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Decarbonisation of Energy

Determining a robust mix of energy carriers for a carbon-neutral EU

Policy Department for Economic, Scientific and Quality of Life Policies
Directorate-General for Internal Policies
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Abstract

Decarbonising the energy system requires a fundamental transformation in the way societies provide, transport and consume energy. Disagreement exists over how this system should look in 2050. The large-scale expansion of low-carbon electricity, phase-out of unabated fossil fuels, and widespread direct electrification are uncontroversial. In more controversial areas, like the deployment of hydrogen and synthetic methane, policy should forcefully explore options and be willing to accept and learn from failures. This report discusses concrete policy options for doing so.

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LIST OF ABBREVIATIONS

BCM	Billion cubic metres
BOF	Blast Oxygen Furnace
CAPEX	Capital Expenditure
CCS	Carbon capture and storage
CCU	Carbon capture and utilisation
CO_2	Carbon dioxide
DRI	Direct Reduced Iron
EAF	Electric Arc Furnace
EC	European Commission
ENTSO-E	European Network of Transmission System Operators – Electricity
EU	European Union
EU ETS	European Union Emissions Trading System (addressing the greenhouse gas emissions CO_2, N_2O, and perfluorocarbons)
FEC	Final energy consumption
FF55	Fit for 55 (EU energy package)
GW	Giga Watt (unit for electricity generation capacity)
GWP	Global Warming Potential
GHG	Greenhouse gas(es)
GDP	Gross Domestic Product
H_2	Hydrogen
IPCC	Inter-governmental Panel on Climate Change
IEA	International Energy Agency (an OECD agency)
JRC	Joint Research Centre
MWh	Mega Watt hour (quantity of electricity generated)
Mt	Megatonne (million tons)
$MtCO_{2eq}$	Megatonne of carbon dioxide or equivalent
CH_4	Methane
MRV	Monitoring, reporting, verification (of emissions)
OPEX	Operating Expenditure
PV	Photovoltaic

PPCA	Powering Past Coal Alliance
SMR	Steam methane reforming (a hydrogen production process)
Syngas	Synthetic gas (methane)
TRL	Technological Readiness Level
TWh	Terawatt Hour
UNFCCC	United Nations Framework Convention on Climate Change

EXECUTIVE SUMMARY

Background

The European Union (EU) aims to become the first climate-neutral continent by 2050. To deliver on this ambition, decarbonising the energy sector is crucial because the production and use of energy accounts for more than 75% of the EU's greenhouse gas emissions (EEA, 2021). Today, almost three-quarters of the EU energy system relies on fossil fuels. The European Green Deal can thus only be successful when the unabated combustion of oil, natural gas and coal is phased out. But Europeans will continue to demand energy-based services such as transport, heating, cooling, lighting and manufacturing. For all of these energy-based services, a number of alternative, climate-friendly technology options and energy carriers are possible, ranging from electrification to synthetic methane gas and other synthetic hydrocarbons to hydrogen.

Aim

Our study provides European lawmakers with science-based recommendations on adapting the regulatory framework for the gas, coal and hydrogen sectors towards climate neutrality. The recommendations are based on an extensive analysis of possible development pathways for these three fuels. Based on transparent assumptions, we have developed three scenarios on the contribution of hydrogen, methane and electricity to final EU energy use. For each scenario, we describe the demand for each fuel in each sector, the implied necessary upstream investments (e.g., electrolysers for hydrogen production) and the implied necessary investments in infrastructure (e.g., hydrogen fuel stations). This allows us to identify a number of uncontroversial elements that will be required for cost-effective decarbonisation of the European energy sector. But our analysis also highlights for which elements of the energy sector the most suitable solution is not yet clear. This allows us to formulate recommendations on a resilient energy system decarbonisation strategy and the translation into sensible policies.

Key Findings

Decarbonisation of the energy system will require a massive transformation in the way energy is provided, transported and used. However, views on what the system should or would look like in 2050 still strongly diverge. While a cost-minimal energy system is not possible to determine (because too many driving factors are uncertain) we are sufficiently confident on a few important building blocks.

First, the high efficiency of direct electrification in transport and heating implies that in most cases it is the preferable solution.

Second, electrification of transport and heating, but also any production of hydrogen or synthetic fuels in Europe, will ultimately require a massive build-up of renewable electricity generation. Accordingly, installing too much renewable generation capacity will be almost impossible.

Third, as a general rule there should be no investments in fossil-fuel production, transmission or utilisation, as most of them would have to be quickly decommissioned within the next decades. Investment in such assets should only be accepted in exceptional circumstances.

Fourth, current national energy and climate plans are insufficient to achieve a cost-efficient pathway to EU-wide climate neutrality by 2050. Consequently, a strong commitment framework is needed to ensure that Member States' policies are aligned with the European targets.

Fifth, as the bulk of investment in decarbonisation will have to come from end-users, they quickly need clear signals on the direction of travel. Hence, 2021-2030 should be the decade of infrastructure investments.

The above building blocks will not be sufficient to ensure the decarbonisation of Europe's energy system. Hard-to-abate sectors in industry, heavy transport, aviation as well as periods of renewable energy droughts pose challenges that cannot be solved by the 'uncontroversial' solutions. It is likely that hydrogen and synthetic fuels will be useful to tackle some of these issues. But we cannot yet predict an optimal mix of solutions.

However, we do not have the time to wait until clear winners emerge. Moreover, system and learning effects that bring down the cost of technologies as they are deployed make it impossible to comprehensively assess the potential of different solutions *ex ante*. Hence, we need courageous deployment of different solutions, knowing that some will turn out to be dead-ends. Accordingly, policies should leave room for numerous and sufficiently sizeable regulatory[1] and technology experimentation – Europe with its size and different Member States is a very fertile ground for this. But it is as important to test many different solutions in parallel, so that unfit solutions are identified and eliminated.

A somewhat sobering result of our analysis is that large amounts of the knowledge required to facilitate this transition are still lacking. Much crucial information on the current energy system and the assumptions underlying the policy plans is not accessible. Currently the EU has no appropriate knowledge infrastructure that collects, structures and ensures the quality of the available energy sector data and makes it publicly accessible. In order to improve the analytical basis and make it relevant for the political debate, the EU could seek inspiration from the US Energy Information Administration, the Intergovernmental Panel on Climate Change and the International Energy Agency. Moreover, the EU Member States National Energy and Climate Plans (NECPs), which are already a very useful tool to put different national plans in perspective, can be made more useful by carefully reviewing the data that Member States provide, and encouraging them to use a harmonised reporting system. Finally, regulatory and technical experimentation should be better accompanied by robust *ex-ante* and *ex-post* analysis, so that it serves the purpose of identifying solutions.

While we cannot provide a comprehensive assessment of the massive European Green Deal proposal, we think it addresses crucial elements. To ensure that the above-described decarbonisation pathway is implemented, the existing proposals could be strengthened in the following way:

Greenhouse gas pricing should cover all sectors and greenhouse gases, provide more long-term price guidance, and prices in different segments should converge over time. Upcoming revisions of the EU ETS have to ensure the alignment with the long-term goal of climate neutrality.

The climate balance of **energy imports should be certified** according to strict criteria that encourage suppliers to ensure low carbon/carbon-neutral value chains.

Europe will require an energy network infrastructure that enables a fundamental transition – including a substantial increase in electricity generation from renewables. A deep rethink of how **energy infrastructure is incentivised and financed** in the EU is needed. Internal energy market principles must be ensured, also for new network-based energy industries such as hydrogen.

One key challenge in the new energy world is how to carry abundantly available renewable energy (especially in summer) over to periods when energy is less available (especially in winter).

[1] By regulatory experimentation we mean a regular process of repeated evaluation and revision of the policies in place.

This involves the question of how different energy markets are co-designed (sector coupling). Investors will require clarity on how European **energy market design** will ensure the profitability of investments that address the described challenge.

Appliances and industrial processes based on clean fuels need to be deployed early on to encourage learning and to identify the most suitable. Policy can help here by offering **commercialisation contracts for industry and households** that guarantee that clean solutions are competitive with carbon-emitting technologies – even when carbon prices are not yet high enough.

The transition will require a massive deployment of renewable electricity. Strengthening the EU governance of the renewables target will incentivise further investment into corresponding assets.

1. INTRODUCTION

KEY FINDINGS

The Fit for 55 package foresees a significant speeding up of European decarbonisation. This requires many new and upgraded policy frameworks. The European Commission has already proposed extensive reforms to the EU's energy and climate policy framework, and more are forthcoming before the end of 2021.

The purpose of this report is to provide insight into the rationale behind these revisions. Specifically, this is done by informing policymakers about the implications of different fuel mixes in a decarbonised EU in 2050. We explore three scenarios with differing demand assumptions for electricity, hydrogen and alternative green gases.

1.1. Objective, scope, and targeted output of the Study

This study provides science-based recommendations for adapting the European regulatory framework for the gas, coal and hydrogen sectors to increased decarbonisation[2] ambition. Based on transparent assumptions, we develop three scenarios of the contribution of hydrogen, natural gas and electricity to final European Union (EU) energy use. For each scenario, we describe the demand for each fuel by sector, the implied necessary upstream investments (e.g., electrolysers for hydrogen production), the implied investment needed for infrastructure (e.g., hydrogen pipelines) and the required annual payments for imports where appropriate.

By comparing scenarios, we outline trade-offs in terms of speed of decarbonisation, security of supply (import shares), volume and timing of investment needs, corresponding investment gaps and total cost (chapter 6). For each of the fuels (hydrogen, natural gas and coal) a separate chapter describes in a detailed and illustrative way the impact of the individual scenarios. Thereby, crucial elements of the current regulatory framework, as well as current Commission proposals, are discussed with respect to their adequacy and consistency with the outlined scenarios. This allows us to identify policy gaps.

Based on the above, we make clear recommendations on how to ensure that European policy enables the most effective and efficient transformation of the coal, natural gas and hydrogen sectors.

1.2. Background

With the European Green Deal (EGD), the EU aims to become the first climate neutral continent by 2050. This vision, also fostered by the European Parliament's climate emergency declaration of November 2019, was enshrined into legislation with the European Climate Law[3]. This transformed the EU's climate-neutrality pledge into a binding obligation, and increased the EU's 2030 emissions reductions target from 40% to at least 55% compared to 1990 levels.

To deliver on its climate obligations, the EU must pursue one main goal: make its energy sector climate neutral. The production and use of energy across economic sectors accounts for more than 75% of the EU's greenhouse gas (GHG) emissions[4].

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[2] Throughout the paper, we use the term decarbonisation referring to a move toward climate neutrality. That is, by using decarbonisation we do not intend bias against synthetic hydrocarbon molecules in the cases that they have a net-zero carbon emissions effect.

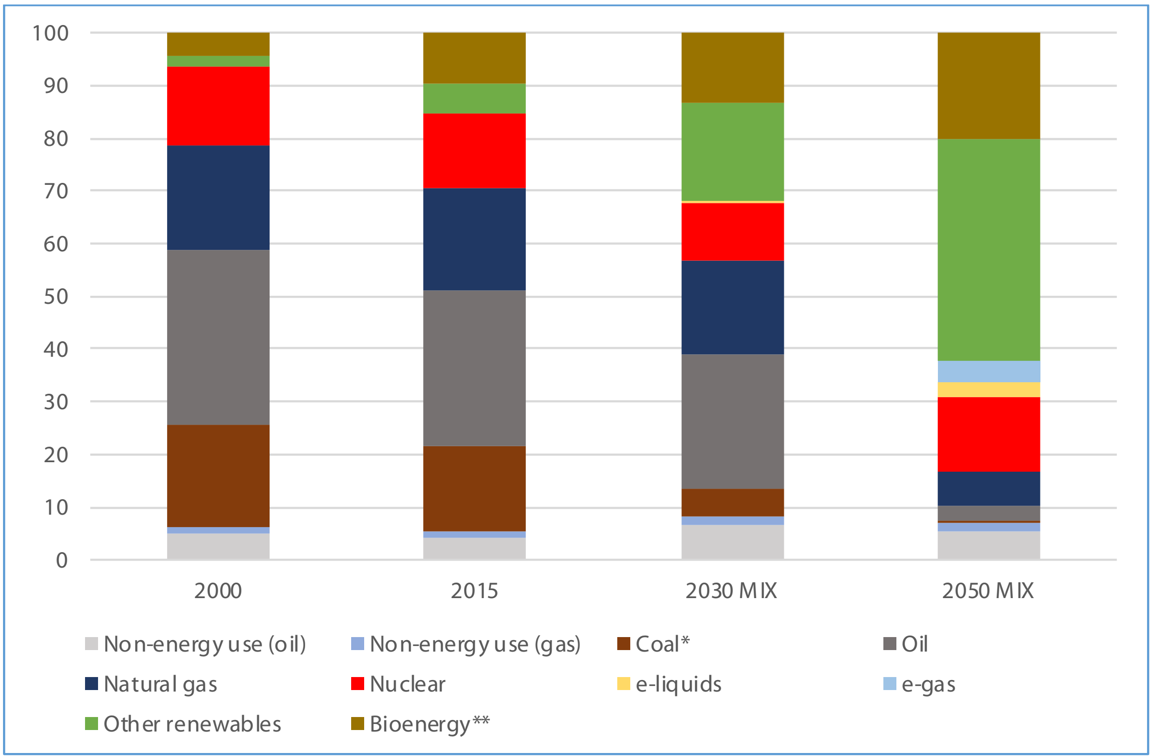
[3] See https://ec.europa.eu/clima/eu-action/european-green-deal/european-climate-law_en for a description of the EU's Climate Law.

[4] See https://www.eea.europa.eu/data-and-maps/data/data-viewers/greenhouse-gases-viewer for an overview of the EU's greenhouse gas emissions as reported to the UNFCCC.

Today, almost three-quarters of the EU energy system relies on fossil fuels. Oil dominates the EU energy mix (with a share of 35%), followed by natural gas (24%) and coal (14%). Renewables are growing in share but still play a more limited role (14%), as does nuclear (13%) [5].

Should the EGD be successfully implemented, this situation would be transformed by 2050. But change will not happen overnight. According to European Commission (EC) projections, fossil fuels will still contribute to half of the EU's energy mix in 2030 (EC, 2020). While coal – the most polluting element in the energy mix – has to be substantially reduced before 2030, oil and especially natural gas can be phased out later to achieve the climate targets. It is indeed between 2030 and 2050 that most of the change for oil and natural gas is expected to happen. Within this timeframe, oil is expected to be almost entirely phased out, while natural gas is expected to contribute a tenth of the EU energy mix by 2050 (Figure 1-1).

Figure 1-1: EU energy mix evolution in one of the scenarios leading to a GHG emissions reduction of 55% in 2030 compared to 1990 levels and to climate neutrality in 2050



Source: Bruegel based on EC (2020). Note: among the various scenarios consistent with EU climate targets used by the EC we picked the MIX scenario. Note: e-liquids and e-gas are synthetic fuels, resulting from the combination of green hydrogen produced by electrolysis of water with renewable electricity and CO_2 captured either from a concentrated source or from the air. Bioenergy includes solid biomass, liquid biofuels, biogas, waste.

To achieve the required energy-mix transformation, the Commission on 14 July 2021 proposed the Fit for 55 package, covering a broad range of policy areas. A revision of the European Union Emission Trading System (EU ETS) is proposed, with the inclusion of maritime emissions and a reduced number of annual allowances. A second EU ETS is proposed for road transport and buildings. Both the renewable energy directive and energy efficiency directive see strengthened targets, while the energy taxation directive will be revised and CO_2 emission standards for road vehicles will be tightened.

[5] Data are made available by Eurostat, here: https://ec.europa.eu/eurostat/statistics-explained/index.php?title=Energy_statistics_-_an_overview#Final_energy_consumption.

1.3. Recent and upcoming developments

The use of coal in Europe's energy sector has substantially decreased in the last decades, for economic reasons, because of emissions regulation and following national phase-out policies. The share of coal (lignite and hard coal) in electricity generation in the EU has been reduced significantly in the past two decades, from 31% in 2000 to 19% in 2018 and 14% in 2019. Recently, the EU ETS reform further deteriorated the economics of coal.

Importantly, national, coal-sector-specific policies now lead to the definite phase-out of coal in many EU Member States. Often, national policies take the form of mandated phase-out schedules with planned closures of coal power plants and mining sites. Only rarely are alternative policies, such as emission performance standards, chosen as a phase-out policy. Table 1-1 reports on the progress of the coal phase-out in EU Member States. Nine of the 27 Member States are already coal-free and eleven more will have shut down all their coal-fired power plants by 2030. Germany, Romania, Poland and the Czech Republic currently plan for a phase-out later than 2030. Bulgaria, Croatia and Slovenia have not yet decided on the timing of their coal phase-out.

Table 1-1: Coal phase-outs in EU countries

Coal free	Coal phase-out achieved	Coal phase-out by 2025	Coal phase-out by 2030	Coal phase-out by 2040	Coal phase-out later than 2040	Coal phase-out under consideration	No coal phase-out planned
Cyprus	Austria	France	Denmark	Czech Republic	Poland	Bulgaria	
Estonia	Belgium	Hungary	Finland	Germany		Croatia	
Latvia	Sweden	Ireland	Greece	Romania		Slovenia	
Lithuania		Italy	Netherlands				
Luxembourg		Portugal	Spain				
Malta		Slovakia					

Source: Updated from https://ec.europa.eu/energy/topics/oil-gas-and-coal/EU-coal-regions/coal-regions-transition_en, https://beyond-coal.eu/wp-content/uploads/2021/03/Overview-of-national-coal-phase-out-announcements-Europe-Beyond-Coal-22-March-2021.pdf.

For natural gas and hydrogen, in contrast, the relevant policy developments take place at the EU level. The EC has already started the process of reviewing and revising the Gas Directive 2009/73/EC [6] and the Gas Regulation (EC) No 715/2009 [7], generally referred to as the hydrogen and decarbonised gas market package. The Commission has already presented a hydrogen strategy [8] and an energy-system integration strategy [9], which will serve as building blocks for the forthcoming package.

[6] Available here: https://eur-lex.europa.eu/legal-content/EN/ALL/?uri=CELEX%3A32009L0073.

[7] Available here: https://eur-lex.europa.eu/legal-content/EN/ALL/?uri=celex%3A32009R0715.

[8] Available here https://ec.europa.eu/energy/sites/ener/files/hydrogen_strategy.pdf.

[9] Available here: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52020DC0299&from=EN.

It has also presented its legislative proposal for the revision of Regulation (EU) No 347/2013 [10] on guidelines for trans-European energy infrastructure (the TEN-E Regulation).

The hydrogen strategy presented by the Commission in July 2020 identifies the top priority for the EU as development of renewable hydrogen (i.e., produced using renewable sources), as this is the option which is the most compatible with the EU climate objectives. However, the document also outlines that in the short and medium terms, other forms of low-carbon hydrogen might be needed, primarily to rapidly reduce emissions from existing hydrogen production and support the parallel and future uptake of renewable hydrogen. The Commission thus foresees a gradual trajectory for hydrogen deployment in Europe, characterised by different speeds depending on sector and region. The Commission expects this trajectory to unfold in three phases (table 1-2).

Table 1-2: The European Commission's hydrogen strategy for a climate-neutral Europe

	Period	Installed renewable hydrogen electrolysers (Gigawatt)	Renewable hydrogen production (TWh)	Main sectorial target
Phase 1	2020-2024	6	33	Decarbonise existing hydrogen production in industry
Phase 2	2025-2030	40	333	Take-up in new end-use applications
Phase 3	2031-2050	Large-scale	Large-scale	Reach all hard-to-decarbonise sectors

Source: Bruegel based on EC (2020).

In parallel with the hydrogen strategy, the Commission also presented in July 2020 an energy-system integration strategy, aimed at proposing policy measures to abate technically and economically inefficient silos and coordinate the planning and operation of the energy system 'as a whole', across multiple energy carriers, infrastructures and consumption sectors. The strategy has three key principles and related actions:

- Energy-efficiency-first and circular energy system;
- Greater direct electrification of end-use sectors; and
- Use of renewable and low-carbon fuels, including hydrogen, for end-use applications where direct heating or electrification are not feasible.

The strategy also focuses on the infrastructure aspects of system integration, highlighting that, while natural gas networks might be used to enable blending of hydrogen to a limited extent during a transitional phase, dedicated infrastructures for large-scale storage and transportation of pure hydrogen may be needed. The strategy remains vague on the role of CO_2-dedicated infrastructure, limiting itself to flagging the need for reflection on how to transport CO_2 between industrial sites for further use, or to large-scale storage facilities.

This infrastructure dimension was already developed by the Commission in December 2020, within its legislative proposal for the revision of the TEN-E Regulation. This included a number of proposals, from obliging all projects to meet mandatory sustainability criteria, to an update of the infrastructure categories eligible for support through the TEN-E policy.

[10] Available here: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32013R0347&from=en.

Importantly, the proposal ends support for natural gas infrastructure and introduces support for new and repurposed hydrogen transmission infrastructure and storage, as well as electrolyser facilities.

Finally, the Commission ran in early 2021 a public consultation on the revision of the hydrogen and decarbonised gas market package, based on an inception impact assessment[11], which foresees the revision focusing on the following four problem areas: i) Hydrogen infrastructure and hydrogen markets; ii) Access for renewable and low-carbon gases to the infrastructure and the market; iii) Consumer rights, competition and transparency; iv) Lack of integrated energy markets, in particular through network planning. The results of the consultation, which closed in June, will feed the Commission's work on the package, which will be adopted in late 2021.

[11] Available here: https://ec.europa.eu/info/law/better-regulation/have-your-say/initiatives/12911-Gas-networks-revision-of-EU-rules-on-market-access_en.

2. HIGH LEVEL SCENARIOS FOR COAL, METHANE AND HYDROGEN DEMAND

KEY FINDINGS

The decarbonisation pathways envisaged by Member States in their National Energy and Climate Plans (NECPs) are noticeably different to the pathways modelled by the JRC. In particular, NECPs foresee higher levels of energy consumption in 2030, higher shares of fossil-fuel combustion in final demand, and lower levels of electricity. Relatively speaking, a larger share of final energy consumption lies in the transport sector in NECPs compared to JRC. It is likely that this is driven by slower electrification of transport in NECPs.

The conclusions of this analysis are that national plans and EU top-down targets are not yet aligned. An equally strong conclusion is that the transparency and harmonisation of NECP data needs to be improved.

2.1. Total EU energy consumption pathways up to 2050

Future requirements for infrastructure and regulation depend on how much of each fuel (coal, methane and hydrogen) will be consumed in each sector. These demands will change drastically as Europe decarbonises over the next three decades, but the end-position is very uncertain.

Coal will have to be phased out. The same holds for large volumes of natural gas. Some natural gas may potentially be replaced by other methane sources, such as bio-methane or synthetic methane, or have its emissions captured. Finally, hydrogen might emerge as a new energy carrier. A large share of energy demand today arises in the transportation sector and is covered by oil and oil products. The transportation sector is only indirectly covered by this study as synthetic fuels (including hydrogen) or electricity might replace oil products as decarbonized fuel alternatives.

Moreover, different Member States might adopt different routes – increasing uncertainty even more. Notwithstanding this, present fuel demand, existing infrastructure and current national and European plans (especially for the period up to 2030) are still valuable indicators of the future. In this chapter we explore European and national projections for sectoral fuel demand up to 2030 (and, if available, 2050).

The main bases are the National Energy and Climate Plans (NECPs) and one of the scenarios by the Joint Research Centre (JRC). The JRC scenario FF55 MIX underpins the impact assessment accompanying the EC's -55% by 2030 proposal, and is based on expanding carbon pricing combined with introduction of other decarbonisation policies. Comparison allows us to outline national differences in starting points and transition and enables us to identify inconsistencies between national plans (which, according to the Commission, fell short of meeting the old targets) and the EU-wide scenario (that implies meeting the more ambitious new targets).

2.1.1. Top-down: EU

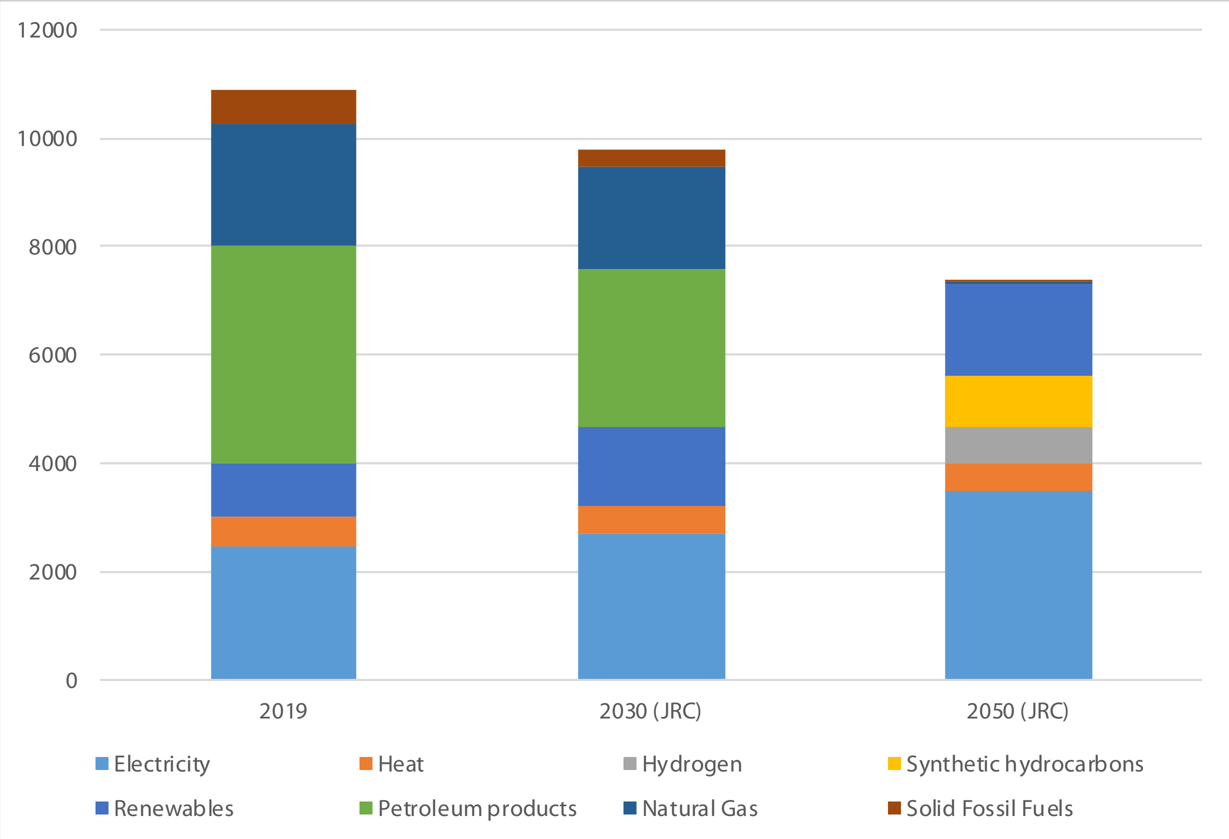
Final energy consumption (FEC) in the EU27 was around 11,000 TWh in 2019 [12]. More than 35% of this energy was provided by oil, with significant further shares from coal and natural gas, and 20% was

[12] Throughout the paper we consolidate all energy reported numbers into terawatt hours (TWh) to allow for comparison across scenarios and fuels. One TWh is equal to 86,000 tonnes of oil equivalent (toe) or 3,600 terajoules (TJ).

provided by electricity. Figure 2-1 represents the evolution of FEC fuel shares for the FF55 scenarios in 2030 and 2050.

There are substantial significant drops in consumption of fossil fuels and increases in production from electricity. There is a gradual transformation to 2030, before transition to a fuel mix vastly different from that of today by 2050.

Figure 2-1: JRC Final Energy Consumption by Fuel (TWh)



Note: Estimations are our best understanding of the numbers reported by JRC [13]. To our knowledge, no set of comprehensive final energy consumption indicators have yet been published. International aviation, maritime, and non-energy fuel uses are not included in the figure.

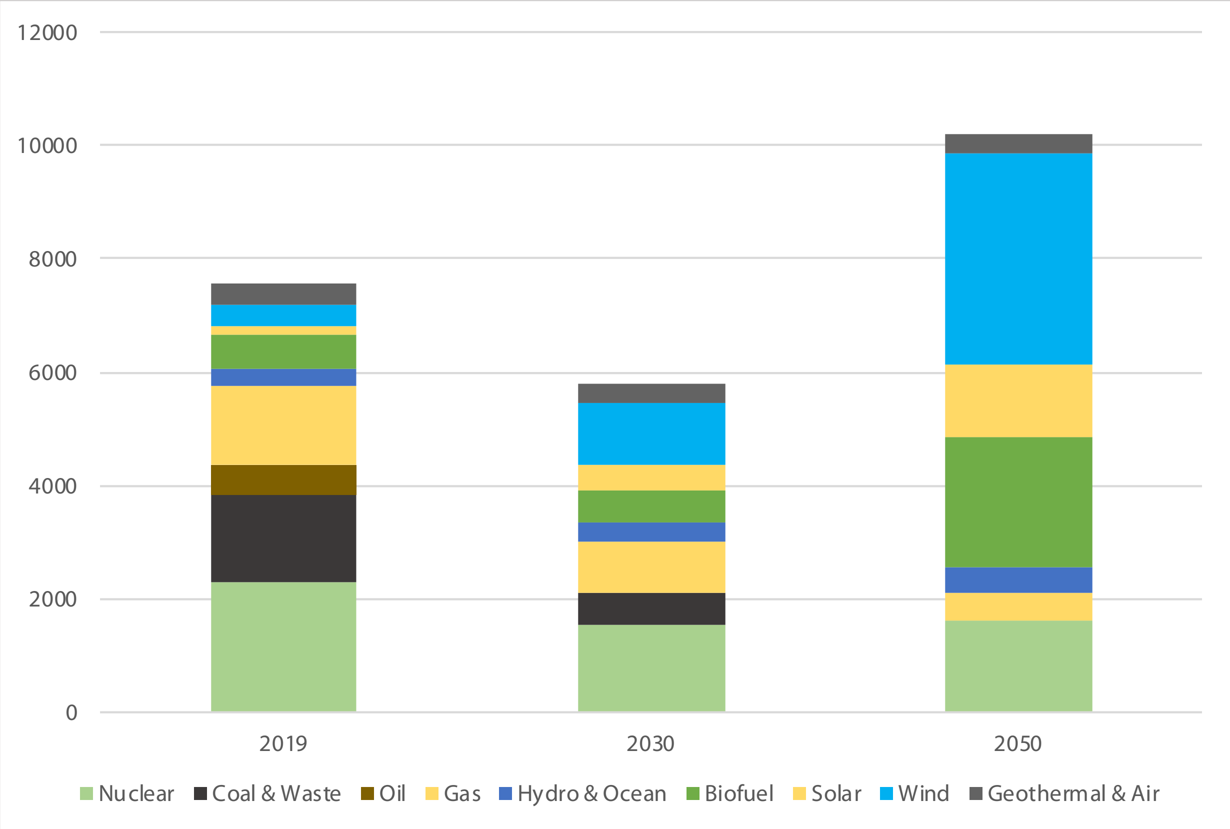
While some fuels, such as oil, are directly consumed, the use of electricity first requires the transformation of a separate energy input, for example, solar, wind or natural gas. In Figure 2-2, we show the changing energy inputs for the production of electricity, heat [14] and electrically-derived fuels (hydrogen and synthetic hydrocarbons). The mix shifts from being dominated by fossil fuels in 2019 to renewable sources in 2050. The big increase in energy input required by 2050 arises from the increasing involvement of synthetic hydrocarbons and hydrogen in final energy consumption.

To give one example, to produce pig iron from iron ore, blast furnaces are currently used. Much of the coal used in those is not counted as energy as the carbon is not used to heat the iron but to catch the oxide molecules. In the future, hydrogen might do this. The hydrogen used for the reduction of iron-oxide is not counted as energy, but the production of hydrogen from electricity is counted as energy usage. Hence, there will appear to be a significant increase in energy use.

[13] See https://visitors-centre.jrc.ec.europa.eu/tools/energy_scenarios/app.html#today:EU27/today:EU27.

[14] Heat refers to central heat and power units as well as district heating.

Figure 2-2: JRC Scenarios – Energy for electricity, heat and derived fuels (TWh)



Source: https://visitors-centre.jrc.ec.europa.eu/tools/energy_scenarios/app.html#today:EU27/today:EU27.

2.1.2. Bottom-up: Member States

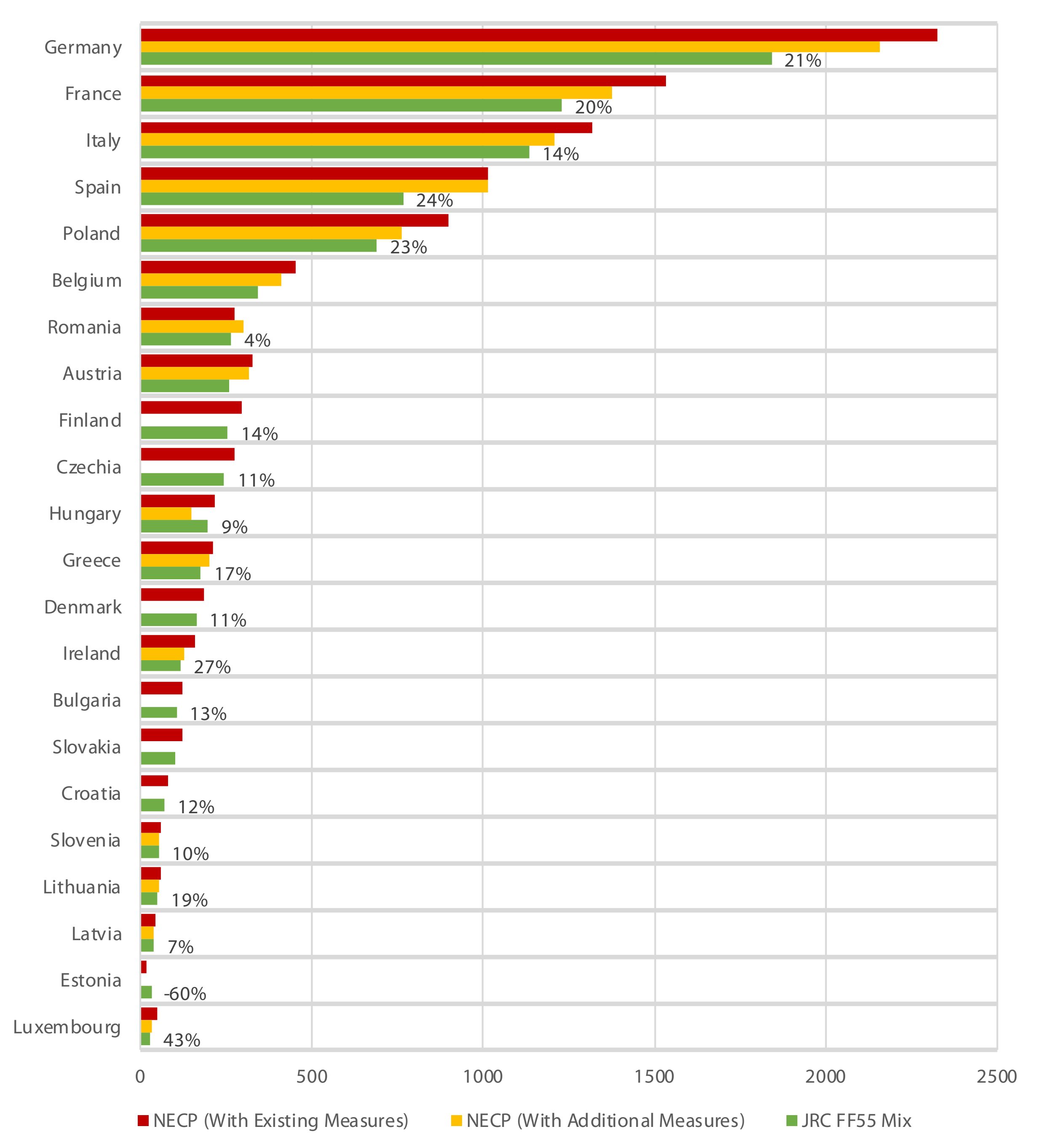
By the end of 2019[15], Member States were required to submit to the Commission their NECPs, detailing their plans for the transformation of their energy systems up to 2030. The NECPs were drawn up before the decision to speed-up decarbonisation was confirmed[16]. The plans typically contain two sets of estimations, one based on existing measures (WEM), and one based on the possible inclusion of additional measures (WAM). We consolidate data across NECPs, and compare them with centralised scenarios developed by the JRC.

Figure 2-3 shows that JRC scenarios see larger reductions in final energy consumption than NECPs (on average about -14%). In other words, current NECPs imply approximately 20% higher final energy consumption by 2030 than the JRC scenarios, which are compliant with the new climate targets.

[15] This was the deadline, although some were late.

[16] On 11 December 2020; see https://www.bbc.com/news/world-europe-55273004.

Figure 2-3: Final Energy Consumption (FEC) Projects NECPs and JRC 2030 (in TWh)

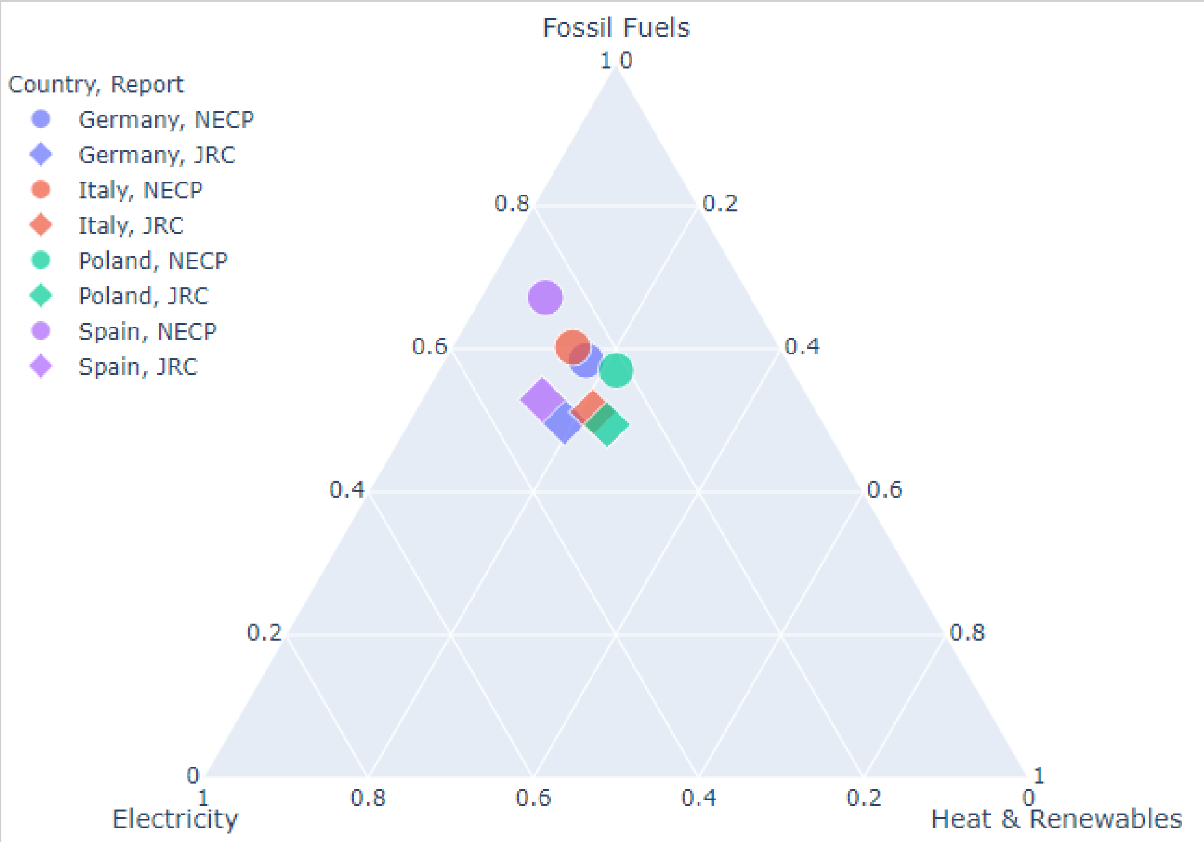


Note: JRC data for final energy consumption by Member State in the fit for 55 scenario are available here: https://ec.europa.eu/energy/content/excel-files-mix-scenario_en. NECP numbers are by collation of respective country documents. The percentages show the reduction in demand for JRC scenario compared with NECP existing measures.

The NECPs for which comparable data are available differ not only in total final energy consumption but also in the structure of the fuel mix. Using the examples of Germany, Italy, Poland and Spain, a general trend is revealed. The NECPs plan higher levels of fossil fuel, and lower levels of electricity (Figure 2-4). JRC scenarios also see higher shares of renewables in FEC.

For Germany, the JRC scenario would see an almost complete coal phase out in FEC already by 2030, while the NECP still expects almost 100 TWh. For natural gas – a hotly debated fuel in the German debate [17] – the values of the JRC and the German NECP closely align (400 TWh).

Figure 2-4: Comparison of FEC fuel shares: NECPs vs JRC



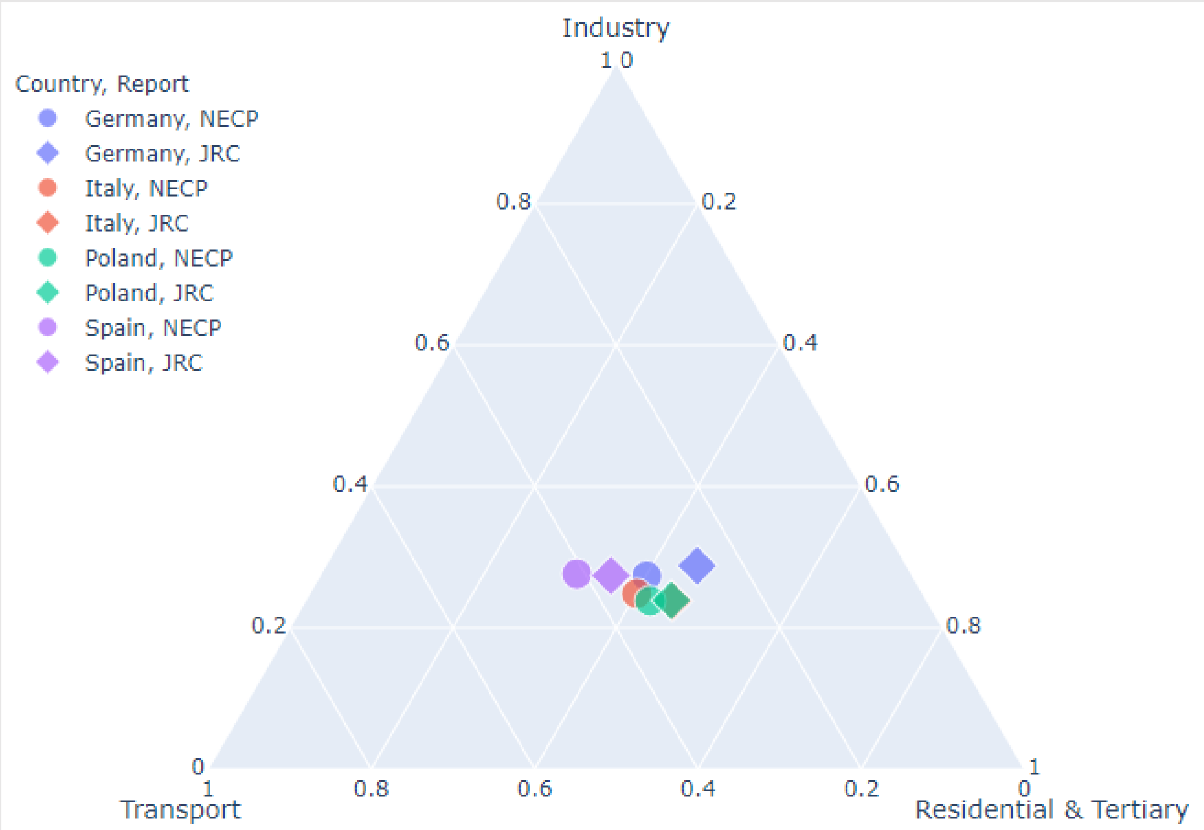
Note: The graph shows final energy consumption. Fossil fuels includes solid fossil fuels, petroleum products and natural gas. Heat and renewables refers to biofuels and the use of renewables in FEC that is not for the production of electricity.

