Hydrogen4EU

CHARTING PATHWAYS TO ENABLE NET ZERO

2022 edition

Hydrogen for Europe study

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Executive summary

1. *Hydrogen for Europe* is a joint industry research project on the contribution of hydrogen to the European energy transition. It is a science-based study that uses detailed energy modelling to investigate the transformation of the European energy system towards climate neutrality. The project explores optimal pathways for reaching net-zero emissions in Europe and unlocking the full potential of different renewable and low-carbon technologies, including hydrogen. The study's first edition, published in May 2021, informed industrial stakeholders and policy-makers as they made their first steps in the development of a European hydrogen economy. Its results confirmed the expectations that hydrogen is to play a key role in Europe's decarbonisation efforts.

2. Important policy and industrial initiatives have now kickstarted the uptake of the European hydrogen economy. A dynamic policy environment has been shaping the future decarbonisation and hydrogen frameworks, already clarifying some of the missing elements for a proper market and regulatory functioning. Institutional support and public financing instruments have also started emerging in parallel to increasingly focused and ambitious strategies to develop a competitive hydrogen value chain. Recent geopolitical and macroeconomic upheavals, including the invasion of Ukraine by Russia in February 2022, have intensified further policy and industrial efforts around climate neutrality and hydrogen. Skyrocketing natural gas and electricity prices combined with a strategy to phase out Russian energy supply before 2030 have been rebalancing European energy policy towards energy security, affordability and diversification of energy sources. The development of a resilient European hydrogen value chain, including imports routes from outside Europe are key elements of European hydrogen policy.

3. In the current context, the prospects for natural gas and low-carbon hydrogen have become increasingly uncertain. Turmoil on natural gas markets and uncertainties on the ability to secure resilient supply options for the years to come could lead to a re-evaluation of gas-related investment decisions. Meanwhile, methane emissions have moved up on policy-makers agendas. Methane emissions are a significant contributor to global warming alongside CO_2 emissions. Policy-makers are preparing steps to incentivise concrete monitoring and abatement initiatives, such as the 'Global Methane Pledge' or the EU proposal for a regulation to reduce methane emissions in the energy sector.

4. The 2022 edition of the *Hydrogen for Europe* study provides a full update to the assessment of hydrogen's contribution to achieving climate neutrality, considering major new trends that have emerged since spring 2021. The modelling framework was notably updated to account for a progressive phase-out of imports of Russian energy commodities. It also includes methane emissions associated with the production, transport and use of natural gas and low-carbon hydrogen in Europe, all along their value chains. The study considers a gradual reduction of combined CO_2 and methane emissions to net-zero by 2050, in alignment with the underlying objectives of the European climate law.

5. The detailed energy system model MIRET-EU provides a robust and proven methodology based on linear programming to represent the European energy system. The hydrogen import model HyPE assesses the competition between domestic hydrogen production in Europe and import from non-European countries. The modelling allows to analyse the European energy transition and hydrogen's potential within it with a detailed technological, sectoral and geographic scope, including 27 European countries and imports from North Africa, the Middle East and Ukraine. For the purposes of this edition, specific work has been carried out to assess methane emissions along the natural gas and low-carbon hydrogen supply chains. The data-driven assessment covers emissions in the upstream, mid-stream and downstream for over thirty countries and three alternative cases of mitigation strategies and abatement technology rollout.

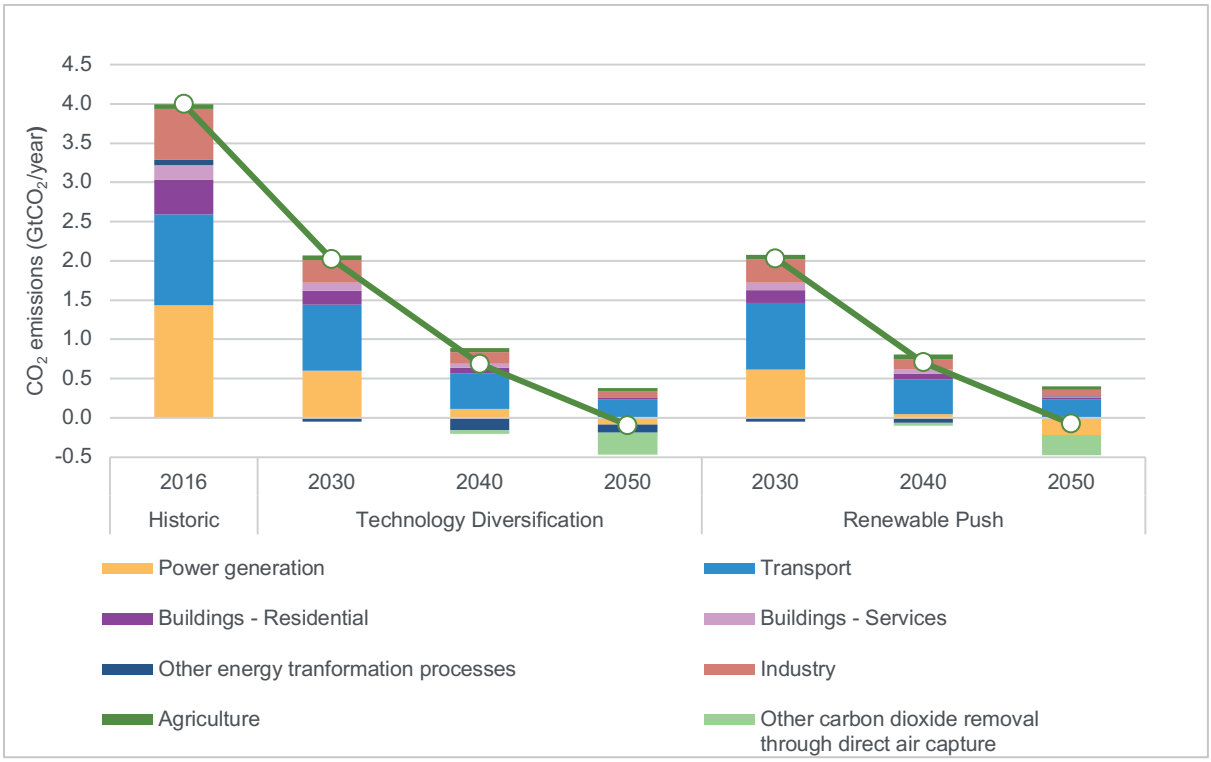
6. The study describes two pathways to climate neutrality in Europe. The "Technology Diversification" pathway provides insights on an inclusive approach to energy transition, that considers a wide range of decarbonisation technologies and aims at achieving a cost-efficient transformation of the European energy system by 2050. The "Renewable Push" pathway examines the conditions and implications of an increased focus on renewable energy, reflecting the current policy preferences in Europe. This is represented by a

series of targets on the share of renewable energy in gross final energy consumption: 45% in 2030 (versus 40% in the Technology Diversification pathway), 60% in 2040 and 80% in 2050. As regards methane emissions, the pathways consider a net-zero paradigm in which best available technologies are rolled out to rapidly reduce emissions along the whole natural gas value chain.

7. The *Hydrogen for Europe* pathways describe alternative trajectories along which the European energy system could move if the underlying economic, technological and regulatory assumptions unfold in a certain way. They must not be interpreted as a forecast nor as the only viable scenarios to be explored. Rather, they can be used to stimulate debate and inform strategic decision making, indicating how the underlying assumptions impact technology choice, investments and the achievement of the overarching policy objectives. The economic outcomes of the modelling should be traded off against other policy considerations e.g. industrial, environmental or geopolitical.

8. Both pathways achieve a 100% net reduction of combined CO_2 and methane emissions from the natural gas value chain by 2050. Fuel switching, energy efficiency improvements and carbon capture, utilisation and storage technologies (CCUS) allow for a progressive decrease of CO_2 emissions over the outlook period, complying with the legal targets of the European climate law (figure 1). This reduction is led by energy transformation sectors, such as power generation, hydrogen production and refineries, that become net-negative by the early 2030s, due to the use of bioenergy combined with carbon capture and storage (BECCS). The average methane emission intensity associated with natural gas and low-carbon hydrogen falls by nearly 80% in the period to 2050, following the adoption of best available technologies for methane emission abatement.

Figure 1. Evolution of direct CO_2 emissions by sector in the Technology Diversification and Renewable Push pathways, 2016 to 2050



Other energy transformation processes include hydrogen production and refining.

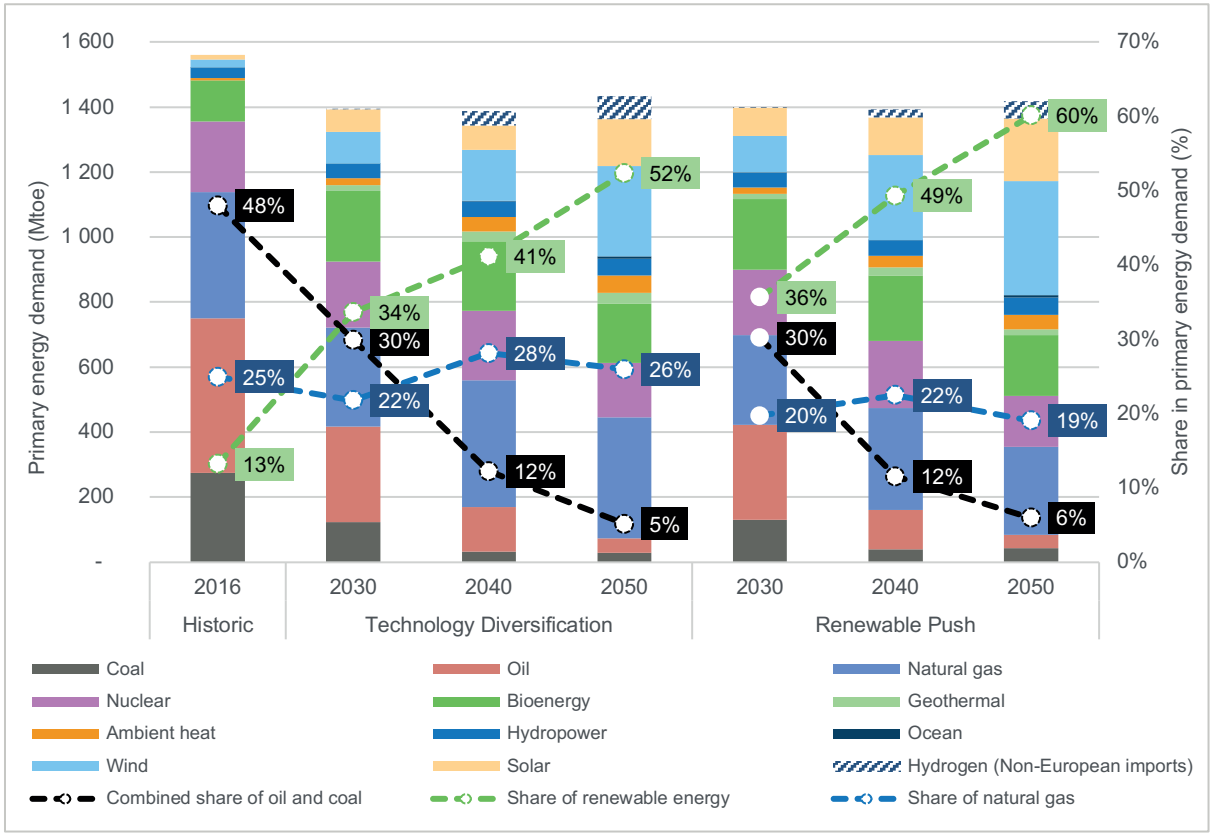
Source: Hydrogen4EU

9. The creation of a CCUS value chain is indispensable for the success of the energy transition. Carbon capture and storage allows for a cost-effective transition in industry and power generation and allows for the production of low-carbon hydrogen. Carbon dioxide removal technologies such as BECCS or direct air capture also play a key role to develop carbon-neutral production of e-fuels and other CO_2-dependent

processes and to remove sufficient amounts of CO_2 from the atmosphere by subsequent permanent storage (negative emissions). By 2050, negative CO_2 emissions serve to offset residual CO_2 emissions from the hard-to-abate sectors and unabated methane emissions. Annual injection into CO_2 storage sites needs to already reach over 300 Mt by 2030 in the Technology Diversification pathway. By 2050, CO_2 storage injection reaches 1.2 $GtCO_2$/year in the Renewable Push pathway and 1.4 $GtCO_2$/year in the Technology Diversification pathway.

10. Continued technology development combined with ambitious targets for decarbonisation and renewable energy development underpin a fundamental transformation of the primary energy mix (figure 2). A profound shift from fossil fuels towards renewable energy is at the heart of the transition. The share of renewable energy in gross final energy consumption reaches 65% in the Technology Diversification pathway and 80% in the Renewable Push pathway at the end of the outlook period. It is fostered by massive investments in wind and solar PV, whose combined supply in 2050 shows a more than ten-fold increase from historic levels. This upscaling is mirrored by a dwindling role for oil and coal in the energy system: their use falls by some 90% over the outlook period in both pathways.

Figure 2. Evolution of total primary energy demand in the Technology Diversification and Renewable Push pathways, 2016 to 2050



Source: Hydrogen4EU

11. By 2050, natural gas represents a quarter of primary energy demand in the Technology Diversification pathway and a little less than a fifth in the Renewable Push pathway. However, the *Hydrogen for Europe* pathways underscore that natural gas can play an important role in the European energy transition only if three interrelated conditions are fulfilled.

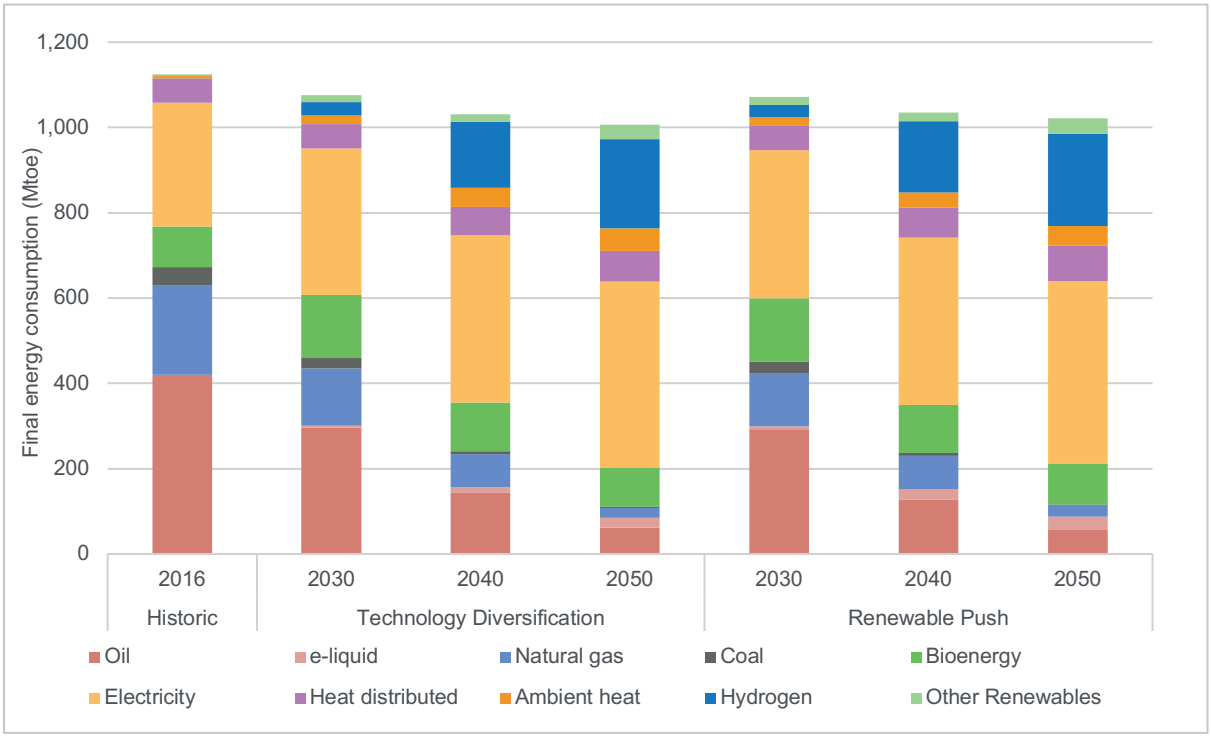
    a. Continued use of natural gas is contingent on the availability of CCS: most of its consumption is shifted from dispersed final energy demand to large-scale transformation processes, notably to low-carbon hydrogen production and power generation, where CCS is technically feasible. Unabated natural gas use is inconsistent with climate-neutrality objectives.

b. The industry needs to take rapid action to slash methane emissions, deploying best available mitigation technologies. The *Hydrogen for Europe* modelling shows that failure to bring down methane emissions from current levels would result in natural gas use plummeting to less than 10% of primary energy demand in 2050, i.e., natural gas sharing the same fate as coal and oil.

c. The period to 2030 shows a marked drop in supply caused by the phase-out of natural gas imports from Russia, high prices and lead times for additional LNG capacities. If the industry fails to demonstrate that natural gas supply is secure and affordable, European consumers will inevitably turn away and look for alternatives.

12. Energy efficiency and electrification are critical elements in the transition to net zero (figure 3). Final energy consumption decreases over the outlook period driven by efficiency improvements in the transport and buildings sectors and the switch to more efficient end-use technologies. Electrification is one of the main enablers of decarbonisation in energy end-use. Electricity's share in gross final energy consumption grows by over 50% between today and 2050, serving mostly the industry, transport and buildings sectors. Further uptake of electricity in end-use is held back by the challenges of deep electrification of hard-to-abate usages like heavy-duty transport, aviation or high temperature heat; also in the Renewable Push pathway that sees greater renewable energy deployment. This underscores the strong complementarity between electricity and molecules: by 2050, more than half of final energy consumption is supplied by non-electrified technologies in both pathways.

Figure 3. Evolution of gross final energy consumption in the Technology Diversification and Renewable Push pathways from 2016 to 2050



Other renewables in final energy consumption correspond to solar and geothermal energy.

Source: Hydrogen4EU

13. European hydrogen demand exceeds 15 Mt by 2030 in both *Hydrogen for Europe* pathways (figure 4). This is in-line with the European Commission's REPowerEU plan released in May 2022, that targets a European hydrogen demand (excluding ammonia) of 16 Mt by that date. Demand ramps up substantially over the 2030s and 2040s and reaches around 100 Mt by 2050. This is equivalent to more than 3,300 TWh or around 300 Mtoe (in lower heating value). The Renewable Push pathway, which shows a stronger deployment of

renewable energy, demonstrates hydrogen's complementarity with renewable energies, helping to absorb, store and transport the bulk of the additional energy from renewable sources. Hydrogen's long-term potential is in the same range as the study's first edition: this illustrates the resilience of hydrogen's contribution to the energy transition despite the macroeconomic and geopolitical turmoil over the past year.

