Global Atlas of H_2 Potential

Sustainable locations in the world for the green hydrogen economy of tomorrow: technical, economic and social analyses of the development of a sustainable global hydrogen atlas

HYPAT Working Paper 01/2021

Importing hydrogen and hydrogen derivatives: from costs to prices

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The information was compiled to the best of our knowledge in accordance with the principles of good scientific practice. The authors assume that the information in this report is correct, complete and up-to-date, but do not accept any liability for any errors, explicit or implicit.

Contents

1 Introduction

Today's hydrogen industry is currently still a sector without significant trading activities. Only five percent of the globally produced hydrogen is transported and traded at the moment (see Monopolkommission 2021). This trade is mainly conducted by industrial gas suppliers, who provide direct connections for large industrial consumers. Most of the hydrogen currently produced is either from these industrial gas suppliers or on-site by the industrial enterprises themselves, for instance, directly in the refineries that then make use of the hydrogen. This is why there is currently little need for an expanded hydrogen transportation infrastructure. Hydrogen is not traded on a market at present. Therefore, the costs of production are usually not made public or are not available in bilateral contracts in the sense of a free public market. Hydrogen demand is expected to increase strongly in the future according to a large number of studies (Wietschel et al. 2021), in order to achieve the ambitious greenhouse gas reduction targets. The number of applications is expected to increase strongly as well, and hydrogen will no longer be produced using fossil-based sources, as is the case today, but predominantly using renewable energy sources or at least low-carbon energy sources.

Since there are limited potentials to produce sustainable hydrogen and its derivatives domestically based on the availability of renewables, there is a general consensus that the lion's share of the hydrogen required and its derivatives will have to be imported to Germany. This implies that hydrogen transportation will also become more important.

A number of studies have analyzed the economic viability and import potentials. However, these studies do not generally make statements about market and price development, because so far they have usually been limited to the analysis of production and transportation costs. However, market prices are decisive for any realistic estimation. These are based on the marginal costs of production including transport plus markups for profits, risks, sales, warranties and R&D costs. The state can also influence prices through taxes or levies. The strategic behavior of market players, price agreements and lack of competition also have a decisive influence on price, as is the case with today's oil and gas prices. Scarcity pricing can occur when demand is high, but supply is low (as has been the case at times for crude oil), or pricing can be based on the prices of other energy sources (indexation, such as for natural gas). It is also relevant whether different regional markets and price regions have emerged, as for natural gas, or a quasi-global market exists, such as that for crude oil, although, even here, there are also product differentiations and different contracts. Given such possible developments, it is conceivable that analyses employing approaches referring only to production costs are potentially underestimating the actual development and volatilities of prices.

Faced with this problem, this working paper aims to reveal the different challenges when surveying market developments and price scenarios for hydrogen and its derivatives, and to develop a methodology to determine prices. The focus here is on hydrogen. In addition, derivatives such as methanol or ammonia are considered, although their transportation costs over longer distances are significantly lower than those for hydrogen. For hydrogen, it is conceivable that supply on a relevant scale could take place via a well-developed pipeline network, while its derivatives ammonia and methanol of fossil origin are already being transported over longer distances by ship. The transport infrastructures are already in place for these derivatives, whereas they still have to be developed for hydrogen.

The working paper is structured as follows: The next chapter addresses the problem based on the need to import hydrogen and its derivatives. In addition, it presents an evaluation of the studies made so far on the economic perspective of imported hydrogen and its derivatives. This leads to a number of open research questions, some of which are addressed in the subsequent chapters.

Based on the assumption that price formation on the hydrogen market could be similar to the market for natural gas, Chapter 3 looks at pricing on today's natural gas and electricity markets. Analogies to a potential hydrogen market are highlighted, and it is considered which of these aspects can be transferred to possible hydrogen markets.

Chapter 4 presents a methodological concept to determine the prices of hydrogen and its derivatives. Starting with an overview, it presents the main aspects needed to derive a supply function, a demand function, transportation costs and possible capital costs. Chapter 5 presents the first steps to implement the concept and the insights gained from this. The final chapter presents a summary and conclusions.

This working paper describes a methodological aspect of the HYPAT project. HYPAT is developing a global atlas of hydrogen potentials and, for the first time, comprehensively identifying possible partner countries of Germany for the cooperative development of a future green hydrogen economy, including the importance of the regions producing hydrogen for a secure, economic, and environmentally sustainable supply.

2 Description of the problem and the current state of knowledge

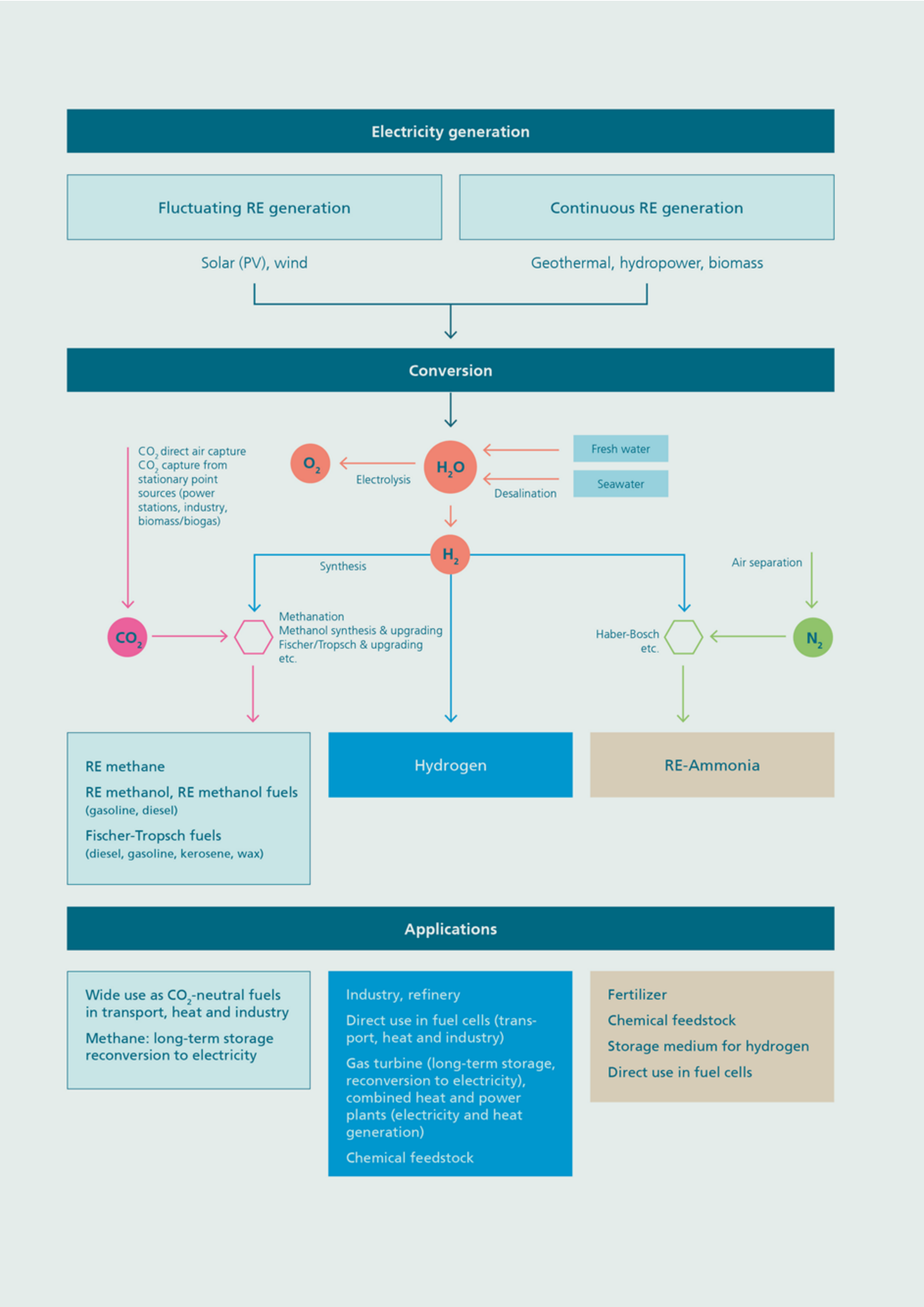
2.1 The need to import hydrogen and its derivatives

The political goal of achieving climate-neutrality in Germany and the EU by 2050 demands a complete shift away from fossil fuels by 2050. Since the path taken to reduce greenhouse gases from today until 2050 is also relevant for the impact on climate change, this means that all greenhouse gas emissions have to be significantly reduced early on.

To achieve this, fossil fuel savings must be made through comprehensive energy efficiency measures on the one hand, and through very far-reaching substitutions by sustainable, renewable energies on the other hand. Since the potential of sustainable biomass is limited and subject to competition with food crops, the main substitutes are renewable electricity and energy carriers based on this, in particular hydrogen and its derivatives. Renewable electricity is used directly wherever this is technically possible and economically viable, for example, in electric vehicles, heat pumps, heating grids, or to generate process heat in industry. However, there are a number of applications, such as international aviation or shipping as well as the iron and steel industry or the basic chemical industry, where this does not seem feasible at present due to the energy densities required or for process engineering reasons. This is where green hydrogen has a role to play, or green synthesis products made from it, such as methanol. This is why green hydrogen is currently considered an additional important component of the energy transition, and why German and European climate policy are increasingly focusing on it. Germany and the EU have therefore developed hydrogen strategies (see European Commission 2020 and Bundesregierung 2020). In principle, fossil fuels could continue to be used even in the case of climate neutrality if combined with Carbon Capture, Use or Storage (CCUS). This is being intensively discussed in the case of "blue" hydrogen, i.e., hydrogen produced from natural gas in conjunction with CCS. In general, however, there is a low degree of acceptance of CCS in society, especially in Germany. Furthermore, upstream GHG emissions continue to be produced from natural gas production and transportation.

According to the majority of scenarios, there is not enough affordable renewable electricity available in Germany to produce the quantities of hydrogen required to meet the long-term German demand exclusively in Germany or in the EU, and the hydrogen produced would be comparatively expensive in large quantities (see Wietschel et al. 2021). Sensfuß et al. (2021) show that the EU has interesting and relatively inexpensive potentials for hydrogen production that could be used to meet demand in Germany. Despite this, the current discussions focus strongly on imports from other regions of the world for larger quantities of hydrogen and its derivatives. The idea is that regions with favorable conditions for renewable energies (e.g., high solar irradiation or good wind conditions) could produce sustainable energy carriers like hydrogen and its derivatives cost-effectively. These so-called green synthetic fuels, i.e., those produced using renewable electricity, could then be exported to Germany or other countries. Figure 1 illustrates the individual conversion steps from source to application.

Figure 1: Selected conversion paths to produce green hydrogen and synthesis products based on renewable electricity (Ragwitz et al. 2020)



The topic of hydrogen is also firmly anchored on the political agenda of the European Commission. Its hydrogen strategy (see European Commission 2020) addresses the issue of importing green hydrogen. One goal is to contribute to the transition to clean energy and promote sustainable growth and development through cooperation in the field of producing green hydrogen with the EU's neighboring countries and regions. Germany's current "National Hydrogen Strategy" (see Bundesregierung 2020) also assumes that the anticipated relevant amounts of green hydrogen will not be able to be produced in Germany. From this perspective, Germany will remain a major importer of energy in the future as well, with all the consequences this entails. An important element of the National Hydrogen Strategy is therefore to prepare for importing hydrogen and its derivatives.

2.2 From production costs to prices and the resulting research questions

A number of studies have addressed the production costs of imported synthetic fuels based on renewable electricity generation (see Lux et al. 2020, IEA 2019, Deutsch et al. 2018, Pfennig et al. 2017, Hobohm et al. 2018, Kramer et al. 2018, Timmerberg et al. 2019, Hank et al. 2020, Fraunhofer IEE 2021, Hydrogen Council 2021). Electricity prices as well as the efficiency and full-load hours of the electrolyzers have the biggest influence on production costs. Since electricity costs from renewable energy installations in countries with correspondingly favorable climate conditions, such as North Africa, for example (electricity generation costs with PV and wind less than 3 ct/kW with more than 4,000 full-load hours per year), are significantly lower than in Germany, the pure production costs of hydrogen in these countries are usually also lower. Since, in addition, the costs for transporting synthetic fuels are also rather low, depending on the distance covered and the type of transport involved, and since low-cost renewable energy potentials in Germany are limited, many studies conclude that it can make sense from a production cost perspective to import synthetic fuels to Germany or the EU.

