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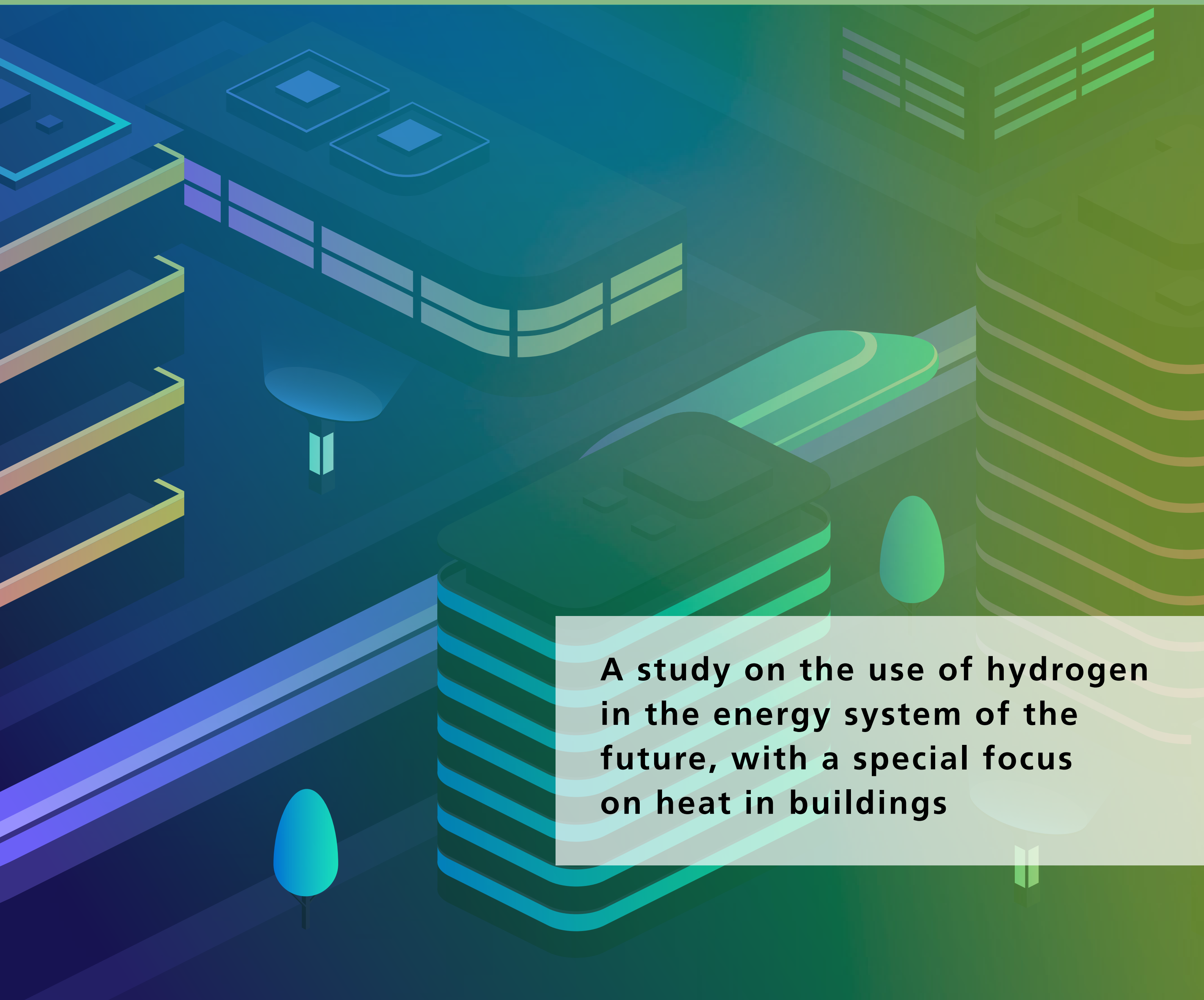
HYDROGEN IN THE ENERGY SYSTEM OF THE FUTURE: FOCUS ON HEAT IN BUILDINGS



A study on the use of hydrogen in the energy system of the future, with a special focus on heat in buildings

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HYDROGEN IN THE ENERGY SYSTEM OF THE FUTURE: FOCUS ON HEAT IN BUILDINGS

A study on the use of hydrogen in the energy system of the future, with a special focus on heat in buildings

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Executive Summary: The role of hydrogen and H_2-based decentralized heating

Hydrogen is viewed by policymakers, business leaders and scientists as an important energy carrier for the success of the clean energy transition. Numerous recent studies have investigated areas of application for hydrogen, presenting various roadmaps for the broad-based introduction of hydrogen technologies.

The energy-policy debate of recent years has often focused on how the energy system can be made sustainable while necessarily relying over the long term on the sun and wind, two key sources of renewable energy. In this discussion, a broad consensus has emerged that the direct use of electricity should be maximized whenever it is technically viable and expedient.

With a view to the heating of buildings, it is now clear that heat pumps, which extract up to three times more heat from the environment than they consume in electrical energy, are much more efficient than synthetic fuels based on power-to-gas (PtG) due to the large conversion losses of PtG (with energy being transformed in multiple steps from electricity to hydrogen, from hydrogen to methane, and then from methane to heat) [3]. Scientific studies conducted in recent years substantiate this pronounced disparity in efficiency between heat pumps and PtG. The most comprehensive study on this subject, entitled "Building Sector Efficiency: A Crucial Component of the Energy Transition," was published by the Berlin-based think tank Agora Energiewende [4].

For this study, we assessed recent studies regarding hydrogen supply, demand, and infrastructure and conducted our own analyses. In the following sections, we present our findings with regard to the role of hydrogen in the transformation of the energy system, particularly in the building sector.

A. The general role of hydrogen:

1. **The development of hydrogen infrastructure (electrolysers, grids, storage, and PtL) is essential for the success of the clean energy transition.**

   The establishment of a central hydrogen grid offers important advantages for an efficient and cost-effective transformation. The **use of hydrogen by industry and power plants must be prioritized**, since the conversion losses compared to SNG or PtG and the necessary electricity generation from renewable energies can be reduced. Priority should also be given to existing processes in which natural gas reforming **must necessarily be substituted with green hydrogen**. **A residual level of hydrocarbon demand will be unavoidable in international transport** (PtL) **and for non-energy consumption**, for which hydrogen must also be produced.

2. **Estimates show hydrogen demand of 600–1,000 TWh in Germany in 2050, depending on the share of biomass in the power mix. This demand would increase by 25–40% if hydrogen were used for the decentralized heating of buildings.**

   The 50% replacement of natural gas for the heating of buildings with hydrogen would result in an additional hydrogen demand of 250 TWh in Germany. This figure is based on a comparison of scenarios for the efficient achievement of a 95% reduction in emissions by 2050 (including the German share of international transport). By way of comparison, the Fraunhofer Hydrogen Roadmap [32] estimates 2050 hydrogen demand at 250 to 800 TWh in Germany and between 800 and 2,260 TWh in Europe (without building heating).

3. **Most of this hydrogen demand will have to be covered by imports.**

Only green hydrogen is sustainable. Between 50 and 150 TWh of sustainable green hydrogen can be produced from domestic renewable energy in Germany. The global potential for the production of green hydrogen is fundamentally high in regions rich in sun and wind. **Pipeline transport is the cheapest option** for **importing hydrogen** from neighbouring regions.

4. **The import potential from North Africa is limited and can only cover a fraction of German and European demand.**

   Under consideration of local area and site restrictions, Morocco and Tunisia together may supply 400 TWh. Yet even if hydrogen production capacities in viable North African countries were to be fully expanded, **this would only cover part of German and European demand.**

5. **Accordingly, the greater the volume of hydrogen demanded in Europe and Germany, the more expensive it will become on a unit basis.**

   Our analysis shows that land area potential with **very low costs** (H_2 production costs + import by pipeline) is very limited. Our estimates for **Morocco and Tunisia** yield **pipeline-based import prices** of 5.3–9.9 ct/kWh for compressed hydrogen and 7.6–12.8 ct/kWh for **liquid hydrogen. Imported liquid hydrogen** from regions in South America or South Africa with high average wind speeds and high solar radiation will cost at least 6 ct/kWh. Additional infrastructure costs in the importing country for storage, transport, and distribution of 3–6 ct/kWh must be added to this amount, yielding **total import costs** of 9–12 ct/kWh.

6. **Blue hydrogen based on Carbon Capture and Storage (CCS) is not carbon-neutral.**

   When blue hydrogen is produced from fossil natural gas, at best 85–95% of the emissions can be captured and injected underground. In addition, depending on the country of origin and application, 0.5–4.1% leakage occurs during pipeline transport. Therefore, blue hydrogen can at best be a bridge technology to enable early **structural change by industry**.

   The supply bottlenecks that will invariably occur in the global market ramp-up for green hydrogen is an additional factor that must be taken into account. The more hydrogen is needed in the long term, the greater the likelihood that dependence on blue hydrogen will become locked in. This would move us further away from achieving climate targets. **This situation would be significantly aggravated if blue hydrogen were to be used directly for the decentralized heating of buildings.**

B. The role of hydrogen in the decentralized heating of buildings:

1. **Hydrogen-based low-temperature heating systems consume 500–600% more renewable energy than heat pumps.**

   Taking the energy losses that arise from the conversion and transportation of hydrogen into account, it is much more efficient in terms of renewable energy demand to supply heat to buildings using heat pumps.

2. **The medium-term introduction of a 20% hydrogen share in the gas grid would only induce low reductions in carbon emissions.**

   The blending of hydrogen into natural gas grids is currently limited to 10%, and an increase to 20% is under discussion. However, this only corresponds to an energetic share of 7–8%, meaning that little would be obtained in the way of climate protection.

3. **A long-term transition to 100% hydrogen supply by repurposing existing natural gas grids is possible. However, under a decentralized heating system, enormous costs would result for the premature replacement of end-customer boilers.**

   There is significant regional divergence in the restrictions and degrees of freedom that govern hydrogen blending. These restrictions hinge on the origin of the natural gas and the characteristics of end-customer and industrial applications in each respective distribution grid. In order to exceed a 20% hydrogen blending threshold, it would be necessary to completely and abruptly switching distribution grids to 100% hydrogen supply. This would require the premature replacement of all existing natural gas boilers, a cost factor that would considerably exceed that of converting the gas grids.

4. **Supplying heat to buildings with heat pumps would ease demand for hydrogen while also considerably reducing necessary import quantities.**

   Today's heat pumps can efficiently service even buildings that have not yet undergone energy efficient retrofitting. Accordingly, the building sector would not compete with other sectors in the area of hydrogen demand.

5. **Security of supply and reliable power grid infrastructure are compatible with high heat-pump penetration rates.**

   The technical requirements associated with **ensuring security of supply during periods of no wind or sun** and for **expanding distribution grids** can be fulfilled at moderate additional cost. Electricity grid infrastructure does not represent a significant obstacle to reliance on heat pumps to supply heating energy to buildings. **The electricity required to run heat pumps can be covered in a cost-effective manner almost exclusively with domestic renewable energy sources.**

1 Introduction

There are no alternatives to renewables in the effort to establish a carbon-neutral energy system. The next phase of the clean energy transition will involve integrating the transport, heating, and industrial sectors in a comprehensive transformation process. In the building sector, a two-pronged effort is needed to make buildings more energy efficient and transform heat supply.

In Germany and Europe, the energy policy debate is currently dominated by a focus on hydrogen, which is seen as the universal energy carrier for the clean energy transition. In this debate, discussion has centered on the **direct use of hydrogen**. However, hydrogen can also be converted to a synthetic fuel using various techniques, such as power-to-liquid (PtL); power-to-gas (PtG; in this study, including methanisation) and power-to-chemicals (e.g. ethylene or naphtha). In general, a distinction is drawn between the direct use of electricity and the conversion of electricity into hydrogen and other PtX-based derivatives.

At the end of January 2020, the Federal Ministry for Economic Affairs and Energy (BMWi) presented a **draft National Hydrogen Strategy**. This document focuses on the economic opportunities for Germany as a supplier of hydrogen production systems. It also assesses the potential for a hydrogen-based transport sector. Hydrogen is seen as offering industry a competitive advantage insofar as it allows carbon emissions to be reduced or avoided [1].

Fraunhofer, Germany's largest application-oriented research organization, recently released its own **Hydrogen Roadmap**. This roadmap also places an emphasis on industrial policy, highlighting the technical potentials offered by hydrogen. However, it does not address in detail the use of hydrogen in the building sector.

In December 2019, the EU Commission presented its plan for a **European Green Deal**, which foresees a carbon neutral Europe by 2050. The European Green Deal also augments the 2030 abatement goal, ratcheting up ambition from a 40% reduction to between 50 and 55% [2]. These targets, which place the EU at the vanguard of climate policy ambition, has knock-on effects for German energy policy. Germany will assume the presidency of the European Council on 1 July 2020 and there are indications that it will use this position of influence to promote the creation of markets and infrastructure for hydrogen in the EU [1].

Furthermore, policymakers are currently working to revise the **Ecodesign Directive**[1] and the **Energy Label**[2] for space heating systems and water heaters. In this context, the EU intends to establish European-wide minimum technical standards for the installation of space and water heaters while also updating guidelines for energy consumption labels. In this regard, technical requirements for "hydrogen ready" gas boilers are currently being deliberated. With a view to the heating-system transformation pathway, two questions emerge: (1) what is the lifespan of existing boilers? And (2) can these boilers tolerate a gradual increasing percentage of H_2 in the natural gas grid, or will it be necessary to conduct early replacement of all existing equipment within a given grid area? Of course, the potentially low hydrogen tolerance of other natural-gas-based technology that is currently connected to the grid needs to be taken into account. On the other hand, there are key large-scale consumers that can be supplied with pure hydrogen. Prior to defining

[1] Review of Commission Regulation (EU) No. 814/2013 [Ecodesign]
[2] Commission Delegated Regulation No. (EU) No. 812/2013 [Energy Label]

technical standards for gas boilers, policymakers should first answer these questions concerning the overall transformation of the gas system.

The energy-policy debate of recent years has often focused on how the energy system can be made sustainable while necessarily relying over the long term on the sun and wind, two key sources of renewable energy. In this discussion, **a broad consensus has emerged that the direct use of electricity should be maximized whenever it is technically viable and expedient**. With a view to heating energy for buildings, PtG should not be considered an option due to (1) the large conversion losses it entails (electricity → electrolysis → methanisation [3] → heat) , and (2) the considerable efficiency advantage enjoyed by heat pumps (electricity + ambient heat → heat) [3].

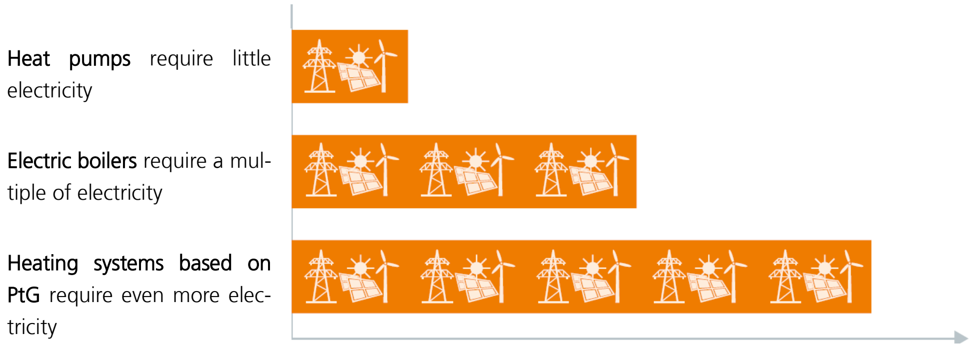


Figure 1: Electricity consumed by various technologies to replace one unit of fossil-fuel-based heat

Source: [3]

Scientific studies conducted in recent years substantiate this pronounced disparity in efficiency between heat pumps and PtG. The most comprehensive study on this subject, entitled "Building Sector Efficiency: A Crucial Component of the Energy Transition," was published by the Berlin-based think tank Agora Energiewende [4]. This study undertakes a detailed assessment of various issues, such as how the technologies used to heat buildings impact German and European energy systems, and how a growing proportion of heat pumps impacts local power distribution grids. It also models system-transformation costs, including expenditures to retrofit the building stock. A key finding of the study is that the **cheapest scenario for transforming the system is to retrofit buildings at a medium pace in combination with the large-scale deployment of heat pumps**. By contrast, heavy reliance on PtG is the least favorable scenario option, not only with a view to technology costs, but also in terms of energy consumption. Figure 2 below shows 2011 energy consumption in Germany as well as energy consumption associated with the "Efficiency[2]," [4] "Efficiency + Heat Pumps (HP)," [5] "Efficiency + Power to Gas (PtG)," [6] and "Business as Usual (BAU) + PtG" [7] scenarios.