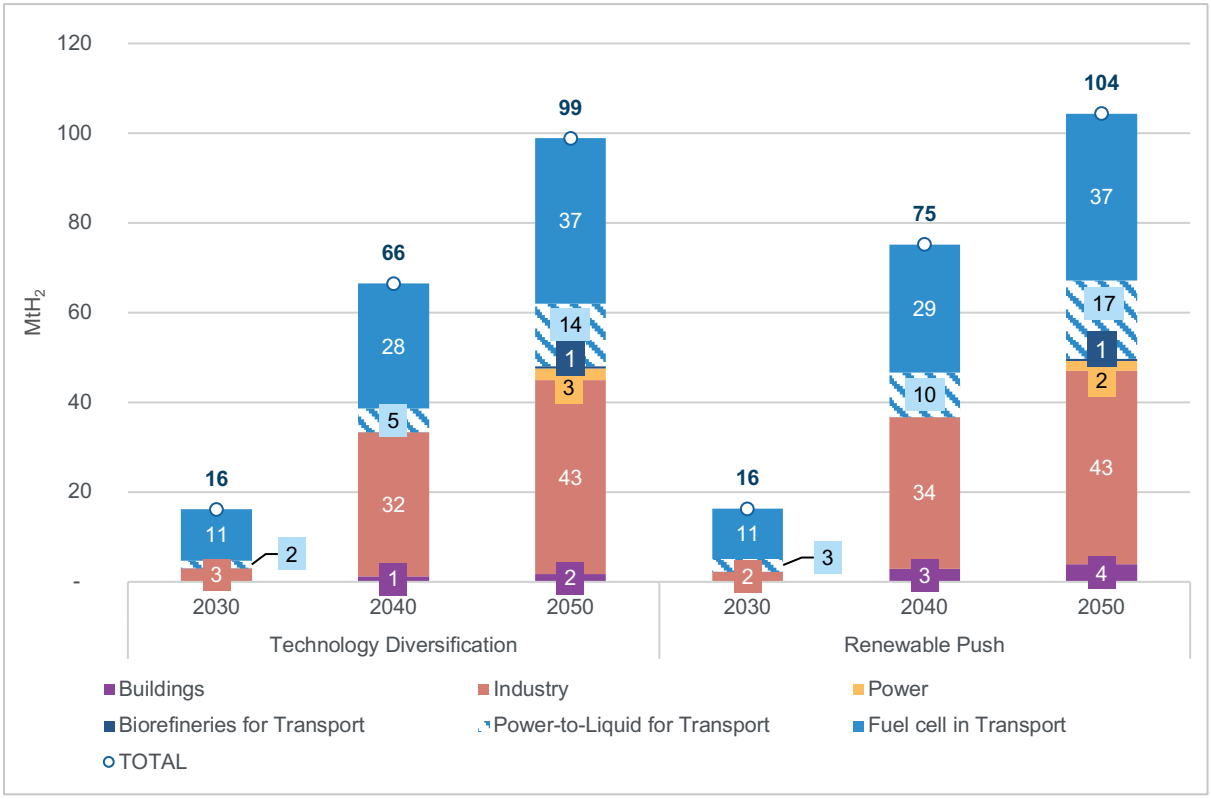
14. Overall, hydrogen becomes one of the key energy carriers of the climate-neutral energy system, replacing natural gas as the main gaseous molecules. By 2050, hydrogen and hydrogen-derived solutions are the second largest contributor to decarbonisation of end-use after electricity, covering about a quarter of gross final energy consumption:

    a. Hydrogen demand in transport reaches up to 55 Mt in 2050, used either directly as a fuel for fuel cells, or as intermediary feedstock for e-fuels and biorefineries. Hydrogen demand for e-fuels reaches around 15 Mt in 2050, mostly for use in aviation. Hydrogen, e-fuels, ammonia and other hydrogen-related molecules provide energy dense fuels where electrification is complex. Their versatility is particularly relevant for heavy and long-distance road transport, aviation and shipping.

    b. Hydrogen proves to be a key contributor to the decarbonisation of the industry sector. Here demand exceeds 43 Mt by 2050, primarily for energy purposes related to the production of heat and steam. Hydrogen is a particularly important solution for steel-making and chemical industries.

    c. Hydrogen demand in buildings and for power is rather limited compared to the aforementioned sectors. Combined, they represent up to 6 Mt in the Renewable Push pathway. Hydrogen can provide space heating or peak generation for the power system, but it is facing competition from a wide range of other decarbonisation options including energy efficiency, heat pumps for buildings or biogas.

Figure 4. Evolution of hydrogen energy-related demand by sector in the Technology Diversification and Renewable Push pathways, 2030 to 2050

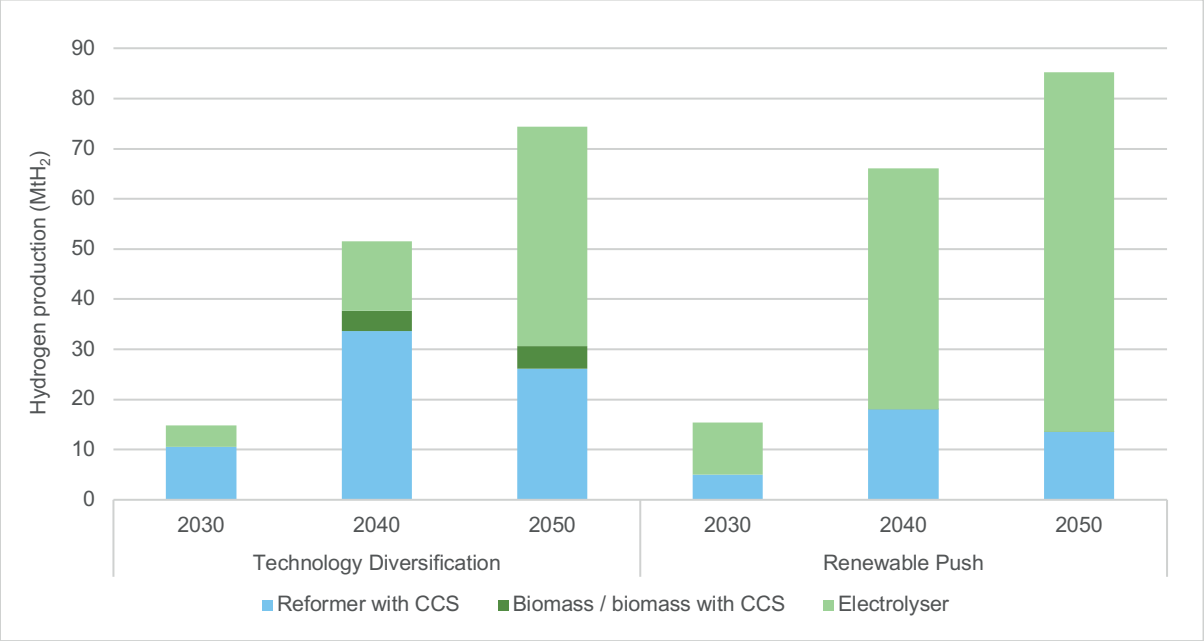


Source: Hydrogen4EU

15. European production of renewable and low-carbon hydrogen must grow rapidly over the coming years to support an optimal market uptake, meeting the demand of around 15 Mt by 2030 in both pathways (figure 5). This growth further amplifies in the subsequent decade, topping 50 Mt by 2040 in the Technology Diversification pathway and a massive 66 Mt in the Renewable Push pathway. The momentum in the Renewable Push pathway is driven by the ambitious development targets for renewable energies: the results for that scenario demonstrate the value of renewable hydrogen to integrate the additional variable renewable electricity sources into the system. New investments in the 2040s bring total domestic production to around 75 Mt and 85 Mt in the Technology Diversification and Renewable Push pathways.

16. In the Technology Diversification pathway, low-carbon hydrogen from reformers with CCS helps to establish a hydrogen economy and support demand uptake in the 2020s and 2030s. Renewable hydrogen from electrolysis and biomass grows more progressively and meets the bulk of the additional demand growth in the last decade. The production mix is balanced in 2050, with renewable hydrogen providing around two thirds of domestic production. Renewable hydrogen's upscaling happens sooner in the Renewable Push pathway, with a production reaching 10 Mt in 2030 and exceeding 70 Mt by the end of the outlook period. Low-carbon hydrogen is also featuring in that pathway. It complements renewable hydrogen to establish the hydrogen economy in the first half of the outlook period.

Figure 5. Evolution of European hydrogen supply in the Technology Diversification and Renewable Push pathways, 2030 to 2050



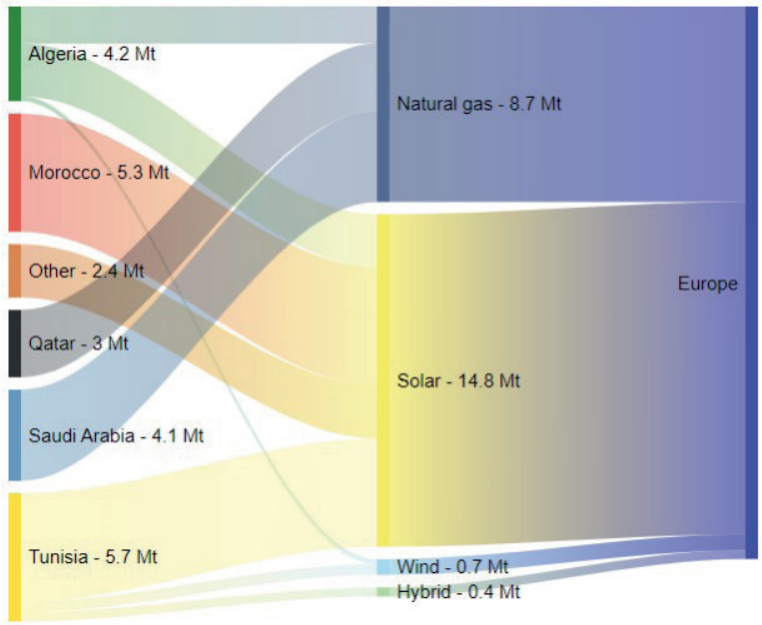
Source: Hydrogen4EU

17. Development of renewable hydrogen as described in the *Hydrogen for Europe* pathways is underpinned by falling technology costs over the outlook period and massive investments in electrolysers and renewable electricity capacities. In the Renewable Push pathway, more than 1,400 GW of electrolysers and around 1,600 GW of dedicated wind and solar PV capacities must be installed by 2050 to support the formidable uptake in renewable hydrogen and top 70 Mt of output. This is an unprecedented industrial effort, requiring an average installation rate of around 57 GW/year dedicated renewable electricity. As a comparison, the European installed capacity in wind and solar PV grew from 13 GW in 2000 to 371 GW in 2020. Social acceptance of renewable energy installations, fast-tracked administrative procedures and the ability of the supply chains to deliver this ramp-up, are indispensable features of the pathway towards net-zero emissions.

18. Installed capacity of reformers with CCS grows rapidly in both pathways to achieve optimal production levels of low-carbon hydrogen. In the Technology Diversification pathway, installed capacity jumps from virtually zero today to more than 40 GW in 2030 and nearly 140 GW in 2040. Compared to electrolysers, reformers are associated with higher utilisation rates, up to 90%, which reduces capacity investment needs. This momentum underlines the existence of a transitory window of opportunity for investment in low-carbon hydrogen – independent of whether policy-makers give preference to renewable energy. Investors need to sanction their projects in the first half of the outlook period to take advantage of it. This coincides with a period of turbulence and uncertainty in natural gas markets, possibly requiring bold decisions from investors if projects are to move ahead.

19. The acceleration of hydrogen's uptake in the 2030s and 2040s is complemented by imports. In both pathways, hydrogen is imported from neighbouring regions to complement European production (including Norway and the UK) and serve countries with limited options for cost-efficient domestic hydrogen production. In the Technology Diversification pathway, imports from North Africa, the Middle East and various smaller exporters reach 15 Mt in 2040 and nearly 25 Mt in 2050, covering up to a quarter of total European demand. In 2050, nearly 60% of hydrogen imports are from renewable energy sources. Countries like Morocco, Tunisia and Algeria leverage competitive renewable energy potential, existing gas resources, and their proximity to existing cross-border infrastructure to supply Europe with large amounts of both renewable and low-carbon hydrogen. They are complemented by seaborne imports of low-carbon hydrogen from Middle Eastern countries (Qatar and Saudi Arabia) and other smaller import sources.

Figure 6. Origin of hydrogen imports in 2050 in the Technology Diversification pathway

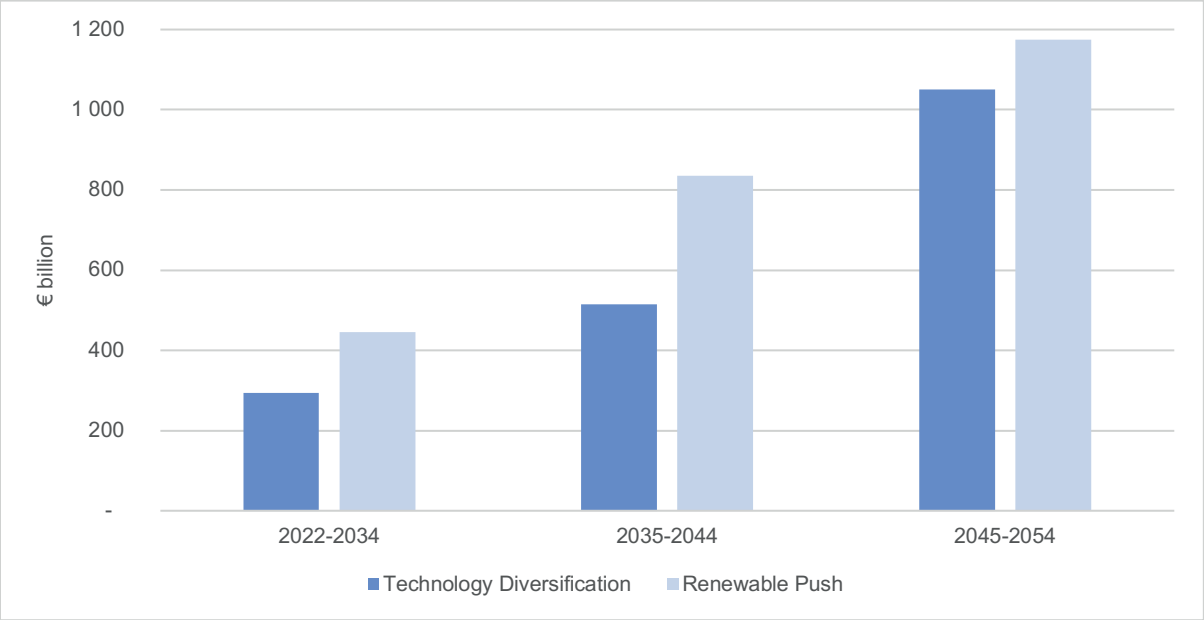


Source: Hydrogen4EU

20. The *Hydrogen for Europe* pathways highlight the increasing need for a fully developed and efficient hydrogen infrastructure, connecting burgeoning hydrogen hubs and allowing for the development of a liquid and efficient hydrogen market. A robust European hydrogen infrastructure relies on cross-border coordination and the capability to transport and store large quantities of hydrogen. Cumulative investments in transport, storage, distribution and refuelling top €850 billion in both pathways. The results are well aligned with the current plans of the European Hydrogen Backbone initiative. They show the importance of repurposing existing natural gas infrastructure for a fast and low cost deployment of the hydrogen backbone.

21. Cumulative investments in the European hydrogen value chain amount to several trillions of euros over the next thirty years. Access to financing at the right time and at the right cost is critical to unlock timely technology rollout and ensure demand and supply can grow in lockstep. Between €300 billion (in the Technology Diversification pathway) and €450 billion (in the Renewable Push pathway) need to be mobilised through the mid-2030s to finance the development of the European hydrogen supply chain (figure 7). Project financing over the coming decade is particularly put at risk by recent macroeconomic developments, with the post-covid economic recovery and Ukraine war having translated into a marked uptick of inflation. This may translate into rising financing costs, which would particularly affect capital-intensive investments such as those needed for deep decarbonisation and hydrogen's uptake.

Figure 7. Investments in the hydrogen supply chain per period in the Technology Diversification and Renewable Push pathways, 2022 to 2054



Source: Hydrogen4EU

22. For European consumers and citizens, an underlying issue is the affordability of the switch to hydrogen, and more generally of the transition to net-zero emissions. The *Hydrogen for Europe* results can be used to illustrate the economic implications when contrasting two paradigms to achieve net-zero emissions: a diversification-focused approach, harnessing the competition between a wide range of renewable and low-carbon technologies, and a technology-focused approach that favours proven renewable energies. As such, the social, environmental and geopolitical implications of the Renewable Push pathway should be contrasted with the slightly higher cost the scenario entails from the perspective of energy system economics: total energy system cost over the next thirty years is around €650 billion (or more than €40 billion per year) higher in the Renewable Push pathway than in the Technology Diversification pathway.

23. The upscaling of the European hydrogen value chain is also a policy affair. Important work over the past two years has gone into the creation of a full-fledged hydrogen policy framework in Europe, as manifested by the regulatory proposals of the European Commission included in the Fit-for-55 and Hydrogen and Decarbonised gas market packages and in the recently published REPowerEU plan. The EU and national governments have started implementing a first slate of financial instruments and support schemes to de-risk first projects and incentivise innovation and investments in hydrogen, including the preparation of an Important Project of Common European Interest (IPCEI) on hydrogen. Nevertheless, a misalignment remains between the currently available framework and tools, and an increasingly clogged project pipeline. This limits the ability of first projects to get off the ground and increases the risks of hydrogen staying behind the development described in the pathways.

24. The next couple of years are critical to address the gaps in the policy toolkit, unlock investment decisions in first projects and get hydrogen's upscaling going. The *Hydrogen for Europe* results and their underlying set of assumptions allow to identify three key areas for direct action and gap mitigation:

    a. Bridging the cost gap with emitting technologies: most commercial projects currently planned still lack the government guarantees and support mechanisms that would allow for a viable business model and trigger investment decisions. Inertia in the rollout of binding targets and bans and in the implementation of the next ETS and CBAM calls for an intensification of efforts to propose support mechanisms at a large scale. Among possible options, Carbon Contract for Difference (CCFD) appears as one of the most promising to incentivise hydrogen investments in an optimal way, rewarding projects on the basis of CO_2 abatement costs.

    b. Reducing uncertainty for investors: while the European Commission and governments have acted fast to propose a set of regulatory measures, the reality of legislative negotiation is putting a break on the momentum and could postpone the finalisation of the regulatory framework for hydrogen. Investors lack the visibility as to the final definition of renewable and low-carbon hydrogen, the framework for CCUS and carbon removal certification or the acceleration of permitting procedures for renewable energies. Finalisation of the policy framework and close coordination with industrial stakeholders is needed to give the necessary visibility and insights into the future market and regulatory conditions for hydrogen.

    c. Controlling the cost of financing in light of the current macroeconomic turbulences: policy-makers and public institutions have a role to play to address financing challenges. In light of the current fears of soaring inflation and monetary counter-measures, it is particularly important that investors have access to financing at a low cost. Development banks and other public financial institutions should double down on their loan and support programmes into sustainable investments, while central banks may retarget their asset purchase programmes towards the energy transition, keeping money flowing into the nascent hydrogen economy.