The sectoral composition of FEC is also an area of divergence. Lower final energy demand, higher renewables and lower fossil fuel shares are partially explained by different takes on transport sector decarbonisation. Many NECPs expect transport energy consumption to be significantly higher in their country in 2030 than assumed in the JRC scenario (700 TWh vs 450 TWh for Germany, for example). This is likely due to lower electrification of transport, which would imply reduced FEC given the greater efficiencies of electric transport compared to fossil-fuelled transport.

Hence, there is not yet a consensus view on how national energy consumption will develop up to 2030, how fuel shares will develop and which sectors will switch fuels. NECPs and the JRC see similar relative levels of demand in the industrial sector. Relatively speaking, levels of consumption will be higher in the residential and tertiary sectors for JRC scenarios (Figure 2-5).

[17] See, for example, the discussion over Nord Stream 2 (https://www.cleanenergywire.org/factsheets/gas-pipeline-nord-stream-2-links-germany-russia-splits-europe).

Figure 2-5: Comparison of FEC sector shares: NECPs vs JRC



Note: The numbers are percentages of shown data and not quite total demand. That is due to inconsistencies across NECPS. For example, fishing and agriculture are excluded as they are not reported uniformly across the studies.

2.1.3. Result

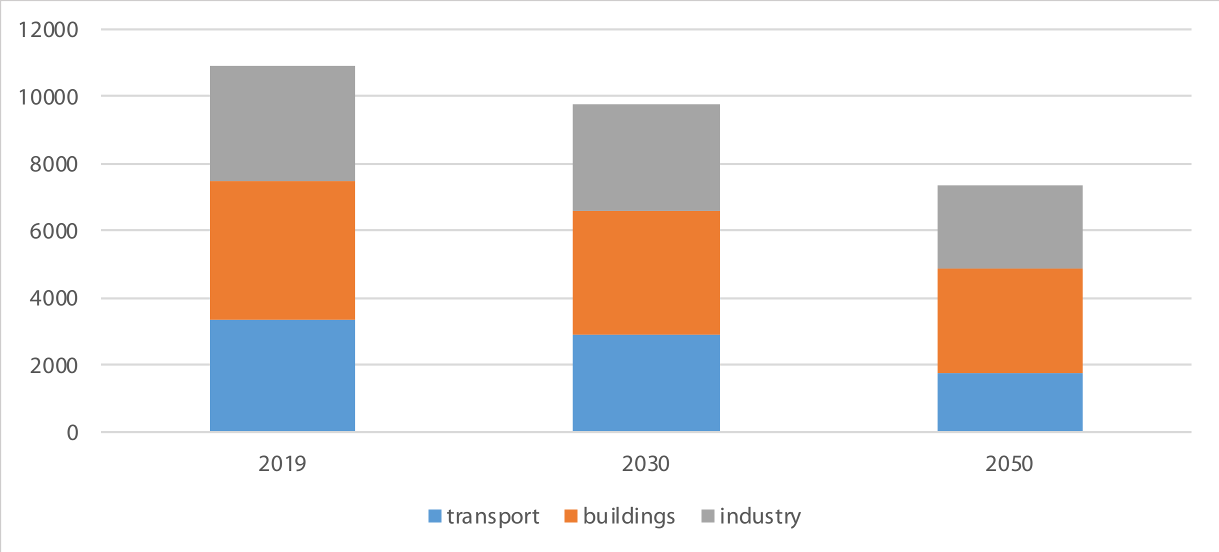
National plans and EU targets are not yet aligned. NECPs still foresee much higher levels of final energy demand, and higher shares of fossil fuel consumption to meet that demand. They do not envisage the levels of electrification as JRC modelling.

However, an equally strong conclusion is that the transparency and harmonisation of NECP data needs to be improved. NECPs are a very useful tool to better inform coordination of climate policy across Member States. Currently, the documents are often inconsistent and do not report similar metrics in a transparent manner.

2.2. EU energy consumption pathways by sector up to 2050

Beyond the four countries considered above, JRC modelling also provides an indicative pathway for the evolution of sectoral energy demand in the EU (Figure 2-6). It is clear that the big reductions in final energy consumption (FEC) will come from the transport sector, largely owing to electrification. There are also sizeable reductions in buildings FEC, while the reductions in industry demand are modest in comparison.

Figure 2-6: JRC energy scenarios, final energy consumption by sector (TWh)

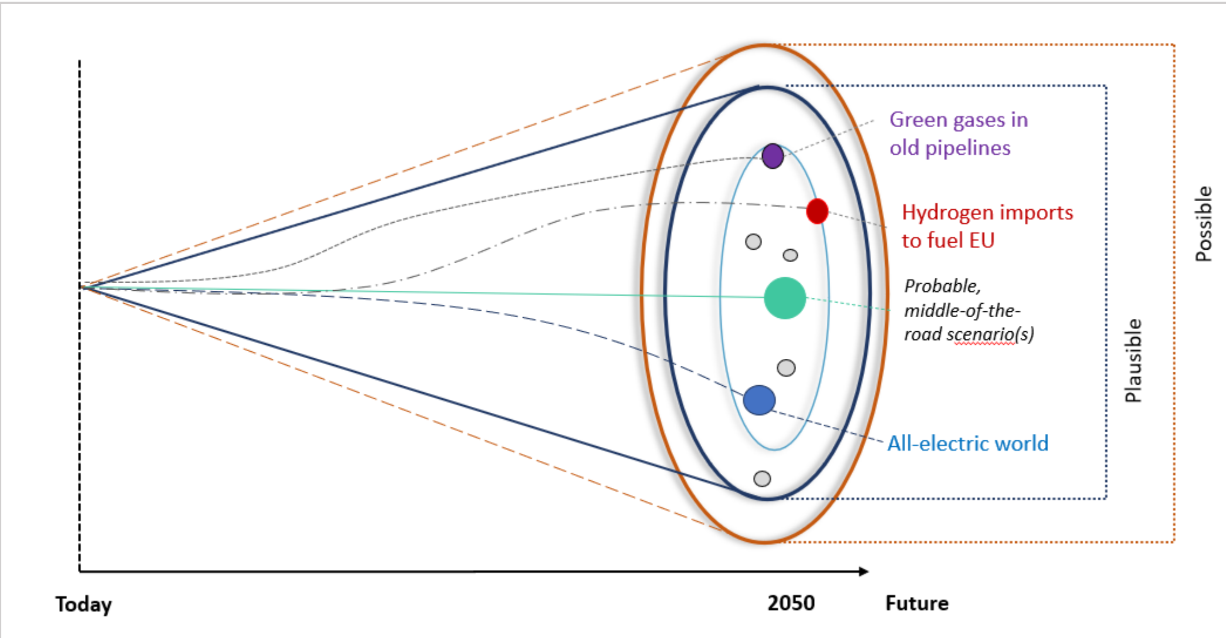


Note: Our interpretation of the figures reported by JRC [18]. Non-energy use of industry is excluded, and international aviation and maritime too.

2.3. Corner scenarios

Modelling studies, such as the JRC's, perform scenario analysis to provide insights into a variety of future pathways. Depending on technological developments, consumer preferences and political choices, there are a range of possible net-zero scenarios. These comprise different levels of gross production, energy efficiency and fuel consumption.

Figure 2-7: Stylised scenario logic



Source: Authors' own depiction. The three scenarios differ in a multitude of factors. The y-axis is not supposed to represent any one individual variable but rather the range of variables which differ across scenarios.

[18] https://visitors-centre.jrc.ec.europa.eu/tools/energy_scenarios/app.html#today:EU27/today:EU27.

We explore three "corner scenarios" which assume a plausible pathway for energy system evolution when all indicators are biased toward the development of one fuel (Figure 2-7). That is, in each 'corner scenario' we make strong assumptions for the respective fuels to penetrate energy systems. They are not intended to be optimal pathways, but rather allow for the comparison of different fuels in extreme scenarios. We investigate three systems: one of deep electrification, one reliant on the use of hydrogen as a fuel, and one significantly dependent on the use of "*green gases*". Table 2-1 provides an overview of each scenario.

Table 2-1: Key features of considered scenarios

	Green gases	Hydrogen	Renewable electricity
All-electric world	Gas transmission and distribution infrastructure is largely decommissioned [consumed where it is produced]	Hydrogen clusters with very concentrated pipeline network; some hydrogen storage for electricity seasonal storage	**Significant upgrading of European transmission and distribution grid**
Hydrogen imports to fuel EU	Gas transmission and distribution infrastructure is largely repurposed (i.e., green gas is consumed where it is produced)	**Meshed European transmission infrastructure connected to import points and hydrogen distribution grids in repurposed methane pipelines,** **hydrogen fuelling station infrastructure**	Electricity distribution only strengthened where no hydrogen is available, Electricity transmission modestly strengthened
Green gases in old pipelines	**Gas transmission and distribution infrastructure is largely maintained and used by green methane**	Hydrogen clusters with very concentrated pipeline networks; some hydrogen storage for seasonal electricity storage	Electricity distribution only strengthened where no methane is available; electricity transmission modestly strengthened

Source: Authors' own elaboration.

2.3.1. All-electric world

In this scenario, the overwhelming share of end-use demand shifts to electrification. This involves almost all road transport, as well as shares of water and air transport, a large share of buildings demand, and where possible industrial cases. This results in huge increases in average and peak electricity demand. Large volumes of renewable electricity generation would need to be deployed annually, and significant investment in the capacity and resilience of electricity grids would be required. Moreover, sources of seasonal and short-term flexibility would need to be developed to ensure that electricity grids can meet demand at all times. Finally, end-use sectors need to invest in electrification equipment.

In this scenario, hydrogen plays a niche role in the energy system (and non-energy) for some particular use cases. Synthetic gases would have an even more limited role.

2.3.2. Hydrogen imports to fuel the EU

In this scenario, hydrogen emerges to become a significant fuel in the EU energy mix. Hydrogen would be used to power a significant share of transport, industrial use cases and buildings demand. Domestically, hydrogen would be used at large-scale to balance seasonal demand for renewably-powered electricity grids.

This scenario would require coordinated infrastructure investments to retrofit natural gas pipelines to carry hydrogen, and the construction of new hydrogen pipelines. Additionally, if hydrogen demand accelerates rapidly, it is unlikely that production within the EU will be sufficient. Production within the EU would place significant strains on electricity grids (assuming that methane-derived hydrogen is not feasible by 2050). In this case, the EU would need to import significant volumes of hydrogen from neighbouring, and renewably-attractive countries.

2.3.3. Green gases in existing pipelines

This scenario involves the use of existing natural gas grids. Today's natural gas would be replaced by low-carbon alternatives: synthetic gases and biogases. Synthetic gases involve some combination of industrial processes to recreate the naturally occurring fossil gases consumed today (the inputted CO_2 is removed from elsewhere theoretically leading to net-zero emissions).

Biogases are produced from the breakdown of organic matter. Such gases can be used in existing natural gas grids and so transmission/distribution infrastructure costs would not be large. However, the production of such gases would be highly energy-intensive and expensive. In this scenario, significant shares of residential and industrial use cases would remain on the gas grid. Synthetic liquid fuels would also play some role in decarbonising the transportation sector[19].

[19] For the remainder of the paper, we will refer to the three scenarios as "*all-electric world*", "*hydrogen import*" and "*green gases*", respectively.

3. PHASING OUT COAL IN EUROPE

KEY FINDINGS

The use of coal in the electricity sector has to be phased out in order to reach the EU's climate-neutrality target. Coal is responsible for less than a fifth of the EU's electricity and heat generation but for half of the associated greenhouse gas emissions. Most EU Member States already have national phase-out policies, usually with a phase-out schedule for coal-fired power plants and a terminal date.

Only a few Member States in Central and Eastern Europe do not have an end date or have a very late end date for phasing out their national coal-fired electricity. Results from our electricity sector model show how the future system might look like without coal-fired power plants. Ensuring a substantially increasing speed of renewable expansion in the coal countries is crucial.

EU policies such as stringent CO_2 emission targets (EU ETS), other pollution targets and methane regulation complement national phase-out policies by providing additional economic rationale. EU support for coal-mining regions in the framework of the Just Transition Mechanism further helps affected coal countries to engage in the climate friendly transition. While the total number of employees in EU coal mining is small, mining regions may strongly depend on coal and need support to re-orient their economies.

There is now a widespread understanding that ending the use of coal in Europe's energy sector is crucial in order to achieve quick and substantial GHG emission reductions. Although the share of coal (lignite and hard coal) in electricity generation in the EU already decreased substantially, from 31% in 2000 to 14% in 2019, a relatively small number of coal-fired power plants are still responsible for sizable GHG emissions.

A series of EU ETS reforms that led to substantially higher CO_2 prices and have worsened the economics of coal since 2018 and have played an important role in recent reductions in coal use [20].

In addition to economic forces, and after more than a decade of low CO_2 prices, many EU countries have presented ambitious national plans to phase out coal from the electricity sector. Nine EU Member States are already "coal-free" and 11 more will shut all their coal-fired power plants by 2030.

Using an open-source numerical modelling, we show how the EU's demand for electricity can be met without the use of coal-fired power plants. Based on this, we stress the importance of accelerating the deployment of renewable energy sources.

Many of the EU Member States with late coal phase-out plans have domestic mining sectors. EU support for the transition in mining regions using the Just Transition Mechanism effectively provides additional incentives to these Member States to advance the coal phase-out.

[20] At the point of drafting the report, increasing gas prices have somewhat reversed that trend as coal power plants became relatively cheaper compared to gas power plants.

3.1. Status quo of coal use today

The use of coal [21] in the EU has decreased enormously in the last few decades [22]. Since 1990, the share of coal in the energy supply [23] of the 27 EU Member States has more than halved both in absolute numbers (from 4900 TWh in 1990 to 2200 TWh in 2019) and relative terms. Compared to 24% of the energy supply relying on coal in 1990, coal was only responsible for 10% in 2019 (Figure 3-1).

However, coal's share in energy supply varies across the Member States: seven countries in Central and Eastern Europe – Poland, Czechia, Bulgaria, Germany, Slovakia, Romania, Slovenia – still rely strongly on coal, which provides more than 10% of their primary energy supply (Figure 3-2). Mostly, this dependence on coal coincides with strong usage of coal in the electricity and heat sector. In all of these countries, coal is also mined domestically, i.e., the coal sector also contributes to national employment and Gross Domestic Product (GDP) more than in countries that rely exclusively on imported coal [24].

Figure 3-1: Coal in energy supply over time

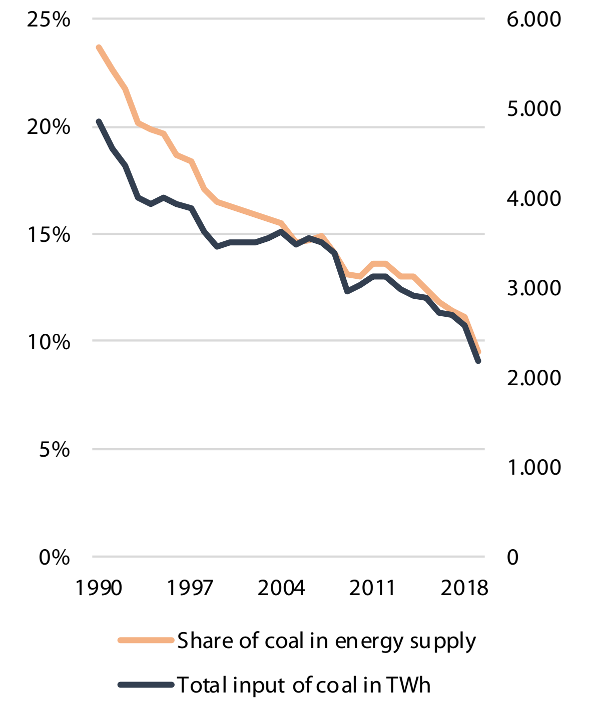
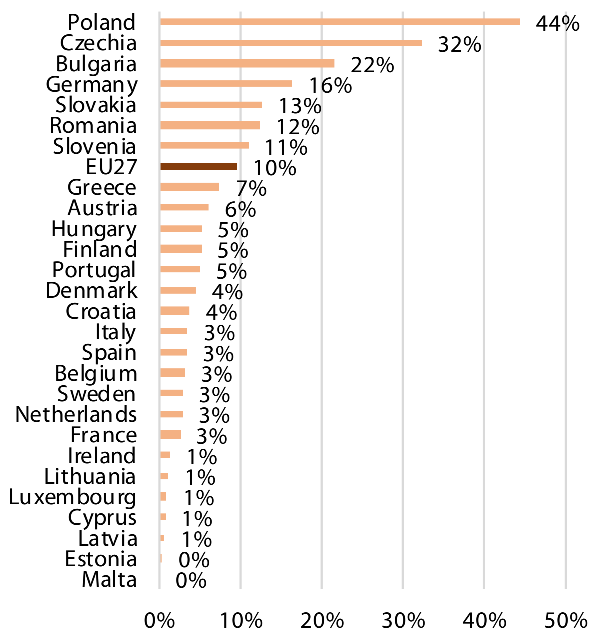


Figure 3-2: Share of coal in energy supply in 2019



Note: Basis for the share calculation is imports+production

Source: Authors' own calculations based on Eurostat (database ngr_bal_c).

With respect to the origin of the coal used in the EU, there are significant differences between the type of coal [25]. Lignite is typically used 'mine-mouth', i.e., close to the extraction (production) site. Hence, all of the lignite consumed in the EU is produced in the EU.

[21] Throughout this chapter, the term "coal" comprises hard coal and lignite (also called brown coal) alike/together. If one of the subcategories is meant specifically, we mention it.

[22] In this section, we discuss the entirety of coal use, i.e., in power generation and industry, unless indicated otherwise.

[23] Energy supply is defined as the sum of primary production, recovered and recycled products and imports.

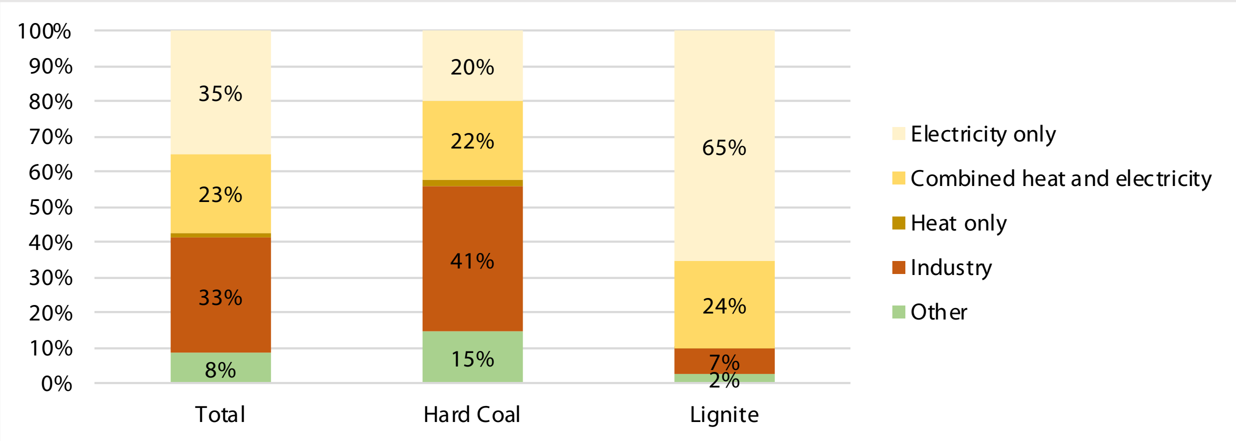
[24] Coal mining still takes place in the following EU Member States: Bulgaria, Czechia, Germany, Greece, Hungary, Poland, Romania, Slovenia and Slovakia.

[25] Based on typical European coal statistics, we differentiate between lignite, hard coal and coal products. Lignite contains also small quantities of sub-bituminous coal. Hard coal comprises predominately "(other) bituminous coal" (that is often called steam coal or thermal coal in the international market) as well as coking coal and anthracite. Coal products emerge from the processing of coal and include brown coal briquettes, patent fuels, coke oven coke, gas coke, and coal tar.

In contrast, 68% of the hard coal consumed in the EU is imported. Only Poland still has significant domestic extraction of hard coal, representing 94% of the hard-coal extraction in the EU. Most of the steam (thermal) coal is imported from Russia, Colombia, the United States and South Africa. Coking coal, which is about one third of total hard-coal imports to the EU, is primarily imported from Australia, Russia and the US (IEA, 2019a).

Lignite is predominantly used in the power sector to generate electricity (65% of the consumed lignite) and heat and electricity combined (24%) (Figure 3-3). Most of the remaining lignite is transformed into brown coal briquettes. A major part of the hard coal (44%) serves as an input for the generation of heat and electricity, and almost the same fraction is used in industrial processes. In industry, hard coal is used both for process heat generation and also as feedstock, in particular in the production of coke-oven coke and blast furnace gas for the iron and steel industry.

Figure 3-3: Usage of coal



Source: Authors' own calculations based on Eurostat (database ngr_bal_c). Remaining usage of coal to add up to 100% are statistical differences, energy sector usage and changes in stock

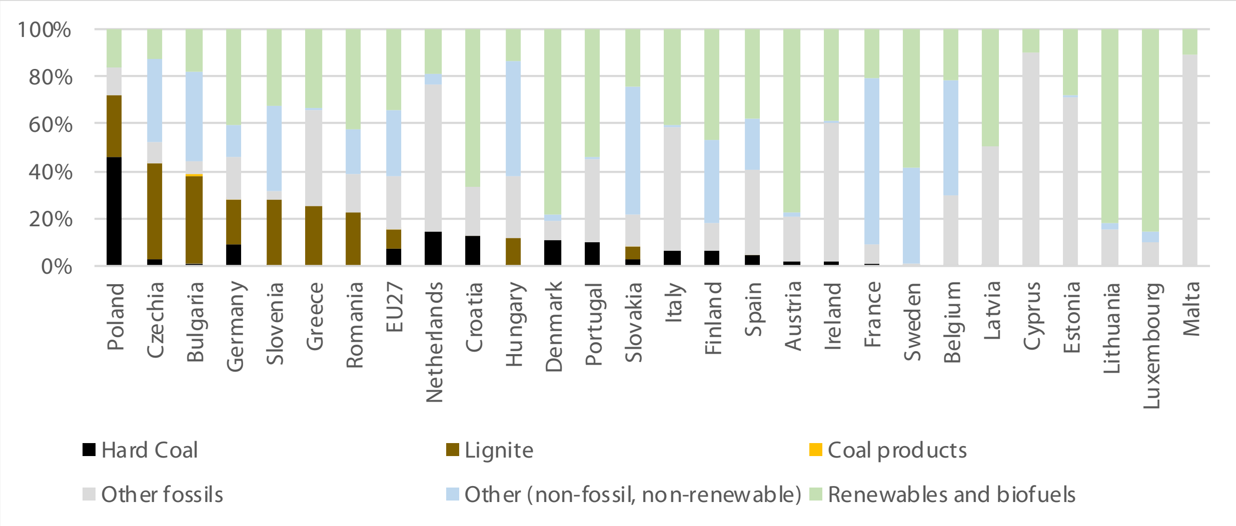
3.1.1. Power sector and heat generation

Most of the coal burned in the EU is used to generate electricity and heat (Figure 3-3) [26]. In parallel to its shrinking role in the total energy supply, the share of coal in the generation of electricity and heat has also decreased in the last few decades. While in 1990 around 35% of gross electricity was generated by coal, this share had dropped to 15% by 2019. Heat supply saw a similar decoupling from coal. However, the speed of reduction has slowed down in recent years, and around 22% of heat in 2019 was still supplied by coal. While hard coal and lignite are equally used in electricity, hard coal is the main coal type in the generation of heat.

Although coal has become markedly less important, it is still a vital for some Member States' electricity systems. In 2019, in seven EU Member States (Poland, Czechia, Bulgaria, Germany, Slovenia, Greece and Romania) more than 20% of total electricity was still produced from coal (Figure 3.4). While most of these countries rely on burning domestic lignite, Poland uses large quantities of hard coal, also mined domestically, for electricity production. In addition to the seven heavy coal-using Member States, another twelve Member States use coal (usually imported hard coal) in small quantities in their electricity mixes.

[26] Since the predominant part of heat supply derived from coal is produced by combined heat and electricity plants, this section covers the role of coal in the power and heating sector jointly.

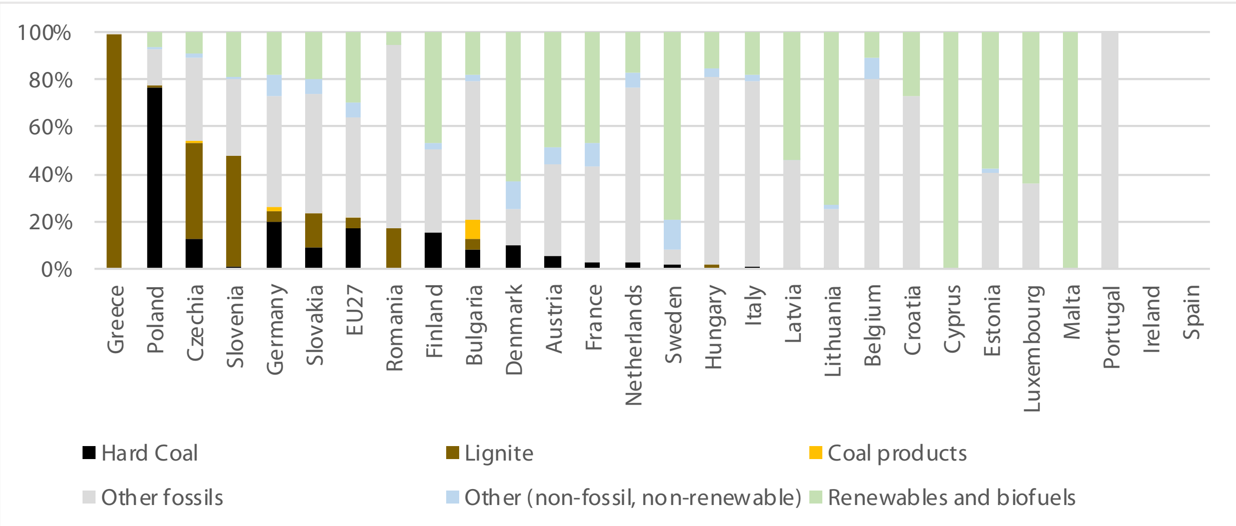
Figure 3-4: Share of coal (hard coal and lignite) in domestic gross electricity production in 2019 (in %)



Source: Authors' own calculations based on Eurostat (dataset ngr_bal_peh).

With respect to heat (space heating and industrial heat), the EU picture is even more variable. While most EU countries produce heat from other fossil fuels (natural gas, oil/oil products) or renewable sources, a few Member States rely heavily on coal: Greece, Poland, Czechia, Slovenia, Germany and Slovakia produce more than 20% of their heat from coal. Greece produces almost 100% of its heat from lignite, Poland 76% from hard coal, while Czechia and Slovenia both have shares of around 50% (mostly using lignite) (Figure 3-5).

Figure 3-5: Share of coal (hard coal and lignite) in domestic gross heat generation in 2019 (in %)



Source: Authors' own calculations based on Eurostat (ngr_bal_peh).

These figures show that the challenge of phasing out coal in the EU is focused on a small number of Member States. For around two thirds of the Member States, coal plays only a minor role in electricity and heat generation. However, the coal-dependent countries rely heavily on it and on several levels: electricity generation, space heating and industrial use, as well as domestic mining and employment.

3.1.2. Coal use in industry and other sectors

As Figure 3-3 shows, a substantial share of hard coal is used in industrial processes. While in the power and heating sector, steam coal (thermal coal) is the predominant type of coal, coking coal plays a key role in industrial processes. Almost 70% of the industrial hard coal consumed is coking coal, which serves predominately as an input for coke ovens in the steel industry. The usage of hard coal for steel production is mainly present in Germany, followed by the Netherlands, Poland and Slovakia. While we do not focus on the use of coal in industry in this report, decarbonisation of industrial demand is another major challenge (see, e.g., Bataille *et al*, 2018). Of course, the requirement to decarbonise the energy input as much as possible in order to meet the EU's climate neutrality target also includes the energy used in steel production and other industry. For the steel sector specifically – the most important coal consuming industrial sector – technology development is ongoing to replace traditional processes with processes that use hydrogen (see Chapter 5).

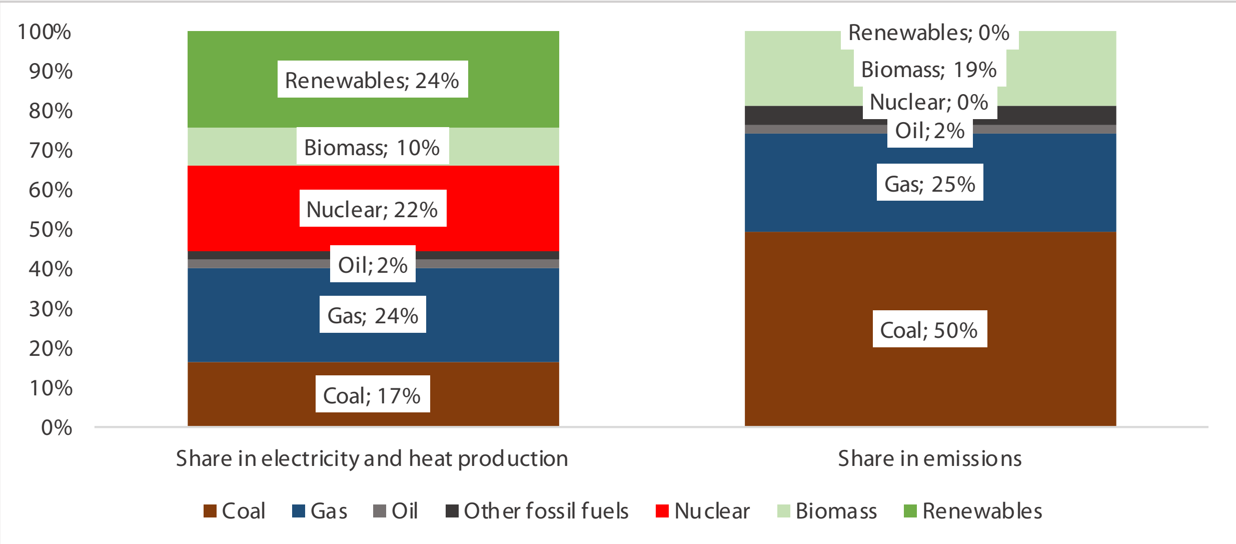
Coal use in other sectors is very small. Private households consume around 77 TWh of coal in the EU, other sectors even less: agriculture (9 TWh), services (8 TWh), fishing and rail transport (1 TWh). In many of these sectors, coal can be replaced by electricity or by (green) gas.

3.1.3. Greenhouse gas emissions from coal

a. CO_2 emissions

Coal, especially lignite, is one of the most CO_2-emitting fossil fuels used to generate electricity. To generate 1 MWh of electricity, emissions from lignite are around 1,000 kg CO_2, while emissions from hard coal are around 750 kg CO_2. To generate the same amount of electricity, emissions from burning natural gas are only 350 - 500 kg CO_2 – less than half than lignite [27]. Consequently, coal is responsible for less than a fifth of the electricity and heat generated in the EU, but for half of the emissions from the electricity and heat sector.

Figure 3-6: Share of coal in emissions and electricity and heat production



Source: Authors' own calculations based on Eurostat (ngr_bal_peh) & EU CRF Tables reported to UNFCCC (at: https://www.eea.europa.eu/ds_resolveuid/550712a8ce11432ab2cb7f0143ac478e). Renewables are without biomass and renewables waste; biomass includes renewables waste; Other fossil fuels includes non-renewable waste.

[27] Data on carbon content is taken from Kunz et al. (2017), data on thermal efficiency comes from Schröder et al. (2013).

In line with the reduced use of coal in the European energy system, CO_2 emissions from solid fossil fuels [28] have decreased over time. Compared to 1990, the CO_2 released from solid fossil fuels decreased by 65% from almost 1700 Mt to below 750 Mt in 2019. Despite the long-term decrease, CO_2 emissions from solid fossil fuels are still responsible for 20% of the total GHG emissions of the EU Member States.

Similarly, to the difference in the dependence on coal of the energy supply, CO_2 emissions from the use of coal vary strongly across Member States. Thus, Germany and Poland together emit more than 50% of the CO_2 from solid fossil fuels in the EU. The six largest emitters [29] of CO_2 from solid fossil fuel use are responsible for more than 75% of these emissions, and the 14 largest for 94% of these CO_2 emissions.

Although the EU ETS reform in 2018 and the increasing CO_2 price thereafter reduced the economic viability of coal (section 3.2.1), phasing out coal will be central to the reduction of EU's greenhouse gas emissions.

b. Methane emissions

In the last decade, global environmental research has increasingly addressed methane (CH_4) emissions and their greenhouse gas effect (UNEP, 2021). It is now clear that the environmentally harmful effect of methane – its so-called global warming potential (GWP) – is substantially higher than the GWP of CO_2. In particular in the short run (within 20 years), the GWP of methane is 81 times greater than that of CO_2 (IPCC, 2021). Over 100 years, the methane GWP is still 28 times greater than that of CO_2. In other words, the release of methane has an enormous impact on global warming in the very short run – an effect which was underestimated until recently and has hardly been addressed in environmental and climate policy [30]. For example, despite being a greenhouse gas and one of the so-called Kyoto gases of which emissions are reported to the UNFCCC, methane is not regulated by the EU ETS [31].

The focus of ongoing policymaking is on addressing methane emissions from agriculture, waste facilities, and the oil and gas sector (see section 4). However, methane emissions can also occur in the coal sector where they have traditionally been treated primarily as a security risk in mining. Fugitive methane emissions from solid fuels (i.e., coal) in the EU27 are even slightly greater than all the fugitive emissions from oil and natural gas. According to UNFCCC data, they represent about 6% of total EU27 methane emissions, and about 36% of all methane emissions from the energy sector [32]. This is about 1.8% of the EU27 total greenhouse gas emissions (see Appendix A1 for more details). Methane emissions from the solid fuel sector have declined by two-thirds since 1990 – when they were responsible for almost half of all methane emissions – in line with the decreasing role of coal over the same time period.

However, the decreasing trend of fugitive methane emissions from solid fuels has slowed since the late 2000s. This reflects the fact that methane leakage does not happen in the same way at all coal production sites, but depends on the geology (methane content) of the coal deposits. Most methane emissions in the EU's coal sector come from Polish underground coal mines (Kasprzak and Jones, 2020).

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28 The category 'solid fossil fuels' used in emission statistics comprises hard coal, lignite as well as coal products such as coke oven coke or coal briquettes. In addition to coal, it includes peat and oil shales and sands, which all have a very small role in the EU.

29 Germany, Poland, Czech Republic, Italy, France and the Netherlands.

30 In addition, methane has an environmental impact because it contributes to the production of ozone, which is also a potent air pollutant.

31 There is a structural difference between CO_2 emissions as covered in the EU ETS and fugitive methane emissions. The EU ETS addresses point emission sources, while fugitive methane emissions often arise along the infrastructure chain and cannot always be attributed to one single emission location.

32 According to UNFCCC data, fugitive methane emissions from the coal sector in the EU are about 3% (1%) the level of CO_2 emissions in the EU if the short-term GWP of 81 (the long-term GWP of 27) is used for calculating the methane emissions' CO_2 equivalent.

Unlike other EU Member States, Poland has continued to produce and use coal in large amounts, and has thus continued to emit fugitive methane from solid fuels. However, fugitive methane emissions also arise from abandoned coal mines and require monitoring and further actions (Olczak and Piebalgs, 2021).

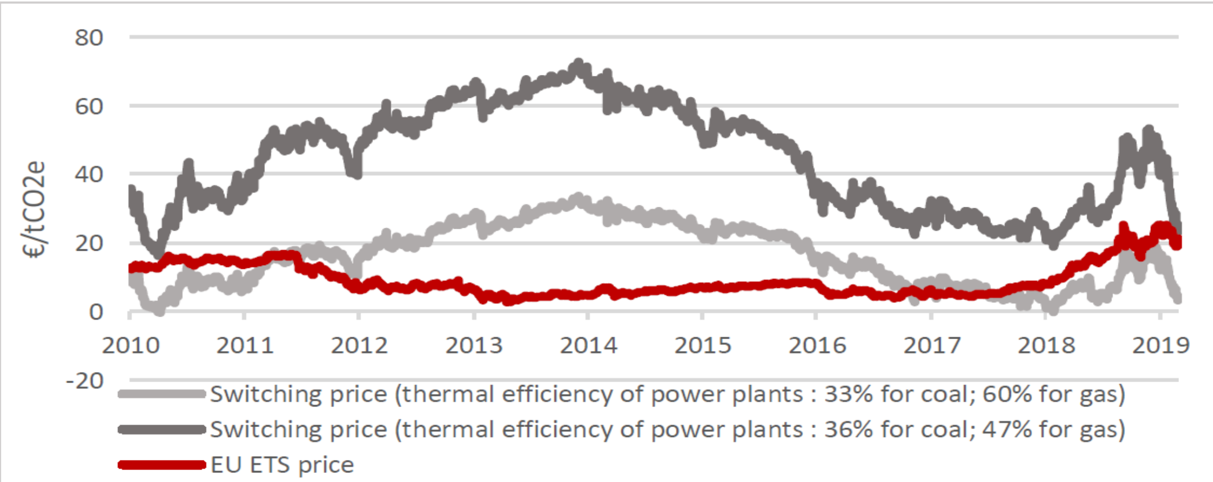
3.2. The effects of European environmental policies on coal

3.2.1. EU ETS

For many years after the establishment of the EU ETS in 2005, the CO_2 price remained too low and did not provide a great enough incentive to crowd-out the use of coal in the EU [33]. On the contrary, the low CO_2 price rather provided an incentive to use coal, while disincentivising the use of natural gas. Moreover, free allowances from the new entrants reserve in the 2000s provided incentives to build new coal plants, such as Hamburg-Moorburg in Germany (Pahle, 2010).

Since the 2018 EU ETS reform, the European CO_2 allowance price has risen substantially: from well below €10/tCO_2 until early 2018, to a price around €25/tCO_2 in 2019 and even above €60/tCO_2 in September 2021 [34]. This has affected the economics of coal in comparison with natural gas and other low-carbon/no-carbon electricity generation options. The switching price is the price at which it is economically attractive to change (switch) from coal-fired power generation to natural gas-fired power generation [35]. It has been exceeded by the CO_2 price since 2019, at least when comparing older, less efficient coal power plants to modern, efficient natural gas power plants (figure 3-7, light grey line) [36]. Even though lignite is more carbon-intensive than hard coal, its very low production and transport costs make it less sensitive to an increasing CO_2 price. Therefore, it is estimated that phasing-out lignite on economic grounds requires an even higher CO_2 price than seen in the last three years.

Figure 3-7: EU ETS CO2 price and two hypothetical fuel switching prices (2010-2019)



Source: Marcu et al. (2019)

[33] In this section, we focus on coal in the electricity sector.

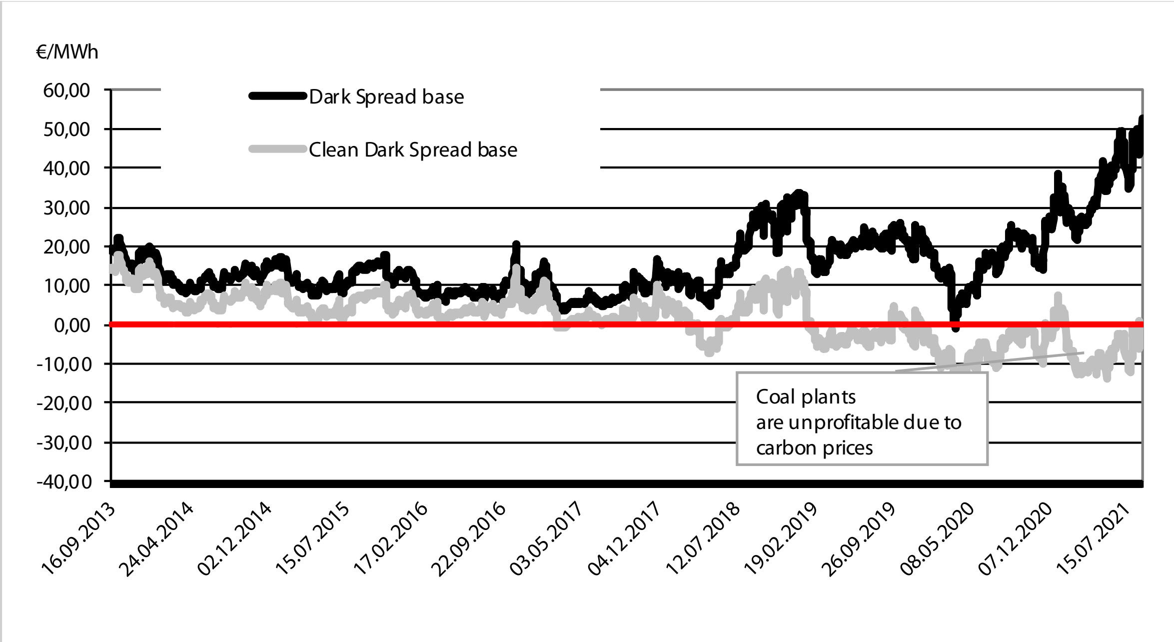
[34] Quoted prices are EU Allowance prices.

