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THE LIMITATIONS OF HYDROGEN BLENDING IN THE EUROPEAN GAS GRID

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Table of contents

Executive Summary

Limitations of hydrogen blending in the European gas grid

Natural gas currently accounts for at least 22% of EU27 greenhouse gas emissions (without pre-chain). In order to achieve the 2050 climate targets, emissions from natural gas have will to decrease continuously over the next decades. To achieve these reductions, the EU will need to pursue policies to reduce and replace the use of natural gas in the buildings, industry and power sectors where the fuel currently plays a major role.

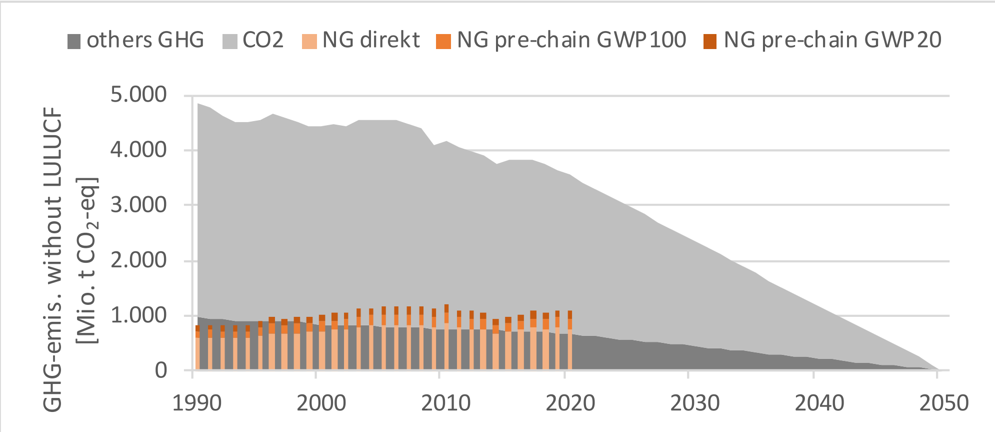


Figure 1: Development and target of EU27 GHG emissions and share of natural gas (NG) without and with pre-chain

In recent years, various studies have put forward the prospect of relying on low-carbon or renewable gases such as green hydrogen (H_2) or biomethane to replace the supply of natural gas. Hydrogen in particular is receiving much attention as a versatile energy carrier that could complement direct electrification in a plethora of end-uses and questions over its production and deployment play an important part in the ongoing discussions around the energy chapters of the European Commission's Green Deal agenda.

The aim of the short study was to assess the technical feasibility, emission savings and cost impacts of the addition of hydrogen to the existing gas transport network, the so-called practice of "hydrogen blending", which is currently being discussed as a deployment pathway in the context of the review of the EU Gas Market Regulation (GMR) and the Trans-European Networks for Energy (TEN-E) regulation.

To capture the impact of gas demand and supply on the results of this analysis, this study analysed a range of three scenarios, which represent different degrees of ambition towards decarbonisation with a significant effect on the gas market. Within an accelerated drop-out scenario for fossil fuels (the PAC scenario), a high degree of blending could be reached with rather low quantities of hydrogen. However, blending is likely to be deployed only for a short period of time (until 2035).

Within another scenario, which is more compatible with the European Commission's climate plan (EU / GfC scenario), the role of methane on the energy market would remain important until 2050. The EU hydrogen strategy strives for an installed electrolysis capacity of about 40 GW in 2030. Substantial quantities of hydrogen could be absorbed at relatively low degrees of blending. Yet, high degrees of blending would compete with other, rather localised large hydrogen demands in the industry and transport sector for a limited green hydrogen resource by 2030.

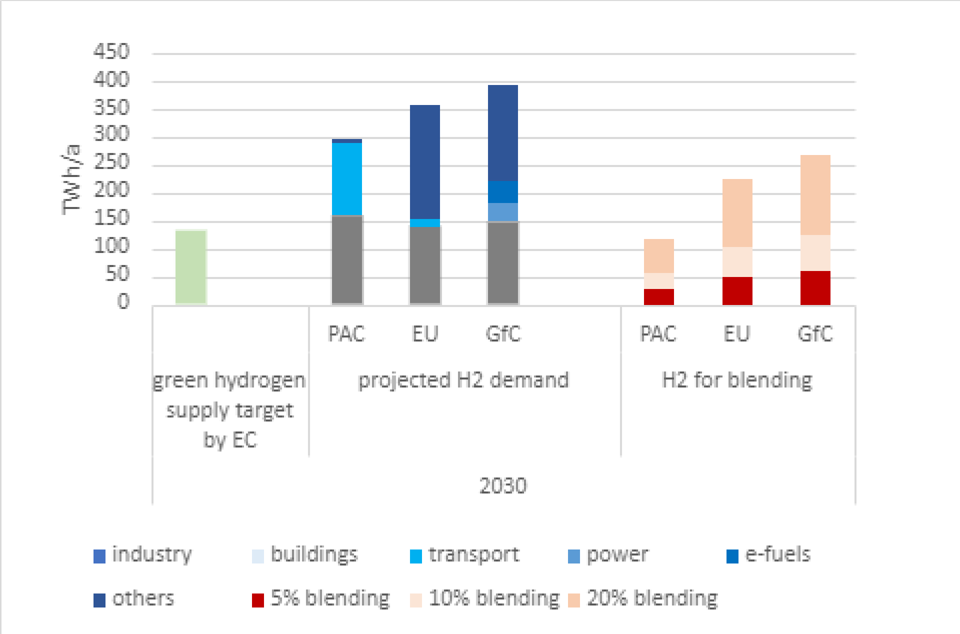


Figure 2: H_2 required for blending vs. targeted green H_2 supply and scheduled demand for 2030

Limited availability of Hydrogen

Decisive for this analysis is that hydrogen blending competes with direct use of hydrogen in focused applications. **In the medium-term, the limiting factor is the availability of green hydrogen - which means that additional renewable energy (RE) capacity has to be built to cover the hydrogen production.**

The next figure ranks the various areas of application for direct hydrogen use in terms of their efficiency (i.e. increased or reduced electricity consumption and thus RE expansion requirements compared to the reference technology) and infrastructure requirements (centralized or decentralized and year-round/seasonal).

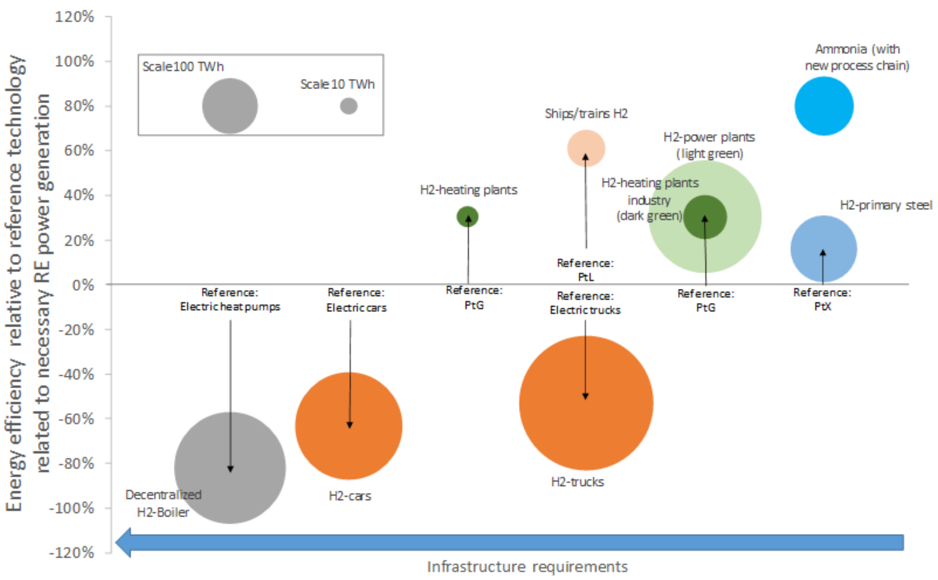


Figure 3: Comparison of efficiency with respect to energy demand by sector

With the European hydrogen strategy's target of 40 GW of electrolysis capacity in 2030, a generation of about 132 TWh can realistically be expected. The analysis shows that a 5% blending target within the EU 2030 scenario would already require about 50 TWh of hydrogen - a significant share of the 132 TWh target for 2030. This 50 TWh could instead be deployed to meet demand in a number of no-regret applications. A demand of 148 TWh H_2 (45% of the identified Europe-wide "no-regret" demand [1]) in 2030 is concentrated in four selected North West Europe regions alone.

Direct green H_2 use has clear advantages for achieving the 2030 climate targets. However, investment decisions must take long-term efficiency into account. The creditability of the limited amount of green H_2 in the respective sectors in 2030 must also take this long-term use into account.

Building an infrastructure for blue hydrogen would also take time. Furthermore, blue hydrogen is not CO_2-neutral in particular due to the associated methane emissions. Apart from this, it would be available only in limited quantities at an early stage of development and should therefore not be treated as equal to green hydrogen.

In view of the limited amounts of green hydrogen that will be available in 2030, it is important that these should find concrete applications with high CO_2 reduction potential, instead of being "poured as if with a watering can" into the natural gas network where it will offer limited CO_2 reduction.

There are a number of no-regret options for sectors in which green hydrogen should be deployed with priority including replacing grey (fossil fuel based) hydrogen, use in steel production and other industrial applications, shipping and aviation fuels and in the long-term power generation.

Technical feasibility:

To implement H_2 blending technically, a number of complex measures are necessary. A blending level up to 20 Vol-% is technically achievable, but the feasibility of different blending levels depends on factors such as the origin of the natural gas the hydrogen would be blended with. Apart from this, there are still many uncertainties regarding (long-term) material sensitivities (pipes, devices, etc.) in particular with regard to a reduced lifetime when hydrogen is present which require further investigations.

At the distribution networks level, today blending levels would be limited mostly by the presence of CNG-refuelling stations due to the 2% hydrogen admixture limitations of gas-fuelled cars. But in general requirements for infrastructure adjustments are lower for many distribution networks.

On the other hand, for transmission networks, hydrogen blending can introduce challenges for directly supplied industrial consumers, power plants and underground pore storages. Here de-blending demands can occur at network nodes and directly supplied hydrogen sensitive consumers. For the same amount of hydrogen, opting for the approach of on-site blending at i.e. industrial sites would reduce the need for de-blending measures in the natural gas grid.

The following table shows selected examples for different percentages of H2-blending rates (for the transmission system (TS), storage (ST), distribution system (DS) and utilisation (U)), that are at least possible without adjustments according to the current state of knowledge (dark green), where modifications may be needed (light green), where conflicting references were found and further R&D or clarification is required (yellow) as well as where significant modifications or replacement required (orange) and which are not technically feasible (red) .

		[%]→	2	5	10	20	25	30	40	50	60	70	80	90	100
TS	Pipeline (steel, > 16 bar)	10%													
TS	Compressors	5%													
ST	Storage (cavern)	100%													
ST	Storage (porous)														
ST	Dryer	5%													
TS/DS	Valves	10%													
TS/DS	Process gas chromatographs														
TS/DS	Volume converters	10%													
TS/DS	Volume measurement	10%													
DS	Pipeline (plastics, < 16 bar)	100%													
DS	Pipeline (steel, < 16 bar)	25%													
DS	House installation	30%													
U	Gas engines	10%													
U	Gas cooker	10%													
U	Atmospheric gas burner	10%													
U	Condensing boiler	10%													
U	CNG-vehicles	2%													
U	Gas turbines	1%													
U	Feedstock														

Table 1: Limitations for H_2-blending rates of selected components of gas infrastructure and utilisation options.

Emissions savings:

The technical effort for blending that substitutes 20 Vol-% of natural gas by green H_2 is high and corresponds to only about 6 to 7% Greenhouse Gas (GHG) savings due to the lower heating value of hydrogen compared to natural gas. In the graph below, the amount of CO2-equivalent emissions that is not being emitted when using hydrogen directly i.e. as fuel instead of diesel or natural gas or to replace coal, is calculated for selected applications. Significantly higher GHG emission reductions of up to 50% can be achieved through the direct application of hydrogen in the transport sector and in industrial applications.

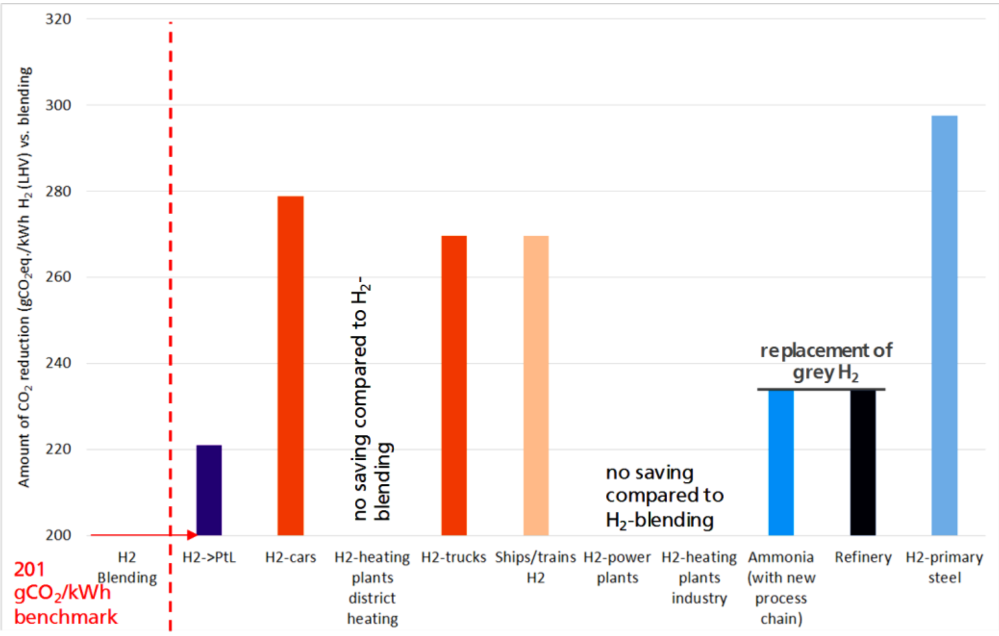


Figure 4: direct CO2 savings from limited amount of hydrogen (gCO2/kWh HHV) compared to blending in 2030

Costs:

The technically complex adjustments needed for the gas grids to accommodate hydrogen require new investment will increase operating costs and will have a high impact on end-user gas prices in the EU.
Blending levels up to 5% still show modest price increases for all customer groups. However, it must be taken into account that the introduction of hydrogen blending in one European country would force almost all the other EU countries to also take adjustment measures due to cross-border trade and supply security. In contrast to low blending levels, higher levels would lead to substantial price increases (especially for industrial customers).

Industry	**End-user**	Blending tax			End-user price increase		
Year 2018	**Gas price**	5%	10%	20%	5%	10%	20%
Country	**ct/kWh**	ct/kWh	ct/kWh	ct/kWh	Percent	Percent	Percent
EU	**3.135**	0.042	0.312	0.746	1.3	9.9	23.8
Germany	**3.160**	0.026	0.308	0.767	0.8	9.8	24.3
France	**3.715**	0.043	0.296	0.683	1.2	8.0	18.4
Italy	**2.895**	0.037	0.328	0.794	1.3	11.3	27.4
Portugal	**2.840**	0.052	0.555	1.230	1.8	19.6	43.3
Ireland	**3.650**	0.000	0.231	0.480	0.0	6.3	13.1

Table 2: End-user natural gas price increase for industrial customers because of blending

An early gas network conversion to achieve over 20 Vol-% blending would be expensive. Only a long-term conversion would theoretically be possible at low costs by "hydrogen ready" standards for end-user application if components are not replaced before their end of lifetime. However, to step-up from 20 to 100% in the period well after 2040 would be too late to meet climate targets.