[3] $H_2 + CO_2 \rightarrow CH_4$
[4] Very high retrofit rate and lowest heat demand; mixed technology use.
[5] High retrofit rate and medium heat demand; more heat pumps.
[6] High retrofit rate and medium heat demand; more gas boilers.
[7] Low retrofit rate and higher heat demand; even more gas boilers.

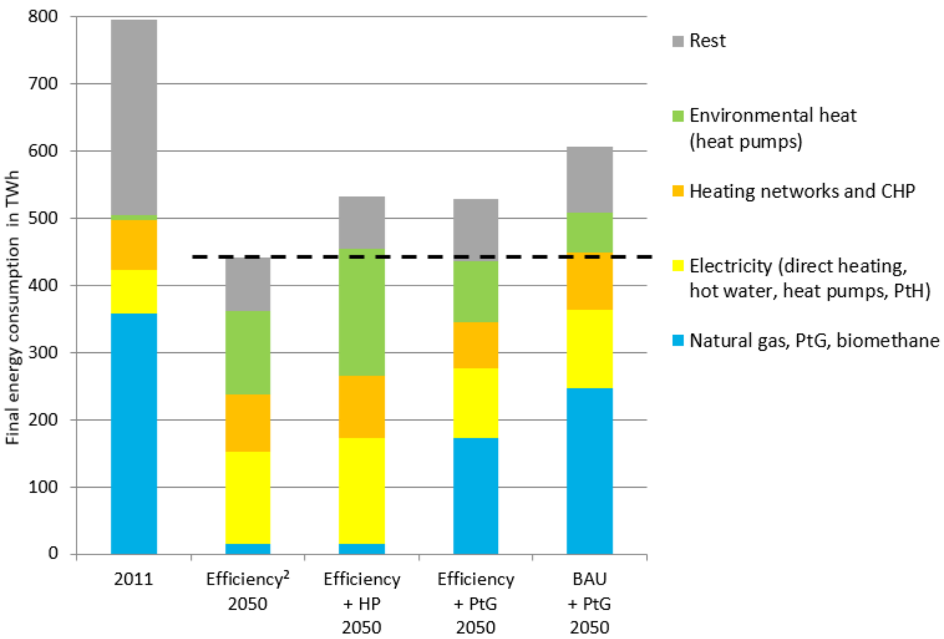


Figure 1: 2050 energy consumption in the building sector in various scenarios

Source: Authors' figure based on [4]

The dashed line in Figure 2 allows comparison between the last three scenarios and the Efficiency² scenario. The Effizienz² scenario represents the base line in the following Figure 3, which compares the average discounted cost differentials (from today to 2050) of the three scenarios with the Effizienz² scenario. When comparing costs, the Efficiency + Heat Pumps scenario generates net savings of €2.89 billion annually, while the Efficiency + PtG scenario generates net supplemental costs €3.72 billion annually. For its part, the Business as Usual (BAU) + PtG scenario produces net supplemental costs of €8.15 billion annually. The net supplemental costs are denoted with a black line.

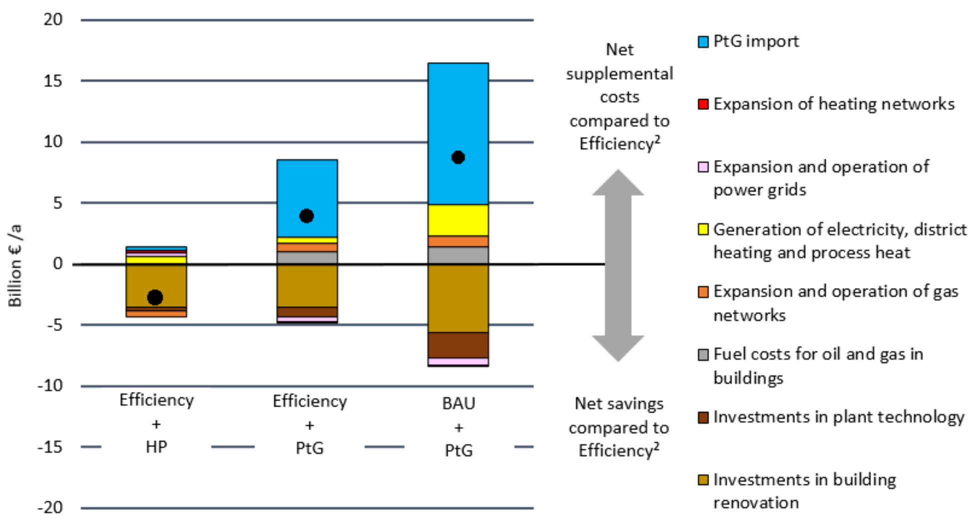


Figure 2: Average discounted cost differentials of the scenarios in relation to Efficiency²

Source: Authors' figure based on [4]

These scenarios clearly indicate that synthetic fuels have a significant cost disadvantage as a solution for decentralized heating. With a view to current discussion regarding the use of hydrogen, however, the following question emerges: To what extent do the lower conversion losses associated with hydrogen in relation to PtG (hydrogen has a 75% efficiency rate, as opposed to 60% for PtG[8]) make it necessary to revise the previously established consensus regarding the optimal long-term solution? An additional option under consideration is to process natural gas using advanced carbon capture and storage (CCS) in order to produce blue hydrogen. In this way, an additional question is: What impacts would the implementation of blue hydrogen have on the energy-system conversion pathway? When the focus is narrowed to applications in industry or in gas-fired power plants, the currently discussed transformation of infrastructure toward greater reliance on hydrogen offers the potential to make the clean-energy transition more efficient and less expensive. With a view to a decentralized system supplying heating energy, however, a more nuanced assessment of the potential offered by hydrogen is required.

This study critically examines these questions in order to arrive at evidence-based conclusions. The first part of the study discusses potential future demand for hydrogen in all applications in addition to potential hydrogen supply. An assessment is then conducted of required changes to existing natural gas grids, as well as to the need for new hydrogen infrastructure, both in general and with a view to decentralized building heating. The next section addresses the opportunities and possible hurdles associated with a heating system that is predominantly based on heat pumps. The final part of the study draws conclusions based on the presented scenarios.

[8] Efficiency measured in terms of calorific value (CV). By comparison, the conversion efficiency of future electrolysis plant is expected to be 88%.

2 Fields of application for hydrogen energy: An assessment

With regard to efficiency, a distinction must be drawn between the direct use of hydrogen and its further processing using PtL or PtG. Furthermore, it is necessary consider the technological contexts in which hydrogen can act as a replacement to existing forms of energy, and the potential alternatives to this usage that exist. Existing studies that model the future energy system in Germany come to strongly divergent conclusions regarding future hydrogen demand, primarily because of differing assumptions regarding hydrogen's areas of application. However, these studies are united by the fact that they do not take into account the current discussions regarding the development of a hydrogen infrastructure. In order to conduct a comparison of these studies, it is necessary to adjust their conclusions using a ranking system.

2.1 Study rankings from an energy system perspective

1. Current areas of application for grey hydrogen (hydrogen manufactured from natural gas)
The replacement of natural gas reformers with green hydrogen – especially in ammonia and methanol production, but also in refineries – is the option with the highest efficiency – that is, the option that leads to the greatest carbon emissions savings over the medium term, as well as the most efficient use of electricity over the long term [5]. Alternatively, some studies (see Section 2.2) assume carbon capture and storage of reformer emissions, which is comparable to blue hydrogen, in addition to the use of PtG.

2. Direct use of hydrogen in industry
The **direct use of hydrogen, e.g. for process heat in industrial facilities, is also highly efficient.** Particularly in steel production, there is a great potential for reducing greenhouse gas emissions, namely by replacing the existing carbon-based reduction of iron ore with hydrogen-based direct reduction in blast furnaces. The hydrogen that is used today as an inert gas, which is obtained from natural gas reforming, can also be replaced by green hydrogen. A complete substitution of coal or coke demand in steel production would result in additional hydrogen demand in Germany of 2.4 Mt H_2/a, which is equivalent to 80 TWh/a [6]. The share of steel that is recycled is to be increased from 25% today to 50% over the long term, which will result in a 25% reduction in required hydrogen quantities, thus reducing future demand to around 60 TWh/a.

3. Direct use of hydrogen in power stations and CHP plants
Hydrogen can also be used in the future to replace natural gas as a fuel for electricity generation in power stations and combined heat and power (CHP) facilities. This allows methanation losses to be avoided. When there is insufficient feed-in from renewables, CHP facilities can be used to **generate industrial process heat and district heating.** In addition, security of supply can be assured, even without CHP heat generation.

In general, it is only efficient to use hydrogen for the centralized generation of heat energy when this heat energy cannot otherwise be produced electrically using electrode boilers or large heat pumps. However, the use of hydrogen as a substitute for biomass (e.g. waste wood) must be discussed here.

4. Unavoidable consumption of hydrocarbons
In the domain of international air and sea transport, there are virtually no technical alternatives to the use of liquid fuels. Accordingly, hydrogen can only be used indirectly in international transport following conversion using PtL. PtL production is also required for

the replacement of existing fossil resources (such natural gas and naphtha) in the chemicals industry. Examples of regeneratively produced hydrocarbons include industrial soot production from PtL hydrocarbons and plastic production from ethylene. PtL conversion of hydrogen is also required to replace natural gas combustion in high-temperature furnaces.

5. Direct use of hydrogen in transport

From a present-day perspective, the role that hydrogen will play in the road transport of the future is unclear. Nevertheless, the emission standards that are adopted over the next ten years will be a decisive factor for car and truck manufacturers. Accordingly, **in comparison to electric vehicles, hydrogen-based propulsion technologies will reach market readiness too late.** This fact is underscored by the limited availability of hydrogen fueling stations: there are less than 100 such stations in Germany at present. Due to these medium-term dynamics, a significant long-term role for hydrogen appears unlikely. In the domain of truck transport, the cost and efficiency difference between hydrogen and electric propulsion technologies is smaller. However, there are already a broad spectrum of battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs) in the domain of truck transport, including fast-charging stations and trolley-truck infrastructure. In addition, small quantities of PtL fuels can be used to extend vehicle range. Hydrogen will gain in importance if policymakers fail to facilitate the expansion of trolley-truck infrastructure. In the area of passenger vehicles, the cost and efficiency differences are larger, and the adoption of electric vehicles depends to a greater extent on customer preferences. Compared to the domain of truck transport, a larger network of hydrogen filling stations will be required for the broad based adoption of hydrogen-fueled passenger vehicles. By contrast, the use of fuel cells in efficient niche applications for ships and trains that cannot be electrified will avoid the high efficiency losses associated with PtL production and combustion.

6. Direct use of hydrogen for low temperature heat

In the domain of low-temperature heat, hydrogen must compete directly with the heat pump, a highly efficient technology. As total demand for heat energy in this area of application is very high, one must consider whether a sufficient supply of hydrogen would even be available for this purpose (see Section 3).

In the domain of district heating and industrial process heat, large heat pumps can be used to supply the necessary heating energy. Existing studies project district heating to be significantly expanded, such that 20%–35% of the building stock is serviced by district heating grids, in order to efficiently supply densely populated areas with heating energy. The environmental heat (e.g. from river water or purification plants) that is available for expanding district heating varies greatly from region to region, however [7]. Further investigation is required to determine the extent to which hydrogen can play a role as an energy source in hybrid district heating systems when there are regional limitations to renewable heat potential.

With a view to the decentralized supply of heating energy to buildings, modern air-source and geothermal heat pumps are technical capable of covering the heating demand of up to 80% of the building stock (see Section 5). As in the domain of road transport, the German climate targets for the building sector (which foresee an emissions reduction of 66% by 2030 compared to 1990) and European burden sharing for the non-ETS sector (which foresees a 38% reduction in emissions by 2030 compared to 2005) create strong pressures for action over the medium term, as meeting the targets will otherwise become inordinately expensive. This means that it is **too late from a technical perspective to implement hydrogen**. Due to the long lifespans of boilers and the restrictions associated with market ramp-ups (e.g. limited contractor availability; time-intensive conversion of production capacities), **lock-in effects must be avoided**. In addition, the requirements and costs associated with hydrogen gas grid infrastructure must be reflected at the household connection level (see Section 4).

This study assumes that hydrogen condensing boilers would be the preferred technology for the decentralized supply of individual buildings with heating energy. We do not consider PEM stationary fuel cells, as over the long term this technology would lead total power demand to significantly exceed available wind and PV power supply. CHP operation should be focused on the creation of heat sinks, as this allows the highest level of efficiency. Gaps between renewable power generation and demand are expected to occur at low demand levels and outside the winter heating period. In comparison to centralized CHP plants, decentralized deployment of PEM fuel cells would have significant cost disadvantages while also lacking benefits in terms of efficiency. The broad-based application of this technology is therefore not considered by this study. However, there is still a need for research on large and efficient solid oxide fuel cells (SOFCs), which can be used for district heating, for industrial process heat, and, if necessary, for process heat in commercial real estate. Particularly in the event of technical restrictions due to methane slip in lean-mix CHPs (see Section 3.1), changes in the CHP sales market may occur in the future. However, this issue is beyond the scope of this study.

2.2 Current and future hydrogen demand

Current trends: Substitution of grey hydrogen
In Germany, methanol and ammonia production volumes are not anticipated to rise sharply in the long term, and refineries are expected to see a decline in fossil fuel production volumes over the long term. In these areas of application, therefore, **the volume of fossil-based hydrogen that will need be substituted in Germany** is anticipated to fall over the long term from 1.7 Mt H2/a (57 TWh/a) today to about 1.1 Mt H2/a (36 TWh/a) in 2050 [8].

Anticipating the future: Forecasted hydrogen demand in energy system studies
In order to evaluate fields of application for hydrogen, we first consider four different studies that model the future of the German energy system. These studies develop various scenarios for total energy demand in coming years. None of these studies consider the development of a hydrogen economy as is currently being discussed.

- **Klimaschutzszenario 2050** [Climate Protection Scenario 2050] was developed by Öko-Institut and Fraunhofer ISI on behalf of the Federal Ministry for the Environment, Nature Conservation, Construction and Nuclear Safety (BMU). It models a 95% GHG reduction over 1990 by 2050 [9].
- **Paths for Achieving Resource-Conserving Greenhouse Gas Neutrality**, also known as the **RESCUE study**, was conducted by the Federal Environmental Agency (UBA). This study's "GreenEe1" scenario envisions a "very high" reduction in greenhouse gas emissions by 2050 [10].
- The study **Climate Paths for Germany**, conducted by Prognos AG and the Boston Consulting Group on behalf of the Federation of German Industries (BDI), also forecasts emissions reductions of 95% over 1990 by 2050 [11].
- **Leitstudie Integrierte Energiewende** [Lead Study for an Integrated Energy Transition], conducted by the German Energy Agency (DENA), presents a 95% GHG reduction over 1990 in its "Technology Mix Scenario TM95" [12].

