
	OPT (low cost/pyrolysis)	0	0	0	5	5	4	0	0	0	2	1	0	0	0	0	0	0	0	0	0	0	7	5	4
	GRT (baseline)	0	0	0	5	6	4	0	0	0	2	0	0	0	0	0	0	0	0	0	0	0	8	6	4
Middle East	OPT (baseline)	0	18	39	112	109	128	0	0	0	7	1	1	0	0	0	0	0	0	0	0	0	120	128	168
	OPT (low cost)	0	18	32	112	112	134	0	0	0	7	1	1	0	0	0	0	0	0	0	0	0	120	131	168
	OPT (low cost/pyrolysis)	0	9	16	112	114	150	0	0	0	7	1	1	0	0	0	0	0	0	0	0	0	120	124	167
	GRT (baseline)	0	31	32	111	98	74	0	0	0	7	1	1	0	0	0	0	0	0	0	0	0	119	130	107
N. America	OPT (baseline)	0	0	0	181	211	162	0	0	0	25	12	57	0	0	0	4	5	7	0	0	0	210	229	226
	OPT (low cost)	0	0	0	182	198	108	0	0	0	25	8	97	0	0	0	4	5	3	0	0	0	211	211	208
	OPT (low cost/pyrolysis)	0	0	0	184	299	246	0	0	0	25	4	56	0	0	0	4	6	7	0	0	0	213	309	309
	GRT (baseline)	0	0	0	139	154	144	0	0	0	14	0	0	0	0	0	4	3	10	0	0	0	157	157	153
Total	**OPT (baseline)**	0	43	60	525	554	513	0	0	0	41	19	64	0	0	0	4	5	7	1	0	0	**570**	**621**	**643**
	OPT (low cost)	0	43	58	527	548	439	0	0	0	41	16	104	0	0	0	4	5	3	1	0	0	**572**	**611**	**605**
	OPT (low cost/pyrolysis)	0	43	65	529	657	669	0	0	0	40	12	63	0	0	0	4	6	7	1	0	0	**574**	**717**	**805**
	GRT (baseline)	0	41	55	501	502	358	0	0	0	29	6	6	0	0	0	4	3	10	1	0	0	**534**	**551**	**428**

D. Supplementary Material for Chapter 5

D.1. Models, Data and Assumptions

D.1.1. Model indices, parameters and variables

D.1.2. Electricity market model

The electricity market model is an investment model covering electricity production and consumption in 28 countries in Europe[1]. Initially developed as a standalone electricity market model by Richter (2011), to better replicate future energy systems in which final energy consumption is increasingly electrified, it has since been extended to cover additional end-use sectors, conversion technologies and electricity-derived energy carriers (Helgeson and Peter, 2020).

The objective function (equation D.1) minimises the total system cost (TSC), which is the sum of the fixed and variable cost terms over all energy production technologies i, markets n, years y and time steps t. $\phi_{i,n,y}$ is the fixed cost vector, covering both the fixed investment and operations and maintenance (O&M) costs. Fixed costs are incurred per unit of installed capacity ($\mathbf{C}^{el,ptg}_{i,n,y}$) of all electricity ($el$) and hydrogen/synthetic methane (ptg) production technologies i. $\gamma_{i,n,y,t}$ is the variable cost vector, which comprises the fuel or feedstock costs and other variable O&M costs. Total variable costs depend on the level of production ($\mathbf{P}^{el,ptg}_{i,n,y,t}$) of technology i.

$$\min \;\; TSC = \sum_{i,n,y,t} \phi_{i,n,y} * \mathbf{C}^{el,ptg}_{i,n,y} + \sum_{i,n,y} \gamma_{i,n,y,t} * \mathbf{P}^{el,ptg}_{i,n,y,t} \tag{D.1}$$

The optimisation problem is subject to a number of constraints. The most important constraints governing the model of the electricity system are equations

[1] Austria, Belgium, Bulgaria, Croatia, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Netherlands, Norway, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden, Switzerland and the United Kingdom.