Dedicated hydrogen infrastructure:

A pure H_2 transport grid could enable the efficient supply of hydrogen to large consumers. The connection of small remaining distribution networks to this grid must, if applicable, be decided locally.

For the case that more green hydrogen is imported (or blue hydrogen is produced), the question how to overcome the challenge of a missing hydrogen transmission grid in 2030 arises. In this case, a blending up to 2 Vol-% today (in the case of CNG vehicles) and up to 5 Vol-% by 2030 without high costs could theoretically be considered provided such an approach avoids **indirect lock-in effects, which are contrary to the prioritization of direct hydrogen.** Such a step (2 Vol-% or 5 Vol-%) should only follow after a thorough examination of possible options for direct hydrogen use.

If an H_2 grid is not available, it is necessary to consider, whether production or import of Power to liquids (PtL, including kerosene, diesel, methanol) instead of H_2 is more sustainable, or whether on-site electrolysis at industrial sites or hydrogen refuelling stations are an option.

6 KEY TAKEAWAYS FOR HYDROGEN POLICY

1. Policy makers face a choice of how to cost effectively deploy the limited amounts of green hydrogen that will be available in the medium-term. There are a number of no-regret options for sectors where green hydrogen should be deployed (such as for the replacement of grey hydrogen and in industry or shipping).

2. Blending green hydrogen into the grid indiscriminately instead risks "wasting" hydrogen by having it deployed to sectors like heating where more efficient and cost effective solutions such as direct electrification using heat pumps are possible. The analysis shows that a 5% blending target within the EU 2030 scenario would require about 50 TWh of hydrogen. This represents a significant share of the total green hydrogen (132 TWh) that would be available in 2030 under the COM hydrogen strategy.

3. Green hydrogen blending offers only GHG savings in the amount of replaced natural gas. 50 TWh of additional direct H_2 use instead of blending, on the other hand, could save an estimated additional 3 million t CO_2eq (30 % more) compared to 10 million t CO_2eq when blended.

4. The adaptation measures for hydrogen blending into the grid will increase costs for end users (by up to 43 % for industrial end-users and up to 16 % for households at a blending level of 20 Vol-%). The current cost increases for gas prices show how political this factor is.

5. In the long term, a H_2 backbone transport network can provide an efficient infrastructure for central H_2 consumers. However, this will only use part of the current natural gas network, due to high localised future hydrogen demands in industrial clusters.

6. Therefore blending, even at low percentages, constitutes a sub-optimal pathway for the deployment of hydrogen and should be avoided in favour of policy instruments, which can deliver hydrogen to specific sectors. Doing so would avoid lock in risks, generate greater GHG savings for the investments made and avoid added costs being put on all gas consumers.

1. Introduction

Current political discussions

Following the announcement of the European Green Deal and an increased greenhouse gas (GHG) emission reduction target of 55 % by 2030, the European Commission is undertaking a review of the EU energy and climate laws to achieve this target via its so-called "Fit for 55 Package". The first part of this package was published in July 2021 and contained proposals to review the Renewable Energy Directive (RED), Energy Efficiency Directive (EED) and the EU Emission Trading Scheme (ETS). Subsequently, a second part of the package published on December 15 also introduced proposals to update the EU gas market framework and regulate methane emissions from the energy sector.

With its review of the Gas Market Regulation and Directive, the European Commission is giving a strong signal that natural gas will have to be fully phased out in order for the EU to meet its 2050 targets. Its proposals aim to make the gas market fit for the gradual integration of low carbon gases, such as biomethane and hydrogen, to replace natural gas. Much attention is therefore being given to the establishment of a market for hydrogen, to rapidly scale up production and use of hydrogen, and in particular green hydrogen, within the next decade. This in turn would support the targets set under the EU hydrogen strategy from July 2020 to develop 40 GW of electrolyser capacity and produce 10 million tons of green hydrogen[1] by 2030.

Included in the proposals is a measure to support the integration of hydrogen into existing gas grids, also known as blending. The European Commission proposes to set an EU-wide 5% cap for hydrogen blending up to 2030. Though it explicitly acknowledges that blending is less efficient than direct use and diminishes the value of hydrogen, the Commission has argued such a measure will be necessary to facilitate cross-border flows and provide a consistent approach across the internal market. Proponents of blending argue that it provides an easy way to scale up the market for hydrogen in the short term, in the absence of dedicated networks and end-users, with European gas transmission system operators (TSOs) providing strong support for a blending target. A blending target though would have specifically mandated TSOs to integrate a certain percentage of hydrogen into existing networks, whereas a cap only mandates TSOs to facilitate that integration up to a certain percentage. This is a distinction that signifies a preference for direct hydrogen use over blending, but which in effect could lead to a similar outcome.

The discussion around hydrogen blending also needs to be put into the context of hydrogen infrastructure development plans and the build out of dedicated hydrogen pipelines linked to specific end-users to allow efficient use of H_2. On this front, the Commission aims to establish a European Network of Network Operators for Hydrogen (ENNOH) mirroring the role of ENTSO-G, the European Network of Transmission System Operators for gas, to help guide the development of a European network for dedicated hydrogen infrastructure. This would be achieved through both the refurbishment of existing gas pipelines and the development of new dedicated infrastructure, supported also by EU funds made available under the Connecting Europe Facility and via the Projects of Common Interest (PCI) process which has seen a revision that will shift funding away from natural gas infrastructure projects and towards electricity and hydrogen projects.

[1] The figures for installed electrolysis capacity and hydrogen to be produced do not match (see chap.3)

Consistent long-term target image

To better assess the complex requirements of today's regulation, it is helpful to understand the target image for a climate-neutral Europe. Energy system models can determine a target system of minimum cost, independent of today's market conditions or taxation. By means of economic optimisation (lowest CO_2 avoidance costs), the repercussions of a future energy supply dominated by weather-dependent RES (wind, PV) are solved. We use the cross-sectoral capacity expansion planning framework 'SCOPE Scenario Development' (SCOPE SD) [2] to develop a long-term carbon-neutral energy system scenario in Europe for the scenario year 2050. The underlying large-scale optimisation model captures the power, building, industry, and transport sector for each country modelled as one bidding zone. By meeting climate targets as well as the end-use demands of each sector in every hour of the considered scenario year, the cross-sectoral capacity expansion planning model is able to determine the cost-optimal installed capacities, including the economic dispatch of single technologies.

The following example results of Fraunhofer IEE's complex models are intended to illustrate the interrelationships. At this point, we use existing model calculations that are comparable to hydrogen demand of the 1.5°C long term EU scenario. It becomes clear that a target system tends to maximise the direct use of electricity, and that PtX products (H_2, PtL, ...) are mainly used where the use of electricity is not possible (or is too expensive) in terms of time (less RES generation) or space (grid bottlenecks). This is illustrated by the following example of electricity generation and consumption in a CO_2-neutral Europe. H_2 offers the advantage of a relatively large amount of capacity with short operating times (gas-fired power plants or heating plants in industry). In contrast, electricity consumption is dominated by new sector coupling applications. Electrolysis (power-to-gas) is one part of it. Heat supply for (most of today's gas demand) is concentrated on heat pumps and district heating.

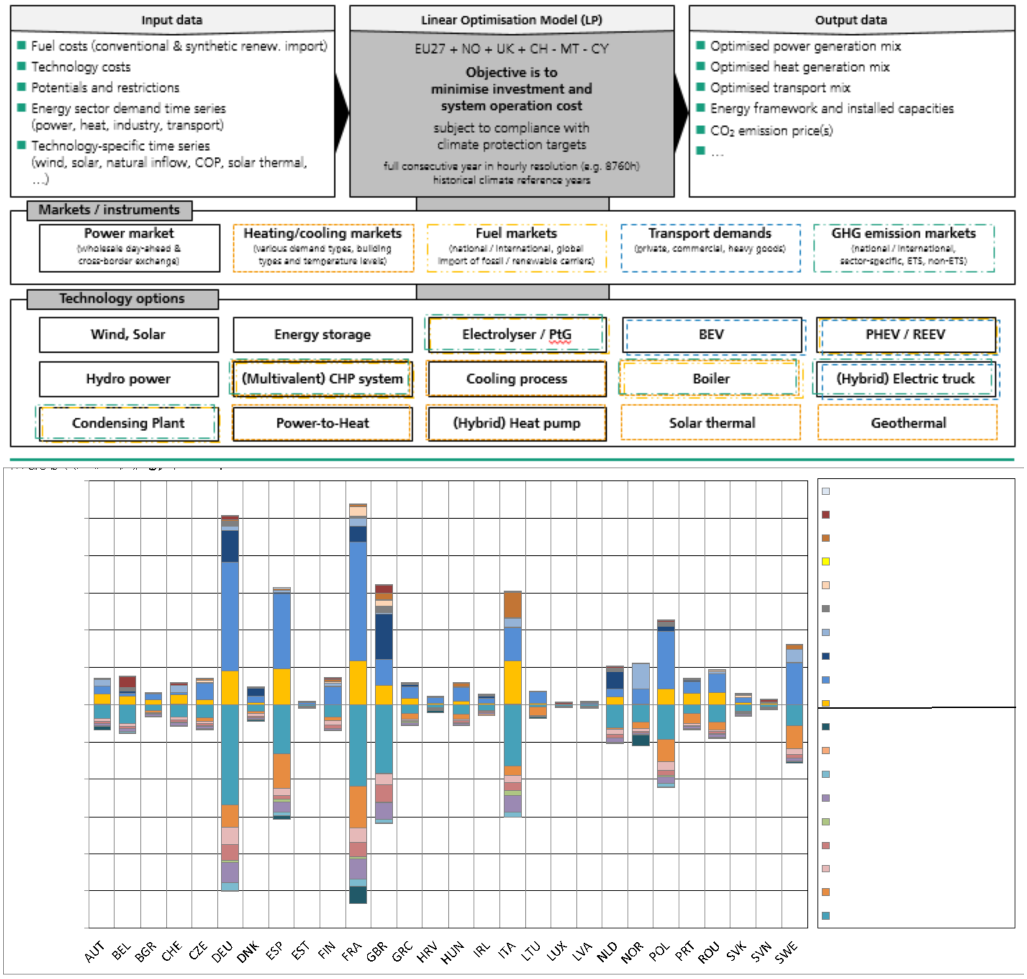


Figure 7: SCOPE-SD Scenario Development (Fraunhofer IEE) and example of cost-minimal electricity system 2050
Source: Authors' figure based on own scenario calculation [3]

With regard to the future hydrogen network, the effects on the gas market can be determined in a separate model. Compared to the electricity grid, it is evident that the H_2 grid can transport large amounts of energy more cost-effectively and with greater capacity. The infrastructure therefore adapts to H_2 generation. It is a robust assumption that most of the future H_2 generation relevant for Europe comes from offshore wind plants and is imported from the MENA region by pipeline. Liquefaction and transport by ship, on the other hand, is very expensive and not competitive with European H_2 production [4]. The majority of direct H_2 demand in this scenario is expected in industry and gas-fired power plants [5]. Power-to-liquid, in contrast, tends to be imported from outside this region by ship.

The cost-optimised gas system results in a Europe-wide gas transport network to which large consumers are connected. Depending on the scenario, a gas network supplied with biomethane may exist in parallel for the remaining methane consumers. If so, however, the demand here is lower than for hydrogen. Repurposed old natural gas pipelines mainly form the new H_2 gas network. However, new H_2 pipelines would be necessary in certain places because hydrogen production and demand centres will be different to those for natural gas today. The need for new salt cavern storage facilities, on the other hand, is more significant, as existing porous storage facilities cannot be used for H_2.

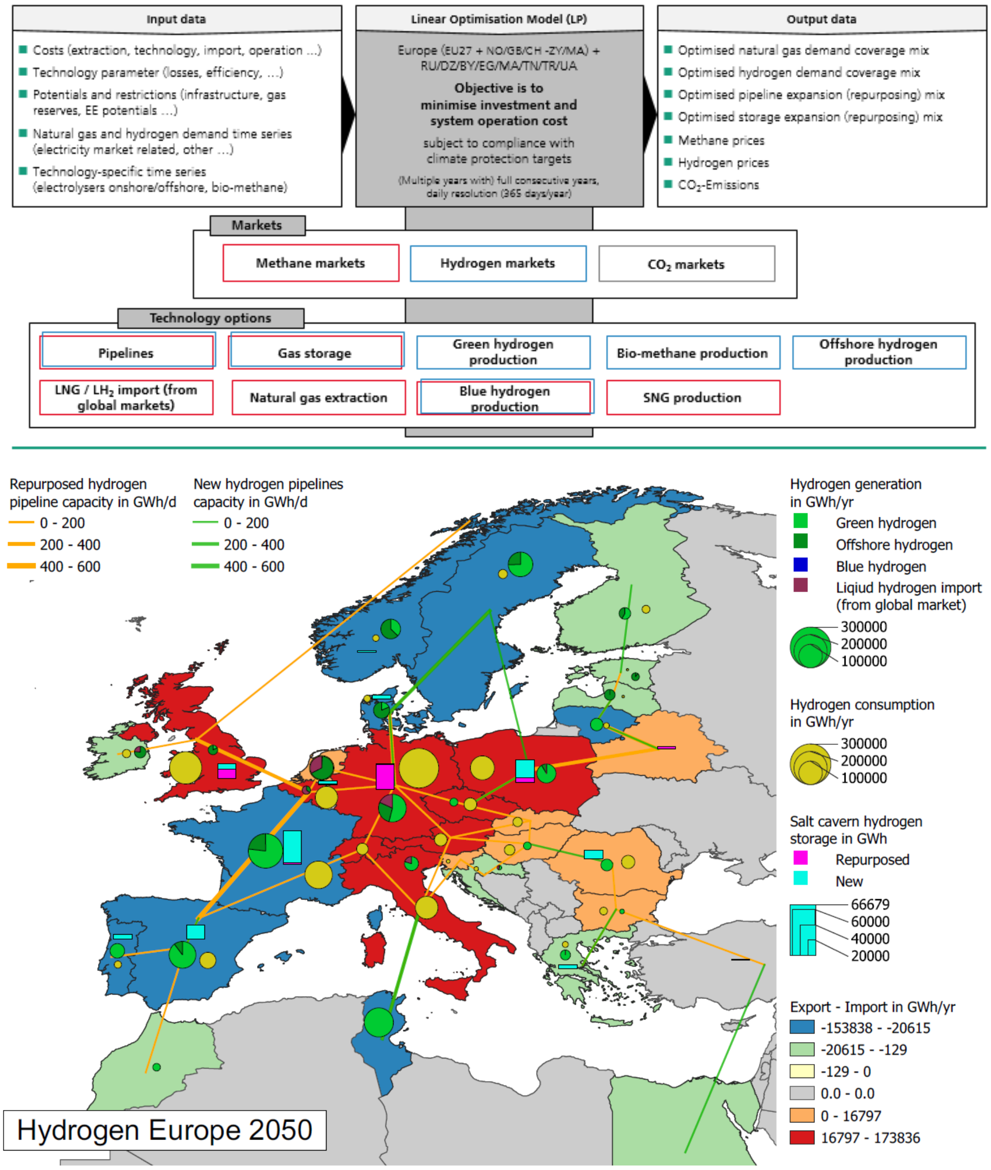


Figure 8: ENIGMA European Infrastructure Gas Market model (Fraunhofer IEE) and example of cost-minimal gas system 2050
Source: Authors' figure based on own scenario calculation - Comparable to the 1.5°C long term EU scenario [6]

Under standard conditions, the calorific value of methane per cubic meter is three times that of hydrogen. But, due to a faster flow of hydrogen, the energy transport capacity is only slightly smaller compared to high-calorific natural gas [7]. Conversely, for storage in caverns, H_2 requires more than three times the space because methane has better compressibility [8]. Compared to today, many pipelines are no longer in operation in the future hydrogen network (based on the hydrogen demand of the 1.5°C long term EU scenario). Cavern storage facilities, on the other hand, are scarce and must be further expanded. Independent of the development of H_2 demand (e.g. H_2 trucks vs. e-trucks, import of PtX pre-products for the chemical industry vs European generation), there is a need to decommission natural gas pipelines - as can be seen from the direct comparison of figure 8 with figure 9.