In addition, we draw on current data from the "Energy Transition Barometer" maintained by Fraunhofer IEE. On the basis of various scenarios that are regularly updated, this barometer illustrates potential options for the energy system of the future. The latest version can be found at the Fraunhofer IEE website [13].

The first three studies mentioned above are united in forecasting that a large share of energy for heating buildings will be provided by decentralized heat pumps in combination with expanded district heating grids that rely on high-capacity heat pumps. In the transport sector, electric passenger cars achieve very high penetration rates, and trolley truck networks are also expanded. These studies also foresee significant progress in the energy efficient retrofitting of the building stock, although they neglect the effects of urbanization and demographic change in rural and structurally weak areas. Finally, it must be mentioned that none of the studies consider the development of a hydrogen economy. Comparing the studies to one another, the following points of difference emerge: the BMU and UBA scenarios assume high resource efficiency, while the BDI scenario assumes average resource efficiency. By contrast, the DENA study shows relatively high resource consumption, and power-to-x demand is very high.

The **BMU scenario** only foresees the use of blue hydrogen in steam reforming, and green hydrogen is only used to a very limited extent for electricity generation. The scenario also assumes a comprehensive transition to sustainable transport. Performing our own calculations based on data from this study, we conclude **demand for hydrogen from primary sources of consumption would total 654 TWh/a**. This figure is a composite of direct hydrogen consumption, hydrogen for international transport, non-energy consumption, and residual demand.

The **UBA scenario**, by contrast, does not foresee the use blue hydrogen, and green hydrogen is only used in the chemicals and steel industries. In this scenario, there is a partial transition to sustainable transport. Performing our own calculations based on data from this study, **we estimate total hydrogen demand at 1,052 TWh/a.**

The **BDI scenario** envisions the use of blue hydrogen only for steam reforming, and the use of green hydrogen to a very limited extent in transport. In the heating sector, no hydrogen consumption is presumed, nor is hydrogen used to generate electricity, meaning the figures for natural gas must be converted to estimate hydrogen demand. This scenario does not expect a comprehensive transition to sustainable transport, and transport activity remains high. **Own calculations based on data from this scenario estimate total hydrogen demand at 1,095 TWh/a.**

The **DENA study** assumes reliance on a wide range of energy sources and technologies in the industrial, buildings, and transport sectors. Electric heat pumps and gas and oil heating systems, among other technologies, are used to provide heating energy to buildings. In the industrial sector, the energy supply mix is anticipated to remain largely unchanged, with the exception of greater reliance on natural gas. In the transport sector, the vehicle fleet is composed of a mix of conventional and electric vehicles. Based on data from this study, **we estimate total hydrogen demand at 1,621 TWh/a.**

The **Energy Transition Barometer** estimates 2050 final energy demand of 1,594 TWh/a, broken down as follows: 208 TWh for households, 183 TWh for the commercial/retail sector, 530 TWh for industry, 299 TWh for domestic transport, 168 TWh for international transport, 114 TWh for raw materials, and 92 TWh for maritime transport. **Hydrogen demand in 2050 is estimated at 192 TWh for direct use, 306 TWh for international transport and non-energy consumption, and an additional 68 TWh for residual demand.**

The left-hand side of Figure 3 shows the final energy demand forecasted by the four scenarios and the Energy Transition Barometer. While final energy consumption in Germany stood at 2,841 TWh/a in 2015, the predicted figures for 2050 range between 1,449 TWh/a (UBA) and 2,078 TWh/a (DENA). The right-hand side of Figure 4 shows estimated hydrogen demand in 2050. None of the scenarios assume direct consumption of pure hydrogen for heating energy in the building sector; PtG is used to heat buildings in the DENA study, however.

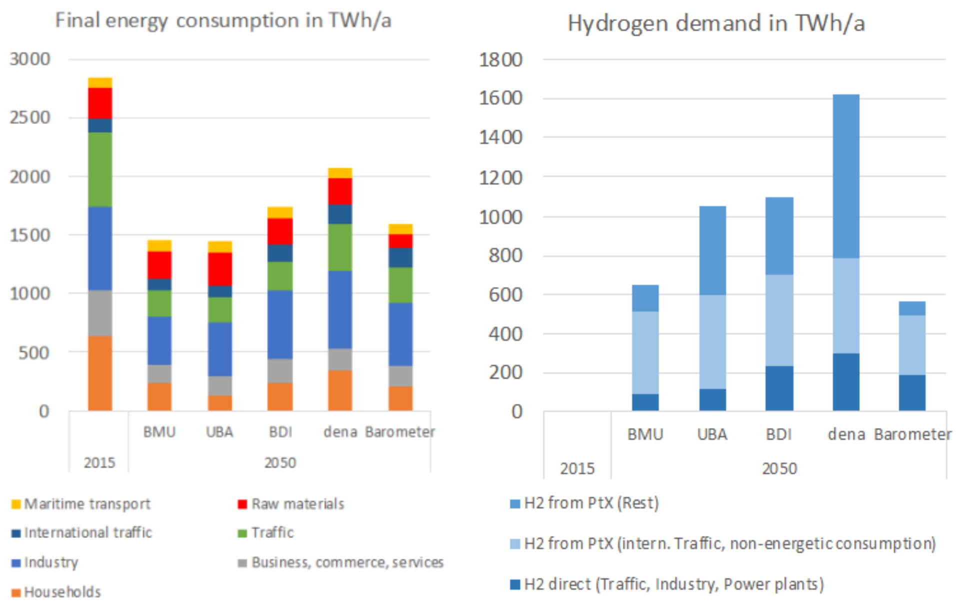


Figure 3: Final energy consumption and hydrogen demand in the various scenarios

Source: Authors' figure based on [9–13]

2.3 Conclusions

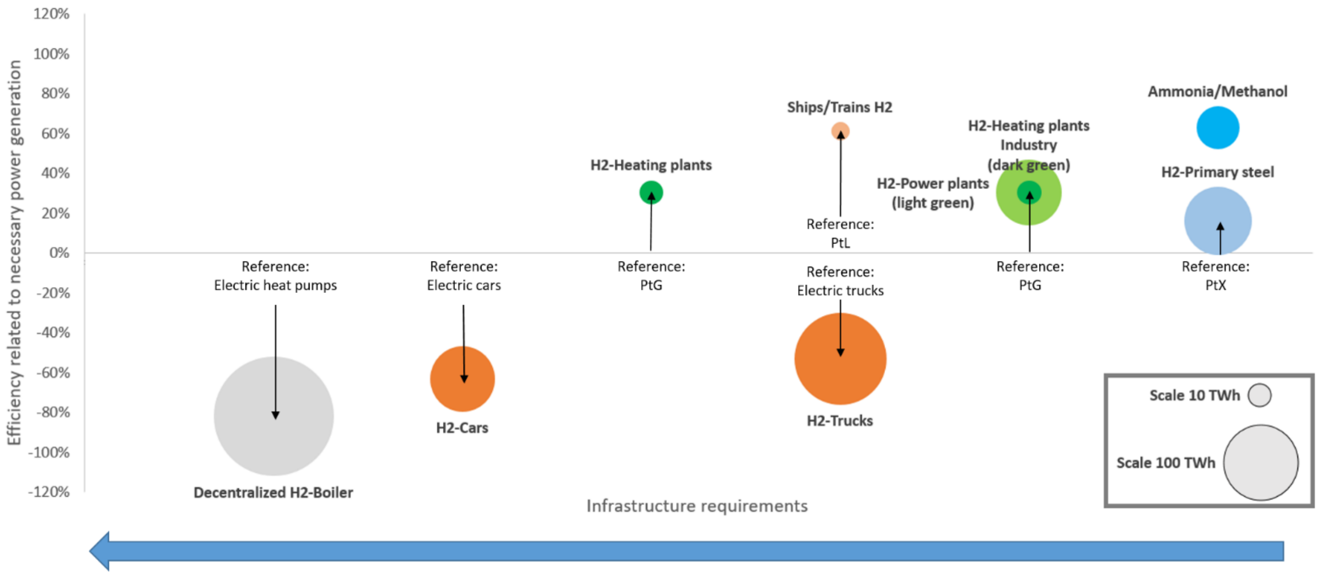
Section 2 showed the need to determine the **priority with which hydrogen should be used, i.e. within the sense of a ranking system. This ranking should be based on the efficiency of the application in question and should take place when there are no alternatives to hydrogen.** The use of hydrogen is beneficial in the industrial sector (e.g. for ammonia, methanol, and steel production) and in power plants, both with or without CHP operation. Hydrogen use is also necessary to produce PtL fuels for international transport and for raw materials such as ethylene in non-energy consumption.

The role that hydrogen will play in road transport remains unclear, however. The reliance on electric vehicles is maximized in the considered scenarios. In scenarios with a high share of chemical fuels, annual hydrogen demand for road transport alone would amount to some 220 TWh. Approximately two-thirds of this demand would be attributable to heavy freight transport. In this connection, we assume that there will be approximately 5,000 hydrogen filling stations, some 10 million fuel cell passenger cars, and about 100,000 fuel cell trucks. Calculations based on the IEE scenario, which foresees a 95% GHG reduction, indicate hydrogen demand of 566 TWh (for chemicals production and energy needs in industry; for PtG and PtL fuels in the transport sector; and for the German share of international air and sea transport). Due to the assumption that the energy efficient retrofitting of the building stock will only proceed at a moderate pace, in this scenario heating energy for buildings is covered by heat pumps, which results in electricity demand of 113 TWh/a (specifically, 85 TWh for decentralized heat pumps and 28 TWh district-heating heat pumps).

Alternatively, if the current 50% share of demand covered by natural gas in building heating were to be replaced with hydrogen, then **hydrogen demand for combustion purposes would increase by 250 TWh. Accordingly, reliance on hydrogen in the building sector alone would lead to a 25–60% increase in German hydrogen demand.**

Figure 4 ranks the various areas of application for direct hydrogen use in terms of their efficiency (i.e. increased or reduced electricity consumption compared to the reference technology) and infrastructure requirements (centralized or decentralized and yearround/seasonal). These estimated demand figures are based on the previously presented data.

Figure 4: Assessment of hydrogen's direct application potential according to efficiency and infrastructure requirements in 2050
Source: Authors' figure



3 Global demand and green hydrogen production in Germany

This section discusses various techniques for producing hydrogen, including the associated color-based nomenclature. A primary focus is placed on **green and blue hydrogen.**

3.1 Hydrogen production options

Color-based nomenclature
In the domain of hydrogen production, a colour system is used to refer to hydrogen types.[9] Figure 5 provides a simplified representation, ignoring direct comparison between types. In current discussion regarding medium and long-term solutions, a particular focus is being placed on the volume of **carbon-neutral green hydrogen** that can be produced at an acceptable cost. The quantity of **low-emission blue hydrogen** that can be produced over the medium term, and at what cost, is additional issue for discussion. Other hydrogen production techniques are less relevant, as explained below.

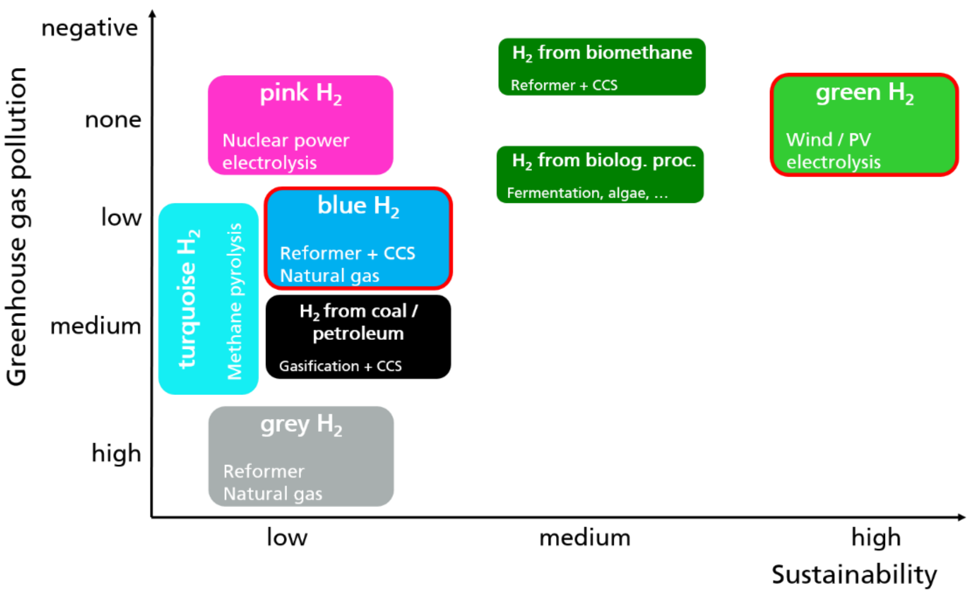


Figure 5: Hydrogen types: A qualitative comparison

Source: Authors' figure

The GHG impact of hydrogen produced using natural gas, and other types of hydrogen production
The fact that natural gas-based hydrogen, despite CCS, cannot be described as CO_2-free, but rather only as low in CO_2, is due in particular to the emission effect of methane slip (i.e. the emission of CH4 from leakage or incomplete combustion), which occurs throughout the entire natural gas process chain (extraction, processing, transport, distribution, and use). **Methane slip** can have a strong climate impact over the short term. The global warming potential (GWP) of a ton of methane is 34 times higher than that CO_2 over a time frame of 100 years; over 20 years, methane is 86 times as powerful as CO_2. The short-term potency of methane is particularly relevant considering the tipping points in our climate system (e.g. the melting of polar ice caps or artic methane release). Once these tipping points have been reached, it will be impossible to return to climate equilib-

[9] White hydrogen is not considered in this figure. It is naturally occurring in some parts of the world, such as Africa, but has limited exploitation potential. It can also be produced through fracking.

rium that formerly prevailed, even following a lowering of methane levels in the atmosphere [14]. Figure 6 shows the global warming potential of methane over time. The x-axis shows the number of years since initial release into the atmosphere. The y-axis shows GHG potency in comparison to carbon dioxide.

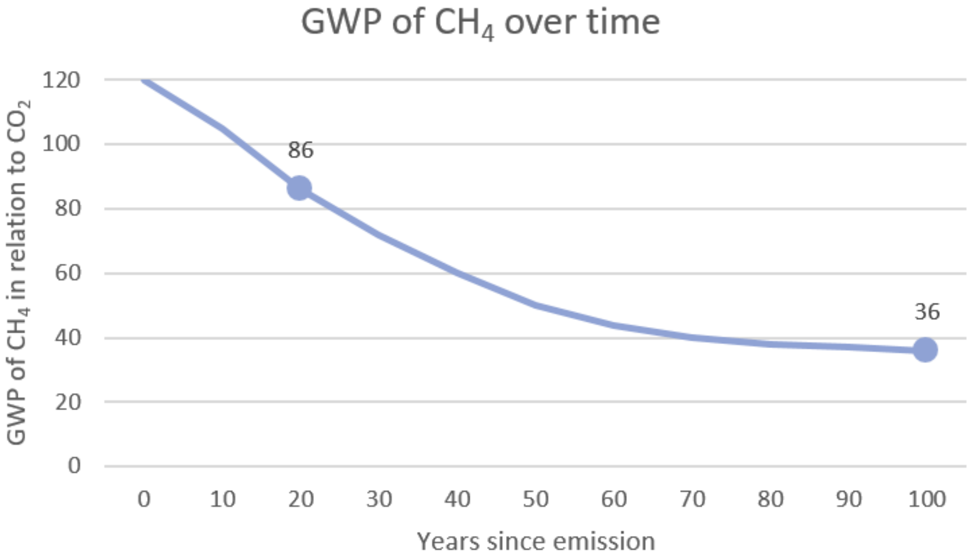


Figure 6: Global warming potential of methane over time

Global Warming Potential (GWP)

Source: Authors' figure, as in [15], based on [16]

Available data concerning the magnitude of the methane slip problem are plague by uncertainty; experts are working to better understand this issue [17]. The volume of emissions also needs to be assessed individually in relation to the country in question, grid level, and area of application. The range that is presented in Figure 8 is in agreement with the estimates produced by various sources, from environmental scientists to the natural gas industry.[10] Yet it must also be mentioned that there are various technical options for further reducing methane leakage. Unintended leakage is also a problem with carbon capture and storage (CCS), as CCS generally has a capture rate of 90%. Similarly, there are invariably upstream losses in the transport of natural gas.[11] With a view to the present study, these emissions are relevant for the assessment of blue hydrogen and for the blending of hydrogen to natural gas (which would keep natural gas emissions elevated over a long time frame). Figure 7 shows minimum and maximum estimates for the impact of the methane slip, which is most pronounced over a 20-year time domain.