[35] The switching price takes into account the aggregated costs of generating electricity and indicates at which CO_2 price level generating from either coal or natural gas has equal costs. Above this CO_2 price level, it is more economic to switch to electricity generation from natural gas. The costs included in the calculation are the fuel prices (coal or natural gas), the operational costs and efficiencies of the power plants (i.e., how much electricity can be produced from the input fuel), as well as the CO_2 price which is proportional to the fuel input. In an inefficient plant (i.e., with lower thermal efficiency), more fuel needs to be used which therefore leads to higher CO_2 emissions and higher expenditures for CO_2 allowances than a more efficient plant (i.e., with higher thermal efficiency).

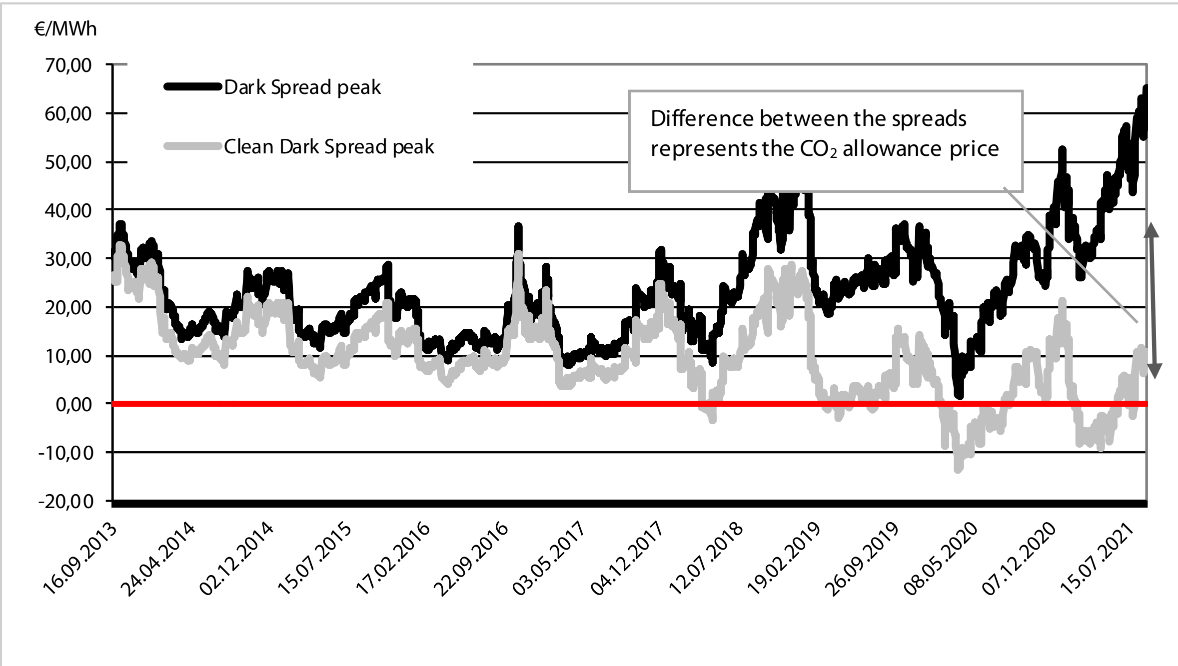
[36] The dark grey line shows the switching price between a more efficient coal-fired power plant and a less efficient natural gas-fired plant.

Figure 3-8: Baseload (a) and peakload (b) spreads for coal fired electricity plants (dark spreads), including the CO2 price (clean dark spread), in Germany 2013-2021

a) Dark Spreads BASELOAD



b) Dark Spreads PEAKLOAD



Source: EnergieInformationsdienst.

Notes: NCG gas prices. Here, representative power plants have representative efficiency rates of 49% (natural gas fired power plant) and 38% (hard coal fired power plant. Dark spreads are calculated as difference between the electricity price and the coal price. For Clean dark spreads the CO_2 emission allowance price of the same day is further subtracted.

The long period of low CO_2 prices and favourable market conditions for coal can also be observed in the clean dark spreads shown in Figure 3-8. The clean dark spread is a standard indicator used in energy trading which shows the stylised gross profits for a representative coal power plant ("dark")[37]. More precisely it's the difference ("spread") between the electricity price (i.e., the revenue of the power plant operator) and the simplified costs incurred by the power plant operator which are made up by fuel (coal) price and the CO_2 emission allowance price ("clean"). All other costs (maintenance, staff, capital costs, etc.) are ignored by the indicator and must be covered by the spread. The indicator without the CO_2 price cost is called the "dark spread" and is also shown in Figure 3-8.

Until 2018, the clean dark spread (grey line) was always positive, meaning that coal power plant operators earned a positive profit. Only since 2019 has the clean dark spread become negative, because of the continuous rise of the CO_2 price. The gap between the dark spread (electricity price minus coal price) and the clean dark spread (electricity price minus coal price minus CO_2 price) shows the effect of the CO_2 price. This gap has widened substantially since 2019 and even more since 2020.

The broad trends have been the same for base load and peak load hours[38]. However, in peak demand periods, even very recently when CO_2 prices were above €60/tCO_2, the clean dark spread was still positive because the peak electricity price was higher than the combined fuel and CO_2 costs. This shows that a further rise of CO_2 prices would be required to effectively phase out coal during all time periods.

The low EU ETS price level in the previous decade – consistently below €10/tCO_2 between end 2011 and early 2018 – stopped carbon pricing from having an effective impact on electricity generation from coal, both in short-run dispatch and long-term investment decisions. In this environment, many EU Member States favoured alternative policies to reduce the role of coal such as regulated phase-out policies. However, these phase-out policies have some disadvantages compared to price-based mechanisms. First, they control emissions only indirectly by limiting the installed capacity instead of the actual generation of electricity from fossil fuels. Second, they lead to compensation payments to plant owners, whereas a price-based mechanism allocates the costs to the polluting units. Apart from the EU ETS, such a price-based instrument could be implemented by Member States individually through, for example, national carbon price floors, i.e., a minimum price on carbon emissions (e.g., Oei *et al*, 2015). For Germany, a price of around €34/tCO_2 would be sufficient to reach the 2030 climate target whereas the current coal phase-out schedule misses this target (Osorio *et al*, 2020).

The higher CO_2 price level since 2018, in turn, has effectively deteriorated the economics of coal power in the EU. For example, it is likely to have contributed to the high participation rates in the German hard-coal phase-out auctions in 2020 and 2021, in which even recently opened, modern and highly efficient hard-coal power plants such as Hamburg-Moorburg (opened in 2015) bid to stop operations for a bonus payment[39].

The CO_2 price is projected to increase further with the tightening of the EU ETS cap envisioned in the EC's 'Fit for 55' package. Some analysts argue that this will lead to an almost entire coal phase-out by 2030 (e.g., Pietzcker *et al*, 2021), which would be in line with the Paris Agreement (Climate Analytics, 2017).

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[37] Spread indicators also exist for other types of power plants: natural gas ("spark spread"), nuclear ("quark spread"), biomass ("bark spread"). Only for coal-fired power plants, it is called "dark spread".

[38] Peak load is a period of very high demand when electricity prices are usually high (higher than during baseload time).

[39] The German regulator Bundesnetzagentur provides a list of coal-fired installations that successfully bid for bonus payments if they close early (in German), available at: https://www.bundesnetzagentur.de/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/Kohleausstieg/start.html.

Lastly, for the EU ETS to maintain a high price level, it is essential that the emission rights of closed coal-fired power plants are cancelled and not transferred back into the market to other emitters. This has been highlighted by, for example, Anke *et al* (2020) and Keles and Yilmaz (2020), and is applied, for example, in the German coal phase-out law [40].

3.2.2. Other pollution limits

Replacing the Large Combustion Plant Directive (LCPD, in force until end 2015) [41], the Industrial Emissions Directive regulates pollution from sulphur dioxide (SO_2), nitrogen oxides (NO_x), dust and a variety of other pollutants (e.g., heavy metals) [42]. For coal and lignite combustion plants specifically, it also includes requirements, from summer 2021, on the control of mercury emissions. While several Member States temporarily applied for derogations[43], the emission limits will ultimately force operators to choose between pollution-reducing costly retrofits of their old plants or speeding up the retirement of their plants.

3.2.3. Methane regulation

Methane emissions from the coal sector have not been regulated so far. However, for climate reasons and acknowledging latest research findings, methane emissions from coal must be included in current and future methane regulation. The EC has proposed to include it in its methane strategy update from which concrete policy proposal are due at the end of 2021 [44].

Given the urgency of reducing methane emissions, regulation should go beyond establishing standards for monitoring, reporting and verification (MRV). In order to achieve the EU climate neutrality target, methane emissions should be capped as soon as possible and a policy to reduce the emissions introduced. Such a policy could, for example, follow the example of the EU ETS with a methane cap-and-trade system, or integrate methane into the EU ETS, or take a different approach, such as capping methane intensities of (coal) production units.

3.3. Status quo of national coal phase-out policies

Coal phase-out decisions provide a signal about climate policy credibility to the market and the international policy community, which is one major reason why many EU Member States have adopted them. Many countries around the world have taken this decision – several of them as part of the Powering Past Coal Alliance – under pressure from civil society that does not want to wait to see cross-sectoral policies, such as CO_2 emission caps, to tackle coal-fired power generation effectively. Phasing out coal generation has the benefit of also effectively addressing other externalities and challenges related to coal-fired combustion and coal mining, such as pollution and related health effects, and land degradation. The continuous cost reduction of renewables in the last two decades is one factor that has convinced national political decision-makers and other stakeholders that coal phase-outs would be achievable in many EU Member States.

[40] Details on the German federal coal exit law(s) available at: https://www.bmwi.de/Redaktion/DE/Artikel/Service/kohleausstiegsgesetz.html (in German).

[41] Directive 2001/80/EC on the limitation of emissions of certain pollutants into the air from large combustion plants (the LCP Directive), replacing Directive 88/609/EEC on large combustion plants as amended by Directive 94/66/EC.

[42] Directive 2010/75/EU of the European Parliament and of the Council of 24 November 2010 on industrial emissions (integrated pollution prevention and control). Available at: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32010L0075.

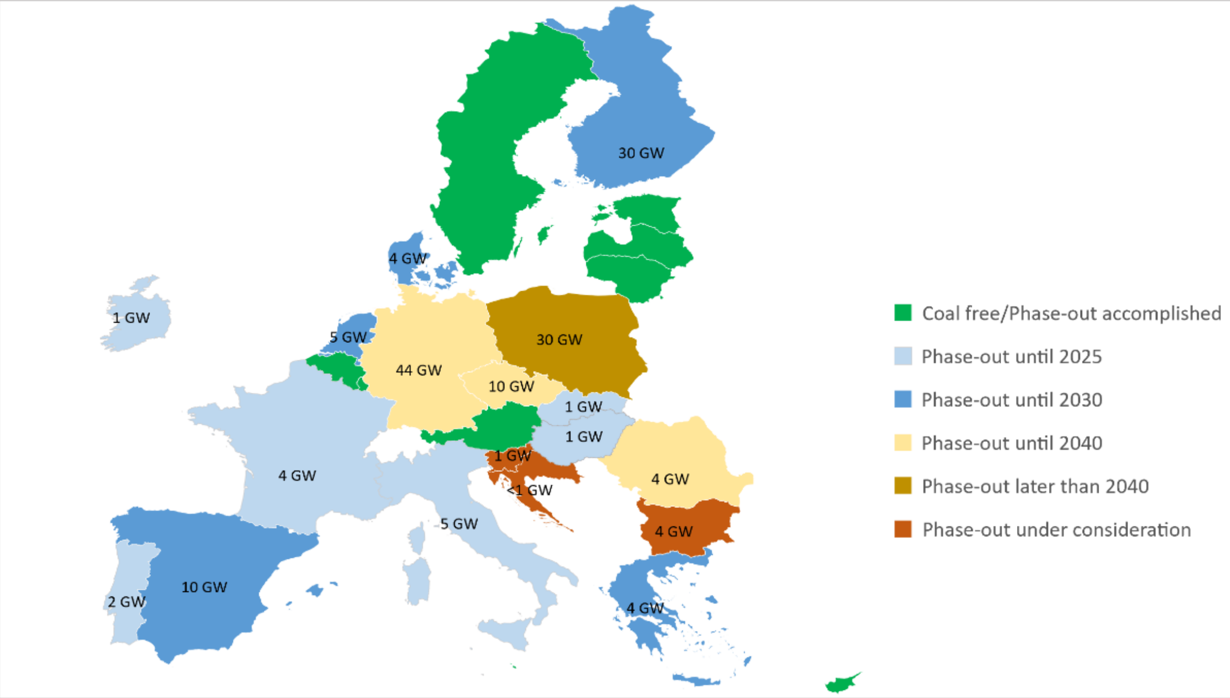
[43] See https://eeb.org/four-years-of-unnecessary-pollution-eu-governments-fail-to-curb-emissions-from-most-toxic-plants/.

[44] COM(2020) 663 final on an EU strategy to reduce methane emissions.

The current status of national coal phase-out decisions varies across EU Member States (Figure 3-9). In some cases, coal played little role in the energy and electricity mix for various reasons, e.g., because of local non-availability (e.g., in the Baltics and on the Mediterranean islands).

In some cases, old coal power plants were quite easily replaced with domestically available energy sources (e.g., Austria, Belgium). The situation is very dynamic and there have been some recent additional commitments to – relatively – early coal phase-outs in the process of deciding on National Resilience and Recovery Plans (NRRP) as a response to the COVID-19 crisis, and where additional EU funds can help support the energy transition (e.g., Romania).

Figure 3-9: Coal phase-out status in EU Member States as of September 2021



Source: Authors' own depiction. Blank map from Bing (Microsoft). Numbers indicate the installed capacities of hard coal and lignite power plants in 2020. Power plant capacities from ENTSO-E Transparency Platform (Installed Generation Capacity Aggregated [14.1.A]), Available at: https://transparency.entsoe.eu/generation/r2/installedGenerationCapacityAggregation/show.

In **Poland**, discussions on advancing the coal phase-out commitment – of which the current deadline is 2049 – are ongoing, and more and more indicators point towards a phase-out earlier than 2040. Most importantly, in June 2021, the operator PGE decided to close the largest coal-fired power plant Bełchatów in 2036, which has triggered earlier phase-out plans for the connected lignite mines [45]. It is reported that the decision was influenced by the willingness to apply for funding from the EU Just Transition Fund [46]. However, economic factors (very high extraction costs, combined with low – regulated – coal and electricity prices) certainly also play an important role. The Polish government has shown signs to be willing to bail out unprofitable coal power plants, which would not be compatible with the state-aid rules for energy and environmental protection.

[45] See information collected by the *Global Energy Monitor* and made, available at https://www.gem.wiki/Belchatow_power_complex (last visited on August 1, 2021).

[46] See the company PGE's press release available at: https://www.gkpge.pl/Press-Center/press-releases/corporate/pge-group-just-transition-for-belchatow-region-becoming-a-fact (last visited on August 1, 2021). PGE is a stock company; more than 50% of its shares are held by the Polish State (information available at: https://www.gkpge.pl/Investor-Relations/Shares/Shareholders).

In the **Czech Republic**, a multi-stakeholder national coal commission that has deliberated since 2019 suggested in May 2021 to set a final phase-out date of 2038, as in Germany.

Yet, parts of the government rejected this date and asked for an alternative suggestion with an earlier phase-out date [47]. The next government after the October 2021 elections is supposed to take the final decision. In the meantime, one of the two coal companies, the state-owned utility CEZ, announced a substantial reduction of the share of coal in its generation mix: from 36% of its capacity in 2020 to 25% by 2025 and 12.5% by 2030 [48]. This continues an ongoing trend of mothballing coal-fired power plants in the country.

In **Slovenia**, discussions about advancing the coal phase-out (envisaged for 2050 by the NECP) are currently under way. Several proposals are on the table, with the earliest suggested phase-out in 2033. Slovenia has one lignite mining region and any progress on coal phase-out will depend on the alternative employment and income chances that are developed in a draft territorial plan in the framework of the EC's Coal Regions in Transition Initiative.

In **Romania**, the situation is very dynamic. Until spring 2021, there was no commitment to a coal phase-out. In June 2021, the Romanian government submitted a National Resilience and Recovery Plan (NRRP) to the EC that aims at phasing out coal from the electricity sector by 2032 and closure of domestic coal mines even much earlier, in 2022. These decisions came after rising CO_2 prices substantially deteriorated the economics of Romanian coal. Romania is hoping to obtain support from EU funds, in particular to support the transition in the mining regions. However, the details of the phase-out are yet unclear and other policies such as the almost non-existent expansion of renewable capacities and the government's restructuring plan of the state-owned utility Complexul Energetic Oltenia still contradict the phase-out announcement [49]. It is reported that a 'coal commission' similar to those in Germany and the Czech Republic will work out the details [50].

The situation is very challenging in **Bulgaria** which has large coal mining activities and employment, in addition to a high share of coal in the electricity mix while there has been hardly any expansion of renewable capacities in the last nine years. Previous governments had opted for a wait-and-see strategy and did not take any coal-phase out decision. Now, the Bulgarian coal sector is under economic pressure from increased CO_2 prices. Bulgarian decision-makers also see a chance to possibly obtain support from EU funds for the transition of mining regions. Yet, without a stable government in place [51], there is no commitment to an exact phase-out date or schedule.

Croatia joined the international Powering Past Coal Alliance (PPCA) in June 2021 and now works, together with the PPCA, on a coal phase-out policy and date [52]. So far, Croatia has no coal phase-out date. It is reported that the coal phase-out is envisaged for the early 2030s [53].

[47] Based on information available at: https://www.nasdaq.com/articles/czech-government-to-look-at-speedier-coal-exit-than-2038-target-2021-05-24 (last visited August 1, 2021).

[48] See CEZ's press release available at: https://www.cez.cz/en/media/press-releases/cez-presents-clean-energy-of-tomorrow-its-production-portfolio-is-to-be-rebuilt-to-low-emissions-by-2030-144329 (last accessed August 1, 2021).

[49] See the news announcement available at: https://beyond-coal.eu/2021/06/03/romania-confirms-it-is-ditching-coal/.

[50] See the news announcement available at: https://www.euractiv.com/section/energy/news/romania-will-phase-out-coal-by-2032/.

[51] The next parliamentarian elections in Bulgaria are scheduled for November 2021. This will be the third national elections in 2021.

[52] See the announcement by the Powering Past Coal Alliance available at: https://www.poweringpastcoal.org/news/press-release/spain-heads-list-of-new-powering-past-coal-alliance-members.

[53] See the news report on the Euractiv website from June 28, 2021 available at: https://www.euractiv.com/section/climate-environment/opinion/the-eu-must-tell-the-world-it-will-power-past-coal-by-2030/.

Lastly, in **Germany**, during the federal election campaign in summer 2021, politicians from various parties, including the ruling conservative party, agreed that the *de-facto* coal phase-out will have to be earlier than 2038.

It remains to be seen whether this will simply be economic reality or a renewed political decision and law-making will be arranged. Some observers argue that the updated climate law from summer 2021 implicitly means an end to coal by 2030 [54].

In sum, the insights from the ongoing discussions in the Member States show that the economics of increasing CO_2 prices and decreasing renewable costs have put additional pressure on their coal sectors, which were already highly disputed because of the climate-neutrality target. EU support for the transition of mining regions effectively provides an additional incentive.

3.4. Effects of upcoming coal phase-outs in EU Member States

3.4.1. Effects on the power sector

a. Status quo of the coal-fired power plant fleet

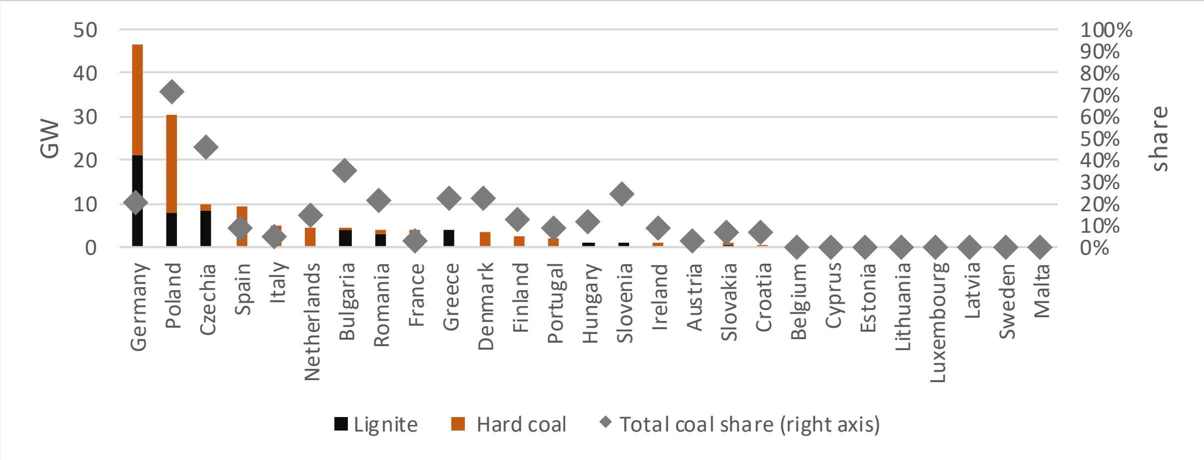
Phasing out coal constitutes a fundamental change to the electricity sector in those EU Member States that still rely strongly on coal. Major infrastructure investments will have to be taken to replace coal-fired power plants. As highlighted in Section 3.1 of this chapter, many EU Member States use coal to generate electricity, though only a few countries still have large active coal-based power plants infrastructure.

Lignite and hard coal capacities are still installed in various EU Member States, with very large capacities in Germany (over 45GW) [55] and Poland (over 30GW), Czechia (around 10GW) and Spain (around 10GW) (Figure 3-9). Especially for several Central and Eastern European Member States, replacing lignite and hard coal is challenging because they still constitute a substantial share in installed total power plant capacity: in Poland (71%), Czech Republic (46%), Bulgaria (35%), Slovenia (25%) (figure 3-10).

[54] It is yet unclear which sector(s) will contribute to the additional emission reduction required by the updated German Climate Law. Because of the high emissions from the coal sector and the continuous expansion of renewables in Germany, many observers argue that the bulk of the additional emissions reduction should come from the coal sector. One such analysis is available at: https://www.euractiv.com/section/climate-environment/opinion/the-eu-must-tell-the-world-it-will-power-past-coal-by-2030/. However, the Coal Exit Law has not been updated until the parliamentary elections in September 2021.

[55] Out of these 45GW, only 33GW operate currently at the electricity market. The remaining power plants are reserve capacities that can be reactivated by the transmission grid operators to maintain security of supply.

Figure 3-10: Installed capacity in MW of coal-fired power plants in 2019



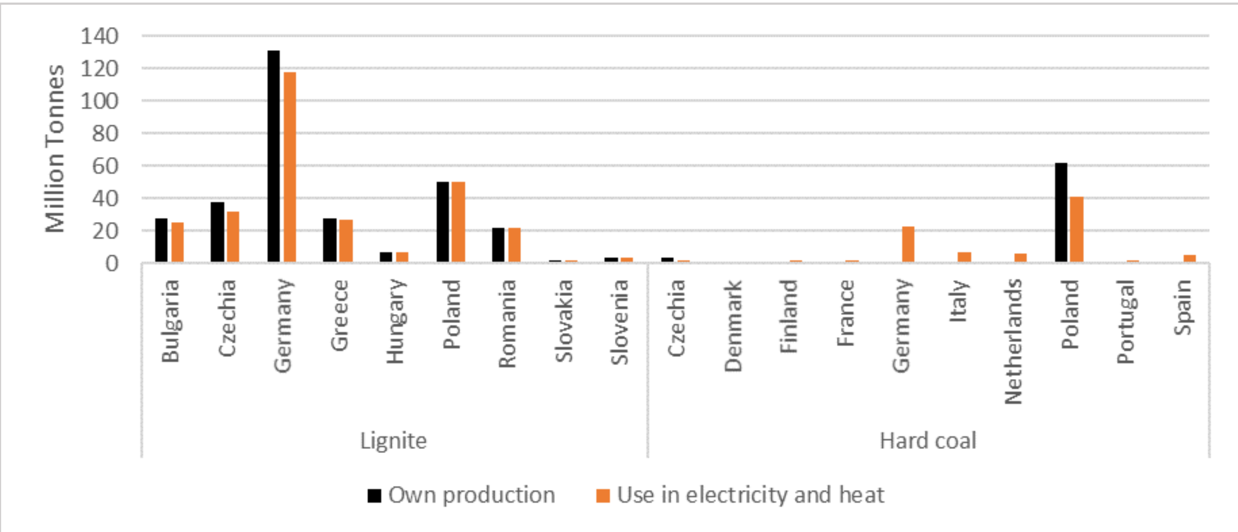
Source: Authors' own calculation on data by ENTSO-E Transparency Platform (Installed Generation Capacity Aggregated [14.1.A]), available at: https://transparency.entsoe.eu/generation/r2/installedGenerationCapacityAggregation/show.

Lignite power plants have traditionally been operated as baseload plants. Hard coal power plants have also been operated as flexible supply with daily cycles when renewable energy sources are not available. Thus, the crucial question arises of how coal-based electricity production will be replaced in the coming decades. Obviously, this question hinges on many factors: political considerations, economic feasibility (e.g., price of carbon) and security-of-supply considerations.

b. Import dependency

When discussing coal phase-outs in the EU, questions of import dependency are at the forefront for many countries. Here, it is crucial to differentiate between lignite and hard coal. Lignite it is overwhelmingly used to generate electricity and heat and is used near the extraction site (Figure 3-11). Because of the low energy content, long-distance transportation of lignite is economically not viable.

Figure 3-11: Use of lignite and hard coal in the EU in 2019



Source: Authors' calculations based on data from Eurostat (nrg_cb_sff).

In the case of hard coal, the picture is fundamentally different. Ten EU Member States use 1 Mt of hard coal per year or more for the production of electricity and heat.

In contrast to lignite, hard coal is only extracted in Czechia and Poland, with Poland producing twenty times as much as Czechia. Thus, almost all EU Member States use imported hard coal to produce electricity and heat [56].

Coal-mining countries (hard coal and lignite) could decide to replace their coal power plants with gas-fired power plants. However, that would not only lead to a greater import dependency because of the lack of domestic natural gas sources, but would also generate the risk of stranded natural-gas assets. The remaining coal countries are located in Central and Eastern Europe where, due to the gas pipeline infrastructure in place, natural gas imports come predominantly from Russia, which can be considered a risky supplier. In this situation, replacing coal power plants by – domestic – renewable energy sources (wind, solar, biomass) would not only avoid the risk of stranded fossil assets but also diminish import dependency.

c. The future EU power plant fleet

EU Member States that still rely on coal for electricity (and heat) generation must replace their coal power plants in the mid- and long-term with low-carbon generation capacities for a successful reduction of greenhouse gas emissions. Unless major quantities of electricity are imported (which is not even possible for heat), we can think of different options for replacement: (1) replacing coal-fired power plants with gas-fired power plants in the short- and mid-term which in turn will be largely replaced by renewable energy sources in the long-term and thus generate possibly stranded assets; (2) a direct replacement of the coal-fired power plants by renewable energy sources; (3) a replacement with nuclear power. Although nuclear power could be considered a stable source of low-carbon electricity, many problems are associated with it and several EU Member States have a moratorium on its use. Extremely long construction times of nuclear power stations in Europe, very high investments costs, unresolved final storage of nuclear waste, the risk of catastrophic accidents, etc. make it a less favourable power source than renewable energy sources. Hence, we do not assume the nuclear option to gain importance in the next years.

We use the stylized open-source numerical electricity sector model DIETER [57] to gain insights on the future electricity system in the EU and in its Member States. As the coal phase-out is central to the climate neutrality in the EU, the results apply to all three corner scenarios. The model allows us to determine the future optimal power generation capacity fleet under certain assumptions [58]. The results of model runs' (shown in Figure 3-12) show:

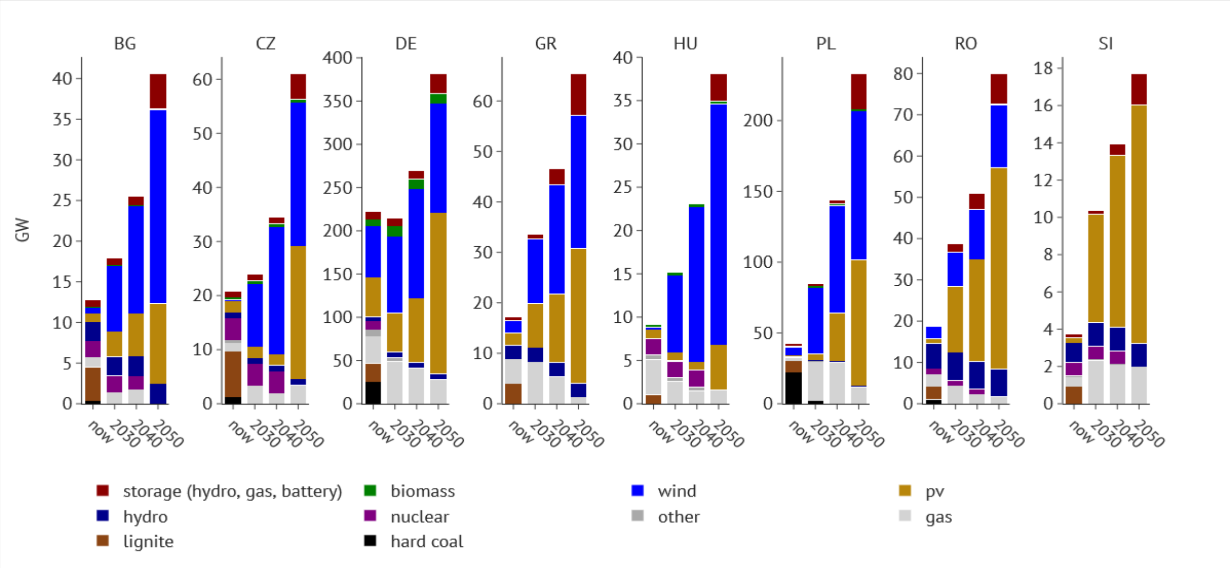
- how a coal-free electricity system in the EU might look;
- that investment needs to replace coal vary between countries; and
- that sizable additional renewable power plant capacities are needed to reduce the greenhouse gas emissions from the EU electricity system.

56 Poland and Czechia export very little hard coal. In Poland, approximately 60% of the consumed hard coal is used for electricity and heat generation, while Czechia only uses 30% for electricity and heat. In addition to their domestic extraction, both countries also import sizable amounts of hard coal.

57 To model the European electricity system, we use the "Dispatch and Investment Evaluation Tool with Endogenous Renewables" (DIETER), a capacity expansion and dispatch model of the European electricity system. For more information, see the Appendix A1 and Zerrahn and Schill (2017).

58 The three target years are differing primarily in the assumed share of renewable electricity produced in total electricity consumed. For 2050, we have assumed "almost 100%" renewable electricity, the years 2030 and 2040 assume shares that would be on hypothetical path from the current, 2020, shares until 2050. For all assumption and data sources, we refer to the Appendix A1.

Figure 3-12: Optimal power plant fleets in different years



Source: Authors' calculations.

Notes: The vertical axes are different for each country.

The figure depicts the cost-minimal power plant (and storage) fleet for countries currently still having today significant coal power plant capacities. Our modelling includes a larger set of countries[37], but we only show a few countries. For three different target years (2030, 2040, 2050), the model generates optimal power fleets. The bar "now" depicts the current existing fleet.

By 2030, most coal power plants could have disappeared from the system. However, the phase-out of coal and the continued decarbonisation of the power system (as assumed in our scenario runs) require major expansion of power generation capacities in all countries.

Yet, investment requirements vary in the short-run: countries with already sizable photovoltaic and wind power plants (such as Germany), hydropower plants (such as Romania), or with nuclear or gas power plants can relatively easily substitute coal power plants with modest additional investment. It depends on the country whether it is optimal to investment in additional gas-fired power plants or to focus all investments on the expansion of renewable energy sources. In countries where coal is central to the electricity system, primarily Poland, significant investments in the short run will be needed to replace coal.

Our modelling results are in line with the findings of other studies. Czyżak and Wrona (2021) concluded that Poland can reduce its share of coal in electricity generation to 13% by 2030 and phase out coal entirely by 2035. They argued though that new investments in gas-fired power plants are not profitable as they will be displaced economically by renewable energy sources in the 2030s. Similarly, Koenig *et al* (2020) concluded that 2032 is a realistic date to phase out lignite as a source of electricity in Germany, Poland, and Czechia.

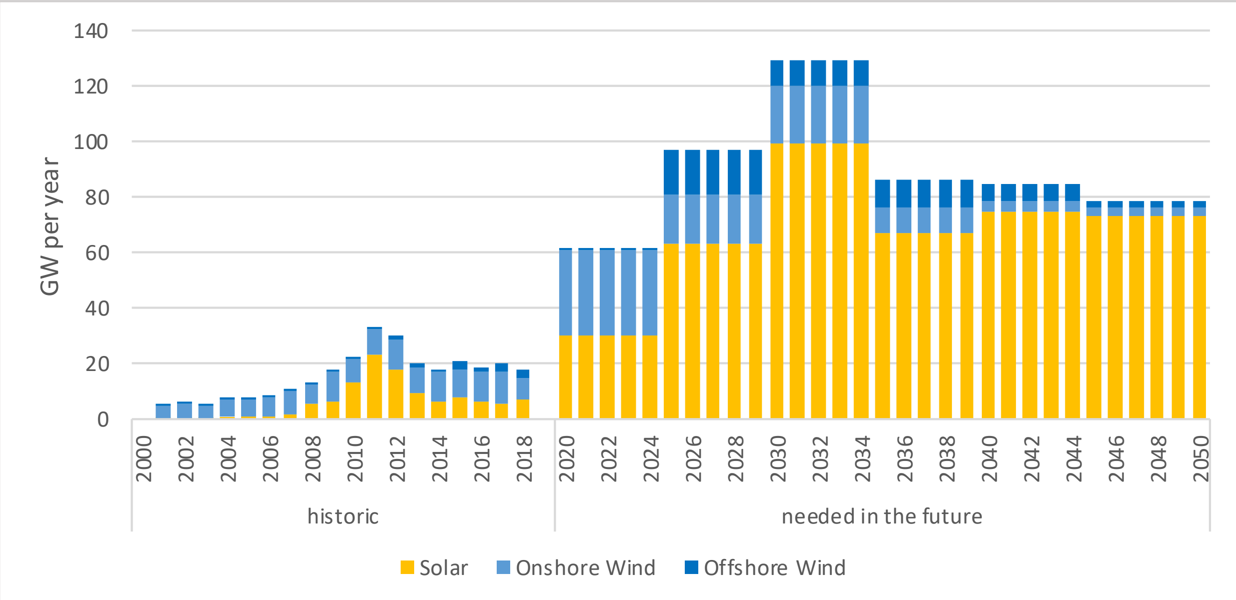
d. Deployment of renewable energies

Major investment in renewable energy power plants (photovoltaic solar power and wind power) is crucial to phase out coal, but also to decarbonise the European electricity sector as a whole – this is especially true for countries still relying on coal. All three scenarios we presented in chapter 2 rely on large amounts of renewable electricity. As shown in Figure 3-12, the overall size of countries' power plant fleets has to increase substantially. As photovoltaic and wind power plants have fewer full-load hours per year compared to coal and gas power plants, the power fleet must be extended by more than the phased-out fossil capacities.

The results in Figure 3-12 are illustrative and not precise predictions: while for some countries, photovoltaic power seems to be a better option than wind when looking only a at specific investment costs, countries might decide to favour other technologies.

European countries have start to immediately to deploy meaningful amounts of renewable energies if the decarbonisations goals of the EU are to be met: investment rates in renewable energy power plants are needed have to go beyond the expansion rates in recent years. Victoria *et al.* (2020) [59] argue that European-wide installation rates for solar photovoltaic, onshore, and offshore wind need to increase above historic maximum levels. Figure 3-13 depicts that graphically: historic installation rates of renewable energy power plants are below what is needed in the future. However, some Member States have achieved substantial installation rates in the past: Italy added almost 10 GW of solar PV capacity in a single year (2010), and Germany had very high solar PV installation rates (> 7 GW yearly) in the years 2010, 2011, and 2012.

Figure 3-13: Renewable installation rates in the EU needed to achieve decarbonisation of energy



Source: Authors' visualization based on Victoria et al (2020).

3.4.2. Other economic effects and transition in coal-mining regions

In several Member States with domestic coal mining, the coal phase out is not exclusively a challenge for the electricity sector but also has implications for regional transitions and employment. The EU has started to provide support to these regions through the Just Transition Mechanism. Coal mining still takes place in the following EU Member States: Bulgaria, Czechia, Germany, Greece, Hungary, Poland, Romania, Slovenia and Slovakia.

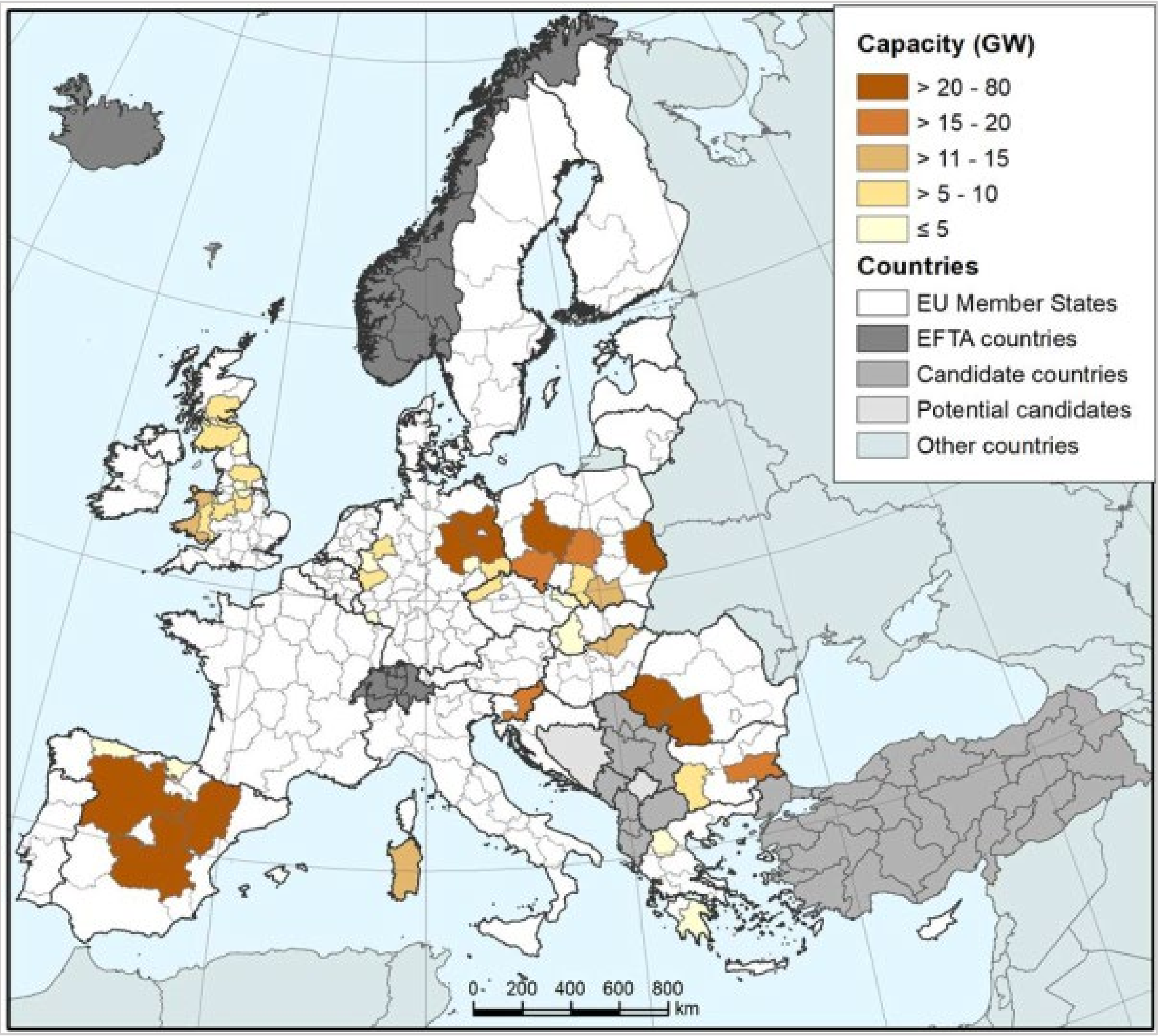
Despite its regional importance, the overall share of coal mining in the EU's economy and employment is small. According to Alves Dias *et al* (2018), around 237,000 people in the EU are currently employed in the coal sector, mainly in coal mining (185,000). This is about 0.1% of total EU employment. Another 215,000 people work in jobs indirectly related to the coal sector: another 0.1% of total EU employment.

[59] While the analysis by Victoria et al. (2020) is based on different assumption, data, and models than our modelling, the message that ambitious investments in renewable energy power plants are needed, remains unaltered.

In other words, there are considerably fewer jobs at risk in the ongoing coal phase outs than were in previous economic transitions when millions of jobs were lost. In coal mining, the bulk of coal jobs in the EU have already been lost.

It will be challenging to find alternative employment for coal miners in the short run. Transition measures must include the support of business creation in sectors that value the skills from the coal mining sector just as much as re-training measures and education in effort to overcome regional resource curse. However, positive effects usually can only be expected after a number of years. Likewise, Kapetaki *et al* (2020) estimated that about the same number of jobs could be created by deploying renewable-energy power plants by 2030 as the number of jobs currently at risk from phasing out coal. Up to 2050, the number of newly created jobs could even double. They also found that the European regions affected by a coal phase out have high technical potential for renewable energy, and could contribute more than half of the additional installations needed EU-wide for carbon neutrality up to 2050, if this potential is fully tapped. Figure 3-14 shows technical potentials for ground-mounted solar PV in European coal regions.

Figure 3-14: Cumulative technical potential (GW) for ground-mounted solar PV in coal regions



Source: Kapetaki *et al* (2020).

In addition to this long-run transition perspective, the EU supports regions in transition today with funding and knowledge transfer. The knowledge transfer and local capacity building is organised by the EC via the Initiative for Coal Regions in Transition[60].

In terms of monetary support, several funds, some of them specifically dedicated for coal regions, can be tapped in the new funding period 2021-2027:

- Within the Just Transition Mechanism (JTM) [61]:
  a. The Just Transition Fund (JTF) with a budget of €17.5 billion;
  b. A dedicated InvestEU scheme to foster private investment; and
  c. The Public Sector Loan Facility leveraged by the European Investment Bank (EIB) combining €1.5 billion in grants with €10 billion in loans targeting only public entities;
- "Traditional" regional funds; and
- Funding in the framework of the EU recovery plan for Europe (Next Generation EU).

The allocation of funds from the JTF is mainly based on the greenhouse-gas intensity of the economy, employment in highly carbon-intensive sectors and in coal mining. This is meant to ensure that the supported regions are those most affected by the transition. Distributing funds conditional on coal phase-out plans and end dates incentivises countries to opt for an effective phase-out of coal.