However, these studies generally only show the pure production costs without taxes and levies. Furthermore, they do not consider any profit mark-ups, R&D costs, marketing costs etc. An economy or a market does not function based on production costs. The analysis of other energy markets, such as the oil and gas markets, shows that import prices are also significantly influenced by other factors, such as shortages or strategic behavior, and often lie considerably above the costs of exploration and transportation. Any economic evaluation of importing hydrogen and its derivatives must therefore go beyond simply analyzing production costs.

The following research questions or sub-questions result, which encompass three dimensions:

- Market mechanism dimension: How will prices be formed on the markets for hydrogen and derivatives?
    a. To what extent is a perfect market expected (competitive markets, where there are no problems with price formation)?
    b. Or is it more likely that imperfect markets will emerge (e.g., due to monopolies, oligopolies, product differentiation, intransparency, state intervention)?
- Market size dimension: Which or how many markets will there be?
    a. Will there be a global market (analogous to the oil market or coal market)?

   b. Or are regional markets or price zones more likely, e.g., due to transport costs, use of transport and distribution infrastructures, bottlenecks (analogous to the natural gas market)?
   c. What role do bilateral contracts play?
- Time dimension: How will the market develop over time?
   a. Will individual bilateral contracts between industrial partners dominate to start with?
   b. Over time, will more and more actors enter the market as producers and suppliers, or will the market become concentrated on a few global actors – at the beginning or only during a later phase?

These questions serve as orientation and guidelines to structure the analysis and estimate future market prices. The working paper does not answer these questions in full, but does address individual ones. To start with, pricing on the natural gas and electricity markets is analyzed and initial conclusions drawn from this for establishing a hydrogen and derivatives market. Then the market mechanism dimension is addressed by estimating a supply and a demand function under the assumption of a perfect market. This is followed by initial thoughts about when a market could be established. The market size dimension is only dealt with marginally under the aspect of whether the transportation infrastructure is more suitable for regional or global markets.

3 Price formation on different energy markets

3.1 Natural gas markets

Hydrogen, in particular, but also some of its derivatives, show similarities to natural gas in terms of the investments needed, transportation infrastructure and potential fields of application. Therefore, this section considers the price determinants for natural gas in order to identify possible mechanisms for how prices will be formed on a future hydrogen market. This section also looks at historical trends as well as comparisons with the oil market.

Unlike crude oil, there is currently no single global market for natural gas due to the fact that it is mainly transported via pipelines and the continued high costs for transporting liquefied gas by ship. Instead, roughly three main market regions of North America, East Asia and Europe have become established[1], which display persistent discrepancies in the price of natural gas. Depending on the market structure, different pricing mechanisms can be distinguished – in particular *oil indexation* and *hub-based pricing* – which vary over time and price zones[2].

The fact that the physical properties of gas mean that it is primarily transported using pipelines is the reason for a market set-up based on *bilateral contracts*. *Long-term contracts* offer the chance to spread the risk against the backdrop of long-term capital investments including location-specific investment costs of natural gas suppliers. The contracts often include "take or pay" clauses, in which the buyer agrees to purchase a minimum volume of gas. Long-term contracts can also reduce transaction costs, e.g., for acquiring customers, negotiations or securing streams of revenue to refinance investments. Long-term contract obligations in natural gas markets traditionally also display price formation linked to the oil price. The extent of oil indexation varies strongly by country and region.[3] In the meantime, there are some links to the prices of other energy sources as well, such as coal or electricity and benchmark gas prices, e. g., the Henry Hub U.S. exchange price (Hauser et al. 2016, Zhang et al. 2018).

North America has evolved from a gas importer to a gas exporter by exploiting unconventional gas reserves. For the USA, empirical analyses show that a complete severing of the link between oil and gas took place as early as 2009, which can also be traced back to the increase in shale

1 The segmentation of the natural gas market can also be illustrated by a more detailed differentiation of trading regions. In the IEA's Gas Market Report (2021), for example, demand and production are broken down into seven world regions (Africa, Asia/Pacific, Central and South American, Eurasia, Europe, Middle East, North America).

2 There is still some disagreement in the literature about which form of pricing (hub or oil price) should be preferred. Advocates of oil indexation argue that oil and natural gas should continue to be considered substitutes. Those who favor hub-based variants assume that this price system better reflects supply and demand factors and provides a more efficient market framework that decreases price bubbles (Zhang et al. 2018).

3 For example, in 2008, price coupling affected about 30 % of the natural gas prices on the British market, which was already marked by deregulation and hub pricing at that time, while this share was still approx. 80 % in the larger Western European market. In Eastern Europe, where pipeline gas from Russia dominates supply, the oil indexation method accounted for up to 95 % of the natural gas price (Hauser et al. 2016).

gas extraction (Hauser et al. 2016). The American market is characterized by high liquidity, a large number of players and low transaction costs (Neumann et al. 2013). Wholesale trading, which is strongly driven by price and competition, takes place via hubs.

In contrast to this, the *Asian market* is predominantly volume-driven. This is aimed at securing supplies against the backdrop of widespread domestic resource scarcity. The low price elasticity of demand permits (risk) price premiums. Higher prices are also favored by the prevailing monopolistic market structures and a small number of market players. The market is dominated by long-term contracts linked to the oil price (Neumann et al. 2013, Zhang et al. 2018).

Finally, global shortages converge on the *European market*. In Europe, prices lie in-between the US prices, which tend to be low, and the high prices on the Asian market. Long-term contracts are considered the cornerstones of the European gas market structure (Hauser et al. 2016). Slightly shorter contract durations are attributed, among other things, to a fundamental shift in the European market toward gas-on-gas (GoG) competition, which is increasingly dominant, especially in Northern and Central Europe (ibid). However, oil indexation pricing continues to play a major role in Europe despite liberalization tendencies, the widespread substitution of oil by natural gas in national energy sectors and increasing hub trading. Using cointegration regression analyses, several studies show that, apart from short-term decoupling of oil and gas prices, the long-term price relationship still holds in Europe (Hauser et al. 2016). This is sometimes explained by market players being so used to oil indexation gas contracts that this has created a path dependency. Accordingly, hopes of benefiting from competitive pricing at transshipment centers due to liberalization reforms on the European gas market may need to be tempered (ibid.) In addition to these aggregated observations for Europe as a whole, it should be noted that the national European gas markets are still clearly segmented (Neumann et al. 2013).

In addition to the structural aspects mentioned, the natural gas price is also influenced by supply-side and demand-side factors (Hauser et al. 2016). These are listed in Table 1. Coal and oil price trends or the degree of oil price indexation, infrastructure development and the level of natural gas reserves are among the primary *long-term* determinants (Hauser et al. 2016, Nick et al. 2014). Energy and climate policy is another potentially highly relevant variable influencing the natural gas price (Hauser et al. 2016). In the *short term*, seasonal fluctuations and short-term changes to market conditions are relevant for price formation (ibid.). The demand for natural gas is particularly sensitive to temperature fluctuations (IEA 2021). Alongside temperature shocks, Nick et al. (2014) also identify supply shocks as a short-term variable influencing the price of gas using a vector autoregression model (VAR). In 2020, about half of the price paid by household customers for natural gas in Germany was for acquisition and sale of the gas, and roughly one quarter each for the fees for using the gas network and for state-imposed price components such as taxes (Bundesnetzagentur & Bundeskartellamt 2021).

Table 1: Supply and demand drivers of the price determinants of natural gas (own illustration, based on Hauser et al. 2016)

	Time frame	Explanation/ notes	
Infrastructure	Short to medium-term	• Supply disruptions (e. g. Russia-Ukraine pipeline in 2009) • LNG supply chain highly complex, therefore vulnerable to unforeseen disruptions and delays	Supply-driven
	Long-term	• Planning and expansion (removal of pipeline network restrictions)	
Natural gas reserves/resources	Long-term	• Domestic resources determine (together with diversification measures) the degree of a country's dependency on imports	
Storage capacity	Short-term	• Can influence local prices • Price signals resulting from how full gas storage facilities are can strongly influence the price volatility of natural gas • Especially against the background of seasonal fluctuations in demand and the asymmetries between production and consumption related to this	
Geopolitical tensions and crises		• Supply disruptions lead to price fluctuations (depending on the available storage capacity)	
Energy/climate policy	Long-term	• Uncertainty with regard to impact; so far, relatively low influence on natural gas prices • Natural gas as a transitional energy carrier to reduce GHG, but: the growth expected in the use of natural gas to generate energy has not occurred so far	Demand-driven
Season and weather	Short-term	• Weekly components: strong decrease in demand at weekends if industrial enterprises not operating • Annual components: heating applications, esp. temperature fluctuations, winter months	
Economic growth	Medium-term	• Industry and the electricity sector are especially responsive (natural gas prices in these sectors correlate with economic growth patterns in the short, medium and long term) • Higher prices in growth phases due to rising demand	

Compared with the oil market, the price formation process on the gas market is much less market-driven and less efficient, both historically and up until today. The gas market is characterized by lower transparency, which enables individual insiders to behave strategically. The reasons for this can be found in contractual confidentiality clauses, the large number of different units for measuring natural gas, different currencies, and missing statistics about domestic prices for many countries. In addition, oligopolistic behavior is possible, especially among supply-side market players, because they each hold large shares of the supply volume. However, the formation of a cartel, like OPEC or OPEC+ on the oil market, is unlikely despite the potential use of market power by a few players with the accompanying inefficiencies (Egging et al. 2006, Stern 2020).

Conclusions for pricing on a future hydrogen market

It seems plausible that trading hydrogen will also start with long-term and bilateral contracts due to the high investments required, for instance, in production facilities and infrastructure, which are comparable to those for natural gas.

The costs for transporting hydrogen and its derivatives depend on the chosen transportation path (see section 4.4). Regional segmentation of the hydrogen market is expected to start with if hydrogen is transported via pipeline. With favorable options for long-distance transportation, especially by ship, it is theoretically possible that these regional prices would converge. However, it is questionable whether a global market will emerge, similar to that for oil. Prices have yet to align in the case of natural gas, partly due to limited LNG trading[4], among other reasons. Long-term contracts continue to play a dominant role in spite of largely completed infrastructure and increasing market liberalization. All in all, a global market for hydrogen is not expected, at least in the short to medium term.

The level of individual price components, such as the levies to be paid, depends on the deployment concept of the production facilities. It makes a difference, for example, to the required investments, revenues and regulatory costs of a power-to-gas plant whether this is supplied directly with electricity from a new RE installation or from the grid (Haumaier et al. 2020).

In addition, the issue of competing products is key for estimating hydrogen prices. On the natural gas market, pricing was also linked to its most important substitutes of coal and oil. Whether and to what extent the hydrogen price will be contractually linked to the price of other energy carriers therefore also depends in particular on the application involved.

It is also still open to what extent a higher willingness to pay for green hydrogen (compared to hydrogen that is not produced using renewable electricity) will allow price premiums for the property of being "green".

Finally, the political regulations accompanying the hydrogen market startup will play a significant role, for instance, the design of incentives and limiting market power[5].

3.2 Electricity market with renewable energies

On the electricity market, the market price is formed at the point where supply and demand come together, in other words, the generation and consumption of power are matched. Depending on the time between closing the contract and delivery, the electricity market encompasses the forward market and the spot market (day ahead), where the latter is used to coordinate demand for the next day. Trading where contract closure and delivery occur on the same day is called the intraday market and forms part of the spot market. Trading can be done via the electronic power exchange, e.g., EPEX or over-the-counter (OTC), i.e. bilaterally. Contracts are concluded for an agreed supply quantity, period and price. The offer price of the cheapest remaining contract still needed to meet demand always sets the price for the traded period on the exchange. The quantities and prices of electricity currently traded on the exchange are available to all power market participants, i.e., the market is transparent. All (larger) generators and electricity suppliers and large power consumers who are registered on the exchange can

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4 Reasons for the limited trade with LNG are the special technical requirements, high capital intensity and transportation costs (Neumann et al. 2013).

5 The EU's REMIT (Regulation on Wholesale Energy Market Integrity and Transparency) is one example of energy market monitoring. It should also be noted that the complex regulatory system in the EU induces transaction costs for market players and has made it difficult to integrate the national markets (Neumann et al. 2013).

buy and sell. This is why this market is also referred to as the wholesale market. The OTC market is less transparent than the power exchange, i.e., the traded quantities and prices are only partially accessible. Suppliers and buyers of electricity can participate on the power exchange and in OTC trading and operate on one market or the other depending on the supply or demand situation. Since electricity can only be stored to a limited extent, its price is strongly influenced by its physical availability, i.e., by fluctuating renewable energy generation installations as well. Various instruments are employed to reduce this price volatility, e.g., contracts with flexible loads and generation as well as storage of electricity (balancing energy market). Large and small energy suppliers and final consumers come together on the retail market and conclude bilateral, highly standardized electricity supply contracts. The electricity price for final consumers includes not only the price for the energy components, but also for networks and other energy services as well taxes and levies.