[10] [18], [19] and [20] estimate methane slip at between 0.5–4.1%, depending on the application and country in question (see Figure 7), while based on [21], Zukunft Erdgas GmbH assumes a mean value of 0.6% for methane slip.

[11] Upstream CO_2 emissions (from combustion) can be reduced by electrifying gas compressors and expansion valves. In addition, CCS is increasingly being used to reduce emissions from natural gas extraction. The lower value shown in Figure 10 presumes the application of these options.

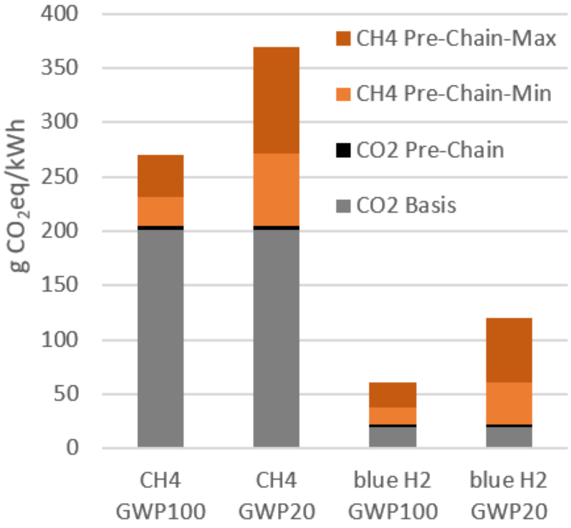


Figure 7: Estimated ranges for methane slip

Global warming potential over a period of 100 years (GWP100) and 20 years (GWP20)

Source: Authors' figure based on [16]

Methane pyrolysis (turquoise in Figure 5) has the advantage of allowing the decentralized production of hydrogen, without the need to develop hydrogen or CO_2 infrastructure. However, turquoise hydrogen is significantly less efficient than blue hydrogen (as production requires natural gas, electricity and high-temperature heat, and some 40% of the energy remains stored in the graphite). While this graphite can be used to replace coke-based graphite, graphite demand is limited, such that a supply glut would result if the use of this hydrogen production technique were significantly expanded. In the case of large production quantities, therefore, there would be significant **energy losses** associated with graphite sequestration as a carbon sink. In this way, compared to blue hydrogen, turquoise hydrogen leads to higher natural gas consumption and, by extension, higher costs. In addition, there is higher methane slip and consequently higher emissions and, depending on the graphite substitution effect, a wider range of emissions. Given these clear disadvantages, methane pyrolysis is not considered further as part of this discussion.

Pink hydrogen is hydrogen produced through electrolysis using electricity from nuclear power plants. The production potential for this type of hydrogen is limited, however, given the lower number of new nuclear plants and their power production costs. This type of hydrogen also cannot be characterized as sustainable, given issues related to operational safety and toxic waste disposal.

Low-CO_2 hydrogen can also be produced **from coal or petroleum** through gasification, given the use of CO_2 capture and storage. Hydrogen can also be produced from **biomass** using various techniques. However, limitations to biomass availability and high production costs militate against their large-scale application.

White hydrogen refers to naturally occurring geological hydrogen. First discovered in the 1970s as underground hydrothermal systems, today white hydrogen is known to occur in the form of subterranean free-gas deposits, as deposits in rock formations, and as a dissolved gas in groundwater. Various research projects and drilling experiments are still seeking to determine the technical and economic feasibility of tapping these deposits. In recent years, an increasing number of natural hydrogen deposits have been discovered that are considered suitable for exploration. Little is known, however, about the geochemical mechanisms that lead to the formation of geological hydrogen or the associated transport mechanisms within the earth's crust. Accordingly, reliable estimates of production potential have not been produced, and viable exploration strategies have yet to be developed. For this reason, we have not included white hydrogen in figure 6, nor do we seek to estimate it future production potential [22].

Blue hydrogen

Steam reforming with CO_2 capture and storage is currently being discussed as the most important alternative to green hydrogen. It must be considered that natural gas reforming has an efficiency loss of 20–25%. Approximately 85–95% of CO_2 emissions can be captured and stored in natural gas reservoirs, meaning 5–15% of the CO_2 is released into the atmosphere.[12] In addition, methane slip occurs, which would be higher in the case of hydrogen supplied from Russia or in the case of domestic reforming with CO_2 removal than in the case of offshore reforming or hydrogen imports. **Assuming natural gas prices and production costs remain constant at over €50/MWh for blue hydrogen, CO_2 avoidance costs of over €150/t CO_2 would be incurred**. In order to prevent CO_2 from entering the atmosphere during carbon capture and storage, regulations require the carbon dioxide to remain completely and permanently underground. In the event of leakage, harmful effects can result for the groundwater and soil.

The **effective monitoring** of above-ground facilities, especially for transport and storage, is therefore a mandatory prerequisite for the use of CCS, but the monitoring technologies required in this regard are not yet available. In addition, there are uncertainties regarding available geological storage capacities and the natural conditions that make for suitable storage sites. While former natural gas and petroleum extraction sites are viewed as preferable storage locations, carbon storage in saline aquifers or under the ocean floor is also being considered. Given these factors, the large-scale use of blue hydrogen over the next decade on the basis of conventional CCS is just as implausible as the large-scale use of alternative processes, e.g. pyrolysis-based hydrogen production, which is still under development [23].

On the other hand, gaseous CO_2 storage is seen as one of several options for avoiding emissions or achieving negative emissions (via BECCS[13] or DAC[14]). One point of discussion at the present time is whether blue hydrogen can enable structural change in the industrial sector by serving as a bridge technology. This option is relevant to the extent that it is not possible to supply industry with green hydrogen over the medium term because of insufficient renewables feed-in and competing forms of direct power use.

Green hydrogen

The **electrolytic production of hydrogen** is currently experiencing strong cost declines. Upfront investment costs as low as €200/kW are currently being touted for **alkaline electrolysis** [27]. While some industry observers claim this cost figure is unrealistically low, it is nevertheless clear that fixed investment costs (CAPEX) are falling much faster than expected. Be that as it may, operating costs (OPEX), including power procurement prices, are more important for the economic feasibility of a hydrogen production operation. In this connection, one must differentiate between, on the one hand, hydrogen production using surplus electricity during power production peaks, and, on the other hand, hydrogen production using renewable energy systems that have been specially constructed for this purpose. Setting aside the issue of power price components, in the case of production based on surplus power, the hydrogen production will be economically competitive, but limited in terms of output potential. Accordingly, government subsidies would be required to ensure production at the necessary scale. In the second case – that is, of dedicated renewable energy facilities for hydrogen production – the operating costs for facilities in Germany are very high. As a result, in addition to reliance on offshore wind

[12] E3G_2020_Briefing_Wasserstoffstrategie.
[13] BEECS → Bio-energy with carbon capture and storage.
[14] Direct air capture.

power, it would be economically advised to undertake the hydrogen production in a foreign country.

Conclusions
Blue hydrogen is not emissions free; rather, it is low in emissions.[15] The blending of hydrogen in the natural gas grid still leads to methane slip over an extended time frame. This represents a distinct disadvantage of blending at gradually increasing rates in comparison to conversion to 100% hydrogen for key areas of application, in tandem with structural change in industry. At the same time, expert opinion on the opportunities and risks associated with carbon capture and storage diverge considerably, meaning this issue cannot be adequately assessed at this time. However, due to the residual emission impacts of blue hydrogen – including in particular that of methane over short times scales – it is clear that at best, blue hydrogen can only be a transitional solution, and not a long-term option. **Accordingly, green hydrogen should be preferred in all areas of application, as it is the only form of hydrogen that is truly sustainable.**

3.2 Global production of hydrogen and its import

A global and European perspective – Classifying hydrogen demand
With a view to the global market for hydrogen, potential demand is the only parameter that has been estimated in studies to date. **By contrast, with a view to production potential, only country-specific studies have been performed**. The largest share of global hydrogen demand, which stood at 74 Mt/a (2,457 TWh/a) in 2018, is attributable to applications requiring pure hydrogen, such as ammonia production (which accounts for 42% of demand) and refineries (which account for 52%). This hydrogen is mainly obtained from natural gas reforming, but is also partly produced using crude oil or coal. In addition, hydrogen is a by-product of chemical processes such as chlorine-alkali electrolysis; this accounts for production totaling 48 Mt/a (1,593 TWh/a). This hydrogen, which is utilized in the form of hydrogen-rich mixed gases, is combusted or used in methanol or steel production, among other applications. Since the beginning of the 1990s hydrogen demand has approximately doubled worldwide [28].

As a result of global economic and population growth, **ammonia and methanol demand** is expected to increase by approx. 30% up to 2030, leading to a concomitant rise in demand for hydrogen in the chemicals industry. **Hydrogen demand will also be augmented by new applications (see Section 3).** Despite efficiency measures, **fuel consumption in the global aviation industry** is expected to rise from about 2,400 TWh/a today to about 3,700 TWh/a in 2030 and to 6,700 TWh/a by 2050 [29]. Moreover, **international maritime transport** currently accounts for fuel demand of 4,500 TWh/a.

Fuel consumption in the EU is expected to increase over the medium term up to 2030, bringing PtL consumption to 686 TWh/a for air transport and 582 TWh/a for maritime transport over the long term.[30] The considered scenarios make divergent predictions regarding green hydrogen demand growth. These predictions vary – in some cases considerably – according to the expected degree of electrification in each energy sector, the bioenergy share, and expected cost reductions in hydrogen production and transport technologies. **The 2050 forecasts for global hydrogen demand range from current demand levels to almost 22,000 TWh/a** [31]. Anticipated green hydrogen demand also varies by sector. In the considered scenarios, the share of demand attributable to the

[15] In addition to CO_2 emissions that result from incomplete CO_2 capture in CCS, CH4 emissions occur due to methane slip, which is why blue hydrogen must correctly be described as low in CO_2 equivalents, rather than merely low in CO_2.

transport sector ranges between 28% and 88%. In all scenarios, however, it is the sector responsible for the largest share of demand. For the EU, plausible demand in 2050 ranges between 800 and 2,259 TWh/a; for Germany, it ranges between 250 and 800 TWh/a [32].[16] Some of this demand will take the form of direct hydrogen consumption, while some will take the form PtL or PtG. The Fraunhofer Barometer anticipates total demand of 566 TWh/a, of which 249 TWh takes the form of direct hydrogen consumption (including 57 TWh of hydrogen imports, which are processed nationally to ethylene for non-energy consumption) [13]. Figure 8 depicts forecasted demand levels.

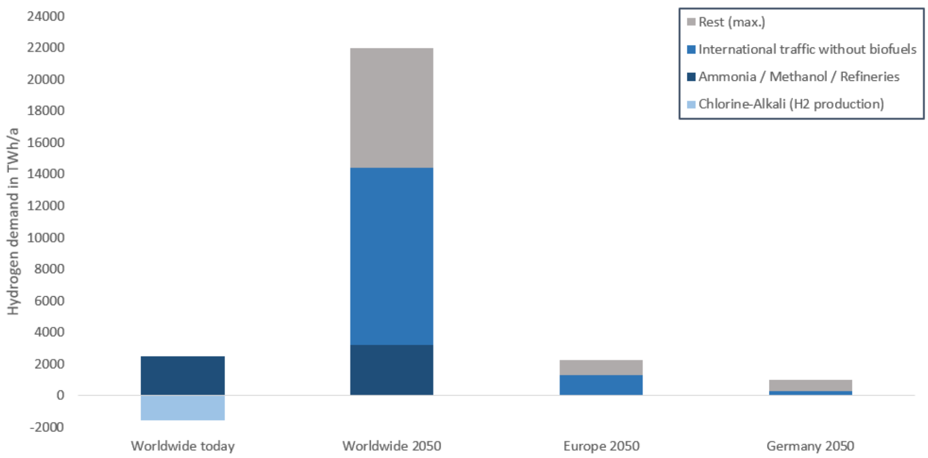


Figure 8: Hydrogen demand in Germany, Europe, and worldwide

Source: Authors' figure

Hydrogen supply from a global, European, and German perspective (hydrogen imports)
Internationally, some locations enjoy preferential conditions for export-oriented green hydrogen or PtL fuel production, such as Australia or Patagonia. As liquid H2 is more expensive, from a European perspective it would be economically sensible to import hydrogen in gaseous form by pipeline from North Africa.

In order to model possible international locations for the production of green hydrogen and the resulting import volumes and costs for Germany, we carried out an assessment of suitable locations, including a cost analysis, of two countries in North Africa that are relatively stable politically and have existing natural gas connections to Europe: namely, Morocco (extensive wind and PV resources) and Tunisia (PV resources only). This analysis allows us to generate representative insights. Our assessment of suitable locations is based on the *Devkopsys* project [33]. The first step is to exclude areas that are not suitable for renewables production or for which restrictions exist to hydrogen production using water electrolysis. From the maximum theoretical area of available land (considering land use, protected areas, slope inclination, and population density), the remaining areas are then circumscribed based on maximum permissible distances (e.g. to seawater desalination, available manpower, port infrastructure). A further reduction is performed based on maximum permissible electricity production costs. When estimating technical and economic potential, it is also necessary to take into account societal and ecological requirements [34]. Against this backdrop, we assume 50% of the identified potential areas will be used to cover local energy demand.

The selected regions identified in this manner for export-oriented green hydrogen production are now assigned an area requirement figure, a renewable energy to electrolysis output ratio, and efficiency and utilization factors for electrolysis in order to estimate hydrogen production volumes. **Two options for the transport of the produced hydrogen to Germany are investigated**:

[16] A comparative assessment that includes international maritime traffic projects demand of 600–1000 TWh/a (see Figure 3).

- **By liquid hydrogen tanker** (LH_2 path)
    - liquefaction of the hydrogen by cooling down to -253°C
    - Average distance between production country and Hamburg
        - Morocco: 3,500km
        - Tunisia: 4,500 km
    - Approx. 5% losses (supply chain to the buyer)
- **By hydrogen pipeline** (CH_2 path)
    - Compression of the hydrogen to 100 bar
    - Average distance along existing natural gas pipelines between the production country and the centre of Germany
        - Morocco: 2,800 km
        - Tunisia: 2,400 km
    - 8% losses per 1,000 km

Totaling 400 TWh/a, the pipeline export potential of the two countries would fail to meet European demand for pure hydrogen, even in the very efficient scenarios. This makes it clear that Europe will most likely need additional liquid hydrogen imports from other regions. While this would lead to higher costs, other regions are generally more flexible with a view to potential for renewables development.