Table D.1.: Model indices, parameters and variables

Name	Unit	Definition
Sets		
$t \in T$		Time
$i, j \in I$		Technologies (electricity generation, PtX)
$y \in Y$		Years
$n, m \in N$		Nodes (gas) or markets (electricity)
$l \in L$		Sectors (Electricity, industry, households, transport)
$z \in Z \subset N$		Gas storage
$g \in G \subset N$		Natural gas production locations
$r \in R \subset N$		LNG import terminals (regasifiers)
$v \in V$		Countries
Parameters		
ϕ	EUR	Fixed cost
γ	EUR	Variable cost
α	-	Generator's availability
σ	-	Secure capacity factor
l	MWh	Annual peak load
η	MWh_{el}/MWh_{th}	Generator's efficiency
ϵ	tCO_2eq/MWh	Fuel-specific emission factor
$emcap$	tCO_2eq	Annual emission cap
d	MWh	Exogenous demand
κ	-	Quota obligation
λ	-	Hydrogen injection limit
τ	-	Gas storage injection/withdrawal rate
q	MWh	Synthetic gas injection
cap	MWh/mcm	Electricity/gas infrastructure capacities
Variables		
C	MW	Installed capacity
P	MWh	Production or regasification
F	MWh	Energy flows
S	MWh	Storage flows
D	MWh	Demand
VC	EUR	Variable cost
TSC	EUR	Total system cost

D.2 to D.5. Constraints describing the production of hydrogen, methanation and the renewable hydrogen quota are given by equations D.6 to D.10.

The equilibrium constraint (equation D.2) ensures that electricity production ($\mathbf{P}^{el}_{i,n,y,t}$), net imports ($\Delta\mathbf{F}^{el}_{m,n,y,t}$) and net storage flows ($\Delta\mathbf{S}^{el}_{i,n,y,t}$) in market n match the electricity demand ($\mathbf{D}^{el}_{n,y,t}$) for each time step t.

$$\mathbf{D}^{el}_{n,y,t} = \sum_{i} \mathbf{P}^{el}_{i,n,y,t} + \sum_{m} \Delta\mathbf{F}^{el}_{m,n,y,t} + \sum_{i} \Delta\mathbf{S}^{el}_{i,n,y,t} \qquad \forall\ n,y,t,m \neq n \quad \text{(D.2)}$$

Equation D.3 states that a generator's electrical output ($\mathbf{P}^{el}_{i,n,y,t}$) cannot exceed its available capacity, which is derived by multiplying the installed capacity ($\mathbf{C}^{el}_{i,n,y}$) with the time-dependent availability ($\alpha^{el}_{i,n,y,t} \rightarrow [0,1]$). The same constraint also applies to the net transfer capacity linking two electricity markets.

$$\mathbf{P}^{el}_{i,n,y,t} \leq \mathbf{C}^{el}_{i,n,y} * \alpha^{el}_{i,n,y,t} \qquad \forall\ i,n,y,t \quad \text{(D.3)}$$

To reduce the computational burden, the model operates with a reduced temporal resolution. A year is represented by 16 typical days, which are modelled in hourly resolution. Accordingly, it may not capture rare situations of extreme system stress (e.g. combinations of high load and low RES feed-in) in the time slices that are modelled. To remedy this, a peak load constraint is introduced (equation D.4), which requires the sum of generation capacities ($\mathbf{C}^{el}_{i,n,y}$), weighted by their respective secure capacity values[2] ($\sigma_{i,n} \rightarrow [0,1]$), to be greater than or equal to an exogenous, market-specific annual peak load ($\mathbf{l}^{el}_{n,y}$), thereby ensuring that sufficient capacity is installed to maintain security of supply even in situations of extreme load which are not modelled directly.

$$\mathbf{l}^{el}_{n,y} \leq \sum_{i} \mathbf{C}^{el}_{i,n,y} * \sigma_{i,n} + \sum_{m} cap^{ntc}_{n,m,y} * \sigma_{n,m,y} \qquad \forall\ n,y,m \neq n \quad \text{(D.4)}$$

In the EU, power plants are subject to a cap on emissions imposed by the EU ETS. In the model, this is approximated by equation D.5, which requires the aggregated annual emissions[3] of all power-generating technologies to be lower than the annual cap. The CO_2 emissions are calculated by dividing a generator's output ($\mathbf{P}^{el}_{i,n,y,t}$) by its efficiency ($\eta^{el}_{i}$) to determine its fuel consumption, which is then multiplied with the fuel-specific emission factor (ϵ^{CO2}_{i}).