Alongside transparency and competition, homogeneity of the traded good is another prerequisite for electricity trading and the existence of a functioning market. If the origin of the electricity is used as an additional product characteristic, two (sub)markets can emerge on which green, sustainable or renewable electricity, and conventional electricity (usually a mix of fossil-based and renewable energy sources) are traded at different prices and quantities. This product differentiation thus results in another submarket for electricity. Wholesale trading for this submarket largely takes place as OTC retail trading via various marketplaces for small consumers. Of course, green electricity can also be traded as an undifferentiated product on the power exchange, i.e., simply as electricity.

The state can intervene in the electricity market in the event of market failure, for example, via a price surcharge for CO_2, aimed at internalizing the external costs incurred from the combustion of fossil energy sources. Other instruments include fixed feed-in payments, usually made to small generators of renewable energy when they feed power into the grid, irrespective of the current electricity supply and demand. Through this intervention in the market and depending on the availability of renewable energy sources, a certain amount of electricity is fed into the grid completely independently of the market price. This priority feed-in shifts the slope of the electricity supply curve to the right. If demand remains constant, this results in a falling electricity price on the power exchange.

In order to reduce this market distortion, but at the same time to push the development of renewables and to better integrate them into the power market, the government has supported their market-based expansion and established the auction market for renewable energy sources. On these markets, project developers offer a fixed volume or capacity in renewable electricity generation plants at a fixed price over a period of up to 15 years. The lowest bidders receive the surcharge for the amount offered in accordance with their offer price until the bidding volume has been reached. This surcharge is linked to a purchasing agreement that includes purchase price regulations, terms and volumes/capacities, i.e., a type of governmental power purchase agreement. Similar auctions are also conducted by large private consumers such as data centers or energy-intensive industries to meet their electricity demand. These contracts are called private Power Purchase Agreements (PPA) and can be traded bilaterally.

In summary, due to different degrees of transparency, product differentiation and state interventions, the electricity market is characterized by different submarkets with different pricing mechanisms. However, these submarkets can interact closely, i.e. the same players can operate on different submarkets and use different price windows. This means that the prices on the different submarkets are partially correlated. The different electricity markets and their characteristics are summarized in Table 2.

Table 2: Overview of electricity markets and their characteristics

	Power exchange	OTC	Green electricity	Small generator market	Auction market	PPA market
Product characteristic	Electricity from generation mix	Electricity from generation mix	Renewable power	Renewable power	Bidding contract	Private PPAs
Market	• transparent • large number of participants	• limited transparency • bilateral exchange	• transparent • limited number of participants	• no market	• transparent • competition	• limited transparency • unclear competition
Product	undifferentiated	undifferentiated	differentiated	differentiated	differentiated	undifferentiated - or differentiated
Price mechanism	market	Bilateral negotiation	market	Policy instrument	Auction (public)	Auction (private)
Quantity control	Price	Price	price	-	public tender	private tender
Investor risks	Price/purchasing risk	Price/purchasing risk	Price/purchasing risk	null	Auction risk	Depends on design of contract, auction
Market distortion	no	no	no	yes	?	no
Additional costs for state	no	no	no	possibly yes	possibly yes	no
Additional costs for consumers	none (excl. CO_2 price)	none (excl. CO_2 price)	WTP for "sustainability"	Depend on how remuneration is financed	Depend on how prices are financed	Depend on terms of contract

With a view to the hydrogen market, questions arise as to which players will be active on the market, how strongly the state will intervene, and which market mechanisms will be established. Based on the product differentiation for hydrogen – into green, blue and gray variants – submarkets could emerge as long as buyers are willing to pay more for sustainability features. Since green hydrogen can also be traded on the submarket for gray hydrogen, these two markets will interact. Since the production of hydrogen requires large investments, and large energy consumers or suppliers are on the demand side to start with, it is very likely that bilateral supply contracts will be concluded in an initial phase similar to private PPAs. If supply contracts are made via state auctions, a submarket will also be established here. A major difference to the electricity market is the distribution or transportation of hydrogen. Whereas electricity is available for the entire market area due to good infrastructure and its relatively good transportability, there are still significant restrictions for hydrogen that can affect market formation. In addition, derivatives can be formed from hydrogen, such as methanol or ammonia, which in turn can interact with their respective "raw material markets".

4 The methodological concept for modeling price formation

4.1 Overview

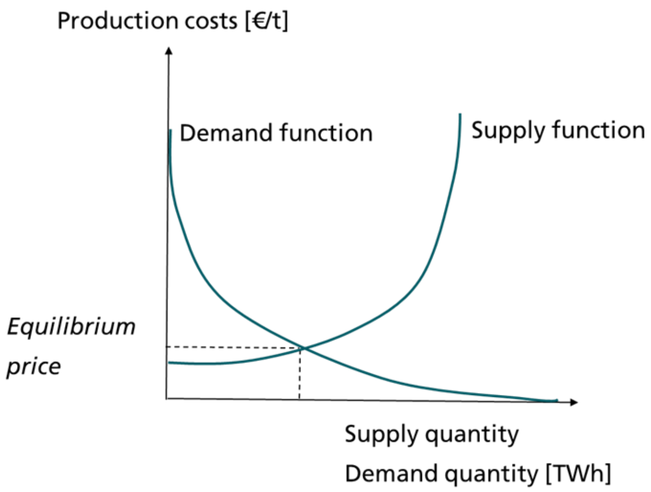
The starting point of the analysis is price formation on a perfect market (starting hypothesis). In a perfect market, the market price, also called the equilibrium price, results at the point where the supply function and demand function intersect.

To create the supply function, first of all, the costs for production and transportation are determined as are the potential production quantities in the producing countries. This takes into account a number of influencing factors that affect the costs and quantities. The method to create a supply function is presented in more detail in Chapter 4.2. In a subsequent step, the potential demand quantities are determined depending on the price, and a demand function formed from this. See the explanation in Chapter 4.3.

As mentioned above, transport costs do not play a significant role for hydrogen derivatives, and therefore a global supply and demand function can already be created for these now. Additional analyses are required for hydrogen to determine whether it makes more sense to plot such curves globally or regionally (although regional curves are of course interdependent). Transport costs play a more important role for hydrogen. There are references to transport cost analyses in Chapter 4.4. The dependencies between hydrogen and its derivatives must also be taken into account. The methodology here requires further development.

The comparison shows which supply quantities from which regions could actually be procured under the given willingness to pay.

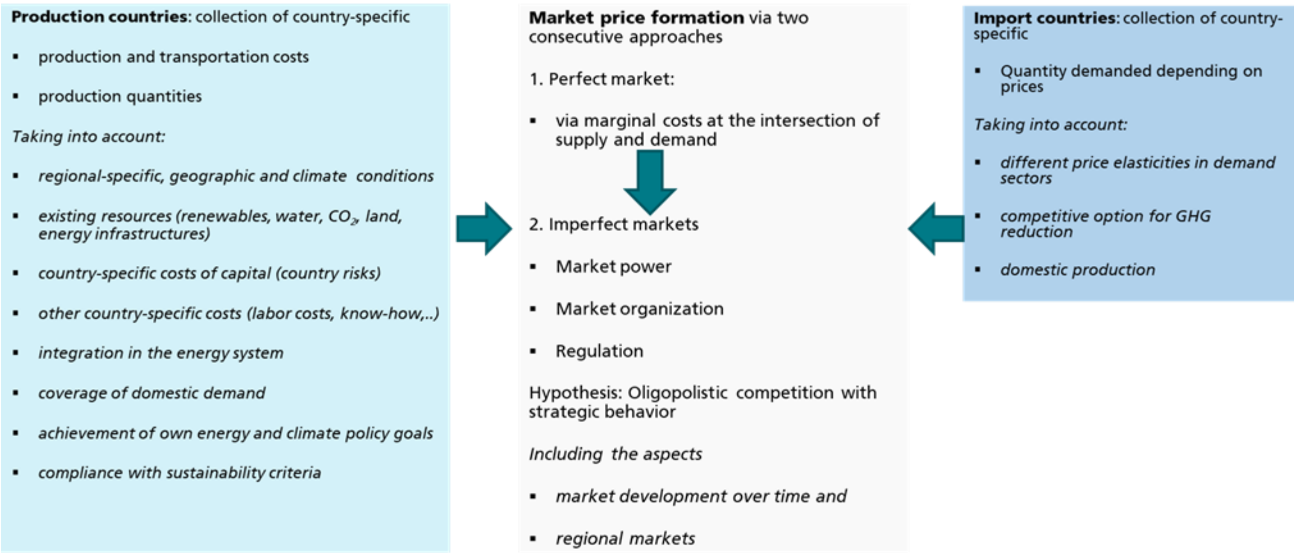
Figure 2: Price formation on perfect markets



The results show an initial picture of the potential number of countries producing and exporting hydrogen as well as the potential countries demanding it, and thus allow an approximate estimation of market size and expected competition. Of course, the latter is also influenced by the number of different players, such as private investors and producers. A large number of producing countries and importing countries trading on one or at least on larger regional markets would underpin the starting hypothesis of almost perfect competition. If the analyses indicate only a small number of producing countries, then modeling a "different" market must be considered: price formation on imperfect markets. Here, market power, market organization and regulation play an important role. This could be based on oligopolistic competition with strategic behavior of market participants. In addition, the trade and supply of different "colors" of hydrogen, i.e., the homogeneity of the product hydrogen, are also important for the market's "perfection". The market can thus be characterized by several suppliers and imperfect competition.

Figure 3 shows the entire procedure.

Figure 3: General procedure for price formation.



It should also be noted that the market is expected to develop over time. In these emerging markets, it seems appropriate to consider the following different phases:

1. Pilot phase (2025 to 2030)

Initial projects for importing hydrogen and its derivatives are currently being planned (in Chile, Kazakhstan, Saudi Arabia, Australia, and Morocco). Which of these will actually be realized remains to be seen. It is unlikely that any of these initial projects will be completed before 2025 on account of the necessary planning and construction phase and still missing transportation infrastructures. The implementation of projects continues to be hampered by uncertain economic framework conditions and unclear or still developing state support as well as the lack of certification systems for green hydrogen.

2. Development phase (2030 to 2035)

The development phase is characterized by first international trade with PtX products and by the strong dominance of bilateral contracts. Regional focal points will be set by the construction of the first transportation infrastructures, especially the repurposing of existing natural gas pipelines. These will be located from 2030 onwards, as relevant production quantities will only be available from this point in time. The first long-distance pipeline on the European continent could then be established (see Oeko-Institut 2021). According to the Oeko-Institut 2021, the economic feasibility and political strategies in important third countries with additional transport distances indicate that direct marketing of these derivatives can only be expected once hydrogen derivatives make landfall and the corresponding infrastructure is developed (e.g. further distribution of ammonia in Germany). It could be that, at this time, a limited number of suppliers face a larger number of buyers (supply-side oligopoly or a seller's market). In this case, suppliers have greater market power and can set the prices to a large extent since the buyers at the beginning belong to the so-called "no regret" group and do not have any major alternatives (see explanation in Chapter 4.3).

3. Growth phase (2035 to 2040)

During the growth phase, ever-increasing quantities of hydrogen and derivatives are traded between many countries and also compete with fossil energy sources due to rising CO_2 prices. The first transcontinental imports based on newly constructed pipelines and new shipping options (carriers or liquefied hydrogen) can emerge and the corresponding landfall and distribution infrastructure in Germany (see Oeko-Institut 2021).

During this phase, more suppliers can enter the market and raise the competitive pressure.

4. Mature phase (from 2040)

The mature phase is characterized by the displacement of fossil energy sources and that only greenhouse gas-neutral energy sources are traded and used. An international market or at least larger regional markets are established.

Due to the greater number of players on both sides, a bilateral polypoly could emerge here. On the other hand, using hydrogen is only seen as necessary in a particular field of application and is only one of several alternatives in other groups. In an extreme case, many suppliers enter the market so that the market dynamics result in a "buyers' market" (demand-side oligopoly), in which buyers determine the price because of the large number of competitors.