	Morocco:	Tunisia:	
Renewable energy output (in selected regions)	125 (62 Wind, 63 PV)	193 PV	GW_{Out}
Electrolysis/renewables ratio	0.5	0.56	-
Max. pot. electrolysis output	62.5	108	GW_{In}
Electrolysis efficiency	71	71	%
Electrolysis full-load hours (optimized)	6,000	3,200	h
H_2 production volumes (select regions)	266	245	TWh_{H2}
LH_2 import volumes (liquid hydrogen by ship)	183	168	TWh_{H2}
CH_2 import volumes (gaseous hydrogen by pipeline)	206	198	TWh_{H2}

Table 1: Hydrogen production potential – Estimates for Morocco and Tunisia

Source:
Authors' calculations; preliminary results [33]

The resulting production area potentials and associated production costs for the selected regions are shown in Figure 9, including existing natural gas pipelines between Africa and Europe and potential new pipeline routes. Morocco has a high area potential and low hydrogen production costs in the south of the country. By contrast, significantly higher production costs would result in the preferred regions in Tunisia.

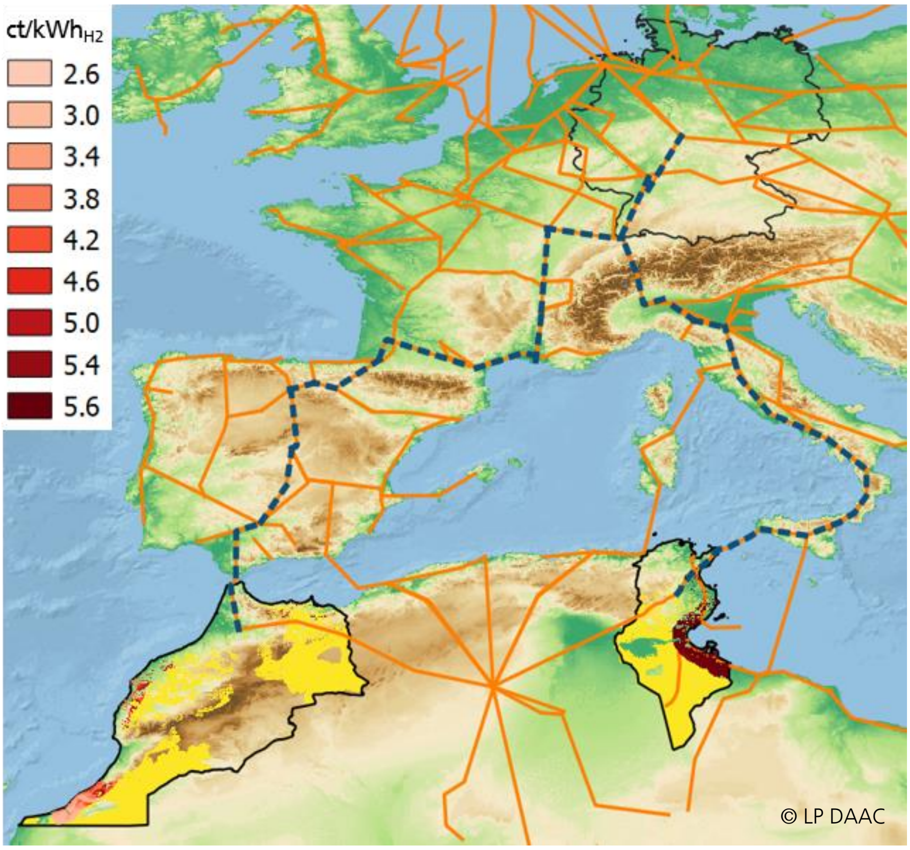
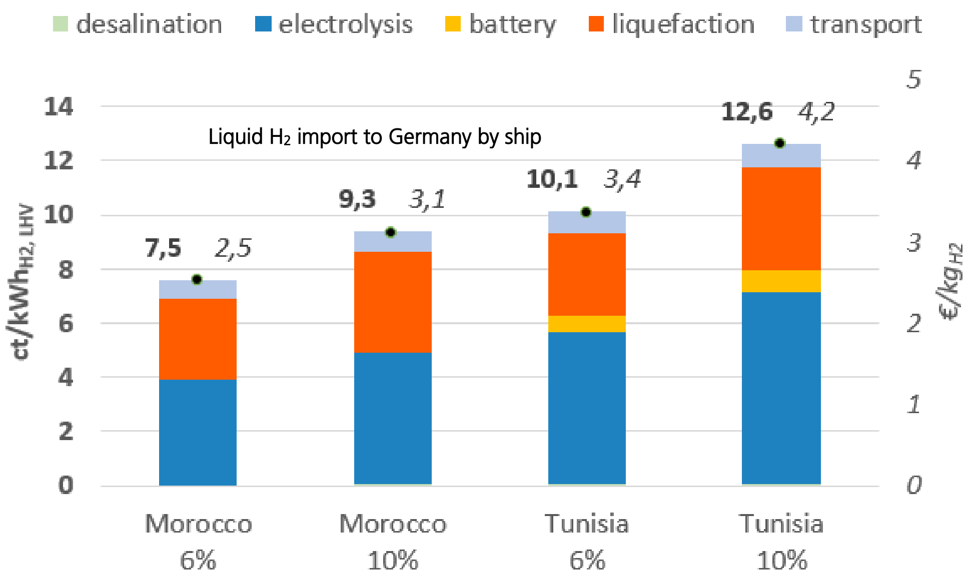


Figure 9: Potential areas for hydrogen production with a 6% cost of capital rate, excluding non-feasible inland areas (yellow) and along the coast (red).
Orange lines designate existing natural gas pipelines; the dashed lines indicate potential pipelines.

Source: Authors' figure based on [35]; map adapted from [36]

The estimations for Morocco show how renewables production is limited by lack of available area; this is particularly true of wind energy. In the case of Morocco, hydrogen production costs rise in a linear fashion with increasing production volumes up to 150 TWh. Production costs increase at a higher rate for the remaining 100 TWh of production potential. By contrast, fewer restrictions are associated with the exploitation of PV potential, as can be seen in our estimations for Tunisia. The first 200 TWh can be realized at a nearly a constant cost rate. Solely the exploitation of the final fifth of production potential leads to significant cost increases.

The losses attributable to transport (including those for liquefaction and compression) amount to approx. **31–32%** in the case of LH_2 and approx. **19–22%** in the case of CH_2. To improve comparison of cost differences between import options, average LH_2 and CH_2 import costs and cost components are shown in the following figure. **Although the CH_2 import options have higher transport costs, they are significantly overshadowed by the high liquefaction costs for LH_2** (see Figure 10).



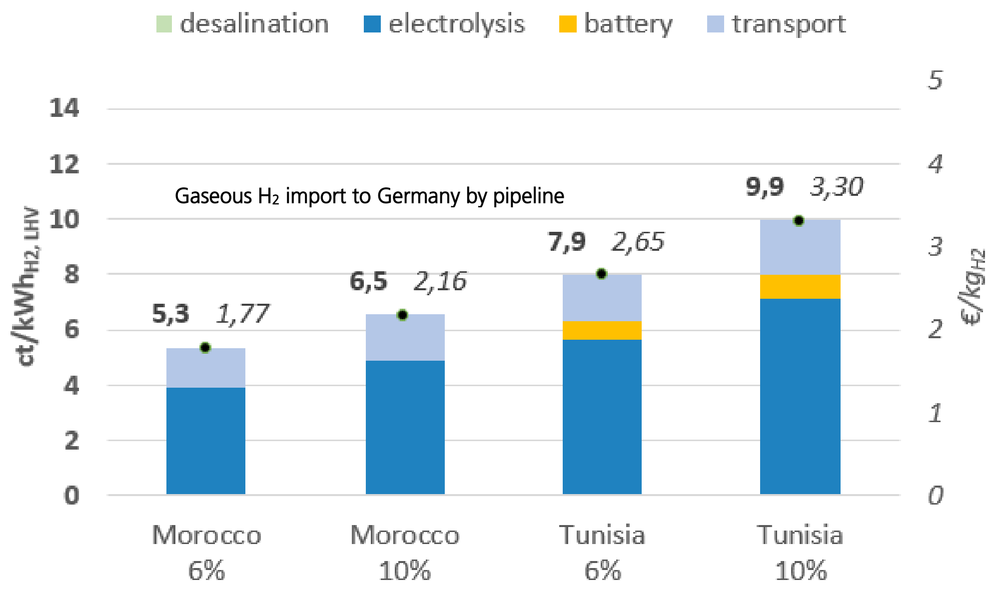
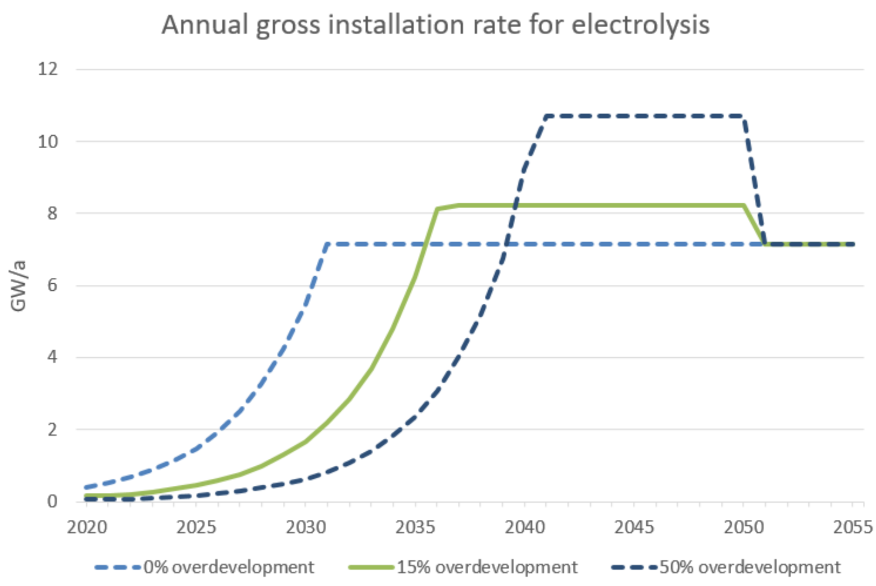


Figure 10: Average import costs to Germany from Morocco and Tunisia with variable cost of capital rates (6%; 10%)

Above: LH_2 import costs by ship
Below: CH_2 import costs by pipeline

Source: Authors' calculations
Preliminary results based on [33]

Market ramp-up in PtX exporting countries may pose an additional limitation. With a view to fulfilling global climate targets, necessary infrastructure would have to be developed in the first or most important exporting countries by 2050, and there would also be a need to replace this infrastructure as it ages. This, in turn, creates a need for local technical and manpower resources. As the ongoing replacement of ageing plants will require the dedication of increasing manpower and technical resources, there are limitations to the pace at which market ramp-up can occur in each country. Accordingly, planning that foresees the short-term development of extensive renewables capacity in these countries must be characterized as overly ambitious. As an alternative, one could deploy excess manpower and technical capacities to these countries over the short-term. Their subsequent withdrawal, however, could lead to economic dislocation. What is more, the higher the global demand for hydrogen, the greater the need in terms of supporting manpower and technical resources. An additional 1,000 TWh of hydrogen imports worldwide would require an additional 350–650 GW of electrolysis capacity and 700–1,150 GW of renewables capacity. By way of comparison, the current global increase in wind and PV capacity is about 200 GW per year. In the following, we illustrate the market ramp-up that would be necessary in Morocco and Tunisia. The 0% and 50% overdevelopment pathways are negative examples,[17] while the 15% overdevelopment pathway is a feasible positive example from today's perspective (see Figure 12).



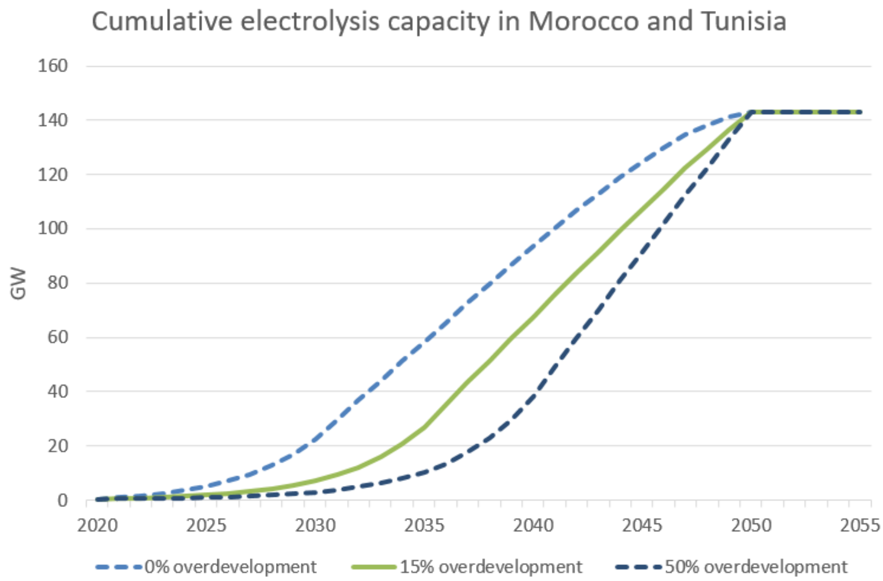


Figure 11: Illustrative market ramp-up for electrolysis plants in Morocco and Tunisia with various overdevelopment rates in relation to long-term annual demand potential

Source: Authors' calculations

Our analysis shows that the potential area for development with very low costs (i.e. hydrogen production costs and import by pipeline) is very limited. Accordingly, the greater the volume of hydrogen demanded in Europe and Germany (i.e. due to more areas of application), the more expensive it will become. Another bottleneck is posed by the speed of the early market ramp-up at a global scale. The more green hydrogen is needed over the long term, the more unlikely it becomes to reach the climate-policy target that is defined in this regard.

[17] Goal output cannot be realised as quickly with 0% overdevelopment. However, 50% overdevelopment would lead to economic dislocation.

Offshore hydrogen in Europe and Germany, with a focus on the North Sea: A potential alternative?
Compared to pipeline-based hydrogen imports from North Africa, hydrogen production using electricity from offshore wind would be significantly more expensive due to higher electricity generation costs and offshore infrastructure requirements. However, in contrast to onshore wind or PV within Germany, offshore wind has the potential to efficiently produce hydrogen at an early stage. This fact is primarily attributable to grid restrictions, including bottlenecks in north–south electricity transmission. Because of these restrictions, hydrogen production plants relying on electricity generated offshore would face less competition from direct consumers when procuring electricity. However, when wind is intensely harvested in a given region, this can lead to large-scale reductions in wind speeds. For this reason, sufficient space between wind parks must be allotted. In the absence of measures to ensure adequate space between wind parks, full-load operation could shrink to between 3,000 and 3,300 hours per year, down from its current level of around 4,000 hours.[18] If Germany were to install 50 to 70 GW of wind power in the German Bight alone, the number of full-load hours would decrease considerably [37].

Yet even if the technical and economic potential of German/European hydrogen production using offshore wind power has not been fully quantified from a present-day perspective, it is clear that this potential is limited due to regional wind speed reduction effects. Furthermore, depending on the cost of capital for foreign investment, hydrogen produced from offshore wind in Europe would be more expensive than compressed hydrogen imports and comparably expensive or more expensive than liquid hydrogen imports. For the sake of simplification, if one presumes long-term offshore wind power generation costs of 5 cents/kWh, then the resulting compressed hydrogen generation costs would be 9.1 cents/kWh.