Apart from the targeted support schemes within the JTM, transition in coal regions can also be supported by the economy-wide stimulus package Next Generation EU.

Indeed, 37% of the loans and grants provided by the Recovery and Resilience Facility must be dedicated to investments tackling climate change. This instrument could be leveraged to support the transition, but also incentivise countries to phase out coal faster than currently planned.

The recent coal phase-out discussions in some Member States show that transition support can potentially be a tipping point that enables the countries to take decisions on (early) coal phase outs in the current economic environment that is unfavourable for coal. Therefore, this support must be continued in the next years and the requirement for clear-cut phase-out decisions must be maintained.

3.5. Conclusions: coal phase out underway but needs some additional support

We find that the coal phase-out is well underway across Europe but needs more support to come to fruition in all Member States. Some Member States, particularly Bulgaria and Poland, are later than others, either with their decision on a coal phase-out schedule or their final phase-out date. However, in addition to the pressure from climate commitments in the Paris Agreement, the Glasgow climate conference COP 26 (November 2021), and the EU climate-neutrality target, the economics in place will push even these countries to further advance their coal phase-outs. Most notably the comparably high CO_2 price, which can be expected to remain high if the EU ETS reforms are maintained, and the continuously falling renewable costs provide economic incentives to exit coal.

However, it is important that the upcoming revision of the EU ETS aligns to the goal of the EU 'Fit for 55' package and tightens the cap accordingly. A sufficiently tight EU ETS cap could lead to a phase out of coal by 2030 because it makes coal power plants unprofitable. Moreover, those Member States that

[60] Further information on the Initiative for coal regions in transition (available at https://ec.europa.eu/energy/topics/oil-gas-and-coal/EU-coal-regions/initiative-for-coal-regions-in-transition_en) and on the Secretariat Technical Assistance to Regions in Transition (available at: https://ec.europa.eu/energy/topics/oil-gas-and-coal/eu-coal-regions/secretariat-technical-assistance-regions-transition-start_en).

[61] Further information on the Just Transition Mechanism: https://ec.europa.eu/info/strategy/priorities-2019-2024/european-green-deal/finance-and-green-deal/just-transition-mechanism/just-transition-funding-sources_en.

still rely on coal must be prevented from artificially keeping unprofitable coal businesses open by providing subsidies and other state aid.

In addition, support for mining regions via the EU Just Transition Mechanism provides an incentive to phase out domestic coal mining.

Closing the loophole and including methane (CH_4) from the coal sector in the EU ETS or an alternative pollution control scheme could provide further incentives to phase out coal more quickly. In addition, the Industrial Emissions Directive will further push old polluting plants out of the system within the next few years.

Using an open-source numerical modelling, we show how a coal phase-out across Europe could be achieved, leading to a drastic change in Member States' power fleets. Importantly, substantial renewable capacities and electricity storage will need to be installed to replace phased out coal power plants. Renewable expansion has been stalling in some coal countries such as in Bulgaria and Romania, but also in Germany in the last years and therefore must quickly increase in speed. Given the lower capacity factors of renewable generation, a more than proportional capacity expansion has to take place. Replacing coal-fired electricity capacities with natural gas-fired power plants would be only a short-term option that would not be compatible with the EU's 2050 climate-neutrality target. Likewise in the heat sector, replacing coal with natural gas is only a short-term option that risks leading to fossil path dependencies and stranded assets towards 2050 and should, therefore, better be avoided.

Continued and accelerated expansion of renewable electricity capacities is of the utmost importance. The increase in renewable energy instalment rates is central to achieving the EU's climate-neutrality target.

Therefore, further support must be provided to ensure the required expansion of renewable capacities:

- national renewable targets will provide clearer incentives;
- capital and loan costs for renewable projects in coal-dependent countries must be reduced, in particular in Central and Eastern European Member States; and
- the internal energy market must be strengthened with improvement of market access conditions for new entrants, including renewable players.

One challenge we cannot address in this study is the phase out of coal in industry, in particular in steel production. One alternative to current coal-intensive steel production is a combination of electricity (as energy input), hydrogen, and scrap-steel recycling, which is currently under development across Europe (also see chapter 5).

We will discuss in the next chapter why fossil natural gas is not a long-term option for the electricity and heat sectors in the EU. Hence, current coal capacities should not be replaced by natural gas capacities. Generation capacities often run longer than 30 years, i.e., longer than the EU's target year for reaching climate neutrality. Hence, to be compatible with the EU's long-term targets, coal-fired electricity and heat generation must be replaced by renewable generation.

4. DECARBONISATION OF METHANE USE IN EUROPE

KEY FINDINGS

In order for the EU to reach climate neutrality by 2050, the use of natural gas in the European energy system will have to cease. Several options for decarbonising the use of natural gas exist. We argue that the use of natural gas in combination with carbon capture and storage (CCS) is unlikely because of the virtually non-existent progress in R&D on the CCS value chain. Natural gas consists of almost pure methane (CH_4). Other – non-fossil – fuels can potentially replace it because they also have a high CH_4 content. Biogas/methane are already used today, but have a limited potential. Synthetic methane (syngas) obtained from the methanation process of hydrogen can also potentially replace natural gas, but is subject to high costs and low transformation efficiencies. Rather, green hydrogen – a different gas, but with some similar properties and lower costs – is likely to replace natural gas in several end uses. In addition, a number of end uses that currently rely on natural gas are likely to be electrified in a climate-neutral future.

In the medium term, the footprint emissions from natural gas should be taken into account in order to address comprehensively the climate effect of extracting, transporting and using natural gas. In addition to the CO_2 emissions from combustion, fugitive methane emissions along the value chain are harmful greenhouse gases. Methane is considerably more harmful than CO_2, but currently not included in the EU ETS or any other pollution control scheme. Fugitive methane emissions from imported natural gas mostly arise outside the European Union. Comprehensive methane emission monitoring, and reporting requirements for natural gas imports, as planned in the European Commission's Methane Strategy are an important first step. Pricing the life-cycle methane emissions of natural gas is required as a next step to provide an incentive to reduce the harmful climate effect.

In contrast to the coal sector, where coal phase-out targets arise from national policies, EU policies are likely to take the lead in setting the framework for decarbonising the gas sector. In addition to the revision of the Gas Directive and the Gas Regulation [62], the gas sector will be subject to a number of climate-related policy measures, including greenhouse gas emission targets and the EU ETS revision, but also the pending methane regulation of natural gas imports. Moreover, the interaction with and delineation from hydrogen – another gaseous fuel – will need to become clearer in the next years. These policy processes will be critical in determining the pathway of gas in the next decades and we take them into account in our analysis.

However, efforts are underway to address the role of decrease fossil natural gas directly, similarly to coal. Most notably, the Beyond Oil and Gas Alliance (BOGA) that was announced in September 2021 [63] and will be launched at COP26 in November 2021 by its founding members Denmark and Costa Rica, may be modelled after the Powering Past Coal Alliance (PPCA) [64]. The PPCA has succeeded in raising a number of constituencies committed to a firm coal phase out. BOGA will equally reach out to consumers and producers of natural gas.

62 Gas Directive 2009/73/EC and the Regulation (EC) No 715/2009.

63 Announcement of the BOGA at the Energy Action Day on 16 September 2021, available at: https://www.irena.org/events/2021/Sep/Energy-Action-Day-2021).

64 More information on the PPCA available at https://www.poweringpastcoal.org/.

Fossil natural gas is almost 100% methane (CH_4). In this chapter, we focus on the future of methane from various sources, whether fossil (natural gas), biogenic (biomethane)[65] or methanised hydrogen (also called synthetic gas, e-gas, or power fuel). We call biomethane and synthetic gas 'green gases'. Hydrogen (H_2), which is often included in the discussions of green gases, is a different fuel which requires somewhat different infrastructure to CH_4. We, therefore, deal with hydrogen in chapter 5.

Given the EU's greenhouse-gas neutrality target, the current widespread use of natural gas will have to be reduced in the next decades. Just as with coal, the question of substitution in the different demand sectors is crucial – and potentially even more challenging because of the large variety of uses of natural gas:

- in industry as both feedstock and fuel (e.g., for process heat generation);
- in the power sector for both baseload generation and flexibility as back-up for intermittent renewables;
- in space heating; and
- to a small extent, in transportation.

Natural gas can potentially be replaced by methane from "green" sources (biomethane or synthetic gas obtained with renewable electricity) and, in some demand fields, also by hydrogen. Moreover, processes that are fuelled by natural gas today could be replaced by electricity-based processes, for example in space heating and industrial heat. These alternatives come at different costs, both operational costs and investment costs, and with specific advantages and disadvantages.

We investigate the future of natural gas, green gases (CH_4) and gas infrastructure through the scenario lens introduced in chapter 2. For each of our three scenarios, we assess the substitution effects. More precisely, we assess the impact on natural-gas demand, imports and infrastructure, and on the supply of and demand for green gases. Most natural gas consumed in the EU today is imported. Hence, a reduction in consumption in the long run will strongly affect imports, relationships with importers, and import infrastructure utilisation. We find that some of the current natural gas imports will in future be replaced by imports of green gases (hydrogen, syngas).

The natural gas sector relies on asset-specific infrastructure (pipelines, underground storage, LNG terminals) that is currently regulated in the EU by the Gas Directive (2009/73/EC) and "Gas Regulation" (715/2009/EC). The use of these infrastructure assets will be substantially altered in varying ways, depending on the scenario. The revision of the current rules in a broad "Hydrogen and Gas Markets Decarbonisation Package" should help ensure an orderly transition from the current situation to any future 2050 state; we explore the main points in our study.

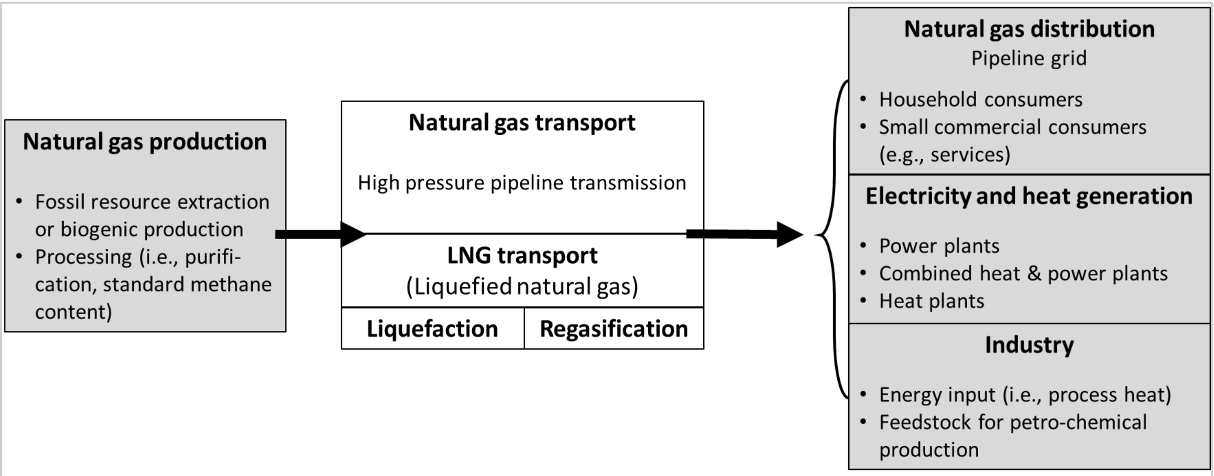
4.1. Natural gas use, supply and infrastructure today

The natural-gas sector has a complex value chain (Figure 4-1). Transportation infrastructure plays an important role in the form of pipelines and (import) terminals of liquefied natural gas (LNG). Remaining natural gas reserves in the EU are very small and most natural gas consumed in the EU is imported via pipeline or LNG terminals (see below). Natural gas transportation infrastructure is highly specific, i.e., pipelines and LNG terminals can only be used for the transport of gases and not for other energy carriers.

[65] Biomethane has a high methane content and can be used interchangeably with natural gas (CH_4). Biogas, in contrast, has a lower CH_4 content and is used locally, at the production site, without transportation via transmission and distribution pipelines.

The commercial product "natural gas" has a methane content of about 95% (87%-99%) [66]. Natural gas deposits may have a lower methane content and contain impurities, but it is cleaned and brought to standard energy content by processing. Production and processing of most of the natural gas consumed in Europe today take place outside the EU. Over long distances, natural gas can either be transported in high pressure pipelines (transmission pipelines) or by sea as LNG (cooled down to less than -162°C). Natural gas is liquefied to LNG in the export market and regasified in the import market. There are no liquefaction terminals in the EU (there is one in Norway) and there are 27 regasification terminals (GIIGNL, 2021).

Figure 4-1: Natural gas value chain



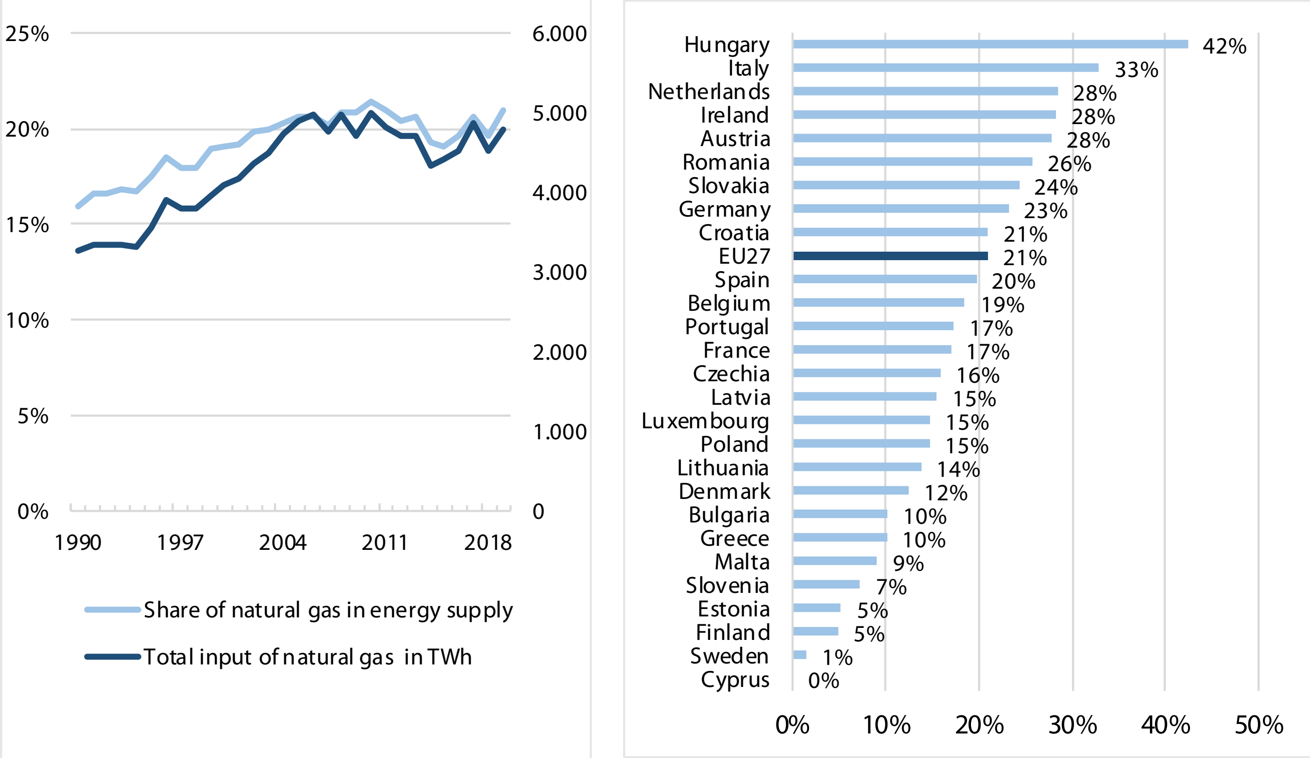
Source: Authors' own elaboration.

In the final value chain stage, natural gas is consumed – which often means combusted (i.e., used for its energy content) – in one of three sectors: electricity and heat generation, industry, or by smaller consumers who receive the natural gas via distribution pipelines. Natural gas trade – between exporters and importers as well as between natural gas traders and large consumers – is carried out either in the framework of long-term contracts or via the commodity markets that have successfully developed in the last decade in the EU internal energy market (Stern and Rogers, 2017; Heather, 2019).

Natural gas accounts for approximately one fifth of the total energy supply in the EU. This share has risen by five percentage points since 1990 but has remained relatively constant in the last 20 years. In absolute terms the input of natural gas into the energy system increased by almost 50% between 1990 and 2019 (from 3200 TWh to 4800 TWh).

[66] An exception to the standard methane content of ca. 95% – and the related calorific value of ca. 11.1 kWh/m³ – is so-called L-gas (low-calorific gas), which is still produced and consumed in the Netherlands and western Germany, but will be phased out by 2030. L-gas has a methane content below 87% (80-87%), and, hence, a calorific value of max. 8.9 kWh/m³.

Figure 4-3: Natural gas in energy supply over time



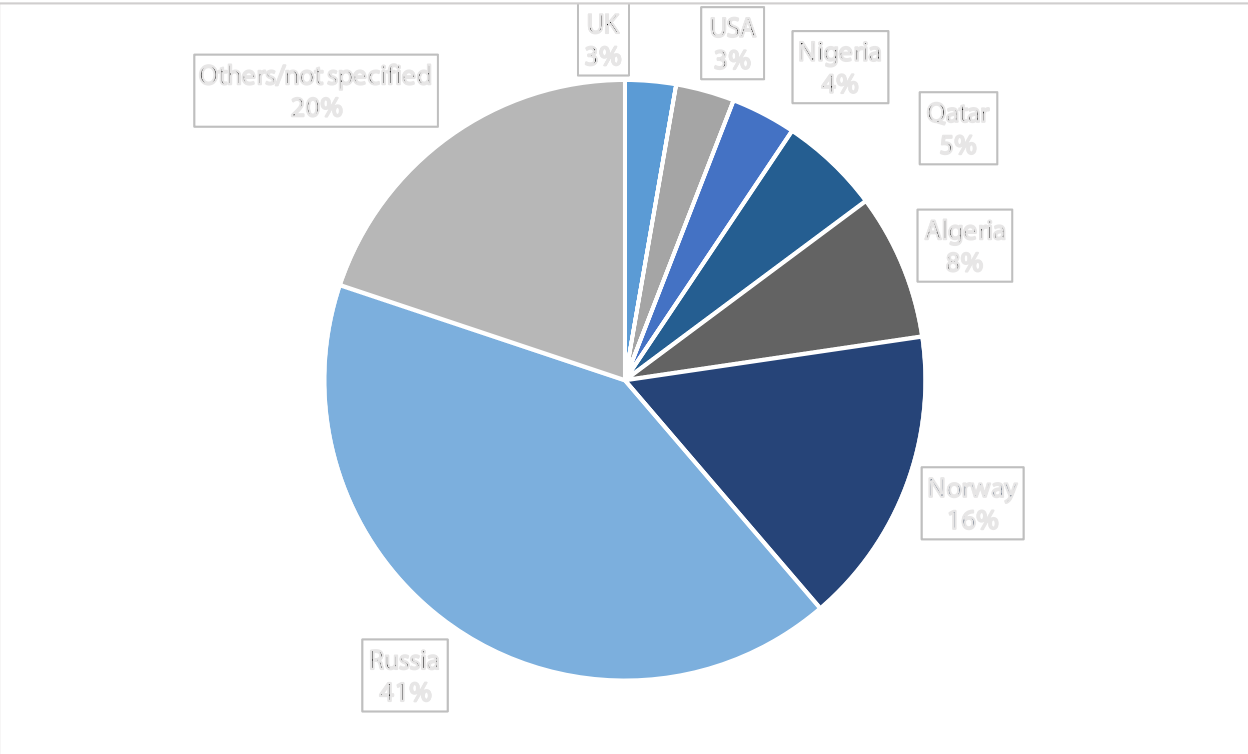
Source: Authors' calculations based on Eurostat, database ngr_bal_c..
Note: Basis for the share calculation is imports + production

4.1.1. Supply of natural gas and biogas/biomethane in the EU today

The EU is a major net importer of natural gas. Domestic production still exists in some countries, but has decreased significantly in recent years because of geological problems (Netherlands) and local moratoria on fracking technology (Germany), as well as overall declining reserves [67]. Hence, more than 80% of the EU's total natural gas supply is imported (88% in 2019). Russia is the main source, followed by Norway and Algeria (Figure 4-4), all of which have large pipeline capacities to deliver to the EU.

[67] There is significant domestic fossil natural gas extraction per year in the EU in the following EU Member States (ranked by decreasing production level 2018, according to IEA 2019b, production levels larger than 9 TWh/year): Netherlands, Romania, Germany, Poland, Italy, Denmark, Ireland, Hungary and Austria.

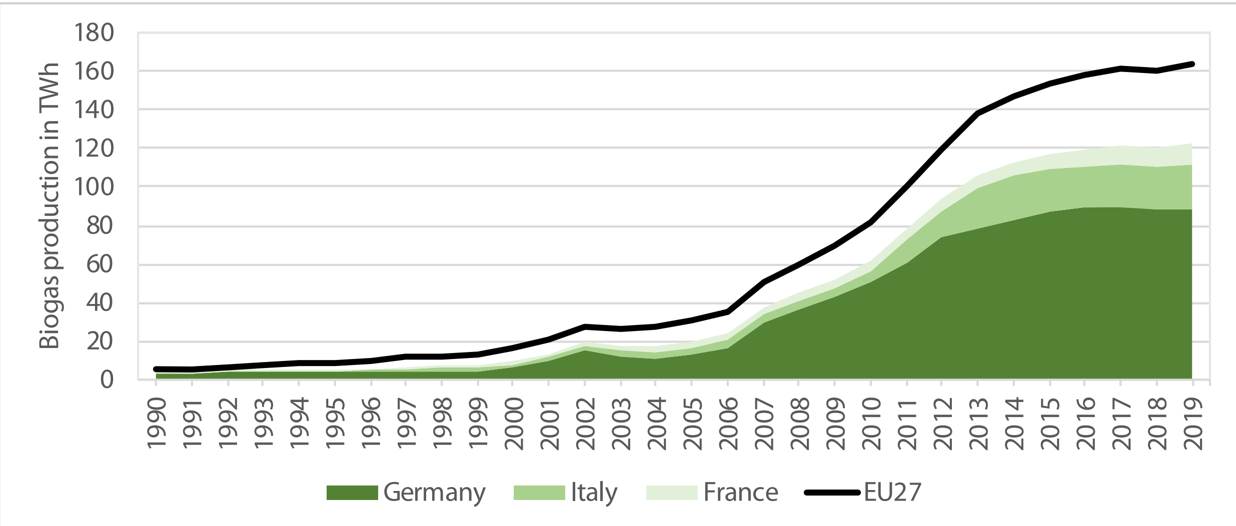
Figure 4-4 Exporters of fossil natural gas to the EU in 2019



Source: Authors' calculations based on Eurostat, database ngr_ti_gas.

Depending on global market conditions – i.e., the (relative) price in the competing demand region Asia, and global supply availabilities or bottlenecks – LNG imports play a smaller or larger role in the EU. In 2019 and 2020, LNG imports were considerably above average because of a rise in global LNG export capacities (in the USA, Russia, Australia) and low prices in Asia due to mild (winter) weather (ca. 1000 TWh, about a quarter of total natural gas supplies in the EU). There are import capacities for approximately two times greater LNG imports in place.

Figure 4-5: Biogas production in the EU27 (1990-2019)



Source: Authors' own calculations based on Eurostat, database ngr_bal_c.

The production of biogas within the EU has surged in recent years. In 2019 around 160 TWh were produced which is more than 10 times the level in 2000. However, this is only a meagre 3% of the gas supply in the EU. Nevertheless, Europe is the largest biogas producing region in the world (IEA, 2020a).

The main supplier is Germany, which produces more than half of the biogas in the EU and also is the largest single producing country worldwide. In Italy, biogas production has also grown rapidly in the last 10 years.

Biogas is produced from a large variety of sources, technologies and processes. The main sources in Europe today are crops (energy crops, crop residues and sequential crops, almost half of total production), animal manure (one third), municipal solid waste (ca. 10%), and municipal wastewater (ca. 5%).

More precisely, we distinguish between biomethane and biogas[68]. Biomethane has the same – very high – methane content as natural gas (> 90%) and can be fed into the natural gas pipeline system. Biogas, in contrast, is a mixture of methane, CO_2 and small quantities of other combustible gases. Only a very small fraction of biogas is upgraded to biomethane today (ca. 10%), with considerably higher shares in Denmark and Sweden. Low-methane biogas is used locally near the production site, i.e., without being transported via a pipeline network. In fact, most of the biogas/biomethane (almost 80%) is used for electricity and heat generation.

4.1.2. Infrastructure value chain

As shown in Figure 4-1, the natural gas sector relies on asset-specific infrastructure (pipelines, underground storage, LNG terminals) that is regulated (access, tariffs, unbundling). "Asset specificity" describes that an asset cannot or hardly be used for alternative uses or by alternative fuels. Asset specificity can be found in the value chains of all energy sectors. The conversion of natural-gas assets to other gases will incur greater or lesser cost if these gases are not predominantly methane (e.g., conversion to hydrogen). Moreover, not all asset types can be converted to be used by non-methane gases. This is particularly the case for underground gas storage.

The European pipeline system today has substantial overcapacity in many places, but bottlenecks in others. Between 2008 and 2020, the average utilisation rate of European cross-border points was only 30%[69]. In fact, transparency data reveals that – despite the push for efficient capacity expansion and allocation from the various EU energy packages – over-dimensioning of capacity has often been used to ensure security of supply, but also to improve market access for the dominant supplier, Russia.

Bi-directional (reverse flow) capacities have only relatively recently – since the Crimea crisis in 2014 – been used as additional supply security measure, though not uniformly across Europe. Reverse flow capacities are concentrated on the capacities to/from Ukraine, and around Germany.

Reverse flow capacities are not limited on cost grounds because it is relatively cheap to add compressor capacity in the opposite direction on existing pipelines. Rather, the reasons for limited reverse flow capacities are the exertion of market power and limiting by incumbents of market entry, (geo-) political tensions and similar disagreements between national regulators. There is a lot of potential for improved efficiency in gas trade – and in fact relatively low-cost expansion potential of gas trade capacities – if EU Member States succeed in establishing reverse flows as foreseen by the Internal Energy Market.

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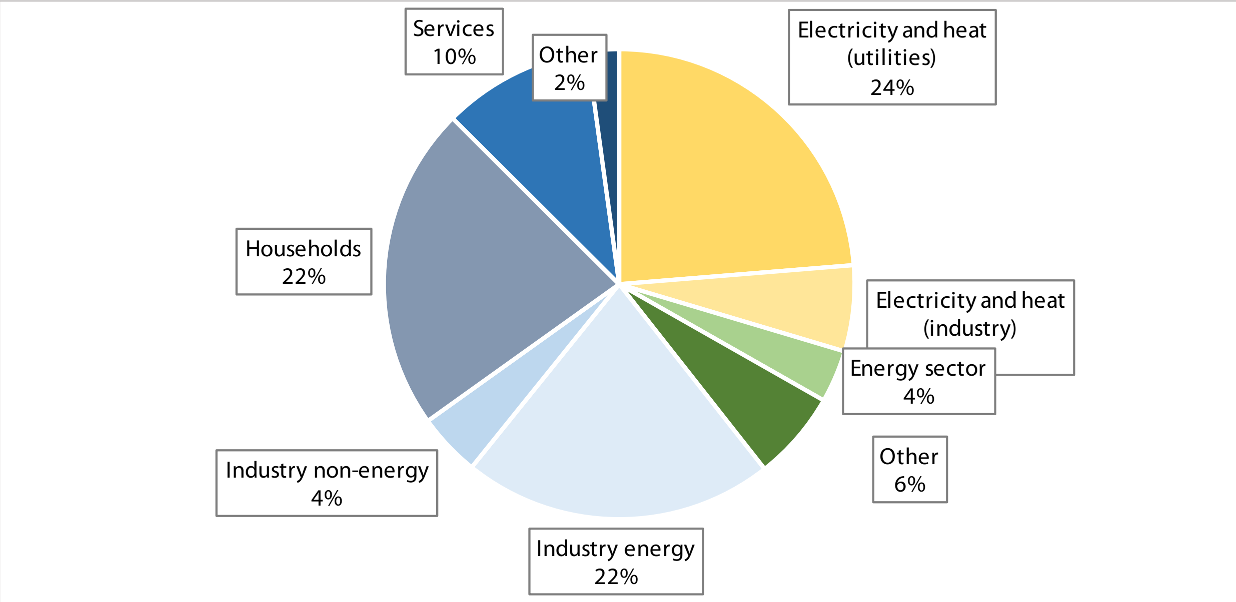
[68] Eurostat data does not make the distinction between biogas and biomethane but aggregates them.

[69] See https://www.iea.org/reports/gas-trade-flows where pipeline flow data on cross-border points in Europe is provided.

4.1.3. Utilisation of methane gas today

Around 60% of natural gas is used directly in final energy consumption without prior transformation. Figure 4-6 shows the sectors that consume natural gas, including both final consumption and transformation sectors such as electricity and heat generation. The industrial sector uses around 22% of the total natural-gas supply. While the majority of industrial consumption (96%) is used for energy purposes, 4% flows into non-energy uses. Private households consume around one fifth of natural gas supply, and one quarter serves as an input for the generation of electricity and heat. Combined heat and electricity generation uses 15%, electricity-only plants 13%, and heat-only plants 2%.

Figure 4-6: Utilization of natural gas in the European Union (EU27) in 2019

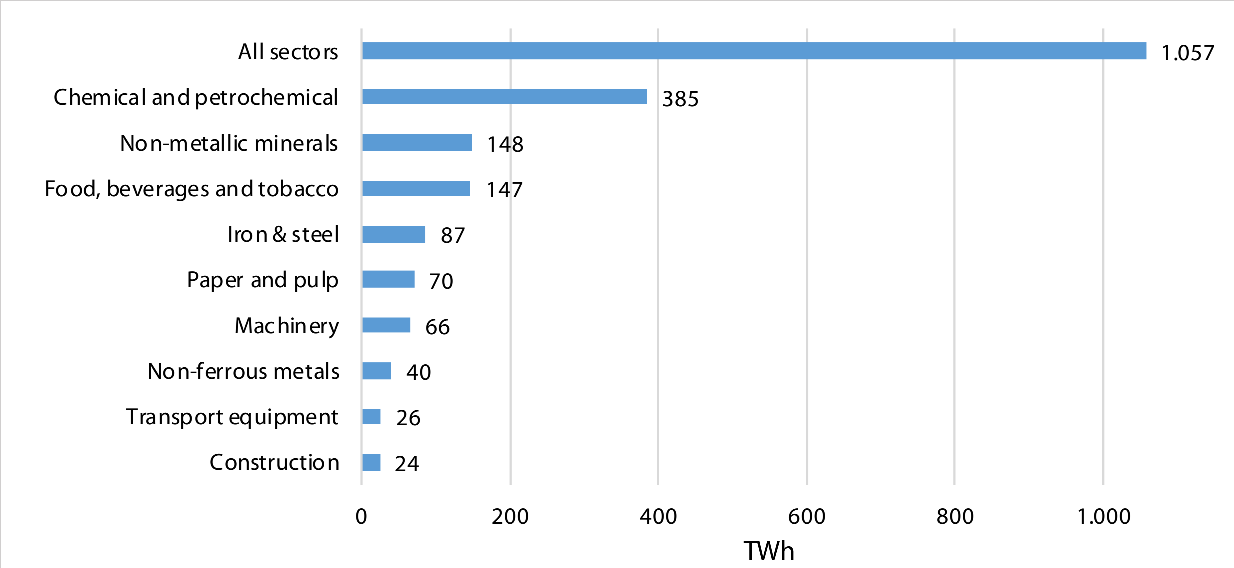


Source: Authors' own calculations based on Eurostat, database ngr_bal_c.

Industrial use of fossil gas can be differentiated into energy (96% in the EU) and non-energy applications (Figure 4-7). The latter consists almost entirely of feedstocks in the chemical and petrochemical industry[70]. However, fossil gas serves predominately as an input for energy purposes, e.g., for the generation of process heat. There, too, the chemical and petrochemical industry absorbs the majority of the fossil gas, but other sectors including cement and iron and steel are also large-scale natural-gas consumers.

[70] The share of feedstock use of natural gas is considerably higher in the USA where natural gas replaces crude oil as feedstock to more petro-chemical (intermediate) products (e.g., naphtha).

Figure 4-7 Industrial usage of fossil natural gas



Source: Authors' own calculations based on Eurostat, database ngr_bal_c.

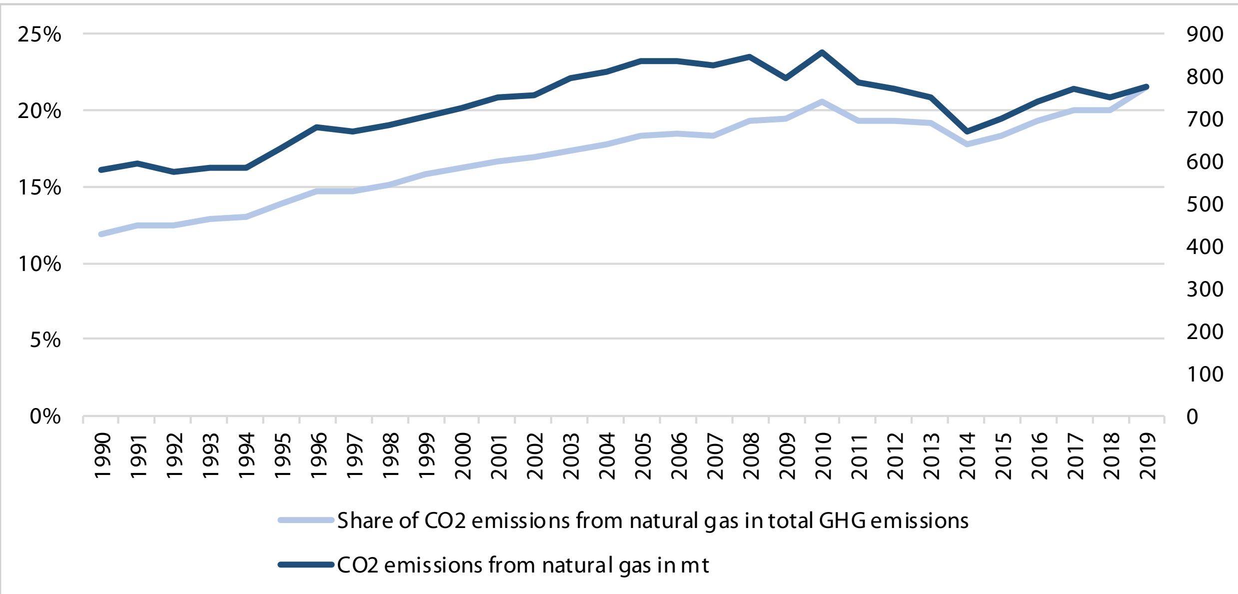
4.1.4. Greenhouse gas emissions from the natural-gas value chain

Natural gas is typically consumed through combustion, which generates CO_2 emissions. Moreover, natural gas consists primarily of methane (~95%) which itself is a potent greenhouse gas with considerably higher warming potential than CO_2 and which may leak from the production and transport of natural gas ('fugitive methane emissions').

a. CO_2 emissions

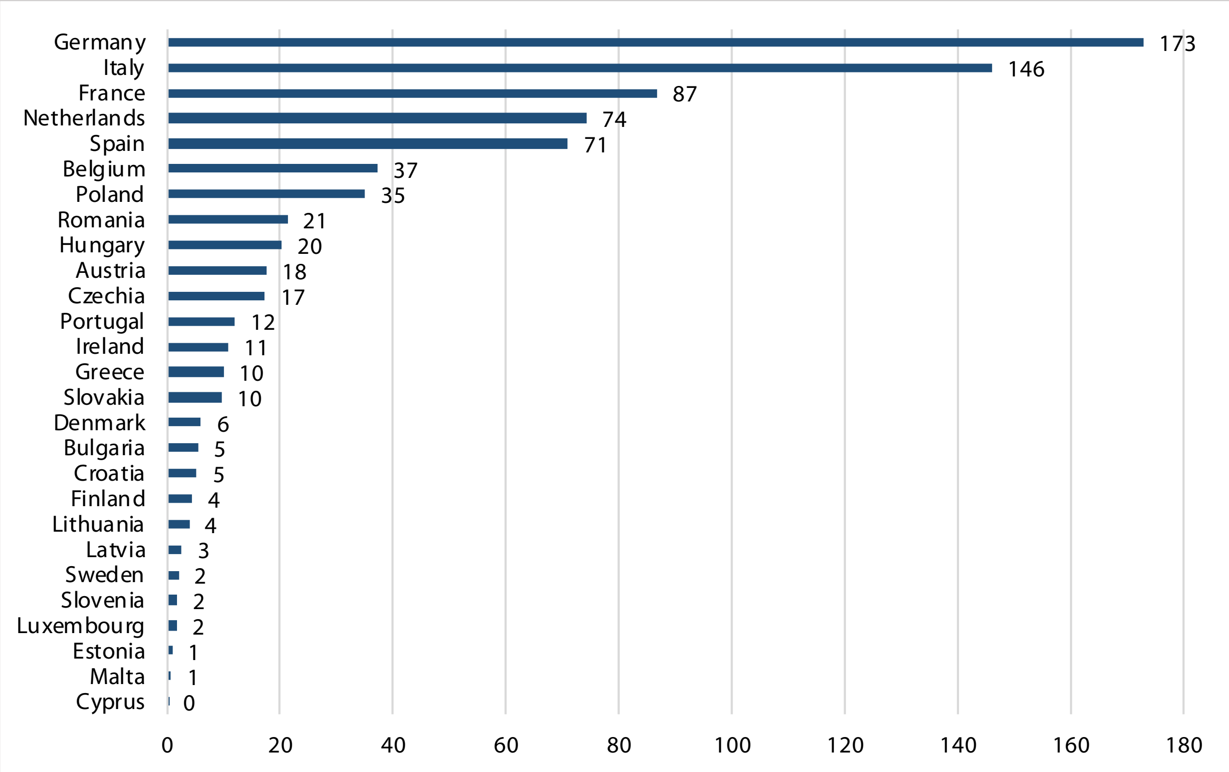
CO_2 emissions from natural-gas consumption have increased by 34% since 1990 (Figure 4-8), reflecting the increasing use of natural gas in the 1990s and 2000s. In 2019, 776 Mt of CO_2 was released from natural-gas combustion, which is more than the CO_2 emissions from coal (739 Mt).

Figure 4-8: CO2 emissions from natural gas over time



Source: Authors' own calculations based on https://ourworldindata.org/emissions-by-fuel and https://www.eea.europa.eu/data-and-maps/data/data-viewers/greenhouse-gases-viewer.

Figure 4-9: CO_2 emissions from combusting natural gas in Mt by country in 2019



Source: Authors' own calculations based on https://ourworldindata.org/emissions-by-fuel and https://www.eea.europa.eu/data-and-maps/data/data-viewers/greenhouse-gases-viewer.

b. Methane emissions

Methane leaking from natural-gas infrastructure because of low-quality technology, insufficient maintenance or other causes, is a dangerous greenhouse gas. Because of their involuntary nature, leakage emissions are usually classified as 'fugitive emissions'. UNFCCC signatories must report fugitive CH_4 emissions as part of their greenhouse-gas inventory reports. However, the reporting is usually not based on measurements and CH_4 emissions are typically not verified. Reporting of fugitive emissions from the energy sector makes a distinction between the solid-fuel sector (i.e., coal, see Chapter 3) and the oil and gas sector. Each of these sectors is responsible for CH_4 emissions equivalent to about 1% of the EU's CO_2 emissions, if the warming potential after 100 years is considered (over 20 years, the proportion is approximately 2%, also see Appendix A1). In 2019, around 0.85 Mt of fugitive methane emissions from oil and gas were reported from within the EU. Altogether, the oil and gas sector is responsible for a third of the energy's sector CH_4 emissions and about 6% of the EU's total methane emissions, as reported to the UNFCCC. Other large methane-emitting sectors are agriculture and waste.

Most methane leakage in the natural-gas sector does not occur within the boundaries of the EU but in the export and transit countries from where the EU imports natural gas. Hence, given the large role of imports to the EU, the CH_4 footprint along the entire value chain should be taken into account for proper accounting of the GHG that the EU natural-gas use causes. The EC's Methane Strategy promises legislative proposals to address the methane leakage from natural gas imports, in the first place by requiring certified reporting of the methane emissions associated with natural gas imports and, in general, by improving MRV of methane emissions[71].

Currently, there is globally very little knowledge and measurement of methane emissions. Methane measurement infrastructure via satellite is currently being developed by a number of parties and is expected to be operational by 2023. In the meantime, there is hardly more information available than some hard-to-verify estimates collected by the International Energy Agency in its *Methane Tracker*, which was established in 2020[72]. According to some estimates, abating (reducing) CH_4 leakage in the natural gas sector by up to ~75% would be possible at relatively low costs[73].

More far-reaching policy instruments than reporting, such as pricing (taxing) the methane content of natural gas imports, should be considered. Such a methane border price should be proportional to the methane content of the natural gas imports in question in order to provide an incentive to reduce the leakage. Greif and Ecke (2021) estimated the effects of different methane border price levels. Based on the – flawed and unverified – available CH_4 leakage date from the IEA *Methane Tracker*, Russia and the USA would be affected most by an EU CH_4 border tax. Norway – the only country with a CH_4 monitoring and tax system in place – would hardly be affected and could even export more to the EU if its production and export capacities were larger. Exporters from the Middle East (e.g., Qatar) are estimated to have low fugitive methane emissions and could therefore benefit and export more natural gas (LNG) to the EU (Greif and Ecke, 2021). However, a CH_4 tax would have to be substantial to achieve an effective reduction of the CH_4 content of the EU's natural-gas imports: based on the 20-year GWP (i.e., CH_4 GWP 81 times higher than CO_2 GWP), a border tax of €25/tCO_2eq. would lead to an 18% smaller CH_4 footprint from the EU's natural gas consumption. A border tax of €100/tCO_2eq. would lead to a 48% smaller CH_4 footprint of the EU natural gas consumption. This would be the result of replacing high-leakage imports from Russia and the USA with low-leakage imports from the Middle East, and a small consumption reduction of less than 5% with the €25/tCO_2eq. scenario (8% in the €100/tCO_2eq.).

4.2. Decarbonisation potential of natural gas

In this section, we review briefly the different options for replacing current natural-gas utilisation with low-carbon/no-carbon alternatives. They range from the continued use of natural gas, with a large share of the associated emissions abated (captured) in a carbon capture and storage (CCS) process (Section 4.2.1), to continued use of methane or gases, but from renewable sources, i.e., biomethane, synthetic methane or hydrogen (Section 1.2.2), to replacement of methane by an alternative energy vector, namely renewable electricity (Section 1.2.3). For each of these replacement options, we review briefly the replacement potentials, the costs and limitations for the various demand sectors for natural gas: space heating, industry, power generation and transportation.