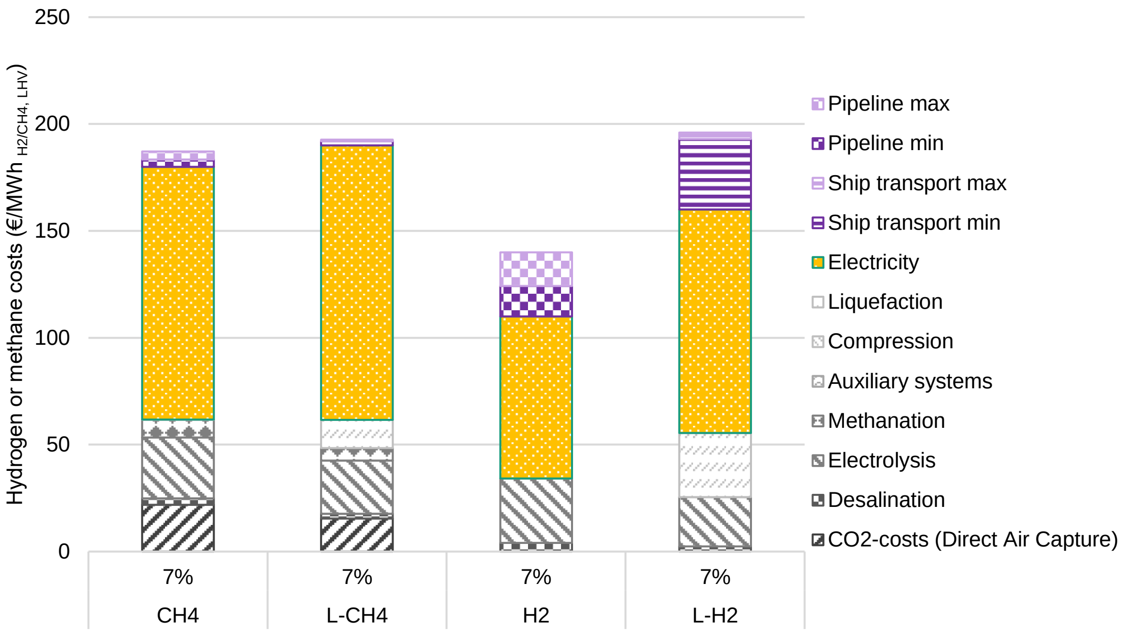
Even if a perfect market could emerge in the mature phase, the assumption is that imperfect markets are more likely during the development and mature phases. A corresponding price model must therefore be developed for this phase, too.

4.2 Determining a supply function

Supply curves for hydrogen and derivatives have already been and are being collected. Most approaches follow a similar procedure based on techno-economic analyses. A detailed concept is presented below.

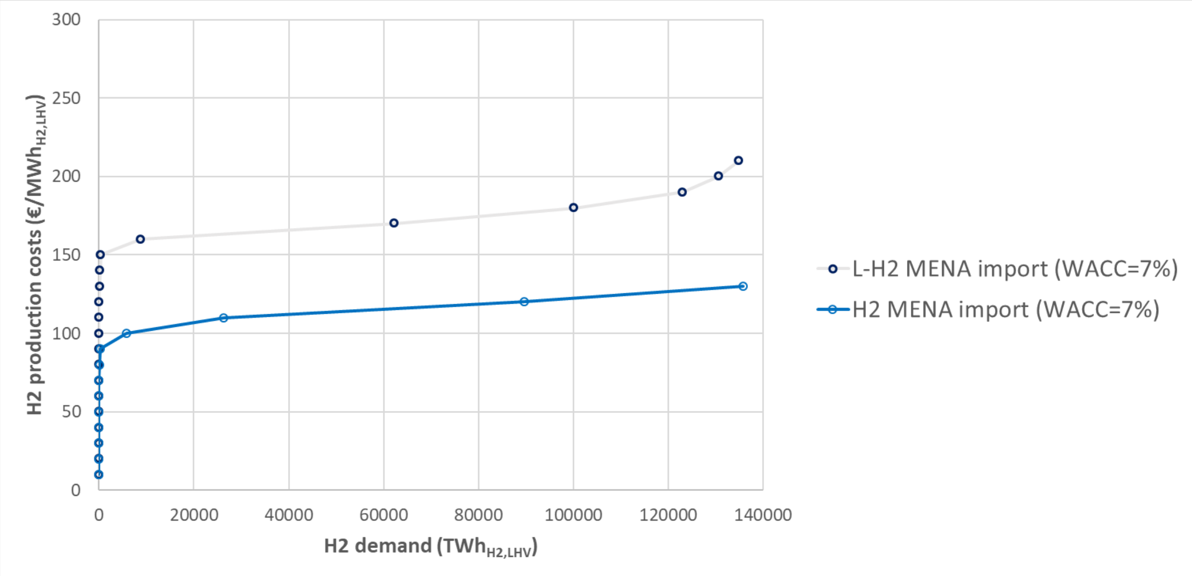
In a first step, the relevant technologies and investments (also in infrastructures) are identified and the specific production costs (LCOE) and quantities are determined (see the example for the MENA region in Figure 4).

Figure 4: Hydrogen and methane costs for a fixed demand quantity in the MENA region 2030 (data from Lux et al. 2021)



The LCOE are sorted in ascending order with the respective potentials (see the example in Figure 5). This first step of the supply curve concept considers natural potentials, such as the availability of resources (wind, solar radiation, water CO_2, land, and energy infrastructures) as well as technical feasibility and costs for plants and infrastructures.

Figure 5: Supply curves for hydrogen from the MENA region 2030 (following Lux et al. 2021)



The second step integrates economic, social, energy, and development policy goals and restrictions, e.g., industrial structures and know-how concerning the assembly speed of production capacities, available capital for plant investments, training and education structures and capacities, environmental aspects etc. These aspects are priced into the LCOE directly as costs (e.g. environmental costs) or using a differentiated set of factors. This set of factors considers the different conditions in the respective countries that are not directly calculable as investments, and increases the LCOE via different discount rates. They comprise the costs for capital (reflecting risks and opportunity costs, capital market) as well as social and societal aspects that can have an impact on risks or the pace of development. Finally, the interests of local actors as well as global players and stakeholders (e.g., risk and profit surcharges) also influence production. These are included in the analysis by weighting the different technologies. The supply derived in this way thus depicts the extended (societal-economic) marginal costs of producing hydrogen (and synthesis products).

4.3 Determining a demand function

4.3.1 Possible demand development depending on price

The future demand for hydrogen is not yet foreseeable in detail. At present, the actual, global demand for hydrogen is around 120 million tonnes (4.0 TWh), about 4 % of global final energy demand (including non-energy uses) and is limited to a few sectors (IRENA 2019).

However, hydrogen is expected to have numerous applications in a decarbonized world. For instance, IRENA (2021) shows that hydrogen and its derivatives could contribute 10 % of the CO_2 reduction needed by 2050 in order to reach the ambition level of a maximum global temperature increase of 1.5 °C. The actual quantities are coupled with significant uncertainties. In a Meta study, Wietschel et al. (2021) identify large ranges in the demand for hydrogen and its derivatives in the EU alone, varying from 15 to 221 TWh in 2030 and from 17 to 1,841 TWh in 2050.

The following sections develop a method to determine the correlation between demand and possible supply prices of hydrogen. The analysis assumes that the instruments of the EU Green Deal and other bundles of measures will achieve greenhouse gas neutrality in 2050 or that this path will be pursued. For this reason, only decarbonized technology options are considered as alternatives to hydrogen use. Supply prices are equated with consumer costs for demand. The costs for hydrogen represent only one cost item within the total costs for a decarbonized technology at a specific point in time (e.g. the year 2050). Other costs are incurred, for example, due to increased energy demand, other raw materials or investments in other plants.

4.3.2 Determining the demand curve

The amount of hydrogen demanded is determined by the various sectors in a market (transport, industry, buildings) and subordinate sectors (ammonia production, steel, cement, heavy-duty goods transport etc.). In each of the different subsectors, hydrogen use faces a varying number of alternative decarbonization options depending on the respective application. The investments and the running costs of the hydrogen application and the alternative option determine whether hydrogen is used. The willingness to pay for hydrogen is derived from this.

The demand curve describes the quantity demanded at an offered price. The demand curve is therefore a measure of the subsectors' willingness to pay for one unit of hydrogen. The curve is plotted one bit at a time. The following sections describe how to determine the quantities demanded and the corresponding prices. When determining the demand curve, it is not decisive whether a global market is formed or separate regional markets, and whether these are perfect markets or not. An equilibrium price will be established on each market.

Quantity demanded

Projecting the quantity of hydrogen in the different subsectors is associated with uncertainty and can vary depending on scenario assumptions. For this reason, the hydrogen demanded can only be given as a range. The subsectors must be delineated across the sectors with a consistent level of detail. It is also helpful to divide the subsectors into three groups depending on their flexibility for using hydrogen alternatives. These are described in more detail below (a similar approach is taken in Wietschel et al. 2021, Agora Energiewende and Guidehouse 2021). These groups will also play a role in assigning prices and when considering the development over time.

- **No regret:** In this group, demand for hydrogen is driven by the lack of alternative decarbonization measures. Direct electrification is only possible to a limited extent or not at all, which is why the only alternatives to hydrogen are the use of fossil fuels with CCS or biomass. The limited alternatives mean that demand is inelastic and consumers cannot react responsively to changes in the price of hydrogen. This group features industrial applications that are already the main demand sectors for hydrogen today, such as ammonia and basic chemicals, supplemented in the future by steel. On the other hand, international air and sea transport will also demand hydrogen and especially hydrogen derivatives.

- **No lock-in:** This group contains applications where decarbonization can be implemented by both the direct use of renewable electricity and renewable hydrogen and it is not yet clear which alternative will be the more cost-efficient. These includes, for example, high-temperature heat in industry or heavy-duty transport. Demand is elastic and consumers are responsive to changes in the price of hydrogen.
- **Game-changing:** In this group, including passenger transport and space heating, using electricity directly is the more efficient decarbonization measure. There may be other factors that favor hydrogen and its derivatives such as available infrastructures or acceptance as well as plummeting production costs for hydrogen. In this case, the total amount demanded would soar due to widespread use. In this group, demand is very elastic and buyers are very responsive to changes in the price of hydrogen.

Accepted prices of demand

In the no-regret group, the supply price determines the accepted price of demand, since there are no alternatives. Nevertheless, transport costs and other possible surcharges must be taken into account, so that the price on the market is not identical to the production costs.

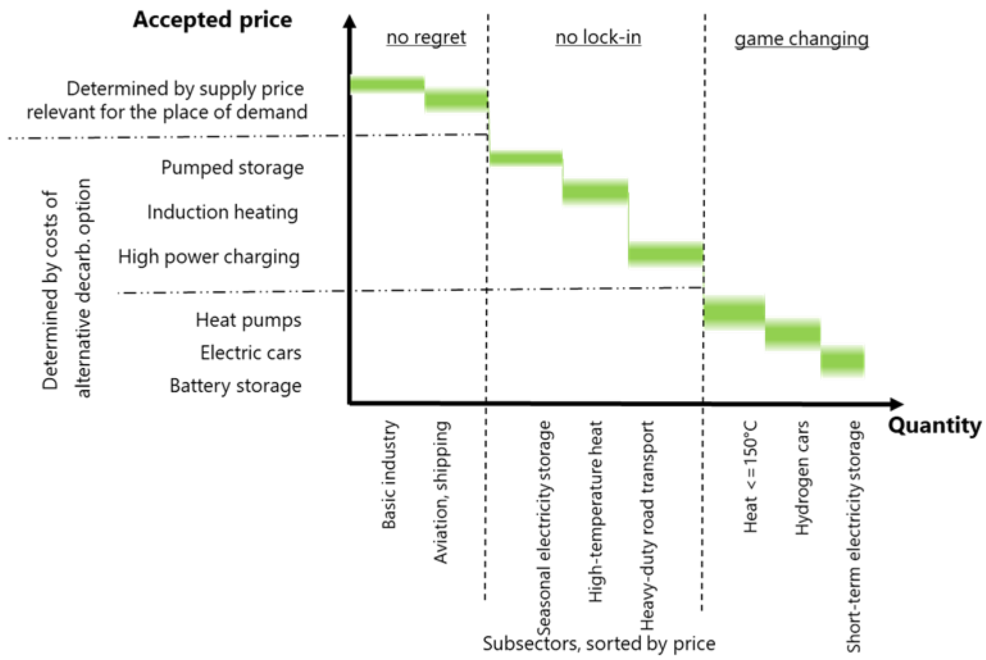
In the no lock-in and game-changing groups, there are one or more decarbonization options besides the hydrogen–based alternatives. To determine the willingness to pay for one unit of hydrogen, therefore, not only the costs for conversion to hydrogen use are decisive, but also the cost of using the alternative decarbonization option, e.g., direct electrification. The respective option prevails on the market based solely on economic considerations. The costs for each of the options include both investments (e.g., costs for electrolyzers or electric furnaces) and operating costs (including the costs for feedstocks and fuels). On top of this, the lifespan and efficiency (of energy and material use) of the converted plants must be included. A suitable functional unit (e.g., one ton of steel produced or one kilometer driven) has to be selected for each sector or application, so that the hydrogen option can be compared with the alternative production route. If the production costs per unit of final product for the hydrogen-based alternative are competitive or the same as those for the alternative decarbonization options, the hydrogen option is chosen and prevails.