[2]The capacity value is the percentage of the plant's capacity that is reliably available in situations of extreme system stress. For dispatchable power plants, the capacity value may deviate from 100% due to, e.g., unplanned outages. Weather-dependent variable RES generally have low capacity values.

[3]In tonnes of CO_2.

$$emcap_y^{CO2} \geq \sum_{i,n,t} \frac{\mathbf{P}^{el}_{i,n,y,t}}{\eta^{el}_i} * \epsilon_i^{CO2} \qquad \forall\ y \tag{D.5}$$

The following constraints pertain to the production of hydrogen and synthetic methane through the electrolysis of water. Equation D.6 links the production of hydrogen and synthetic methane (ptg) to the electricity system: Total electricity demand per time period ($\mathbf{D}^{el}_{n,y,t}$) is the sum of the exogenous electricity demand ($d^{el}_{n,l,y,t}$) in market n and sector l and the sum of the electricity consumed by PtG technologies i in market n. This is obtained by dividing the hourly output of a PtG process ($\mathbf{P}^{ptg}_{i,n,y,t}$) by its conversion efficiency (η_i^{ptg}).

$$\mathbf{D}^{el}_{n,y,t} = \sum_l d^{el}_{n,l,y,t} + \sum_i \frac{\mathbf{P}^{ptg}_{i,n,y,t}}{\eta_i^{ptg}} \qquad \forall\ n,y,t \tag{D.6}$$

PtG production ($\mathbf{P}^{ptg}_{i,n,y,t}$) is limited to the installed electrolyser or methanation capacity ($\mathbf{C}^{ptg}_{i,n,y}$) (given in kW-electric), times their efficiency (η_i^{ptg}) (equation D.7).

$$\mathbf{P}^{ptg}_{i,n,y,t} \leq \mathbf{C}^{ptg}_{i,n,y} * \eta_i^{ptg} \qquad \forall\ i,n,l,y,t \tag{D.7}$$

Equation D.8 operationalises the renewable hydrogen quota. For each year y, it requires the supply of hydrogen and synthetic methane ($\mathbf{P}^{ptg}_{i,n,y,t}$) across all markets n to match the demand for gas in final demand sectors l, times the quota ($\kappa^{ptg}_{y,l} \to [0,1]$).

$$\sum_{i,n,t} \mathbf{P}^{ptg}_{i,n,y,t} \geq \sum_{n,l,t} d^{gas}_{n,l,y,t} * \kappa^{ptg}_{y,l} \qquad \forall\ y \tag{D.8}$$

We assume that the hydrogen produced to fulfil the quota obligation is blended into the natural gas grid at the distribution grid level. Equation D.9 establishes blending limits for hydrogen. The volume of hydrogen injected is derived by multiplying the production of raw hydrogen ($\mathbf{P}^{H2}_{i,n,y,t}$) in market n with hydrogen's volumetric energy density ($ncv_{H2} = 3$ kWh/m^3). It has to be less than or equal to the volume of natural gas consumed in the final demand sectors l, which is derived by multiplying the final gas demand of each sector ($d^{gas}_{n,l,y,t}$) with the volumetric energy density of natural gas ($ncv_{CH4} = 10$ kWh/m^3), times the hydrogen injection limit ($\lambda_{y,l} \to [0,1]$).