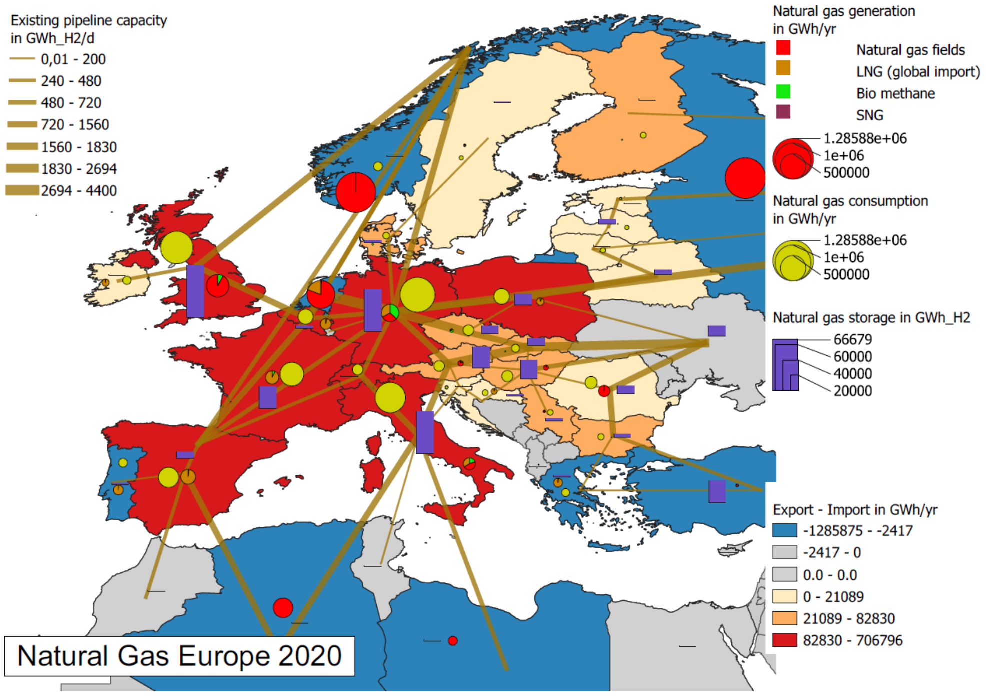


Figure 9: Today's gas market and infrastructure
Source: Authors' figure [6]

Research questions of this study

It becomes clear that hydrogen has an important role for an energy transition toward a climate-neutral energy system with high certainty around some applications (industry) but much less certainty around others. These applications will require a dedicated hydrogen infrastructure that can accommodate the new flows, but the scope of this H_2 transport network (interconnected clusters or a wider EU network) is still partly uncertain, as it depends on hydrogen end-uses, storage and production locations. At the transport network level, new gas-fired power plants do not exhibit a lock-in effect when they are already designed H_2-ready today. In the long term, this grid may also provide technical degrees of freedom for connecting specific H_2 consumers at the distribution grid level. But, due to the lack of area-wide infrastructure in the medium term, the question arises what advantages and disadvantages H_2 blending would have. The following questions for this study are derived from the current regulatory discussion and the target image:

- What influence does the quantity development (until 2050) of the hydrogen market ramp up and direct hydrogen demand have on the need for H_2 blending?
- What are the EU infrastructure sensitivities, current technological capabilities and restrictions for H_2 blending?
- What are the adaptation costs of blending levels at 0%, 5%, 10%, and 20% by volume in 2030? What is the effect on end-user prices?
- What is the emission reduction impact of 0%, 5%, 10%, and 20% by volume hydrogen blending in 2030, compared to direct green/ blue/ grey H_2 use?
- What volumes of grey H_2 are currently used in the EU and how are the medium-term green H_2 quantities transported to the demand sinks?
- Is hydrogen blending required to create additional demand or do the no-regret hydrogen applications with relevant CO_2 reduction potential identified provide sufficient demand in 2030?

Throughout this report, "hydrogen blending" refers to the blending of hydrogen with natural gas at the level of the gas grid (grid-level blending). This is different from ongoing parallel discussions on blending hydrogen with natural gas at the site of consumption (onsite blending), by way of two, separate - one methane and one hydrogen, pipelines which could offer an attractive alternative approach to scaling up hydrogen use in specific end-uses like gas power plants or steel making,[2] but this was not studied in this report.

[2] First, steel made using direct reduced iron can start with natural gas and later add increasing shares of hydrogen (1). This would open up the possibility to invest into a transformative technology (DRI) even if not running it on 100% hydrogen from day one. Second, if new gas power plants are needed for backing up renewables, they could be designed to be 100%-hydrogen ready and gradually blend in increasing amounts of hydrogen, before making the transformative step to 100% hydrogen use. See also https://static.agora-energiewende.de/fileadmin/Projekte/2020/2020_10_Clean_Industry_Package/A-EW_208_Strategies-Climate-Neutral-Industry-EU_Study_WEB.pdf#page=166

2. Short overview of the current EU gas and hydrogen market

In this chapter, the main figures (demand, production, prices, etc.) are presented to give a short overview of the current EU gas market. Because of the worldwide COVID-19 pandemic and its impact on the market, publicly available data from the years 2018 and 2019 was analysed as there was no data from 2020 and 2021. In addition to the summed and averaged figures for the whole of the EU, five example countries were also reviewed. These are the three largest gas consumers: Germany, France and Italy. Furthermore, Ireland and Portugal were also chosen because they had to face relatively high (Portugal) and low (Ireland) additional costs regarding H_2 blending in a previous analysis.

Year 2018	Natural gas demand	Natural gas production	Biogas	Biomethane	Prim. energy demand	Share of natural gas
Country	GWh	GWh	GWh	GWh	GWh	Percent
EU	3,777,258	688,443	160,318	23,117	15,999,317	23.61%
Germany	855,412	54,832	87,912	11,015	3,397,568	25.18%
France	428,384	90	10,228	2,333	2,778,858	15.42%
Italy	692,141	51,892	22,006	1,586	1,712,402	40.42%
Portugal	58,656	0	959	0	263,476	22.26%
Ireland	52,191	31,950	586	35	170,638	30.59%

Table 3: Gas demand and production in the EU
Source: [9], primary energy demand [10]

In Table 3 it is stated that the total demand for natural gas in 2018 was more than 3,777 TWh. In addition, more than 160 TWh of biogas and 23 TWh biomethane were also consumed in the EU. The entire quantity of biogas and biomethane used in 2018 was produced in the EU itself, but only a small share of natural gas (less than 690 TWh, respectively 18.2%) was internally produced in the EU. The main volumes were delivered by Russia and Norway through pipelines.

Germany is the largest consumer of natural gas (more than 855 TWh) and biogas (nearly 88 TWh) plus biomethane (11 TWh) in the EU. However, Italy uses the highest share of natural gas in comparison to primary energy consumption with ca. 40%. France has a relatively low share of natural gas with ca. 15% because most of their electricity is produced by nuclear power plants.

The hydrogen demand in the EU is currently produced mostly using natural gas or coal (so-called "grey hydrogen").

Year 2019	Trans-port	Ammonia	Refinery	Methanol	H_2O_2	Other chems	Energy	Other	Sum
Country	GWh	TWh	TWh	TWh	TWh	TWh	TWh	TWh	TWh
EU	18.74	98.95	154.74	12.78	2.42	24.64	3.69	16.54	313.79

Table 4: Hydrogen demand in the EU in 2019
Source: [11]

Today's grey hydrogen demand accounts for more than the potential H_2 production in 2030 from 40 GW of electrolysis capacity under the EU hydrogen strategy (see also chapter 3). Table 4 shows that hydrogen is mainly needed in the EU in refineries (nearly 155 TWh, respectively about 3.9 million metric tons of hydrogen regarding the upper heating value in 2019) and to produce ammonia (nearly 99 TWh). For hydrogen peroxide (H_2O_2) approximately 2.5 TWh and for other chemicals nearly 25 TWh (as a whole) of hydrogen was used in 2019. Currently only small amounts of hydrogen are needed for energy production (ca. 3,7 TWh) and transport (less than 20 GWh) but that will undoubtedly increase and be produced with renewable energies (so-called "green hydrogen") to reach the goals of the Paris Agreement. The "Other" category with a need of ca. 16.5 TWh hydrogen covers the demand from small to medium scale hydrogen users, including the food industry, glass manufacturing, automotive, generator cooling in the power sector, metal welding and cutting, electronics, research labs, and other small-scale applications.

Emissions

Natural gas is a fossil fuel and causes CO_2 emissions when it is burned for heating. It causes even greater emissions when methane (CH_4) and natural gas, consisting mostly of CH_4, enters the atmosphere (e.g. because of leakage or incomplete combustion). The burning of natural gas causes 181 gCO_2/kWh direct emissions regarding the upper heating value. Additionally, pre-chain CO_2 and CH_4 emissions occur throughout the entire natural gas process chain (extraction, processing, transport, distribution and use). The pre-chain CH_4 emissions are much more relevant and depend on which observation period is used. 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 (see figure 22 in chapter 6). The short-term potency of methane is particularly relevant considering the tipping points in our climate system (e.g. the melting of the polar ice caps).

The direct and indirect emissions combined for GWP 20 are 255 gCO_2eq/kWh and 223 gCO_2eq/kWh for GWP 100. **The natural gas consumption in the EU was ca. 3.8 TWh in 2018. This means direct emissions of ca. 684 million tons CO_2 and, from a 20 years GWP perspective, more than 963 million tons of GHG emissions (respectively ca. 842 million tons GHG emissions for GWP 100).** Direct GHG emissions related to the production of grey hydrogen accounted for 73.5 million tons in 2019. The figures demonstrate that natural gas consumption causes a relevant amount of GHG emissions and must be reduced to reach the Paris agreement. More detailed information about emissions, including emissions related to the production of grey compared to green hydrogen, can be found in chapter 6 with the relevant sources.

Prices

The current price structure of natural gas in the EU member states consists in principle of the three price categories energy price, energy taxes (including levies), and grid fees plus the value-added tax (VAT) for end customers (VAT is a recoverable tax for companies). The gas retailers buy natural gas at an energy exchange or in bilateral negotiations (oriented at the exchange prices). Therefore, the energy price for all customers is based on the average wholesale prices of the European energy exchanges. Sales margins differ between households, commercial and industrial customers, but they were not taken into account in this chapter because they are not publicly available and the differences should not be significant. Also, detailed data for grid fees were not available but could be calculated as the difference between end customer prices excluding taxes and levies and average price data of the wholesale markets (as energy prices).

Year 2018	**End-user price**	Energy taxes	Energy price	Grid fees	VAT
Country	**ct/kWh**	ct/kWh	ct/kWh	ct/kWh	ct/kWh
EU	**6.675**	0.960	2.302	2.338	1.075
Germany	**6.080**	0.595	2.291	2.224	0.970
France	**7.140**	0.955	2.364	2.806	1.015
Italy	**8.325**	1.605	2.461	2.939	1.320
Portugal	**7.715**	0.505	2.360	3.405	1.445
Ireland	**6.965**	0.370	1.988	3.782	0.825

Table 5: Natural gas prices for households in the EU
Source: [12], wholesale "energy price" [13]

In Table 5 are presented the four price categories for households and the end-user price, which is the sum of the four price categories.

The energy price of the EU (2.338 ct/kWh) is the average price of all wholesale markets for each member state in the EU. The end-user price of an average household in the EU was 6.675 ct/kWh in 2018. Here, the price in Germany was lower, but the prices of the other example countries were higher (Italy considerably so with 8.325 ct/kWh due to high energy taxes). The average grid fees of the EU were 2.338 ct/kWh (including storage costs, etc.) in 2018. Here, the German grid fees were also slightly lower, but the grid fees of the other example countries were again higher than the EU average. In particular, the grid fees of Ireland were much higher with 3.782 ct/kWh in 2018.

Year 2018	**End-user price**	Energy taxes	Energy price	Grid fees.
Country	**ct/kWh**	ct/kWh	ct/kWh	ct/kWh
EU	**4.715**	0.715	2.302	1.698
Germany	**4.215**	0.410	2.291	1.514
France	**5.310**	0.865	2.364	2.081
Italy	**5.690**	1.010	2.461	2.219
Portugal	**5.470**	0.735	2.360	2.375
Ireland	**4.980**	0.370	1.988	2.622

Table 6: Natural gas prices for commercial companies (<1TJ) in the EU
Source: [14], [13]

In Table 6 are shown the gas prices of commercial customers with less than 1 terajoules (TJ) of gas consumption and the three price categories (which are the sum of the gas prices).

The average EU gas price for this customer group was 4.715 ct/kWh in 2018. Italy has the highest gas price for this customer group with nearly 1 ct/kWh more than the average price because of high energy taxes (1.010 ct/kWh). Ireland had the lowest energy taxes with 0.370 ct/kWh and the lowest energy (wholesale) price with less than 2 ct/kWh (EU average energy price was 2.302 ct/kWh) compared to the other example countries. On the other hand, Ireland had the highest grid fees with 2.622 ct/kWh (EU average grid fees were 1.698 ct/kWh).

Year 2018	**End-user price**	Energy taxes	Energy price	Grid fees
Country	**ct/kWh**	ct/kWh	ct/kWh	ct/kWh
EU	**3.135**	0.405	2.302	0.428
Germany	**3.160**	0.400	2.291	0.469
France	**3.715**	0.735	2.364	0.616
Italy	**2.895**	0.195	2.461	0.239
Portugal	**2.840**	0.065	2.360	0.415
Ireland	**3.650**	0.360	1.988	1.302

Table 7: Natural gas prices for industrial companies (> 10 TJ and < 100 TJ) in the EU
Source: [14], [13]

In Table 7, the gas prices for industrial customers with more than 10 TJ and less than 100 TJ are pictured. Here, Portugal and Italy had the lowest prices because of very low energy taxes (Italy 0.195 ct/kWh and Portugal 0.065 ct/kWh). France had the highest gas price because it had the highest energy taxes with 0.735 ct/kWh (the average in the EU was 0.405 ct/kWh in 2018). Italy also had the lowest grid fees in this customer group with 0.239 ct/kWh compared to the other example countries (EU average grid fees were 0.428 ct/kWh in 2018).

This price analysis demonstrates that the gas prices are influenced by all price categories. Most notably, the energy taxes differ greatly between countries and in the countries, including between customer groups. This also applies to the grid fees. Here, Germany is always near the average EU grid fees. The other example countries have mostly higher grid fees, especially Ireland. Only for industrial customers are the grid fees in Italy and Portugal lower than the EU average.

3. Short overview on gas market development towards 2030 and beyond towards full decarbonisation 2045/2050

Bandwidths of the development of CH_4 and H_2 quantities

The future role of gas – be it fossil or renewable – will be strongly influenced by technological, economic, regulatory and social developments. As such, it is subject to many uncertainties, which should be taken into account for robust conclusions. Numerous studies have treated the future development of the gas market in the context of GHG emission reductions in Europe. To reflect the wide spectrum of assumptions and outcomes, three scenarios are picked for discussion here:

- the “MIX” scenario of the 2030 climate plan impact assessment by the EC [15],
- the “PAC” (Paris Agreement Compatible) scenario by the Climate Action Network (CAN) and the European Environmental Bureau (EEB), two umbrella organisations for European climate change and environment NGOs [16], and
- the “Accelerated Decarbonisation Pathway” by Gas for Climate, a consortium of ten European gas transmission grid operators [17].

In the following, these scenarios will be referred to as the "EU', “PAC" and "GfC" scenarios, respectively.