4.2.1. Natural gas and carbon capture and storage

In countries that produce and export natural gas (including Norway, Australia, the US, UK and Russia), CCS is seen as a technology that can help maintain the *status quo* of natural gas utilisation.

[71] Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions on an EU strategy to reduce methane emissions. COM(2020) 663 final. Brussels, 14.10.2020. Available at: https://ec.europa.eu/energy/sites/ener/files/eu_methane_strategy.pdf.

[72] IEA *Methane Tracker* (online). Available at: https://www.iea.org/reports/methane-tracker-2021.

[73] See the section 'Abatement and Regulation' in the IEA *Methane Tracker*. Available at: https://www.iea.org/reports/methane-tracker-2021/methane-abatement-and-regulation.

However, this perception ignores several problems with this technology, which lead us to conclude that CCS is not a realistic option for most sectors in the EU.

Among the problems are:

- Carbon capture is not a working technology that is operational at commercial scale anywhere in the world or in any sector (Holz *et al.*, 2018a) [74]. In other words, there is obviously still significant need for research, development and deployment (i.e., demonstration and pilot projects) before widespread use of the technology at reasonable cost can be assumed (Kelsall, 2020). Further hurdles may appear in development of the technology;
- Any known capture technology today has CO_2 capture rates well below 100% [75]. In other words, residual GHG emissions would remain – contradicting the target of full decarbonisation.
- Commercial-scale carbon storage underground has so far only been done in operating oil or gas fields (enhanced oil/gas recovery) and not in other geological formations. Research and development in relation to geological safety is still required (also see Cao *et al*, 2020);
- There is strong opposition to underground CO_2 storage in large parts of the EU. Accordingly, the European legal framework, the CCS Directive [76] leaves the legislation to EU Member States. In most EU Member States, powers are conferred on regional authorities, which are under civil society and voter pressure to not allow CO_2 underground storage [77];
- Cross-border CO_2 trade and offshore transportation of CO_2 are currently not allowed (Heffron *et al*, 2018; Banks *et al*, 2017); and
- For a cost-effective CCS value chain, large point sources and large storage sinks need to be connected via CO_2 pipelines (Holz *et al*, 2018b). There are currently no such pipelines in place. Moreover, pipeline systems lack the flexibility to adjust easily when storage is full.

For these reasons, CCS deployment in the power sector has become unlikely because other no-carbon alternatives have become cost-competitive, in particular renewable electricity and related grid integration measures. Moreover, the cost decrease seems to be more dynamic in the green hydrogen sector. Therefore, we focus in the following passages on the options of replacing natural gas by renewables gases or electricity.

Consequently, in our extreme scenarios (chapter 6 and section 1.3), we assume that there is no need for CCS because other more-viable alternatives are available.

However, in "middle-of-the-road" scenarios (not discussed in this report), there may well be a place for CCS, in particular in hard-to-decarbonize industrial activities. Indeed, it is now widely acknowledged that, if there were effective CCS development and deployment, it would focus on hard to decarbonise sectors such as in industry (e.g., cement). From a market organisation perspective, the development of

74 For Europe, the association Oil & Gas Europe provided a list projects in July 2021, available at: https://www.oilandgaseurope.org/wp-content/uploads/2020/06/Map-of-EU-CCS-Projects.pdf Only three projects in the list are operational and all of them are associated with oil and/or natural gas recovery (and not with the use/combustion of fossil fuels). The lists of planned projects were also long in the 2000s, when substantial support funding was available nationally and at EU level. Yet, not a single project was realized. Globally, the IEA provides a map of CCS projects in power generation available at: https://www.iea.org/reports/ccus-in-power This indicates two projects in operation, one of them in Canada (Boundary Dam, one small generation unit just above the threshold to be considered "commercial scale") and the other one in the US (Petra Nova, closed after about three years of operations, in 2020). Two projects are too few to realize sufficient learning.

75 Capture rates are assumed to be in the range of 90%, i.e., about 10% of CO_2 emissions are not captured. See, for example, Lockwood (2017) or the MIT Climate Portal available online: https://climate.mit.edu/ask-mit/how-efficient-carbon-capture-and-storage.

76 Directive 2009/31/EC of the European Parliament and of the Council of 23 April 2009 on the geological storage of carbon dioxide. Available at: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A32009L0031.

77 Vögele *et al.* (2017) discuss the public acceptance problem of CCS in the German case.

small-scale integrated industrial CCS projects as discussed in Jagu & Massol (2020) is more likely than the large-scale roll-out of a pan-European CO_2 pipeline and storage infrastructure.

Also, utilisation of the captured CO_2 – i.e., implementation of a CCU (carbon capture and utilisation) value chain – would reduce some of the challenges associated with CCS, in particular on the storage side. A user paying for the captured CO_2 could potentially even reduce the costs of CCS (Holz *et al*, 2021). However, so far, there has only been CCU with Enhanced Oil (or Gas) Recovery, i.e., the improvement of recovery rates in oil and/or natural gas fields. Other uses for captured CO_2 are envisageable, for example in the food industry where CO_2 is used as input (e.g., carbonation of drinks), but have not been put into practice yet.

4.2.2. Substitution of natural gas by other gases (hydrogen, syngas, biomethane)

Fossil natural gas can be replaced without problems by methane from other sources such as synthetic methane ("syngas") or biomethane. Moreover, hydrogen can potentially replace methane in a number of applications because of its same gaseous state and other similarities. Hydrogen is discussed in detail in Chapter 6. Before we present the various substitution possibilities for other gases in the main gas demand sectors, we review the production methods to obtain alternative gases.

Synthetic methane produced via so-called electrochemical pathways is obtained from the methanation of hydrogen. In this process, hydrogen and CO_2 are used as inputs (Götz *et al*, 2016). If the inputs are GHG-free over their lifetime – e.g., obtained from electrolysis with renewable electricity – the final product is also GHG-free. Given the special role for (renewable) electricity in the hydrogen production process, this syngas production route can be called 'power-to-gas' or "power-to-methane". The CO_2 feedstock may originate from the atmosphere (direct air capture, DAC), from biomass (e.g., biomass gasification or biogas upgrading plants) or from carbon capture technologies (e.g., applied to fossil fuel combustion).

The additional methanation process makes synthetic gas obtained from hydrogen and CO_2 more expensive than hydrogen. According to Schiebahn *et al* (2016), costs for a complete power-to-methane system including electrolysis, methanation, compression and more are estimated to be in the range of €2000 /kW_{el}. However, such a process is not in place at commercial scale at the moment and there is still large cost uncertainty for each of the components of the system. Evangelopoulou *et al* (2019) estimated that, overall, the technologies involved in the process have a medium technology readiness level. In combination with poor overall energy efficiency, high investment costs and very high electricity requirements, 'power methane' is likely to play only a minor role.

The other alternative green gas or renewable gas is biogas/biomethane. IEA (2020a) projected a rapid and strong growth of biomethane production and consumption in Europe and globally. Biomethane has a very high methane content (>90%) and is equivalent to methane from fossil sources or methanation. Small volumes already feed into gas pipelines today. In some countries, it is considered an instrument to decarbonise gas transport and there are government policies in place that support biomethane injection into natural gas grids (e.g., in Germany, Italy, the Netherlands).

Biomethane is obtained either by 'upgrading' biogas (i.e., removing the CO_2 and other gases, thereby increasing the methane concentration) or through the gasification of solid biomass. IEA estimated that the future biomethane potential in the EU and its neighbouring regions is many times above current production volumes. If biomethane is produced by upgrading biogas, CO_2 in a relatively concentrated form is obtained as a by-product.

In combination with hydrogen, this CO_2 could be used to produce an additional stream of methane (IEA, 2020a). Another option would be to store the CO_2 underground so that the biomethane is a CO_2-negative source of energy (BECCS).

However, biomethane production is costly. Depending on the source and technology, biomethane costs exceed current natural gas prices. The average cost for biomethane produced today is around €55 /MWh (IEA, 2020a), with only biomethane from landfill (solid waste) below €45 /MWh and some even below €30 /MWh. The IEA expects the costs to decrease substantially at global scale, with a large share of future production at around €30 /MWh. In particular, the process of thermal gasification of solid biomass – as yet immature – has large potential for future cost reductions (IEA, 2020a). However, for the technologies relevant in Europe, the IEA expects less of a cost decrease and costs may well stay above €45 /MWh (IEA, 2020a).

There will be a need for a shift in production sources, so that sustainable sources play a greater role. In addition to the sources currently used, such as municipal wastewater, municipal solid waste and animal manure, other sources including woody biomass and crop residues will play a larger role. At the same time, sustainable biogas/biomethane production requires a reduced role for direct crop use, because of the competition with food.

In addition to biomethane, biogas production can be expected to continue to expand in the next few decades, though more slowly than biomethane production. Biogas is the low-methane gas obtained from the biochemical pathway. Biogas will continue to serve local demand for heat and power, in particular in areas where renewable electricity cannot guarantee to provide 100% of the energy supply. Despite their growing potential and further cost reductions, biogas and biomethane are likely to continue to play a rather small role in replacing natural gas. In particular, costs are likely to remain above other renewable alternatives such as electricity and hydrogen. However, support policies, which can compensate for parts of the costs, could lift biogas/biomethane out of their niche.

Fendt *et al* (2016) compared the costs and efficiencies of the two types of renewable methane. For biomethane obtained from the traditional biochemical pathway (i.e., the upgrading of biogas), they estimated efficiencies in the range of 55%–57%, with a potential to improve above 80%. For biomethane from gasification, they expected somewhat higher efficiencies of up to 70% today and 75% in the future. Power-to-methane (i.e., methanation of hydrogen) is expected to achieve efficiencies between 54% and 60%, with future improvement to up to 78%. Of course, in addition to technological improvement from learning, scale effects prevail in renewable methane production, so that production and investment costs will decline with increasing plant sizes. Production costs vary between 5.9 and 13.7 €ct/kWh (biochemical biomethane production), 5.6 and 37 €ct/kWh (thermochemical biomethane production), and 8.2 and 93 €ct/kWh (power-to-methane) (Fendt *et al*, 2016). Thus, none of the renewable production routes can compete with today's natural gas prices, but all options are able to provide carbon-free methane.

Using methane from these renewable sources will allow the continued use of the existing infrastructure, for transportation and long-term (inter-seasonal) storage, and in final-user appliances. The risk of asset stranding only arises if the use of renewable methane is considerably lower – or limited to specific regions – compared to today's demand levels.

a. Demand side

1. Industry

Synthetic methane can serve as a substitute for fossil natural gas in the industrial sector, potentially reducing the emission factor substantially (Fleiter *et al*, 2019).

The main advantage compared to pure hydrogen is that synthetic methane can be supplied through the existing natural gas grid and can use existing underground storage facilities for long-term (inter-seasonal) storage. This leads to lower investment costs for the transport infrastructure. Furthermore, replacing fossil natural gas by synthetic methane requires fewer changes to industrial production processes compared to other decarbonisation options for the industrial sector, such as direct electrification. Hence, the investment costs are accrued on the supply side while industrial users can mainly maintain their appliances. However, given the substantial electricity requirements and the costs for the methanation process, synthetic methane is unlikely to be economically viable as a replacement for all industrial natural-gas usage (Bataille *et al*, 2018). Instead, synthetic methane is a useful alternative for specific industrial processes and subsectors for which direct electrification is technically infeasible or not economically desirable.

Most fossil natural gas in the industrial sector is used for the generation of heat and steam (Mantzos *et al*, 2018). While low-temperature heat requirements can be met through electrification with existing and established technologies, hydrogen and synthetic methane are useful to supply heat above 1000°C (Maddedu *et al*, 2019). High-temperature demand stems mainly from clinker burning in the cement industry, production of primary steel with blast furnaces and aluminium smelting (Honoré, 2019). To produce clinker, other fuels such as biomass or waste are less expensive than synthetic methane (Hübner and von Roon, 2021). Synthetic methane can be used as a reducing agent in conventional blast furnaces in the production of primary steel. However, the potential to decrease GHG emissions is limited. Other technologies are required to fully decarbonise steel production, such as the direct reduction of iron ore in combustion-free reactors fuelled by hydrogen (Bailera *et al*, 2021). Another option is to replace primary steel by secondary steel which is produced by re-melting scrap steel in electric arc furnaces, and which is 100% electrifiable (Maddedu *et al*, 2019).

The chemical sector relies to a great extent on fossil natural gas, which is mostly used for energy-related processes but also as a feedstock (see Figure 4-6). Although the chemical industry produces many diverse products using different processes, most of the sector´s emissions arise from the production of ammonia, methanol, propylene, ethylene and benzene/toluene/xylene (BTX) (Schiffer and Manthiram, 2017). Ammonia is produced from hydrogen and nitrogen from the air. Currently hydrogen is mainly provided by steam methane reforming (SMR) from fossil natural gas (see chapter 5 on hydrogen). Therefore, decarbonising the supply of ammonia requires substituting hydrogen from SMR by production from electrolysis with renewable energy. Methanol is produced from the association of hydrogen with carbon monoxide or carbon dioxide (Parigi *et al*, 2019). Similarly to the production of ammonia, a shift towards hydrogen based on renewable energy would be crucial. Furthermore, this process allows for use of CO_2, which can either be sourced from captured emissions from other production processes or via direct air capture. The synthetic methanol can serve as a feedstock for the production of propylene and ethylene and BTX, which is currently mainly produced by steam cracking of naphtha (Chan *et al*, 2019). The methanol-to-olefins (MTO) production process is already commercially established and could lead to an almost halving of GHG emissions. If the CO_2 for methanol production is captured from the air, emissions could even be negative (Dechema, 2017). The costs for this production pathway are above €1000 per ton of ethylene and between €1300 and €2800 for BTX, and are thus not yet competitive with production using feedstocks based on fossil fuels (Dechema, 2017).

2. Power and heat demand

Using green gases (synthetic methane or hydrogen) in power generation has the big advantage of providing a dispatchable, stored fuel available in periods that require flexibility, such as when there is low renewable supply (for example, the so-called *"Dunkelflaute"* moments with no sun and no wind).

For this purpose, green gases can be used in the same way as fossil natural gas in the transition period. Green gases compete with other flexibility tools in this role, including electric storage (pump hydro, batteries) and demand-side management. Green gases, in this context, are often referred to as "power-to-gas" (or power-to-X).

Clearly, using synthetic methane as input fuel in power generation is very inefficient, given that multiple conversion efficiency losses add up: conversion of renewable electricity to hydrogen and conversion of hydrogen to synthetic methane and then combustion in power plants to electricity again. Currently, electrolyser conversion efficiency is less than 65%. Gorre *et al* (2019) predicted it increasing to 75% in 2030 and 78% in 2050. Electricity losses for the initial generation of hydrogen and subsequent synthetic methane production are above 20%-30%. The reconversion of synthetic methane in electricity can take place in combined cycle gas turbines (CCGTs) or open cycle gas turbines (OCGTs). While CCGTs conversation efficiency is above 60%, the efficiency even of modern OCGT is only in a range between 35% and 40%. In sum, the aggregated efficiency of these conversation steps is slightly above 30%, meaning that almost 60% of the initially generated electricity is lost.

Clearly, the same holds for the generation of hydrogen from renewable electricity and the subsequent combustion of this hydrogen. Here, fuel cells could – potentially – replace OCGTs. However, their efficiency is only slightly above 60%, so in sum an efficiency of ~45%-50%. In addition, because hydrogen diffuses in air, there are more losses in this value chain. So, using synthetic gases as storage medium for long-term (inter-seasonal) storage is expensive.

In addition, synthetic methane is produced at high costs, considerably higher than natural gas prices today. Similarly, electricity generation from biogas/biomethane is associated with high costs because of the relatively high costs of production of the biogenic fuel. Depending on the specific biogas/biomethane production plant and feedstock, the levelised costs of electricity generation are estimated to be between €43/MWh and €160/MWh (IEA, 2020a). A substantial part of this range lies above the cost of generation from wind and utility-scale solar PV, which have come down sharply in recent years [78]. However, unlike wind and solar PV, biogas-fired power plants can operate in a flexible manner and, hence, provide balancing and other ancillary services to the electricity network (IEA, 2020a).

Similarly for heating, where local heat demand is present, a combined heat and power plant fired with biogas can be operated economically and more efficiently than an electricity-only plant. This is because a combined heat and power plant can provide a level of energy efficiency of around 35% in electricity generation and an additional 40%-50% when the waste heat is put to productive use.

The economics of power/combined heat and power plants fired with hydrogen are better than those fired with synthetic methane, because one fewer conversion step is required in the value chain. The 'saved' conversion losses more than compensate for the lower energy density of hydrogen.

Of course, both synthetic methane and hydrogen will need to be stored for a period of time between their production and use in gas turbines. For synthetic methane, the entire capacity of underground gas storage in Europe can be used. In 2017, the EU had more than 977 TWh working gas capacity in underground gas storage (IEA, 2019b). The vast majority of gas storage capacity in the EU is in depleted oil and gas fields (68%), while salt caverns are only a small share of 17%, slightly more than aquifers (15%). In contrast, only salt caverns are suitable for the storage of hydrogen (e.g., Caglayan *et al*, 2020), i.e., about 166 TWh working capacity, mostly located in Germany (83% of the 166 TWh).

[78] In 2020, the levelized costs of electricity generation of utility-scale solar PV were 48€/MWh, for onshore-wind 33€/MWh and for offshore-wind 71€/MWh (IRENA ,2020). Conversion of Dollars to Euros with an exchange rate of 0.85€/$.

3. Transport sector

Natural gas is little used in the transportation sector (i.e., road transport, railways, ships, aviation). However, there is currently a growing market – albeit at very low levels – for LNG-fuelled ships and trucks. LNG (liquefied natural gas, cooled down to less than -161°C) is a lower-emission alternative to heavy fuel oil that can help in complying with emission standards in coastal emission control areas.

Likewise, distribution trucks with LNG fuel are reported to cause less local pollution than diesel trucks, which is particularly attractive in urban areas. Yet, even participants from the shipping industry, such as the Maersk CEO, have called for fossil-free shipping fuels[79]. This would exclude LNG, too.

Synthetic methane could technically replace fossil natural gas in the same demand uses in the transportation sector. Moreover, synthetic methane can replace oil products. Synthetic methane would be used with the same type of internal combustion engine as today, thereby reducing the need to further push technology development in pursuit of alternative drive propulsion systems.

However, the cumulative costs of synthetic methane production and cooling to LNG-temperatures are likely not decreasing to a level at which synthetic LNG could compete with other non-methane alternatives such as hydrogen, ammonia or electrification. In addition to the direct costs, the multiple transformation processes in the synthetic-LNG production chain would cumulate high losses (from electrolysis, then methanation, then cooling).

b. Transportation infrastructure

Synthetic methane – both from the methanation of hydrogen and from biogenic sources – can use current (fossil) natural gas infrastructure because they are all almost-pure methane. Indeed, biomethane is already fed into the European natural gas grid in small volumes. In other words, the transport – and also storage – of synthetic methane in current natural gas infrastructure would not cause any conversion costs.

Research on potential challenges in converting natural gas pipelines to the use for the transport of hydrogen is ongoing (also see Chapter 5). For long-distance, high-pressure transmission pipelines, Cerniauskas *et al* (2020) concluded from an in-depth analysis of the materials used in the German natural gas pipeline system, that most pipelines can be reassigned to hydrogen transport despite the different properties of hydrogen (and in particular hydrogen's tendency to dissolve in many metals and to leak out, leading to so-called hydrogen embrittlement of materials). However, conversion of the methane infrastructure for hydrogen would incur some costs because certain elements of the grid infrastructure would need to be replaced (e.g., valves). For the distribution grid, early research results from ongoing projects also indicate that at least recently built natural-gas distribution pipelines (with plastic material) and equipment can be converted to use for hydrogen[80]. There, too, the conversion potential seems to depend on the pipeline material.

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79 See for example the interview transcript with the CEO of Maersk here: https://newsrnd.com/business/2021-09-08-maersk-boss-skou--%22we-have-to-ban-new-ships-with-fossil-fuels%22.SkT8j-Uzt.html (last accessed on September 13, 2021).

80 See the HYPOS project in Germany: https://www.hypos-eastgermany.de/en.

4.2.3. Substitution of natural gas by electricity

a. Industry

The rapid reduction of the cost of electricity generation from renewable energy leads to the electrification of industrial processes as a key pathway to achieve zero GHG emissions in this sector. One can distinguish between direct electrification, i.e., the substitution of fossil fuel-based production processes with technologies using electricity, and indirect electrification such as the production of synthetic fuels and hydrogen from electricity. While the latter are covered in chapter 1.2.2, this part considers only direct electrification. Direct electrification is likely to be more efficient and cost-effective for most industrial production processes than relying on indirect electrification methods, because of their low conversion efficiency.

As mentioned earlier, the main use of natural gas is in the generation of heat. Especially, low temperature heat requirements (below 400°C) are electrifiable with existing technologies such as electric boilers or heat pumps. This covers most of the natural-gas usage in the food, wood, textiles and pulp and paper industries. Moreover, electrified furnaces such as resistance, induction and arc furnaces can provide heat above 400°C needed to fire ceramics and melt metals. With these technologies, about 78% of industrial energy demand, excluding feedstocks, can be electrified (Madeddu *et al*, 2020). For high-temperature heat requirements, the electrification potential depends on the specific sector. In the iron and steel industry, secondary steel making from scrap steel is completely electrifiable and already competitive (Wei *et al*, 2019). Direct electrification of primary steel production through electrolytic reduction of iron has been tested in pilot projects, while production using hydrogen to reduce iron ore offers a greater technological readiness (Philibert, 2019). For the cement industry, it is possible to generate the high-temperature heat for clinker production, but these technologies are still at the research phase (Madeddu *et al*, 2020). Therefore, biomass or production of different types of cement that do not rely on clinker burning offer more viable alternatives (Chan *et al*, 2019).

With available and mature technologies, a large share of natural gas usage could be replaced by direct electrification. Major obstacles are the high electricity price compared to fossil natural gas and high investment costs.

b. Power demand

Supplying electricity with 100% renewable energy is feasible (Zappa *et al*, 2019). A key challenge will be increased peak electricity demand arising from the electrification of the transport, residential and industrial sectors (Madeddu *et al*, 2020). Because of the intermittent supply of electricity from renewable sources, storage facilities or plants that provide electricity flexibly are necessary. Natural-gas plants provide such a dispatchable source since they can be ramped up within a few minutes and have comparatively low operational costs. However, other technologies are available which do not emit greenhouse gases.

One option is electrical energy storage which transforms electricity in a storable form and provides electricity at a later point in time (Luo *et al*, 2015). This covers a wide range of technologies with different conversion efficiencies. While most electrical storage, such as pumped hydro or batteries, cannot be scaled up to store enough energy to replace a shortfall of renewables for more than a couple of hours, hydrogen-based facilities might provide storage for up to several weeks (Schill, 2020).

Storage facilities become especially important for high shares of renewable energy in the electricity supply (above 80%). For lower shares, other flexibility options such as the deployment of transmission lines or demand-side management provide more efficient alternatives (Schill and Zerrahn, 2018). To balance differences in electricity supply and demand across long distances and time periods, the conversion of electricity to synthetic methane or hydrogen ("Power-to-gas" – PtG) is a plausible solution (also see Chapter 5). These technologies are still expensive but could become cost-efficient compared to fossil natural gas plants by 2050 (Maeder and Boulouchos, 2021).

c. Heating demand

Today, fossil natural gas is used widely for the generation of heat, both in large-scale heat (or combined power and heat) plants for district heating systems, and in individual home boilers. There is a strong consensus that, in the long run, individual homes can efficiently obtain heating from electrically powered heat pumps. Also for large-scale district heating systems, sourcing from renewable (electricity) sources is envisaged, such as large-scale electrically powered heat pumps with various heat sources (air, ground, seawater, sewage water, ground source water).

This may be coupled with cooling supply. There will need to be further innovation and cost reductions, for example in heat storage technologies, to achieve a 100% renewable heating supply.

However, the transition to renewable sources in heating will require the proper incentives. In the current system, there are strong path dependencies and many countries provide support to convert coal-fired (power and) heat plants to natural gas fired plants in the ongoing coal phase-out wave. Given the long lifetime of heat plants and combined heat and power plants (usually above 30 years), converting to natural gas fired plants now creates a lock-in of fossil fuels.

d. Transport sector

There is now a general consensus that the decarbonisation of the transport sector will in large parts be achieved by electrification (Agora Verkehrswende, 2020). There is continued improvement of battery technologies, and the deployment of charging infrastructure at increasing speed has created lock-ins into the technology.

The ongoing electrification efforts are best known in individual transport (cars). However, natural gas – in the form of LNG – is used in heavy-duty freight transport, e.g., urban truck transport (heavy-duty distribution). However, battery development is also progressing for heavy-duty trucks that require high energy provision (because of the heavy weight) but not long distance (because they only serve local customers), with the first demonstration fleets in place. Similarly, R&D and pilot projects are in place for coastal ship transport, in particular ferries. By and large, the ongoing improvement of battery technologies indicates that natural gas can be replaced by electricity in the medium and long run to 2050.

4.3. Development of methane supply and demand in three extreme scenarios

In the following, we look at the potential development up to 2050 of methane gas supply. We focus in sections 1.3.1 - 1.3.3 on the future role of synthetic methane gas. The three corner scenarios are very different in their general characteristics, for example with respect to the role of electrification and hydrogen. Chapter 2 provides an introduction to the scenarios and Chapter 6 an overview across sectors, shows the main results relevant for the gas sector. Figure 4-10 shows the main results relevant for the gas sector.

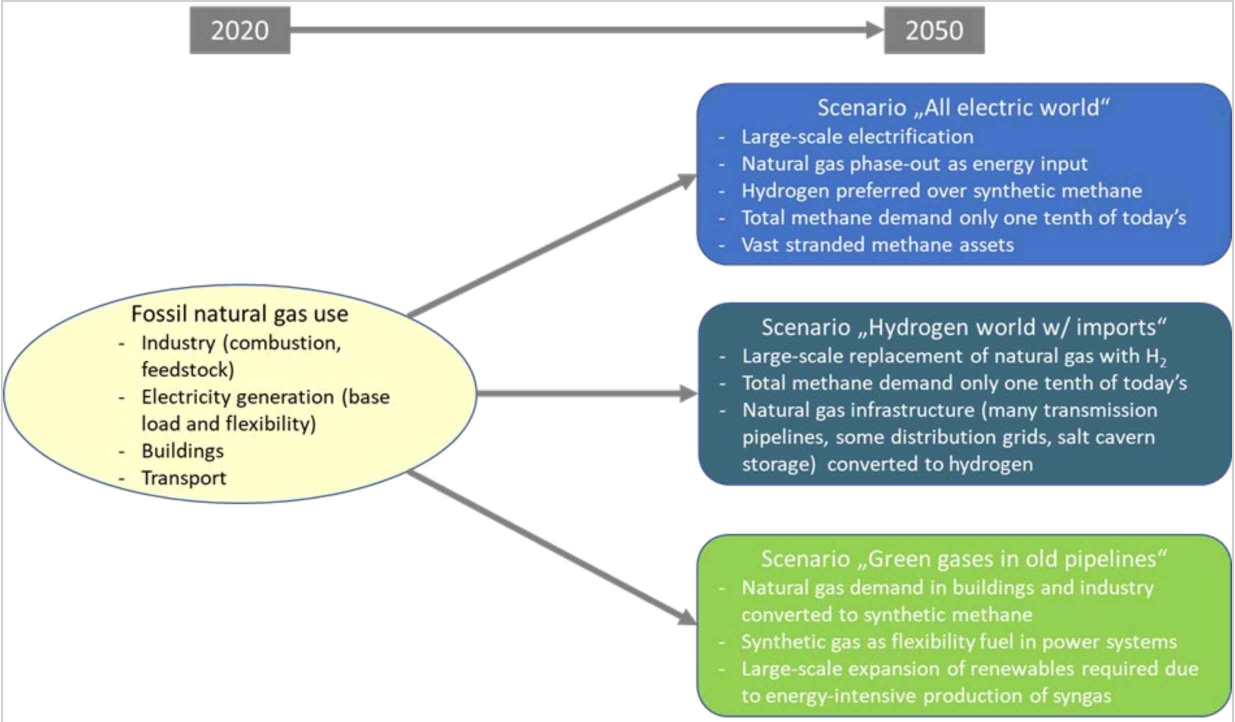
However, there are some trends in the development of fossil natural gas and of synthetic methane common to all scenarios. In other words, these are developments that we expect to take place in all circumstances, because of the EU's climate neutrality target, the technical potential of biogas/synthetic gas production in the EU and its neighbourhood, infrastructure economics, the development of CCS technology, and the relative costs of synthetic gas and hydrogen.

These common trends are:

- Fossil natural gas use will be completely phased out by 2050 to achieve climate neutrality in the EU;
- The EU will need a substantial expansion of renewable electricity generation that will be either consumed or used to produce H_2 or synthetic methane (also see chapter 6);
- Fossil natural gas will no longer be used for power generation by 2050 in the EU. In 2030, natural gas power plants will still contribute to provide flexibility in electricity systems with increasing shares of renewables, as well as to (combined) heat (and power) in district heating systems across Europe. Methane-fired power generation will cease completely by 2050, i.e., synthetic gas will not replace fossil natural gas in power generation;

  Rather, hydrogen will play a role as a flexibility provider in the electricity sector, in addition to other flexibility options, including electricity grid expansion, demand side management, pump and battery storage, etc;
- Fossil natural gas will cease to be used as energy input in industry (i.e., for combustion). It will be replaced by alternative processes based on electricity, hydrogen or synthetic gas, with varying shares of these depending on the scenario;
- Synthetic gas will to a great extent replace fossil natural gas as a feedstock in industrial processes, although not necessarily entirely and with varying extents in the scenarios;
- Fossil natural gas will not be used for the production of (grey or blue) hydrogen in steam methane reforming (SMR) or pyrolysis processes in the EU by 2050. Hydrogen will exclusively be generated from electrolysis of renewable electricity by 2050 (see chapter 5). This is required to achieve the climate neutrality target;
- Given the extensive existing natural gas pipeline systems (both high-pressure transmission and low-pressure distribution), as well as the generous LNG import capacities in the EU, no further investments in methane transportation infrastructure are needed beyond what is currently in place and under construction in the EU; and
- Fossil natural gas is hardly used in the transport sector today. This use will be completely phased out by 2050. It will be replaced by electricity, hydrogen and syngas, with varying shares depending on the scenario.

Figure 4-10: Overview of scenario trajectories and methane sector outcomes



Source: Authors' own elaboration.

4.3.1. All electric-world

In the *all-electric world* scenario, all uses of natural gas that can possibly be served by electricity will be electrified by 2050. Where electrification is not possible and gaseous input fuels are required in 2050, green hydrogen is the fuel of choice because of its lower costs of production than synthetic methane.

This means that, in 2050, there is no use of natural gas as an energy input in an all-electrified EU. Some small quantities of natural gas are still used as feedstock in industry. Natural gas has some cost advantage over synthetic methane. However, some synthetic methane that can be produced at the lower end of the cost range (e.g., biomethane) will also be used as a feedstock where available. In sum, about one third of the methane feedstock will come from fossil natural gas and two thirds from synthetic methane. Moreover, some very small volumes of synthetic methane will be used as energy input in industry.

Some of the synthetic methane, around a quarter, will come as imports from neighbouring regions. However, total methane demand volumes will be very small (less than a tenth of today's natural gas demand), so the vast majority of natural gas infrastructure for supply to and within the EU will become stranded. Hydrogen, which also plays only a small role in the *all-electric world*, will not prevent the stranding of most natural gas transport and storage assets.

In the transition to the *all-electric world*, natural gas will continue to be used through the next decade, though with somewhat smaller volumes already by 2030 as electrification progresses quickly. While the EU power system increases its share of renewables, natural gas can provide flexibility.

4.3.2. Hydrogen imports to fuel the EU

In this scenario, hydrogen replaces natural gas at large scale in uses across the economy. Consequently, natural gas and synthetic methane are hardly used by 2050. As in the *all-electric scenario,* only some small volumes of industrial demand for energy use (synthetic methane) and for feedstock (both synthetic methane and fossil natural gas) remain. In total, in a hydrogen world in 2050, synthetic methane and natural gas combined provide only about one tenth the supply levels of today.

In the *hydrogen imports* scenario, about half of the synthetic methane is assumed to be imported, in addition to hydrogen imports. Given the relatively small volumes of synthetic methane consumption in this scenario, just as in the *all-electric world* scenario, most of the natural gas infrastructure will become idle. However, in *hydrogen imports* some of the natural gas infrastructure can be re-purposed for the transport and storage of hydrogen. The exact amount that can be converted is still a topic of research, but it seems that a larger share of pipelines can be converted (e.g., Cerniauskas *et al*, 2019), in particular in distribution networks where modern pipelines are plastic-made (not metal). The conversion possibility is smaller in storage because only about 17% of the underground gas storage capacity in place can be used by hydrogen, namely salt caverns.

4.3.3. Green gases in old pipelines

The *Green gases* scenario involves large and widespread use of synthetic methane across all sectors of the economy. Total synthetic methane demand in 2050, therefore, is ten times greater than in the other two scenarios and about the same level, if not slightly higher, than today's natural gas demand. In contrast to today's natural gas world, the import share of synthetic methane is comparably low at around 50%. In other words, the dependency on imported methane will significantly decrease.

In buildings, in 2050, electricity will be the main energy carrier also in the *green gases* scenario, because of higher efficiencies and lower fuel costs. But there will continue to be some use of (synthetic) methane in buildings, relying on distribution networks in selected regions.

Moreover, the *green gases* scenario is the only of the extreme scenarios in which synthetic methane is used in power generation in 2050, though at moderate volumes, indicating the importance of synthetic methane as a flexibility fuel that can be dispatched in periods of low renewable supply because it is readily available from storage.

In addition to today's large demand sectors for methane, buildings and industry, a large share of the synthetic methane will also go to transport demand. For the transport sector, we assume in the *green gases* scenario that there will be a focus on the continued use of internal combustion engine vehicles. This traditional technology has a much lower tank-to-wheel efficiency than electric vehicles (~90%) or fuel cells (~60%) of only about 30%, thereby requiring massive fuel input in the form of synthetic gas.

4.4. Conclusions: next steps in EU gas policy

In this chapter, we discussed in detail that the use of natural gas will have to cease by 2050 and that natural gas can be replaced by a variety of alternatives:

- By synthetic methane from various, costly sources (biogenic, or methanised hydrogen) easily; but probably limited in quantity;
- By hydrogen relatively easily, but with some challenges because of hydrogen's different characteristics, which would require conversion of natural gas infrastructure assets (in particular pipelines and related equipment), and at moderate costs of production once large-scale renewable electricity generation and electrolysis are in place (also see chapter 5); and
- By electricity in a number of end-uses, e.g., in heating supply, in several industrial processes, etc., at modest supply cost, but with – more or less costly – conversion of end-uses required.

Most likely, the outcome by 2050 will be a mix of options. Hence, policy today must ensure that all options can be implemented.

The natural-gas sector relies on asset-specific infrastructure (pipelines, underground storage, LNG terminals) that is currently regulated by the Gas Directive (2009/73/EC) and the "Gas Regulation" (715/2009/EC). The use of these infrastructure assets will be substantially altered in varying ways, depending on the scenario. For example, in the *Hydrogen imports scenario*, re-purposing of natural gas pipelines will be an option, while greenfield development of a hydrogen pipeline grid will be another option. In the *green gases* in old pipelines scenario, in contrast, the current pipeline system can continue to be operated. However, it must be questioned whether the production potential for green gas(es) is large enough to justify economically the continued operation of the very long and very dense European gas pipeline system. We do not find, even in our most gas-intensive scenario, the same large volumes of methane gases as are used today. Similarly, the pipeline need for hydrogen transport is not as large as the fossil natural gas volumes transported today.

Our quantitative findings are somewhat in contrast with the assumptions of the ongoing revision of the gas market rules in the framework of the "hydrogen and decarbonised gas market package" where a large role for gaseous fuels by 2050 is taken as starting point. We agree that a new regulatory framework Gas Directive to a hydrogen and decarbonised gas market package should help ensure an orderly transition from today's natural gas world to any future 2050 state. While the internal market rules are not be questioned, there will be need for additional provisions. Importantly, there needs to be a framework to address stranded fossil gas assets (i.e., unused infrastructure assets that cannot be re-purposed to accommodate hydrogen or other non-methane gases or liquids).

In this, questions such as financial compensation for prematurely stranded assets, the obligation to demolish or re-purpose must be addressed. As usual, the "devil will be in the details". For example, it will need to be defined when an asset is "prematurely" unused which is challenging in a sector where most data and information is private and confidential. Given the uncertainty on the future developments that is highlighted by our scenarios, we recommend the regular revision (i.e., evaluation and adaptation) of the legislative framework for methane and hydrogen gases in the next years.

Of course, in view of the need to stop consuming fossil natural gas within the next two decades, any construction and newbuilt of fossil natural gas must be stopped, because they might become stranded within a short period of time. The revised TEN-E regulation and the projects of common interest (PCI) criteria, therefore, do not include natural gas assets anymore. The EU might consider supporting a very limited set of infrastructure facilities that help improving the Internal Energy Market, e.g., reverse flow capacities, new entry pipelines in current monopolistic markets and similar, but this should be done under a different label and with very limited, carefully designed restrictions. Also, convertibility to hydrogen ('H_2 readiness') could be an additional criterion for support in this case.

In addition to transportation infrastructure, consumption assets (appliances) used by the final consumers of natural gas will be affected if the fuel is changed from methane (CH_4) to hydrogen (H_2) or electricity. Here, too, there is a regulatory challenge of how to incentivise or require consumers (in households, industry, commercial) to participate in a potential fuel – and appliance – switch. The organisation of the transition (i.e., of the switching) is usually done by the utilities, under the supervision of national regulators. However, there is clearly a case of for regional (multi-country) or even EU-wide coordination of the national and sub-national activities and the national regulators.

Despite their increasing potential and further cost reductions, biogas and biomethane are likely to continue to play a rather small role in replacing natural gas.

This is in particular due to the fact that costs are likely to remain above other renewable alternatives such as electricity and hydrogen. However, support policies that help offset parts of the costs could lift biogas/biomethane out of their niche.

In the short run, it is unlikely we will see a raft of national fossil-gas phase outs similarly to coal phase outs, despite some activism and early steps in this direction (e.g., BOGA, Beyond Oil and Gas Alliance, to be launched at COP 26 in November 2021). Rather, we argue that we need better – comprehensive – pricing of the externalities caused by the use of natural gas to provide economic incentives to reduce its consumption. Notably, this includes pricing of upstream fugitive CH_4 emissions of the natural gas consumed in Europe, including imports which dominate the EU's consumption with a share above 80%. This requires proper monitoring, reporting and verification of the methane footprint of natural gas imports first, and pricing second.

5. THE ROLE OF HYDROGEN IN DECARBONISATION

KEY FINDINGS

Today, hydrogen consumption within Europe is primarily as a chemical feedstock, and its production is highly carbon intensive.

Hydrogen could play a very different role within energy systems. Alongside its chemical uses, hydrogen can also be combusted in a turbine to generate heat, or passed through a fuel cell to produce electricity. This could allow hydrogen to replace fossil fuel consumption in sectors such as steel production, large road vehicles, or aviation and maritime. Just like fossil fuel gases it is also well suited for storing energy for long periods of time or transporting energy over long distances.

Importantly, there are also cleaner production methods, including those with zero operational carbon emissions. The driving cost component of production is the fuel input required for transformation. In the case of water electrolysis, this means the average cost of electricity used is the key determinant of final hydrogen price.

To arrive at some version of this future, a range of policies are under consideration. These have been driven by the publication of a European hydrogen strategy as well as a number of country level strategies.

5.1. Situation today

In 2018, demand for hydrogen in the EU was 330 TWh (Hydrogen Europe, 2021), with approximately 100Mt related CO_2 emissions [81]. Demand is driven by the need for hydrogen in the production of ammonia and in the refining of crude oil. To a lesser extent, demand exists for hydrogen feedstock in methanol and other chemicals. Demand for use in transport, industrial heat generation, and residential heating does not exist.

Hydrogen is produced by a process known as s*team methane reforming (SMR)*. Methane (natural gas) is heated with steam, under the presence of a catalyst, to produce streams of hydrogen and CO_2. For every tonne of hydrogen produced, nine tonnes of CO_2 are emitted (IEA, 2020b). Hydrogen produced in this way is commonly known as *grey hydrogen*.

Today, only 15% of hydrogen is produced by merchant plants (where hydrogen is traded); the remainder is produced on-site, or as a by-product of chemical production processes (Hydrogen Europe, 2021). Hydrogen is not considered an energy carrier today and as such no regulation or infrastructure exists to support large scale trading of hydrogen. Within Europe, there are 1,800 km of hydrogen pipelines in operation, usually in chemical industry areas, with the largest a 950 km pipeline between the Netherlands and Belgium (FCH JU, 2020).

The future role for hydrogen could be vastly different to today. Alongside chemical uses, hydrogen can also be combusted in a turbine to generate heat, or passed through a fuel cell to produce electricity, with zero carbon emissions from the production process. Just like fossil fuel gases it is also well suited for storing energy over long periods of time or transporting energy long distance. In the following section, we explore key sectors which will determine future European hydrogen demand.

[81] Estimate based on the benchmark for hydrogen production under the ETS carbon leakage list of 8.85tCO_2/tH_2.

The same section explores ways of decarbonising hydrogen production and transporting it efficiently into and across Europe. In the final section, we propose a framework for hydrogen and concrete policy decisions.

5.2. Futures for hydrogen

5.2.1. Demand

Potential demand for hydrogen in our 2050 scenarios is divided into a *probable* and a *speculative* demand. The *probable* demand comprises sectors which either already consume hydrogen, or for which industrial and policy developments already strongly indicate emerging demand. The *speculative* demand is for sectors in which hydrogen can technically play a substantial role but for which the economics are still very uncertain. This can be due to a strong competing fuel or the existence of significant uncertainty around hydrogen's commercial viability in the sector. Here, public policy, technological development, and consumer preferences will determine end solutions.

For industrial feedstock hydrogen demand, there is no directly competing input and hydrogen consumption will ultimately be determined by final product demand. When used as a store of useful energy, hydrogen will compete with alternative fuels (or energy vectors) and the relative merits will be determined on a case-by-case basis. In many cases, the competing energy vector will be electricity. A secondary key driver will be the availability of biofuels, and development of second-generation biofuels, where there are still large uncertainties.

Some hydrogen demand for energy may not be met directly by hydrogen, but by hydrogen containing fuels. For example, hydrogen can be combined with CO_2 to produce synthetic hydrocarbons such as kerosene. This is useful for cases where properties of certain hydrocarbons are beneficial: for kerosene, the relatively higher energy density is more attractive for long-distance aviation.

Table 5-1 presents the key sectors where hydrogen demand may emerge, splitting them by *probable* and *speculative* demand. Within each, sectors are ordered by decreasing likelihood of hydrogen to play a sizeable role in final demand. The brackets present the range of final energy consumption (FEC) for each sector met by hydrogen for the EU27 in a net-zero 2050 scenario. This numbers are the result of a bottom-up analysis carried out for this study[82].