Consumers from the no-regret group are forced to accept the hydrogen price offered (supply price) due to the lack of alternatives. The demand from the other two groups is elastic, which is why the hydrogen prices and, if required, investments in the conversion must decrease at least to the point where parity is achieved with the alternative technology (substitute price).

Determining the demand curve

The demand curve is determined by plotting the quantities of hydrogen demanded with their respectively assigned accepted prices. The quantities are cumulated across the subsectors. The subsectors are then sorted by the accepted prices so that a decreasing step function is formed, starting from the highest prices in the no-regret group. Figure 6 demonstrates the concept; the legends here are purely for illustration. The width of the steps indicates the range of the quantity demanded for a specific hydrogen price, while the respective height (the value on the price axis) indicates the willingness to pay for a specific cumulated quantity of hydrogen. The equilibrium price relevant for the market results at the intersection of the supply and demand curves.

Figure 6: Illustration of the different demand groups with their respective quantity (cumulated on the x-axis) and the accepted price (y-axis) (sorting and relative quantities are purely for illustration purposes)



Development over time

Over time, learning effects, economies of scale, technology innovations and other developments can decrease the production costs of hydrogen, reducing the supply price that still covers costs. If the demand function remains the same, a larger quantity then falls into the acceptable price range for potential consumers. As a result, the quantity demanded will increase in line with the curve determined by the principle described above. If prices are high to start with, the subsectors of the no-regret group will be the first to use hydrogen, before falling prices trigger demand in other sectors as well. In principle, however, this relationship is reciprocal and the quantity demanded first generates an increase in supply.

Higher total costs of the non-hydrogen-based alternative (especially rising costs for energy and raw materials as well as other operating costs) can result in increased production costs per functional unit of the final product for such an alternative and thus also in an increased willingness to pay for the hydrogen technology. Hydrogen then becomes the more cost-efficient alternative even in groups with more elastic demand (no lock-in and game-changing). As a result, the quantity demanded increases if the price of hydrogen remains constant, or the accepted costs in more elastic demand groups (no lock-in and game-changing) rise, so the steps in Figure 6 move upwards. However, the costs and investments for the alternative decarbonization options can also decrease in the same way over time and influence the curve in the opposite direction. These processes take place at the level of the subsectors. Changes in the curve can also be understood as a re-sorting of the subsectors according to the accepted price and assigned quantity.

4.3.3 Influences on global demand

It is not foreseeable for the near future whether such a global market will emerge for hydrogen. To start with, demand will be met at a regional price on each regional market. As there are different prices in the different demand regions, there does not have to be a global consensus on the areas for which hydrogen will be demanded. Even if a global market emerges and a price is formed, this does not mean that the same hydrogen options will prevail for decarbonization in all the regions, because the alternative decarbonization options are also associated with regionally varying costs and framework conditions. Even with a global price, the subsectors that rely on hydrogen will still vary regionally.

If regional markets merge (for instance due to imports), this opens up an expansion of the supply at different supply prices, which can trigger additional demand. If the supply prices vary strongly by region, this can lead to a certain share of the potential demand in a regional market migrating to a different region. This will change the demand in both regions. If the migrating application was already a consumer of hydrogen, prices will fall in the region of origin and the quantity demanded in the destination region will increase. This does not necessarily imply a change in price, for instance, if the exported quantity decreases as a result.

4.4 Transport pathways and costs

During the course of the HYPAT project, both potential production (or exporting) countries and demand (or importing) countries are identified. Countries that constantly have high renewable energy potentials after meeting their own energy needs are identified as exporting countries. Those designated as importing countries have insufficient renewable potentials to reach climate neutrality and are dependent on hydrogen (product) imports. Within the framework of a global transportation cost model, simplifications are made to reduce the complexity of determining the transportation costs c_{Trans}, which ultimately form the export costs c_{Exp} together with the production costs c_{Prod} and, if applicable, the separation costs, and represent a lower threshold for an export price p: $c_{Prod} + c_{Trans} + c_{Sep} = c_{Exp} \leq p$.

The transportation costs model for hydrogen and its products comprises the following three steps:

- Identification of the main transport pathways
- Determination of the transport costs depending on the transport pathway, quantity and distance
- Derivation of the export prices.

4.4.1 Determining potential transport pathways

There are different conceivable pathways for transporting hydrogen. Hydrogen is either compressed (GH2), liquefied (LH2) or chemically bonded. It can be chemically bonded in the form of a derivative (NH_3 – ammonia, SNG – synthetic natural gas, MeOH – methanol, Fischer-Tropsch products) or using a hydrogen carrier material (LOHC Liquid Organic Hydrogen Carrier). Hydrogen can be chemically converted into NH_3 via the Haber-Bosch process by adding nitrogen. Via methanation, hydrogen can be converted into SNG or MeOH using carbon dioxide.

Fischer-Tropsch synthesis further enables conversion into long-chained molecules or synthetic fuels. The product to be transported can be in a liquid (L) or gaseous (G) state and exported using ships or pipelines. 18 different potential transportation pathways result when considering the different process routes, physical states, upgrades, and transport infrastructures. It is assumed that hydrogen is made available for transport at ambient pressure at the system boundary of electrolysis. Transport here includes the conversion of hydrogen to its derivatives or compression or cooling.

NH_3 constitutes a special case with regard to the transport pathway, as ammonia can be traded both as a feedstock for the chemical industry and as a hydrogen carrier. In the latter, separation of the hydrogen takes place after its import to the demand center, i.e., the bonded hydrogen is separated again. So far, there are no direct applications for LOHC, which is why H_2 separation must take place at the point of use. The costs shown below include this separation in the case of LOHC and ammonia and would have to be subtracted if these are used directly.

The main transport pathways that have currently reached a technology readiness level of at least 6 or that are already technically and economically viable are selected and used to determine the transport costs between exporting and importing country, or between export and import hub. TRL 6 indicates that the technology has already been tested and demonstrated in an operational environment so that it is assumed to be scalable until 2030 (Nationale Kontaktstelle für Wissenstransfer und Geistiges Eigentum 2021). The preliminary selection is limited to GH2 by pipeline and LH2, LNH3, MeOH, LOHC and Fischer-Tropsch synthetic fuels (FT) in liquid form by ship. The HYPAT consortium does not consider synthetic natural gas on the grounds that the energetic use of natural gas can be substituted by H_2, and that it is already being used as a material today to produce H_2.

4.4.2 Determining the costs for transportation depending on the pathway, quantity and distance

The transport costs for hydrogen (products) depend on

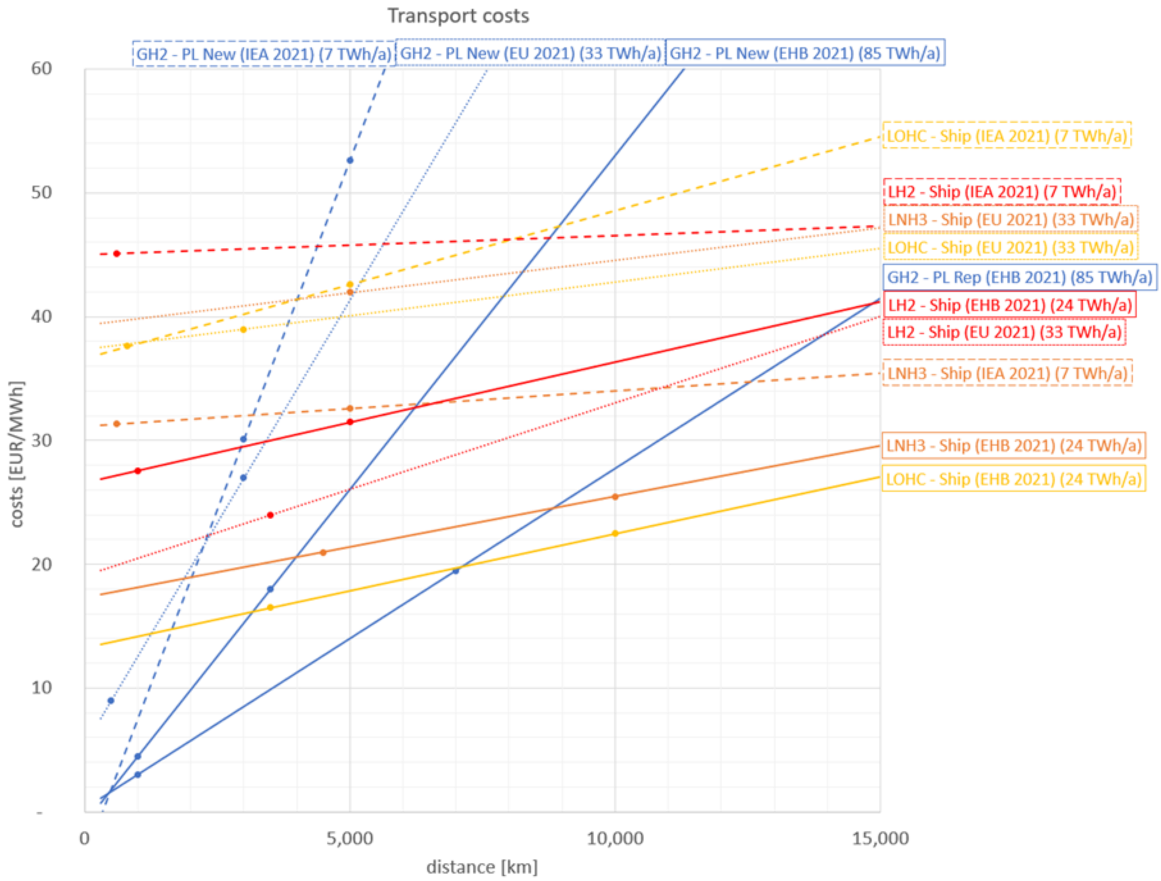
- The preliminary transport pathway selected (GH2, LH2, LNH3, MeOH, FT-SynFuels, LOHC)
- The quantity transported and
- The distance to be covered.

Recently published studies deal with the costs for transporting hydrogen and its derivatives, such as the European Hydrogen Backbone study (Wang et al. 2021), the IEA's Global Hydrogen Review Report (IEA 2021b) and the JRC paper of the European Commission on Hydrogen Transport Options (European Commission 2021).

The three sources cited examine the transport costs of gaseous hydrogen by pipeline and of ammonia, LOHC and hydrogen in liquid form by ship. Wang et al. (2021) assume high TRL for derivatives and are the only ones to analyze the costs of a repurposed pipeline and varying pipeline capacities. Furthermore, the transport capacities (24-85 TWh/yr.) in the Hydrogen Backbone report are up to ten times higher than the other two studies: up to 85 TWh/yr. for pipeline transport and 24 TWh/yr. per derivative. Comparatively high transport capacities and high TRL result in correspondingly low transport costs in Wang et al. (2021). In contrast, the IEA's calculations are based on relatively small transport capacities of 7 TWh/yr. per transport medium. This results in higher transport costs per technology over long distances compared to the other two studies. The EU-JRC paper is in a medium range, with transport capacities of 33 TWh. Despite these medium capacities, the transport costs of the derivatives for long distances are comparatively the highest. In addition, the European Union estimates that the transport costs for GH2 in a repurposed pipeline are about half those for a newly constructed pipeline (European Commission 2021).

The results are summarized in Figure 7 below.

Figure 7: Transport costs for gaseous hydrogen per pipeline in new (GH2-PL new) and repurposed pipelines (GH2-PL rep.), as well as for ammonia (LNH3 ship), hydrogen (LH2 ship) and LOHC (LOHC ship) in liquid form by ship. Data taken from (IEA 2021b), (EC 2021) and (EHB 2021). Transport capacities are converted into TWh/yr. assuming 5,000 full-load hours.



All three sources indicate that GH2 transport by pipeline is the cheapest option up to 1,500 km. If the IEA study is not considered due to its low transport capacities of 7 TWh/yr. and if a repurposed pipeline is assumed for the JRC study (50 % cost reduction), then new pipelines up to 3,500 km and repurposed pipelines up to about 5,000 km are the cheapest alternative at costs below 30 Euro/MWh (1 Euro/kg) transported hydrogen. For distances longer than 5,000 km, it is not possible to rank the different transport options LNH3, LH2 and LOHC by ship based on cost, because the sources calculated the costs of the transport technologies using different TRLs and transport quantities. In general, ships are used for intercontinental flexible long-distance transport in order to avoid politically unstable regions, for instance, or be able to change routes at short notice (Wang et al. 2021).