The EU scenario in accordance with the ambitions of the European Commission heads for a 55% reduction of greenhouse gas emissions by 2030, and climate neutrality by 2050. This scenario presumes a mixture of increased policy ambitions with respect to energy efficiency, decommissioning of renewable energies, conversion of the transport sector, as well as expanding carbon pricing. With regards to the gas market, the EU scenario states a modest reduction and shift from natural gas to biogas and hydrogen by 2030, which progresses continuously until 2050.

The GfC scenario similarly aims to be in line with the targets of the European Commission, while keeping a larger role for gas on energy supply by the means of carbon-low and carbon-free gasses like natural gas with CCS and blue hydrogen. The colour “blue” in this context refers to hydrogen that is generated from fossil energy carriers (in particular natural gas) with CCS.

The PAC scenario, in contrast, promotes an as-soon-as-possible exit from fossil energy carriers. It states a complete exit from natural gas usage by 2035. All three scenarios assign an important role in decarbonisation to electrification. Gases should mainly be deployed where electrification would either be uneconomic or technically unfeasible, like in some high-temperature industrial processes in steel, cement, and ceramics production, or in transport for heavy-duty road transport and shipping.

In the following, the projections of the EU, PAC and GfC scenarios on the methane and hydrogen market towards 2050 will be discussed. Before going into details, it is essential to note that conclusions from direct scenario comparisons should be drawn with some caution, as the scopes of the underlying models are not identical. The most striking difference is their regional scope – EU27 (excluding the United Kingdom) for the EU scenario, and EU28 (including the United Kingdom) for the PAC and GfC scenarios. Moreover, the GfC scenario neglects agriculture as a GHG emitter, while the EU scenario does not differentiate between biogas and biomethane within the published data set. Moreover, the EU and PAC scenarios do not reflect the by-products of hydrogen production (e.g. from the chlorine alkaline synthesis) and grey hydrogen production (e.g. for hydrolysis in refineries, or ammonia synthesis) in their data sets. Also, they present only the final energy demand for hydrogen, thereby excluding the hydrogen demand for e-fuel synthesis, as well as the demand for hydrogen as a feedstock. In order to compensate for some of these differences, and hence facilitate the comparison, a couple of adjustments are made to the original data sets here.

- The PAC and GfC data are scaled by a factor of 0.83, which represents the ratio of natural gas inland consumption of the EU27 to the EU28 in 2019 [18].
- The volumes of by-product from hydrogen generation in the GfC scenario are added to the hydrogen volumes for the EU and PAC scenarios.
- The green hydrogen supply within the EU scenario is derived from the projected electrolyser capacities, i.e. 13 GW by 2030 and 554 GW by 2050. Assuming 4000 full load hours and a conversion efficiency of 70% with respect to the LHV of hydrogen, this translates into 43 TWh in 2030, and 1835 TWh in 2050.
- The 2030 value for grey hydrogen within the EU scenario is calculated so that the sum of green and grey hydrogen volumes by 2030 equals the grey hydrogen volume in 2020, plus the additional 13 TWh of hydrogen for new applications within this scenario by 2030.
- Industrial hydrogen demand according to the GfC scenario for 2020 is added as an offset to the (new) industrial hydrogen demand in the EU scenario.
- For the EU scenario, the 2040 values are linear interpolations of the data for 2030 and 2050.

Development of the methane market

Figure 10 and Figure 11 show the development of methane consumption for the EU (i.e. EU27) resolved by type and sector.

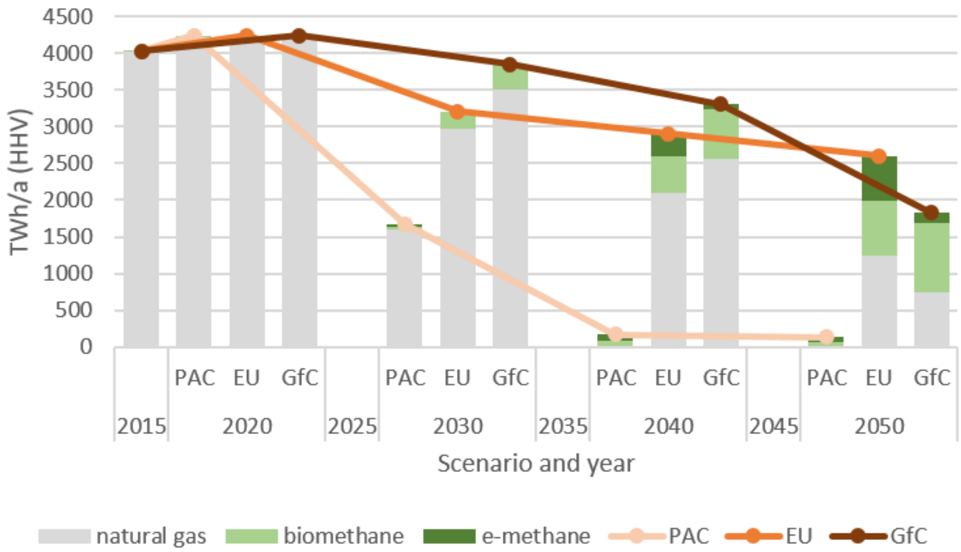


Figure 10: Development of methane consumption in scenario comparison
Source: Authors' figure based on the analysis of the PAC, EU and GfC scenario.

Following the quick exit by 2035 within the PAC scenario, natural gas consumption in 2030 is already cut by more than 60% compared to the reference year 2015. Although the amount of biomethane (which was 18 TWh in 2015) more than doubles during the same time span, and finally triples to 62 TWh in 2050, the overall methane consumption drops to only a minor fraction of today's quantities. Within the EU and GfC scenarios, on the other hand, methane keeps playing a much bigger role on the energy market. Due to the deployment of CCS, e-methane production, and in particular a substantial increase in biomethane capacity, the total methane consumption in these two scenarios remains on a comparatively high level until 2050. Expressed in numbers, this means an overall methane consumption of 80% to 90% of today's 4200 TWh by 2030, and 45% to 60% by 2050.

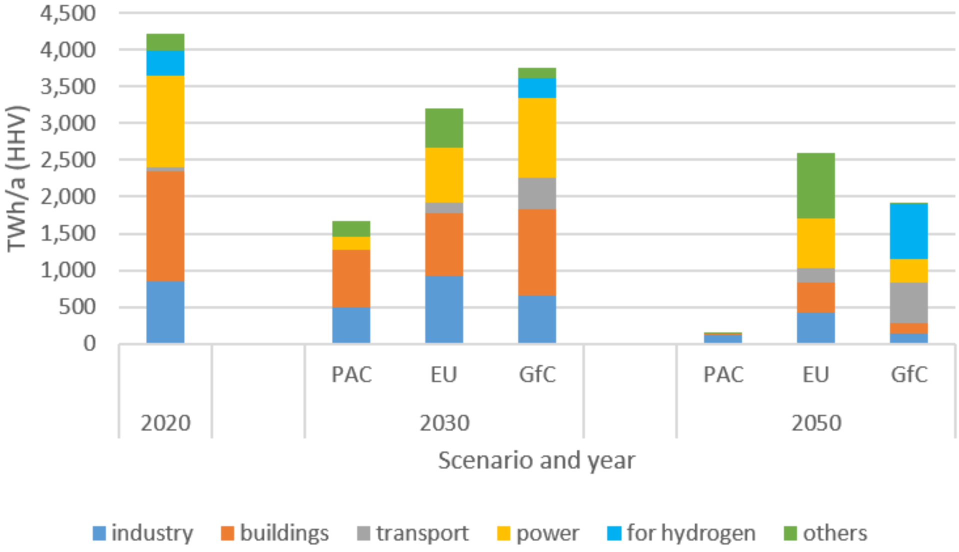


Figure 11: Development of methane consumption by sector in scenario comparison
Source: Authors' figure based on the analysis of the PAC, EU and GfC scenario.

Considering the projected evolution of methane demand by sector, the EU and GfC scenarios again draw a rather similar picture. The demand by all current main end users - buildings, industry and power – will decrease substantially. For the buildings sector, methane consumption will fall most significantly by 20% to 40% until 2030, and 70% to 90% until 2050, until this sector becomes a minor end user of methane. Conversely, the hydrogen production from methane and the transport sector could become important new fields of demand in the GfC scenario.

<u>Development of the hydrogen market</u>

Figure 12 and Figure 13 show the development of hydrogen generation and consumption in the EU resolved by type and sector.

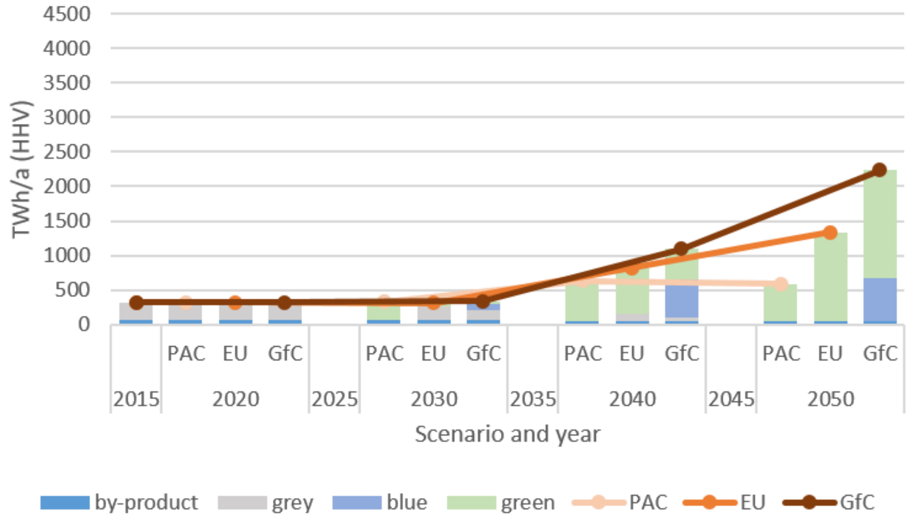


Figure 12: Development of H_2 supply in scenario comparison
Source: Authors' figure based on analysis of the PAC, EU and GfC scenario.

Today's hydrogen is produced mainly as a by-product of the chlor-alkali electrolysis and as grey hydrogen from steam reformation. All three scenarios agree in that they foresee a significant ramp-up of the domestic green hydrogen production capacity in the EU. By 2030, the PAC scenario is most ambitious with almost 300 TWh of H_2 produced from renewable energies, while the EU and GfC scenarios anticipate around 40 TWh of green hydrogen. By 2050, this picture turns around as the hydrogen volumes in the PAC scenario "just" double to about 590 TWh, while they increase by a factor of 40 to 45 to reach around 1570 TWh in the GfC scenario and an estimated 1800 TWh within the EU scenario. In total, between 300 TWh and 350 TWh of H_2 are expected to be produced and consumed by 2030 and between 590 TWh and 2200 TWh by 2050.

Within its hydrogen strategy from 2020, the EC formulates a target capacity of 40 GW of water electrolysers by 2030. Counting with 4000 full load hours on average and a conversion efficiency of 70%. With respect to the hydrogen LHV, this translates into around 130 TWh of green hydrogen.

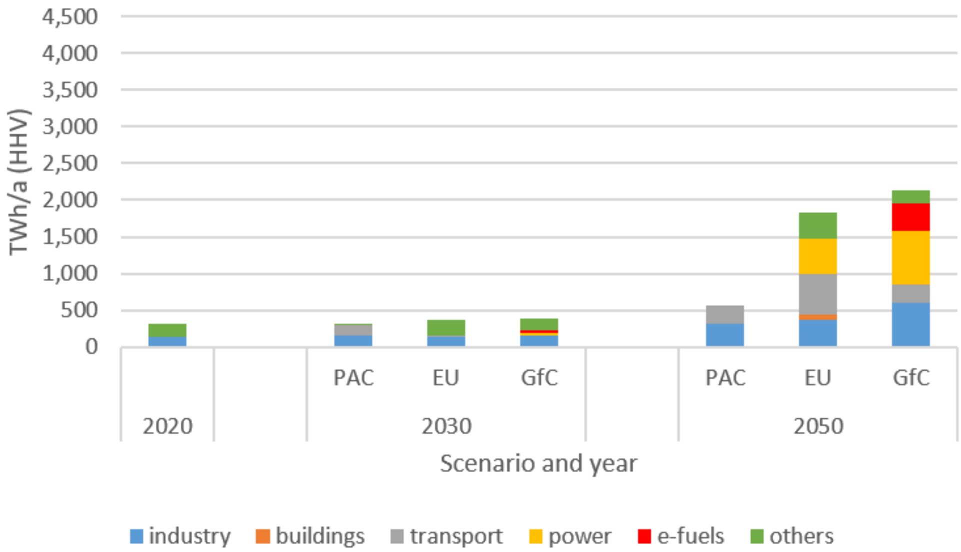


Figure 13: Development of H_2 consumption by sector in scenario comparison
Source: Authors' figures based on analysis of the PAC, EU and GfC scenario.

The prioritisation of sectors that use hydrogen differs somewhat between the three scenarios. Within the PAC scenario, hydrogen usage is allocated with roughly even shares to industrial and mobility applications. According to this scenario, their hydrogen volumes will amount to 160 TWh and 130 TWh by 2030 respectively and would from there double towards 2050. The PAC scenario, however, allocates hydrogen neither to the power, nor to the buildings sector. The EU and GfC scenarios also consider the industry and transport sectors as important hydrogen end users. Additionally, however, they also attribute a significant part of hydrogen consumption to the power sector, as reserves in times of low renewable energy generation, as well as for minor consumption by the buildings sector for heating in the time after 2030. Until 2030, the EU scenario counts only a few new fields of hydrogen usage – mainly 13 TWh in the power sector. The role of hydrogen in this scenario manifests itself in the period after 2030, with roughly 550 TWh for transport, 480 TWh for power, 370 TWh for industry and 80 TWh for the buildings sector in 2050. Within the GfC scenario, the 390 TWh of hydrogen consumed in 2030 is composed of 170 TWh for feedstock (~5 TWh less than in 2020), 150 TWh for the industry sector (10 TWh more than in 2020), 40 TWh for the transport and e-fuels sector and 30 TWh for the power sector. By 2050, the GfC scenario foresees the power, transport/e-fuels and industry sector with volumes between 720 TWh and 600 TWh to be by far the main end users for hydrogen in the EU.

Hydrogen blending

The three scenarios discussed above (EU, PAC, GfC) do not consider the blending of hydrogen and methane explicitly. Hydrogen blending in general is discussed mainly as a transition technology for the ramp-up phase of the hydrogen market. It is hence most useful to assess the potential volumes in question for the year 2030. Figure 14 depicts the hydrogen volumes that would be required to blend all methane consumed in the PAC, EU and GfC scenario in 2030 by 5%, 10%, 15%, and 20% of hydrogen by volume. The figure also replots the anticipated hydrogen consumptions by sector for 2030 from Figure 13, as well as the targeted green hydrogen capacity of 130 TWh by 2030 of the EC, quoted earlier.