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Glossary

Term	Definition
Ambient heat	Energy captured from the air, the ground or water for use by heat pumps
ATR	Autothermal reforming
BAT	Best available technology
BECCS	Bioenergy with carbon capture and storage
BEV	Battery Electric Vehicles
Biorefineries	Production process for first and second-generation biofuels
CBAM	Carbon border adjustment mechanism
CCS	Carbon capture and storage
CCUS	Carbon capture, utilisation and storage
CCFD	Carbon contract for difference
CIF	Cost, Insurance and Freight
DAC	Direct air capture
DACCS	Direct air capture with permanent carbon dioxide storage
Decarbonised	Related to CO_2 emissions: from which CO_2 emissions have been removed
Distributed heat	Heat produced in a centralised way and distributed to final locations for end-use requirements
EC	European Commission
EF	Emission factor
ETS	Emission trading system
e-fuels	E-fuels are gaseous and liquid fuels such as hydrogen, methane, synthetic petrol, and diesel fuels generated from electricity
Energy transformation process	(or energy conversion) Process to transform one form of energy to another. For example, solar irradiation is converted into electricity thanks to solar panels.
FCEV	Fuel Cell Electric Vehicle
Final energy consumption	Total energy consumed by end users, such as households, industry and agriculture. It is the energy which reaches the final consumer's door and excludes that which is used by the energy sector itself.
GHR	Gas Heated Reforming combined with autothermal reforming
Gross final energy consumption	The gross final energy consumption is the energy used by end-consumers (final energy consumption) plus grid losses and self-consumption of power plants. It also includes international aviation according to Eurostat definition but excludes maritime bunkers.
ICE	Internal Combustion Engine
IPCEI	Important Project of Common European Interest
LCOH	Levelized cost of hydrogen (in €/kg of hydrogen consumed)
LHV	Lower Heating Value. 1 Mt of hydrogen is equivalent to 120 PJ (around 33.3 TWh) in lower heating value.
Low-carbon hydrogen	Hydrogen produced from low-carbon energy sources such as nuclear, low-carbon electricity or fossil fuels with carbon capture (e.g., reformers with CCS, pyrolysis)
$MtCO_2$	Unit of mass measurement of CO_2 (carbon dioxide): Million metric tonnes of CO_2
MtH_2	Unit of mass measurement of hydrogen: Million metric tonnes of hydrogen
Mtoe	Unit of energy measurement: Million metric tonnes of oil equivalent

Term	Definition
NDC	Nationally determined contribution
Offgrid electrolyser	Electrolyser connected directly to renewable power plants for renewable hydrogen production
Ongrid electrolyser	Electrolyser withdrawing electricity from the main power grid for hydrogen production
PCI	Project of Common Interest
PHEV	Plug-in Hybrid Electric Vehicle
Renewable hydrogen	Hydrogen produced from renewable energy sources. It includes hydrogen produced from biomass or electrolysis, assuming that the electricity stems from renewable sources.
SMR	Steam Methane Reforming
WACC	Weighted average cost of capital

From \ To	TWh	Mtoe	bcm	MtH2	TBtu	EJ
TWh	1	0.086	0.094	0.03	3.41	0.004
Mtoe	11.63	1	1.1	0.35	39.68	0.042
bcm	10.6	0.91	1	0.32	36.30	0.038
MtH2	33.33	2.87	3.14	1	113.7	0.120
TBtu	0.293	0.025	0.028	0.009	1	0.001
EJ	277.8	23.88	26.11	8.33	947.8	1

Note: lower heating value (LHV) is assumed for conversions to Mt H_2

1 Introduction

1.1 Context of the study

25. The *Hydrogen for Europe* study is a joint industry and research initiative that assesses the contribution of hydrogen to the European energy transition. The study's first edition, published in May 2021, explored two pathways along which the European energy system could move to reach a 55% reduction in greenhouse gas emissions by 2030 (compared to 1990) and climate neutrality by 2050, as pledged in the 2019 European Green Deal[1] and since then enshrined into law with the EU climate law[2] (*Hydrogen for Europe*, 2021). It confirmed that hydrogen has a central role to play in reaching these objectives. Hydrogen is a versatile energy carrier and a cost-efficient solution for hard-to-abate sectors such as industry and transport. It also shows strong synergies with renewable energy deployment, helping to absorb, store and transport energy produced by renewable sources such as wind and solar photovoltaics. The first edition put in perspective the value of diversification in technologies and supply routes. For hydrogen in particular, it showed the complementarities between production of renewable and low-carbon hydrogen and with imports from non-European countries, to achieve a quick upscaling of the hydrogen value chain and de-risk the European energy transition.

26. The industrial, political, and regulatory developments of the past year have only strengthened European commitments to decarbonise. They have also confirmed the relevance of the study's key findings regarding the contribution of hydrogen to the transition. At EU level, the release of the EU taxonomy, Fit-for-55 packages and Hydrogen and Decarbonised Gas Market package have clarified some of the missing elements for a proper hydrogen market and regulatory framework. Institutional support, public financing instruments and other support schemes have started emerging, targeting specifically the hydrogen value chain, with the goal of closing the competitiveness gap with conventional technologies and allowing a rapid upscaling of hydrogen clusters and valleys throughout Europe.

27. Momentum has also picked up at national level, with a sharp increase in the number of strategies (figure 8), programmes and regulatory frameworks around hydrogen. The German hydrogen strategy calls for the development of 10 GW of electrolysers and 3 Mt of inland production of renewable hydrogen by 2030, supported notably by a dedicated €8 billion IPCEI fund. Electrolysis is a key technology throughout Europe, with other major countries like Spain (4 GW of electrolysers connected to renewable power plants) or France (6.5 GW of electrolysers built by French giga-factories) focusing primarily on this production route. Other countries like the Netherlands, Norway or the UK explore a more diversified mix of production options encompassing both renewable and low-carbon hydrogen produced from natural gas.

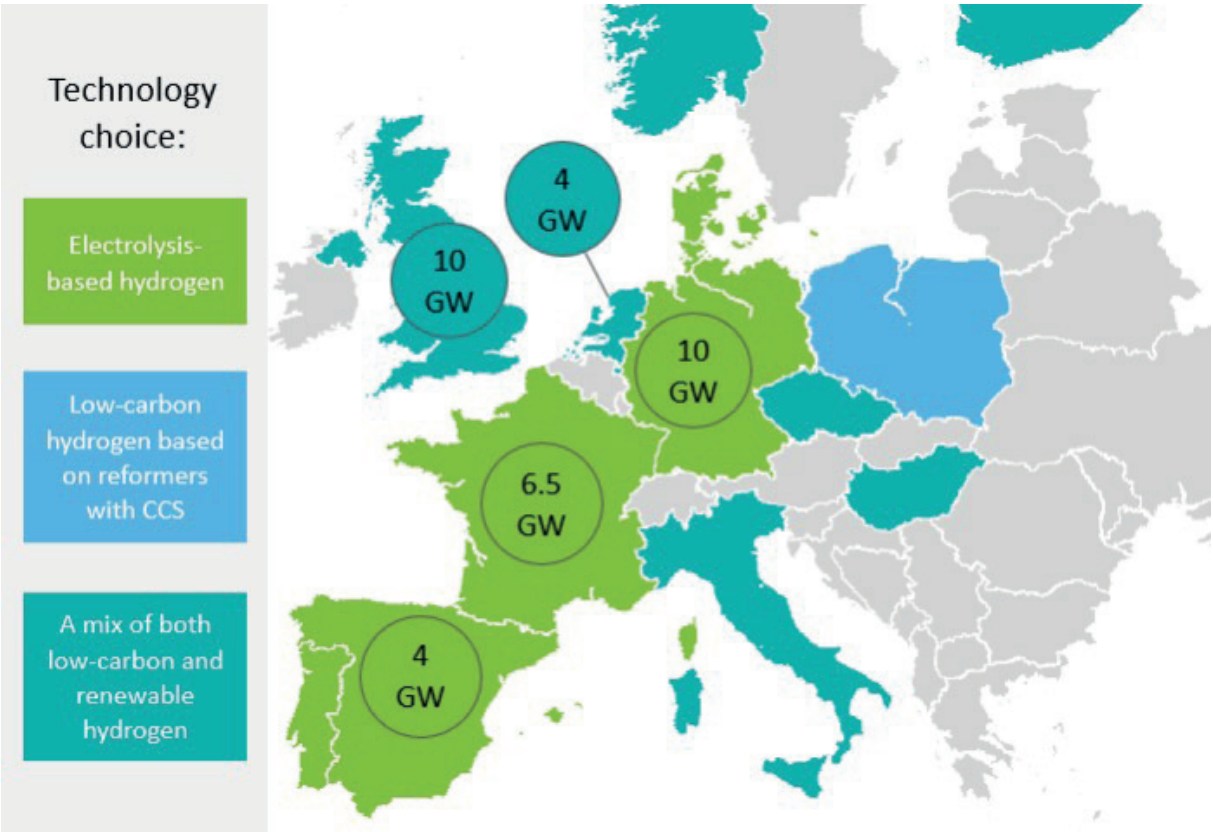
28. Renewable energy sources, and consequently renewable hydrogen, are associated with high land-use requirements that can result in social and environmental backlash causing delays. To tackle this issue, several European countries plan to complement local production of hydrogen with imports. In its hydrogen strategy, Germany plans to import up to 3 Mt of hydrogen by 2030. To that effect, it has signed several memorandums of understanding with countries with high solar potentials such as the UAE, Saudi Arabia or Australia. Its hydrogen import programme, H2Global is backed by a €900 million State aid funding and aims to match via a two-side auction demand for hydrogen in Germany with long-term supply contracts[3]. The first purchase contracts are to be awarded as early as 2022, with first deliveries of hydrogen-derived products envisaged to arrive in Germany in 2024. Following the German trend, other European coastal countries and port regions, such as Belgium, the Netherlands or Italy, also plan for securing hydrogen trend relations with MENA and South American countries, that benefit from higher solar irradiation levels and lower land constraints.

29. Recent macroeconomic and geopolitical upheavals have reinforced the concretisation of European ambitions around climate-neutrality and hydrogen. The invasion of Ukraine by Russia in February 2022 put in question the economic and geopolitical paradigm that had seen Russia emerging as Europe's biggest oil, natural gas and coal supplier. Since the invasion, European countries have been developing a wide range of sanctions

[1] https://ec.europa.eu/info/strategy/priorities-2019-2024/european-green-deal_en
[2] https://ec.europa.eu/clima/eu-action/european-green-deal/european-climate-law_en
[3] https://ec.europa.eu/commission/presscorner/detail/en/ip_21_7022

against Russian energy imports. Current tensions on natural gas markets caused by the war and lingering effects of the Covid-19 crisis have already led to significant delays in replenishing in European natural gas storage and skyrocketing natural gas and electricity prices. At a higher level, the current geopolitical and energy crisis is rebalancing European energy policy towards energy security and affordability. The current situation is also encouraging European policy-makers to double down on their climate neutrality commitments.

Figure 8. Overview of announced national strategies for hydrogen and targeted supply capacities for 2030



Source: Hydrogen4EU

30. In response to these upheavals, the European Commission published its REPowerEU plan to rapidly reduce Europe's dependence on Russian fossil fuels and accelerate the clean energy transition. The plan aims at accelerating decarbonisation efforts and improving the resilience in the European energy structure. Such an acceleration can be achieved via energy savings, energy supply diversification and strengthening international partnerships. Moreover, acceleration of renewable energy roll-out and reduction of fossil fuel consumption in industry and transport sectors (notably via substitution of hydrogen to these sources) can smoothen the pathway towards a decarbonised and resilient energy system. The plan targets notably a phase-out of Russian fossil fuels by 2030 while hydrogen is stressed once again as one of the key solutions to replace natural gas, coal and oil in the industry and transport sectors. REPowerEU hence sets an aspiration of 10 Mt of domestic renewable hydrogen production and 10 Mt of imports of hydrogen and derivatives by 2030[4].

31. While key regulatory developments in the past year have focused on renewable hydrogen, the European policy framework has also provided the opportunity for low-carbon hydrogen, based on natural gas, to develop. The EU sustainable taxonomy sets the threshold for hydrogen's inclusion as 100gCO_2/kWh, above the emissions of technologies such as ATR reforming of natural gas with CCS. The North Sea is seen as one of the priority regions for this development to leverage the proximity with natural gas infrastructure and potential CO_2 storage sites. Shell and Uniper's low-carbon hydrogen in Uniper's Killingholme site in North Lincolnshire passed the UK government's eligibility phase for CCUS cluster sequencing process in April

[4] https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=COM%3A2022%3A230%3AFIN&qid=1653033742483

2022[5]. The project aims at using low-carbon hydrogen to decarbonise heavy industry, transport, heating and power sector across Humber. Another reformer-based low-carbon hydrogen project in the Aukra municipality in Norway brings together Shell, Aker Clean Hydrogen company, and CapeOmega for the production of low-carbon hydrogen and its use as maritime fuel.

32. In the current context, the prospects for natural gas and low-carbon hydrogen in the European energy transition have become increasingly uncertain.

    a. On the economic side, turmoil on natural gas markets and uncertainties on the ability to secure resilient supply options for the years to come could lead to a serious re-evaluation of gas-related investment decisions, resulting notably in a stronger focus on renewable energy and hydrogen imports.

    b. On the environmental side, the past year has also seen methane emissions moving up on policy-makers' agendas. Methane emissions are a critical contributor to global warming alongside CO_2 emissions. Methane is 29.8 to 82.5 times more potent than CO_2[6], depending on the considered greenhouse effect period[7]. The IPCC, in its Climate Change 2021 report, highlights specifically the necessity of tackling the emissions of methane, which experiences its highest concentration level in the air in the last 800,000 years (IPCC, 2021). Following the invitation of the EU and the US, 105 countries pledged at COP 26[8] to reduce their methane emissions by 30% by 2030 compared to 2020. This 'Global Methane Pledge' now encompasses 111 participating countries, accounting for 45% of global methane emissions[9]. In Europe specifically, regulatory agendas have shown an acceleration of discussions on the question, after an initial strategy released late 2020. The December 2021 Hydrogen and Decarbonised Gas Market package now includes a formal proposal for a regulation to reduce methane emissions in the energy sector[10]. The EU and several Member States also fixed not only carbon-neutrality but climate-neutrality (thus including methane) targets. This is the case of France with its energy climate law[11].

1.2 Objective of the study

33. The 2022 edition of the *Hydrogen for Europe* study provides an update to its assessment of hydrogen's contribution to the European energy transition until 2050, considering the key evolutions, developments and shifts in focus that have happened since summer 2021. Based on a joint research effort by Deloitte, IFPEN, Carbon Limits and SINTEF Energi and underpinned by detailed modelling, the study investigates the transformation of the European energy system towards climate neutrality. It aims at analysing the optimal pathways in reaching net-zero emissions in Europe by unlocking the potential of different renewable and low-carbon technologies.

34. By capturing the main economic, regulatory and geopolitical developments of the past year, the study's 2022 edition is firmly based on the current EU policy context. It helps address new questions that have emerged since and are critical to establish a clear, forward-looking strategy and policy framework for the creation of a European hydrogen economy:

    a. How does the current macroeconomic and geopolitical context affect the opportunities of the European energy transition and the optimal development of hydrogen within it? How resilient is the role of hydrogen to major shifts and disruptions such as those observed recently?

    b. How can ambitious renewable energy targets accelerate the development of renewable hydrogen? How can renewable hydrogen help integrate variable renewables like wind and solar PV into the European energy system?

[5] https://www.uniper.energy/news/shell-and-uniper-to-work-together-on-blue-hydrogen-production-facility-in-the-uk
[6] 29.8 corresponds to methane emissions if their impact is considered over a 100-year period, while 82.5 corresponds to an impact period of 20 years.
[7] https://ghginstitute.org/2010/06/28/what-is-a-global-warming-potential/
[8] https://www.globalmethanepledge.org/
[9] https://www.iea.org/reports/global-methane-tracker-2022/the-global-methane-pledge
[10] https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=COM%3A2021%3A805%3AFIN&qid=1639665806476
[11] https://www.ecologie.gouv.fr/loi-energie-climat

c. Under which conditions can natural gas still play a role in the energy transition? How wide is the window of opportunity for investing in low-carbon hydrogen and to what degree does it depend on the actions taken by the industry and policy-makers regarding methane emissions?

d. To what extent does the current policy and regulatory framework foster an optimal energy transition strategy and the development of renewable and low-carbon hydrogen within it? How can this framework be complemented in the near term to reduce the risk to investors and accelerate project upscaling?

1.3 Methodology

1.3.1 Overview of the *Hydrogen for Europe* scope

35. The *Hydrogen for Europe* study is based on energy system modelling that considers all steps from primary resources to final energy consumption via transmission, distribution, conversion and storage and provides a detailed representation of energy carriers and technologies over the whole value chain. The modelling integrates a wide range of existing and future hydrogen technologies and allows for the possibility of importing hydrogen from other regions of the world. It follows an optimisation logic that minimises the total cost of the energy system: over the outlook period (2016-2050), it chooses the least-cost technology mix to meet the energy demand of each sector, considering the interdependencies between different sectors, energy carriers and their supply options, and conversion technologies. Table 1 provides a schematic overview of the main categories of technologies and end-uses that are represented in the model.

36. The energy system modelling provides a comprehensive framework for assessing the potential role of different energy carriers, such as electricity and hydrogen, for serving energy demand across the entire European energy system (24 EU Member States and 3 non-EU countries: Norway, Switzerland and the UK, see figure 9). Feedstock use of hydrogen is only included for iron and steel-making using the direct reduction of iron route and production of e-fuels as substitute for both gasoline and diesel/kerosene. Other feedstock uses of hydrogen, for example in the chemical industry, are beyond the scope of this study.

Table 1. Aggregated overview of the technological scope

Primary energy supply	Energy transformation	Final energy supply	End-use sector
Lignite (resources and import) Oil (resources and import) Coal (resources and imports) Natural gas (resources and imports) Uranium (resource and import) Water Bioenergy Solar energy Wind power	Electricity production CHP sector Electrolysis Biomass gasification Methane pyrolysis Methane reforming Liquefaction Coal processing Refineries Biofuel plants Gas network …	Electricity Hydrogen Coal Natural gas Oil Other final RES	Residential Commercial Industry Transport (road, rail, aviation, maritime[12]) Agriculture
+ Representation of CCUS routes (direct air capture or carbon capture, CO_2 use and storage) + Representation of electricity, natural gas and hydrogen storage			

37. In coherence with the 2021 edition, the *Hydrogen for Europe* study describes two scenarios denoted as the "Technology Diversification" and "Renewable Push" pathways. The first pathway is designed to provide insights on an inclusive approach to energy transition, that considers a wide range of decarbonisation technologies and aims at achieving a cost-efficient transformation of the European energy system by 2050[13].