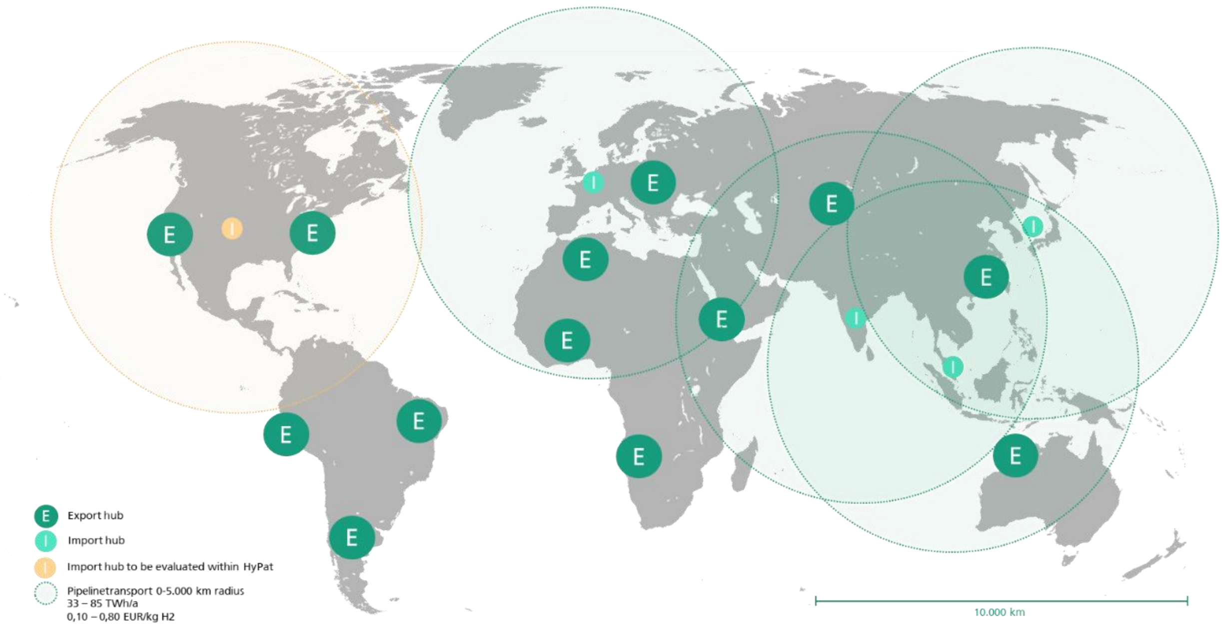
In order to draw conclusions with regard to transport costs and the choice of derivative depending on the transport distance, HYPAT needs to make its own quantity-dependent calculations.

4.4.3 Export and import hubs

4.4.3.1 Introduction of export and import hubs

Under the restriction that pipeline transport is the most economical variant for up to about 5,000 km, first potential "pipeline partnerships" can be derived by introducing export and import hubs and preselecting potential importing and exporting countries. Exporting countries that are unable to serve import hubs within a 5,000 km radius will export derivatives by ship in accordance with current research. Further data should be gathered for the transport costs of repurposed long-distance pipelines of more than 10,000 km. The figure below provides an illustrative overview. Extensive modeling within the HYPAT project further differentiates the choice of derivative depending on the transport distance.

Figure 8: Qualitative illustration for indicatively established import (I) and export (E) hubs based on renewable energy potentials as well as future demand for energy.



Notes:
Rings around import hubs with indication of potential suppliers of GH2 by pipeline.
Import: East Asia (Japan, South Korea), Southeast Asia (Thailand, Vietnam, Indonesia, Malaysia), South Asia (India), Western Europe (Germany), [tbd: North America (Canada, USA)].
E: Oceania (Australia), East Asia (China), Central Asia (Kazakhstan), Eastern Europe (Ukraine, Turkey), Near East/Eastern Africa (Saudi Arabia/Ethiopia), Western MENA region (Mauretania, Morocco, Algeria, Egypt), Western Africa (Nigeria), Southern Africa (Namibia), North America – East (Canada, USA), North America – West (Canada, USA), South America – East (Brazil), South America – West (Chile), South America – South (Chile, Argentina).

This approach means that the most economical option for the provisionally defined import hub in Western Europe is to transport hydrogen from the provisionally defined export regions of Eastern Europe, the western MENA region, Western Africa, Eastern Africa or the Near East and Central Asia. It is conceivable that these regions will export hydrogen by pipeline to Germany.

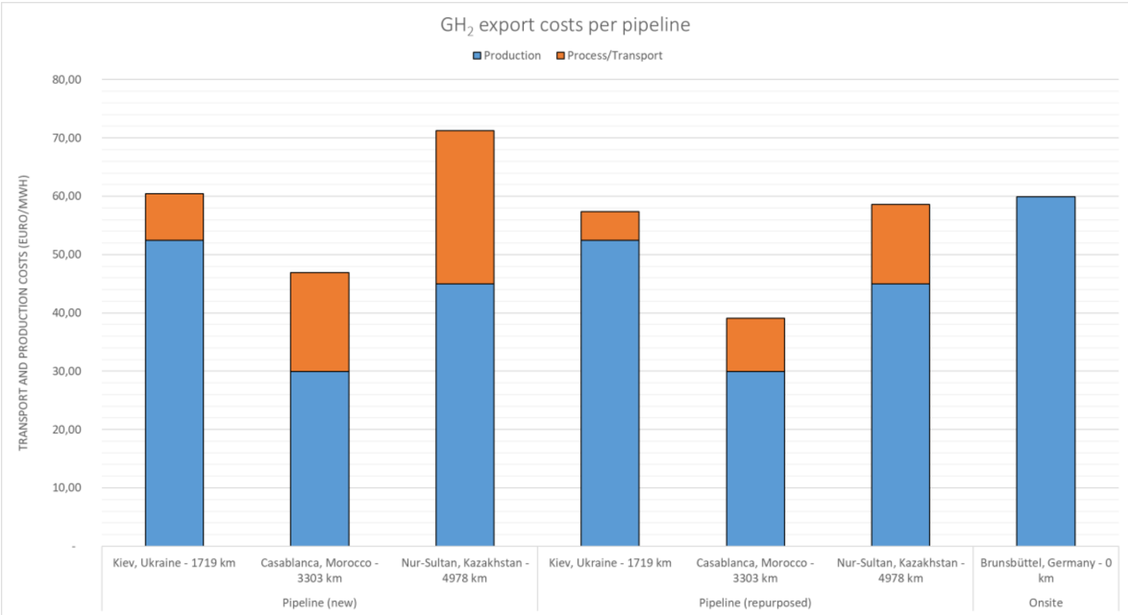
The identified export regions are characterized by their high renewable energy potentials with low generation costs. In order to ascertain in an initial approach how high transport costs may be that still keep the individual export regions competitive, the following locations are examined as examples:

- Central Asia (Nur-Sultan, Kazakhstan)
- MENA region (Casablanca, Morocco)
- Eastern Europe (Kiew, Ukraine)
- South America (Iquique, Chile)
- Import point/local production (Brunsbüttel, Germany)

The production and transport costs for gaseous hydrogen are compared under optimistic conditions using both repurposed and new pipelines (Wang et al. 2021).

When analyzing transportation, the perspective of the exporting countries is taken, with Germany the country buying. In the case of Casablanca, Morocco, transport by both pipeline and ship is examined. For Iquique in Chile, only transport by ship is analyzed (Correa et al. 2020). The production costs for hydrogen were taken from the PWC study (Price Waterhouse 2021) for all the locations apart from Chile, where a lower value of 23.98 Euro/MWh was used. H_2 production costs will be calculated within the course of the project, but these are not yet available. The transport costs for pipelines (new and repurposed) and ships were interpolated based on the study by Wang et al. (2021) (cf. Figure 7). The transport capacity of the pipeline is 85 TWh/year. The transport capacity of the ship is less than one third of this with 24 TWh/year. The transport costs include the different processing costs that are necessary for the energy carrier, e.g., compression. Brunsbüttel is the import port in Germany. The results are shown in Figure 9.

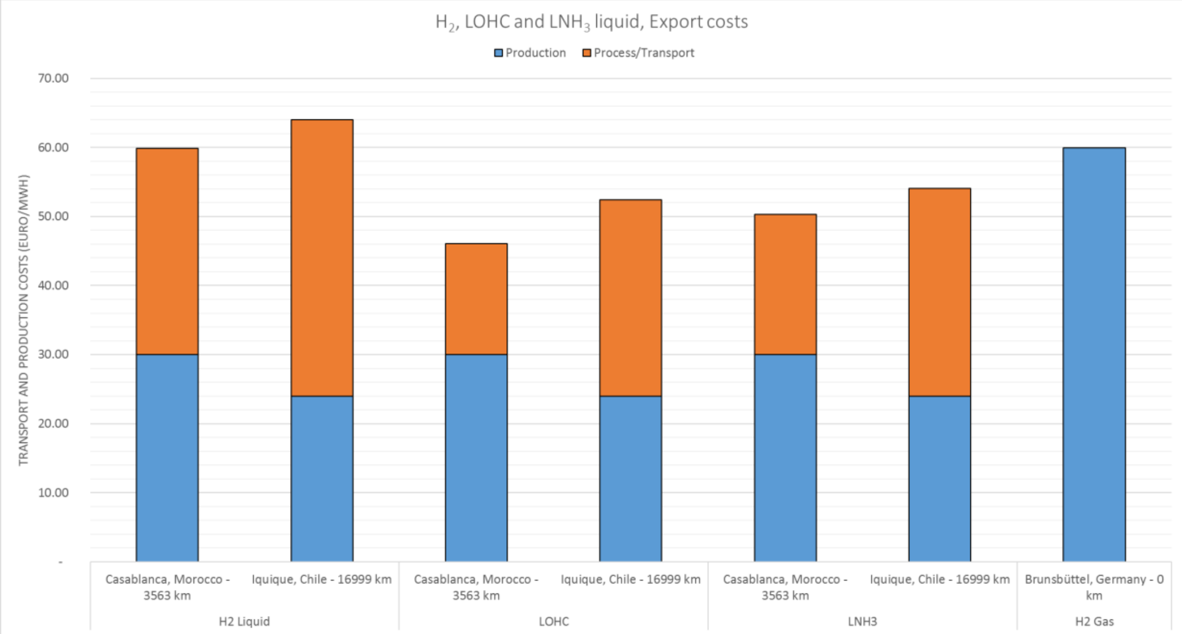
Figure 9: Global production and transport costs of gaseous hydrogen by pipeline in 2050. Transport costs taken from Wang et al. (2021); assumptions: 85 TWh/yr. H_2 transportation. Production costs taken from PricewaterhouseCoopers (2021), capacities not given.



The lowest export costs with 39.12 Euro/MWh result for transporting gaseous hydrogen from Morocco via repurposed pipelines. If repurposed pipelines are used, the export costs are still lower even at more distant locations with higher generation costs such as the Ukraine (57.38 Euro/MWh) and Kazakhstan (58.57 Euro/ MWh) than producing hydrogen locally in Germany.

A similar comparison was made for transporting liquid hydrogen and the hydrogen carriers LOHC and LNH3 by ship:

Figure 10: LH2, LOHC and LNH3: Export costs per ship in 2050; transport costs taken from Wang et al. (2021)



Assumptions:
24 TWh/yr. H_2 transportation. Production costs taken from PricewaterhouseCoopers (2021). Production costs for Chile taken from the National Green Hydrogen Strategy. Distances to ports calculated using ports.com (World seaports catalogue, marine and seaports marketplace 2021).

The costs of the conversion process were not taken into account in Germany. The ship has a loading capacity of 24 TWh/year (Wang et al. 2021). In the case of liquid hydrogen, Casablanca, Morocco, (59.90 euros/MWh) has lower costs than locally produced hydrogen (59.95 euros/MWh). In the case of LOHC, the costs are lower at both export locations. For LNH_3, Morocco has the lowest costs (50.30 Euro/MWh) compared to Chile (54.07 Euro/MWh).

It can be concluded from this that Europe has various options to choose from for importing hydrogen and that several factors must be considered in the decision.

It should be emphasized that this study only considered the cheapest available production costs for hydrogen and not the quantity that can be produced at these costs. It is possible that this cheaply produced hydrogen will be used locally and that more expensive options will be exported.

4.5 Calculating the costs of capital and risk premiums

Producing and using hydrogen as an energy carrier and feedstock require extensive investments in facilities to supply electricity and water as well as in conversion and application technologies. To mobilize private capital, the expected return on investment is decisive, taking into account existing risks, while the default risk is relevant if borrowed capital is provided (Gerhard et al. 2015). High risk drives up the financing costs (Agora Energiewende 2018), which in turn are reflected in the specific production costs. Instead of expected return, the expression "hurdle rate" is also commonly used (Investopedia 2020). This represents the minimum return above which a business is willing to invest. It takes into account appropriate compensation for the potential risk and alternative investment opportunities, i.e., it reflects opportunity costs and risks. Two orientation variables are often used here: the weighted average cost of capital (WACC) of the company or the internal rate of return (IRR) of a project, which is calculated independently of the type of project financing.