3.3 Conclusions

Section 3 shows that **only green hydrogen can be considered sustainable.** Furthermore, it must be imported, especially from regions with a strong endowment of wind and solar resources. **Blue hydrogen is low in carbon emissions but not carbon neutral.** Furthermore, expert opinions diverge concerning carbon capture and storage. Nevertheless, given unavoidable limitations to the supply of hydrogen, it should only be used for a given application when no alternatives are available. Accordingly, hydrogen will not be available in sufficient quantities for applications such as the heating of buildings. The potentials associated with the efficient and cost-effective import of gaseous hydrogen by pipeline connection is limited. For this reason, it would be necessary to rely in part on the import of liquid hydrogen by ship, which is more expensive. Furthermore, when a greater volume of hydrogen is required over the long term, it becomes more expensive and more difficult to fulfill hydrogen targets. **What is more, if blue hydrogen is used as a bridge technology in this context, the more difficult it will be to switch to green hydrogen later. In this way, the higher the demand for hydrogen, the greater the risk of remaining dependent on blue hydrogen.**

[18] The effects of such an expansion have not yet been quantified, as there are various options for responding to these challenges, including international coordination in wind-farm site selection decisions, or the development of floating offshore wind farms.

4 Presentation of options and infrastructure requirements

The following key insights emerged from BMWi's "2030 Dialogue Process on Gaseous Energy" [38]:

- Gaseous energy sources are an integral part of transition to clean energy, even given ambitious long-term climate targets.
- Over the long term, gaseous energy sources will be a necessary part of the energy system in Germany.
- Given the ambitious climate protection targets for 2050, there is practically no room for the use of fossil-based natural gas.
- This means that policymakers and business must embrace a process of fundamental change in order to usher in an essentially carbon-free or carbon-neutral gas industry.

With regard to gas infrastructure, the following recommendations and calls for action and emerge from these insights [38]:

- Existing natural gas infrastructure must be further developed in order to accommodate diversified supply sources and routes for pipeline gas and LNG.
- Gas infrastructure must be adapted in order to be able to accommodate a greater share of hydrogen in the future. This transformation process (referred to as "H_2 readiness"), which is necessary over the long term, should elaborated in a stakeholder process with relevant interest groups before the end of this legislative period and implemented in the coming legislative period.
- German states should be encouraged to promote long-term regional and municipal planning, especially for heat supply, taking into account gas, heating, and electricity grids.
- At the federal level, a comprehensive approach that interweaves electricity, heating and gas infrastructure is necessary. This issue is already being examined.
- German positions and proposals should be drawn up on the basis of the results of this dialogue process and introduced at an early stage to ongoing political processes at the EU level. The development of uniform European regulations should then be sought.

4.1 Technical requirements and their effects

Hydrogen blending depending on the origin of natural gas

In a position paper regarding the application of natural gas grid regulations concerning the feed-in biogas to the feed-in of hydrogen and synthetic methane, the German grid regulator BNetzA states [39]: "Hydrogen is a gas that differs substantially in its composition and combustion characteristics from natural gas and other grid-compatible gases. Furthermore, without mixing, it can cause damage to grids, storage facilities, and customer installations. **Accordingly, pure hydrogen is not grid-compatible.** However, hydrogen can still be grid-compatible, provided that intermixing with grid-compatible gas downstream of the feed-in point does not have any effect on the interoperability of the gas supply grid."

This means that hydrogen can be feed into the grid as a so-called *Zusatzgas* ("additive gas"). Additive gases are gas mixtures that differ substantially from the *Grundgas*, or "primary system gas," in their composition and combustion characteristics. They can be added to the primary system gas (which is usually natural gas) in limited quantities. The amount of blending is governed by the need for consistent combustion behaviour [40].

The Wobbe index, which provides a measure of gas substitutionality (with regard to the heat load of gas systems), is of particular importance, especially for grid management. "When adding hydrogen to the publicly accessible network, the limits defined in G 260 for relative density, calorific value, and Wobbe index must always be observed" [41]. DVGW Technical Regulation G 260 on "Gas Quality" specifies, among other things, the requirements for the quality of combustive gases in public gas grids.

In the following Figure 12, the change in gas composition characteristics is shown by way of example for three natural gases ("Holland-L," "North Sea-H," and "Russia-H") as a function of hydrogen concentration. **While the natural gas types Holland-L and North Sea-H are still clearly within the permissible G 260 thresholds for H and L gases given a hydrogen concentration of 10%, this is no longer the case for Russia-H.** The lower threshold for relative density (d = 0.55) is not met by Russian-H plus 10% hydrogen. Furthermore, at a hydrogen concentration of 20%, all three natural gas types fail to meet the required threshold value for relative density. If the relative density level requirements are not met by higher blendings, the G 260 Technical Regulation calls for individual testing. This means that gas mixtures containing hydrogen which fall below the lower threshold value for relative density can potentially be used.

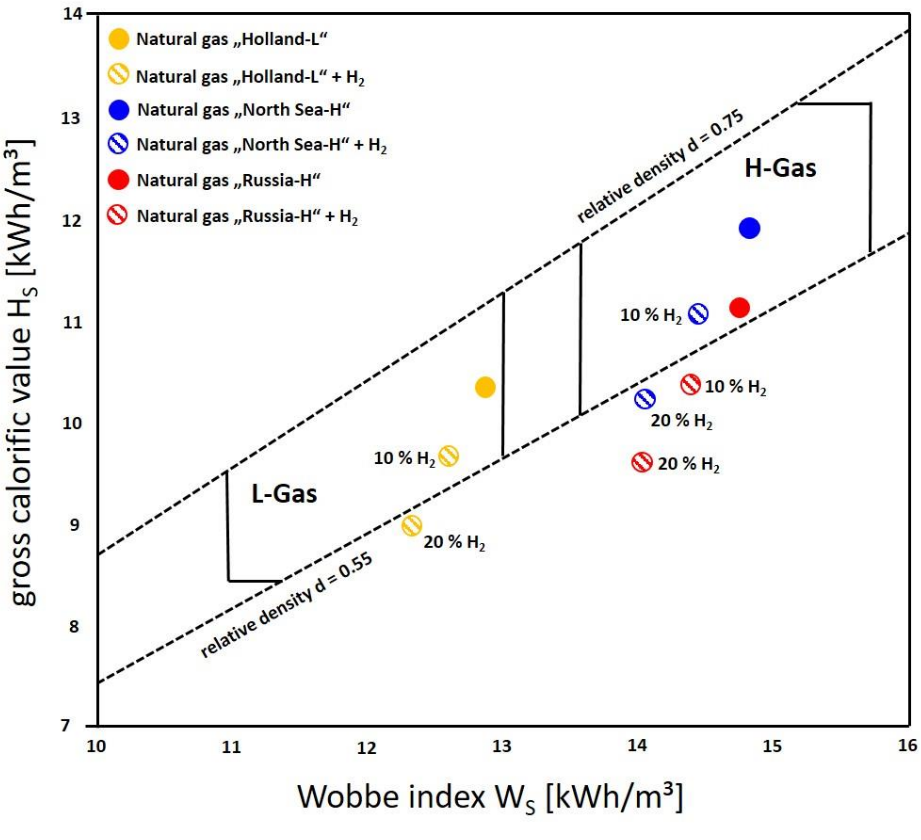


Figure 12: Change in gas quality characteristics (H_S, W_S, d) as a function of hydrogen concentration for three different natural gases, taking into account G 260 thresholds (as of 2013).

Source: Authors' figure based on [40–42]

The DVGW Technical Regulation Code of Practice G 262, titled "Using Gases from Renewable Sources in Public Gas Grids" (last updated: 2004), which is currently applicable to the feed-in of regenerative gases into natural gas grids in accordance with German grid regulations, states that the maximum share of hydrogen in combustive gases is to be limited to ≤ 5% by volume. However, the current version of DVGW Code of Practice G 262 (A) (September 2011) indicates that hydrogen concentrations in the single-digit percentage range (< 10%) in natural gas are non-critical in many cases if the requirements for combustion characteristics are observed. According to DVGW, the future regulations should initially aim for a hydrogen feed-in target of about 20 percent by volume [43].

However, further restrictions, which are described below, stand in the way of the wide-ranging blending of 20% hydrogen in all grid areas.

Hydrogen tolerance of end-customer systems and storage devices

With regard to the hydrogen tolerance of gas burners, it can be stated that manufacturers of gas-fired end-customer systems must ensure that all systems placed on the market can be operated safely with gases in accordance with DVGW Code of Practice G 260. "Furthermore, DIN EN 437, which applies to all gas systems connected to public gas grids, prescribes a test gas (G 222) with a **23% share by volume** for the group **natural gas H**." This G 222 test gas is used to conduct a short-term test (to check the tendency of gas burners to flash back) and, accordingly, **does not allow any statements to be made about the long-term suitability of the systems for hydrogen-rich gases** [44].

An additional aspect that must be taken into account with the direct feed-in of hydrogen is the use of natural gas as a vehicle fuel. It is specified that a maximum hydrogen concentration of 2% by volume may not be exceeded in local distribution grids in which natural gas filling stations are located. This requirement was imposed due to the **risk of gas tanks in older vehicles suffering from material failure** [41]. This risk affects gas tanks that are made of steel. Since gas tanks made of other materials (that no longer suffer from this weakness) are now commonly used, over the medium term the threshold value for compressed natural gas (CNG) filling stations could potentially be raised.

Another important factor pertaining to the use of natural gas mixtures that contain hydrogen in **CNG vehicles** and **combined heat and power plants** is the "methane number," which is a measure of the **knock resistance** of the fuel gas mixture in gasoline engines. Methane has a methane number of 100, while hydrogen has a methane number of 0. Higher hydrocarbons (ethane, propane, butane, etc.) also have a reduced methane number. The natural gas types "Denmark-H" and "North Sea-H" have a relatively high share of higher hydrocarbons (approx. 9%), which means that these gases already have relatively low methane numbers of 72 and 79, respectively. DIN 51624 specifies a minimum methane number of 70 for natural gas as a vehicle fuel [40]. The addition of hydrogen **to natural gas is thus extremely limited for these two gas mixtures.**

Furthermore, DVGW Code of Practice G 262 (A) imposes clear restrictions on the hydrogen content of fuel used to operate **gas turbines**. Depending on the gas turbine manufacturer, the limit values for hydrogen range between 1 and 5% by volume. In the future, however, new gas turbines are likely to have significantly higher hydrogen tolerances (up to 100%).

Regarding **industrial applications**, the following is stated in the "Gas 2030 Dialog Process": "However, even small blending quantities in domains that depend on consistent gas quality (e.g. material applications in chemistry) or constant temperatures (e.g. glass, ceramics) can pose significant risks for process reliability. Moreover, as hydrogen has 1/3 the calorific value of natural gas, it is not suitable for all high-temperature applications in pure form. In the case of blending, given the increased need for measurement and control technologies, we can also anticipate impairments to the energy efficiency of production processes. Consequently, hydrogen blending is not viewed as a priority option for the applications in the industrial sector" [38].

Since hydrogen serves as a substrate for sulfate-reducing bacteria, there is also a risk of bacterial growth, especially in subterranean **pore storage facilities**. According to G 262, it is therefore recommended that the injection of hydrogen into pore storage facilities be limited. With a view to hydrogen grids, the use of cavern storage facilities (see diagram below) – among other storage options – is thus anticipated.

Conversion of the natural-gas supply grid to a 100% hydrogen grid

An alternative to the blending of hydrogen to natural gas is to convert existing natural gas supply grids to 100% pure hydrogen grids. FNB Gas, the German non-profit association of gas grid operators, has published the following map, which envisions the layout of a potential hydrogen supply grid [45]. The imagined grid is based on the rededication of 90% of existing natural gas transport pipelines (which often consist of several pipelines running in parallel). This rededication will be possible **if the demand for natural gas, especially in the building sector, decreases over the medium term**, thus freeing up pipeline capacity. The total length of the pipeline grid is approx. 5.900 km. Only some 600 km of new hydrogen pipelines would have to be built nationwide over a medium time frame in order to enable two discrete grid systems, operated in parallel – namely, one for natural gas (or methane-rich gases of the 2nd gas family) and one for hydrogen. Cavern storage facilities could be connected to the hydrogen grid based on the relative shares of hydrogen and natural gas demand. This infrastructure would enable the supply of hydrogen **to key existing and new industrial consumers and, if necessary, to new gas turbines from 2030 onward** (see Figure 13). Furthermore, this infrastructure would enable the pipeline-based distribution of hydrogen over a wide area to hydrogen filling stations, as well as the setting of fixed blending ratios in natural gas distribution grids that vary on a regional basis (depending on local base gases and end-customer system tolerances).

The expansion of hydrogen infrastructure is one facet of the National Grid Development Plan for 2020–2030. This plan foresees aggregate hydrogen demand of approximately 94.4 TWh in 2030. Compared to the hydrogen produced in 2017 via natural gas reforming, this would mean additional demand of 25.4 TWh/a, primarily due to higher hydrogen consumption in industry and the transport sector. The plan foresees a particularly robust rise in the Ruhr region and along the Rhine river [46]. Against this backdrop, German pipeline operators forecast national hydrogen feed-in from electrolysis plants of 1.6 GW. Accordingly, demand will far outstrip national production using electrolysis, necessitating significant green and blue hydrogen imports [47]. In light of the time needed to ramp up green hydrogen production, output levels in 2030 are likely to be just 5% of their required 2050 levels (i.e. 25 TWh in 2030, compared to 500 TWh in 2050), as shown in Figure 11. This vividly demonstrates the medium-term dependence of these scenarios on blue hydrogen.

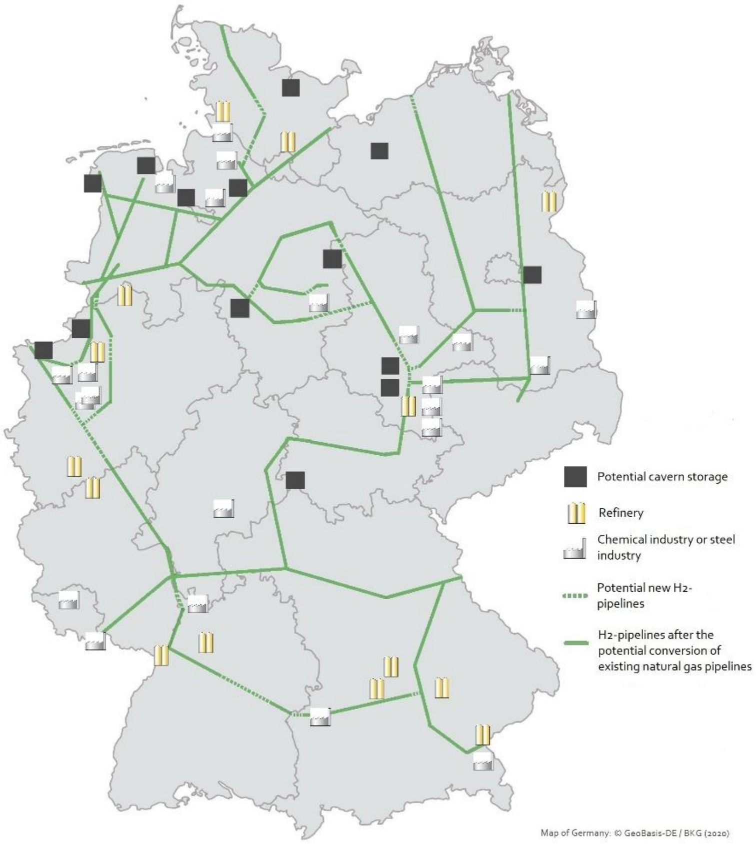


Figure 13: Vision for a Hydrogen Grid of the Future

Source: Authors' figure based on [45]

4.2 Decentralized hydrogen infrastructure: A cost assessment

Based on the German Environmental Agency's roadmap for gaseous fuels as part of the clean energy transition [48], specific costs of between €10 and €19 per MWh of hydrogen energy will be incurred, depending on the model for converting natural gas infrastructure to hydrogen. By comparison, the distribution costs that arise for newly constructed hydrogen grids tend to be twice as high per unit of energy.