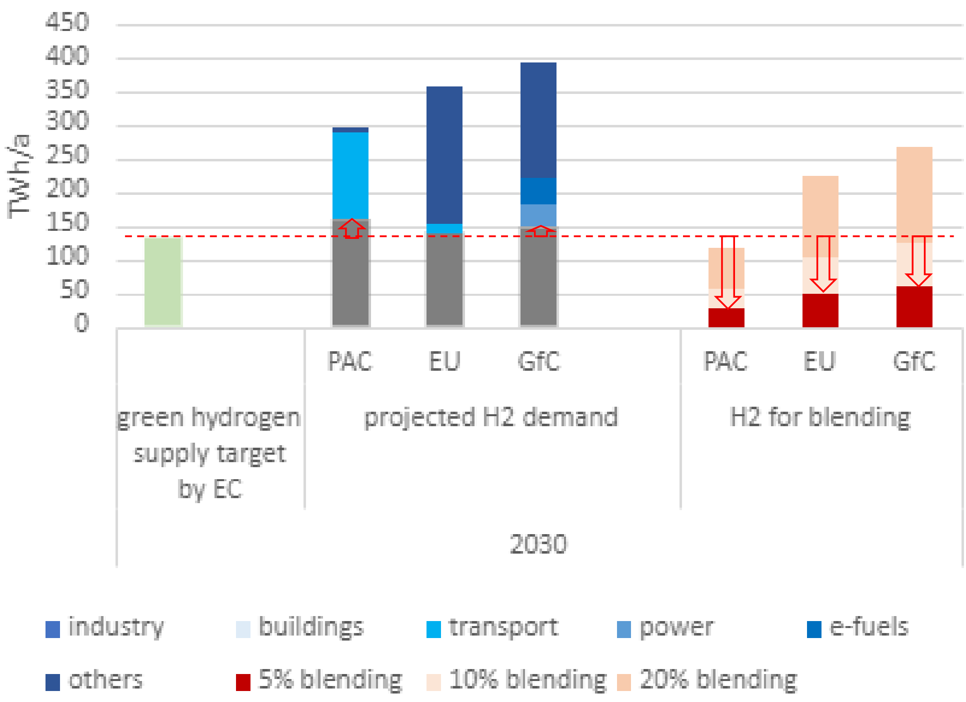


Figure 14: H_2 required for blending vs. targeted green H_2 supply and scheduled demand for 2030
Source: Authors' figure based on analysis of the PAC, EU and GfC scenario, and the hydrogen strategy of the European Commission.

Within the PAC scenario, total methane usage by 2030 is already very limited. In this case, high degrees of hydrogen blending would be required to absorb a substantial amount of green hydrogen. At the same time, the period of application would also be very limited, as the PAC scenario presumes a complete drop-out from natural gas by 2035. Within the EU and GfC scenarios, 5% of blending would translate into hydrogen amounts of 50 TWh (EU) and 60 TWh (GfC), and 20% to 115 TWh (EU) and 125 TWh (GfC).

In other words, hydrogen blending of 5% would already consume almost 40% of the 130 TWh green H_2 supply, which results from the EC 40 GW water electrolyser target. High blending volumes of 20% would consume 90% of it.

This means that relatively low degrees of blending already lead to a large absorption capacity of green hydrogen. **At the same time, the overall demand for no-regret hydrogen exceeds the 130 TWh of green hydrogen generation capacity according to the EC hydrogen strategy in each of the three scenarios.** Within the GfC scenario, industry would already require 147 TWh of hydrogen. Within the EU scenario, 120 TWh of grey hydrogen for ammonia synthesis could be replaced by green hydrogen. Within the PAC scenario, the transport sector alone could absorb 129 TWh of hydrogen by 2030, while the industry sector potentially absorbs 159 TWh.

It must be noted here, that the quantification of blending in Figure 14 technically requires constant annual H_2 proportions. The green H_2 generation depends on the electricity supply and therefore fluctuates with respect to the gas shares. In the transmission grid, a higher equalisation occurs due to seasonal storage. However, this has to be checked on a case-by-case basis. If H_2 was fed into the distribution grid, the fluctuations would be very high.

Regional distribution of H_2 applications to be prioritised

For the market ramp-up of green hydrogen, the question is how it can be transported to the demand centres, or whether it must be fed into the natural gas grid by blending. In the industrial sector, the applications to be prioritised were identified regionally by Agora Energiewende [1]. This includes the applications already supplied with grey hydrogen today, as well as new ones such as steel production and recycling. In 2030, the potential demand still exceeds the supply of green hydrogen.

TWh H_2 (HHV)	2020	2030	2040	2050
Refinery	163	136	17	0
Ammonia	129	123	118	114
Methanol	12	12	12	12
Chemical plastics recycling	0	5	33	50
Steel	0	53	131	145
Total H_2 demand	**304**	**329**	**311**	**320**
Green H_2	**0**	**130**		

Table 8: H_2 consumption by industry to be prioritised in the EU
Source: Authors' figure based on Agora Energiewende, 2021: No-regret hydrogen: Charting early steps for H_2 infrastructure in Europe [1].

For the applications identified by Agora Energiewende, four clusters were formed, which could form the core of a H_2 startup network because consumption and generation are in relative spatial proximity. In the four regions, a demand of 148 TWh H_2 HHV (45% of the Europe-wide demand) would be encountered in 2030. **This focused H_2 usage represents more demand than the estimated 130 TWh of**

green hydrogen generation from the EC 40 GW of electrolysis target. Thus, there would still be a residual demand of grey H_2.

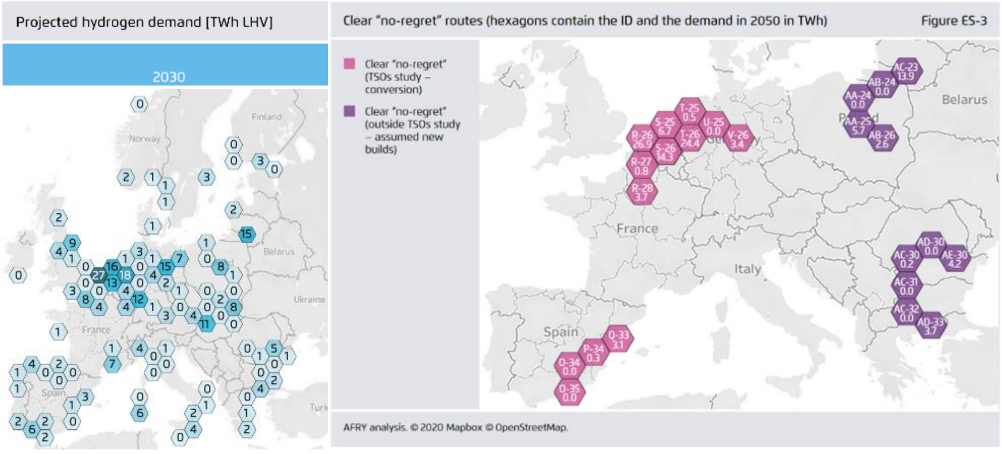


Figure 15: H_2 consumption by industry in four concentration areas to be prioritised in the EU
Source: Authors' figure based on [1].

But even within a scenario, where more H_2 is imported (or blue H_2 is produced), the question of how a missing H_2 transmission grid in 2030 will be compensated becomes increasingly important. As stated earlier, on-site hydrogen generation and/or onsite blending can provide alternative solutions for industrial applications and thereby compensate for the lack of a hydrogen transport grid.

4. Technical aspects of blending hydrogen into the natural gas networks

Within this chapter, the blending aspects analysed are related to public gas networks only.

The gas network infrastructure is basically divided into gas transmission networks and gas distribution networks. For domestic gas demand, the gas transmission networks transport gas from the border crossing points to the interfaces of the gas distribution networks as well as to large consumers, e.g., industry or power plants. Furthermore, they serve the transit of gas volumes within Europe as well as to gas production areas. In addition, they are connected to underground natural gas storage facilities. The gas distribution networks distribute the gas to the majority of gas consumers, such as household customers or CNG filling stations.

General blending limits from the perspective of distribution grids without critical end use

"Hydrogen blending" or "grid-level blending" refers to the addition of H_2 to CH_4-rich gases transported in natural gas networks. Such admixtures are possible in principle and have already been applied in several projects, but they are not unlimited. It is essential to note that **there is no unique limit for a general blending cap for hydrogen-natural gas mixtures**. From the technical perspective, the **upper blending limits essentially depend on the tolerances of the various gas consumers or customers within a network area**. But they also depend on the tolerance and sensitivity of the gas infrastructure itself. The gas properties of the various methane-rich gases also have an influence on the absorption capacity for hydrogen. These **H_2-blending limits** are described in the technical standards of the gas sector or other e.g. legal regulations and can **differ between different European countries** [19].

Within standard EN 16726 from 2019 it is stated: "**At present, it is not possible to establish a limit value for hydrogen that is universal for all areas of European gas infrastructure, and therefore a case-by-case analysis is recommended**." [20]

Besides the technical sensitivities of gas infrastructure components described below, calorific value, Wobbe index and relative density also affect the blending capacity for hydrogen in natural gas networks.

In the following figure (with reference to the example of the German gas market) 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 admixtures, 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 still be used.

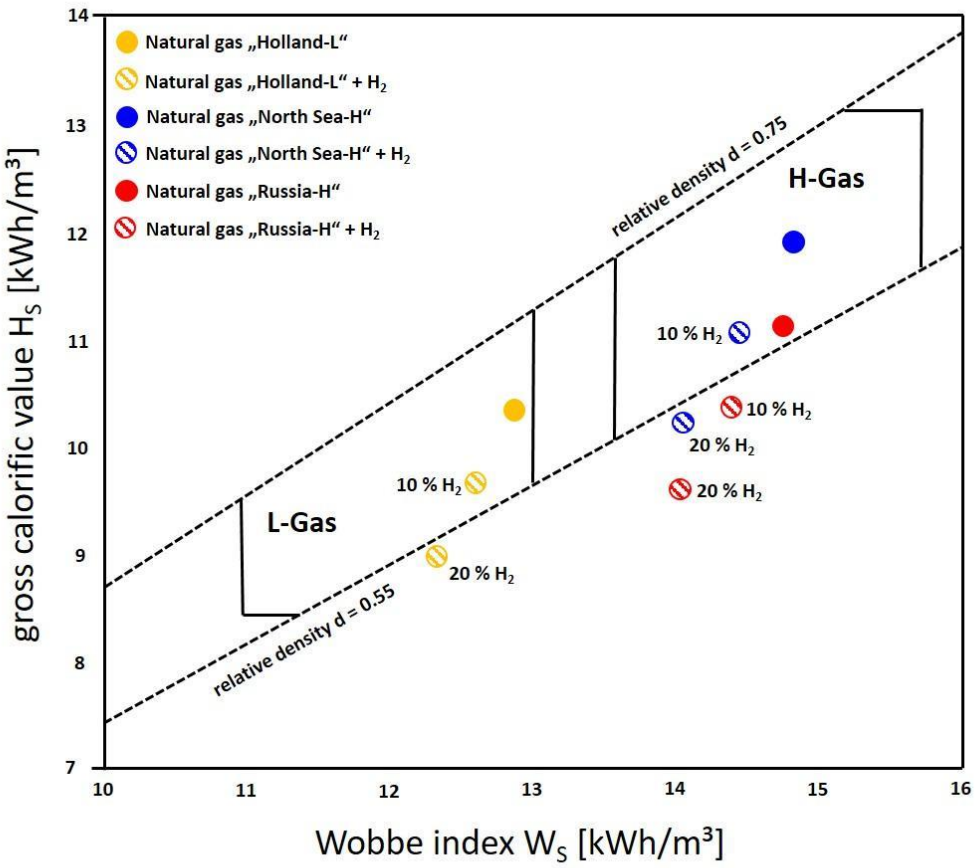


Figure 16: Change in gas quality characteristics (H_S, W_S, d) as a function of hydrogen concentration for three different natural gases, taking into account DVGW G 260 thresholds (as of 2013).
Source: Authors' figure based on [21] [22] [23]

<u>**Boundaries of critical end users**</u>

The following table shows selected examples for H_2-blending rates that are at least possible without adjustments according to the current state of knowledge (dark green). It shows furthermore:

- Dark green: No significant issues,
- Light green: Modifications/other measures may be needed
- Yellow: Conflicting references were found, R&D/clarification required
- Orange: Technically feasible, significant modifications/ other measures or replacement expected
- Red: Currently not technically feasible
- White: insufficient information, R&D demand

Most relevant restrictions occur within utilisation in material use at industrial applications, gas turbines and CNG-mobility. Increased H_2-concentrations can create a demand for de-blending measures for sensitive consumers about membranes. In addition, many other adjustments are necessary. These are sometimes complex to implement and involve varying degrees of cost.

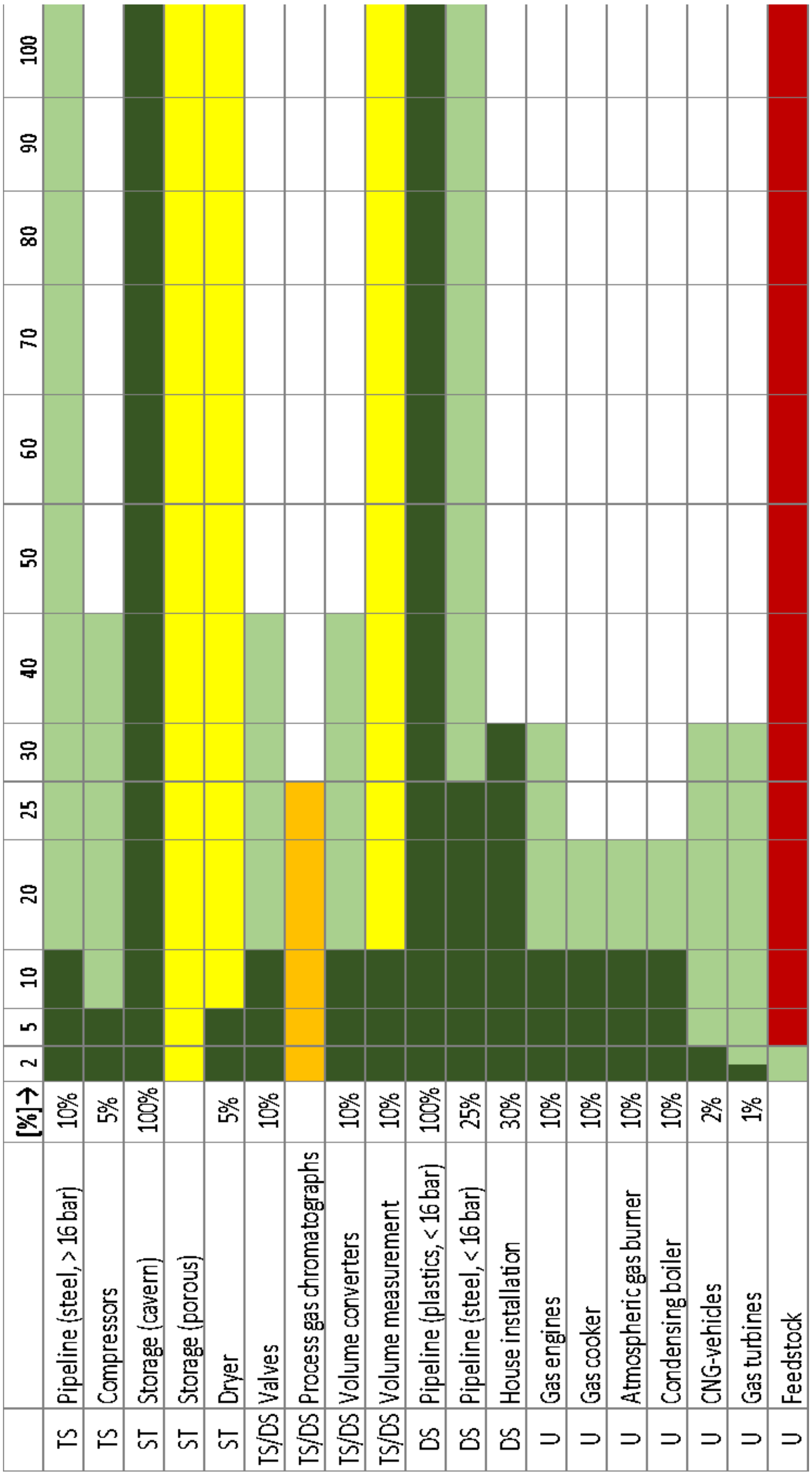


Table 9: Limitations for H_2-blending rates of selected components of gas infrastructure and utilisation options. (TS: Transmission system, ST: Storage, DS: Distribution system, U: Utilisation

Source: Authors' figure based on [24] [25] [26]

Gas infrastructure

Pipelines in transmission and distribution systems

In the area of transport pipelines, it can be assumed that up to 10% by volume H_2 admixture is unproblematic at pressure levels > 16 bar. Higher H_2 tolerances may be possible, but depend on the respective pipeline materials. In the area of distribution networks, in contrast to transport networks, plastic pipelines are also used. Here, a H_2 tolerance of up to 100% can be expected. When steel pipes are used in the distribution network, it is assumed that in the pressure range < 16 bar, 25% by volume H_2 admixture is possible without any problems [24] [25].