[12] Within Europe.
[13] The time-steps in the modelling framework are: 2020 (today's system; no new investments), 2030, 2040 and 2050. Each period represents 10 years, e.g. 2045 – 2054 for 2050. The first day after the planning horizon is thus 2055.

The second pathway examines the conditions and implications of an increased focus on renewable energy, reflecting the current policy preferences in Europe.

38. The modelling framework is aligned with the European climate agenda and EU pillars and targets, incorporating the main targets for CO_2 and methane emission reductions, share of renewable energy targets in final energy consumption, energy efficiency, and national decisions on the phasing out of coal and nuclear plants for power generation, among others. It also incorporates the recent European sovereignty and resilience policy shifts to phase out energy imports from Russia by 2030, as planned by REPowerEU plan. Russian energy imports (coal, oil, natural gas and hydrogen) are thus excluded from both pathways from 2030 onwards. Note that although these pathways reflect the latest relevant changes in economics and regulatory factors, they are not an attempt to predict the actual development of the European energy system.

39. The study's scope now includes methane emissions associated with the natural gas consumed in Europe, from upstream to downstream. It assumes a gradual reduction of combined CO_2 and methane emissions to net-zero by 2050, under the climate neutrality commitments and in alignment with the underlying objectives of the European climate law. As such, the study considers the Global methane pledge and other national policies of natural gas exporting countries regarding methane emission reductions, but it goes further by assuming that deep reduction in methane emissions is a pre-requisite to any legitimate pathway toward climate neutrality. The scope also considers methane emissions associated with the production of extra-European production of hydrogen.

Box 1. Introduction to the *Hydrogen for Europe* pathways

Technology Diversification pathway

The Technology Diversification pathway assumes a perfect market where the European energy transition is underpinned by the European climate law in combination with already approved national targets as well as the overarching objectives for renewable energy share and energy efficiency. The markets are characterised by perfect foresight, meaning that investment decisions are made in each period with full knowledge of future developments. Further, deployment of technologies needed for decarbonisation of the energy system occurs at the time of demand without any delays. As such, the pathway allows to assess how a wide range of technologies, including for renewable and low-carbon hydrogen production, can be leveraged to transform the energy system at the least cost.

Renewable Push pathway

Using the same starting point with respect to currently implemented policies, policy announcements and overarching objectives, the Renewable Push pathway is designed to assess the conditions and implications of a framework oriented more decisively towards investments in renewable energies, especially wind and solar. As shown in table 3, this is implemented in the form of a series of targets on the share of renewable energy in gross final energy consumption. The Renewable Push pathway is more ambitious for 2030 compared to today's policy (45% versus 40% in the Technology Diversification pathway, reflecting the proposed increase in the REPowerEU plan) and includes binding targets for 2040 (at 60%) and 2050 (at 80%). This scenario also analyses the energy system under perfect foresight.

40. The scenarios are based on enacted and proposed energy policies and assume them compulsory. They are binding in each scenario. An overview of all implemented policies is provided in table 2, and table 3 provides a summary of the targets set at EU level for CO_2 and methane emissions, energy efficiency and share of renewables in gross final energy consumption.

Table 2. Overview of implemented policies

Policy	Description
GHG targets	Under the EU's commitment to climate-neutrality by 2050, we model a 100% CO_2 and methane emission reduction (compared to 1990 levels) by 2050 at the European level, i.e., a collective constraint. The scope of CO_2 emissions included in that target corresponds to emissions at combustion within the European perimeter in the study (see table 3). That of methane emissions extends to midstream and upstream emissions of the natural gas imported in Europe (see Section 1.3.3 for more information). The intermediate reduction target for 2030 has also been implemented as it has been set as minimum binding legislation to achieve the transformation towards a low-carbon energy system. In the modelling, it is represented by a -55% reduction in CO_2 emissions compared to 1990 levels. The binding trajectory for both CO_2 and methane emissions along the outlook period is based on the resulting pace in CO_2 emission reduction.
EU Energy efficiency target	Energy efficiency measures and targets up to 2030 are a second strand of comprehensive measures in the policy of the European Commission. The amendment to the Directive on Energy Efficiency (2018/2002) targets a 32.5% improvement in energy efficiency by 2030 relative to a 'business-as-usual scenario'. This corresponds to a primary energy consumption of 1128 Mtoe (million tonnes of oil equivalent) which is no more than 846 Mtoe of final energy consumption for the European Union in 2030[14].
Emission reduction targets for the transport sector	Regulation (EC) 443/2009 set mandatory emission reduction targets for new cars. The first target became operative in 2015 and a new target was phased in during 2020 and is fully implemented from 2021 onwards. The enforced 2021 target for the EU fleet-wide average emissions is set at 95 gCO_2/km. Furthermore, regulation (EU) 2019/631, adopted in 2019, sets CO_2 emission performance standards for new passenger cars and vans in the EU. The regulation maintains the former 2020-targets and adds new targets for 2025 and 2030. The proposal to ban the sale of internal combustion vehicles from 2035, voted by the European Parliament on June 8, 2022, is not included in the model.
Emission reduction targets for EU ETS sectors	The EU emissions trading system (EU-ETS) is a cornerstone of the EU's climate change policy and its key tool for reducing greenhouse gas emissions in a cost-effective way. Under Directive 2009/29/EC of the European Parliament and Council amending Directive 2003/87/EC; and under Directive (EU) 2018/410 of the European Parliament and Council amending Directive 2003/87/EC, emissions from the EU ETS sectors should be reduced by 21% in 2020 compared with the 2005 levels (including aviation), and by 43% in 2030.
Emission reduction targets for Non-EU ETS sectors	The Effort Sharing Regulation (ESR) defines legally binding national GHG emission targets in 2020 and in 2030 compared with 2005 for sectors not covered by the EU ETS excluding LULUCF, such as transport, buildings, agriculture. The national targets for 2020 are ranging between -20% (for the richest Member States) and +20% (for the less wealthy countries) compared with 2005 levels to collectively achieve a reduction of 10% in total EU emissions (Decision No 406/2009/EC). The targets for 2030 will range between 0% and -40% compared with 2005 levels in order to achieve a collective 30% reduction of the total EU emissions of the non-EU ETS sectors (Regulation (EU) 2018/842)
Renewable energy directive (RED) target for final energy consumption	European Union Directive 2009/28/EC establishes binding renewable energy targets for each Member State for 2020 that collectively amount to a share of renewables of 20% in the total gross final energy consumption by 2020. The currently binding target for 2030 of 32% was legally set in 2018 by renewable energy directive 2018/2001/EU, with a clause for a possible upwards revision by 2023[15]. Under the new Governance regulation (EU/2018/1999), EU Member States have submitted their draft NECPs national contributions that are sufficient for the collective achievement of the Union's 2030 target. As part of the Fit-for-55 package, the EC has proposed in July 2021 an increase of the target to 40% in its proposed revision of the RED II directive. The recently released REPowerEU plan now proposes an even higher upward revision to 45%. Given the overarching importance of this target and the confidence on the increase to at least 40%, the modelling considers as binding target a share of renewable energy of 40% in the Technology Diversification pathway and 45% in the Renewable Push pathway.

[14] Without the withdrawal of the UK these figures correspond to 1273 Mtoe (million tonnes of oil equivalent) of primary energy consumption and/or no more than 956 Mtoe of final energy consumption. Note that the target has been set for EU Member States only (at the time of the directive) and thus does not include Norway and Switzerland, which are part of the modelling scope. Furthermore, no additional targets beyond 2030 have been assumed at EU level.

[15] The original target of 27% has been revised upwards.

Policy	Description
Renewable energy directive (RED) target for transport sector	The 2018 RED directive sets targets specifically for use of energy from renewable sources in the transport sector. By 2020, at least 10% of the EU transport fuels (road and rail) must come from renewable sources. For the period 2030 to 2050 the target is set to 14%. The contribution of biofuels produced from food and feed crops (1st Generation) is capped at 7% of road and rail transport fuel in each Member State from 2020 onwards. Furthermore, the contribution of advanced biofuels and biogas (2nd Generation) should be at least 0.2 % in 2022, at least 1 % in 2025 and at least 3,5 % in 2030 (as a share of the final consumption of energy in the transport sector).
National energy and climate plans (NECPs), climate and energy objectives established by Non-EU Countries	National objectives for energy and climate sets targets for energy efficiency, share of renewable final energy consumption in general and for the transport sector, to comply with the targets set out by the RED, ESR, EU-ETS and EED, as described above. National objectives comprise targets for efficiency improvements in buildings and for heating and cooling. They also outline target dates for phasing out coal and nuclear energy, as well as limitations on nuclear production.

Table 3. Targets of main energy policies set at the European level

Target	Year	Technology Diversification pathway	Renewable Push pathway
CO_2 emission reduction with respect to 1990 levels (European scope)	2030	- 55%	- 55%
	2050	Net-zero emissions	Net-zero emissions
Methane emission reduction targets (along the gas value chain)	2022-2050	Pace of CO_2 emission reduction (when combined with CO_2)	Pace of CO_2 emission reduction (when combined with CO_2)
	2050	Net-zero emissions (when combined with CO_2)	Net-zero emissions (when combined with CO_2)
Energy efficiency target with respect to business as usual	2030	32.5%	32.5%
Share of renewable energy supply in gross final energy consumption	2030	40%	45%
	2040		60%
	2050		80%

41. The main input assumptions regarding macro-economic indicators, fossil fuel prices and energy demand values rely on the following sources:
    - The main macroeconomic drivers, population growth and GDP, have been collected from the JRC assumptions under the EU Reference 2016 scenario.
    - Oil, natural gas and coal prices are according to the proposed trajectories from the EU Reference scenario 2016 as considered by the JRC in their energy models, modified to 2022 prices and 2023-2026 future prices to consider the effects of the Russian invasion of Ukraine. The retained trajectories fall on the Stated Policies (SPS) scenarios of the IEA World Energy Outlook, 2021 (WEO, 2021).
    - The JRC-EU-TIMES database is used for energy demand projections.

42. Costs, technical assumptions, and deployment and resource availability constraints for all included technologies are based on authoritative databases such as ENSPRESO, JRC-IDEES database, IEA database, and ENTRANZE. Notably, the potential for solar and wind follows the reference scenario of ENSPRESO, while the biomass potential is based on the JRC alternative BaU scenario[16]. The 2021 edition of the *Hydrogen for Europe* study was carried out using dynamic learning-by-doing, where the cost of the emerging technologies (such as solar PV, wind power, electrolysers, reformers with CCS etc.) depended

[16] Alternative to the JRC Reference trajectory, this constitutes a more conservative assessment of the bioenergy potential considering a potential of bioenergy around 9,000 PJ in 2050 (vs. 12,000 PJ in JRC Reference), assuming added forestry potential (Ruiz et al., 2019).

on their installed capacities along the period outlook. The inter-dependency between installed capacity and technology cost was modelled by linking the models MIRET-EU (detailed European energy system model) and Integrate Europe (dedicated learning model). In the present edition of *Hydrogen for Europe* study, the resulting learning by doing results have been considered as exogeneous input data for technology cost evolution.

43. In a common effort with the stakeholders of the 2021 edition, the dataset was strengthened for hydrogen production technologies to reflect the current state-of-the-art. The current updated study database includes the cost and the performance data for new technologies such as molten media methane pyrolysis and combined gas heated/autothermal reformers with integrated capture of the produced CO_2, as well as modified data for existing technologies such as electrolysers and steam methane reformers with added CO_2 capture.

44. A major change compared to the study's first edition is that direct methane emissions along the natural gas value chain (upstream, midstream and downstream) are included in the environmental footprint of natural gas consumed within the European energy system. From a modelling perspective, including these emissions leads to a higher climate burden for natural gas technologies. Data for these methane emissions are fed into the modelling by a methane footprint module. The scope of these methane emissions goes beyond downstream emissions and emissions associated with European production: it also includes all natural gas exporters' upstream emissions from extraction until exports, pipeline or shipping transport and liquefaction and gasification terminals (for the case of LNG) up to Europe's boundaries. Methane emissions associated with the production of extra-European production of hydrogen are also considered in this updated assessment.

45. Methane emissions along the natural gas value chain have been assessed for three separate cases (box 2). The *BAT* case (Best Available Technology) considers a net-zero paradigm where the oil & gas industry pursues all necessary efforts to deploy best available technologies and rapidly reduce methane emissions along the whole natural gas value chain (production, transport, distribution and consumption). Two other cases have been defined and studied to evaluate the impact of inaction regarding abatement of methane emissions (*Current Emissions*) and limited methane abatement based on announced policies (*Harmonised Pledges*).

Box 2. Methane emission cases

Including methane emissions in the environmental footprint of natural gas requires assessing the level of emissions at each stage of the value chain, from upstream to downstream. A key metric for this assessment is the emission factor, i.e., the level of methane emissions per unit of natural gas consumed (in end-use appliances or for energy transformation purposes). Considering the aggregate value chain, the emission factor of natural gas consumed in Europe or for production of imported low-carbon hydrogen varies with respect to the origin of natural gas, the transport method and downstream distribution of natural gas. A key part of the new edition's research activities was to assess these methane emission factors along the whole gas value chain, for all relevant countries involved in the supply and consumption of natural gas and low-carbon hydrogen in Europe. The assessment was carried out for three different cases, accounting for different sets of assumptions regarding emission mitigation policies and roll-out of abatement technologies in the assessed countries. Their comparison allows to assess the importance of methane emission mitigation strategies on the available decarbonisation pathways and on the window of opportunity for natural gas.

a. The *BAT* case is the central case used for the study's two pathways in the main results. It represents a future in which the oil & gas industry proactively implements the most effective mitigation solutions.

b. The *Current Emissions* case maintains the status quo in terms of methane emission mitigation. Emission factors associated with each step of the value chain and each producing region remain at current levels due to lack of action by policy or industry stakeholders. This case allows to look at the implications on the role of natural gas in Europe if no concrete action is taken to mitigate methane emissions.

c. The *Harmonised Pledges* case represents an intermediate stage, where some concrete actions start happening to tackle methane emissions but without reaching the ambitions of the *BAT* case. It assumes that currently announced policies, NDCs (nationally determined contributions) and other pledges are implemented. For example, NDC targets are considered as the reference policies to be implemented for European countries.

They include the current European non-CO_2 greenhouse gas emission policies[17] (EU methane emissions to be reduced by 29% by 2030 compared to 2005 levels). The signed international pledges or policies were applied as a percentage reduction by target year, compared to 2019 as the reference year. The emission factors are considered flat after the pledge or policy is implemented.

All three cases consider the same starting point in terms of actual methane emission levels for the reference year 2019. Those were estimated based on the current best understanding of methane emission from the oil & gas sector. Information from country-level academic papers, actual measurements and estimates, emissions reported to UNFCCC[18] and IEA methane tracker (IEA, 2022) were all leveraged to develop a coherent understanding of emissions from the gas sector in each country. The three cases start diverging in the 2020s based on different sets of technological development and policy improvement assumptions.

46. Methane emissions as calculated based on the emission factor estimations, have then been converted in the energy system modelling into CO_2 equivalent emissions (CO_{2eq}) based on methane's global warming potential (GWP). This allows to make methane and CO_2 emissions comparable in order to assess the trade-offs and investments necessary to get to climate neutrality by 2050. GWP is the most common metric in the policy arena to assess the potency of methane and other greenhouse gases in relative terms to CO_2. It represents the heat absorbed by different greenhouse gases in the atmosphere as a multiple of the heat that would have been absorbed by the same mass of carbon dioxide. Box 3 gives an overview of other metrics that have been suggested by the scientific literature for potential consideration.

47. GWP can be estimated over a chosen time frame, 20 (GWP_{20}) and 100 (GWP_{100}) years being the most common ones. Both of these metrics have evolved to be the 'default' metrics in the policy arena. Most scientific literature assessing the impacts of greenhouse gases on climate change consider the longer time effects and thus use GWP_{100}. However, as the lifetime of different greenhouse gases in the atmosphere differs, distinct reference periods need to be fixed for the choice of the GWP measure. IPCC (2022) highlights that the metric highly depends on the considered context and the period during which the CO_2 emissions should be stabilised in the atmosphere. Similarly, the same assessment report of IPCC highlights that reaching climate neutrality in 2050 implies stabilisation of greenhouse gas emissions, notably methane emissions by 2045. According to Abernethy and Jackson (2022), in case of choosing GWP as the metric, the considered reference GWP period should include the period between the assessment year (2022) and the methane concentration stabilisation year (2045), that is closest to GWP_{20}. Therefore, the *Hydrogen for Europe* study uses the overall greenhouse gas effect of methane over a 20-year period compared to CO_2. According to the latest IPCC Assessment Report (AR6), the "GWP_{20}" value for methane is equal to 82.5 for the methane emissions stemming from fossil gas (IPCC, 2021). With this metric, 1 tonne of methane is considered to have a global warming impact equal to 82.5 tonnes of carbon dioxide.

Box 3. Other possible metrics for assessing the climate impact of greenhouse gases

Other metrics to evaluate the greenhouse gas effect of other-than-CO_2 gases in the scientific literature are presented in the following:

Global Warming Potential* (GWP*): an adjusted GWP that considers near-performance of CO_2 perturbation resulting from changes in CO_2 and other greenhouse gas emissions over the years (Lynch et al., 2020)[19].

Global Temperature-Change Potential (GTP): a cause-effect type climate metric, assessing the global temperature change at a given time due to continued emissions or change in emission of greenhouse gases. It is the ratio of global mean surface temperature change at future time due to emissions, relative to a reference gas, mostly CO_2 (Abernethy and Jackson, 2022).

Absolute Global Temperature-Change Potential (AGTP): another cause-effect type climate metric that assesses the global temperature change at a given time due to continued emissions or change in emission of greenhouse gases,

[17] https://unfccc.int/sites/default/files/NDC/2022-06/EU_NDC_Submission_December%202020.pdf
[18] https://di.unfccc.int/flex_annex1
[19] https://iopscience.iop.org/article/10.1088/1748-9326/ab6d7e

without being compared to any reference gas, as in the case of GTP18.