By comparison, a French study cites specific costs of €1–8 per MWh for adapting 10–40 TWh/a of natural gas infrastructure to hydrogen (given a total gas volume of 195–295 TWh/a) [49].

If the **gas distribution grids** are repurposed for operation with pure hydrogen, expenditures ranging between €3.1 and €6.2 billion are anticipated up to 2050. Due in particular to a drop in consumption in the building sector, there will be a need to decommission grids at the local distribution level. The costs incurred in this connection will range from €3.1 billion to €17.2 billion. This decline in consumption will also lead to rising operating costs at the distribution grid level (up to a factor of 2.5) [48].

At the **grid level of long-distance transport**, there is also a need for modifications, especially with a view to compressor stations. If the dismantling of compressor stations is not necessary, costs of up to €1.6 billion are estimated up to 2050. Decommissioning requirements arise "in the case of an extreme hydrogen growth path, and only for pipeline sections through which no gas transit to neighbouring countries takes place." If such pipeline sections are decommissioned, the corresponding compressor stations will need to be dismantled and removed. This will result in costs of approx. €4.6 billion up to 2050, including the costs for new compressors in the remaining pipeline sections. At the transport grid level, a moderate increase in operating costs of €0.90/MWh can be expected in a gas scenario with a high hydrogen share [48].

4.3 Conclusions

The blending of hydrogen in natural gas networks is already technically possible and generally permissible today. However, in comparison to regeneratively produced methane (biomethane, SNG[19] or PtG), feed-in is limited to <10 % and, depending on the composition of the base gas in the natural gas grid and downstream consumers, is not possible in the same concentration ranges. In the future, this figure is to rise to 20%, but this is associated with technical uncertainties and a need for local clarification. Due to the lower calorific value of hydrogen in comparison to methane, the prospectively **envisaged blending of 20%** hydrogen by volume to natural gas would lead to a **reduction in the hydrocarbon content of only 7–8%** (in the case of natural gas vs. green hydrogen, a figure equivalent to CO_2 savings), since a larger gas volume is required to supply gas consumers with the same amount of energy. The conversion of the transport grid to 100% hydrogen would enable considerable freedom for the transformation of the natural gas supply, since hydrogen-critical elements (pore storage, existing gas turbines, certain industrial consumers) can continue to be supplied with pure natural gas and can efficiently supply key hydrogen consumers (industry, new gas power plants). However, if larger quantities of hydrogen are integrated into the energy system in other applications, there will be a need to repurpose the grids (from natural gas to hydrogen) and/or construct new grids for pure hydrogen transport at the local distribution level. In this case, the cumulative costs for gas heating systems (i.e. decentralized house connections) will be significantly higher than for supplying vehicle filling stations at central locations. If a significant reduction in GHG emissions in the building heating sector is to be achieved through the use of hydrogen, **it would be necessary to achieve a higher hydrogen blending share (up to approx. 100%). However, this would require the replacement of all end-customer heating systems**. An **alternative** to the physical supply of energy to gas consumers is **virtual supply**, such as that offered today for biomethane or SNG. However, the goal of a climate-neutral building stock cannot be achieved in this way.

[19] SNG stands for synthetic natural gas, a natural gas substitute based on electricity and PtG.

5 Decentralized heat supply concepts based on heat pumps

The option of supplying building heat with hydrogen on a decentralized basis must be compared to the alternative of supplying heat using heat pumps. However, when considering this option, the question arises as to whether Germany will be able to achieve sufficient wind and PV power expansion to supply the high demand for direct electricity use that would be associated with large scale reliance on heat pumps. Furthermore, it must be clarified whether an energy system that relies predominantly on heat pumps in the building sector is technically feasible.

5.1 Renewable power potential for direct electricity use

The following Figure 14 summarizes national electricity consumption for Germany in the first three scenarios presented in Section 3 (excluding the DENA study). These scenarios feature a high share of direct electricity use. The demand forecast presented by the Fraunhofer Barometer is also included. According to these scenarios, total national electricity consumption will increase from 558 TWh/a in 2015 to between 711 TWh/a (BDI) and 791 TWh/a (UBA) in 2050. The Fraunhofer Barometer foresees consumption of 900 TWh in 2050. Indirect power consumption (hydrogen and PtG/PtL) is outlined in red.

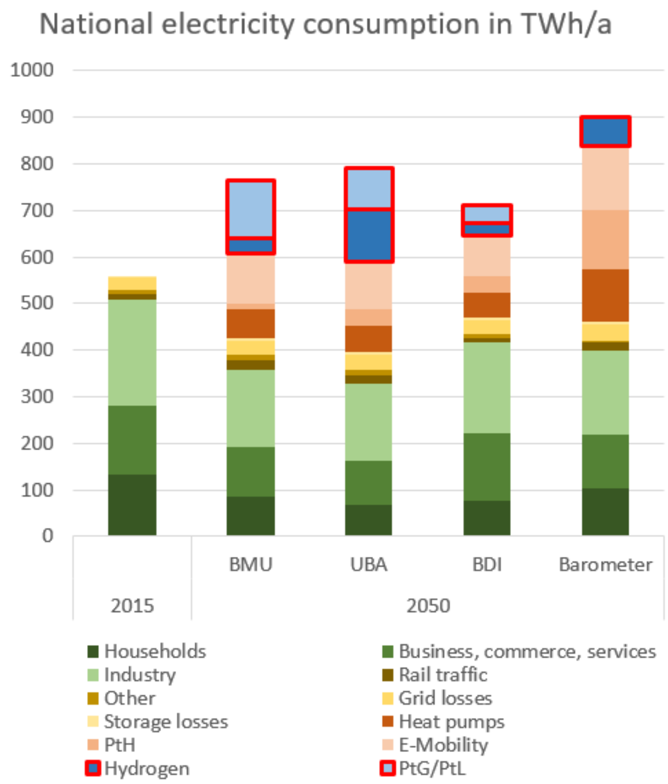


Figure 14: National electricity consumption in four scenarios

Source: Authors' figure based on [9–11, 13]

Current figures from the Fraunhofer Barometer anticipate direct electricity use of approx. 837 TWh in 2050, which exceeds the consumption in the BMU, BDI, and UBA scenarios. This demand is composed of 113 TWh for building heating, 126 TWh for industrial process heat, 137 TWh for road traffic, and 461 TWh for conventional electricity consumption, including the associated grid and storage losses. This anticipated demand for electricity must considered in relation to the feasible expansion of generation potential:

Offshore Wind

- The ability of offshore generation to serve as a source for direct electricity use will depend on the availability of connections to the transmission grid as well as the capacity of the north–south transmission lines.
- Assuming a total expansion potential of 40 to 50 GW [37], it will be possible to devote some 25 GW to direct consumption, according to a conservative estimate (i.e. 100 TWh). This leaves a potential of 15–25 GW for direct hydrogen use.

Photovoltaics

- Ground-mounted PV has a high potential of 140 GW [50]. Additional areas can also be converted for PV panel installation. The potential offered by roof-mounting is very high at approx. 280 GW and will increase further as technological progress improves efficiency [10].
- Given numerous recent advances in PV technology, it appears increasingly clear that PV will make a decisive contribution the fulfillment of climate targets. Potential PV output is much greater than potential demand. Numerous synergies will arise locally through new flexible consumers (electric vehicles and heat pumps). However, the key criterion should remain as follows: from a present-day perspective, what quantity of electrical power can be used directly at low cost for grid expansion and storage? Based on modeling experience and scenario comparisons, we use 250 GW → 250 TWh for this purpose.

Onshore Wind

- The expansion of onshore wind is rendered somewhat uncertain by ongoing public resistance and legal hurdles. The allocation of new areas for onshore wind will be a decisive factor moving forward. Depending on the urbanization patterns native to each German state, regulations pertaining to required turbine distance from inhabited areas are often of secondary importance.
- If 2.3% of land area in Germany is used at distances of 800 to 1,000m from inhabited areas, and reductions are made for protected areas, forest areas, and reference yields, the capacity potential for low-wind turbines is approx. 200 GW [10]. Given a generally applicable requirement of 1,000m between turbines and inhabited areas, the land area potential is reduced to 1.7%, and, by extension, the capacity potential shrinks to 150 GW.
- In view of current developments, we use the lower value of 150 GW → 450 TWh.

In total, this results **in an estimated potential of over 800 TWh.** If we add hydropower generation from hydrogen balancing power plants and renewable electricity imports, **the potential for direct electricity consumption is over 900 TWh**. It should be noted that Germany is densely populated. Other countries have higher land potentials (e.g. France or Poland could serve as possible long-term onshore wind exporting countries). **Accordingly, even if direct electricity use is maximized at a low level of efficiency, power demand can be met in a cost-efficient manner almost exclusively from national sources.**

5.2 Heat-pump integration in the building sector

In Germany, the heat pump sales market is strongly concentrated in the new construction sector, accounting for around 55–60% of sales. However, in order to achieve climate targets in the building sector, the near-term ramp-up of heat pump installation is also necessary in the existing building stock. Some 70–75% of heat pumps sold for installation in existing buildings are air heat pumps. Given a low renovation rate for the building envelope (roof, walls, windows), and taking into account boiler replacement rates, this means that heat pumps don't merely need to be installed in "efficient" existing buildings (i.e. buildings built from 1977 onward according to the First Thermal Insulation Ordinance, or from 1995 onward according to the Third Thermal Insulation Ordinance). Even if the rate at which the energy-efficient retrofitting of residential buildings takes place were to be increased from its current rate of approx. 1% up to 2% as a long-term average, it would take 50 years to refurbish the existing building stock (rather than 100 years). However, in order to achieve complete decarbonisation of the building sector by 2050, all buildings would have to be supplied with renewable heat within 30 years. Accordingly, the heat pump sales market must grow faster than the building refurbishment market. In this way, there will be a need to install a large number of heat pumps in unrefurbished existing buildings built prior to 1978 (even if energy efficient retrofitting in combination with heat pump installation makes economic sense).[20] Due to the low heat density of air and heat transfer mechanics, the technical effort to provide high flow temperatures is slightly higher for air-source heat pumps than for ground-source heat pumps. Systems based on ground source heat pumps never reach negative temperatures on the cold side of the heat pump, allowing them to generate the required flow temperatures with higher efficiency [7].

In existing buildings, however, higher temperatures are often used than would be necessary for heating. If the heating circuit is not hydraulically balanced, short-circuit flows will occur and, as a result, the return temperature will rise. To avoid uneven heat distribution, heating water circulation pumps are dimensioned larger and/or the flow temperature is set higher than actually necessary. In addition, the heating curve is often set so that sufficient heating power is still available in the transitional period (e.g. for heating the building after night-time cooling). In many cases, the return temperature is not based to the design temperature, but increased.

In addition, compared to design specifications, there are usually already improvements in the building fabric (e.g. double-glazed windows), which leads the heat pump to be tailored to a larger heating area than necessary. Furthermore, a higher temperature is usually sought in order to avoid the dew point of low temperature oil boilers. According to this generalized description, there is a high potential to optimize the required heating supply and return temperatures by means of installing new circulation pumps and adjusting the heating curve and hydraulic balancing [7]. In addition, there are various options for improving the readiness of existing buildings for heat pumps. Hydraulics in existing buildings, for example, can be easily accommodated by using inverter units (air heat pumps) or well-dimensioned fix-speed heat pumps with buffer storage tanks (ground heat pumps) [51]. The temperature requirement can also be reduced in the area of domestic hot water by using cellar air. In the case of apartment buildings, this requirement can be reduced by means of floor heat exchangers or fresh water stations, which avoid the legionella problem.
In addition, in order to achieve lower supply temperatures in existing buildings, sectional radiators (cast iron, steel, or tubular steel) can be replaced by panel heating (floor, wall

[20] Especially in the case of semi-detached homes and apartment buildings (regardless of age), serial refurbishment techniques (such as *Energiesprong* from the Netherlands) can be used to standardise a large number of relatively similar building modifications and then implement them both faster and cheaper.

heating, edge strip heating) or low-temperature radiators. In the case of radiators, there is the option of using large flat surfaces (with a lot of radiant heat) or deeper convectors that have natural lift or a fan [7]. In many cases it is sufficient to replace the radiator only in individual rooms, e.g. in the bathroom [51]. If it is not possible to improve the building insulation or replace radiators in an existing building, high-temperature heat pumps can be used for flow temperatures up to 70°C. Alternatives include hybrid or bivalent systems, in which a heating element or a conventionally fired peak load boiler (gas, oil, pellet) is added as a backup in cases in which maximum load is required. In a renovation schedule for a building, a heat pump can be installed at an early stage and, after the heat requirement has been reduced later through renovation, the conventional boiler can then be shut down. Hybrid compact systems can also be permanently installed in historical/half-timbered buildings or other types of buildings that cannot be fully renovated at a later date [7].

To address noise pollution concerns associated with air heat pumps, manufacturers have been using larger heat exchangers with lower flow speeds or specially shaped fans. Noise emissions are also being reduced by designs that blow the air upwards. Split units, which locate compressors inside the building, are another solution in this regard [52].

The efficiency level of heat pumps is likely to increase moderately in the future. Many technical enhancements, such as speed-controlled compressors/fans and electronic expansion valves, have already been implemented. The necessary use of new refrigerants, on the other hand, could have a negative impact on product efficiency. The ongoing adaptation of systems to changing user behaviour could have considerable potential for reducing the energy consumption of heat pumps. Another energy-savings feature currently under development is automatic self-optimization. To increase convenience, multifunctional devices are being used that provide heating, domestic hot water preparation, efficient ventilation, and active cooling. Alternatively, in the case of passive cooling, heat can be extracted from the building by means of a suitable hydraulic circuit and dissipated into the heat sink that otherwise acts as a heat source (geothermal probes, ice storage) [51]. Geothermal probes and ice storage tanks can be used as seasonal heat storage in combination with inexpensive solar thermal absorbers. This can make a decisive contribution to increasing the efficiency of geothermal heat pumps, especially for ground regeneration. In the commercial buildings, there are a number of heat pump solutions. In addition to heating, efficient cooling (office buildings, hotels, etc.) is often required. Air-to-air heat pumps are also particularly suitable for renovation projects, as they can be installed flexibly and in a space-saving manner.

Despite these technical and economic possibilities, there are also restrictions – for example, with regard to air heat pumps in apartment buildings, especially due to the space required for air supply.[21] For such buildings, the efficient supply of heating energy via local or district heating grids is a sensible alternative. Further study is required to determine whether niche applications may arise in the non-residential buildings sector in connection with GHD process heat, or what contribution hydrogen can make to district heating, depending on existing local infrastructure (see Section 2.1).

5.3 Power supply and grid requirements

Bottlenecks or dark doldrums?

"Dark doldrums" refers to a time of no or very low solar and wind power production. **In such situations, the supply of power will have to be assured by burning fossil fuels or PtX energy sources.** A survey by the German Weather Service (DWD) in 2018 systematically

[21] To solve this problem, however, one solution is roof-top installation, as well as the use of parking spaces for waste disposal.

investigated the frequency with which dark doldrums occur. The survey sought to identify periods of at least 48 hours between 1995 to 2015 during which wind and PV electricity – as defined by the DWD – could be fed into the grid at only 10% of potential output. To simplify the analysis, generation capacity was assumed to be equally distributed across the country, and no grid restrictions were taken into account. The following Figure 15 shows the result of the survey: Over the twenty year period that was examined, very low wind feed-in occurred just 13 times per year if both onshore and offshore wind turbines are taken into account, and 23 times per year if only onshore turbines are taken into account. By contrast, low wind generation in combination with low PV output occurred just twice per year for more than 48 hours. If one broadens the analysis to include PV across Europe, dark doldrums occur statistically less than once per year (0.2 times), a figure that can be attributed meteorological adjustment effects.