- We assume that this point is economically uncritical, as only a few lines need to be replaced in individual cases.

Domestic gas piping

In general, such piping systems in households should be applicable for 20 Vol.-% of hydrogen. Nevertheless, exceptions can occur e.g. for gas meters regarding calibration requirements. The long-term durability of elastomer seals is the subject of current research [27].

- To avoid meter expansion, we assume the introduction of calorific value reconstruction systems at distribution grid level for an increase from 10% to 20% H_2 by volume.

Compressors

According to [24] [25] for H_2-blendings up to 5 Vol.-% no problems are to be expected. In Germany's natural gas infrastructure mainly turbo-compressors with one or two impellers are used, which are operated with gas turbines or motors. Depending on the hydrogen content in the pipeline, this infrastructure can be maintained or adapted accordingly: Up to approx. 10% H_2, the compressor can usually continue to be used without major modifications. Up to approx. 40% H_2, the compressor housing can be retained; impellers and recirculation stages as well as gearboxes must be adapted. Above approx. 40% H_2, the compressor must be replaced [26].

- In simplified terms, we assume that an increase from 10 to 20% H_2 by volume accounts for about 50% of the investment costs for new compressors.

Measurement technology

The most important measuring devices within the gas infrastructure are volumetric meters and process gas chromatographs for gas composition measurements.
For gas volume measurements, meters of different measuring principles are used with divergent H_2 sensitivity. According to this, a H_2 compatibility of up to 10% by volume can be assumed in principle. Higher compatibility levels are not excluded depending on the measurement method but require further investigation [24] [25] [28].
Process gas chromatographs were in the existing natural gas infrastructure usually only designed for very low H_2 concentrations ≤ 0.2 Vol.-% H_2. For gas chromatographs, a case-by-case approach is required. To measure relevant hydrogen contents, helium is required as an additional carrier gas. Meanwhile process gas chromatographs with H_2-compatibilities up to 25 Vol.-% are available at the market. Therefore, the exchange of such devices is necessary but technically feasible [24] [28].

- We assume that an increase from 5 to 10% H_2 by volume will cause corresponding costs.

Underground storages

Since hydrogen serves as a substrate for sulfate-reducing bacteria, there is also a risk of bacterial growth, especially in underground pore storages. This bacterial growth can lead to the formation of hydrogen sulfide, the consumption of hydrogen and damage to the permeability of the storage itself. According to DVGW G 262, it was therefore recommended to limit the injection of hydrogen into pore storages. In [27] it is described that for certain pore storages 10 Vol.-% hydrogen by volume can be tolerated. According to [25] there is still R&D/clarification demand.

With regards to cavern storages, H_2-blendings up to 100 Vol.-% are for the storage itself uncritical.

- There are high uncertainties here and the restrictions are locally very storage-specific. We assume that investments in desulphurisation are already made from 5% H2 by volume. However, the costs are low. We have neglected the possible loss of permeability. Depending on the geometry of the gas storage facilities, however, 20% of blending could lead to the successive loss of individual storage facilities or they may have to be protected by de-blending. This must be examined in each individual case.

Gas utilisation:

Gas burners

In Germany, 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 [29].
According to [24] the equipment test for natural gas terminal equipment approved in the EU indicates a safe operation with up to 23 % hydrogen with regard to the flashback behavior and thus the risk of explosion. According to [24] [25] for H_2-blendings up to 10 Vol.-% no problems are to be expected. Up to 20 Vol.-% modifications or other measures may be needed.

CNG-vehicles

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** [22]. 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.

Gas engines

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 [21]. The addition of hydrogen **to natural gas is thus extremely limited for these two gas mixtures.**

Gas turbines

The table above shows that for gas turbines, a H_2-content of 1 Vol.-% is possible without adjustments. In addition, the German 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. Furthermore, the table above shows that in a range by 30 Vol.-% H_2 modifications or other measures may be needed. In the case of H2-ready turbines, in order to make the leap to 100%, the combustion chamber must be replaced, which entails higher costs.

Industrial applications

Regarding industrial applications, the following is stated in the "Gas 2030 Dialog Process": "However, even small admixture 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 admixture, given the increased need for measurement and control technologies, we can also anticipate impairments to the energy efficiency of production processes. Consequently, hydrogen admixture is not viewed as a priority option for the applications in the industrial sector" [30].

De-blending measures for H_2-sensitive consumers

A demand for de-blending measures can occur mainly for H_2-sensitive consumers such as industrial applications, especially if gas is used as a feedstock, for gas turbines for electricity generation or for the mechanical drive of compressors in the gas grid and storage as well as other power plants or, in individual cases, the protection of underground pore storages. Depending on network operation strategies, demand for de-blending can also occur on network nodes. Within the gas distribution network currently, CNG-refueling stations are most sensitive for increased H_2-concentrations. In this case de-blending demands can also occur.
Several technical options can be considered for de-blending. The most relevant seem to be the conversion of H_2 to CH_4 and the separation of H_2 from the CH_4-rich gas stream. The conversion of H_2 to CH_4 implies a reaction of H_2 with CO_2 using the methanation processes. For gas separation, gas permeation processes, adsorption processes or cryogenic processes can be considered as technical feasible options.[25]

- For the chemical industry and gas turbines (power plants, drive compressors in the gas grid and gas storage), we assume costs from 5% H2. For CNG vehicles, we assume that by 2030 old vehicles with old tanks will have disappeared from the market. For engines and steam turbines, we assume de-blending measures with an increase from 10% to 20% H2.
- For process heat (furnaces), we assume a calorific value adjustment of 10% and 20% H2 (blending of LPG - liquid petroleum gas).

The investment costs for de-blending membranes are relevant, but not decisive. This is because de-blending takes place at ambient pressure and the methane can be used directly by the end consumer, so no expensive post-compression by compressors is necessary. However, this is also accompanied by the fact that the valuable hydrogen can sometimes only be used inefficiently locally.

Opting for an approach of onsite blending instead of grid-level blending at i.e. industrial sites would reduce the need for de-blending measures in the natural gas grid.

<u>Conclusions</u>

Up to 20 Vol-% of H_2-blending seems to be technically feasible in a mid-term perspective. It has to be stated that by the substitution of 20 Vol-% natural gas by H_2, the energy flow is decreased by ca. 13% (assuming the same volume flow). This means **ca. 6-7 % GHG-savings by substitution of 20 Vol-% NG by green H_2.**

Besides the sensitivities of transport and storage infrastructure components, possible blending levels depend amongst others, on natural gas-origin, resp. composition. There are still many uncertainties regarding the (long term) H_2-sensitivities of materials (pipes, devices, etc.). In distribution networks, increased H_2-concentrations are still most critical for CNG-vehicles. But in general, in the distribution system there are lower requirements for infrastructure adjustments below 20% H_2-blending compared to the transmission grid. In the transmission networks, blending is more critical, even at low %, for directly supplied industrial consumers, power plants and underground pore storages.

De-blending demands can occur at network nodes and by directly supplied sensitive consumers and impose additional costs. However, direct feed-in through decentralised electrolysis into the distribution grid already shows high fluctuations at very low H_2 percentages on an annual average and thus exceeds the limit. As long as there is not already a pure H_2 transport network covering almost the entire area, H_2 must be fed in mainly via the transport network in order to use the balancing effect of seasonal storage.

The following limits are considered in the next chapter:

- From today's perspective, 2% H_2 is a limit, but in the next few years this will be less relevant. At 0% to 5% H_2, a big first adjustment step is needed because of the large number of gas turbines.
- At 5% to 10% H_2, a wide range of costs are added.
- At 10% to 20% H_2 there is more additional costs and technical need for adaptation, mainly because of volume-based billing in the distribution grid and the loss of valuable hydrogen through de-blending.
- 20% H_2 is a hard limit because of the replacement of boilers.

In the cost calculation in Chapter 5, these adaptation measures are only related to the old plants that are still in operation in 2030. For the plants that will be commissioned by then, we assume H_2-ready plants in the sense of a potential calculation.

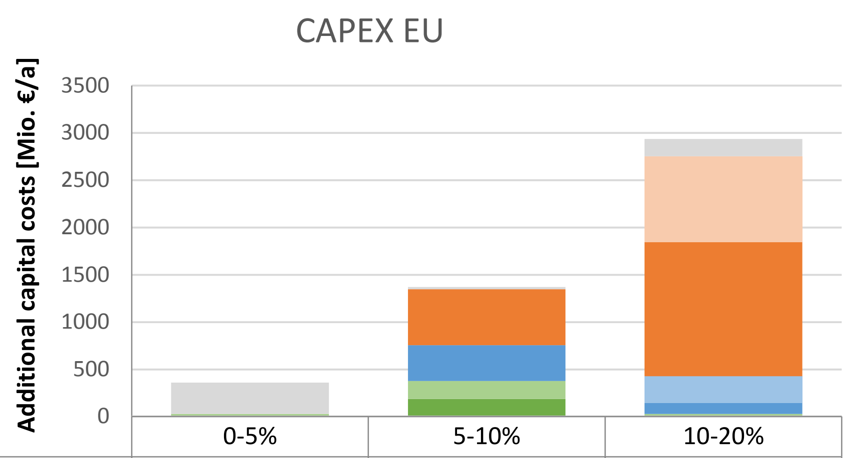
5. Economic aspects of hydrogen blending

Costs of the adaptation measures

The blending of hydrogen to the natural gas grid places very complex needs on the necessary infrastructure adaptation and causes additional costs. For the following analysis, these costs are separated into capital expenses (CAPEX) and operational expenses (OPEX). The gas grid consists of transport pipelines for long distances operated by transmission service operators (TSO) and the distribution grid to bring the gas to the customers operated by the distribution service operators (DSO). These grid levels are also separated because blending strategies can vary between the TSO and the DSO grid. Furthermore, additional costs depend on the blending levels, which are separated in this analysis into 0 – 5%, 5 – 10%, 10 – 20% and higher 20% until 2030. Again, onsite blending would provide an alternative and potentially lower cost solution, but has not been analysed within the scope of this study.
Finally, various sectors are affected by blending. Researched here, beside the grid sector, are the gas storages (closely linked with the grid infrastructure), various industries, the gas- fired power plants, including combined heat and power (CHP) and the gas fired heating systems of the building sector that must be exchanged because of H_2-blending in households and companies. The individual cost components are grouped as described in chapter 4.

All assumptions for the following analysis stem from a cost calculation tool for country-specific H_2 adaptation costs based on Fraunhofer IEE's own data for the development of end consumers, generators, storage and pipelines within the European gas market model ENIGMA.
Price assumptions (2030) are: natural gas price (without CO_2) 22 €/MWh, CO_2 price 90 €/ton, H_2 price 170 €/MWh, LPG price 65 €/MWh, electricity price 100 €/MWh.

In the next figure are graphically illustrated the additional capital costs (CAPEX) of blending including de-blending for all 27 member states of the EU.

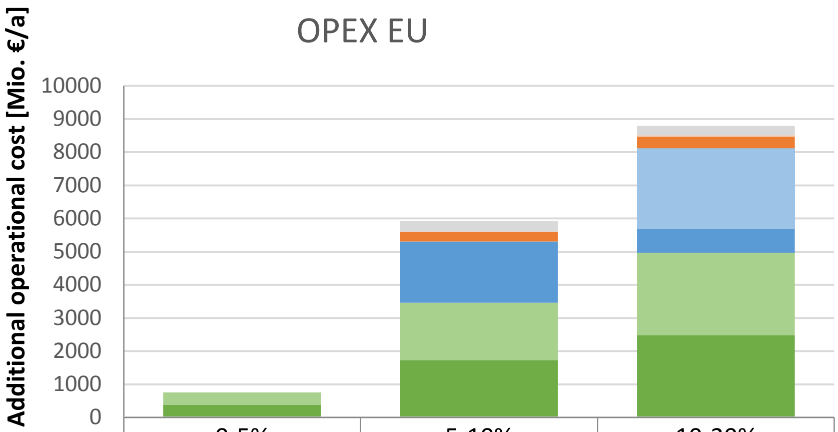


	0-5%	5-10%	10-20%
TSO - Storage	332	23	181
DSO - Grid			906
TSO - Grid		592	1418
DSO - Power			283
TSO - Power		377	116
DSO - Industries	14	188	15
TSO - Industries	14	188	15

Figure 17: Additional capital costs for various blending levels of the EU
Source: Authors' figure based on ENIGMA

The capital costs are annualised. This means that these costs arise yearly and the displayed costs can easily be summed up with the operational costs to calculate the yearly total costs. For the blending level 0-5%, the main cost block is the porous storages, which have to be desulphurised and dried. For the blending level 5-10 %, the biggest cost block is the grid adjustments on TSO level. Here, the installation of higher gas turbine capacities for compressors in particular is very expensive. For the blending level 10-20 %, the grid investments for the TSO grid are also very expensive. It has to be stressed that the total capital costs for the 20 % blending level are the sum of costs of all three illustrated columns.

In the next figure the operational costs for various blending levels in the EU are illustrated.



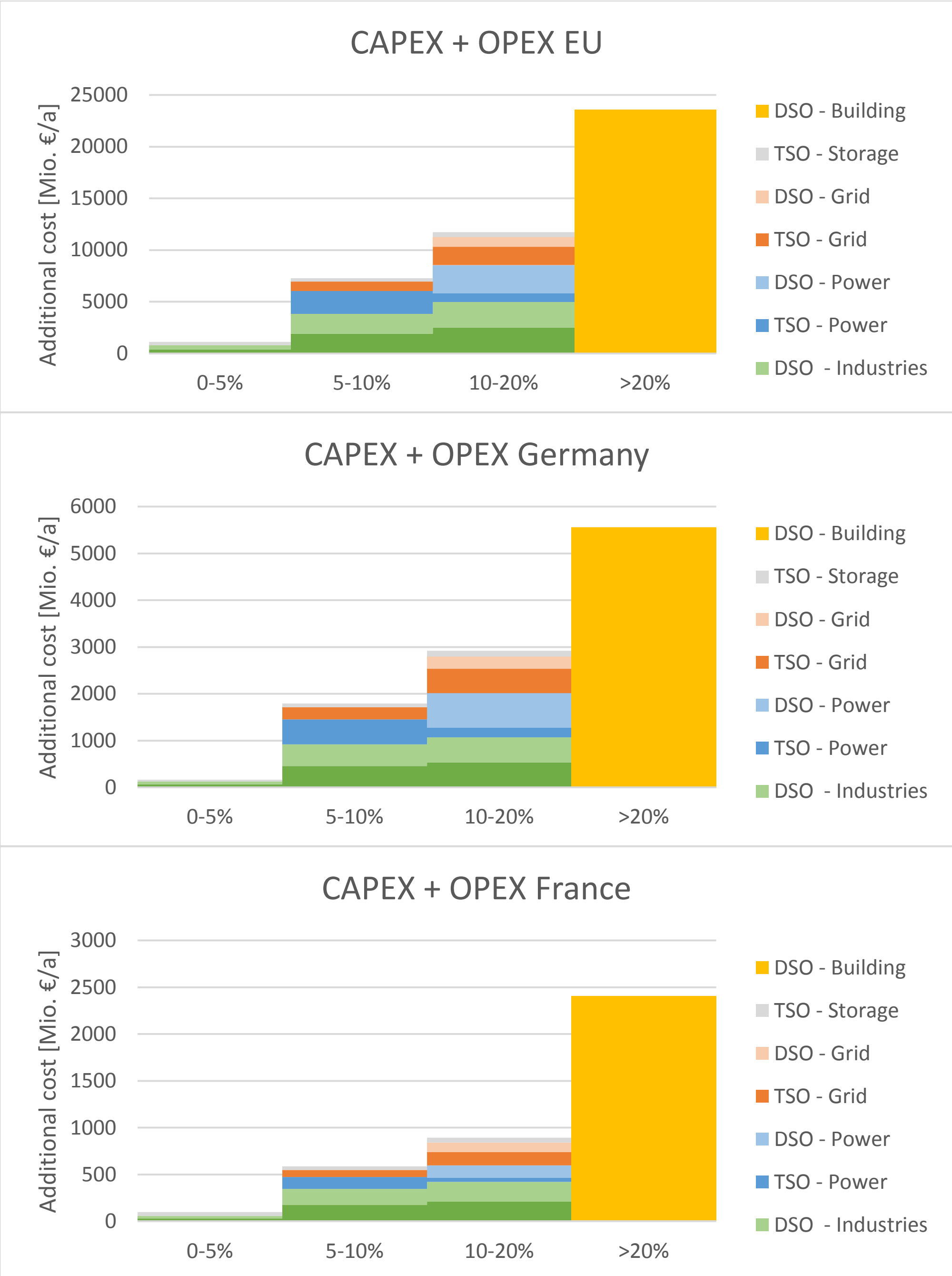
	0-5%	5-10%	10-20%
TSO - Storage		320	298
DSO - Grid			37
TSO - Grid		304	346
DSO - Power			2423
TSO - Power		1839	729
DSO - Industries	381	1733	2483
TSO - Industries	381	1733	2483

Figure 18: Additional operational costs for various blending levels of the EU
Source: Authors' figure based on ENIGMA

The operational costs are also indicated in millions €/a. For the blending level 0-5%, operational costs will only arise because some industrial customers on the DSO and TSO level need pure natural gas for their processes and so the hydrogen has to be de-blended.