[82] The analysis is largely based upon scenario analysis the long-term climate strategy of the European Commission (2018) and data provided by JRC under the IDEES project, available here: https://data.jrc.ec.europa.eu/dataset/jrc-10110-10001. Where appropriate additional literature is used to strengthen assumptions on a sector-by-sector basis.

Table 5-1: Bottom-up estimations for potential hydrogen demand 2050 (TWh)

Probable Demand	Speculative Demand
Ammonia Production (100-250)	Shipping (0-320)
Methanol Production (20-30)	Aviation (10-170)
Steelmaking (70-260)	Heavy-duty trucks (10-220)
(Rural) Rail (1-5)	Industrial heat (0-70)
Seasonal Electricity Storage	Buildings (50-430)
Oil Refining (50-110)	Light Commercial Vehicles (0-60)
	Passenger Vehicles (10-140)

Source: Authors' own elaboration.

a. Demand within industry

Ammonia is an essential chemical for the production of fertilisers. Europe currently produces around 17 million tonnes of ammonia annually. As global population, and by extension food and land demand, increases food production must become more efficient. Ammonia can play a key role. However, efforts are ongoing within the EU to shift away from chemical fertilisers and toward organic material or alternative agricultural techniques. These two conflating factors will drive the evolution of EU ammonia demand to 2050.

While future demand for ammonia is uncertain, the need for clean hydrogen to produce it is not. Today, hydrogen is extracted from natural gas before being combined with nitrogen from the air to produce ammonia. The use of zero-carbon hydrogen would eliminate emissions associated with ammonia production. Many of the investments into zero-carbon hydrogen production today are in combination with an ammonia plant[83].

EU **methanol** production is currently 1.5 million tonnes annually and is used as a feedstock for a variety of further useful chemicals. Like ammonia, the required hydrogen is met using SMR, and so replacing it with zero-carbon hydrogen is imperative for reducing associated emissions. Final demand varies depending on methanol demand.

Hydrogen is important in the **crude oil refining** process, transforming crude oil into a range of commercially attractive products. Two key processes are: hydrotreating, removing sulphur impurities and hydrocracking, transforming heavier residual oils into lighter fuels. Future demand for hydrogen depends on the evolution of demand for crude oil products. This can be expected to significantly decrease from today's levels. However, even in deep decarbonisation scenarios, some refining is likely to be necessary, e.g., for the production of intermediary inputs in the production of plastics.

The EU produces 177 million tonnes of **steel** annually [84], accounting for 4% of total EU GHG emissions; 60% of this steel is produced in blast oxygen furnaces (BOF; EC, 2018), which rely on coal and are not compatible with decarbonised scenarios. The remaining 40% of steel is produced using electric arc furnaces (EAF) with electricity as the primary energy input.

[83] For example, https://www.chemengonline.com/major-green-ammonia-and-hydrogen-project-announced-in-morocco/?printmode=1 in Morocco, or https://www.offshorewind.biz/2020/10/05/orsted-and-yara-form-green-ammonia-pact/ in the Netherlands.

[84] https://ec.europa.eu/growth/sectors/raw-materials/industries/metals/steel_en.

Two different physical feedstocks can be used in the EAF: scrap steel and direct reduced iron (DRI). Increasing the share of scrap steel in the EAF is preferable as it facilitates steel recycling, but there will always be an upper limit given the availability of high-quality scrap steel. To produce new primary steel without carbon emissions, iron ore can be reduced to DRI using hydrogen and then purified to steel in an EAF. Currently this route is already operational in the Middle East using a mix of hydrogen and carbon monoxide (IEA, 2019c).

All major European steelmakers are currently building or testing hydrogen-based reduction for use in EAFs. Their target is to use purer streams of hydrogen to perform the chemical reduction process and thus avoid emissions. The use of both scrap steel and DRI produced using hydrogen in the EAF is considered the most viable decarbonisation option for the sector within the EU (Hoffmann *et al*, 2020). Competing options include the use of biofuels and electrowinning (electricity).

Within industry, there is a need to decarbonise **high temperature heat.** While lower temperature heat, and other standard processes can relatively easily be switched to electricity, there are technical challenges associated with high temperature heat provision by electricity.

Hydrogen could replace some natural gas in the provision of heat. Biofuels, fossil fuels with CCS and potentially electricity will be the alternative options. However, Madeddu et al. (2020) find that 78% of existing industry energy demand is electrifiable with existing technologies, while 99% of the demand is electrifiable with the addition of technologies currently under development.

b. Demand within transport

For **rail transport**, the strongest decarbonisation option is electrification. 77% of EU27 rail vehicle kilometres are already electric-powered (Mantzos *et al*, 2018). Electrification involves significant upfront fixed costs in overhead rail lines, which need to be justified by significant returns on investment. Therefore, for rail lines with heavy usage, electrification is a simple choice. However, for rural and less-frequented routes, the return on investment often cannot justify large upfront investments.

On more rural rail routes, trains still consume diesel. Shifting away from diesel consumption is possible using hydrogen powered fuel cells. But while hydrogen can be useful here, aggregate demand will be relatively small.

While the future of decarbonised passenger vehicles appears increasingly battery electric, there is one key difficulty with the use of batteries for electricity provision: manufacturing batteries which contain sufficient energy but are not too heavy. Hydrogen is able to store more energy in a smaller space and weighting less than a battery. While this is increasingly irrelevant for small passenger vehicles, it remains essential for **heavy-duty trucks** where hydrogen fuel cells are an attractive alternative.

The pace of innovation in lithium-ion and other types of batteries has been rapid so that it is possible that deployment at scale will drive down battery costs faster than that of other technologies. The use of biofuels, as well as more radical solutions such as overhead electric catenary lines, are also options.

The **shipping** fuel mix is dominated by heavy fuel oil. Fuel consumption in the sector is already being squeezed by sulphur restrictions and with imminent inclusion into the EU ETS, decarbonised fuels are essential. For short distance shipping, where power requirements are not too large, hydrogen fuel cells are an option. Key competition will come from battery electric ships.

For longer distance shipping, liquefied hydrogen, ammonia and synthetic fuels derived from hydrogen have greater potential (Middelhurst, 2020). Ammonia and synthetic fuel consumption would result in indirect hydrogen demand. In our scenarios, we assume ammonia to be the key fuel for decarbonising long-distance shipping. However, whichever route is taken, hydrogen will likely be required as an intermediary input. For example, the recent Maersk order for methanol compatible ships would require zero-carbon hydrogen[85].

Aviation is considered a hard-to-decarbonise sector. Little pressure from public policy, as well as difficult engineering issues mean that solutions for the aviation sector are not clear. Evidence suggests that hydrogen may have a key role to play.

Within the EU27, intra-EU flights contribute 54% of aviation energy demand, and extra-EU flights 46% (Mantzos *et al*, 2018). For short-distance (intra-EU) flights, hybrid options containing both electricity and hydrogen combustion are an option. Airbus have released three concept designs for planes which would combust hydrogen and produce electricity through a fuel cell, which they say could enter service by 2035 (Airbus, 2020).

For longer distance (extra-EU) flights, hydrogen and electricity are not likely to be sufficient because fuels with higher energy densities are required. Advanced biofuels and synthetic fuels (e-kerosene) derived from hydrogen are the most promising decarbonisation options. Biofuels would require new aviation design, while synthetic kerosene could largely be a drop-in replacement for today's fossil kerosene.

Light commercial vehicles sit between passenger vehicles and heavy-duty trucks with regards to power density requirements. It appears increasingly likely that battery powered vehicles will suffice. However, an advantage of hydrogen is quicker refuelling times, which might be a decidedly positive attribute for delivery and other vehicles with high utilisation rates. This is why hydrogen is also considered an attractive option for certain niches such as buses, taxis, and already today for forklift trucks.

For **passenger vehicles**, hydrogen fuel cells are not likely to be competitive with battery electric vehicles (BEVs). The market for BEVs is rapidly expanding, and importantly so too are investments in battery recharging facilities. The first-mover advantage of BEVs is by now clear. However, the total energy demand for passenger vehicles is very large. If fuel cells emerge to play even a small role for any technical or consumer preference reason, demand would be substantial.

c. Residential demand

The primary route for decarbonising **buildings** is electrification, electrically powered heat pumps are a particularly attractive option. They have an efficiency rate of 300%, meaning they are able to draw three times more heat energy from outside air or ground than they consume in terms of electric energy[86]. By contrast, the route from electricity through hydrogen to heat would have an efficiency around 50%. Today, the share of electricity in final residential heating demand is approximately 5% but EC scenarios forecast a growth in this share to between 22% and 44% by 2050 (EC, 2018).

The use of hydrogen to decarbonise building energy demand would involve retrofitting natural gas distribution grids to carry hydrogen. This requires significant investments, and will therefore be more attractive for countries or cities with dense existing natural gas networks that can be converted to hydrogen transport. A complementary option is for hydrogen to replace the combustion of fossil fuels in heat plants for district heating systems. Again, this will be more attractive for areas with already established district heating networks.

[85] See here: https://www.ft.com/content/800faea2-1024-4ea6-ade6-1680820e925b.

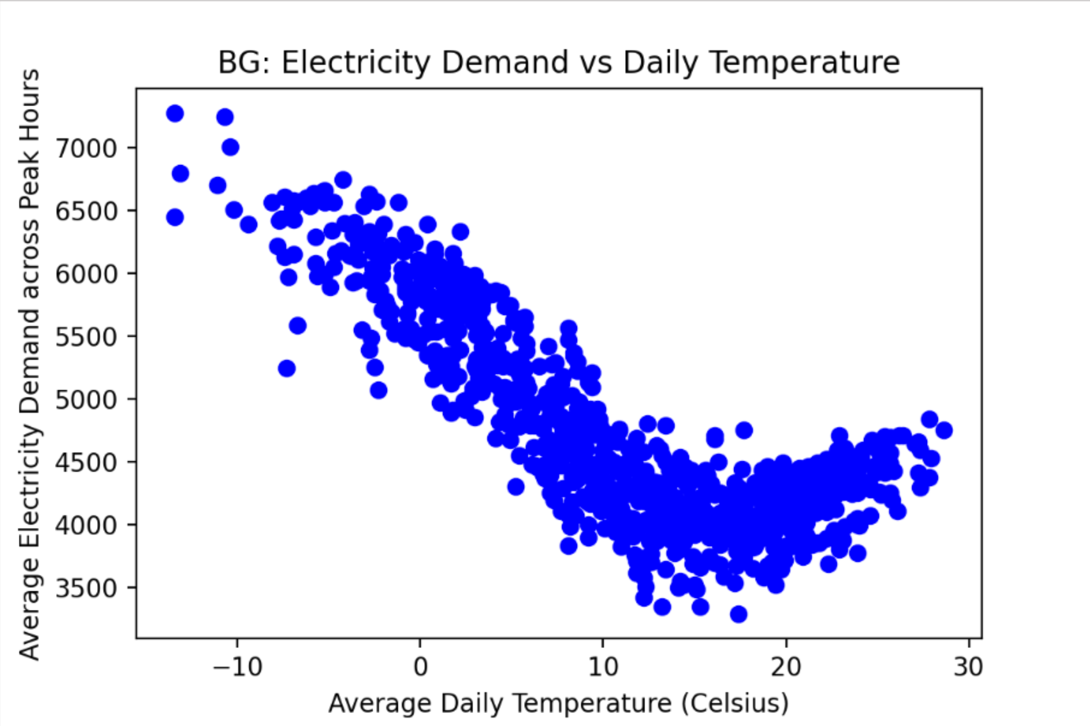
[86] Ground source heat pumps may have even more efficient.

When taking an overall energy system perspective, buildings are currently among the weaker contenders for consuming limited supplies of clean hydrogen. The next 10-20 years of building decarbonisation is likely to be driven by electrification, bar a potential small role for hydrogen (or alternatives) in district heating [87]. The role for hydrogen will be determined by the remaining requirements for decarbonisation around 2040 when hydrogen may be more widely available, and any limitations on the use of electricity will have become clearer.

d. Seasonal power Storage

European electricity grids are set to become overwhelmingly dependent on production from renewable sources of electricity, namely wind and solar power. Warmer, sunnier months will see increased renewable production alongside decreased demand owing to fluctuations in demand by heating requirements (see Figure 5-1). A challenge for the grid will be shifting supply from periods of oversupply to periods of excess demand: **long-term electricity storage**.

Figure 5-1: Bulgaria average daily electricity demand vs daily temperature



Source: Bruegel electricity tracker, available here: https://www.bruegel.org/publications/datasets/bruegel-electricity-tracker-of-covid-19-lockdown-effects/.

Nowadays this function is often provided by flexible gas power plants or hydropower, which has a limited geographical potential and little scope for expansion in Europe. By 2050, assuming electrification of further end use cases (heating), winter demand peaks will be much more pronounced, and in the absence of a political/technological breakthrough on CCS, gas plants will not be able to play such a significant role.

The transformation of electricity into hydrogen, long-term storage, and subsequent use in electricity generation is a plausible option for seasonal demand flexibility. Storage is not too expensive [88] and if a

[87] We focus on fuel switching options. Energy efficiency retrofits are the first essential step for reducing final energy demand in buildings and facilitating decarbonisation.

[88] IEA (2019c) estimates hydrogen storage in a salt cavern costs €15/MWh H_2.

hydrogen transmission grid exists, then fluctuations of volume within the grid (linepack) can also be used to meet extra demand. The downside is that the process of converting electricity into hydrogen and back again is very inefficient from an energy standpoint as only around 30% energy content of the initial electricity would be retained.

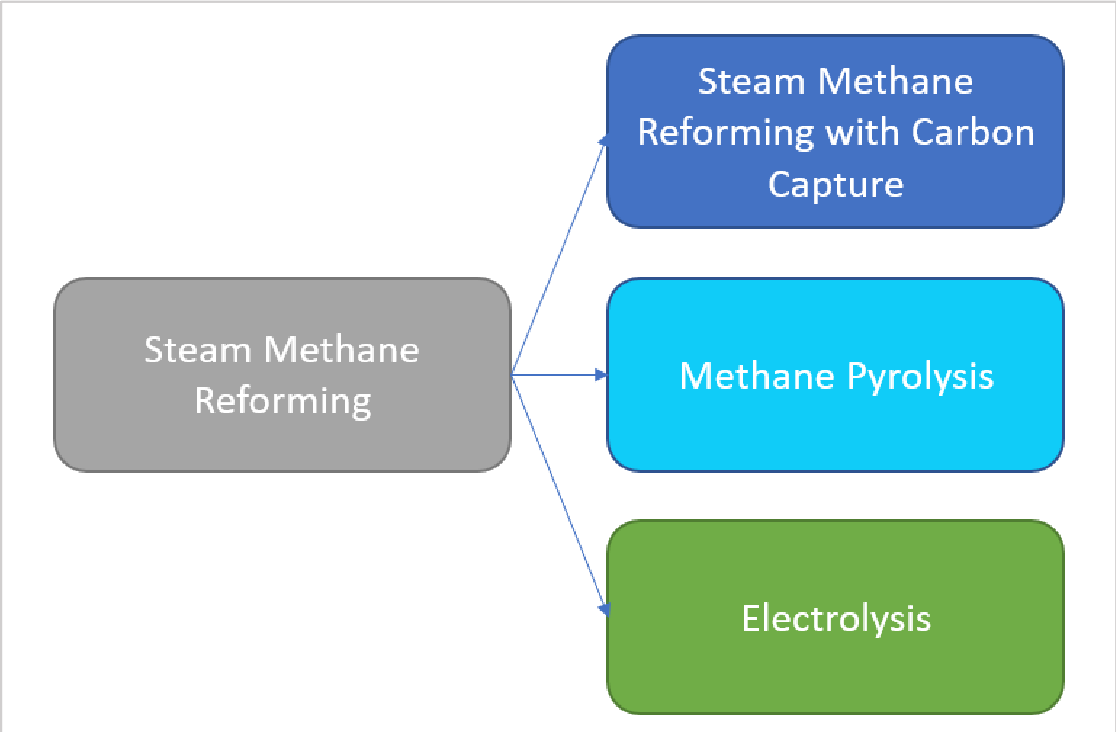
5.3. Supply

5.3.1. Domestic production

In the EU, hydrogen is currently predominantly provided by SMR. Hydrogen production falls under the EU ETS but it is one of the industries that receives a substantial share of their emissions allowances for free. This facilitates continued high emissions.

Figure 5-2 shows the three commonly discussed routes for decarbonising hydrogen production.

Figure 5-2: Low carbon production routes for hydrogen

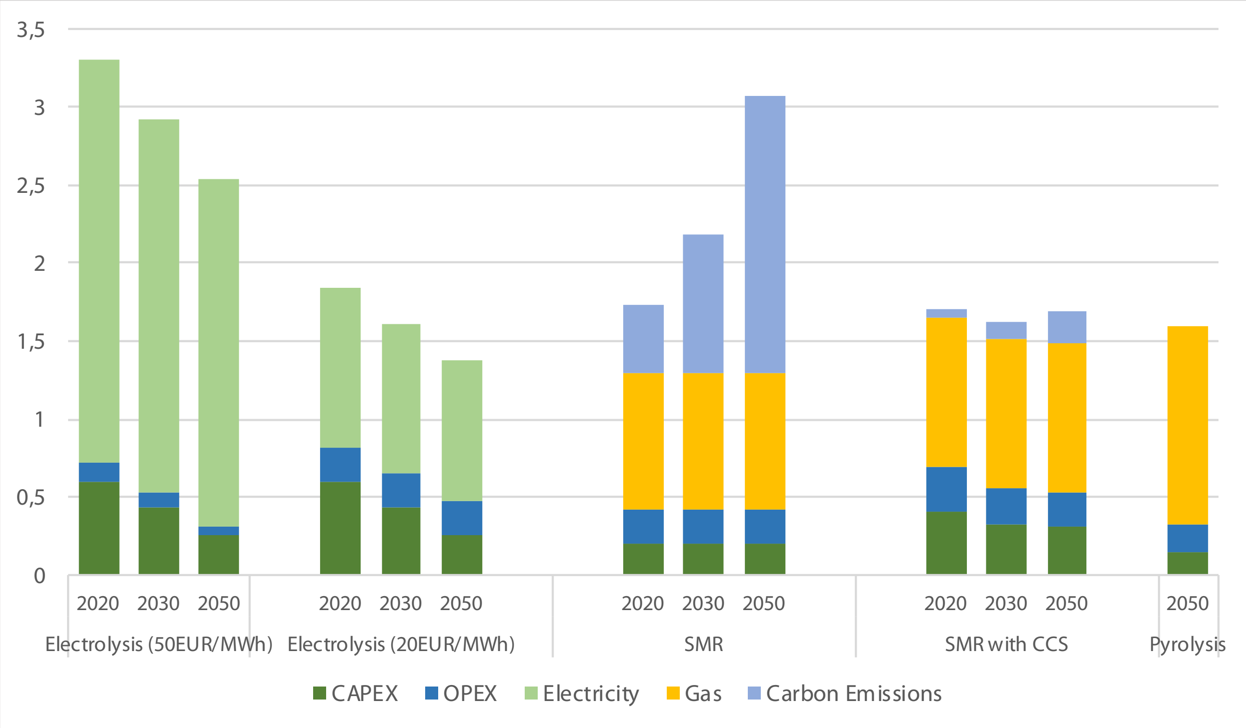


Source: Authors' own illustration.

- **SMR with Carbon Capture and Storage or Utilisation**, commonly known as blue hydrogen. A stream of methane is decomposed into carbon gases and hydrogen. In this case, the carbon gases are captured and stored (CCS) or utilised (CCU);
- **Electrolytic hydrogen production**, commonly known as green hydrogen when the inputted electricity is provided by a renewable source. An electrical current is passed through water which decomposes into hydrogen and oxygen; and
- **Pyrolysis hydrogen**, commonly known as turquoise hydrogen. Under special conditions, the decomposition of methane produces hydrogen and solid carbon (rather than gaseous carbon emissions). Solid carbon is a commercially attractive product.

The IEA ranks energy technologies based on their technological readiness level (TRL) ranging from 1 (initial idea) to 11 (predictable market growth reached)[89]. SMR with CCS is ranked as an 8 or 9. While SMR is very mature technology, the application of CCS requires developments to achieve commercial competitiveness. Depending on the type, the TRL of electrolysers ranges from 8 to 9. Finally, pyrolysis has a TRL of 6, a full prototype has been demonstrated at scale but there is still the need for commercial maturity to be proven.

Figure 5-3: Hydrogen Production Cost Decomposition (EUR/kg)



Source: Authors' own illustration.

Figure 5-3 uses IEA assumptions[90] to compare the cost evolution of these three competing pathways, alongside legacy SMR costs including a carbon price. There are three important factors to note:

- Capital expenditure (CAPEX) for electrolysis is expected to decrease rapidly over the coming years, supported by deployment (IEA, 2019c; BNEF, 2020);
- Electricity or natural gas costs are the primary driving factor for hydrogen production costs. Cheap electricity, available in large quantities, is the essential ingredient for competitive electrolytic hydrogen. Figure 5-3 shows cost difference for electricity at €50 and €20/MWh, with electrolytic hydrogen competitive only for the latter price. Utilising cheaper (or even free) electricity for a few hours a year saves on fuel costs but increases CAPEX as a share of production cost; and

[89] The IEA rankings are available here: https://www.iea.org/articles/etp-clean-energy-technology-guide.

[90] IEA Assumptions (listed for 2019/2030/2050). Electrolysis: CAPEX – 900/700/450 USD/kW; OPEX: 1.5% CAPEX; Efficiency: 64%/69%/74%. SMR: CAPEX – 910 USD/kW; OPEX: 4.7% of CAPEX; Efficiency: 76%. SMR with CCS: CAPEX – 1680/1360/1280 USD/kW; OPEX – 3% of CAPEX; Efficiency: 69%. We assume a 60% load for electrolysers, a gas price of €20/MWh, and a carbon price of 50/100/200 EUR/tCO_2 for 2019/2030/2050. The IEA does not provide assumptions for methane pyrolysis and we take this from Brändle *et al* (2020), CAPEX: 457 USD/kW, OPEX: 5% of CAPEX; Efficiency: 52%, Load Factor: 95%.

- Carbon prices play a key role. With the limited carbon prices faced by industry until recently, SMR is the most competitive technology for producing hydrogen. Increasing the CO_2 price incidence faced by producers is key for supporting lower carbon production routes.

However, the question of which hydrogen production process which will dominate by 2050 is as much political as it is economic. Different European countries foresee very different futures, with Germany focussed on electric hydrogen, while the Netherlands is more open to a future for natural gas-based hydrogen[91]. The position of the EC's hydrogen strategy paper was that while the future is in electrolytic hydrogen, natural gas-based hydrogen production will be required for a transition period.

Indeed, the Commission's strategy is centred around support for the scale up of *renewable hydrogen production*[92], targeted to reach 10 million Mt by 2030. This alone would require 475 TWh annual renewable electricity. For context, the EU added on average 38 TWh wind and solar annually in the period 2010-2030[93]. In 2020, the EU27 generated 540 TWh from wind and solar. Achieving such ambitious targets will require significant policy support, particularly with regards to access to large quantities of low-cost renewable electricity.

Meanwhile, the future of natural gas-based hydrogen within the EU is uncertain. While it will not qualify for support as a 'renewable' fuel, the application of CCS might still become an attractive option for hydrogen producers as the EU ETS price increases over the coming years. There are significant challenges associated with the development of commercial scale CCS which are discussed in chapter 4. Methane pyrolysis appears attractive given zero carbon emissions but is still in commercial infancy.

5.3.2. Foreign production (imports)

Under scenarios of optimistic EU hydrogen demand, it is quite likely that some volume of imports will be competitive. Imports will be competitive in cases where renewable electricity can be accessed at significantly lower costs abroad. In many parts of the world this is possible due to advantageous renewable resources (i.e., high winds or solar irradiation). Low financing rates for projects are equally important. Many areas of the world with attractive renewable resources still have poor financing conditions and hence the levelised cost of renewable electricity would still be too expensive for competitive export to the EU.

For short distance imports (<2000km) hydrogen can be transported cost-effectively via pipeline. For distances of up to 2,000 km, gaseous pipeline transport will add around €0.1-0.5/kg H_2 (BNEF, 2020; Jens *et al*, 2021). For example, one estimation is for a price €0.2/kg to transport hydrogen from Egypt to Greece or Italy (van Wijk *et al*, 2019), while other standard assumptions are €0.5/kg for 1,500km transmission (Brändle *et al*, 2020). This means that with small production advantages, gaseous pipeline transport of hydrogen can be cost-effective. For this reason, Brändle *et al* (2020) found that we are likely to see regionalisation in hydrogen trade, and Hampp *et al* (2021) found that the cheapest hydrogen import options for Germany are by pipeline.

For longer distances, pipeline transport of hydrogen is more difficult, as shipping becomes necessary. In a ship, low energy densities prohibit the transport of hydrogen in gaseous form. Like the trade of natural gas, one option is to liquefy the hydrogen. This involves significant energy requirements and hence costs. Other options involve transforming hydrogen into a chemical more suitable for transport,

[91] See Dutch hydrogen strategy here, (https://www.government.nl/documents/publications/2020/04/06/government-strategy-on-hydrogen), which is discussed in more detail in section 3.

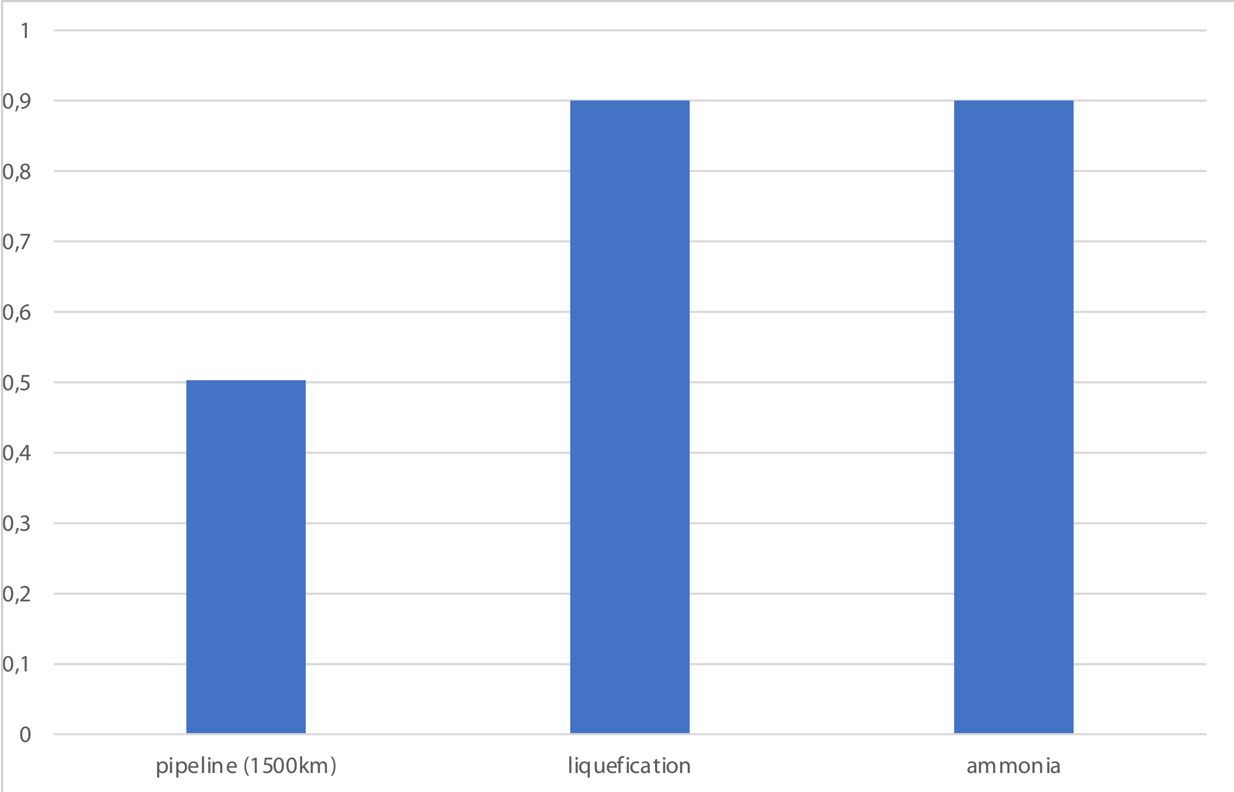
[92] "Renewable" means that the main input must be renewable. In practice until 2030 this will include only electricity but other production methods for example using biogas would be permitted if renewable nature can be proven.

[93] https://ember-climate.org/project/eu-power-sector-2020/.

such as ammonia which can be more easily stored in liquid form, prior to shipping. Once at destination, hydrogen is then removed from its "carrier compound". However, this conversion from and subsequent reconversion into hydrogen are expensive processes.

In Figure 5-4, we show that the costs only of liquefying and conversion/reconversion into ammonia are already double the costs of transporting hydrogen 1,500km by a new pipeline. That is before the costs of shipping and import terminals are taken into account. At minimum cost reductions of €1/kg would be possible for shipping hydrogen to be competitive with domestically produced hydrogen.

Figure 5-4: Additional transport costs (€/kg)



Source: IEA (2019c) and Brändle et al (2020).

Longer distance trade appears to be a more attractive prospect for the final commodities themselves. For example, global trade of ammonia already exists and is likely to retain sensible economics in a world of green ammonia. Demand for final product methanol can be met by imports, and aviation demand for e-kerosene could competitively be met by imports. End-use cases which require liquefied hydrogen (with no costs of re-gasification) might also import.

Thus, evidence today points to the following likely market structure. Europe produces significant quantities of domestic hydrogen from renewable electricity. Production derived from methane will remain a question of political preference, as well as addressing technological constraints on carbon capture. In cases of high hydrogen demand within Europe, imports from neighbouring regions by pipeline are likely to be competitive. Similarly, derivate hydrogen products are likely to be competitive via shipping. It is very possible that a global market will emerge for these commodities, in which the EU is likely to be the first large demand source.

5.3.3. Transmission and distribution

Transmission and distribution of hydrogen are possible by pipeline. Local distribution of hydrogen today is provided by trucking, but if significant commercial demand evolves then a pipeline infrastructure would be more efficient (Shiebahn *et al*, 2015). Pipelines can be new-build, but industry is also confident that retrofitting existing natural gas pipelines is a low-cost option (Jens *et al*, 2021; also see chapter 4).

The EC hydrogen strategy [94] sets out three distinct phases and discusses the commensurate required infrastructure. In the first phase from 2020-2024, the challenge is to decarbonise existing consumption. Here, little transmission infrastructure will be required. Exploratory analysis will still be useful. The first opportunities for doing so may be found in areas where parallel gas transmission pipelines exist and one can be converted to hydrogen.

In the second phase from 2025 to 2030, it is expected that industrial clusters of hydrogen demand will emerge. This is likely to include existing industrial demands such as chemicals, as well as some new demand potentially in steel. The requirements for transmission capacity will depend on the extent to which electrolysers are deployed close to attractive renewable sources or close to demand. In the former case, a growing transmission grid will already be required to connect demand spots with cheaper production sources.

From 2030 to 2050, the costs of low-carbon hydrogen should have significantly reduced to the point of competitiveness in key industries. Alongside a growing production, there will be the need for some volume of transmission pipelines. During this period it will become increasingly clear what role hydrogen can play. For example, in road transport the period from 2020 to 2030 will be dominated by electrification. By 2030, clearer signals will be apparent as to the potential depth of electrification, and the roll-out of hydrogen infrastructure will create stronger competition.

The need for distribution pipelines is unknown and will depend on the extent to which decentralised demand (road transport, buildings) emerges. It is possible that only large point source industrial demand will exist in which case a transmission infrastructure would suffice. Countries such as the Netherlands with the parallel tracked gas infrastructure will be important test-cases for retrofitting segments of the natural gas network (PWC, 2021).

5.3.4. Storage

For providing seasonal flexibility benefits to the power grid, a cost-efficient method for storing hydrogen is essential. Hydrogen can be stored in pressurized tanks above ground when quantities are small. However, for large volumes and long time periods such as inter-seasonal storage underground hydrogen storage would be economically sounder (e.g., Schiebahn *et al*, 2015; Reuss *et al*, 2017).

Underground gas storage usually has three main advantages: large volume, low costs, and operational safety. However, as highlighted by Tarkowski (2019), there is little experience with underground storage of hydrogen up to now.

Salt caverns appear likely to be suitable for hydrogen storage (Caglayan et al., 2020), both for technical and economic reasons. However, only a small share of natural gas underground storage capacity in place today is in salt caverns. In 2017, more than 600 underground storage facilities were operated worldwide and had a working gas capacity of 2700 TWh, of which slightly more than 977 TWh were located in the EU (IEA, 2019b). The vast majority of gas storage capacity in the EU is in depleted oil and gas fields (68%), while salt caverns are only a small share of 17%, slightly more than aquifers (15%).

83% of the salt cavern capacity of the EU27 is located in Germany (140 TWh). Only France (8.1 TWh), the Netherlands (7.9 TWh), and Poland (5.9 TWh) also have sizeable salt cavern storage capacity in place.

94 Available here https://ec.europa.eu/energy/sites/ener/files/hydrogen_strategy.pdf.

Germany has the largest salt cavern gas storage capacity worldwide, even larger than that in the USA (137 TWh). Other European countries have little potential to build up or expand storage capacity in salt caverns due to a lack of the required geological formations (Caglayan et al., 2020).

5.4. Hydrogen in the three extreme scenarios

In this paper, we investigate hydrogen demands and costs in three different 2050 scenarios. Final energy consumption met by hydrogen ranges from 100 TWh in *all-electric world* and *green gases* scenario to 1,400 TWh in *hydrogen imports*. Aviation and maritime sectors see a total demand for hydrogen (indirect and direct) of 100 TWh in the first two, and 300 TWh in the *hydrogen imports* scenario. In all scenarios, there is an additional 300 TWh non-energy demand for hydrogen (e.g., ammonia production).

There is also 300-400 TWh hydrogen demand for providing flexible storage to the power grid. Across the scenarios, differences in final energy consumption are driven by changes in industry, building, and transport demand.

These figures are in line with other modelling studies, with the caveat that different underlying assumptions make an explicit cross-comparison difficult. The EC (2018) hydrogen scenario sees 1,500 TWh hydrogen demand in EU by 2050. Blanco *et al* (2018) report 700 to 4,000 TWh demand. Hydrogen Europe envisaged 2,250 TWh demand in Europe in their optimistic scenario for 2050 (FCH JU, 2019). Finally, Auer *et al* (2020) provided a range of 1,400 to 2,000 TWh.

5.5. Framework for hydrogen

5.5.1. Hydrogen strategies

Alongside the roadmap discussed above, the EC's hydrogen strategy sets some concrete targets. There is a target for 6 GW of (renewable) electrolysis deployment by 2024. By 2030, this target is for 40 GW with a further 40 GW deployed outside the EU. The target for renewable hydrogen production in Europe is set at 10 million tonnes (333 TWh). To 2030, investments in electrolysers could range between €24 and €42 billion, as well as €220 – €340 billion for deploying and additional 80-120 GW renewable electricity capacity.

Beyond the EC's hydrogen strategy, a number of Member States have published national plans [95]. They outline funds for hydrogen, as well as targets for electrolyser capacity and shares of hydrogen consumption in key sectors.

France and Germany set aside €7 and €9 billion respectively in public funding for hydrogen. France sets a target of 6.5 GW electrolyser capacity by 2030, as well as a target for 20-40% of hydrogen consumed in industry to be decarbonised by 2028. Meanwhile, Germany has a target of 5 GW electrolyser capacity by 2030. Germany is also noteworthy for setting aside €2 billion of the total €9 billion funding to work on international partnerships. Indeed, the German strategy is clear in its message that imports of hydrogen are likely by 2050. A key role for Germany lies in developing and exporting the electrolyser technologies.

[95] The French hydrogen strategy is available here (https://www.ecologie.gouv.fr/sites/default/files/Plan_deploiement_hydrogene.pdf); the German hydrogen strategy (https://www.bmwi.de/Redaktion/EN/Publikationen/Energie/the-national-hydrogen-strategy.html); the Dutch hydrogen strategy (https://www.government.nl/documents/publications/2020/04/06/government-strategy-on-hydrogen); the Portugese hydrogen strategy (https://www.portugal.gov.pt/pt/gc22/comunicacao/documento?i=plano-nacional-do-hidrogenio) and the Spanish hydrogen strategy (https://energia.gob.es/layouts/15/HttpHandlerParticipacionPublicaAnexos.ashx?k=16826). Hydrogen Europe also provide an overview on the European level strategies, available here: https://www.hydrogeneurope.eu/wp-content/uploads/2021/04/Clean-Hydrogen-Monitor-2020.pdf.

The Dutch government plans for the development of 3-4 GW electrolyser capacity by 2030. The Dutch strategy is novel in its focus on the inclusion of sustainable aviation fuel quotas – these should be 14% by 2030 and 100% by 2050. Subsequent to the publication of this strategy, the EC expressed intention in the Fit for 55 package to apply such quotas across the EU. A clear message from the strategy is also the importance of developing Rotterdam to be a future hub through which Europe receives imports of hydrogen or hydrogen-derived fuels. Finally, the Dutch strategy is also optimistic on the role for blending hydrogen into natural gas grids.

Portugal and Spain look to mobilise €7-9 and €9 billion respectively for hydrogen. Note the reference to 'mobilise', which implies significant private contributions, not only public funding. The Portuguese strategy sets targets for 2 to 2.5 GW electrolyser capacity in 2030, amounting to 5% of the country's final energy consumption, and 5% of energy consumption in the industrial sector. There is also a target for a 10-15% blend of hydrogen in the natural gas network. The Spanish target is for 4 GW of electrolyser capacity by 2030, as well as for 25% of renewable hydrogen in the industrial hydrogen mix.

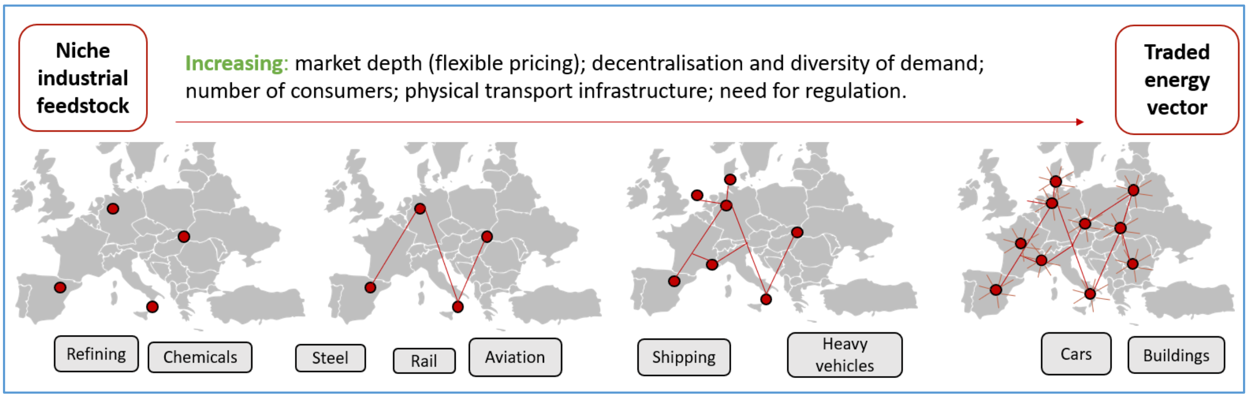
Interestingly, national plans are also keen to push some volume of hydrogen within the transport sector. France sees 20,000 to 50,000 passenger car or light commercial vehicles to be hydrogen-powered by 2028. The same number for the Netherlands is 300,000. Portugal aims for 5% hydrogen share in road transport fuel consumption.

5.5.2. A framework for thinking about hydrogen

Both the demand and supply sides of hydrogen will undergo radical transformations over the next 30 years – but the ending point for this transition is unknowable today. This uncertainty makes it challenging to formulate simple policy answers. Given existing dirty production methods for hydrogen, it is particularly difficult to consider sensible policies for pushing demand-side cases which today appear to increase carbon emissions, but may tomorrow significantly reduce them.

We propose a framework to facilitate better understanding and debate on the future role hydrogen will play in European energy systems (Figure 5-5). The framework rests on the idea that the role of hydrogen will lie somewhere between a *niche industrial feedstock* (situation today) and a widely *traded energy commodity*. One can consider a continuum between these two scenarios. Along this continuum sit all the potential demand cases for hydrogen, as well as the rationale for widely opposing views on correct public policy. Exogenous factors as well as developments within hydrogen will determine hydrogen's position.

Figure 5-5: Hydrogen market framework



Source: Authors' own illustration.

Policy should not be built with the aim of achieving a particular position on this continuum. Rather, the goal is decarbonisation and hydrogen should be pushed by markets to grow into its most efficient role. As markets develop, regulation should adapt dynamically[96].

Niche industrial feedstock is the scenario for hydrogen today (Table 5-2). It is consumed by a few concentrated and large industrial players, often being produced on-site with consumption. Hydrogen is not widely traded and the market is fragmented. Regulation is sensible and permits private investment and ownership of transport infrastructure. Little physical infrastructure for the transport of hydrogen exists. If hydrogen demand remains contained within this niche, then there is no significant need for extensive policy intervention beyond a sensible carbon price.

Within this scenario, the shift to zero-carbon hydrogen is still inevitable. There are different possibilities. If renewable (green) hydrogen dominates: *(a)* large industrial demand may relocate to sources of abundant (renewable) supply, *(b)* large industrial demand may co-locate and share the import costs for hydrogen.

Alternatively, this scenario may lend itself more naturally to methane-produced hydrogen. It would be attractive for industrial clusters to import natural gas using existing infrastructure before transforming it into hydrogen. This would allow industry to maintain current geographical positions with little need for additional hydrogen transport infrastructure.

Moving beyond this, centralised demand may emerge for hydrogen in areas beyond industrial feedstock. In steel, hydrogen can play a role as feedstock and energy. For aviation, hydrogen would need to pass through large industrial facilities (akin to oil refineries) for Fischer-Tropsch processing into e-kerosene. It would then continue its journey as liquid kerosene. For shipping, liquid hydrogen demand would be contained to large refuelling bunkers at ports. These evolutions create an energy demand for hydrogen – shifting one aspect away from the industrial feedstock world, requiring regulation to be based on energy, but they still retain quite similar geographic and market structures to hydrogen today.

The use of hydrogen for seasonal power storage is likely to provide some push toward the *traded energy vector* scenario. First, it will involve significant electrolyser deployment reducing CAPEX. Secondly, if it emerges as an effective solution, it will facilitate increased deployment of renewable power in the EU, a necessary condition for high levels of hydrogen production. Finally, the storage of hydrogen will lead to market developments. Storage may be in isolated facilities (e.g., salt caverns) in which case transmission infrastructure will be necessary from renewable deployment. Alternatively, some storage may be considered within the hydrogen transmission grid itself (linepack).