As both variables represent company-internal data, a cost approach is often used to calculate the production costs of hydrogen, which relies either on surveys, such as in the AURES II database (AURES II 2021), or on a theoretical approach derived from the Capital Asset Pricing Model and interest rate statistics (Damodaran 2019).

When looking at the calculations made so far concerning hydrogen imports, it is clear that these are based on WACC. The capital costs in previous studies assume a WACC of 2 % (Hobohm et al. 2018) up to a maximum of 8 % (e. g. Pfennig et al. 2017). A WACC is often applied with 4 % to 6 % and thus corresponds to the average financing costs in Germany. So far, country-specific WACC are not collected and reported. This means that the risk is considered to be the same for capital providers everywhere around the world and is thus regarded as too low for some countries.

The DESERTEC project reveals that geopolitical instability is one of several obstacles to realizing energy import projects. DESERTEC is an initiative aiming to generate green power at energy-rich locations such as the MENA region and, in addition to using this to meet domestic demand, to export it by developing high-voltage direct current (HVDC) transnational power networks. The geopolitical instability in DESERTEC can be differentiated into planning uncertainty due to political events (civil wars etc.), fear of terrorist attacks (HVDC lines, facilities), breach of contract due to political changes (power shifts in MENA countries) and more difficult communication with MENA countries due to political uncertainties. See the comments in Looney (2018), Schmitt (2018), Stegen et al. (2012).

As Chapter 5.2 will show based on the MENA region, the costs of capital have a decisive influence on the economic efficiency of projects and thus on their viability for hydrogen and its derivatives. Despite the high relevance of the cost of capital, so far, there is no standardized, comprehensive approach that makes it possible to derive country-specific financing costs and risks. This topic is currently being discussed in connection with the return on equity capital for hydrogen networks (BMWi 2021). In addition, a consortium consisting of Adelphi, Dena, GIZ and Navigant listed capital cost rates up to 2030 for green hydrogen production facilities for selected countries that were based on country-specific risk assessments made by the authors on a scale from low (5 %), medium (8 %), to high (11 %) and very high (15 %) (Adelphi 2020).

An approach is presented in the following that draws on Damodaran (2019). This method makes it possible to estimate a risk premium, the equity risk premium (ERP), which represents the risks on the equity market and can be determined for all the countries included in the Moody rating.

To start with, the country's credit risk is determined using credit risk ranking. Moody's rating is the standard for long-term investments and the method used is described by Moody (2021). Moody's rating incorporates very general indicators aimed at reflecting the overall risk for investors in a country. The rating is then assigned a credit spread compared to a risk-free investment (AAA Rating). In order to also include the risk of stock transfers, the credit spread is multiplied by the relative stock market volatility, which results in a country risk premium. The risk premium for mature markets, i.e., countries with the most advanced economies and capital markets (AAA Rating), is added to the country risk premium. This can be taken from S&P 500 Risk Premium (S&P 2021). Altogether, this yields the equity risk premium (ERP), which is calculated below as a simplified approximation for the WACC (Table 3).

Table 3: Applied Weighted Average Cost of Capital (WACC) due to the equity risk premium of selected countries: WACCs vary due to the country-specific risk premiums based on Moody's Rating. Values calculated following Damodaran (2019).

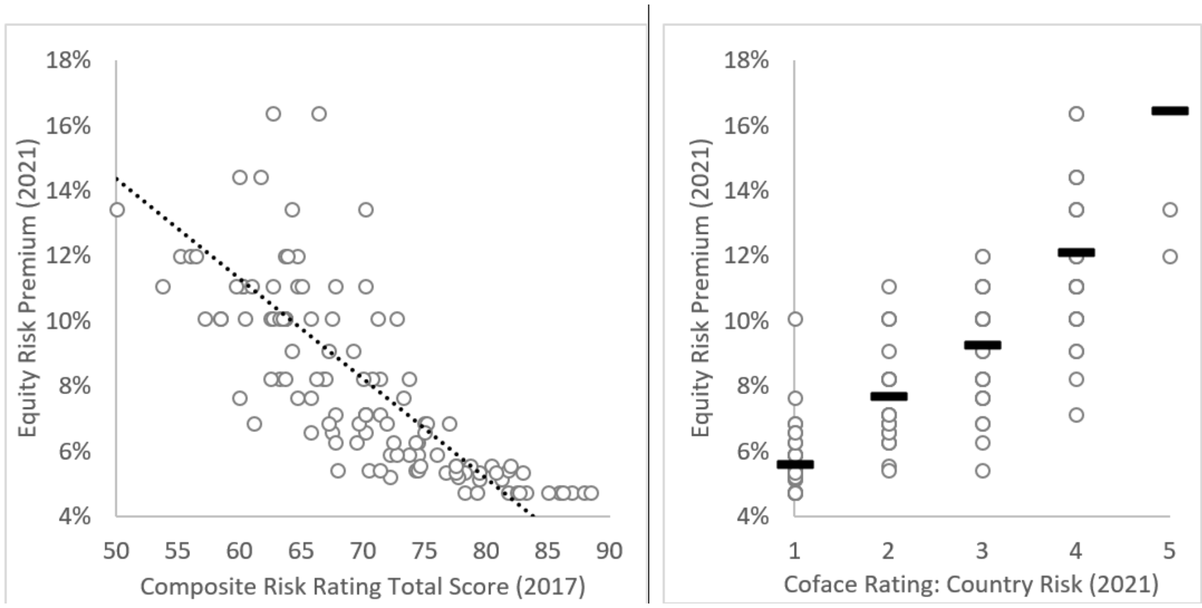
Country	Moody's rating	Credit spread	Relative equity market volatility	Country risk premium	Mature market risk premium	Equity risk premium
Germany	Aaa	0.0 %	1.1 %	0.0 %	4.7 %	4.7 %
Australia						
Chile	A1	0.6 %		0.7 %		5.4 %
Saudi Arabia						
Kazakhstan	Baa3	1.9 %		2.1 %		6.9 %
Morocco	Ba1	2.2 %		2.4 %		7.1 %
South Africa	Ba2	2.7 %		2.9 %		7.6 %
Egypt	B2	4.9 %		5.3 %		10.0 %
Ukraine	B3	5.7 %		6.3 %		11.0 %
Argentina	Ca	10.6 %		11.6 %		16.3 %

The risk premiums calculated here (Table 3) only refer to macro-level risks. However, three different levels are considered to assess the risks:

1) Macro-level risks are those that apply generally to a country. These include economic, financial, societal-social and political stability as well as legal certainty.
2) The meso level covers all the aspects that apply specifically to the sector, such as market and technology maturity, quality and availability of resources – including human resources – support policies and infrastructures.
3) At project level, the main factors include the local conditions, such as natural resources, specific contractual arrangements and project structures as well as the actors involved.

Various studies (e. g., AURES II) and experts indicate that the risks at macro level dominate the financing costs (AURES 2020). Experts cite the ten-year government bonds that are part of different country ratings as a main guideline. This suggests that referring to risk premiums is suitable as a first step toward a country-specific, differentiated estimate of financing costs. This is also indicated by the high correlation between holistic risk ratings and the equity risk premium calculated here (Figure 11).

Figure 11: The data pairs of 118 countries form the scatter diagram shown on the left, which illustrates the relationship between the composite risk rating and the equity risk premium (applied WACC). The graph on the right shows the relationship between ranking using Coface Risk Rating (from 1: lowest risk to 5: highest risk) and the equity risk premium for the same 118 countries. Each country is represented by a gray circle; the dashes show the calculated mean values per risk rating.



Source: Diagrams of country data from Damodaran (2019), Composite Risk Rating (2017) and Coface Risk Rating (2021).

There is a very high correlation between the calculated equity risk premium and the holistic risk rating (Figure 11). The remaining error variance can be attributed to other country-specific risk factors, so that the equity risk premium is a reasonable approximation for the cost of capital, but obviously does not consider all the risk factors (levels 2 and 3). When selecting countries, this is why the background to the risk premiums included should always be examined qualitatively as well in order to shed light on the simplified quantification. In the following paragraphs, the main reasons for the level of risk premiums from the Coface Risk Rating (2021) are summarized for example countries of interest.

Chile (ERP=5.4 %) is a leading producer of copper, has a stable agriculture with fishery and forest resources, and thus a solid economy. Furthermore, Chile is a member of the OECD and the Pacific Alliance and has numerous free trade agreements. The country supports a positive economic development with its flexible monetary, fiscal and tariff policies. At the same time, Chile is vulnerable to external events due to its dependence on copper and a small and open economy. It is potentially threatened by climate and earthquake risks due to its location. Comparatively low spending on research and innovation, high income and wealth inequalities and inadequate education are potential obstacles to long-term economic growth. In spite of these limitations, as a South American country, Chile has a comparatively stable currency, politics and economy, resulting in a positive risk rating and thus an ERP of only 5.4 %. However, this low value can change quickly due to extreme weather events, for example.

In contrast to Chile, its neighbor Argentina has a very high risk premium (ERP=16.3 %), because its role as an agricultural exporter makes it dependent on agricultural prices and weather conditions. There are also infrastructural bottlenecks. However, it is the persistent fiscal framework conditions, in particular, that raise the costs of capital. The state capital controls have been tightened to curb the depletion of foreign exchange reserves. This financial crisis is leading to rocketing inflation, which is substantially increasing the cost of capital as well. At the same time, Argentina has good prospects for improving the cost of capital. It is an important agricultural player, especially for soybean, wheat and corn, and has large shale oil and gas reserves. The standard of education and the GDP per capita in Argentina are also above the South American average.

One of the most promising candidates from the MENA region, Morocco, has only moderate capital costs (ERP=7.1 %). Morocco has a favorable geographic location due to its proximity to the European market. For a country on the African continent, politically, it is also comparatively very stable. Its economy is growing and expanding, increasingly onto the African market as well. Morocco is supported by the international community and Europe is already successfully implementing green investments in the country. Nevertheless, its dependence on agriculture harbors major risk. More than 40 % of its population is employed in this sector. This leads to dependencies on climate and water availability. There are also strong social and regional disparities between urban and rural areas, with recurring discontent in several regions. This could lead to potential unrest. The poverty rate and especially the youth unemployment rate are high. Political tensions with neighboring countries also slightly increase the investment risk.

The Ukraine (ERP=11.0 %) is also being discussed as an important candidate for hydrogen imports for political reasons. The cost of capital is moderately high there. This is mainly due to the ongoing conflict with Russia in the Donbass region, which is having a major impact on the EU's involvement in the region. In addition, due to the lack of competition, oligarchs and monopolies prevail, and the business climate is marked by corruption. An additional risk is the lack of economic diversification, which makes the Ukraine dependent on raw material prices, and the weather for agriculture. There are high real interest rates on loans, which limits lending. There is an opportunity for positive developments on the capital market in the future due to Ukraine's strategic position in Europe, especially as a transit country for gas from Russia. At the same time, Ukraine has had a free trade agreement with the European Union since 2016, and the country is supported internationally, both financially and politically. Ukraine also has high potentials in terms of land use (more than 50 % arable land) for developing renewable energy in addition to agricultural usage. There is a skilled and cheap workforce available, and the population has a low level of private debt.

These examples show that the level of capital costs can change significantly in the future, and is often the result of current events and political situations. This is why it is important to look at the qualitative as well as the sectoral aspects of a country's risk rating, in order to estimate its future development in addition to its current capital costs. Overall, it becomes clear that high economic risks lead to high interest demands and thus the costs of hydrogen production can increase strongly, even in countries with large and low-cost potentials. Potentials that can be exploited in the long term via a pipeline network are in regions that have an average to high default risk.

The high cost of capital can be countered with bilateral contracts and risk sharing among financial institutions. Some of the risks can thus be shouldered by state financial actors in the importing countries, which can lower the capital costs of the individual projects (Oeko-Institut 2021). Default risks change in line with the countries' developments. The interest rate premiums for the years up to 2030 can be estimated by analyzing trends or set by teams of experts considering the country's risks and opportunities.