$$\sum_{i} \mathbf{P}^{H2}_{i,n,y,t} * ncv_{H2} \leq \sum_{n,l} d^{gas}_{n,l,y,t} * ncv_{CH4} * \lambda_{y,l} \qquad \forall \ y, t \tag{D.9}$$

To certify hydrogen as renewable, we presume that the electricity purchased by a PtG producer has to be produced by a RES within the same market area (usually country) and hour. Equation D.10 requires the electricity consumed for the production of hydrogen or synthetic methane ($P^{ptg}_{i,n,y,t}$) within each market n by technologies i in time step t to be matched by electricity generation from renewable energy sources $j \subseteq i$ in the respective market n and time steps t. The constraint ensures that the hydrogen produced to fulfil the quota obligation is renewable. We assume that statistical transfers of renewable electricity between markets are not allowed.

$$\sum_{i} \frac{\mathbf{P}^{ptg}_{i,n,y,t}}{\eta^{ptg}_{i}} \geq \sum_{j} \mathbf{P}^{el}_{j,n,y,t} \qquad \forall \ n, j \subseteq i, y, t \tag{D.10}$$

D.1.3. Gas market model

The gas market model consists of a number of nodes n, connected by pipelines with a given transmission capacity. Demand, as well as storage, production and LNG regasification capacities, are assigned to these nodes. The objective function (equation D.11) minimises the total cost (TSC) of the natural gas supply over all time periods $t \in T$. It is the sum of the natural gas production cost ($\mathbf{VC}^{prod}_{n,t}$), the cost of transportation ($\mathbf{VC}^{trans}_{n,m,t}$) and the cost of storage ($\mathbf{VC}^{stor}_{n,t}$).

$$\min \ TSC = \sum_{n,m,t} \mathbf{VC}^{prod}_{n,t} + \mathbf{VC}^{trans}_{n,m,t} + \mathbf{VC}^{stor}_{n,t} \tag{D.11}$$

The model is subject to a number of constraints. The energy balance condition (equation D.12) ensures that the market clears in every time period and requires that the gas volume entering a node n is equal the gas volume exiting a node. Gas flows into the node can be pipeline flows ($\mathbf{F^{trans}_{m,n,t}}$), storage withdrawals ($\mathbf{S^{out}_{z,n,t}}$), production at the node ($\mathbf{P^{gas}_{g,n,t}}$), LNG regasification ($\mathbf{P^{lng}_{r,n,t}}$) or synthetic methane injection ($\mathbf{P^{ch4}_{i,n,t}}$) at the node. Volumes leaving a node can be exogenous demand at the node ($d_{n,t}$), pipeline flows from the node to another node ($\mathbf{F^{trans}_{n,m,t}}$) or storage injections ($\mathbf{S^{in}_{z,n,t}}$). Hydrogen injection is modelled as a reduction of demand at the node ($\mathbf{P^{h2}_{n,t}}$), since it is assumed to occur at the distribution grid level. Further restrictions to hydrogen injection are stated later.

$$(d_{n,t} - \mathbf{P}^{h2}_{n,t} * \frac{1}{gcv_{ng}}) + \sum_{m} \mathbf{F}^{trans}_{n,m,t} + \sum_{z} \mathbf{S}^{in}_{z,n,t}$$
$$=$$
$$\sum_{m} \mathbf{F}^{trans}_{m,n,t} + \sum_{z} \mathbf{S}^{out}_{z,n,t} + \sum_{g} \mathbf{P}^{gas}_{g,n,t} + \sum_{r} \mathbf{P}^{lng}_{r,n,t} + \sum_{i} \mathbf{P}^{ch4}_{i,n,t} * \frac{1}{gcv_{ng}} \qquad \forall \ n,t \tag{D.12}$$

The storage balance condition (equation D.13) ensures that storage injections, withdrawals and levels are balanced over time.

$$\mathbf{S}^{level}_{z,n,t} = \mathbf{S}^{level}_{z,n,t-1} + \mathbf{S}^{in}_{z,n,t} - \mathbf{S}^{out}_{z,n,t} \qquad \forall \ z,n,t \tag{D.13}$$