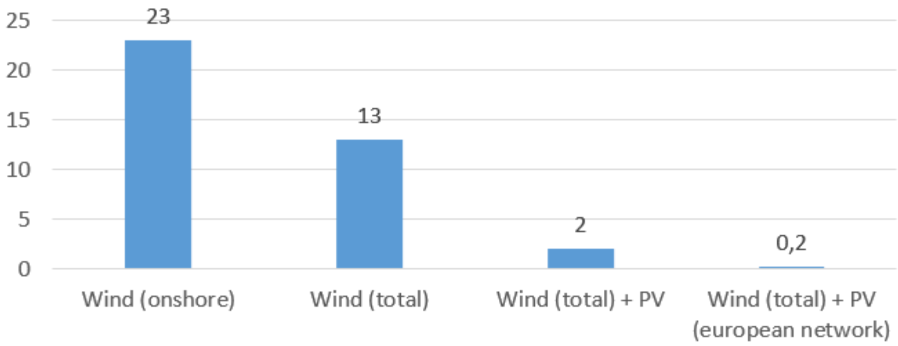


Figure 15: Number of situations per year with dark doldrums (here less than 10% of the nominal capacity for at least 48 hours) (1995-2015)

Source: Authors' figure based on [53]

In order to quantify necessary energy output and costs, the feedbacks to the energy system resulting from these periods of low renewables production must be evaluated, which are shown in the following Figure 16. In addition to compensating for divergence in wind generation between large-scale high and low pressure areas, as well as creating PV feed-in when there are very cold outside temperatures in Germany, we have to assume a number of other offsetting effects. These effects have a strong impact on reducing national power demand, even given moderate European grid expansion.

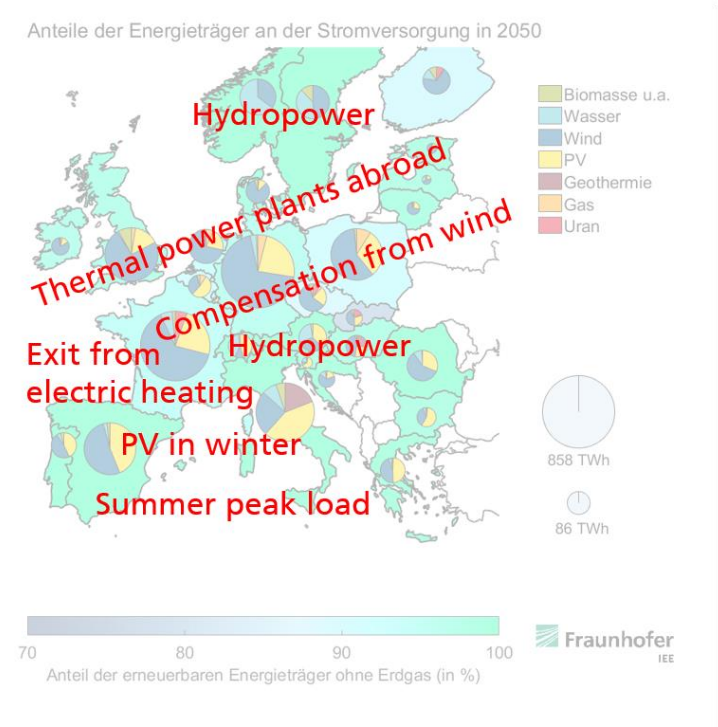


Figure 16: Impacts to the European energy system due to the cold doldrums

Source: Authors' figure

Based on investigations conducted by Fraunhofer IEE [54] into a future energy system that presumes the occurrence of 7 historical weather years, the following Figure 17 shows the operating times of Germany's gas-fired power plants in 2050, portrayed as a continuous line over the year. The utilization and overall low power generation of approx. 30 TWh in relation to a total power demand of over 800 TWh makes it clear that PtX as a fuel in power plants only has to be used very rarely to supply power to heat pumps, and that the plants can almost exclusively be supplied directly with wind and PV power.

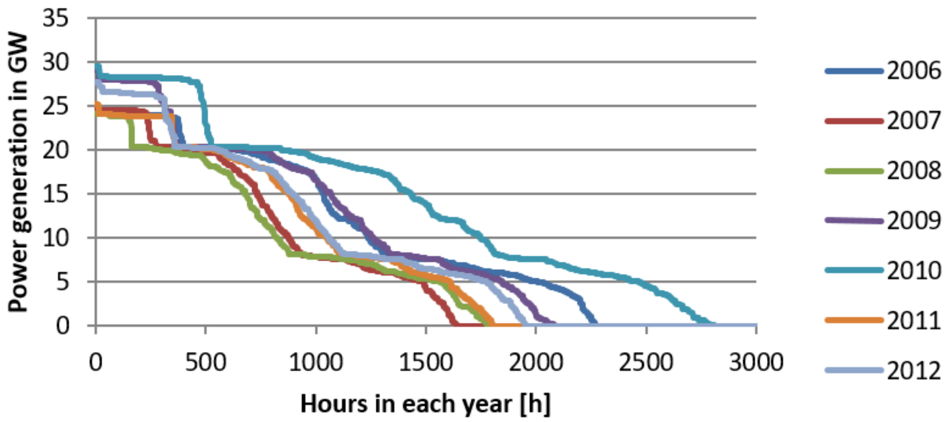


Figure 17: Gas-fired power plant operation in 2050 on the basis

7 historical weather years

Source: Fraunhofer IEE [54]

Based on this publication, the Fraunhofer Barometer depicts a European extreme situation based on the historical weather year 2012 for a 2050 scenario with a very high proportion of heat pumps, widespread use of electric vehicles, and fluctuating renewable energy feed-in. At the beginning of February in this example year, the temperature is below -10°C on average over all residential areas (and is therefore particularly relevant for air heat pumps) and there is very little wind over a long period of time – both in Germany and in large parts of Europe. Depending on assumptions regarding load shedding and flexible operation, conventional power plants with approx. 35–40 GW of capacity will be needed in Germany. This extreme situation was also artificially exacerbated by setting wind generation to zero throughout Europe, and by assuming zero PV feed-in from roof-mounted systems (due to possible snow in Germany). To safeguard against such a hypothetical event, an additional installed gas turbine capacity of approx. 15–30 GW is required. The annual fixed costs for gas turbine capacity are approx. €40,000/MW. In total, this results in a cost factor of approx. €2–2.8 billion in fixed costs, or approx. €0.6–1.2 billion in additional costs, which are very low in relation to total system costs. Scientifically, these analyses show that the dark doldrums require additional power plant capacity to guarantee security of supply. However, the costs for this are low and can be financed via capacity markets, since these power plants are used very rarely and therefore only consume small quantities of expensive PtX fuel.

Based on analysis conducted as part of the IEE project "Transformation Paths in the Heat Sector," a moderate renovation rate in combination with 15 million heat pumps leads to heat generation of 340 TWh and maximum heat-pump electrical consumption of 87 GW (5.8 kW/building). A detailed analysis of the time series shows that maximum power demand by heat pumps during the dark doldrums (given conditions like that in early February 2012, when the outside temperature throughout Germany is significantly below -10°C for several days and there is very little wind generation) is not as high as installed capacity, but stands at just 50% of this capacity, assuming PV feed-in can be used during the day to fill heat storage tanks [7]. The volume of power demanded by electric cars in Germany [33] is of a similar order of magnitude, even considering the higher flexibility potential offered by electric vehicles (due to the higher charging capacity per household connection).

Local power distribution grids: A crucial bottleneck?

The installation of a large number of heat pumps can lead to electrical equipment overload in local distribution grids. In a considered worst case, if the outside temperature in a region is below -10°C for an extended period of time, then all houses would have to be supplied with heating rods. In a worst case, this would require grid reinforcement measures or grid expansion. The costs associated with this grid expansion must therefore be included as a further factor.

Various "distribution grid studies" have been conducted over the last ten years for Germany and for individual German states in order to estimate the grid expansion costs that will arise given forecasted supply and demand trends. Unfortunately, most of these studies focus on the grid expansion necessary to accommodate increased variable renewable generation. The impact that will be exerted by demand vectors such as heat pumps and electric vehicles has been neglected to date [55, 56]. The DENA distribution grid study, for example, assumes no load increase in the calculation of grid expansion costs up to 2030, with the argument that electricity savings from increasingly efficient applications will offset demand from new sources of electrical consumption. By contrast, the distribution grid study undertaken for the state of Baden-Württemberg [57] asserts that if flexibility options such as heat pumps are used in a bundled manner in supra-regional electricity markets, without taking the status of local grids into account, this simultaneity will result in a considerable increase in grid expansion costs in urban and semi-urban low-voltage grids.

Load management to avoid grid expansion and bottlenecks can be carried out directly and indirectly and does not have to exclude the use of flexibility in electricity markets. Rather, it only restricts it temporarily. **Direct load management allows loads to be switched on or off directly by the grid operator in order to compensate for load peaks or drops.** Indirect load management is implemented with the help of so-called incentive models. Flexible consumers such as heat pumps and vehicle charging stations can be managed in a manner beneficial for the grid by means of dynamic pricing. In other words, instead of being a burden on the grid, heat pumps can even be harnessed to reduce grid expansion costs by feeding electricity into the grid and avoiding grid bottlenecks. In [56], load management is ascribed little importance (both with regard to the electricity market and the avoidance of grid expansion). However, it is acknowledged that load management will become more important as the share of flexible loads increases. By contrast, the VDE study on load shifting potentials in Germany [58] assumes that heat pumps can be used to integrate PV and wind power plants as early as 2025. Recent studies on the topic of "redispatch 2.0" are currently assessing the potential and technical use of flexibility options such as heat pumps from the distribution grid to eliminate bottlenecks in the transmission grid. According to the study "Distribution grid flexibility for reducing redispatch costs in Germany" [59], total flexibility potential is estimated at 10 GW, 27% of which would be provided by heat pumps. The provisioning of flexibility is a supplementary benefit that is provided by heat pumps – and one that has yet to be adequately quantified.

The avoidance of grid expansion costs could also be achieved through optimized on-site consumption based on PV panels and heat pumps. It should be noted, however, that such dual systems will only induce the improved integration of PV panels and heat pumps if clear specifications concerning grid interconnection are actually implemented. The subsidy programme for PV battery storage previously demonstrated this fact.

The cost drivers of distribution grid expansion – PV, heat pumps, electric vehicles?

How high will costs to expand the distribution grid be up to 2050? And how will these costs be shared between wind and PV power producers, heat pump operators, and other sources of electrical demand, such as electric vehicles? A rough guide is provided by Consentec's study "Building Sector Efficiency: A Crucial Component of the Energy Transition"

[4] (Figure 2). Using a simplified grid model, this study estimates distribution grid expansion costs in Germany depending on various heat pump adoption and RE expansion rates. These costs increase from €18 billion/a today to just €20 billion/a by 2030 and then, in the scenario with the highest share of heat pumps, to €30.9 billion/a. The supplemental costs of expanding distribution grids are higher in this case than in a scenario with high reliance on PtG to heat buildings – namely, by some 3.2 billion €/a in 2050. (Figure 2 shows the average discounted cost difference from today to 2050.) If these differential costs were allocated to additional heat pump output, this would amount to 186 €/kW$_{el}$ and thus to **only about 5% of the investment cost for a heat pump. Furthermore, these estimates show that over the next decade, a strong expansion of heat pumps can be integrated into existing grids without significant additional economic costs.** Depending on the scenario, heat pumps account for between 10% and 25% of the total increase in grid costs. The majority of grid expansion costs are caused by the addition of RE generation plants and other load increases. Accordingly, heat pumps should not be regarded as the main driver of grid expansion. On the other hand, the expansion of renewables is only ever carried out for electricity consumption – that is, for the decarbonisation of existing consumption; for new direct electricity consumers; and also potentially for electrolysers (if more hydrogen were to be supplied nationally as an alternative to heat pumps or electric vehicles). A cause-based allocation is therefore complex and depends on premises and individual local conditions.

Grid expansion is not so much about the energy required, but rather about the maximum load demanded. The charging capacities of electric vehicles today range around 11 kW (for home charging of a single car). **The connected load of a heat pump is around 3–5 kW for a single-family home and will not scale upward in coming years to the extent expected for home vehicle charging stations.** In relation to a residential building, the connected load of heat pump is thus significantly lower than that of home charging stations for electric vehicles, and also lower than the feed-in capacity of a common PV system.

The demand for heat in the residential sector can be regarded as largely constant and will tend to decline in the coming decades due to changes in climate and, above all, more efficient buildings.[22] The increase in vehicle charging capacity, however, is not yet foreseeable, as the aim is to achieve ever shorter charging times. The simultaneity of power demand is also important for grid expansion. The simultaneity of demand for heat pumps is generally cited at 80%, while electric vehicles are generally considered to fall in the 20–30% range [60]. However, this only applies if there is a large number of vehicles in a grid area. Furthermore, due to the individually higher connected load of electric vehicles, intermittent EV demand is already comparable to that of heat pumps. Locally, especially in the low-voltage range, the consideration of simultaneity underestimates grid expansion costs [61]. Accordingly, the costs incurred by electric vehicles should be seen as a low-end estimate. **In this way, it can be assumed that the installation of charging stations for electric vehicles will be a much stronger driver of grid expansion. Heat pumps are likely to only play a small role, even over the long term.** This conclusion is corroborated by the distribution grid study for the German state of Hessen [62]. In this study, grid expansion costs are estimated for both heat pumps and electric vehicles. The additional installed capacity attributable to heat pumps exceeds that attributable to charging stations in 2024, but by 2034 the charging capacity of electric vehicles is dominant.

In any event, whether and how much additional costs will arise for distribution grid expansion due to heat pumps has not yet been fully clarified. **Intelligent control and load management**, directly or via incentives, can simplify integration, but is also linked to additional costs for information and communications technology. In any event, the installation of the necessary technologies in the field of metering and controls (e.g. smart meters)

[22] Prognos AG and Boston Consulting Group, Ed., "Klimapfade für Deutschland", 2018, p. 221.

should be promoted regardless over the next few years due to new grid operation methods (e.g. for bottleneck management).

In summary, the integration of new renewable generation is likely to be the primary driver of grid expansion costs over the near future, as heat pumps are likely to play a marginal role in driving these costs. In the medium to long term, intelligent load management and the use of large heat pump systems in conjunction with local and district heating grids can make integration more cost-effective. Indeed, if a sustainable transport sector based on electricity is to be ushered in by 2050, electric vehicles are likely to be the major driver of load-related grid expansion, with heat pumps only playing a marginal role. However, a detailed investigation of this topic has not yet been conducted.

5.4 Conclusions

Chapter 5 showed that the **use of hydrogen is not necessary for the decentralized supply of heating energy to buildings.** Even in a densely populated country like Germany, there is sufficient expansion potential for wind power and PV to supply the high prospective demand associated with direct electricity use in the areas of electric vehicles, industrial process heat, and building heat. Comprehensive solutions now exist to enable the efficient installation of heat pumps in existing buildings that have not undergone energy efficiency renovation – a form of installation that will be necessary for rapid market ramp-up, given the limited pace of building renovation. Despite a very high share of direct electricity demand, security of supply in an energy system dependent on variable renewables can be assured during the dark doldrums at low additional cost given moderate additional capacity from gas turbines. Even if high absolute cost increases are anticipated to finance grid expansion, especially in low-voltage grids, **it is clear that heat pumps will not place significant demands on grid expansion in the future.** The motivating factors for grid expansion are the increased deployment of renewable energy to achieve climate targets in combination with higher electric vehicle penetration rates. The share of grid expansion costs attributable to heat pumps is comparatively lower, and also low in relation to heat pump investment costs.

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