For the blending level 5-10%, the biggest cost block is power generation plants because old plants can only handle 5% hydrogen blended natural gas. Here, more than 1,800 million €/a in additional costs arise to de-blend the hydrogen. Also, high additional expenses are necessary because some industries need a caloric value adjustment for more than 5% blended hydrogen that can be realised by adding liquid petrol gas (LPG). For the blending level 10-20% the additional LPG demand leads to even higher additional costs because of the needs of some industrial processes.

In the next figures the total costs (CAPEX + OPEX) of blending for various bending levels are graphically illustrated for the EU on top and below for the five example countries of this analysis.


CAPEX + OPEX EU
Additional cost [Mio. €/a]
25000
20000
15000
10000
5000
0
0-5%
5-10%
10-20%
>20%
DSO - Building
TSO - Storage
DSO - Grid
TSO - Grid
DSO - Power
TSO - Power
DSO - Industries
CAPEX + OPEX Germany
Additional cost [Mio. €/a]
6000
5000
4000
3000
2000
1000
0
0-5%
5-10%
10-20%
>20%
DSO - Building
TSO - Storage
DSO - Grid
TSO - Grid
DSO - Power
TSO - Power
DSO - Industries
CAPEX + OPEX France
Additional cost [Mio. €/a]
3000
2500
2000
1500
1000
500
0
0-5%
5-10%
10-20%
>20%
DSO - Building
TSO - Storage
DSO - Grid
TSO - Grid
DSO - Power
TSO - Power
DSO - Industries

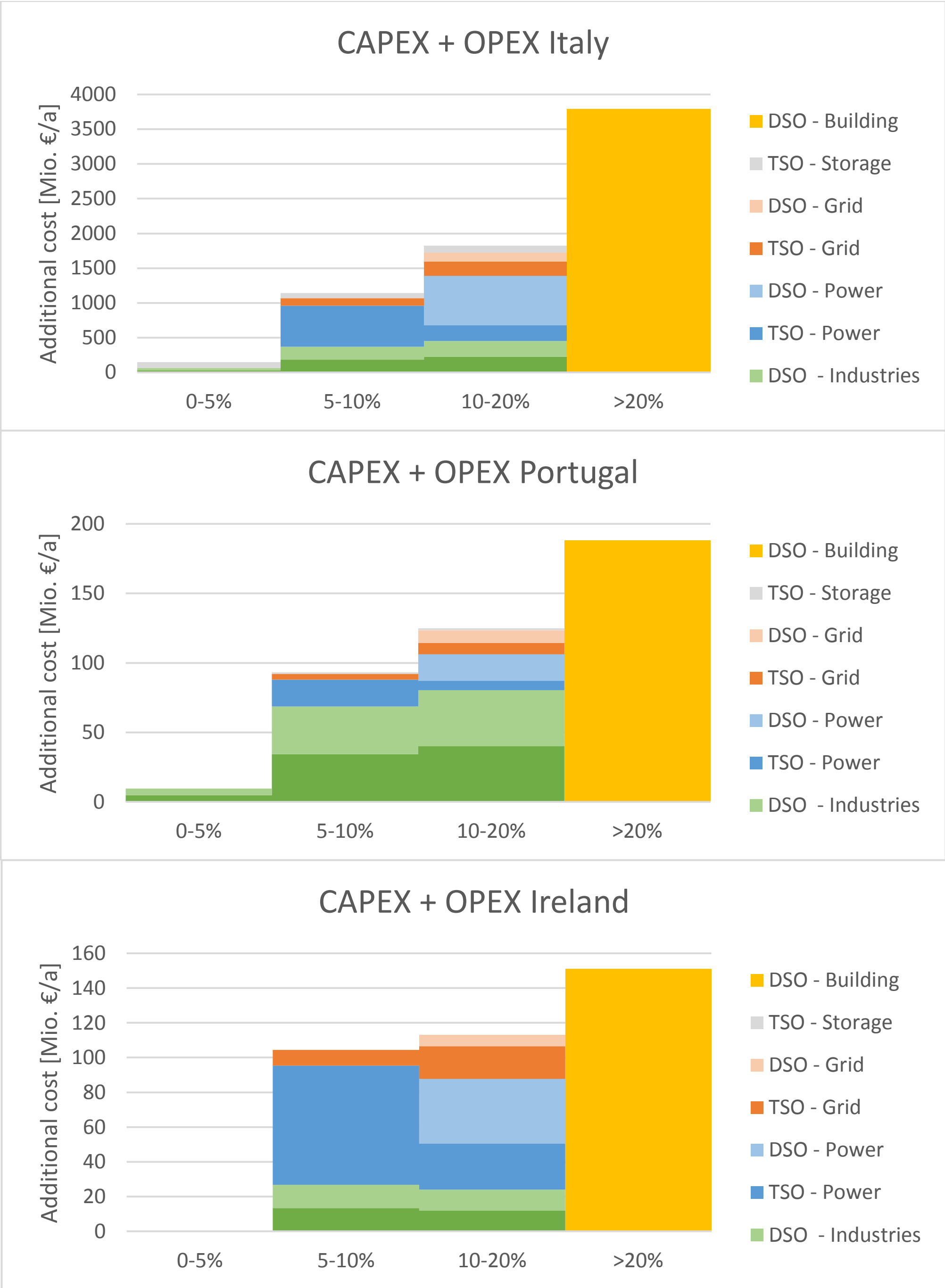


Figure 19: Total costs of blending for the EU and exemplary countries
Source: Authors' figure based on ENIGMA

Beside the blending levels already analysed, the level higher 20 % is also displayed, but only for the costs for the exchange of old boilers which are not capable of handling more than 20 % blended hydrogen in the natural gas.

The comparison of the analysed countries shows that the relations of the cost sectors differ greatly between these countries. The cost sector relations of Germany are quite similar to those of the EU average. The cost sector relations of France are quite small compared to the additional costs for boiler exchanges. In Italy, the costs for power generation on the TSO and DSO levels are relatively high compared to the average. In Portugal, the relative costs for Industries are very high compared to the other countries. In Ireland, the cost relations for power generation on the DSO and TSO levels are very high and the boiler exchange costs are, in relation, quite low.

Influence on end-user prices

The analysis of end-user gas price increases because of blending in 2030 are particularly noteworthy results. Here, the total costs for the blending levels 5 %, 10 % and 20 % are allocated among the total demand of natural gas for the EU and the example countries. The figure for the EU's total natural gas demand comes from the analysis of the 'EU scenario' in chapter 3. It is assumed that all additional costs, for example the additional costs that industrial customers have to face because of blending, have to be paid by all gas customers in the form of a "blending tax". This is, therefore, an allocation of the costs for grid adjustment, whereby the higher costs of hydrogen compared to natural gas as a fuel are also taken into account, but only have a small relative share due to the lower energy share.

Compared to end-user prices 2018 from chapter 2, the following end user gas price increases for households will rise because of blending.

Household	**End-user**	Blending tax			End-user price increase		
Year 2018	**Gas price**	5%	10%	20%	5%	10%	20%
Country	**ct/kWh**	ct/kWh	ct/kWh	ct/kWh	Percent	Percent	Percent
EU	**6.675**	0.042	0.312	0.746	0.6	4.7	11.2
Germany	**6.080**	0.026	0.308	0.767	0.4	5.1	12.6
France	**7.140**	0.043	0.296	0.683	0.6	4.2	9.6
Italy	**8.325**	0.037	0.328	0.794	0.4	3.9	9.5
Portugal	**7.715**	0.052	0.555	1.230	0.7	7.2	15.9
Ireland	**6.965**	0.000	0.231	0.480	0.0	3.3	6.9

Table 10: End-user natural gas price increase for households because of blending
Source: Authors' table based on ENIGMA

The average price increase in the EU for households will be about 11 % for a blending level of 20 %. The highest price increase will be in Portugal (nearly 16%), the lowest price increase will be in Ireland. (ca. 7%). For a blending level of 5 %, the end-user gas prices for households will increase in every country by less than 1 %.

For industrial customers, the percentage price increase will be much higher when they must pay the same "blending tax" as households.

Industry	**End-user**	Blending tax			End-user price increase		
Year 2018	**Gas price**	5%	10%	20%	5%	10%	20%
Country	**ct/kWh**	ct/kWh	ct/kWh	ct/kWh	Percent	Percent	Percent
EU	**3.135**	0.042	0.312	0.746	1.3	9.9	23.8
Germany	**3.160**	0.026	0.308	0.767	0.8	9.8	24.3
France	**3.715**	0.043	0.296	0.683	1.2	8.0	18.4
Italy	**2.895**	0.037	0.328	0.794	1.3	11.3	27.4
Portugal	**2.840**	0.052	0.555	1.230	1.8	19.6	43.3
Ireland	**3.650**	0.000	0.231	0.480	0.0	6.3	13.1

Table 11: End-user natural gas price increase for industrial customers because of blending
Source: Authors' table based on ENIGMA

The average price increase in the EU for industrial customers will be nearly 24 % for a blending level of 20%. This means a cost increase of up to 24% for blending gas achieving lower GHG savings. The highest price increase will be in Portugal with more than 43 %. It has to be stressed that Portugal has the lowest gas prices for industrial customers compared to the other analysed countries. It can be predicted that the industrial customers in Portugal will not pay the same "blending tax" as households to avoid such massive price increases.

Finally, some generic remarks on how the prediction of future gas prices and demand affects the percentage gas price increase because of blending. When the end-user gas price will increase in general in 2030 compared to 2018, then the percentage price increase caused by blending will decrease accordingly.

Furthermore, when the natural gas demand will be lower than predicted in the analyses based on the scenarios of chapter 3, then the relative percentage price increase because of blending will rise (e.g. when the gas demand is 10% lower in 2030 than assumed in the analysis, then the relative percentage price increase because of blending will be approximately 10% higher). But if the gas demand is significantly lower than predicted, the absolute blending costs will still be lower.

The conclusion of this analysis is that in the case of a 5 % blending level, the price increase for gas customers remains modest, but higher blending levels will lead to substantial price increases.

6. Potential for decarbonisation through hydrogen blending vs direct hydrogen use

Potential of hydrogen use in 2050

To illustrate the effect on various gas markets of using either the bridge technology of hydrogen blending or using 100% hydrogen directly, the impact on the overall energy demand and on the direct CO_2eq emissions of both technologies are compared for a set of sectors and applications.

It is expected that in European regulation, a ranking system will soon be necessary to prioritise certain areas of application because of restricted access to hydrogen. The next figure aids the ranking task by presenting the relative energy efficiency advantage (in %), the overall expected energy demand (bubble size correlates kWh/a), and the required infrastructural investments (increasing from left to right) of pure H_2 use over the long-term relative to the CO_2 free reference technology (electricity vs. PtL/PtG equivalent to a limited biomass potential). The underlying assumption is that, until 2030, the resources of available hydrogen are limited. By 2050, the hydrogen energy market is expected to have undergone the ramp up and resources will be less limited.

The next figure ranks the various areas of application for direct hydrogen use in terms of their efficiency (i.e. increased or reduced electricity consumption and thus RE expansion requirements compared to the reference technology) and infrastructure requirements (centralised or decentralised and year-round/seasonal). These estimated demand figures are based on the previously presented data.

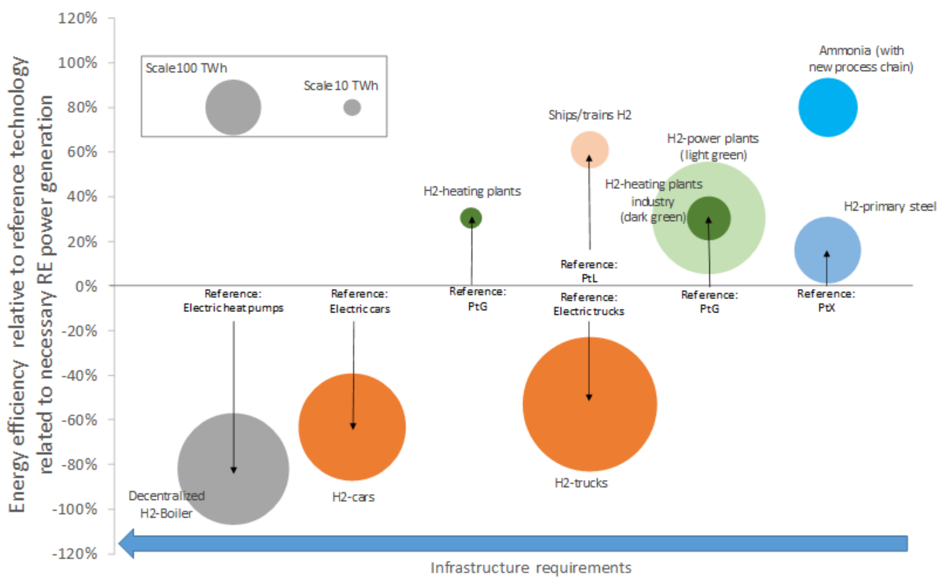


Figure 20: Comparison of efficiency with respect to energy demand by sector
Energy efficiency in relation to the RE expansion requirement of sectors/applications relative to conventional technology. The horizontal axis sorts the sectors by the required infrastructure build-up, increasing from left to right. The bubble sizes are relative to the estimated energy demand (TWh) of the respective sector. These estimated demand figures are based on the data presented in previous chapters

Considering the relatively small H_2 demand, centralised heating plants (more in industry and less in district heating) and the shipping and train sector can be relatively cheaply adapted to H_2, run efficiently and can expect sufficient availability of H_2.
These sectors can be considered "low hanging fruit". It is important to note the shipping and train sector is not connected to the gas grid and as such would not benefit from hydrogen grid blending. They might be adversely impacted as scarce hydrogen is diverted elsewhere instead of supplying these sectors.