Production, transportation, regasification and storage injection/ withdrawal are restricted to the exogenous capacities (equations D.14-D.19), which can change over time, for instance, when pipelines are (de-)commissioned. Storage injection and withdrawal capacities additionally depend on the storage level and a factor τ_z as withdrawal rates decrease with falling storage levels due to a loss of pressure.

$$\mathbf{P}^{gas}_{g,n,t} \leq cap^{gas}_{g,n,t} \qquad \forall \ g,n,t \tag{D.14}$$

$$\mathbf{P}^{lng}_{r,n,t} \leq cap^{lng}_{r,n,t} \qquad \forall \ r,n,t \tag{D.15}$$

$$\mathbf{F}^{trans}_{n,m,t} \leq cap^{trans}_{n,m,t} \qquad \forall \ n,m,t \tag{D.16}$$

$$\mathbf{S}^{level}_{z,n,t} \leq cap^{level}_{z,n,t} \qquad \forall \ z,n,t \tag{D.17}$$

$$\mathbf{S}^{in}_{z,n,t} \leq cap^{in}_{z,n,t} * \tau^{in}_{z} * \mathbf{S}^{level}_{z,n,t} \qquad \forall \ z,n,t \tag{D.18}$$

$$\mathbf{S}^{out}_{z,n,t} \leq cap^{out}_{z,n,t} * \tau^{out}_{z} * \mathbf{S}^{level}_{z,n,t} \qquad \forall\ z, n, t \tag{D.19}$$

For the analysis presented in Chapter 5, the model is extended to model hydrogen and synthetic methane injection into the gas system. The necessary adjustments to the node balance condition were already introduced (equation D.12). Further constraints on PtG are stated below. Blending hydrogen into natural gas pipelines is only feasible up to a defined limit to minimise the risk of damaging equipment (see Section 5.1). Equation D.20 ensures that hydrogen injection at demand nodes cannot exceed a defined injection limit (λ_y), defined as a percentage of gas demand at the node. As the distribution grid level is not explicitly modelled, we split demand at a node into distribution- and transmission-level demand (for assumptions on the split into distribution and transmission demand levels see D.1.4). Large consumers, for instance, gas power plants and large industry, often withdpure directly from the transmission grid and are therefore not supplied by a gas mixture of hydrogen and natural gas. Smaller gas consumers like the residential and commercial sector and smaller industrial consumers are assumed to be connected to the distribution grid and thus allowed to be supplied with the gas mixture. The hydrogen injection, given in energy units, is converted to volumes (gcv_{H2}), as the injection limit refers to gas volumes.

The hydrogen injection limit increases over time as it is expected that technological progress and modifications of infrastructure will allow for higher hydrogen blends in the future (see, e.g., IEA (2019d), Melaina et al. (2013) or DVGW (2019)).

$$\sum_i \mathbf{P}^{H2}_{i,n,t} * \frac{1}{gcv_{H2}} \leq \sum_l \mathbf{D}^{res-com,oth}_{n,t} * \lambda_y \qquad \forall\ n, t \tag{D.20}$$

The PtG capacities ($cap_{i,v,t}$) are exogenous parameters provided by the electricity market model. Equation D.21 ensures that the country-level capacities are distributed optimally[4] to the grid nodes ($\mathbf{C_{i,n,t}}$) assigned in each country. PtG capacities define the upper limit for PtG injection ($\mathbf{P^{gas}_{i,n,t}}$), at each node (equation D.22). The timefactor tf ensures the correct scaling of capacities to generation and depends on the selected temporal resolution of the model.