At the other end of the spectrum is a world of deep hydrogen markets and wide consumption as a ***traded energy vector*** (table 5-2)**.** This is the scenario we explore in '*hydrogen imports to fuel EU*'. Here, there are many decentralised consumers, deep transport infrastructure, and deep markets. Extensive regulation would be required, vastly different from today.

[96] The Council of European Energy Regulators (2020) highlights the need for dynamic regulation.

Table 5-2: Key market features for different hydrogen scenarios

Niche Industrial Feedstock	Traded Energy Commodity
Fragmented market based on private industrial contracts	Deep market, market driven supply-demand price setting (akin to natural gas).
Few, large & centralised consumers. Strong market power/concentration.	Many, small decentralised consumers. Weak power/concentration.
No need for deep regulation. Industrial players can be left to their private (usually bilateral) supply contracts.	Regulation of an infrastructure-based energy sector (with natural monopoly infrastructure in the value chain) needed to a) protect consumers, b) promote competition of supply = regulated infrastructure (unbundling, third-party access, regulated access tariffs).
Industry likely to co-locate and build import capabilities or relocate to source of cheap supply.	
EU might import hydrogen-derived products: ammonia/methanol/e-kerosene.	EU might import hydrogen. As well as ammonia/methanol/e-kerosene.
Little transmission infrastructure. No distribution infrastructure.	Deep transmission infrastructure. Some distribution infrastructure.
Blue hydrogen more likely.	

Source: Authors' own elaboration.

5.5.3. Market drivers

Source: Authors' own illustration.

A range of factors will determine hydrogen's position including the production cost itself. Ceteris paribus, a decrease in the cost of hydrogen production will lead to a rightward shift as the economics of infrastructure and demand cases become more attractive.

The case of production costs for competing fuels is more complicated. This is because fuels which compete on the demand-side (biofuels, natural gas, electricity) are also direct inputs for the production of hydrogen. As Figure 5-3 showed, their price is a key determinant in final hydrogen price. The final effect is therefore the sum of two opposite forces.

For *natural gas*, competition with hydrogen in 2050 will be limited to demand sectors where CCS can be applied. Therefore, the pass through of reduced costs to hydrogen will lead to greater competitiveness for many of the decentralised sectors. The political acceptance and technological maturity of CCS are essential for this to be the case. If CCS is widely acceptable and available, then while natural gas may take a larger role in industrial sectors, the ability to produce low-cost methane hydrogen will provide a push for demand in the rightward sectors.

A similar analysis can be considered for *biofuels*. A caveat is that biofuel combustion without CCS may be permissible, extending competition to decentralised sector, in the case of lifecycle carbon accounting.

For *electricity*, a reduction in average levelised cost will lead to both cheaper hydrogen and electricity. The important dynamic will be the ability for flexibility solutions to keep up with CAPEX reductions. In the case that flexible solutions on the supply and demand side develop, electricity will become increasingly competitive leaving little space for hydrogen in many of the speculative sectors. This development would reduce levelised cost of electricity, and also imply that many demand sectors are able to shift consumption to times of cheap electricity.

On the other hand, if other power flexibility solutions lag CAPEX reductions, the necessity of hydrogen will be strengthened. Hydrogen may play a large role in alleviating pressures on the power grid, and as a result facilitate increased fuel switching toward hydrogen in decentralised demand sectors.

Perhaps the most relevant competing technology on the demand-side is the lithium-ion battery. Reductions in cost, but more importantly improvements to energy density would continue to erode remaining speculative use cases for hydrogen.

5.5.4. Policy issues

The core principles of public policy addressed to hydrogen should be least-cost public support (i.e., achieving private sector buy-in) and technology neutrality. However, public policy can never be completely technology neutral and some public spending will be cost-effective. More precisely, a number of specific policy questions will need political decisions:

1. Production subsidies

The issue: Subsidies purely for the production of low-carbon hydrogen, which may be fixed cost subsidies.

Comment: Forthcoming revisions to the EU ETS will allow electrolytic hydrogen production to claim free allowances. Similarly, low carbon natural gas-based production will be eligible for free allowances. The effect of these allowances will be an implicit subsidy. This change is essential to allow fair competition with existing SMR hydrogen production.

Further production subsidies are slightly controversial, because clean hydrogen is not the end goal which is the final useful products. There is no guarantee that supporting cleaner hydrogen production will be the most sensible use of funds, given that better alternative technologies may emerge.

An important distinction must be drawn between hydrogen production and the round of subsidies which supported renewable electricity deployment in the 2000s. For renewable electricity, a guaranteed offtake market existed. That is, all renewable deployment would be absorbed immediately by existing power grids leading to certain decarbonisation benefits. For hydrogen this is not the case. Larger volumes of hydrogen demand are based on assumptions about the future, and even the existing demand would need to be incentivised to switch from currently dirty hydrogen consumption to consuming whatever clean hydrogen is subsidised.

The case for wide-reaching hydrogen demand necessitating subsidies for cheap production is not yet clear. In any case, public policy could effectively subsidise production by subsidising an ammonia plant or refinery with production on site.

2. Demand subsidies

The issue: Subsidise demand sectors to shift from processes with high carbon emissions to lower carbon emissions.

Comment: Subsidies for sectors which may consume hydrogen appear more attractive. Such subsidies need not specify the consumption of hydrogen, but can retain technological neutrality. Options such as auctioning and carbon contracts for difference allow this to be achieved (McWilliams & Zachmann, 2021).

At a later stage, quotas can also be a useful tool for shifting the burden of subsidies away from public and toward private balance sheets. The EC has already proposed quotas for sustainable fuels in aviation, which act as indirect quotes for hydrogen consumption[97]. In cases, where future clean fuel demand is clear, quotas can be a very effective tool. Agora Energiewende and Guidehouse (2021) propose that broad public subsidies between 2020 and 2030 should shift into quotas post-2030, as the relative use cases for hydrogen become clearer. In this way, the burden of subsidy is shifted onto the private sector.

3. Transmission and distribution infrastructure

The issue: Developing regulation which permits build out of an infrastructure grid able to transport hydrogen molecules across Europe without jeopardizing the Internal Energy Market principles.

Comment: The EC proposes a step-wide approach to hydrogen infrastructure which is sensible. According to this approach, hydrogen will evolve from a series of valleys with large demand and supply connections, to a more distributed resource. At each step of this evolution, the merits of infrastructure and public support should be reconsidered.

Regulatory bodies call for dynamic regulation of infrastructure (CEER, 2020). While lessons can be learned from regulation of natural gas, immediately replicating the market regulation of natural gas would be too constrictive. Instead, a sensible approach would allow hydrogen markets to evolve and monitor development. For examples, issues such as unbundling and third-party access might be postponed for discussion at a later date to first allow build out of the grid.

While funding can be expected from the private sector, industry will need clear signals and time commitments from regulatory bodies to reduce risk on capital investments.

4. Blending

The issue: Industry proposes blending hydrogen into existing natural gas grids. Technically, this appears to work. The rationale for doing so is to provide a demand for hydrogen and reduce carbon emissions associated with final gas combustion.

Comment: Blending hydrogen into existing natural gas grids is in almost all circumstances not a sensible idea. First, from a carbon emissions perspective the effects are marginal at best. In highest cases, a blend of 20% hydrogen into gas grids is possible. Hydrogen contains one-third the energy density of methane. Therefore, you can replace 7% methane energy content with hydrogen resulting in very limited carbon gains.

On the other hand, from a regulatory perspective blending of hydrogen would cause problems on the grid. The acceptable blended share varies by end-use (household, industrial appliances) and by

[97] The proposal is for a target of 63% sustainable aviation fuels as a percentage of total aviation fuel mix by 2050, available here: https://ec.europa.eu/commission/presscorner/detail/en/fs_21_3665.

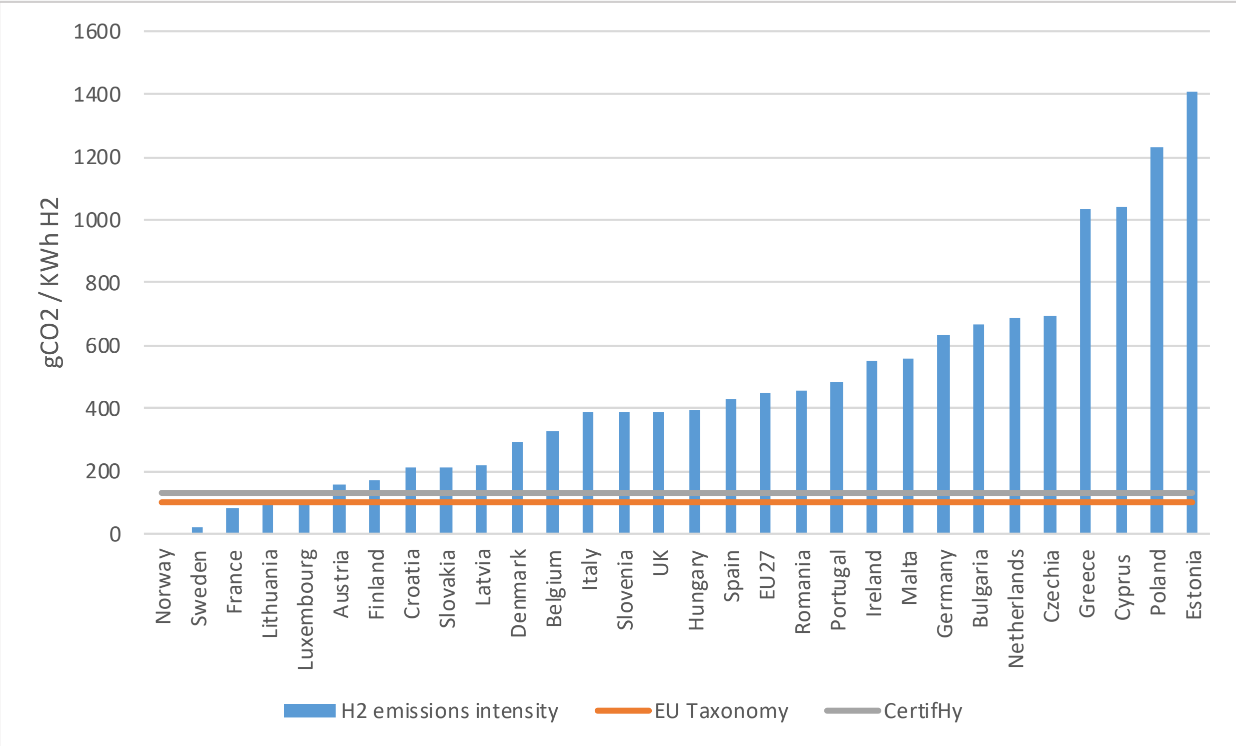
Member States. Fixed levels would need to be agreed on by all affected grid participants. Differences in opinion run the risk of fracturing the internal market for gas.

The claimed advantage is providing a guaranteed offtake for supply. It is argued that this will be essential for allowing low-carbon hydrogen production supply chains to grow. While that is certainly the case, there does not currently appear a shortage of demand for low-carbon hydrogen in Europe. Policy should aim to connect other demand cases, where hydrogen can have a larger and longer-term effect on carbon emissions, with growing supply. For example, building the first pipelines to take hydrogen from areas of attractive production to clear industrial areas of demand.

5. Sustainable taxonomy and guarantees of origin

The issue: The EC will propose a threshold for hydrogen to be eligible under the sustainable forthcoming taxonomy. The European initiative, CertifHy[98], is working to establish an EU-wide certification scheme that provides Guarantees of Origin for the carbon emissions associated with hydrogen production.

Figure 5-6: Electrolytic hydrogen from average grid intensity



Source: Data on the emissions intensity of individual country grids are provided by EEA (https://www.eea.europa.eu/data-and-maps/indicators/overview-of-the-electricity-production-3/assessment). Data for CertifHy are taken here: https://www.certifhy.eu/images/media/files/CertifHy_Presentation_19_10_2016_final_Definition_of_Premium_Hydrogen.pdf and for the EU taxonomy value from Baker McKenzie analysis here: https://www.bakermckenzie.com/en/insight/publications/2021/05/eu-taxonomy-hydrogen-industry.

Comment: If the taxonomy helps shift investment towards greener products than that is desirable. However, the tight levels should not be interpreted as the only investment point for green hydrogen production.

[98] See the European initiative website available at: https://www.certifhy.eu/.

As Figure 5-6 shows, the taxonomy excludes grid-connected investment from all but four EU countries. While we base this on average grid emissions, it should be noted that determined carbon emissions based on electricity input for grid-connected electrolysers are difficult to determine, and in principle the carbon content is more a matter of accounting than an objective value [99].

Moreover, electricity falls under the EU ETS, and hence emissions are priced into production. Any hydrogen produced from the grid will consume EU ETS allowances putting pressure on the market to reduce emissions elsewhere. With manageable annual volumes of electrolyser capacity deployed, the EU ETS and power markets should be able to absorb additional demand effectively.

For imports, the situation is different. Guarantees of origin to certify the carbon emissions of imports are likely to be necessary. The EU today imports a negligible amount of hydrogen, and the ability for industry to import hydrogen should be limited to cases only where its production meets the stringent criteria outlined under the CertifHy project. For gaseous pipeline imports it should be relatively straightforward to calculate emissions from a large point source. For liquid hydrogen-derived imports by ship, this task is likely to be more complex.

6. Additionality

The issue: Additionality is the principle that for hydrogen to count toward renewable targets, the electrolyser must not only consume renewable electricity but must also demonstrate that additional renewable capacity was brought online to match its consumption. Electrolysers can comply by building new isolated renewable plants, or through renewable power purchase agreements (PPAs). The topic has been discussed under the proposed revision to the Renewable Energy Directive, and a delegated act is expected before 31 December 2021 [100].

Comment: Under current design, the principle of additionality appears excessively restrictive toward the deployment of electrolytic hydrogen. There are a range of technological and regulatory difficulties which slow deployment of electrolysers when additionality is required. It is not immediately obvious why such requirements are necessary for electrolysers but not for electric vehicles, heat pumps, and other industrial uses.

In an unfortunate scenario, the principle of additionality will drive deployment of isolated electrolysers situated next to renewable plants. This decreases overall system efficiency as electrolysers are not able to provide valuable flexibility services to the grid. In the better case where electrolysers are able to use PPAs and stay connected to the grid, too tight criteria still unnecessarily hinder development of hydrogen across Member States. Clear advantages accrue to those Member States with the cleanest electricity mixes today. When considering that there will be some essential hydrogen demand in 2050, it would be more sensible to maintain a dynamic view of future grid emissions not a static one routed in emissions intensity today.

The argument in favour of additionality is that by consuming existing renewable generation, electrolysers force other grid participants to consume average emission electricity. Therefore, without additionality, electrolysers should be considered to consume average grid emissions. While in the short term this may be true, electrolysers are likely to stimulate additional demand for renewable deployment when they are sensibly integrated into grids.

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[99] Three very different values can be used for each hour in which the electrolyser was used: cleanest power plant; average power plant; dirtiest power plant or last (marginal) power plant required to meet the demand. In the short-term, the last option seems most plausible, but in the longer term, additional demand from electrolysis might be met be increasing supply, potentially from renewable sources.

[100] See the Directive (EU) 2018/2001 of 11 December 2018 on the promotion of the use of energy from renewable sources (recast), Art. 27, page 47, https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32018L2001&from=EN.

We argue that the implementation of additionality criteria should be paused for a few years. The deployment of electrolysers is still in its infancy, and will not significantly add to carbon emissions over the next couple of years even if average grid intensity is used. The pace of electricity decarbonisation has been rapid and should continue. The Commission should continue to monitor the situation and be ready to intervene on the basis of clear criteria in cases where electrolyser deployment appears to be slowing grid decarbonisation.

7. Geopolitics

The issue: The future of hydrogen will be determined as much by political as economic factors. Particularly for imports, political decisions will be key in driving future trading patterns.

Comment: It is likely that by 2030, the EU will import the first gaseous hydrogen by pipeline. By 2050, it is quite plausible that the EU will import significant volumes of hydrogen. Decisions taken regarding the build-out of pipelines are likely to be as much political as they are economic in nature.

Today, Germany appears to have the most advanced thinking on this front[101].

The EU should be careful to maintain a unified approach to this decision process, and not one that Germany is able to control alone. Independent advice, outside of political influence, will be essential for the EU to redesign its map of energy imports.

8. Overarching climate policy

The issue: A comprehensive climate policy which is conducive to the growth of hydrogen.

Comment: Policy for hydrogen will not be made in a vacuum. Overarching climate policy will ultimately be the largest influence:

- Deploying large volumes of renewables, and driving their costs down is likely to be the best public policy for hydrogen growth; and
- Carbon pricing must remain the cornerstone. Everything else should only be built around it.

[101] The German and Ukraine energy partnership discusses hydrogen, see: (https://www.bmwi.de/Redaktion/EN/Pressemitteilungen/2020/20200826-germany-and-ukraine-to-agree-energy-partnership.html) and a Memorandum of Understanding has been signed with Saudi Arabia for cooperation on hydrogen projects, available at: (https://www.bmwi.de/Redaktion/EN/Pressemitteilungen/2021/03/20210311-altmaier-signs-memorandum-of-understanding-on-german-saudi-hydrogen-cooperation.html).

6. ASSESSMENT OF DIFFERENT DEVELOPMENT PATHWAYS

6.1. Methodology[102]

To illustrate and compare different development pathways we consider a stylised energy system. We base our analysis on the MIX55 scenario developed by the JRC. Our three scenarios correspond with the general trends (especially in terms of energy service consumption) assumed in this scenario. That is, our scenarios differ in terms of the contributions of electricity, hydrogen and green gasses to meet the same energy service demand. Because of the lack of published information, this requires some triangulation.

We first assess the demand for useful energy implied by JRC. This is the useful energy output of an energy appliance, while final energy consumption (FEC) is the input of energy into an appliance (e.g., methane into a boiler). Useful and final energy vary substantially depending on the technology and sector. As useful energy demand is not directly reported by the JRC, we deduce it from the reported FEC and the simplified sectoral conversion factors from final energy (e.g., kWh of electricity delivered to a house) to useful energy (e.g., kWh of heat provided by the heating in this house).

Based on these figures, we impose fuel switches per sector and application, and determine the corresponding FEC per fuel and application. Here, differences in the thermal efficiencies of fuel-specific technologies result in different FEC by fuel and sector. The approach guarantees that the sectoral final demand services, provided by different applications (heating, mechanical energy, lightning, ICT), are identical between scenarios.

Our scenarios report final consumption for the industry, buildings and transport sectors. Aviation and maritime bunkers are reported separately, as is demand in non-energy sectors and inputs to the energy sector. The energy sector comprises electricity generation as well as hydrogen and synthetic hydrocarbons production. Hydrogen and synthetic hydrocarbon demand are the sum of sectoral demand for these fuels plus transport and storage losses. The latter are significant, as we assume that hydrogen covers the inter-seasonal electricity storage needs in 2050, and assume leakage losses of 20% for hydrogen along the whole value chain. The reported numbers in the energy sector are to be interpreted as demand for power storage in the form of hydrogen or synthetic hydrocarbons.

The required production of hydrogen and synthetic hydrocarbons within the EU is defined as the difference between final demand and assumed import shares in 2030 and 2050. From this, the required electricity for hydrogen and synthetic hydrocarbons is determined. Total electricity production in 2030 and 2050 is then set to meet sectoral electricity consumption, electricity consumption from aviation/maritime, and the generation of hydrogen and synthetic hydrocarbons.

All three scenarios differ in their required electricity generation. To improve comparability across scenarios, we assume that generation by all sources but renewables (wind, solar, biofuels and geothermal) is equal for all scenarios. We base the generation of those constant sources on the fuel consumption figures provided by JRC and consider typical transformation efficiencies for deducing the electricity provision by fuel.

Investments in new capacities result from the difference in installed capacities in 2020 and 2030, and 2050 respectively. We assume additionally that 20% of existing capacities in 2020 have to be replaced by new units by 2030 and that 80% of all capacities in operation in 2030 have to be replaced by new units between 2030 and 2050.

[102] More details on the methodology are provided in appendix A3.

6.2. Hydrogen

6.2.1. Downstream

Assumptions on the demand met by hydrogen vary across scenarios. Only for non-energy demand, and replacing coal as reducing agent, are hydrogen assumptions fixed. We assume that the use of hydrogen in the steel sector is identical in all scenarios. In 2030 around 20% of the 2050 demand for hydrogen in this sector is reached.

a. Volumes and Capacities

We assume that hydrogen will provide a significant share of overall fuel demand only in the *hydrogen imports* scenario after 2030. While the hydrogen share of total sectoral fuel consumption is approximately 20% in 2050 in this scenario, its share in the other two is below 7%. In 2030, significant hydrogen demand is only present in the *hydrogen imports* scenario. As hydrogen involves the build-out of new systems, it is to be expected that significant demand will develop only in the later periods.

Table 6-1: Hydrogen consumption 2030 & 2050 by scenario (rounded, in TWh)

Hydrogen consumption (TWh)						
	2030			**2050**		
Scenario	All-electric world	Hydrogen imports	Green gases	All-electric world	Hydrogen imports	Green gases
Industry	0	40		30	400	
Buildings		90		50	600	60
Transport	10	100	10	30	400	30
FEC	10	230	10	110	1,400	90
Non-energy use	60	70	60	300	300	300
Aviation & maritime		200	80	100	300	100
Energy sector			0	400	300	0
Synthetic methane generation			700	300	200	1,900
Total	**70**	**500**	**850**	**1,200**	**2,500**	**2,400**

Source: Authors' own calculation.

In fact, sectoral demands for hydrogen are around ten times greater in the *hydrogen imports* scenario than they are in the other two scenarios for 2031-2050. The fact that synthetic gases are derived from hydrogen explains the result that hydrogen demand is almost as high in the *green gases* scenario as in the *hydrogen imports* scenario itself. For the production of synthetic gases, 1,900 TWh of hydrogen is required.

We assume that hydrogen is used for inter-seasonal storage, whereby the total storage needs depend on total electricity consumption. Only in the *green gases* scenario do we assume that storage takes place through (imported) synthetic hydrocarbons, and see zero hydrogen demand.

Hydrogen demands for non-energy are assumed constant (at 300 TWh) across all three scenarios, implying that there will be a significant baseline demand for hydrogen.

6.2.2. Mid & upstream

a. Volumes and capacities

We assume an increase of hydrogen imports (in absolute and relative terms) from 2030 to 2050. In 2030, 25% of hydrogen demand in the EU is imported while by 2050, 80% of hydrogen demand is met by imports.

In all scenarios, substantial investments in electrolyser capacity are required, ranging from 400 to 800 GW. In the *all-electric world* scenario, there is a large demand for electrolysers not because of final sectoral hydrogen demand but because of the need for electrolysers to complement the increased share of renewables in power generation, via power storage. In the *hydrogen imports* scenario, electrolyser capacity is actually lower than in the other scenarios because of the heavy import assumption.

Table 6-2: Hydrogen consumption/ generation 2030 & 2050 (rounded, in TWh / GW)

Hydrogen consumption & generation (TWh)						
	2030			**2050**		
Scenario	All-electric world	Hydrogen imports	Green gases	All-electric world	Hydrogen imports	Green gases
Total demand	70	500	850	1,200	2,500	2,400
Total demand incl. losses	90	570	860	1,400	3,100	2,500
Import share	0%	25%	0%	25%	80%	50%
Domestic generation	90	430	860	1,100	600	1,200
Electrolyser (GW)	60	290	580	700	400	800

Source: Authors' own calculation.

b. CAPEX and OPEX

Assuming a decline in electrolyser installation costs from €750/kW in 2030 to €450/kW in 2050, and grid costs of €10 billion to €50 billion, the development of the hydrogen generation and infrastructure requires investments of up to €1,000 billion between 2031 and 2050 (Table 6-3).

In the *all-electric world* scenario, investments in electrolysers are pushed back to the 2031-2050 period as they become necessary only with high levels of renewables in power generation.

These factors cause significant differences in annual average investments for the next decade (Table 6.3). For the latter period (2031-2050) annual average investments are quite similar. In the non-hydrogen scenarios, the investment needs are dominated by electrolysers while in the *hydrogen imports* scenario considerable investment is required to build out a hydrogen infrastructure for transport of hydrogen across the EU to end-users, particularly with needs on the distribution side.

Table 6-3: Hydrogen generation & infrastructure investments 2021-2030 & 2031-2050

Hydrogen generation & infrastructure investments & import costs (EUR bn)						
	2030			**2050**		
Scenario	All-electric world	Hydrogen imports	Green gases	All-electric world	Hydrogen imports	Green gases
Power plants for hydrogen generation	40	170	400	560	300	630
Electrolyser	45	220	440	325	185	380
Hydrogen grid	10	50	15	50	145	30
Total	**95**	**440**	**855**	**935**	**630**	**1,040**
Average investments	10	45	85	45	30	50
Average annual hydrogen import costs	0	8	0	15	110	55

Source: Authors' own calculation. All investments and costs are depicted in 2020 €.

Assuming imports of green hydrogen, generated non-domestically by wind and solar sources, and a foreign capital cost of 8%, hydrogen import costs will decline to €80/MWh in 2050. The total average import costs for hydrogen in 2050 will be in the same order as the domestically generated hydrogen investment expenditures (generation and grid infrastructure).

The *hydrogen imports* scenario sees considerable annual expenditure of €110 billion on imports. In this scenario, the EU would be vulnerable to price levels of hydrogen imports.

Our estimates are based on the assumption that the EU will have access to substantial hydrogen imports at €80/MWh which appears reasonable, but is not certain.

6.3. Methane

6.3.1. Downstream

For hydrogen and electricity, it is understood that demand might grow from low-carbon niches, for example, electric heating or hydrogen consumption in industry. This would require commercial maturity to be displayed and the roll-out of accompanying infrastructure. For synthetic methane, the situation is different. The market for the product exists already, and the economic questions revolve around the supply side.

In the *green gases* scenario, for 2050 we assume that synthetic hydrocarbons provide 30% of FEC, roughly the same share as that provided by electricity. Up to 2030 the share may rise to 7% of FEC. In both of the other scenarios, no synthetic gases are present in FEC by 2030, while by 2050 they see 300 TWh synthetic hydrocarbon demand, primarily in industry.

We assume imported synthetic hydrocarbons are used in the energy sector for inter-seasonal storage.

a. Volumes and capacities

Table 6-4: Synthetic hydrocarbons consumption 2030 & 2050 (rounded, in TWh)

Synthetic hydrocarbons consumption (TWh)						
	2030			2050		
Scenario	All-electric world	Hydrogen imports	Green gases	All-electric world	Hydrogen imports	Green gases
Industry			90	200	200	700
Buildings			500			1,300
Transport						300
FEC			590	200	200	2,300
Non-energy use			70	100	100	200
Aviation & maritime bunkers			60			400
Energy sector						330
Total			**720**	**300**	**300**	**3,200**
Import share			25%	25%	50%	50%

Source: Authors' own calculation.

6.3.2. Mid- & upstream

We assume synthetic hydrocarbon import costs identical to those of hydrogen. While import and domestic production costs will be substantial, infrastructure investments will be limited as existing pipelines can be used.

a. Volumes and capacities

We assume that synthetic hydrocarbons are produced from hydrogen. The required hydrogen generation for domestic synthetic hydrocarbons production is included in the hydrogen figures in section 6.2.

In the *green gases* scenario, average annual import costs are €175 billion, assuming a cost of around 160 EUR/MWh for synthetic methane imports. Similarly, to the *hydrogen imports* scenario, this places the EU again in a vulnerable position on world markets.

Table 6-5: Synthetic hydrocarbons import costs (rounded, in € bn)

Synthetic hydrocarbons import costs (€ bn)						
	2030			**2050**		
Scenario	All-electric world	Hydrogen imports	Green gases	All-electric world	Hydrogen imports	Green gases
Synthetic hydrocarbons import costs	0	0	250	140	355	3,500
Average annual import costs	0	0	25	10	20	175

Source: Authors' own calculation. All investments and costs are depicted in 2020 €.

6.4. Electricity

6.4.1. Downstream

Electricity replaces fossil fuels mainly in the transport sector and in heating applications (process, space, and water heating). In heating applications, electricity can either be used directly, or electricity is applied in a heat-pump to bring ambient heat to warm houses. While the thermal efficiency of direct use is slightly below 100%, in a heat pump one kilowatt-hour of electricity can provide about three kilowatt-hours of useful heat. Thus, total FEC declines significantly if fossil fuels[103] can be replaced by ambient heating applications. In transport, the efficiency of electric vehicles is three times that of conventional, fossil fuel-based combustion vehicles. The greater efficiencies of electricity result in lower FEC, the larger the share of direct electrification.

[103] For example, a natural gas boiler has a thermal energy efficiency of around 90%.

a. Volumes and capacities

The clear theme is the inevitability of significant electrification. Even in our purposefully extreme scenarios, final sectoral demands for electricity increases in every sector and scenario. Compared to 2019 (2,500 TWh), the FEC of electricity in the *all-electric world* scenario will increase by 30% by 2030 and 130% by 2050. *Hydrogen imports* sees the lowest electricity demands, which are still a 30% increase by 2030 and 70% by 2050, relative to 2019 levels.

In *all-electric world,* electricity is largely used directly in demand sectors. In the other two scenarios, electricity is additionally required for the generation of hydrogen. While the FEC of electricity in *all-electric world* is the highest, total electricity demand (including energy sector) is actually higher in the *green gases* scenario owing to energy needs in hydrogen production. In total, electricity demand is quite similar across all three scenarios because of this factor. In case the high levels of imports which we assume for hydrogen and synthetic methane do not materialise, energy demand for electricity in those scenarios would be substantially higher.

Only in *all-electric world* does electricity play a role in the aviation and maritime sectors. The additional demand is not dramatic in the overall picture.

Table 6-6: Electricity consumption 2030 & 2050 by scenario (rounded, in TWh)

Electricity consumption (TWh)						
	2030			**2050**		
Scenario	All-electric world	Hydrogen imports	Green gases	All-electric world	Hydrogen imports	Green gases
Industry	1,300	1,100	1,100	1,700	1,400	1,300
Buildings	1,600	1,500	1,500	1,600	1,500	1,300
Transport	300	100	300	800	500	700
FEC	3,200	2,700	2,900	4,100	3,400	3,300
Aviation & maritime bunkers	10			200		
Energy sector	100	600	1,200	1,400	800	1,700
Total	**3,310**	**3,300**	**4,100**	**5,700**	**4,200**	**5,000**

Source: Authors' own calculation.

6.4.2. Mid- & upstream

a. Volumes and capacities

We follow the break-down of conventionally generated electricity per generation type described in JRC for 2030 and 2050. We assume further that additionally required electricity is generated from renewable sources (wind, solar and biomass). We calibrate the increase of RES-capacities considering the relative share by source provided in the MIX50 Impact Assessment analysis. For the share of wind generation by offshore and onshore, we follow the Impact Assessment results for the MIX50 scenario 2020. The scenario sees 80% share of wind generation being offshore in 2030, and 66% in 2050, with onshore providing the remaining generation.

This electricity fuel mix is not to be interpreted as an optimal pathway. Rather nuclear, other RES and fossil fuels follow fixed trajectories, while wind and solar are varied to meet final demand for electricity. More complex modelling would be required to determine optimal shares of power generation output.

Table 6-7: Electricity generation 2030 & 2050 (rounded, in TWh)

Electricity generation - output - (TWh)						
	2030			**2050**		
Scenario	All-electric world	Hydrogen imports	Green gases	All-electric world	Hydrogen imports	Green gases
Wind	1,700	1,500	2,100	3,900	2,700	3,200
Solar	660	610	840	1,350	940	1,100
Other RES	480	480	480	700	700	700
Natural gas	320	320	320	0	0	0
Coal	180	180	180	0	0	0
Nuclear	520	520	520	520	520	520
Total	**3,900**	**3,600**	**4,400**	**6,500**	**4,900**	**5,500**

Source: Authors' own calculation.

b. CAPEX and OPEX

Average annual electricity investments range between €140 and €200 billion from 2020 to 2030. From 2031 to 2050, the same range is €130–€180 billion. This implies a significant frontloading of investment in renewable electricity capacity.

Assuming a replacement of 20% of the capacities in place in 2020, by 2030 around 1,000 GW of new RES capacities have to be installed in the *all-electric world* and the *hydrogen imports* scenarios. Because of higher total electricity generation, the new installations in the *green gases* 2030 scenario sum up to

1,400 GW. By 2050 – assuming 80% replacement of 2030 capacities due to obsolescence – between 2,500 GW and 2,700 GW of new RES capacities will have to be installed.

To determine the investment needed for the development of new generation capacities we follow assumptions provided by E3Modelling, Ecofys and Tractebel 2018 [104]. We assume that grid extension takes place linearly depending on the additional final consumption of electricity – for 2030 compared to 2020 and for 2050 compared to 2030. We assume additional investments of €100 per additional MW of final electricity consumption for grid expansion.

While investment needs for the development of generation capacities in the *green gases* scenario are the highest, the transmission and distribution investments in the *all-electric world* scenario exceeds that of the other scenarios by a factor of two up to 2030, and 0.5 up to 2050.

Table 6-8: Electricity generation & infrastructure investments 2021-2030 & 2031 – 2050 (rounded, in € bn)

Electricity generation & infrastructure investments (€ bn)						
	2030			2050		
Scenario	All-electric world	Hydrogen imports	Green gases	All-electric world	Hydrogen imports	Green gases
Power plants	1,180	1,090	1,505	2,555	1,860	2,095
Electricity grid	845	355	525	1,040	730	390
Total	**2,000**	**1,400**	**2,000**	**3,600**	**2,600**	**2,500**
Average investments	**200**	**140**	**200**	**180**	**130**	**130**

Source: Authors' own calculation. All investments and costs are depicted in 2020 €.

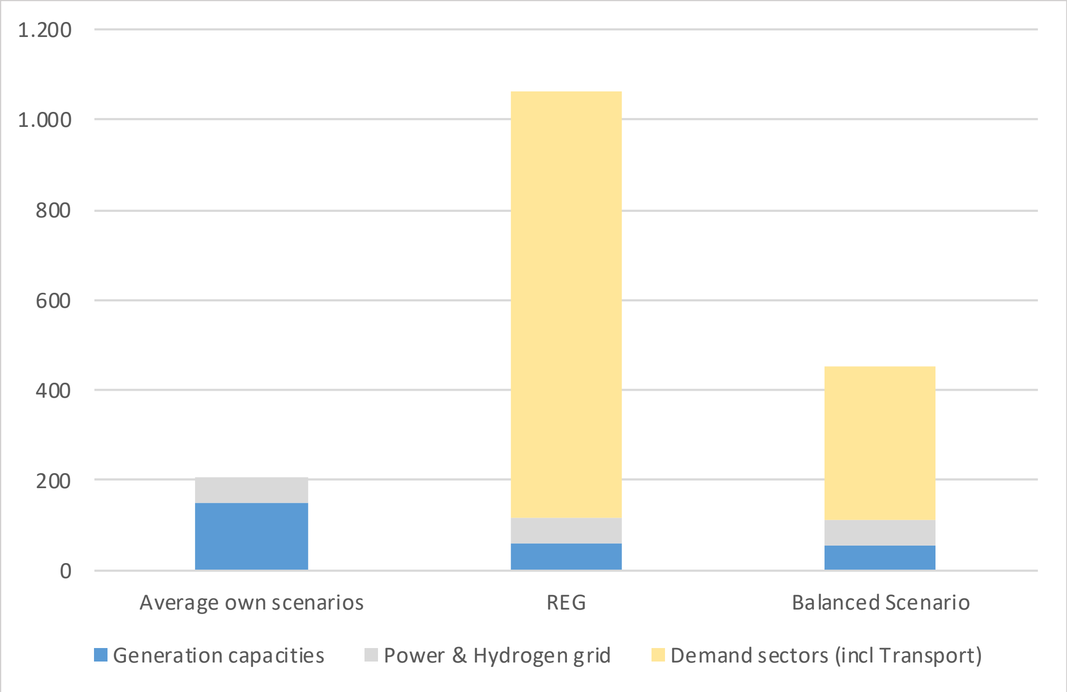
6.5. User-side investments

In our modelling, we were not able to account for user-side investments because of the underlying complexity. Cost differences between technologies at the user side are very difficult to predict, largely because we do not know the gradients of learning curves – in other words, how quickly prices will decrease with deployment. In each scenario with greater deployment of a certain technology, one would expect endogenously-driven cost savings.

Nonetheless, demand-side investments are very important. In fact, their requirements appear to dominate supply-side/infrastructure investments by a factor of 5:1. That is, for every €1 spent on decarbonising the supply-side, €5 must be spent on new demand-side equipment. These considerable sums must largely come from the private sector and households. It is very important that clear, early policy signals are provided to steer these investments.

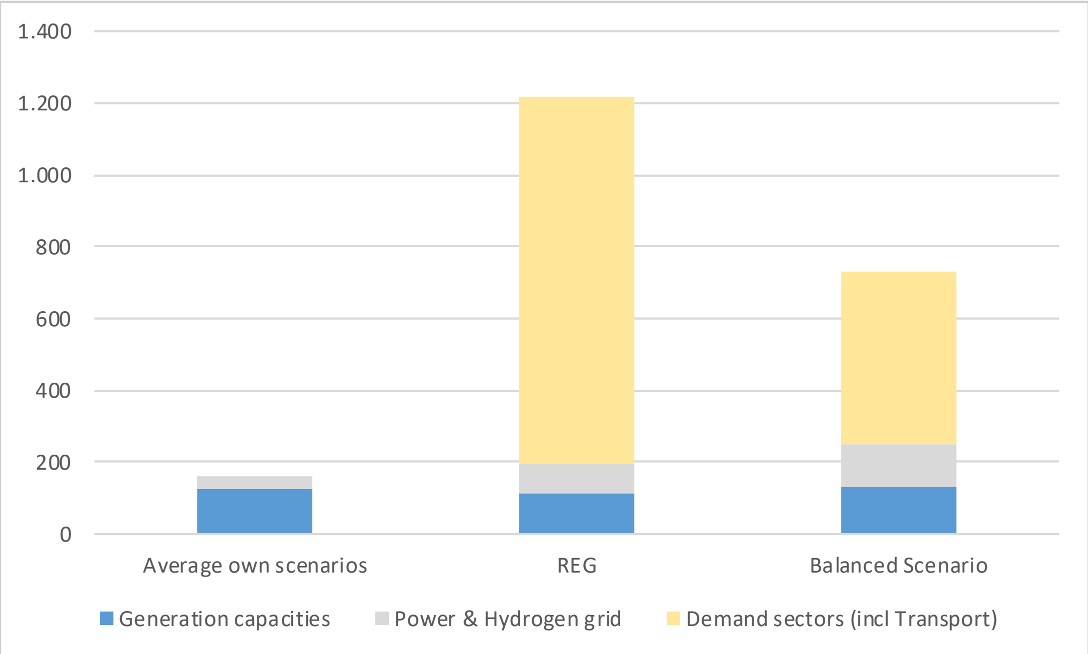
[104] Technology pathways in decarbonisation scenarios, available at: https://ec.europa.eu/energy/sites/ener/files/documents/2018_06_27_technology_pathways_-_finalreportmain2.pdf.

Figure 6-1: Average annual investments (€ bn, supply & demand sectors) 2021-2030



Source: Authors' own elaboration. All investments and costs are depicted in billions of 2020 €.

Figure 6-2: Average annual investments (€ bn, supply & demand sectors) 2031-2050



Source: Authors' own elaboration

Note: REG scenario from EC Impact Assessment Sep. 2020; Balanced scenario: Evangelopoulou et al (2019). All investments and costs are depicted in billions of 2020 €.

6.6. Comparison of scenarios

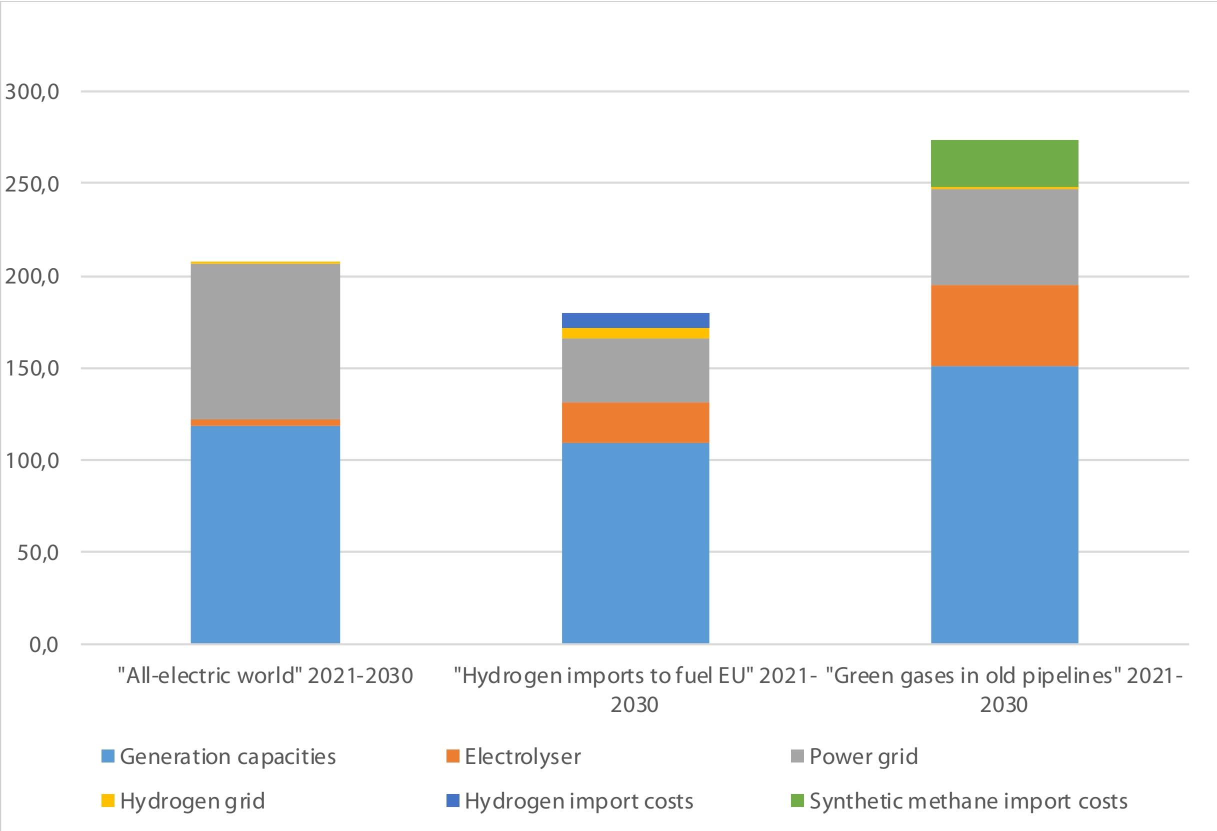
In Figures 6-3 and 6-4 we compare annual average investments required and fuel import costs across our three scenarios. The largest portion of investment is required for building out power-generation capacities – more than 50% of investment needs in all scenarios and across all time periods. The exact requirements differ by up to 30% in the period to 2030, and by up to 10% in the period to 2050. In both cases, the largest expenditures are required in *green gases*.