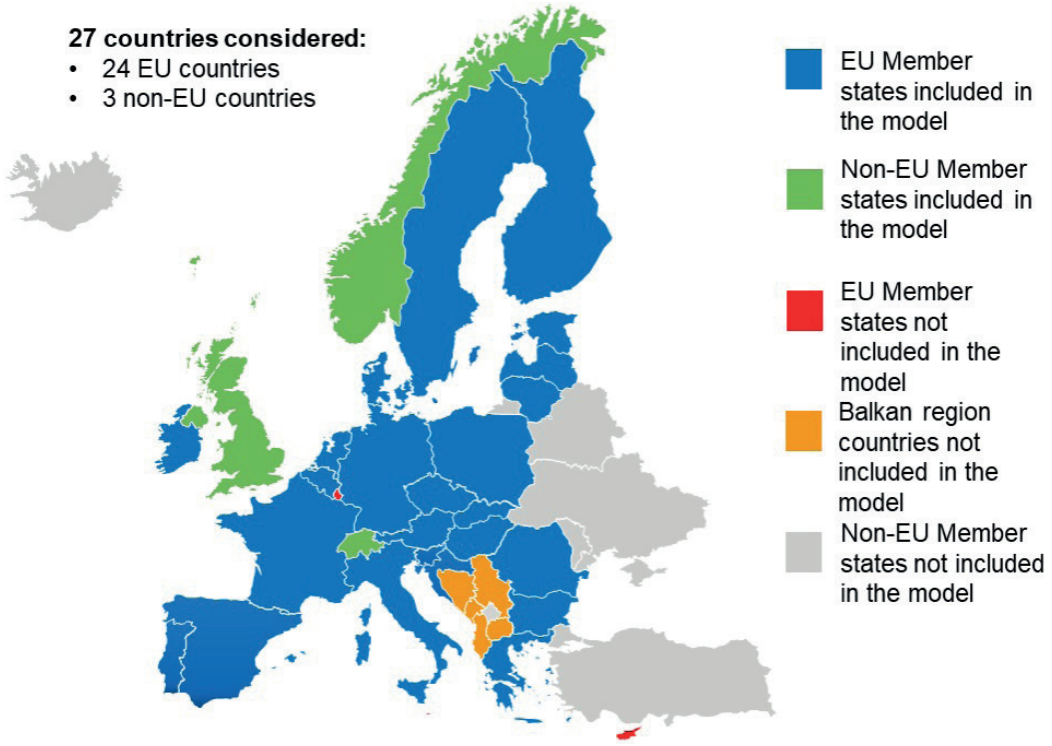
Regional Temperature-Change Potential & Absolute Regional Temperature-Change (RTP & ARTP): an extension of the GTP and AGTP concepts to include surface temperature changes at the regional level due to regional emissions, with and without being compared to a reference gas (Collins et al, 2013).

Each metric has different levels of relevance and uncertainties associated with it; however, in the case of this assessment, GWP has been used as the chosen metric due to its predominant use in the policy sector.

48. As in the study's first edition, specific constraints were implemented for the power sector, the deployment of CO_2 storage and the deployment rate of heat pumps in the residential sector:
    - To ensure the reliability of the power grid in each country in the geographical scope of this study, a restriction of minimum 20% back-up capacity from dispatchable electricity production is applied.
    - The available injection rates for CO_2 to permanent storage, measured in tonnes per year, has been restricted to 1 billion tonnes ($GtCO_2$) per year from 2020 to 2040, 1.2 billion tonnes per year in 2045 and 1.4 billion tonnes per year in 2050. This injection capacity has been derived as a reasonable estimate from a survey of existing literature and expert knowledge.
    - The potential of heat pumps follows the latest assumptions from the JRC's heat pump analysis. The JRC database has been used for the techno-economic characteristics of heat pumps for residential and commercial services.

49. This study includes 27 European countries: 24 EU Member States and 3 Non-EU countries (figure 9). Each country is represented by its own energy system, accounting for the main demand sectors and with the high-resolution technology representation as described earlier. Furthermore, countries can trade petroleum products, electricity, natural gas and hydrogen amongst each other. CO_2 can also be transported across borders, which can occur in already existing trade routes such as pipelines, or new infrastructures can be built, assuming that the corresponding investment costs are known. For hydrogen transport, the possibility to re-purpose cross-border natural gas pipelines is also considered.

Figure 9. Geographic coverage of the *Hydrogen for Europe* project



Source: Hydrogen4EU

50. The possibility to import hydrogen from non-European countries is included in the modelling framework through an import model. The import model follows a point-to-point optimisation logic, thus calculating the optimal hydrogen delivery routes to Europe over time. The landed hydrogen prices in Europe estimated in the study follow the same climate-neutrality and technology-neutrality definitions than that used for the domestic European hydrogen production. European hydrogen imports can come from North African countries, the Middle East and Ukraine, where the hydrogen can be produced both from renewable sources and/or from natural gas with abated CO_2 emissions. In alignment with the REPowerEU strategy, targeting reduced reliance on Russia, Russian-produced hydrogen has been excluded from the modelling framework which is a major update from last year's edition.

Box 4. Technological boundaries of the models

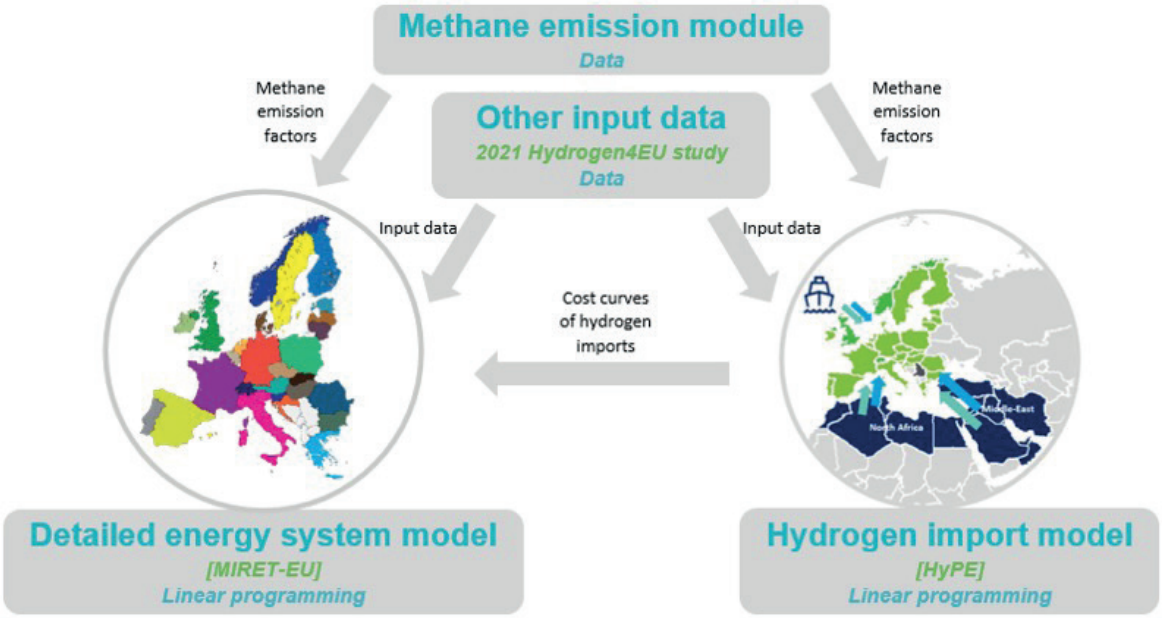
The target of climate neutrality by 2050 sparked an acceleration in the development of technologies that can contribute to the transformation of the energy system. As in the previous edition, the 2022 edition of *Hydrogen for Europe* study includes as many of these technologies as possible. The technologies were selected based on the reliability on the technology development level and availability of data for cost and energy performance. Several other technologies that that are at an earlier stage of technological development and lack reliable data are excluded from this study: e.g., the Allam cycle for electricity production from natural gas with integrated capture of CO_2, adsorption enhanced water gas shift processes for hydrogen production from natural gas or hydrogen rich off-gases from the industry, the Hazer pyrolysis process for production of hydrogen and carbon black from natural gas, pyrolysis processes with hydrogen- or electricity-fired reactors, hydrogen production from nuclear energy via thermochemical cycles or small nuclear reactors and hydrogen-fuelled open and closed cycle gas turbines.

1.3.2 The modelling framework

51. The modelling framework consists of a detailed energy system model (MIRET-EU) and a hydrogen import model (HyPE). The detailed energy system model provides a robust and proven methodology based on linear programming for the representation of the European energy system at country level, with a high degree of detail on all technologies, notably hydrogen production technologies and all other parts of its value chain. The hydrogen import model allows representing competition between European hydrogen production and imports from other countries.

52. Methane emissions calculated for the different scenarios have been converted to CO_2eq using the GWP20 value of methane. These values have been estimated by taking the weighted average of the emission factors relative to each origin composing the EU supply mix (i.e. pipeline imports, LNG imports and European local natural gas production mainly in Norway, UK, and Netherlands). It is worth mentioning that these average methane emission factors include all upstream and midstream emissions up to Europe. Methane emissions relative to the natural gas transport and distribution within Europe have also been included. The final methane emission factors have been added to the direct CO_2 emissions of natural gas leading to equivalent CO_2 emissions which are accounted at consumption sites. The same logic was applied to assess the total GHG footprint (i.e. CH_4 plus CO_2) of low-carbon hydrogen from natural gas produced outside Europe. Figure 10 shows the interactions between the MIRET-EU and HyPE models and main data flows.

Figure 10. Modelling framework linking energy system model and hydrogen import models, methane emissions module and learning-by-doing data



Source: Hydrogen4EU

Overview of the detailed energy system model – MIRET-EU

53. MIRET-EU is a multiregional (multi-node) and dynamic (inter-temporal) energy system optimisation model that minimises the cost of the overall energy system for Europe, based on the partial equilibrium of the different energy demand sectors and end-uses. This model is part of the MARKAL-TIMES[20] models developed by IFPEN. The modelling framework of MIRET-EU follows the same one developed successively in the PET36[21], the JRC-EU-TIMES, MIRET-FR[22] and TIAM-IFPEN[23] models with additional expertise from IFPEN in specific sectors such as transport, refineries and bioenergy conversion technologies, hydrogen infrastructure, power sector and industry.

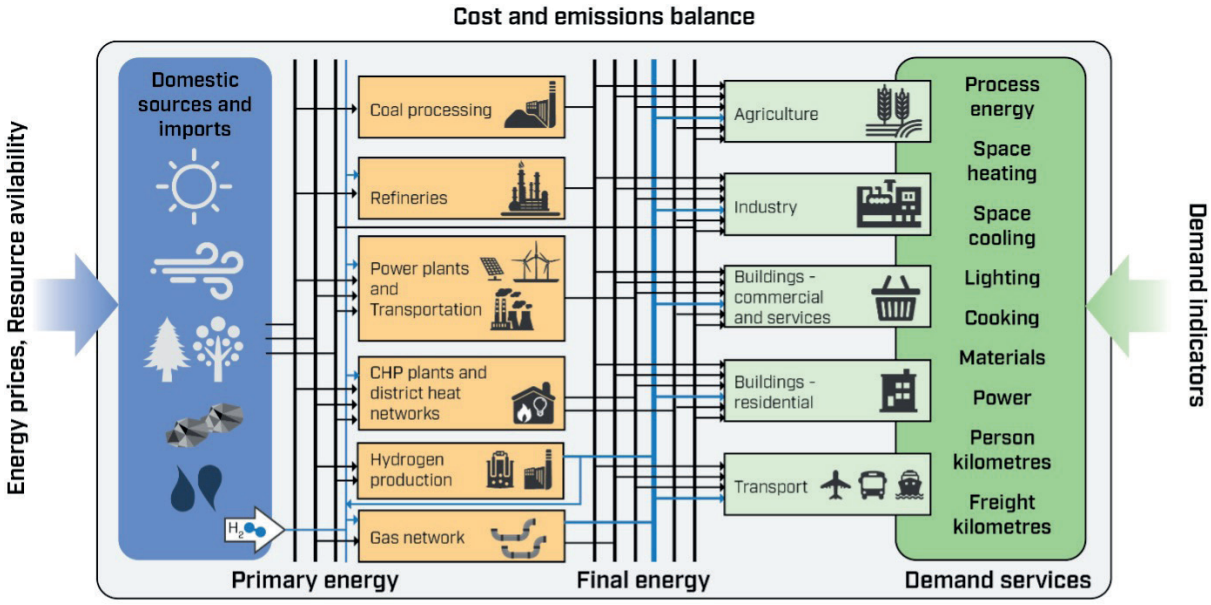
54. The MARKAL-TIMES models' equations are detailed in the ETSAP[24] documentation. MIRET-EU is a bottom-up techno-economic model that estimates the energy dynamics by minimising the total discounted cost of the system over the selected multi-period time horizon through powerful linear programming optimisation tools. The components of the system cost are expressed on an annualised form and the constraints and variables are linked to the considered periods. Special care is taken to precisely track cash flows related to process investments and dismantling for each year of the horizon. The total cost is an aggregation of the total net present value of the stream of annual costs for each of the model's countries.

55. MIRET-EU represents in detail the European energy system divided into 27 countries. It is set up to explore the development of the European energy system from 2016 until 2050 with 10-year steps and is calibrated on the latest data provided by energy statistic offices such as JRC-IDEES[25] database, POTEnCIA[26] database, EUROSTAT database, and other international databases from IEA, IRENA, World Bank, among

[20] MIRET has been based on the TIMES model generator, developed by one of the IEA implementing agreements (ETSAP) in 1997 as a successor of the former generators MARKAL and EFOM with new features for understanding and greater flexibility. The manuals and a complete description of the TIMES model appear in ETSAP documentation (https://iea-etsap.org/index.php/documentation)
[21] The Pan-European TIMES (PET) model has been developed by the Kanlo team following a series of European Commission (EC) funded projects
[22] MIRET-FR has been the version developed for France by IFPEN 13 years ago.
[23] TiAM-IFPEN (TIMES Integrated Assessment Model) is the world version currently developed by IFPEN 4 years ago.
[24] Energy Technology Systems Analysis Program, one of the longest running technology collaboration programmes of the International Energy Agency (IEA), since 1976. https://iea-etsap.org/index.php/documentation
[25] JRC-IDEES (Integrated Database of the European Energy System) that is first released in July 2018 and is revised periodically. We then used the latest data released in September 2019.
[26] POTEnCIA (Policy-Oriented Tool for Energy and Climate change Impact Assessment)

others. The model is data driven[27], its parameterisation refers to technology characteristics, resource data, projections of energy service demands, policy measures, etc. Therefore, the model results such as technology pathways or changes in trade flows vary as the data inputs vary. For each country, the model includes detailed descriptions of numerous technologies, logically interrelated in a Reference Energy System – the chain of processes that transform, transport, distribute and convert energy into services from primary resources and raw materials to the energy services needed by end-use sectors (figure 11).

Figure 11. Simplified overview of the energy system covered in the detailed energy system model



Note: European produced hydrogen is not considered as a primary energy (left hand side) but is represented on the figure for illustrative purposes.

Source: Based on Remme and Mäkela (2001)

Overview of the Hydrogen Pathway Exploration model (HyPE)

56. The HyPE model provides the main energy system model with hydrogen import supply curves from neighbouring regions to represent the competition between domestically produced hydrogen and imports, and between import routes. In line with the EU hydrogen strategy, HyPE focuses on clean hydrogen trade and evaluates the potential partnership with Southern and Eastern Neighbourhood countries. As such, renewable and low-carbon hydrogen can be imported to Europe from North Africa, the Middle East and Ukraine in HyPE.

57. The model estimates hydrogen imports' supply curves, indicating both the potential hydrogen volumes that can be landed into Europe given the local challenges in exporting countries and its associated costs. It follows a levelized cost of hydrogen approach (LCOH[28]). The LCOH is calculated for every link between exporting countries and each delivery point in Europe (Cost, Insurance and Freight logic[29]). The methodology builds on the full delivery value chain from the hydrogen production sites to delivery points.

58. In the upstream, depending on resource endowments, all hydrogen production technologies and their associated cost evolutions are considered as possible for exports. A country-specific risk consideration was included as a mark-up to the weighted average cost of capital (WACC) of each country based on the Ease of Doing Business scores (World Bank, 2020). In the midstream, the transport modes cover inland transport for the transport from production site to exit point in each country of origin (i.e., by national pipelines, gasified

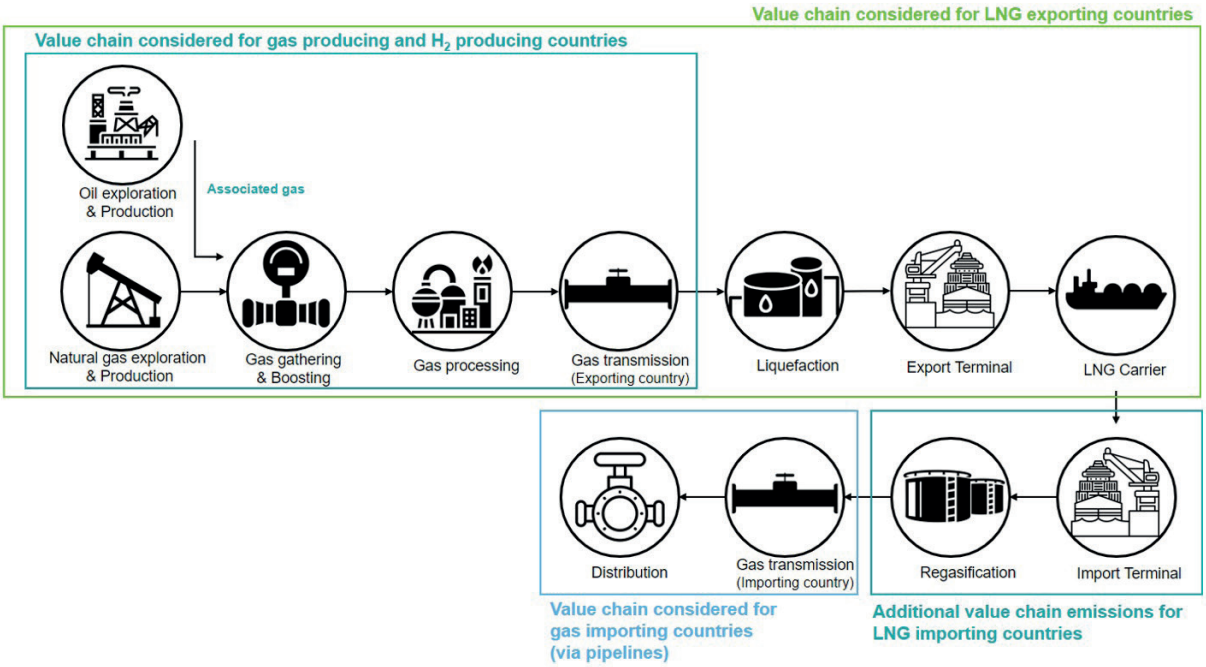
[27] Data in this context refers to the assumptions regarding the input parameters, technology characteristics, projections of energy service demands, etc. Thus, it does not refer to historical data series
[28] The levelized cost of hydrogen (LCOH) uses the life-cycle cost calculation methodology where all related costs and produced quantities are included to compute an average ration on the cost per kilogram produced.
[29] Cost, Insurance and Freight (CIF) includes the cost of transport and logistics from the exit point to the entry point in Europe.

hydrogen trucks and/or ammonia trucks), and international transport for the segment from the exit point, in the producing country, to the entry in Europe (i.e., by cross-border pipeline interconnectors and/or maritime shipping routes). The optimal combination between the transport mode, the distances and the flows are obtained by an optimisation approach resulting in least-cost LCOH CIF import curves. Further details on the methodology are provided in annex E.