[4] From the perspective of the gas transmission system.

$$\sum_{n} \mathbf{C}_{i,n,t} \leq cap_{i,v,t} \qquad \forall\ i, v, y\ \ n \in v \tag{D.21}$$

$$\mathbf{P}^{gas}_{i,n,t} \leq \mathbf{C_{i,n,t}} * \eta_i * tf \qquad \forall\ i, n, t \tag{D.22}$$

The optimal total amount of hydrogen or synthetic methane injection in each country is determined by the electricity market model and serves as exogenous input to the gas market model. As the gas market model has a higher spatial resolution than the electricity market model, the injection volumes are allocated to nodes, constrained by the capacity assigned to each node. Equation D.23 ensures that the total injection of each technology, in each country and in each time period ($q_{i,v,t}$) is consistent with the allocation by the model ($\mathbf{P_{i,n,t}}$).

$$\sum_{n} \mathbf{P}_{i,n,t} \leq q_{i,v,t} \qquad \forall\ i, v, y, n \in v \tag{D.23}$$

D.1.4. Gas demand allocation

We subdivide country-level natural gas demand into EU ETS and non-EU ETS demand, as well as gas transmission and distribution system-level demand. The quota applies only to the demand of consumers not regulated by the EU ETS, all of which are assumed to be connected to the gas distribution grid, owing to their small size relative to the large industrial consumers and power stations subject to the EU ETS emission cap. A detailed overview of the sectoral breakdown used by the models and the respective quotas and injection limits is given in Table 5.1.

Since data on the breakdown of natural gas demand between sectors regulated by the EU ETS and sectors outside the EU ETS, as well as the breakdown of demand between the distribution and transmission grid levels, is scarce, simplifying assumptions were made in order to allocate the exogenous, country-level natural gas demand to the EU ETS and non-EU ETS sectors, as well as the gas transmission and distribution grid levels. Projections are obtained from the POTEnCIA Central Scenario (Mantzos et al., 2019), which provides a breakdown by NACE2 classification (Eurostat, 2008). For the split of natural gas demand, four demand categories are used, each one with an individual demand profile: (i) industrial sector (EU ETS) gas demand, (ii) power sector (EU ETS) gas demand, (iii) residential and commercial (non-EU

ETS) gas demand and (iv) small industry and other (non-EU ETS) gas demand. Mantzos et al. provide a detailed, country-level breakdown of projected emissions by NACE2 economic activity, for both emissions covered by the EU ETS and total emissions from the respective industrial subsector (Mantzos et al., 2019). Similar statistics for the projected fuel consumption of the sectors regulated by the EU ETS are not provided, so for the purpose of this analysis, we made the simplifying assumption that the proportion of gas consumption in each subsector that is subject to the EU ETS is equivalent to the respective subsector's share of emissions covered by the EU ETS. Table D.2 provides an overview of the share of emissions regulated by the EU ETS in each sector for the illustrative example of Germany in 2040. We further assume that the industrial gas consumption subject to EU ETS restrictions generally comes only from individual consumers large enough to be directly connected to the transmission rather than the gas distribution system. The division into EU ETS and non-EU ETS, as well as transmission and distribution-level gas consumption thus derived, align reasonably well with actually measured transmission vs distribution-grid level gas consumption where data could be obtained. A comparison with historical data from Germany and France, for example, shows that the deviation between our assumptions and real grid-level demand is acceptable: in France, the share of gas demand delivered to distribution grid consumers in 2018 amounts to 62% (Commission de Régulation de l'Énergie, 2019) compared to 64% in 2018 data derived using the approach described above. In Germany, the share of gas demand delivered to distribution grid consumers in 2018 was 81% (Bundesnetzagentur and Bundeskartellamt, 2020) compared to 74% in the modelled projection.

Table D.2.: Share of emissions subject to the EU ETS by industrial subsector in Germany in 2040, as projected by Mantzos et al. (2019).