While the use of hydrogen is **energetically beneficial in the industrial sector (e.g. for ammonia and steel production) and in power plants, both with and without CHP operation**, in case of a connection to the transmission grid the infrastructure requirements are not so high, while some uncertainty exists regarding the **availability of rather large amounts of H_2**. But it is conceivable to elaborate a strategy that successively develops infrastructure that provides sufficient amounts over time for direct H_2 use and not via grid-level blending, such that H_2 provision is guaranteed until 2050. Therefore, it is questionable to plan for large quantities of green hydrogen in sectors which could be electrified. The **use of hydrogen in decentralised boilers in the building stock and in road transport is therefore subject to a high degree of uncertainty**.

In the truck sector, there is still a high degree of technological uncertainty regarding the availability of battery-powered trucks for heavy-duty transport. But, here too there is new research that sees hydrogen trucks as economically critical with the potential for fast charging using new battery technology, possibly in combination with overhead wires on busy motorways [31]. In the transport sector in optimal scenarios, the reliance on electric vehicles is maximised. In other scenarios with a high share of chemical fuels, annual hydrogen demand for road transport alone could amount to approx. 1000 TWh. Approximately two-thirds of this demand would be attributable to heavy freight transport.[3] Under these assumptions, the energy efficiency of H_2 usage is negative relative to the reference technology Electromobility. The infrastructure changes would be relatively easy for e-cars but somewhat more extensive for e-trucks. Regarding the decentralised H_2-boilers, the H_2-infrastructure requirements at distribution gas grid level are considered most demanding, but the H_2-demand could be considerable (approx.. 400 TWh) under the assumption that the energy efficient retrofitting of the building stock will only proceed at a moderate pace. In optimal scenarios, heating energy for buildings is covered by heat pumps resulting in electricity demand. Alternatively, if the current 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 some TWh. Since decentralised boilers, in contrast to transport, are already connected to the natural gas grid today, H_2 blending and thus a long-term conversion to 100% H_2 can represent a lock-in effect here. **The theoretically high long-term demands for H_2 in the building and transportation sectors highlight the importance of efficiency measures, both in terms of a turnover feasibility and cost**.

GHG Savings in 2030

Not forgetting the underlying reason for why H_2-technologies are being investigated, the prioritising of H_2-blending should also consider the emission efficiency relative to the CH_4-based alternative (e.g. in the case of trucks, the 2030 alternative is diesel as fuel.) A comparison also needs to be made with alternative uses (non blending) of the green hydrogen. The limited hydrogen production available up to and beyond 2030 leads to the fact that a decision has to be made where that hydrogen is most effectively going to be deployed to offer the biggest GHG savings in a no regrets way. Hydrogen being blended is hydrogen not going to decarbonise industrial end uses or replacing grey hydrogen. In the following illustration, only the direct emission savings of green hydrogen (from additional RES) are shown without life cycle emissions.

[3] For Germany, this inefficient scenario would mean about 5,000 hydrogen filling stations, with about 10 million fuel cell cars and about 100,000 fuel cell trucks. Own calculations based on bottom-up simulation models from Fraunhofer IEE were applied to Europe.

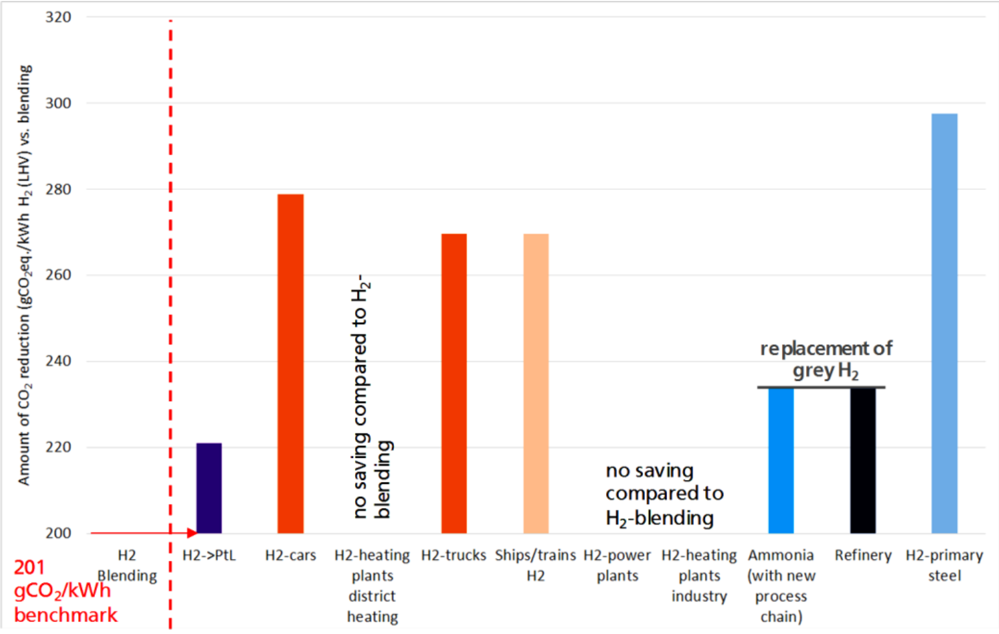


Figure 21: direct CO_2 savings from limited amount of hydrogen (gCO_2/kWh HHV) in 2030
For selected applications, the amount of CO_2eq that is not being emitted when using hydrogen blended gas as fuel instead of diesel or natural gas, is calculated by calculating the sum of the overall more CO_2-efficient technology and the better CO_2-emission-factor of natural gas compared to diesel or coal. Please note, that the pre-chain emissions have considerable uncertainties, in particular regarding system boundaries, and are therefore not considered in these assumptions

Above, it has been argued to prioritise sectors that provide a positive energy efficiency and low infrastructure development requirements in the following order: H_2-heating plants, ships/trains, industrial heating plants and power plants, ammonia with an investment in a new process chain, and H_2-primary steel. Power plants, steel and ammonia require considerable amounts of H_2 that might not be available by 2030, but could be envisioned by 2050.

H_2-cars, trucks and decentralised H_2-boilers are energetically not efficient. On the other hand, the figure above shows that the hydrogen blending technology applied to the transport sector could significantly reduce CO_2 emissions in the next 10-20 years. Considering the urgency of avoiding tipping points in climate change, the opportunity to reduce CO_2 emissions in the transport sector, where carbon capture is not an option, should have an impact in the ranking of ramp-up technologies.

The limiting factor is the availability of green hydrogen, even in blending scenarios. To accelerate a ramp-up of hydrogen technologies by increasing the available amounts, it has been suggested to employ blue H_2 in addition to green H_2. However, natural gas-based hydrogen, despite CCS, cannot be described as CO2-free, but rather only as low in CO_2, due largely to the emission effect of methane slip (i.e. the emission of CH_4 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 arctic methane release). The figure below 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.

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. 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. Available data concerning the magnitude of the methane slip problem are plagued by uncertainty. The range that is presented in the figure below is in agreement with the estimates produced by various sources, from environmental scientists to the natural gas industry. Yet it must also be mentioned that there are various technical options for further reducing methane leakage. The figure shows minimum and maximum estimates for the impact of the methane slip, which is most pronounced over a 20-year time period.

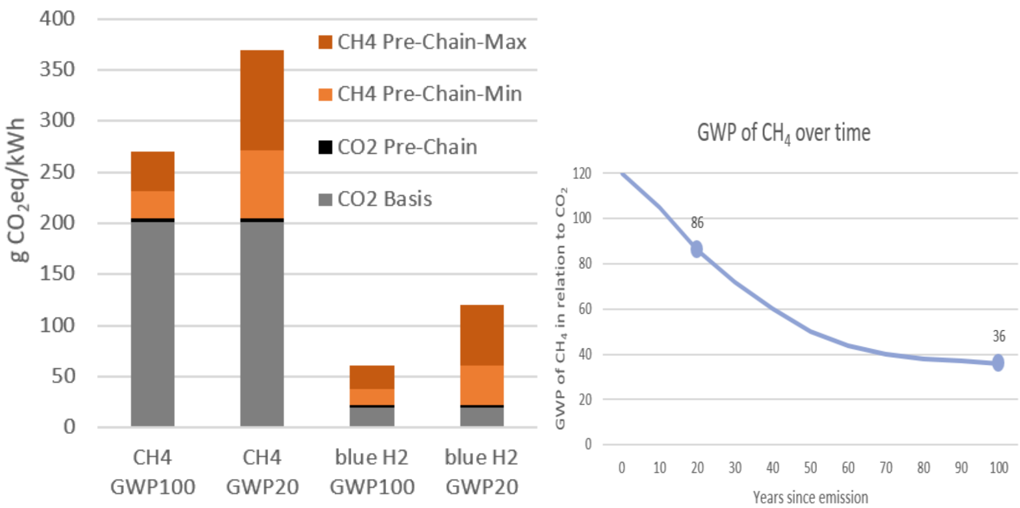


Figure 22: Emission factors for natural gas and blue hydrogen and global warming potential of methane over time 2030
Source: Authors' figure [5]

It is clear from the above that green hydrogen is a limited and valuable resource, especially in the medium term. Blue hydrogen, especially from European offshore production, can theoretically represent a relevant CH_4 saving potential with limited availability. However, compared to Figure 21, upstream emissions need to be considered more than for green hydrogen, and possible lock-in effects and stranded investments need to be assessed.

7. Conclusions

The climate targets are not only defined for the intermediate years 2030 and 2050. Emissions over the entire period until 2050, which is implemented via the carbon emission budget in the ETS and Non-ETS, are relevant. Natural gas accounts for 22% of EU27 emissions. If pre-chains are taken into account, the share is even more extensive, but part of these pre-chain emissions occur outside the EU[4]. In absolute terms, natural gas emissions have remained relatively constant in recent decades. Both the development and the effect of the pre-chain make it clear that, in order to achieve the climate targets, a rapid reduction of these emissions is also necessary. Climate neutrality of gas supply in 2050 alone is not enough.

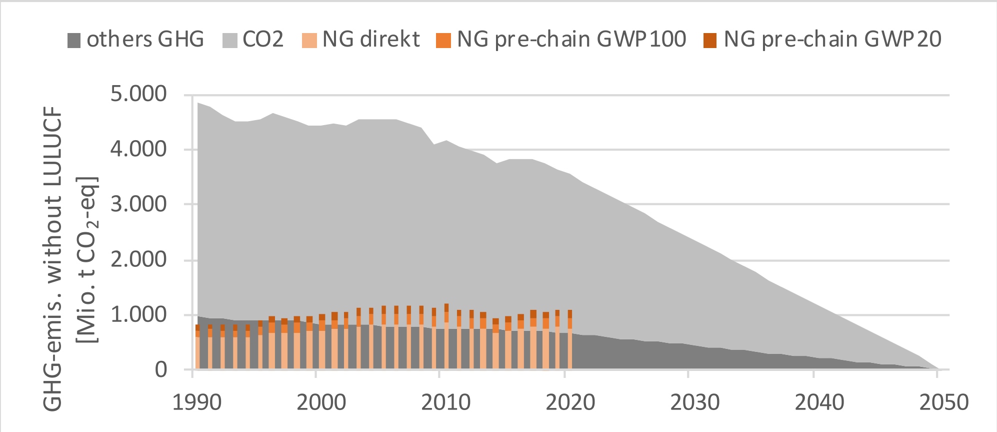


Figure 23: Development and target of EU27 GHG emissions and share of natural gas without and with pre-chain
Source: Authors' figure based on [9]

But the development of an area-wide H_2 transport network infrastructure and the market ramp-up for CO_2-free H_2 generation will take time. Early H_2 conversion to achieve over 20 vol.% of blending is expensive, and the emission saving at 6.6% energy content is low. A long-term conversion would theoretically be possible at low costs because all newly installed applications would be prepared for conversion by "hydrogen ready" and old applications would be removed from the gas system at the end of their service life. **But, to step-up from 20 to 100% in the period well after 2040 is too late to meet the emissions budget. To meet climate targets, gas demand must be reduced early and continuously through sector coupling. This means using direct electrification in other sectors, expanding wind and PV for this additional consumption, and relying on the flexibility of new electricity consumers to integrate weather-dependent electricity generation.**

A pure H_2 transport network enables the efficient supply to large consumers. The connection of small remaining distribution networks to this H_2 transport network for any necessary niche consumers (e.g. H_2–truck, some industry) must be decided locally. In terms of the EU taxonomy and thus the credibility of H_2 to sectoral climate targets (e.g. in the context of REDIII), the physical supply of 100% H_2 has advantages and could still allow for approaches such as gradual on-site blending. In the case of grid-level H_2 blending, a virtual or balance-sheet allocation to the sectors' willingness to produce a majority of H_2 would have to be defined first.

For this reason, taking the approach to blend hydrogen from 0% to 20% in existing grids today represents a lock-in effect as area-wide adaptation measures would have to be financed that are neither necessary nor sustainable in the long term. Introduction in one country in Europe would also force all other

[4] GHG emissions outside the EU are not yet targeted directly by European legislation.

countries to take adjustment measures due to cross-border trade and security of supply, or if it is technically permissible, gas trade would have to be restricted. For blending levels of up to 20%, there are significant price impacts for end-users (especially for industry) and they vary largely from country to country. For blending levels above 20 %, there are significant impacts also for residential applications (boiler exchange) in all countries. A rapid decline in natural gas demand with respect to the achievability of climate targets further exacerbates the cost burden. **Hydrogen blending is not a no regrets option towards 2030. It is suboptimal because it does not specifically target end-uses for which hydrogen is generally agreed to be needed and imposes additional costs for lower greenhouse gas savings compared to using hydrogen directly. Therefore, H_2 usage should be limited to areas where it is needed and cannot be substituted by electricity.** The question is how to transport the hydrogen produced to the consumer.

The EU hydrogen strategy aims to achieve an installed capacity of 40 GW electrolysis in Europe by 2030. This would lead to H_2 generation of approx. 130 TWh (HHV). The four industry clusters from the Agora study (No-regret hydrogen: Charting early steps for H_2 infrastructure in Europe) meanwhile already indicate a H_2 demand of about 148 TWh in 2030 with applications to be prioritised in the industry (which cannot be replaced by electricity and therefore represent higher CO_2 savings than blending). 2/3 of this demand is located in the southern North Sea, where plans are already in place for a first H_2 network in 2030. This launch network is thus also close to the growth of European H_2 offshore generation, which does not compete with direct electricity use due to electrical grid congestion.

Figure 24: H_2 launch network in the largest EU industrial region for direct H_2 demand in 2030

Source: Authors' figure based on [32]

But if even more green H_2 were to be imported or blue H_2 produced, the question is increasingly how to overcome the challenge of a missing H_2 transmission grid in 2030. On the one hand, on-site electrolysis at industrial locations or filling stations is possible. Only small quantities can be blended to the distribution grids (there is no exceeding the summer minimum low load with the permissible proportion of approx. 10% of volume without relevant adjustment costs). However, it is important to check that these long-lived infrastructure investments do not create lock-in effects in both cases. On the other hand, blending up to 2% today (in the case of CNG vehicles) and up to 5% by 2030 into the transmission grid is possible without high costs[5] but could already lead to lock-in effects. Costs may also rise if other countries have to adapt as a result. It has to be evaluated whether this development could result in indirect lock-in effects, which would be contrary to the prioritisation of direct H_2 use. Alternatively, it must be examined whether a generation or import from PtL (Kerosene, diesel, methanol) instead of only H_2 would be more sustainable than blending.

Even though the long-term demand for hydrogen is partly uncertain, only part of the current gas transport network will be converted to hydrogen. Due to the declining demand for methane, the existing natural gas pipelines will have to be decommissioned in the long term. However, the situation is different due to the low energy density of hydrogen and the need for cavern storage. Therefore, lock-in effects for new investments in gas pipelines also need to be assessed.

[5] Individual cases with special customers must also be examined in the distribution network.

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