1.3.3 Methane emission factor module

59. Methane emissions along the gas value chain were compiled for three cases, for over 30 countries between 2019 and 2050, estimating over 150 emission factors overall. Emission factors were assessed for (1) countries exporting gas to Europe via pipeline (2) countries shipping LNG to Europe (3) countries exporting low-carbon hydrogen to Europe (4) European gas producing countries and (5) European countries importing gas or LNG from other countries. The boundaries considered for the emission factor estimation are different for each category, as shown in figure 12.

Figure 12. Natural gas value chain steps considered for the EF calculations



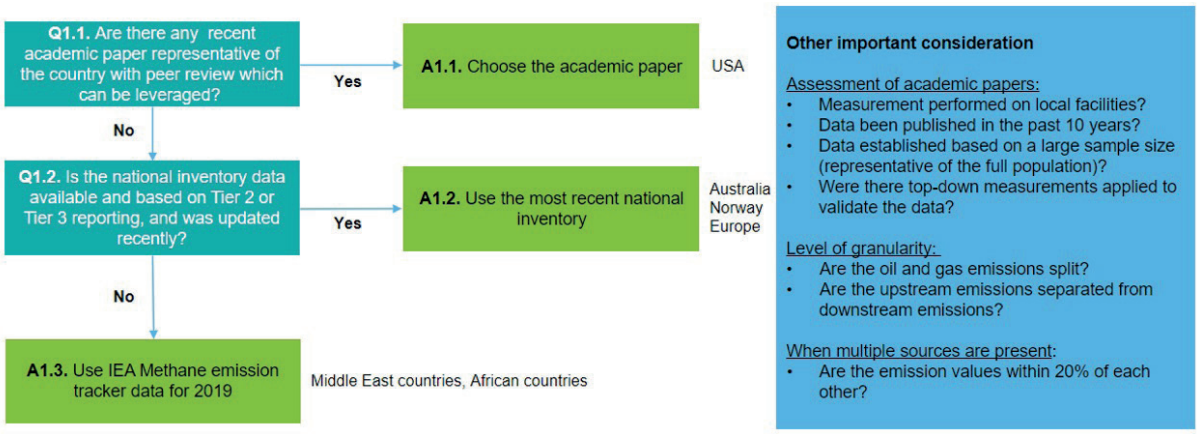
Source: Hydrogen4EU

60. As a first step in the methane emission assessment, current emission factors have been estimated to track the current state of the methane emissions for natural gas and its derivatives depending on its origins. Later, these emission factors have been used in combination to abatement technology development and mitigation policy assumptions to derive the future level of emissions in the *BAT*, *Current Emissions* and *Harmonised Pledges* cases (see box 2 for their definition).

Estimating current methane emissions of natural gas value chain

61. A preliminary step for estimating the future evolution of methane emissions is to assess their current levels, along the value chain of natural gas and low-carbon hydrogen consumed in Europe. This implies selecting the best available source of emissions data at each country and each step of the value chain. A decision tree was developed to select the best available source for each country, as depicted in figure 13. Several other aspects were also considered while selecting the source, to obtain the EFs in the format required for the models. In the *Current Emissions* case, that assumes a status quo in terms of methane emissions' mitigation, the current levels of EFs are directly used as flatline throughout the whole modelling period.

Figure 13. Decision tree to identify the best source for estimating current methane emissions



Source: Hydrogen4EU

62. The following steps were applied to estimate the emission factors:

    a. **Upstream**: emissions from exploration and production of natural gas, gathering and boosting stations, and processing of natural gas were summed up separately and divided by volume of associated and non-associated natural gas produced in the country, to obtain the upstream emission factors for each country.

    b. **Mid- and Downstream**: only transmission emissions were considered for natural gas, low-carbon hydrogen and LNG exporting countries, while importing countries have both transmission and distribution emissions considered. Each of the transmission and distribution emissions were divided by the total volume of natural gas produced, and/or imported into the countries, to estimate the downstream emission factors.

    c. **LNG**: emissions from LNG liquefaction and LNG carriers are associated with exporting country emission factors, while emissions from LNG unloading, and regasification are associated with importing country emission factors. Carbon Limits internal model was used to estimate the LNG carrier emissions. The LNG model is based on several scientific papers and developed in consultation with stakeholders in the maritime industry. The model used average travelling days from LNG exporting country to Europe, distance between the exporting region and Europe and the speed of the ship to estimate the EFs for LNG carriers. Considering the lack of data in this segment, a report from Marcogaz (technical association of the European gas industry) was used to obtain the emission factors for LNG liquefaction and regasification. Total emissions were divided by volume of LNG transported, to obtain the LNG emission factors.

Estimating methane emission factors for the *BAT* case

63. In the *BAT* case, future emission factors are estimated by applying all the potential methane abatement technologies along the natural gas value chain. IEA abatement potential, industry targets set in the countries assessed, or global industry targets for best available technology were considered to estimate the impacts on emission factors from the reference year (2019) to 2050. Depending on the chosen source of information for estimating the current levels of emission factors, different methodologies were applied:[30]

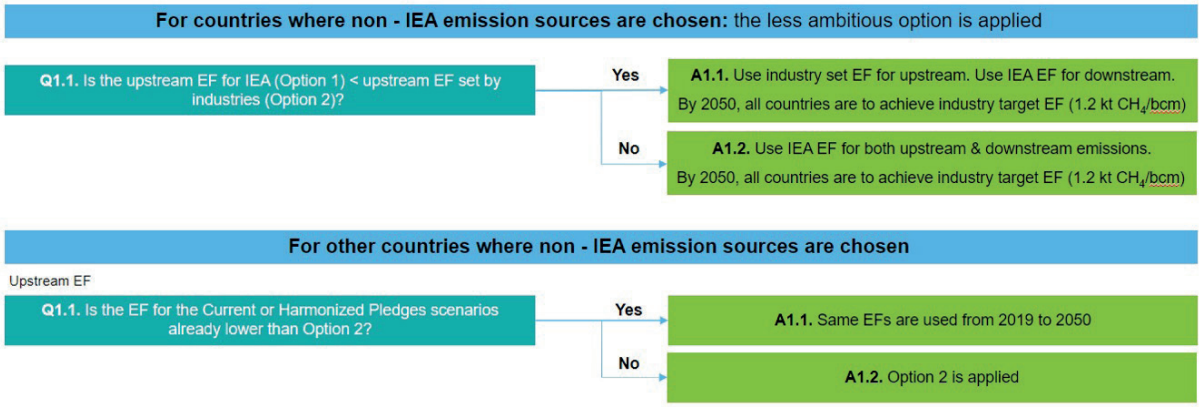
    a. **Option 1**: methane abatement values from IEA methane tracker were used to estimate emission reduction potential - assuming that abatement options at no-net cost are achieved by 2030 and those with positive net-cost by 2035.

    b. **Option 2**: OGCI industry targets for upstream methane emissions for all countries (methane emission intensity of 0.25% by 2030 and 0.20% by 2035) were applied .

[30] The 0.25% target corresponds to an emission factor of 1.50 $ktCH_4$/bcm and the 0.20% target corresponds to an emission factor of 1.20 $ktCH_4$/bcm. https://www.ogci.com/action-and-engagement/reducing-methane-emissions/

64. A decision tree was used to select the best methodology for each country, as depicted in figure 14. When necessary, interpolations between years were made. Several country-specific aspects were also considered while estimating emission factors from 2030 to 2050.

Figure 14. Decision tree to identify the best methodology for *BAT* case



Source: Hydrogen4EU

Estimating methane emission factors for the *Harmonised Pledges* case

65. The *Harmonised Pledges* case considers the effect on methane emissions of country policies, Nationally Determined Contributions (NDC) relevant for GHG emission reduction and international pledges, to assess the evolution of emission factors from the reference year (2019) to 2050. Three international pledges were considered in the assessment (1) Zero Routine Flaring by 2030[31] (2) Methane Pledge Initiative[32] and (3) Methane Alliance initiative[33].

66. Countries were divided into four categories depending on their policies and participation in international pledges (see table 12 in annex C for further information):

    a. **Category 1**: countries with relevant GHG emission reduction policy / NDC and international pledges. The policy or NDC reduction goal is applied by the target year. Then, the optimistic target within international pledges is applied.

    b. **Category 2**: countries with relevant GHG emission reduction policy / NDC without any international pledges. Any policy or NDC target is applied by the target year. The emission factor remains flat beyond this, until 2050.

    c. **Category 3**: countries without policy / NDC relevant for GHG emission reduction and only international pledges. The Zero Routine Flaring is applied by 2030 followed by the less optimistic target among the signed international pledges.

    d. **Category 4**: Countries with no policy / NDC / international pledges and countries where current emission factors are lower than *BAT* emission factors. The emission factors remain flat from 2019 to 2050.

[31] The "Zero Routine Flaring by 2030" initiative is introduced by the World Bank, including commitments to (a) not routinely flare gas in new oil field developments and (b) to end routine flaring in existing (legacy) fields as soon as possible and no later than 2030.
[32] In the "Methane Pledge" initiative, participants joining the pledge agree to take voluntary actions to contribute to a collective effort to reduce global methane emissions at least 30 percent from 2020 levels by 2030.
[33] In the "Methane Alliance" initiative, participants joining have two options as possible targets. (a) Absolute reduction target of at least 45% reduction in methane emissions by 2025 and 60% to 75% by 2030. (b) Intensity target of "near-zero" methane emissions, targeting a CH_4 emission intensity of 0.25% or below.

2 Decarbonising the European energy system

67. The European energy system is engaged in an ambitious transformation effort that aims at achieving climate neutrality by 2050 in the EU. This is a formidable undertaking: in 2019, the European energy system emitted nearly 3 billion tonnes of CO_2[34], stemming mostly from the use of fossil fuels and biomass in a variety of sectors such as buildings, transport, industry or power generation. Reaching net-zero emissions in 2050, as targeted by European policy-makers, requires a coordinated strategy across all sectors, that achieves further electrification of end-uses, energy efficiency improvements, renewable energy deployment and the development of alternative technologies, carriers and fuels, such as hydrogen, biofuels, ammonia or synthetic fuels. This entails an acceleration of efforts compared to the past thirty years, that saw CO_2 emissions decrease by only a third. In response, policy-makers have set interim targets that should trigger early investments and transformation and put the European energy system on the path to net-zero. This includes notably the binding target at EU level to reduce CO_2 emissions by 55% between 1990 and 2030.

68. The efforts needed to keep global warming well below 2°C require looking further than just CO_2 emissions (IPCC, 2022). They entail the extension of targets to other greenhouse gases, which are responsible for about 25% of the observed warming of the atmosphere today[35]. In this respect, European policy-makers are also committed to reducing methane emissions, pledging notably to lower them by 30% between 2020 and 2030. Looking further in time, achieving climate neutrality in Europe by 2050 implies a parallel decrease of both CO_2 and methane emissions. The net-zero goal needs to encompass both greenhouse gases, as advised by the 2022 IPCC report.

69. The *Hydrogen for Europe* study describes in detail the challenges and transformation actions associated with European climate goals. Its Technology Diversification and Renewable Push pathways explore the progressive transition to net-zero emissions by 2050 from the perspective of energy system economics. Compared to the study's first edition, the pathways have been updated to capture the latest regulatory and economic dynamics. This allows for further assessing the resilience of energy transition and hydrogen strategies to major economic and geopolitical disruptions. The new results are notably based on the following key constraints:

    a. A net-zero emission target for 2050 combining both CO_2 emissions and methane emissions (in CO_2 equivalence) associated with natural gas consumed in Europe and allowing for negative CO_2 emissions.

    b. Intermediate reduction targets based on a 55% reduction in CO_2 emissions between 1990 and 2030[36].

    c. A renewable energy target for Europe of at least 40% of gross final energy consumption in 2030.

    d. And a phase-out of imports of Russian energy commodities by 2030 at the latest.

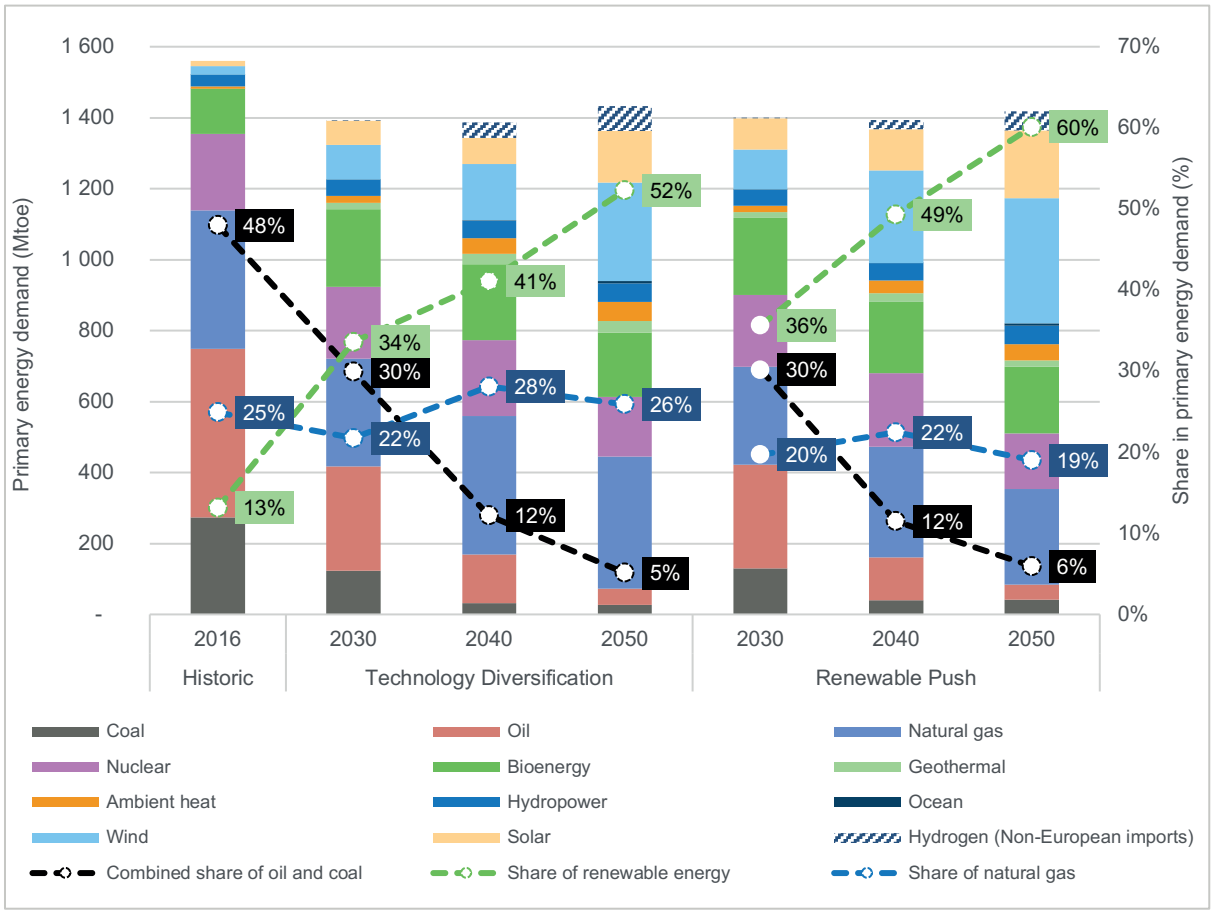
2.1 Evolution of total primary energy demand

70. Primary energy demand in Europe falls by 8% and 9% over the outlook period in the Technology Diversification and Renewable Push pathways (figure 15)[37]. This corresponds to a compound annual growth rate of -0.25% and -0.28% respectively. This decrease is mostly driven by a reduction in the final energy demand (see section 2.2), underpinned by the further electrification of some end-uses and general efficiency gains. Energy efficiency improvements at end-use level are partially offset by increased losses in the transformation process, for production of alternative energy carriers like hydrogen and e-fuels.

71. Both *Hydrogen for Europe* pathways show a fundamental transformation in the primary energy mix, manifested by a major switch from fossil sources to renewable energy. This is supported by increasingly constraining targets for GHG emission reduction, continued technology improvement, and binding targets on their deployment.

[34] https://data.worldbank.org/indicator/EN.ATM.CO2E.KT?locations=EU
[35] https://www.statista.com/topics/4958/emissions-in-the-european-union/#dossierKeyfigures
[36] An interim target has been implemented in the models for 2040 to allow a linearization of the reduction in emissions. The binding trajectory for both CO_2 and methane emissions along the outlook period is based on the resulting pace in CO_2 emission reduction
[37] The results are compared with 2016 historical values from the JRC database through the whole report. The latest available database consolidated concerns 2015-2016 data.

Figure 15. Evolution of total primary energy demand in the Technology Diversification and Renewable Push pathways, 2016 to 2050



Definition of primary energy content is based on Eurostat methodology[38].

Source: Hydrogen4EU

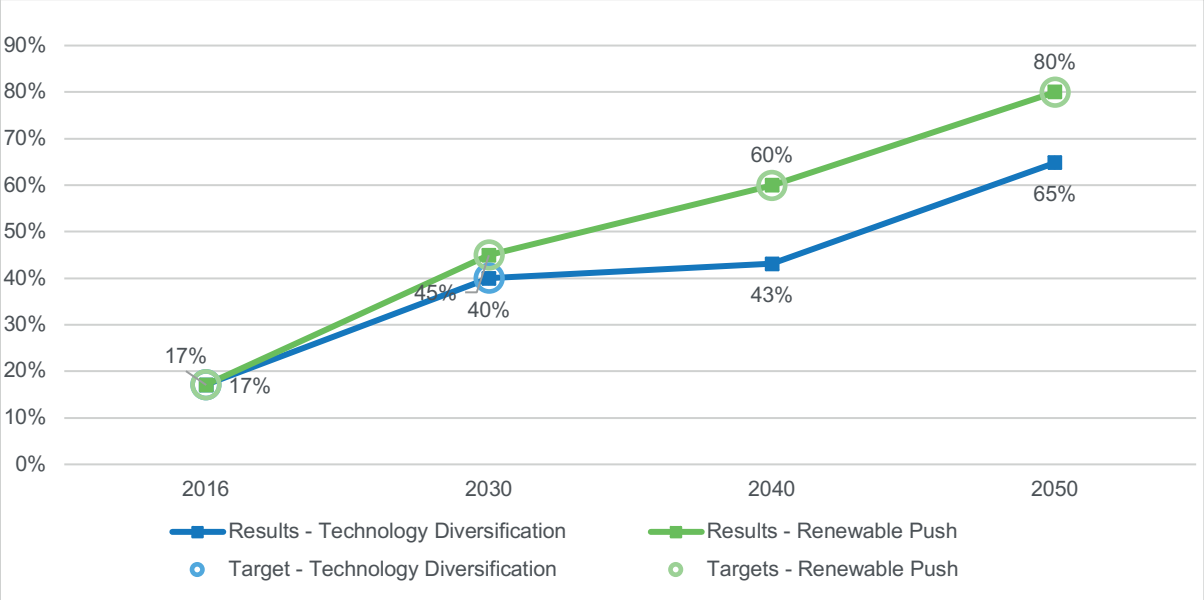
72. In the Technology Diversification pathway, the development of renewable energy is fostered by a 40% binding target on its share for 2030 (related to gross final energy consumption), reflecting the current consensus emerging from the Fit-for-55 negotiations (figure 16). In the long term, renewable energy contributes to decarbonisation efforts on a level playing field with other low-carbon hydrogen technologies. Increasing decarbonisation constraints and improved techno-economic conditions[39] stimulate further deployment of renewables in the 2030s and 2040s. The renewable energy share in gross final energy consumption reaches 65% by the end of the outlook period, nearly four times the historic share. By then, renewable energy supplies about 750 Mtoe to primary energy demand.