NACE2 code	Sector	2025	2030	2035	2040
cenos	Consumption in Energy sectors except power generation	83%	83%	83%	83%
isi	Iron and Steel	88%	88%	88%	88%
nfm	Non-Ferrous Metals	88%	88%	88%	88%
chi	Chemicals Industry	86%	86%	85%	85%
nmm	Non-Metallic Mineral Products	88%	88%	88%	88%
ppa	Pulp, paper and printing	87%	87%	87%	87%
fbt	Food, Beverages and Tobacco	0%	0%	0%	0%
tre	Transport Equipment	0%	0%	0%	0%
mae	Machinery Equipment	0%	0%	0%	0%
tel	Textiles and Leather	0%	0%	0%	0%
wwp	Wood and Wood Products	0%	0%	0%	0%
ois	Other Industrial Sectors	0%	0%	0%	0%

D.1.5. Data and assumptions

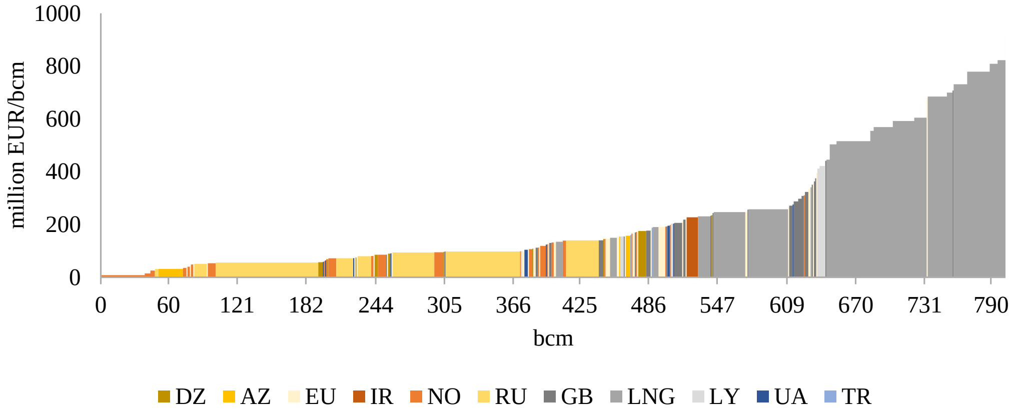


Figure D.1.: European natural gas supply curve and major exporting countries in 2030 (based on Rystad Energy (2020) with own assumptions)

Table D.3.: Assumed conversion factors for fuels referred to net calorific value and gross calorific value

Fuel	Unit	NCV	GCV
Hydrogen	kWh/m³	3.00	3.54
Methane	kWh/m³	9.97	11.05
Natural gas	kWh/m³	10.00	11.11

Table D.4.: Power-to-Gas technologies: CAPEX (no value implies that technology class is not available yet; adapted from Brändle et al. (2021) (baseline assumptions) and IEA (2019c) for methanation.)

Technology	CAPEX (EUR/kW$_{el}$)			
	2025	2030	2035	2040
Alkaline 1	667	530	493	456
Alkaline 2	-	530	493	456
Alkaline 3	-	-	-	456
PEM 1	1070	911	800	689
PEM 2	-	911	800	689
PEM 3	-	-	-	689
PEM 1 + Methanation	1585	1391	1252	1113
PEM 2 + Methanation	-	1391	1252	1113
PEM 3 + Methanation	-	-	-	1113

Table D.5.: Power-to-Gas technologies: Other assumptions (adapted from Brändle et al. (2021) (baseline assumptions) and IEA (2019c) for methanation. CO_2 feedstock costs for methanation are assumed to decline from 220 EUR/tCO_2 in 2025 to 120 EUR/tCO_2 in 2040.)

Technology	Fixed O&M costs (EUR/kW$_{el}$/a)	Lifetime (Years)	Efficiency (LHV)	
			H_2	CH_4
Alkaline 1	15.8	15	67%	-
Alkaline 2	12.5	20	68%	-
Alkaline 3	10.8	25	70%	-
PEM 1	25.3	15	62%	-
PEM 2	21.5	20	66%	-
PEM 3	16.3	25	68%	-
PEM 1 + Methanation	45.9	15	62%	48%
PEM 2 + Methanation	40.7	20	66%	50%
PEM 3 + Methanation	33.2	25	68%	52%