5 First implementation of parts of the methodological concept

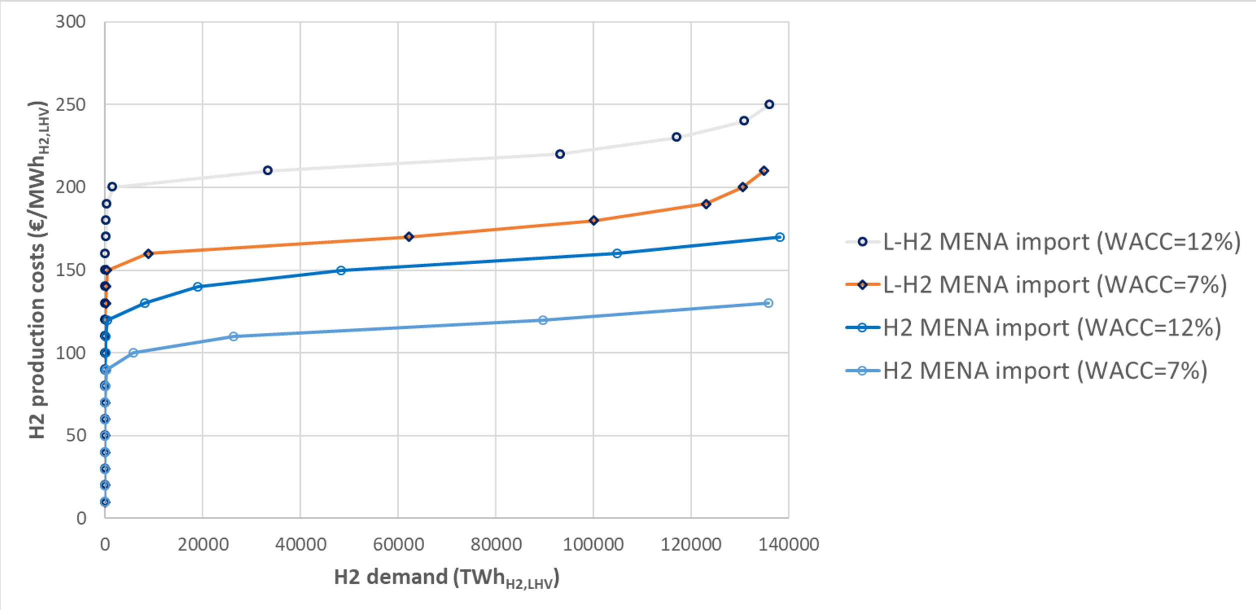
This section presents the first approaches to implementing the methodological concept. It deals with the influence of different costs of capital on the supply function to start with, then presents a supply function together with a demand function.

5.1 The effects of different capital costs on the supply function

Lux et al. (2021) determine the potentials for producing the electricity-based fuels hydrogen and synthetic methane depending on the production costs for the MENA region in 2030 and 2050. They assume that only renewable electricity is used for their production. The analysis is carried out using the energy system optimization model Enertile. The model's results are used to analyze the export of e-fuels from MENA to Europe with distance-dependent transport costs. The energy system optimization in Enertile is based on a high-resolution assessment of the renewable electricity potentials in the MENA region. The resulting cost-potential curves and distribution of the analyzed renewable technologies show that photovoltaic (PV) and concentrated solar-thermal power (CSP) are the most cost-effective technologies in the MENA region. Favorable potentials for generating power from renewable energies are also found in the coastal regions of Egypt, Saudi Arabia, Libya, and Morocco. In line with the scenario, which postulates that e-fuels will only be produced in coastal regions, these countries make the first and cheapest contributions to e-fuel production in the model calculations.

The cost-potential curves are calculated using 7 % and 12 % as two alternative assumptions for the weighted average cost of capital (WACC). The model results for green electricity-based hydrogen production show that significant volumes of gaseous hydrogen can be produced in MENA in 2030, starting from production costs of 100 Euro/MWhH2, LHV (7 % WACC) and 130 Euro/MWhH2, LHV (12 % WACC). There is an enormous difference between calculating with 7 % or 12 % WACC: Compared to 7 %, a WACC of 12 % results in production costs that are higher by 40 to 60 Euro/MWh. WACC analyses must be carried out carefully and taken into account. They comprise an important component of getting a better idea of future prices. Furthermore, they provide indications of where policymakers should start in terms of support, for example by securing investments.

Figure 12: Hydrogen supply curves in the MENA region with transportation to the EU in 2030



Notes: The production and export volumes of gaseous hydrogen (H_2) and liquefied hydrogen (L-H2) are shown for a weighted average cost of capital (WACC) of 7 % and 12 %. The cost benefits of pipeline transportation tend to favor the emergence of regional markets for hydrogen (according to Lux et al. 2021)

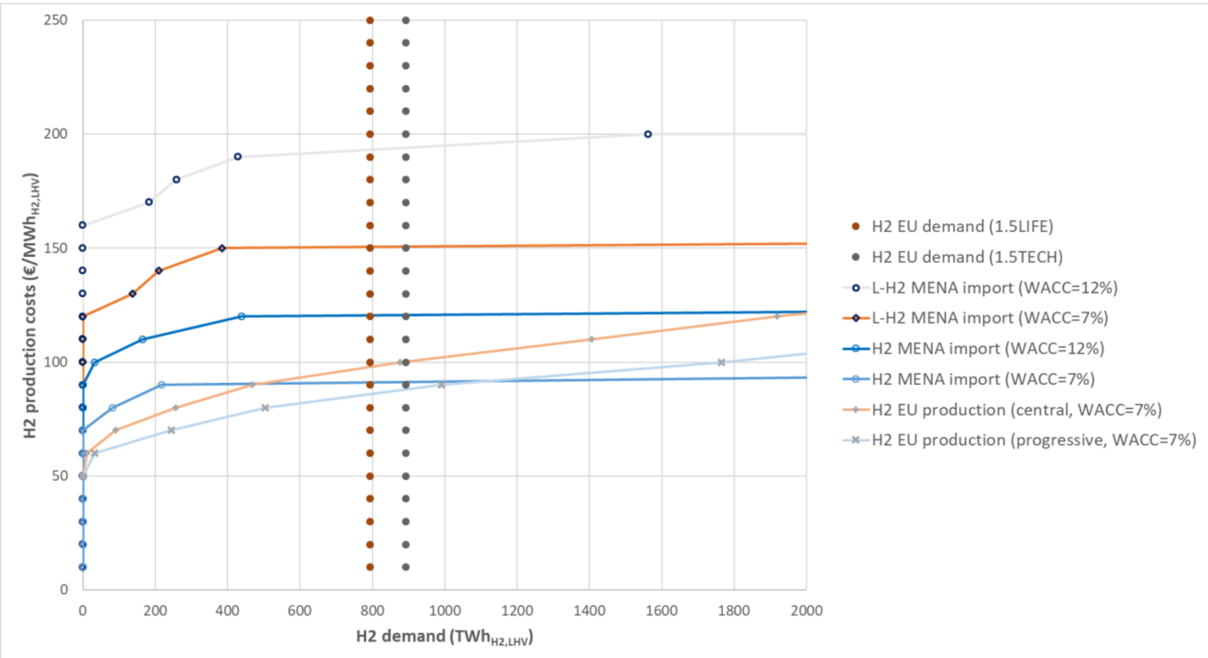
5.2 An initial approach to matching supply and demand

A first approach showing how supply and demand can be matched is presented in Lux et al. (2021). This compares the relationship between the supply costs of European hydrogen and hydrogen imported from MENA depending on the potential quantities demanded. It presents a possible price formation via marginal costs with a price inelastic demand function on an EU market and calculates this with different costs of capital. Thus, only initial approaches of the procedure described above are implemented here.

Figure 13 compares the costs of supplying hydrogen in Europe, which is either produced in Europe itself or imported from MENA. The supply curves of European production are taken from Lux et al. (2020). In general, the modeling approach used to calculate the European supply curves and the MENA import curves is similar. The comparison of the modeling results shows that the import curves are lower than the European supply curve up to a hydrogen price of 90 Euro/MWhH_2,LHV. Up to this selling price and corresponding hydrogen quantities, domestic European hydrogen supply is more cost-efficient. If the same WACC of 7 % is assumed for Europe and MENA, importing gaseous hydrogen from the MENA region becomes economically attractive at hydrogen demand levels between 488 TWhH_2,LHV and 1,118 TWhH_2,LHV, depending on the parameterization of the electrolyzers outlined in Lux et al. (2020). If hydrogen imports are subject to significantly higher risk premiums or profit margins, which are realized in the model runs by a WACC of 12 %, it is only profitable to import hydrogen compared to domestic European production from hydrogen volumes between 2,044 TWhH_2,LHV and 3,571 TWhH_2,LHV. The supply curves for liquid hydrogen imports from MENA intersect with European supply above hydrogen selling prices of 150 Euro/MWhH_2,LHV and a European hydrogen supply of 4,111 TWhH_2,LHV.

In line with the 1.5 °C target, the EC long-term strategic vision estimates a final energy demand for hydrogen of between 794 $TWhH_2$ (1.5LIFE scenario) and 892 $TWhH_2$ (1.5TECH scenario) in Europe in 2050 (European Commission 2018). The comparison of the hydrogen supply curves between European production with centralized electrolyzer parameterization and MENA imports in Figure 13 suggests that, from a techno-economic point of view, this demand could be partially met by MENA imports if the same interest rates apply to Europe and MENA. With progressive parameterization of electrolyzers in Europe and a WACC of 7 %, hydrogen demand could be met cost-effectively by production within Europe. If the MENA imports are assigned a higher WACC of 12 %, then European hydrogen demand would be met by production within Europe, regardless of the electrolyzer parameter scenario in Europe. However, imports could also become necessary if the RE potential in Europe cannot be sufficiently exploited due to a lack of public acceptance.

Figure 13: Competition on the European hydrogen market in the EU in 2050. Modeled export curves from the MENA region are compared with reference values (Lux et al. 2021) for domestic European production. The hydrogen demand of the European Commission is used as a reference for 2050 (European Commission 2018)



The following can be concluded from this analysis:

- If it has to be assumed that the WACC are 5 % higher vis-à-vis the EU, then import options may become significantly less attractive economically.
- Determining global supply and demand appears to be relevant for estimating future prices.

6 Summary and conclusions

Current knowledge indicates that Germany will have to rely on importing hydrogen and hydrogen derivatives to achieve its ambitious targets. The country's own economical potentials for electricity generation from renewables are too limited to be able to meet the projected demand using domestic production alone. So far, analyses of the economic viability of imports have usually been based on calculating the potential production and transportation costs. However, these calculations fall short, as the market prices for imported energy products such as gas and oil are strongly decoupled from production costs and are often significantly higher or display high price volatilities. Against this background, for the first time, an approach was presented for how to envisage a future emerging market and how to move from production costs to prices. First implementation steps were presented and conclusions drawn.

The first methodological step assumes a perfect market. Under this assumption, marginal cost pricing can be derived from the intersection of the supply and demand curves. In addition to the cost potential curves for supplying hydrogen and its derivatives, demand curves for these products have to be determined. Cost potential curves are based on techno-economic analyses. The demand curves must take into account the willingness to pay and competitive options for defossilization, which vary in different fields of application. So-called no-regret sectors, such as iron and steel or international aviation, where there are few alternatives to hydrogen and its derivatives for reducing greenhouse gases, will be prepared to pay a higher price than, e.g., road transport with its option of direct electrification. Transportation costs must also be included, which can make up a significant share of the import costs, especially for hydrogen, depending on the distance and type of transportation involved. Transporting hydrogen using repurposed pipelines is cheaper over distances of a few thousand kilometers than transporting liquid hydrogen or its derivatives by ship. This suggests that transnational price regions for hydrogen could emerge to start with along these transport routes, as is the case on today's gas market. MENA regions or regions in Eastern Europe such as the Ukraine or Kazakhstan could be exporters of interest here. Since established global markets already exist for derivatives such as methanol or ammonia produced using fossil fuels, and since transport costs over distances of more than 5,000 km have a much lower impact, global markets could also be established here for renewably produced derivatives. In addition to transportation costs, flexibility and the security of supply must also be considered in the evaluation. Shipping offers the opportunity to change transport routes at short notice, e.g., due to political unrest or price changes, and increases supply diversification. References are made here to similarities on the natural gas market.

A possible first approach to more accurate pricing is to take country-specific risks into account via the corresponding costs of capital. Equity risk premiums can be used here that are already available for countries. Calculations show that a realistic premium of five to ten percentage points on the costs of capital compared to Germany and other EU countries would have a strong negative affect on the economic viability of importing hydrogen from the MENA region compared to producing hydrogen in the EU. Quantifying country risks as much as possible is thus an important element when analyzing future prices of hydrogen and its derivatives. They also form an important basis for designing policy measures, e.g., by taking on credit default risks.

It can also be shown that different time phases should be considered when analyzing market price formation. The current state of knowledge suggests different pricing mechanisms will emerge, at least during the transitional period. These can be based on the emergence of the gas markets. After the pilot phase, it is assumed that bilateral contracts and oligopoly markets with strategic behavior will have a major role. Legal regulations and support will play important roles in shaping the market.

The concept is further developed and implemented in the HYPAT project.

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