73. The Renewable Push pathway is guided by higher ambitions for renewable energy development. The 2030 binding target is fixed at 45% of gross final energy consumption in 2030, reflecting the current discussions stemming from the REPowerEU plan on a further acceleration of renewable energy deployment. Like for 2030, new binding minimal shares of 60% and 80% for 2040 and 2050 condition the growth of renewable energy in the subsequent years. By 2050, renewable energy covers about 60% of the total primary energy demand, or more than 850 Mtoe.

[38] See Eurostat, 2019. Calculation methodologies for the share of renewables in energy consumption. https://ec.europa.eu/eurostat/statistics-explained/pdfscache/43297.pdf
For example, according to the Eurostat methodology, primary energy content of solar photovoltaic, wind, hydropower and ocean is based on the electricity content.

[39] Maximum potential, competition between the different technologies and supply sources.

Figure 16. Evolution of the share of renewable energy in final gross energy consumption in the Technology Diversification and Renewable Push pathways from 2016 to 2050



Source: Hydrogen4EU

74. The shift to renewable energy relies in both pathways on an ambitious roll-out of wind and solar technologies. In the Technology Diversification pathways, these energy sources provide up to 420 Mtoe by 2050. This covers some 30% of total primary energy demand and corresponds to a more than ten-fold increase from historic levels. The Renewable Push pathway shows an even sharper increase in the development of wind and solar: their combined supply reaches nearly 550 Mtoe by 2050, representing nearly 40% of primary energy demand and fourteen times the volumes supplied in the past. Bioenergy is the second most important renewable energy source. Bioenergy helps the integration of wind and solar power in the energy system by providing further flexibility to both power generation and hydrogen supply. Combining biomass combustion with carbon capture and storage (CCS), can also lead to negative emissions. Bioenergy supply increases by more than 60% over the next decade, reaching more than 200 Mtoe across the 2030s. Its development and long-term role are however constrained by the competitiveness of other technologies and the available potential. Other renewable energy sources like geothermal, hydroelectricity, ambient heat and ocean energy nearly double their supply during the outlook period. Their overall share of primary energy demand remains limited as their potential is either costly or already largely exploited today.

75. The upscaling of renewable energy is mirrored by a dwindling role for oil and coal in the energy system. Their combined share in primary energy demand drops from 48% in 2016 to 5% and 6% in 2050 in the Technology Diversification and Renewable Push pathways. By the end of the period, they provide less than 85 Mtoe (mostly oil) in the two pathways. Oil and coal have a high CO_2 intensity that makes them incompatible with a climate-neutral energy system. Their progressive replacement is also conditioned by increasingly stringent policy actions. Current measures already include a progressive phase-out of coal in the power sector[40], and ambitious CO_2 emission thresholds in the transport sector. European policy-makers are well-advanced in their negotiations to agree on an ICE sales ban for light-duty vehicles from 2035 on, as proposed in the Fit-for-55 package[41]. In any case, the progressive switch away from coal and oil will be challenging and it

[40] Phase-out of coal power production facilities is widely discussed in Europe. Where phase-out decisions have been included in the national NECP or law, phase-out of the corresponding power plant capacities have been included in the modelling. Accelerated phase-out of the existing coal power plants and reaching end of lifetime leads to an average capacity reduction of 92% between 2020 and 2050 (12 GW in 2050). The *Hydrogen for Europe* study also shows very minor investments in coal power production plants with CCUS. Coal power generation in Europe saw a steep decrease in 2019 due to the strong renewable electricity generation and coal-to-gas switching (IEA, 2020). Nevertheless, retrofitted coal power plants with CCS appears to be a solution for decarbonisation in other parts of the world and cannot be disregarded entirely. The IEA identifies it as an attractive solution for Southeast Asia where 45% of the installed capacity of fossil-originated power generation was built within the last decade, and 70% within the last 20 years.

[41] https://www.europarl.europa.eu/news/en/press-room/20220603IPR32129/fit-for-55-meps-back-objective-of-zero-emissions-for-cars-and-vans-in-2035

will take time: both energy sources still provide nearly half of the primary energy supply today, and it will be technically and economically challenging to substitute them entirely throughout the energy system.

76. Nuclear energy, despite being a decarbonised energy source, sees its contribution decreasing slightly in both pathways. The share of nuclear energy remains relatively stable, sliding from 14% in 2016 to between 11% and 12% in 2050. In absolute terms however, nuclear energy supply falls by around a quarter during the outlook period. Its supply decreases to in 2050 at 170 Mtoe in the Technology Diversification pathways and 160 Mtoe in the Renewable Push pathway. This decrease is directly reflected in the electricity mix, where the share of nuclear drops by more than 10 percentage points (from 24% in 2016 to 10% in the Technology Diversification and 8% in the Renewable Push pathways by 2050). Nuclear power generation capacity decreases from 127 GW in 2016 to below 100 GW in 2050. Several countries have announced their intention to refrain from using nuclear (such as Germany, Switzerland or Belgium) in the future, while others have reinstated their ambitions to build new nuclear power stations (e.g., the UK, Czech Republic, Hungary, Finland, France, Poland, etc.)[42], putting in some cases nuclear energy at the centre of their decarbonisation and hydrogen strategies. Although nuclear energy keeps a relatively resilient role in low-carbon electricity supply, in the absence of a strong and harmonised political support it is subject to a progressive decline as new nuclear power plants (EPR – European pressurised water reactors) are costly and they face very long permitting and construction periods[43].

77. The *Hydrogen for Europe* pathways show that natural gas can play an important role in the European energy transition, provided the oil & gas industry swiftly acts to tackle existing barriers and uncertainties. In the Technology Diversification pathway, supply from natural gas lands at around 370 Mtoe in 2050, a near 10% drop compared to recent historical values. Natural gas' value is maximised when it is coupled with CCS. Much of its consumption is thus shifted from final energy demand to intermediary transformation processes, notably to low-carbon hydrogen production and power generation. The transition period shows a temporary drop in supply as a reaction to the current economic and geopolitical crisis: progressive exclusion of Russian natural gas from the supply mix and lead times in the uptake of additional LNG capabilities result in supply falling around 2030 to levels as low as 300 Mtoe (-22% compared to 2016). Supply gradually ramps up again during the 2030s as LNG additions cover the supply gap. By the end of the outlook period, the share of natural gas falls back to around a quarter, markedly below the historical peak.

78. Natural gas plays a more downbeat role the Renewable Push pathway. By 2050 it covers less than a fifth of primary energy demand by 2050, or 270 Mtoe. Over the medium term, the 45% renewable energy target for 2030 helps to replace Russian natural gas imports, leading to a pronounced drop of natural gas demand in the period to 2030. In the Renewable Push pathway natural gas demand does not fully recover from the demand reductions triggered by the phase out of Russian gas imports in the period to 2030. As such, the ambitious development of renewable energy in the 2030s and 2040s implies lesser needs for LNG imports over the outlook period. The 30% difference in 2050 supply levels between our two pathways mostly affect the prospects of low-carbon hydrogen.

[42] About 10 GW of nuclear power plants are planned or under consideration to be operational by 2030 according to the World Nuclear Association (Nov. 2020 update) including 1.6 GW in Finland, 2.4 GW in Hungary, 1.4 GW in Romania and 1.2 GW in Czech Republic. France is expecting to have 1.6 GW of new nuclear power plant capacity to be added to the grid by 2025 and is currently assessing the economic feasibility of construction of 6 new nuclear reactors (EPR2) as an alternative roadmap to a 100% renewable scenario. Nevertheless, the additional 6 EPR2 reactors are not expected before 2040. The UK, with its existing new nuclear power plant project under construction (Hinkley Point C), will add around 3 GW of new nuclear power capacity to its power system by 2030, and the British government is analysing new potential candidate projects (such as Sizewell C) under innovative new financing schemes to boost its nuclear capacity by up to 24 GW by 2050.

[43] In European scale, three EPR power plants are being constructed: Flamanville 3 in France, Hinkley Point C in the UK and Olkiluoto 3 in Finland. By the beginning of July 2022, the first two plants are under construction (Flamanville 3 since 2007 and Hinkley Point C since 2018) and Olkiluoto 3 power plant has ended its construction phase in early 2022 (start of the construction in 2003, 19 years of construction), yet it hasn't started power generation.

79. Against the backdrop of severe turmoil on natural gas markets and the strong impact of methane emissions on climate change, continued natural gas use as depicted in the *Hydrogen for Europe* pathways is contingent on three inter-related conditions:

    a. **Natural gas supply needs to be secure**. The current energy crisis and the decision by European governments to phase out Russian gas have been amplifying political, social and industrial defiance against natural gas. The industry therefore needs to demonstrate that it can replace Russian supply – in the short and in the long term – in a timely manner and at affordable cost. Confronted with skyrocketing prices and lingering shortage risks, existing and potential future consumers might otherwise revise their strategies and favour the visibility and stability offered by other options.

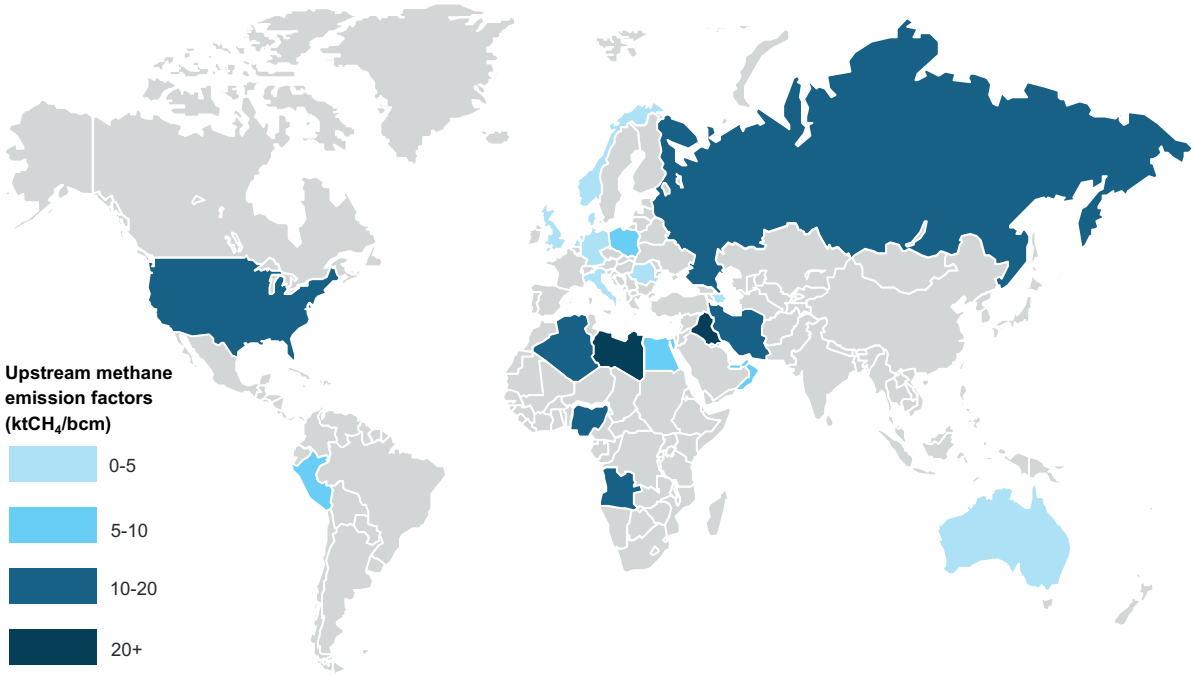
    b. **Natural gas requires a capable CCUS value chain**. The contribution of natural gas to climate policy objectives is inseparably linked to the success of CCUS deployment. As shown in section 2.3, the CCUS value chain must scale up substantially in the years to come to accommodate up to 300 $MtCO_2$ of carbon capture and storage already by 2030. Failure to alleviate barriers related to CCUS (especially social acceptance and regulatory hurdles) would deteriorate both the short- and long-term prospects of natural gas in the transition. The challenge becomes bigger as one gets closer to 2050: as GHG emission reduction targets become increasingly constraining, increasing volumes of CO_2 need to be stored to allow for a sustained role of natural gas in the mix while also unlocking negative emissions from biomass and direct air capture.

    c. **Natural gas needs to be clean**. A strong and unmistakable determination of the oil & gas industry to abate methane emissions along the natural gas value chain is indispensable if natural gas wants to play a role in the transition. The Technology Diversification and Renewable Push pathways show that if best available technologies are deployed rapidly, the additional burden caused by methane emissions on the GHG intensity of natural gas can drop from nearly 40% to below 10%, thus allowing for a sustained role for natural gas in the transition. However, if methane emissions were to stay at current emission levels, natural gas would share the same fate as oil and coal with its share in primary energy demand plummeting to around 9% by 2050 (box 5).

Exploring the importance of methane emissions

80. Natural gas extraction, transformation, transport, distribution and consumption processes are associated with unwanted methane emissions. Indirect methane emissions are caused by methane leakage from these processes. For tracking and analysis purposes, it is generally advised to classify methane emissions between upstream (extraction and processing), midstream (transmission, liquefaction for LNG and regasification of LNG)) and downstream (distribution and consumption). For the modelling purposes, in this study midstream emissions are decomposed and divided between upstream and downstream sections to represent the origins of natural gas at the borders of Europe. Upstream emissions depend on the methane producing country, while downstream emissions depend on the importer. Upstream methane emissions vary significantly among the natural gas producers: Libya and Iraq (with 60 and 45 $ktCH_4$/bcm) were the countries with the highest methane emissions in 2019, while Norway and UK (less than 0.05 $ktCH_4$/bcm) are at the other end of the spectrum (figure 17). Methane emissions of natural gas consumed in Europe therefore first and foremost depends on the origin of the natural gas. Import choices of natural gas can also seriously affect the overall methane footprint: the import option (pipeline or LNG via shipping), distance of transport and distance of distribution within Europe can add more than 20% to the upstream emissions.

Figure 17. Upstream methane emissions of gas producing countries



Source: Hydrogen4EU – based on 2019 methane emission data from BP (2021)

81. If unmitigated, methane emissions can seriously increase the impact of natural gas use on global warming. This is because methane is much more potent as a greenhouse gas than CO_2: considering the GWP20 referential of the *Hydrogen for Europe* study, 1 tonne of methane is considered to have a global warming impact similar to 82.5 tonnes of carbon dioxide. That means that in countries with high upstream emissions (more than 25 $ktCH_4$/bcm, such as natural gas produced in Iraq and Libya), direct CO_2 emissions associated with natural gas combustion[44] actually have a lower impact on global warming than the indirect methane emissions. Said otherwise, methane emissions along the value chain can significantly increase the climate burden associated with natural gas being used in Europe.

82. In such a context, methane emission reduction should become a key strategy of the oil & gas industry to improve the climate footprint of natural gas and secure their licence to operate. The *Hydrogen for Europe* pathways show that implementing best available technologies allows for a progressive decrease of the methane footprint associated with natural gas, from nearly 9 $ktCH_4$/bcm in 2019 to 2 $ktCH_4$/bcm in 2050. By that date, the additional climate burden caused by methane emissions drops to around 8% (from nearly 40%), enabling the sustained role of natural gas as observed in the results.

[44] Natural gas combustion without capture leads to nearly 1,800 $ktCO_2$ of direct CO_2 emissions for 1 bcm of natural gas.

Box 5. No place for natural gas without resolute methane emission reductions

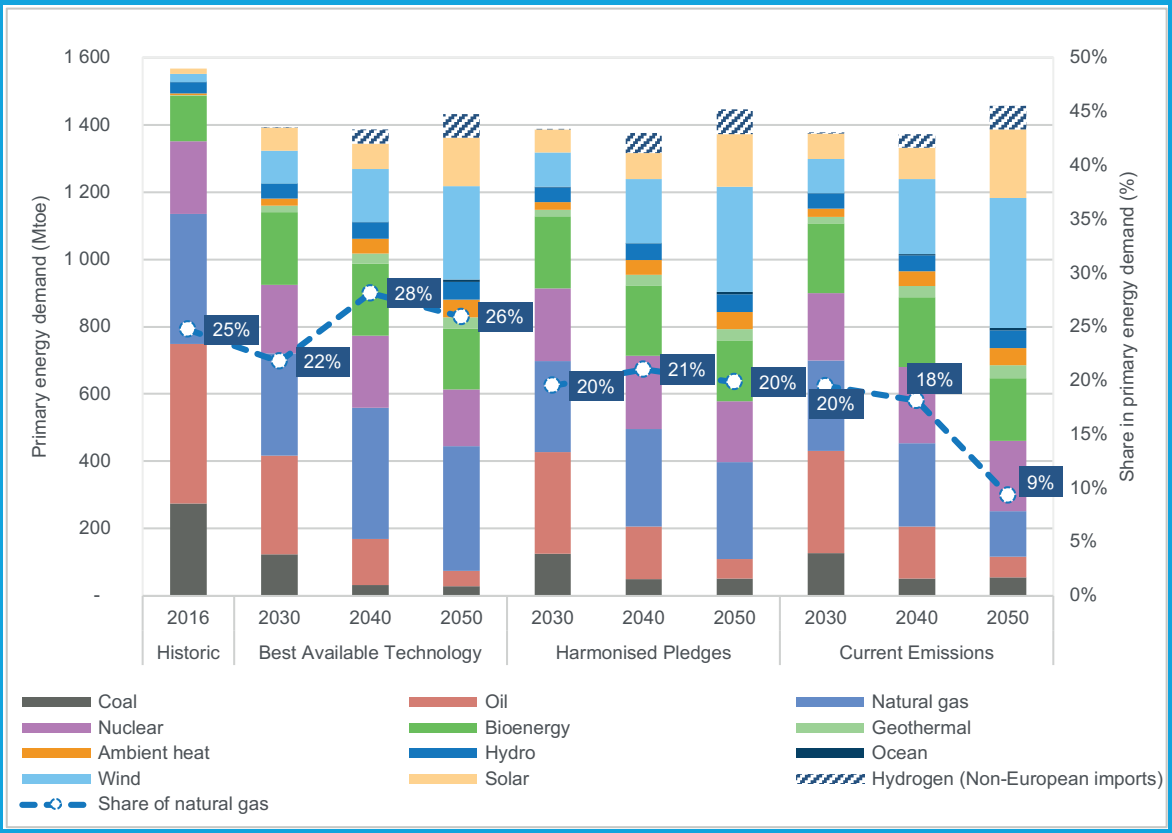
The two main *Hydrogen for Europe* pathways are based on the *BAT* methane emission case, that assumes that industry players and policy-makers act swiftly to deploy best available technologies to mitigate methane emissions. Two alternative cases were also run to assess the consequences on the Technology Diversification pathway if no or limited mitigation actions are taken:

a. The *Current Emissions* case assumes a status quo in terms of methane emission mitigation, with no further implementation of methane emission reduction options. Methane emissions linked to each step of the value chain and each producing region remain at current levels due to inaction by policy or industry stakeholders.

b. The *Harmonised Pledges* case considers the effect on methane emissions of country policies, Nationally Determined Contributions (NDC) relevant for GHG emission reduction and international pledges; leading to some concrete actions to tackle methane emissions but without reaching the ambitions of the *BAT* case. This case assesses the evolution of methane emission factors of natural gas from the reference year (2019) to 2050. Three international pledges were considered in the assessment (1) Zero Routine Flaring by 2030 (2) Methane Pledge Initiative and (3) Methane Alliance initiative.