D.2. Results

Table D.6.: EU gas and electricity demand and PtG production in the REF scenario

Parameter	Unit	2025	2030	2035	2040
Electricity demand	TWh	3054	3167	3265	3444
Gas demand	TWh	3644	3290	3360	3353
EU gas production	TWh	340	355	342	303
PtG capacity	GW	0	0	0	0
PtG production	TWh	0	0	0	0

Table D.7.: EU gas and electricity demand and PtG production in the EUQ scenario

Parameter	Unit	2025	2030	2035	2040
Electricity demand	TWh	3254	3573	3873	4252
Gas demand	TWh	3825	3479	3576	3508
EU gas production	TWh	340	356	339	296
PtG capacity	GW	26	54	84	117
PtG production	TWh	103	220	338	452

Table D.8.: EU ETS and non EU ETS gas demand in the EUQ and REF scenario (in TWh)

	REF		EUQ	
	non EU ETS	EU ETS	non EU ETS	EU ETS
2025	2068	1576	2068	1757
2030	2200	1090	2200	1279
2035	2251	1108	2251	1325
2040	2262	1091	2262	1245

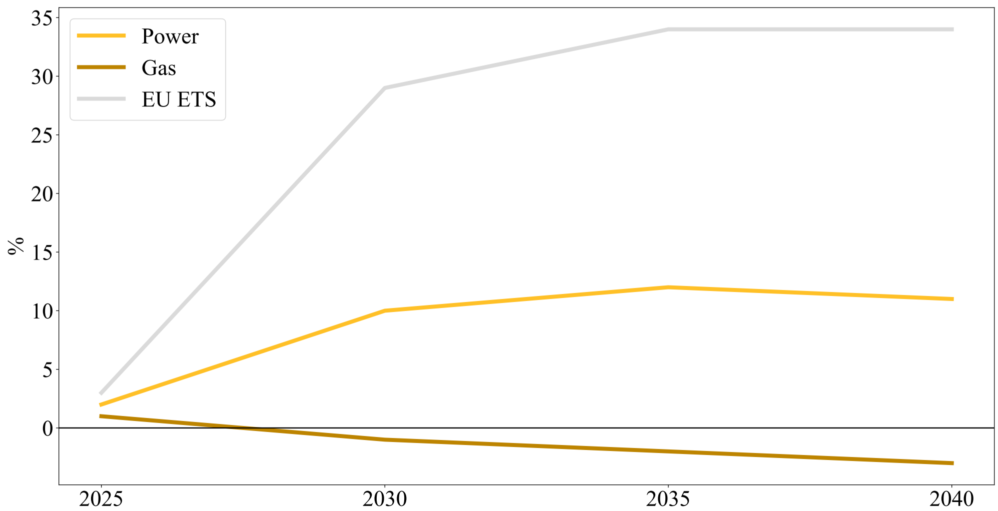


Figure D.2.: Difference in power, gas and EU ETS allowance price between the EUQ and the REF scenario

Table D.9.: Differences in EU gas and electricity market results between the EUQ and REF scenario (EUQ minus REF)

Parameter	Unit	2025	2030	2035	2040
Electricity generation	TWh	199	405	608	807
Gas demand	TWh	181	189	216	154
Natural gas production (imports and EU)	TWh	78	-31	-122	-298
RES producer surplus	EUR/MWh	2.2	3.6	6.9	3.7
Conventional power producer surplus	EUR/MWh	-1.0	1.9	3.8	3.5
Power consumer surplus	EUR/MWh	-1.3	-4.4	-5.1	-1.8
Natural gas producer surplus	EUR/MWh	0.1	-0.1	-0.5	-0.5
PtG producer surplus	EUR/MWh	31.9	18.3	27.4	28.6
Gas consumer surplus	EUR/MWh	-0.2	0.3	0.4	0.7
Quota obliged gas consumer surplus	EUR/MWh	-10.9	-14.6	-25.0	-23.1
Quantity-weighted electricity price	%	2.4	9.9	12.3	11.3
Quantity-weighted natural gas price	%	0.8	-0.9	-1.7	-3.0
EU ETS CO_2-price	%	2.9	28.7	34.0	34.0

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Max Schönfisch