Electrolyser investments are highest in the *green gases* scenario, but stay below 20% of the investment cost of electricity generation capacities.

Electricity grid investments are highest in the *all-electric world* scenario, owing to larger direct electricity demand. Hydrogen and synthetic hydrocarbons import costs are a significant cost component in the *hydrogen imports* and *green gases* scenarios, at around one-quarter of annual costs.

Total system costs[105] range between €180 billion and €270 billion up to 2030, and €220 billion and €370 billion for 2030-2050.

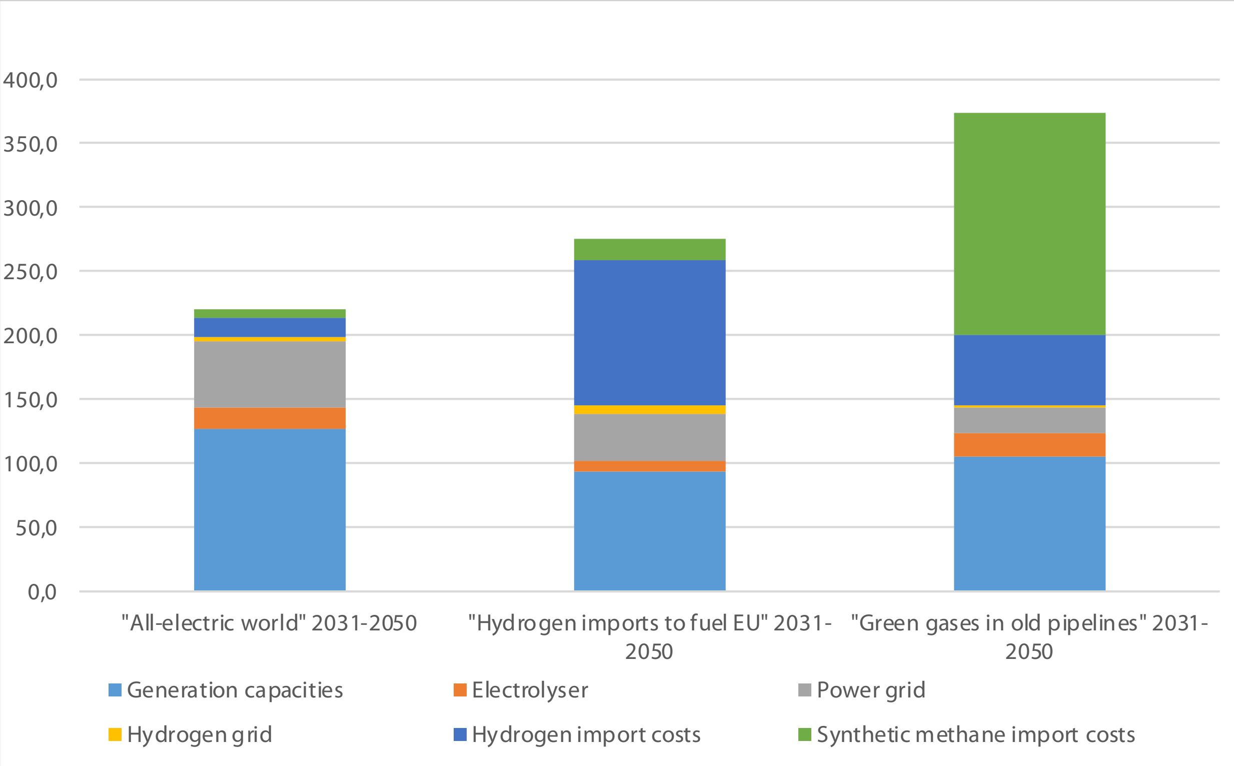
Figure 6-3: Average annual investments and fuel import costs



Source: Authors' own calculation. All investments and costs are depicted in billions of 2020 €.

[105] Excluding fossil fuel costs and reinvestment needs in nuclear and hydro capacities.

Figure 6-4: Average annual investments and fuel import costs



Source: Authors' own calculation. All investments and costs are depicted in billions of 2020 €.

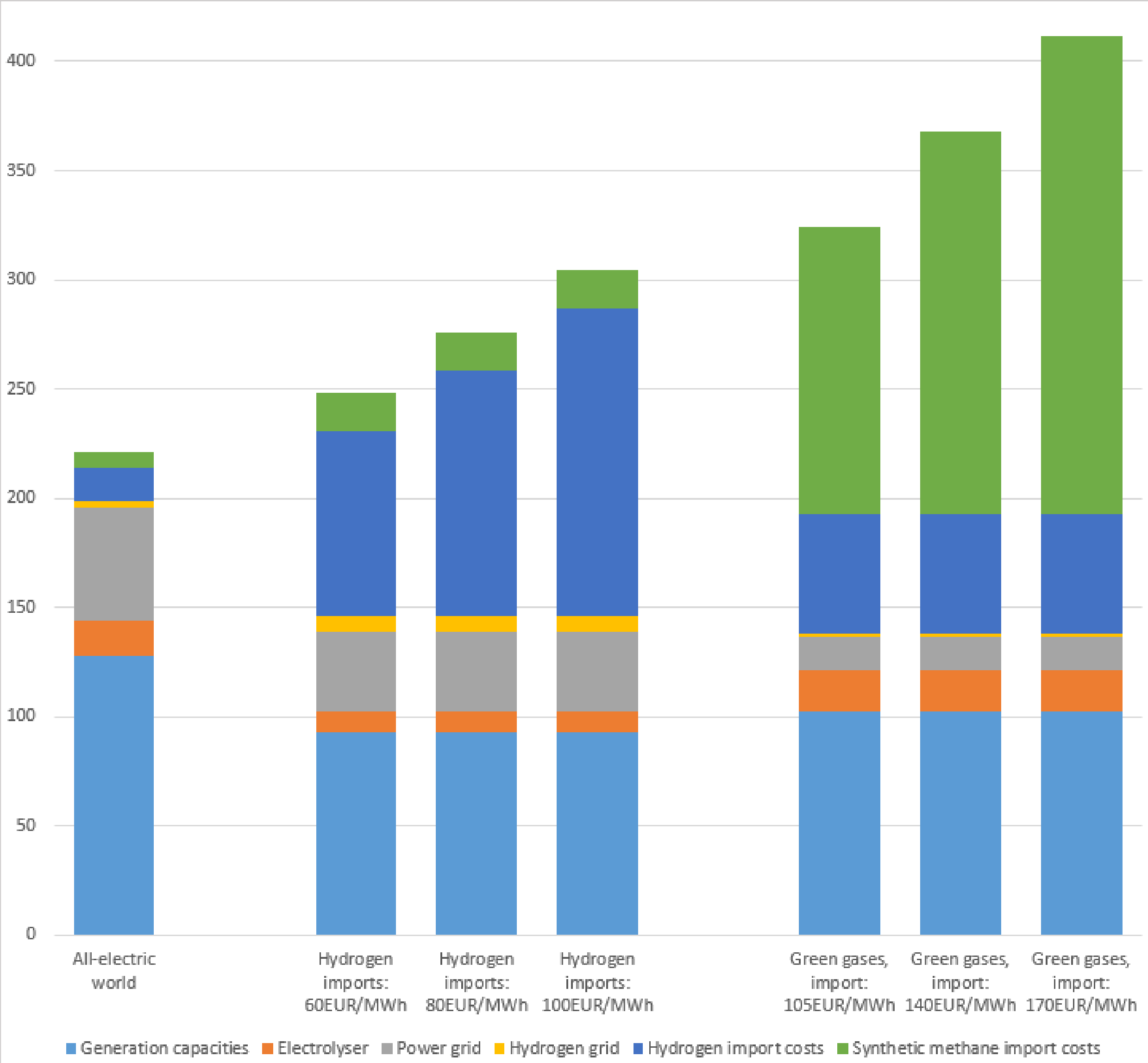
Finally, large shares of the costs of the *hydrogen imports* and *green gases* scenario are driven by import costs. We therefore also present results exploring (+/- 25%) changes to the price of hydrogen and synthetic methane imports, in the two scenarios respectively. This would imply lower bound hydrogen import costs of 60 EUR/MWh, and upper bound 120 EUR/MWh. The respective costs for synthetic methane imports would be 120 EUR/MWh and 200 EUR/MWh. We present these results in Figure 6-5. It is clear that both scenarios are highly vulnerable to changes in import costs.

Table 6-9: Average annual investments and fuel import costs (€ bn)

Average annual investments and fuel import costs (bn EUR)						
	2030			2050		
Scenario	All-electric world	Hydrogen imports	Green Gases	All-electric world	Hydrogen Imports	Green Gases
Generation capacities	120	110	150	130	95	105
Electrolyser	5	20	40	15	10	20
Power grid	85	35	55	50	35	15
Hydrogen grid	1	5	2	3	7	2
Hydrogen import costs	0	8	0	15	115	55
Synthetic methane import costs	0	0	25	7	20	175
Total	**210**	**180**	**270**	**220**	**280**	**375**

Source: Authors' own calculation. All investments and costs are depicted in 2020 €.

Figure 6-5: Annual system costs sensitivity to import prices



Source: Authors' own calculation. All investments and costs are depicted in billions of 2020 €.

7. RECOMMENDATIONS

Decarbonisation of the energy system will require a massive transformation in the way energy is provided, transported and used. Views diverge on what the system should or will look like in 2050. The EU has set a target of carbon neutrality by 2050, but uncertainty on the pathway is present at many levels.

First, it is unclear what Europe will look like in 2050 in terms of demographics, politics, economy, technology and climate. These largely exogenous factors will have a strong impact on European demand for energy services and the ability of Europeans to pay for them. Many modelling studies, including the JRC, do not feature dramatic external changes in the main scenarios.

Second, the pathway will depend on the balance of capital and effort invested in reducing demand for energy services (e.g., through better home insulation, increased longevity of products or measures to reduce transport demand) and the capital and effort invested in providing low-carbon alternatives, such as heat pumps and electric vehicles, to current fossil-fuelled energy supplies. The JRC is expecting that it will be optimal to drastically reduce heating energy demand (about -40% heating-related final energy consumption in buildings by 2050 compared to today [106]), while investing substantially in fuel switching and clean electricity generation [107]. The optimal balance is sensitive to assumptions: it will certainly depend on changes in borrowing costs for the supply of clean energy (relatively low as backed by large companies) and the borrowing cost households will face when investing in energy efficiency (likely higher, especially as some face credit constraints), but also many other factors.

Third, the pathway will depend on the development of the mix of clean fuels. There is consensus that electricity will play a major role in many energy service applications. But for a substantial fraction of the energy market, methane and hydrogen might be suitable alternatives. We have assessed three different scenarios for how this mix might evolve. In practice, the mix will be determined by the development of sectoral energy demand (see first and second drivers, above) and several specific factors including relative cost developments, acceptability, incumbent interest, system effects and market structure, which are often different across sectors, countries and regions.

Finally, the pathway will – for each fuel – depend on the development of the composition of the supply system. Electricity might be imported, produced from nuclear or different types of renewables, from centralised or decentralised sources. Flexibility and back-up might be secured through batteries, demand-response, hydrogen, hydro-storage or geographical averaging. There are also very different possible system configurations for hydrogen and methane supply systems.

Given the multiple uncertainties, it would be imprudent to hardwire one energy system development path. The development pathway must be adjusted in response to new information on the above-outlined factors. And betting on just one silver bullet is not a resilient strategy. Moreover, technical feasibility and cost minimisation (which, as we have argued, cannot be determined because of basic uncertainties) are not the only criteria for an optimal development path. Other factors including broader economic implications (e.g., on international trade or domestic value chains), distributional effects on Member States, regions, and people, public acceptance considerations (e.g., in relation to power lines, nuclear power or CCS), and environmental impacts will have to be part of political considerations. For example, investment requirements would fall on very different stakeholders in our three scenarios.

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[106] Own calculations based on JRC.

[107] See https://visitors-centre.jrc.ec.europa.eu/tools/energy_scenarios/app.html#today:EU27/2050-ff55-mix-eu:EU27 for an overview of JRC assumptions.

If electricity or hydrogen are used for private transportation and heating, end users would have to make a lot of additional investments, while initially, additional costs for households in a scenario that foresees high shares of synthetic fuels would be rather low. The same would be true on the network side, with hydrogen and electricity infrastructure investment needs larger than those in already oversized gas networks. Reduced final-user investment costs will, however, come at substantial import cost in the *hydrogen imports* and *green gases* scenarios.

Our four main recommendations are:

- Ensure the uncontroversial parts of the solution are effectively and efficiently deployed (section 7.1.1);
- Forcefully explore the best way to meet energy service needs in the residual areas, accepting failures (section 7.1.2);
- Actively learn on the way (section 7.1.3); and
- Devise concrete polices to make it happen (see 7.2).

7.1.1. Ensure the uncontroversial parts of the solution are effectively and efficiently deployed

While a minimum cost energy system is impossible to determine (because too many driving factors are uncertain) we are sufficiently confident on a number of plausible solutions.

First, the efficiency of direct electrification in transport and heating implies that wherever it is not prevented by excessive infrastructure costs, electric solutions are always preferable. Public policy should thus ensure that new investments are directed towards electric solutions, and not into any hybrid/bridge technologies that do not pass the carbon-neutrality test. Our results indicate increased final electrification reduces system costs.

Second, electrification of transport and heating, and also any production of hydrogen or synthetic fuels in Europe, will require a massive build-out of renewable electricity generation. In our scenarios, clean electricity demand would increase from less than 2,500 TWh to more than 5,000 TWh in one, and more than 6,500 TWh in two scenarios. Accordingly, installing too much renewable generation capacity will be almost impossible.

Third, as a general rule there should be no investments in fossil-fuel production, transmission or utilisation, as most would have to be decommissioned after a short period within the next few decades. Investments in such assets should only be accepted in exceptional circumstances where no alternative is available and the project logic is clearly compatible with the climate-neutrality target. Such projects should be made ineligible for public financial support. This would apply not only to coal-fired power plants or combined cycle gas turbines, but also to natural gas pipelines and R&D into most combustion engines. Moreover, our results indicate that 'half-solutions' (blending, most synthetic gases, combined cycle turbine) are often not justified on pure cost-efficiency grounds.

Fourth, it is clear that the current member-state national plans – expressed in NECPs – are insufficient to achieve a cost-efficient pathway to EU-wide climate neutrality by 2050. Consequently, a strong commitment framework is needed to ensure that Member States' policies come into line with EU targets.

Fifth, most of the investment in decarbonisation will have to come from end-users changing their appliances; user-side investments outweigh supply-side investments by five to one. Final users need very clear signals on the direction of travel, and quickly. Hence, 2021-2030 should be the decade of infrastructure investments.

While those cost relatively little, they form an implicit commitment from European society that cleaner appliances (e.g., electric vehicles or heat pumps) will be a future-proof investments for end users.

7.1.2. Forcefully explore the best way to meet energy service needs in the residual areas, accepting failures

The above principles are insufficient to ensure the decarbonisation of Europe's energy system. Hard-to-abate sectors in industry, heavy transport, aviation and renewable energy droughts in winter all pose challenges that cannot be solved by 'uncontroversial' solutions. It is likely that hydrogen and synthetic fuels will be useful to solve some of these issues. Energy efficiency investments will also be crucial. But we cannot yet predict an optimal mix.

However, we do not have the time to wait until a clear winner emerges. Moreover, system and learning effects that bring down the cost of technologies as they are deployed make it impossible to perfectly assess the potential of different solutions *ex ante*. Courageous deployment of different solutions will thus be necessary, knowing that some will turn out to be dead-ends in hindsight. Accordingly, policies should leave room for numerous and sufficiently sizeable regulatory[108] and technology experimentation at scale – Europe with its size and different Member States offers very fertile ground for this [109]. But it is as important to test many different solutions in parallel, so the unfit solutions are identified and eliminated.

7.1.3. Actively learn on the way

Europe plans to conduct a massive experiment in changing the energy mix at an unprecedented speed. Every year, some €500 billion (demand and supply-side investments, except transport) – or 2.5% of GDP – needs to be invested into enabling this new energy world (largely instead of current import costs and investments in fossil fuels).

But our understanding of the economic, technical and policy requirements to make this happen remains limited. The EC has with the JRC and Primes [110] provided comprehensive analysis of the transition, and many individual publicly funded research projects have built a basis for analysis. But much (often already existing) crucial information on the current energy system and on the assumptions underlying policy plans is not accessible. Making this highly complex information available only to a few ministries will not facilitate the societal discussion that is needed to determine politically acceptable solutions for the energy transition. Currently, the EU has no appropriate knowledge infrastructure to collect, structure and ensure the quality of available energy-sector data and makes it publicly accessible. To get there, the EU could seek inspiration from international examples:

- The US funds the Energy Information Administration that makes a lot of energy data, as well as its modelling system, publicly available;
- In the IPCC, the UNFCCC has created an institution that structures the relevant scientific literature and puts individual findings into perspective; and
- The International Energy Agency publishes reviewed data and reports for OECD countries.

[108] This might, for example, include deviations from unbundling principles or state-aid derogations for well-designed, regulatory experiments that are clearly limited in time, sector and space.

[109] In this respect, the EU can act – at national and/or regional level – as an insurance pool, able to provide compensation for stranded assets in single regions. At the same time, the EU as a whole will benefit from regional/national learning effects.

[110] The PRIMES model is an EU energy system model which simulates energy consumption and the energy supply system. More details are available here: https://ec.europa.eu/clima/eu-action/climate-strategies-targets/economic-analysis/modelling-tools-eu-analysis_en.

Given the high stakes, the EU should not leave this essential task of organising the knowledge for policymaking to private companies or funding.

A second area of knowledge management is cooperation between Member States. The NECPs are already a very useful tool to put different national plans in perspective and compare them to European plans/projections/targets. This can be further developed by carefully reviewing the data Member States provide and encouraging them to use a harmonised reporting system.

Finally, the experimentation described in section 7.1.2 needs to be accompanied by robust *ex-ante* and *ex-post* analysis, so that experimentation really serves the purpose of identifying appropriate solutions. Accordingly, the experiments should be designed in a way that allows robust analysis where possible. Appropriate funding for such scientific support should be provided.

7.2. Policy tools

In this section we summarise some of the policies that will be needed to implement the above-described pathway choices.

7.2.1. Greenhouse gas pricing

To allow all stakeholders to navigate the complexity of the energy transformation and to prioritise the most effective and efficient solutions, putting a price on greenhouse gas emissions is crucial. Proper pricing of greenhouse gases not only incentivises households and companies to change their innovation, investment and operation behaviour, it also encourages national governments and regional/local administrations to enable the private sector to reduce their greenhouse-gas emission costs. A common greenhouse-gas emission price will also ensure that mitigation activities are well synchronised between Member States. Moreover, the revenues generated from greenhouse-gas pricing can be used to ensure social fairness and be invested in enabling infrastructures and innovation.

The EC's proposal to tighten the EU ETS, extend it to shipping and introduce a second EU ETS for transport and buildings will help to strengthen the central role of carbon pricing. Implementing the proposal will have a major and long-lasting positive impact on ensuring a cost-efficient transition towards a carbon-neutral economy.

Based on our research, we would pick three specific elements:

Convergence to one price

Ensuring the ultimate convergence of emission prices in the existing and the new EU ETS will improve efficiency and simplify and strengthen the system (Edenhofer *et al*, 2021). This might be achieved by dynamically reducing the number of allowances sold in the 'cheaper' system and selling those instead in the more expensive system.

Cover methane emissions along the value chain

It is urgent to reduce fugitive methane emissions from the coal and natural gas sectors. Methane has very high global warming potential in the short run, estimated by the IPCC to be 81 times greater than that of CO_2 (over 20 years). Given the risk of reaching tipping points in the atmosphere, methane emissions need to be reduced quickly. At the moment, methane emissions are not part of the EU ETS and are reported only to the UNFCCC (because methane is a so-called Kyoto gas). The EU needs in the first place to establish its own standards for monitoring, reporting and verification (MRV). Second, fugitive methane emissions from the coal and gas (and also the oil) sectors should be capped as soon as possible and a policy introduced to reduce the emissions. Such a policy could, for example, follow the example of the EU ETS with a methane cap-and-trade system, or integrate methane into the EU

ETS. Or be a different policy approach could be taken, such as capping methane intensities of fossil-fuel production units. However, given the enormous role of imports in the EU's natural gas (and also oil) consumption, it is important to address the methane footprint of imports. This could take the form of a methane border tax or of maximum methane leakage rates.

Certification of green energy imports

Our analysis shows that imports of hydrogen and green gases are a plausible scenario. Moreover, the EU might also import more electricity directly from its neighbours. In climate terms this only makes sense if the imported energy is not associated with massive emissions in the producer country. This is not always straightforward. A certification scheme will be needed to quickly encourage the right investments in the EU and its suppliers.

7.2.2. EU energy infrastructure

Energy infrastructure in the EU is mainly provided by nationally regulated network monopolies. The regulators typically focus on keeping the cost of the system development in check – in order to reduce network tariffs that households have to pay. At the margin, the EU (through the projects of common interest) and individual Member States have provided extra incentives for "strategic" infrastructure. This model – that is deeply interwoven in the European energy market - is incremental and lacks a long-term system-planning perspective. Accordingly, the EU still supports gas and oil infrastructure, while there is no vision for an intercontinental grid for a fully decarbonised electricity system.

The Fit-for-55 discussions provide momentum for a deep rethink of how energy infrastructure is incentivised and financed in the EU. In addition to the need to improve cooperation between national regulators and TSOs for cross-border infrastructure planning, it requires ideas for the potential roll-out of a hydrogen grid. In the past, before the Internal Energy Market, (greenfield) infrastructure construction was done within vertically integrated companies or extensive long-term contracts. A new energy carrier hydrogen should conform to the rules of the EU Internal Energy Market and requires alternative models of infrastructure creation. At the same time, parts of the hydrogen infrastructure may be converted former natural gas infrastructure, while some other natural gas assets may become unused ("stranded"). Regulation needs to be devised that facilitates the conversion, but also regulation that enables the permanent mothballing of fossil infrastructure assets.

7.2.3. EU Energy Market Design

EU electricity and gas markets provide price signals to investors, producers and consumers. In the short-term this helps the efficient allocation of energy over time (whether stored or consumed), between places (should energy flow eastwards or westwards), between producers (which plants should run) and consumers (who should cut their demand). In the longer-term price signals determine investment in power plants, storage and demand-side appliances (including demand-response capabilities).

But current energy markets were designed for a very different system that included a high share of dispatchable power plants and limited substitutability between different energy carriers. The new energy world will consist of high shares of variable renewable electricity as well as alternative energy carriers (green gases, hydrogen, heat), for which local or regional markets might make sense. The main challenge in this new energy world will be to carry abundant available energy (especially in summer) over to periods when energy is scarcely available (especially in winter). This also involves the question of how different energy markets are co-designed (sector-coupling). The discussion has started on whether the current market model based on 'scarcity pricing' is enough to ensure the behaviour and investment decisions needed to make the new system work, or whether alternative market instruments are needed.

Investors will, however, require some clarity on which markets will ensure the profitability of investments that address the challenge. This is a high-stakes discussion, which should be politically moderated and not left to industry alone.

7.2.4. Clean appliances support

Speed up deployment of industrial consumption

Industrial sectors will have to replace emissions-intensive production processes with low-carbon alternatives. The good news is that for almost all sectors, different low-carbon production technologies exist, at least at prototype or pilot stage. The difficulty is that, at too-low carbon prices, many low-carbon technologies are not yet competitive against polluting processes. One solution will be to ensure a constantly increasing greenhouse gas price (section 7.2.1). However, this is politically difficult and the ETS market is characterised by regulatory uncertainty.

One solution to provide already today higher price signals would be a greenhouse-gas pricing-based support instrument – 'commercialisation contracts' (McWilliams and Zachmann, 2021). These could be implemented as a temporary measure to remove the risk associated with uncertain carbon prices for ambitious low-carbon projects. The aim of the contracts would be to increase private investment to the socially-optimal level. Contracts would be allocated through auctions in which fixed prices for abated emissions over a fixed duration would be agreed on a project-by-project basis. On an annual basis, public subsidies amounting to the difference between the agreed carbon price and the actual EU carbon price would be provided to investors, depending on the total carbon emissions abated. As long as EU carbon prices are low, investors would receive larger subsidies to ensure their competitiveness. Contracts would be auctioned at EU level. This would generate increased competition compared to national auctions, leading to more efficient outcomes and preventing fragmentation of the single market. From about €3 billion to €6 billion would be provided to the main industrial emitting sectors annually, with the amount reducing as the EU carbon price rises and low-carbon technologies become competitive without subsidy.

Speed up deployment of household consumption appliances

A similar challenge exists for household investments such as heat pumps, hydrogen boilers or electric vehicles (McWilliams and Zachmann, 2021b). A form of insurance could be offered to consumers so that when they invest in fuel-switching (for example, by installing an electric heat pump), the clean fuel will always be cheaper than the displaced fossil fuel. This would involve a fixed price paid to consumers for the reduction in carbon emissions associated with their investment. The amount of subsidy would be calculated annually, and would depend on total usage of the appliance.

Household contracts would in effect bring forward this scenario for households that wish to invest today rather than wait until 2030. Households would be guaranteed a price of, say, €100/tonne for the annual carbon emissions avoided by installing a heat pump. With no carbon price in place (currently, many EU countries do not explicitly tax the carbon content of fuels used for household heating), this would involve them being paid their annual emission reduction multiplied by the target carbon price. As a carbon price on natural gas is gradually implemented, the household would be paid the difference between that year's carbon price and the target price. In this way the subsidies they receive would be phased out as the actual carbon price increases.

With a high enough target price, annual payments should ensure that clean-fuel appliances are cheaper than their dirty competitors. Guarantees that clean fuels will always be cheaper than fossil fuels should assuage concerns that decreasing demand for fossil fuels will actually make them very cheap, and hence early adopters of clean technology risk becoming worse off than households that stick with fossil-fuel boilers or cars.

Enabling infrastructure

Finally, making consumer-end public infrastructure (electric charging, clean fuels pipelines and sufficient electricity connection capacity) available is crucial for enabling consumers to switch to low-carbon energy appliances. This infrastructure is not delivered in a competitive market, but in a highly regulated environment. Moreover, in urban areas – which will be key arenas of decarbonisation – for efficient use of space and resources, modern energy and transport network systems need to be designed side by side. However, EU energy and climate governance is based on top-down policies that are not complemented by a solid bottom-up system that ensures consistency of EU, national and local measures, and that incentivises decarbonisation at city level.

Hence, better integration is needed of top-down energy and climate policy mechanisms with new bottom-up incentives that aim to promote decarbonisation at city level. A grant-based system could give the EU some control over the effective implementation of cities' decarbonisation projects. EU countries could use city progress reports to provide fiscal incentives to cities that implement in practice their climate plans. This premium system would make economic sense for Member States considering that the better cities perform in terms of decarbonisation, the easier it will be to achieve national decarbonisation targets (Tagliapietra and Zachmann, 2016).

7.2.5. Speed up the deployment of renewables

In all scenarios a huge amount of renewable electricity will be needed already by 2030. The European Green Deal package proposed by the EC includes a revision of the Renewable Energy Directive. This proposal increases the current EU-level target of 'at least 32%' of renewable energy sources in the overall energy mix to at least 40% by 2030. This represents a **doubling of the current renewables share** in just a decade. This will imply that national energy and climate plans must be closely monitored by the EC, which must ensure that they are in line with updated targets.

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APPENDIX

A1. MODEL DESCRIPTION DIETER

To model the European electricity system, we use the "Dispatch and Investment Evaluation Tool with Endogenous Renewables" (DIETER), a capacity expansion and dispatch model of the European electricity system (Zerrahn and Schill, 2017) [111]. The DIETER model uses various data sources [112] and assumptions [113] and includes almost all EU Member States and Switzerland [114]. The model contains all 8760 hours of one specific (target) year but does not model paths between years. Given demand for electricity, weather patterns, renewable energy requirements and other constraints, the model comes up with a cost-minimal power plant and storage fleet as well as their usage during the year. The model does not contain an explicit electricity grid structure; every country is modelled as a "copper plate". Electricity can flow between countries using a "net transfer capacity" model.

The results of the model can be interpreted as long-term optimal equilibrium on the power market, assuming complete linearity, perfect foresight for the entire year, as well as perfect competition. The model has already been used in numerous studies and reports. Gaete-Morales et. al (2021) provide an overview where DIETER and its model derivations have been used previously.

DIETER aims at determining the optimal power fleet composition for different "target years". These target years differ by the required share of renewable electricity produced of all electricity consumed in a country. As our analysis has only illustrative purposes, we decided to determine the share of renewable electricity [115] consumed by assuming that the current actual share (in 2020) will increase in every country in such a way that "almost 100%" [116] of renewable electricity is reached in 2050. Based on this assumed linear increase of the renewable share, the underlying required shares of renewable of 2030 are higher than currently: for example, we assume at least 65% renewables in Germany, 84% in Austria, but only 42% in Hungary due to the lower current share, hence a lower starting point. As this analysis only serves to show stylized results, we are aware that even higher shares of renewable electricity might be required in the short run. The qualitative conclusions yet do not change.

A2. METHANE EMISSION

We refer to methane emissions data as reported to the UNFCCC. There are doubts as to the quality of the self-reporting of methane data to the UNFCCC because it is based on calculations (using parameters like energy input, emission factors, etc.) and there is hardly any verification by measurement.

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111 For more information regarding our open-source model DIETER, please check the information provided at https://www.diw.de/dieter and https://gitlab.com/diw-evu/dieter_public/dieterpy. The model code used in this report (https://gitlab.com/diw-evu/projects/decarbonisation-of-energy/) can be downloaded, used for free and adapted for own analysis.

112 Weather time series (renewable energy capacity factors) are taken from Renewables.ninja (https://www.renewables.ninja), demand time series (load) are taken from ENTSO-E (2018) (scenario 2040ST, climate year 2007). For cost assumptions, we refer to the DIETER version 1.3 (https://gitlab.com/diw-evu/dieter_public/dietergms/-/tree/1.3.0) and the cost assumptions documented there.

113 The model can choose freely to invest in different generation technologies, given the renewable electricity constrains mentioned in the text. Hydro (damns), run-of-river, biomass, and pumped-hydro storage plants generation capacities can be expanded by maximally 10% beyond current levels. Photovoltaic and wind power generation capacities can be expanded up to the maximum bounds in Child et al. (2019). Cross-border electricity transportation capacities are taken from the ENTSO-E (2018) (scenario 2040ST).

114 Austria, Belgium, Bulgaria, Switzerland, Czechia, Germany, Denmark, Estonia, Finland, France, Greece, Croatia, Hungary, Italy, Latvia, Lithuania, Netherlands, Norway, Poland, Romania, Sweden, Slovenia, Slovakia.

115 Renewable electricity does not encompass nuclear energy in our analysis.

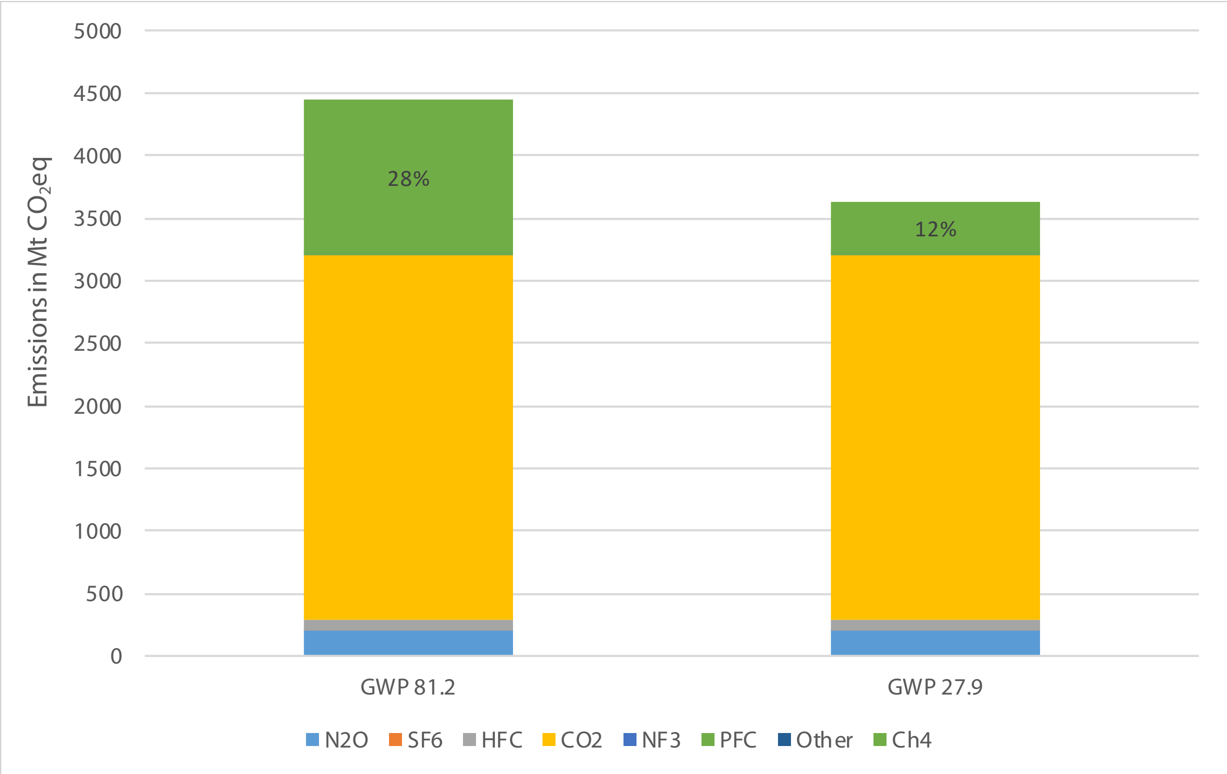
116 Depending on the country, the 2050 target renewable shares vary between 97% and 99%. The reason for not assuming 100% are technical. Modelling a share of 100% renewable electricity within an isolated electricity sector model (we do not include other sectors) could lead to biased results.

However, this is the only comprehensive methane emission database available at the moment. In Figure 7-1, we report total greenhouse gas emissions in 2019 in the European Union (EU27).

In case, the short-term (20 year) global warming potential (GWP) of methane is considered, methane is more than a quarter (28%) of the EU's total greenhouse gas emissions. In the long run (100 year global warming potential), methane still makes up for 12% of the EU27 greenhouse gas emissions.

Figure 7-1 only includes domestic emissions in the EU27 and does not take into account the methane footprint of gas (and oil) imports. This is reported and compared to the EU27s domestic methane emissions in Figure 7-2. The methane footprint of natural gas imports is 20% larger than the total methane emissions in the EU27 energy sector. Fugitive emissions from the EU's coal sector on the one hand and the EU's oil and gas sector on the other hand are each about one third of the methane emissions from the energy sector. The energy sector methane emissions are about one fifth of the total methane emissions in the EU27.

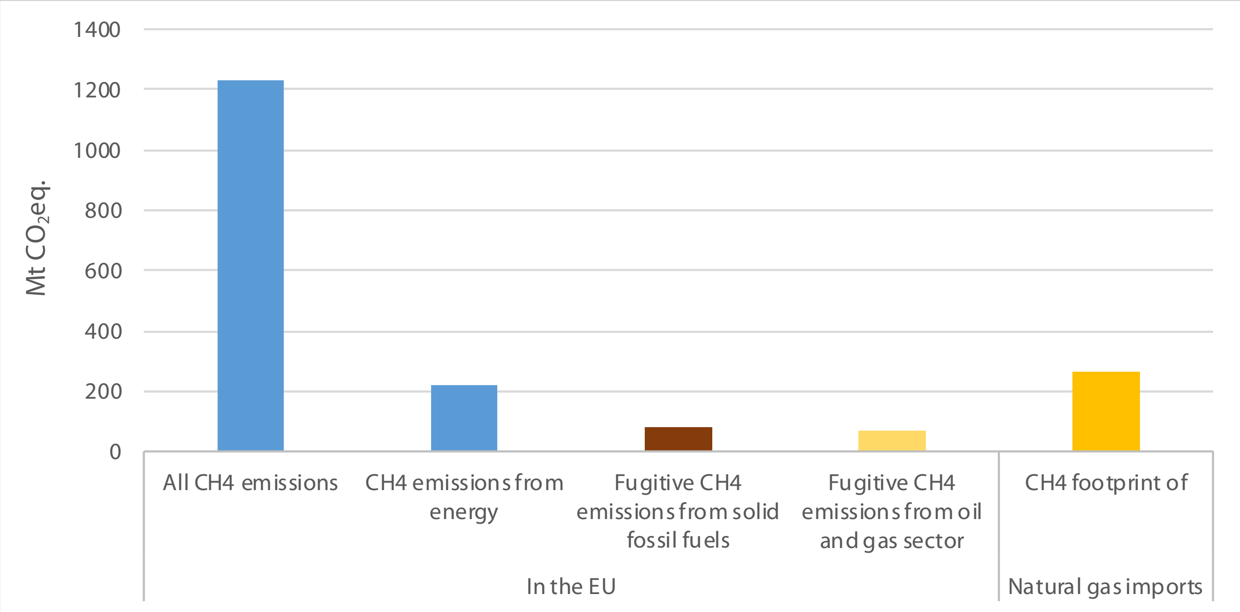
Figure 7-1: Share of methane in total GHG emissions in the EU27 in 2019 (by GWP assumption for methane)



Source: UNFCCC data, available at: https://www.eea.europa.eu/data-and-maps/data/national-emissions-reported-to-the-unfccc-and-to-the-eu-greenhouse-gas-monitoring-mechanism-17.

Note: CO_2 equivalents are calculated based on the updated global warming potentials (GWP) of the different greenhouse gases in IPCC (2021). The GWP of CH_4 is 81.2 for a time horizon of 20-year time horizon and 27.9 for a 100-year time horizon. For N_20 the GWP is 273 for both horizons. For other GHG the 100-year GWP factor was assumed in both graphs due to a lack of data.

Figure A2-2: Methane emissions in the EU27 and methane leakage footprint of natural gas imports in 2019



Source: UNFCCC database.
Note: A GWP of 81.2 is assumed for the conversion of methane emissions to $MtCO_2eq$.

A. METHODOLOGY FOR SCENARIO ANALYSIS (EXTENDED DESCRIPTION)

The purpose of our analysis is to investigate the economic effects of switching between different fuel consumptions. We investigate corner scenarios, where extreme assumptions are taken for consumption of a particular fuel. Our analysis is based on the MIX-55 scenario results reported by the JRC for the evolution of final energy demand in the EU27 to 2030 and 2050. This analysis is available here: https://visitors-centre.jrc.ec.europa.eu/tools/energy_scenarios/.

The JRC source provides sectoral fuel consumptions for 2019, 2030 and 2050 in a reference and MIX-55 scenario. The provided figures are not final energy consumptions but to the best of our understanding also include energy transformation losses and fuel non-energy consumptions that are associated to the demand sectors. To compensate for this, we adjust the figures based on actual 2019 energy balance statistics. This allows us to identify final energy consumption and non-energy fuel consumption per fuel for each sector. We extrapolate the assumptions made on non-fuel demand and energy transformation losses from 2019 through to 2030 and 2050.

Breakdown based on: JRC -2030 (Mix55) (TWh)									
	Electricity	Heat	Hydrogen	Synthetic methane	Renewables [solar, geo biofuels, ambient]	Petroleum products	Natural gas	Solid fossil fuels	**Total**
Industry	1,100	200			320	400	900	300	3,220
Buildings	1,500	300			840	100	900	20	3,660
Transport	100		10		300	2,400	100		2,910
FEC	2,700	500	10	0	1,460	2,900	1,900	320	**9,790**
Non-energy use						800	200		1,000
Aviation & maritime bunkers	10		0			600			610

After constructing our reference scenario, we investigate the effects of switching final energy demand away from the mix determined by the JRC and toward electricity, hydrogen, or green fuels in our three separate corner scenarios. A fuel switch is also associated with a change in total energy consumed by an appliance in a specific sector. For example, battery electric vehicles consume less energy to travel one kilometre than an internal combustion engine vehicle. In other words, changing applications results in changing thermal efficiencies of energy conversion (while an ICE has an efficiency below 50% that of a BEV is above 80%).

Therefore, even if the required useable energy remains constant (e.g., mechanical energy required to move a vehicle a specific distance) the switch from one to another fuel may change the required final energy. To deal with this, we use estimations of the useful energy demand per fuel and sector. We assume three types of useful energy: "thermal", "mechanical" and "ICT & lightning". Based on available sectoral statistics we assign the respective final energy consumption per fuel to the three useful energy types (e.g., 70% of electricity used in buildings is consumed in ICT & lightning processes and the remaining 30% for heating).

The useful energy per application and fuel in all sectors results finally by considering the (thermal) efficiency of the respective application (e.g., 3,000 TWh of oil products in the transport sector allows for 1,000 TWh of useful energy).

The sum of all fuel specific useful energies per sector defines the total useful energy required for one of the three useful energy types (e.g., the total heat generated in buildings is 3,000 TWh and is provided by 30% of natural gas, 10% of electricity and so on.)

Based on this assessment for all useful energy types and sectors the effects of a fuel switch can be calculated. Therefore, we assume for each corner scenario the percentage share of a fuel contributing to the provision of the required useful energy (Based on the example for buildings, providing 3,000 TWh of heat with only heat pumps requires just 1,000 of electricity.)

Resulting from this, for each scenario the final energy and non-energy consumption can be calculated:

"All-electric world" 2030 (TWh)									
	Electricity	Heat	Hydrogen	Synthetic methane	Renewables [solar, geo biofuels, ambient]	Petroleum products	Natural gas	Solid fossil fuels	Total
Industry	1,300	200	0		400	200	700	200	3,000
Buildings	1,600	300			1,250	100	700	20	3,970
Transport	300		10		300	1,900	100		2,610
FEC	**3,200**	**500**	**10**	**0**	**1,950**	**2,200**	**1,500**	**220**	**9,580**
Non-energy use			60			800	200		1,060
Aviation & maritime bunkers	10					500			510

While the aggregated FEC demand of all sectors for all energy carriers but electricity and heat define the primary energy supply of those fuels, the primary energy consumption in electricity (and heat) generation in the energy sector has to be calculated.

We assume therefore that changes in electricity production (compared to JRC figures) result only in changes of wind and solar generation.

Therewith, the required investments in the energy sector can be calculated. They are defined as sum of additional power generation capacities (compared to 2020, 2030 respectively), investments in electrolyser and transmission grids as well as investments in hydrogen grids.

Decarbonising the energy system requires a fundamental transformation in the way societies generate, transport and consume energy. Disagreement still exists over how this system should look in 2050.
The first principle for efficient transformation should be that uncontroversial technologies are swiftly and aggressively deployed. Second, in controversial areas, policy should forcefully explore options and be willing to accept and learn from failures. This report discusses concrete options for doing so.

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