The additional results (see annex A for more detail) show that absence of action from industry or policy stakeholders, as depicted in the *Current Emissions case*, leads to a markedly different energy system over the long term. Looking at the primary energy mix (figure hereafter), a drastic drop of natural gas use is observed, with supply of natural gas dropping to below 140 Mtoe in 2050, 60% lower than in the *BAT* case. Natural gas market share by that date is 9%, placing natural gas around the same position as oil and coal. In that case, there are no long-term prospects for low-carbon hydrogen, with production dwindling to zero by 2050. In the *Harmonised Pledges* case, mitigation actions do not go further than what is envisaged by current pledges and regulations: the long-term share of natural gas in the mix levels at 20%, 6 percentage points less than in the central *BAT* case.

Figure 18. Evolution of total primary energy demand in the Technology Diversification pathway with different methane emission factor cases from 2016 to 2050



Source: Hydrogen4EU

Concluding from these results, deploying the most advanced methane abatement solutions is a precondition for continued use of natural gas and the deployment of low-carbon hydrogen in Europe in the long term. Although the current pledges are a pointer in the right direction, they are not sufficient to secure natural gas a role in the energy transition. It is therefore indispensable that the industry – on its own initiative – shows the way by going beyond the existing policy goals for methane emission reduction. By 2030, natural gas-related methane emissions in the *BAT* case are 45% below the 2020 levels, achieving an additional 21 percentage points of reduction as compared to the *Harmonised Pledges*. By 2050, 150 $MtCO_{2eq}$ methane emissions are observed in the *Harmonised Pledges* case against below 100 $MtCO_{2eq}$ in the *BAT* case (despite higher natural gas use). Environmental benefits of *BAT* translate to economic benefits for European society: the overall energy system cost over the outlook period is about €990 billion higher in the *Harmonised Pledges* than in the *BAT* case. This is to be compared with a cost of implementation of best available technologies for methane abatement of less than €20 billion over the entire outlook period.

As such, the challenge of tackling methane emissions is institutional rather than financial. Notably, limited awareness by policy-makers, legal and structural issues and lack of strategies to leverage economic gains from local abatement actions constrain the current momentum (see box 8 in section 5.2). The oil & gas industry needs to work together with policy-makers to implement clear ambitions and immediate concrete actions that address these barriers, get the industry on the right track for a steep decrease in methane emissions and secure its licence to operate. A number of activities are already ongoing to address some of these barriers by e.g., increasing collaboration and sharing knowledge between operators, investing in new technologies and data sharing, or creating new mechanisms to incentivise emissions reductions.

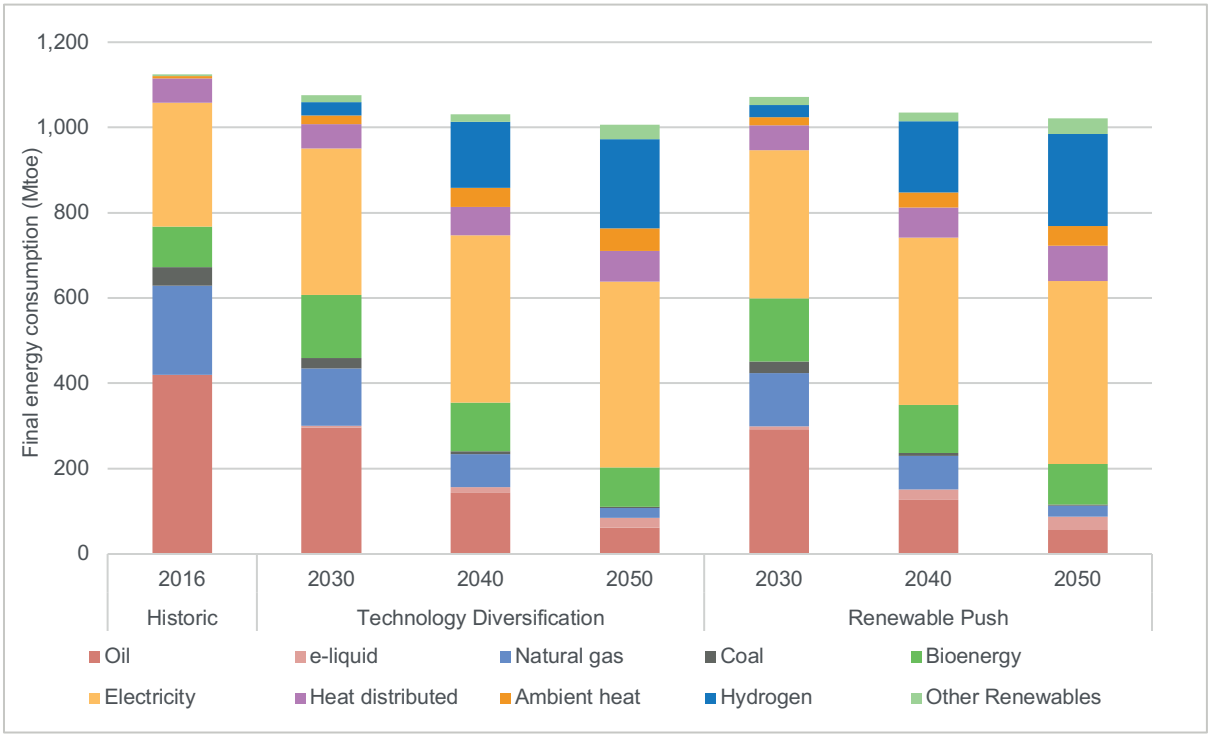
2.2 Evolution of final energy consumption

83. Final energy consumption progressively decreases in both pathways, driven by energy efficiency improvements in the transport and buildings sectors and the switch to more efficient end-use technologies (figure 19). In the Technology Diversification pathway, gross final energy consumption falls from nearly 1,130 Mtoe in the beginning of the outlook period to 1,000 Mtoe in 2050, corresponding to a decrease of 11% over 30 years. The Renewable Push pathway shows a similar pace of demand reduction. Final energy consumption stands at 1,020 Mtoe by 2050 (9% reduction across the period).

84. One of the main enablers of the transition to net-zero is the electrification of end-uses. In the Technology Diversification pathway, final consumption of electricity grows by 50% over the outlook period, reaching 435 Mtoe in 2050 or 43% of gross final energy consumption, against 26% in 2016. Electrification takes place mainly in the industry, transport and buildings sectors, where light vehicles, space and water heating and other appliances can be easily electrified. Even though electricity becomes by far the main energy carrier by 2050, more than half of final energy demand is supplied by other energy carriers. This highlights the complementary between electricity and molecules to decarbonise end-use.

85. The Renewable Push pathway shows a very similar dynamic for electrification: electricity covers 42% of gross final energy consumption in 2050 (figure 20). Interestingly, the intensified development of wind and solar PV in that scenario does not translate into a bigger role for end-use electricity. Instead, most of the additional electricity from variable renewable energy resources is directly used to produce alternative energy carriers such as renewable hydrogen and e-fuels. This stability underlines two key findings: first, electrification is a very costly option for decarbonisation in some hard-to-abate sectors, independent of the amounts of renewable electricity available. The modelling suggests an optimal long-term level of electrification between 40% and 50% of final consumption. Second, integrating large volumes of variable renewable electricity into the power system entails flexibility and network costs. Renewable hydrogen production can absorb local excess production of electricity allowing the hydrogen – instead of the electricity – to be transported (and stored).

Figure 19. Evolution of gross final energy consumption in the Technology Diversification and Renewable Push pathways from 2016 to 2050



Other renewables in final energy consumption correspond to solar and geothermal energy.

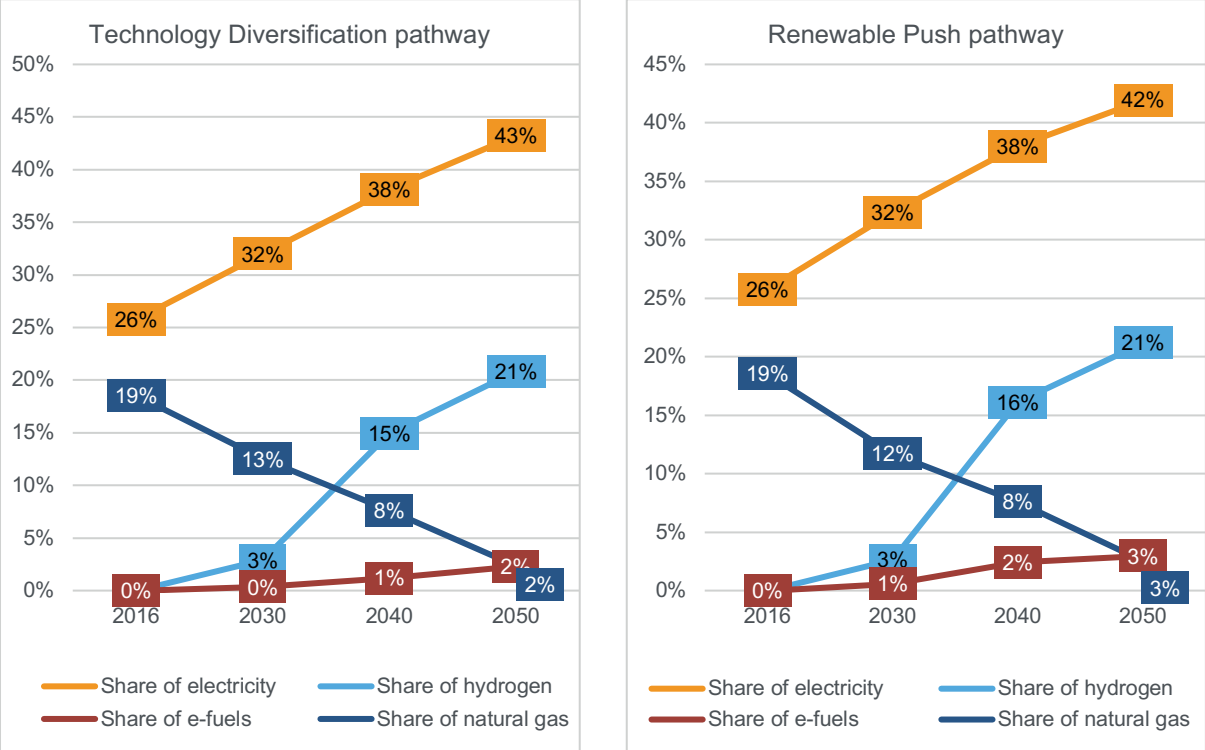
Source: Hydrogen4EU

86. Hydrogen as an energy carrier develops gradually over the outlook period to become the second largest contributor to final energy consumption. By 2050, between 210 and 220 Mtoe of hydrogen are consumed, covering more than 20% of final consumption. E-fuels produced from hydrogen[45] develop during the outlook period and represent a share of 2% to 3% of gross final energy consumption in 2050. Hydrogen and hydrogen derivatives are ideally placed to address the challenges of electrification in hard-to-abate sectors such as transport and industry, and to provide flexibility to the electricity grid (see Chapter 3). Altogether, they cover between 23% and 24% of final consumption by the end of the period. The role of hydrogen in final consumption shows a strong resilience to recent turmoil in energy markets. Comparing with the results of the study's first edition, the geopolitical tensions, the uncertain macroeconomic environment and the planned phase-out of Russian natural gas imports hardly impact the long-term picture for hydrogen in end-uses.

87. Although natural gas supply on a primary energy level remains rather resilient (section 2.1), its consumption in end-uses declines rapidly, contrasting strongly with the uptake of hydrogen. The share of natural gas in gross final energy consumption drops from 19% in 2016 to between 2% and 3% in 2050. This is because natural gas is not consumed as a final energy carrier anymore, but rather transformed to other energy carriers, notably hydrogen via reformers with CCS. Therefore, natural gas transforms from being a primary fuel to an input for producing hydrogen and electricity. These findings also underscore the ability of hydrogen or biogas to replace natural gas where CO_2 capture is difficult.

[45] E-fuels are synthetic substitutes to oil-based fuels like diesel, gasoline, or kerosene. They are produced by combining hydrogen with carbon dioxide through processes like methanol synthesis (potentially coupled with methanol to gasoline) or Fischer-Tropsch. Furthermore, co-electrolysis as a novel process involves the primary use of electricity in an electrochemical reaction to co-produce hydrogen and e-fuels. Carbon dioxide used for e-fuel production is to be recovered through carbon captured in the industry, power and transformation (hydrogen and biofuel production) sectors, or through direct air capture (DAC) technologies (see section 2.3). Synthetic fuels can be considered as carbon neutral under certain conditions: for example, that the electricity and/or hydrogen used is from renewable or low-carbon origin, and that the used carbon dioxide comes from neutral processes like direct air capture or sustainable biomass. Their technical characteristics (e.g., mass and volume to energy ratios) make them promising candidates to decarbonize fuel use in sectors such as maritime and aviation.

Figure 20. Evolution of the shares of hydrogen, electricity, e-fuels and natural gas in gross final energy consumption in the Technology Diversification and Renewable Push pathways between 2016 and 2050



Source: Hydrogen4EU

88. Oil and coal currently supply more than 40% of the final energy consumption in Europe. Their consumption plummets over the outlook period to no more than 65 Mtoe, an 85% fall. These fossil energies are replaced by electricity, hydrogen, e-fuels and other renewable energy carriers in the various end-use sectors. Achieving this level of decrease is a major challenge for oil, which still represented 37% of gross final energy consumption in the beginning of the outlook period. Strong policy, industrial action and innovation are needed to concretise the reduction in oil use.

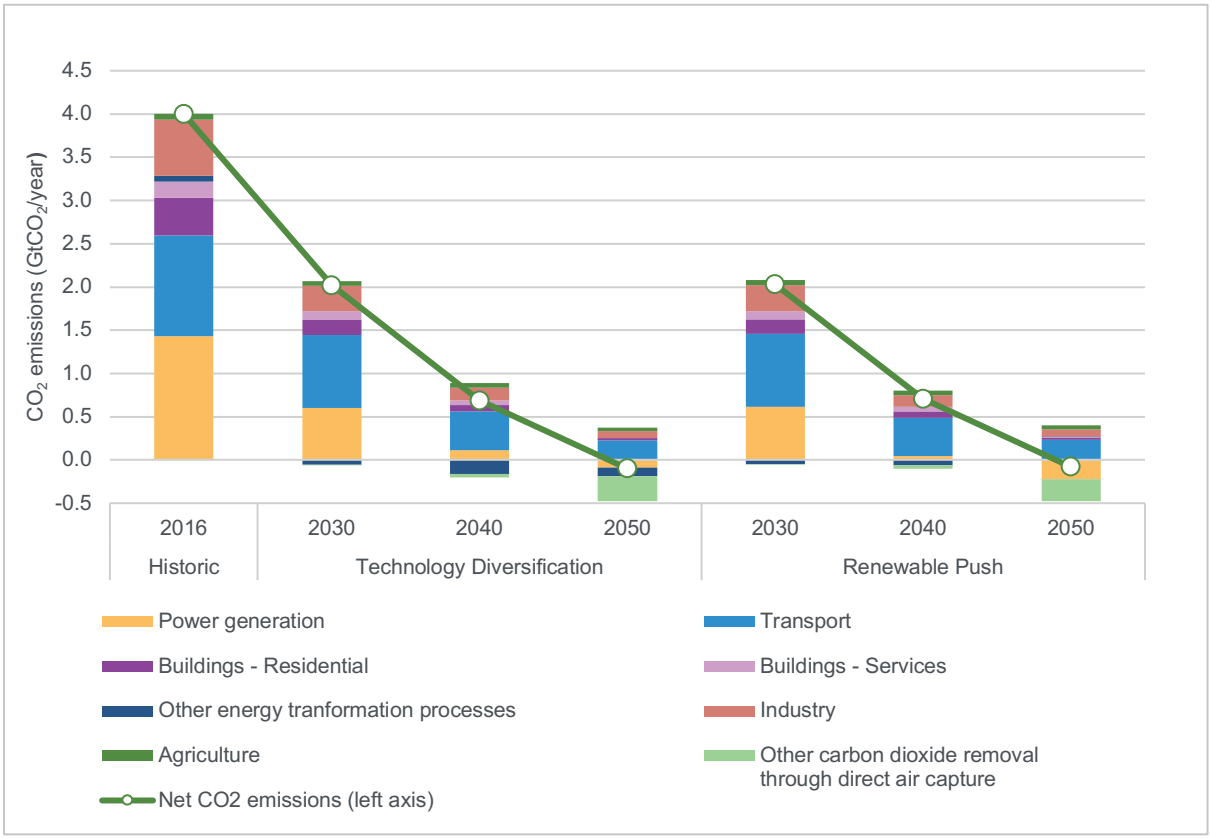
89. Among the other energy carriers, the consumption of ambient heat, representing below 1% of final energy consumption in 2016, experiences a nearly tenfold increase by 2050 and reaches between 45 Mtoe to 55 Mtoe (5% of the final energy consumption) for use in heat pumps (figure 19). The development of heat pumps is a key element to the success of decarbonisation in heating, as it helps overcoming the limits of energy efficiency improvements and fuel switching. They are primarily used in buildings, where they provide this sector with 15% of its final energy demand by 2050. Ambient heat is complemented by other solutions, such as thermal renovation of buildings, continued use of natural gas, bioenergy and geothermal energy.

90. Finally, bioenergy (solid biomass, biofuels and biogas) consumption follows a bell-shaped trajectory. Its consumption in end-use peaks in the next decade at more than 145 Mtoe. This marks a 50% increase in final consumption compared to 2016. Consumption then progressively falls back to recent historic levels below 100 Mtoe. As for natural gas, this decrease in the second part of the outlook period does not imply a lesser potential for bioenergy in primary energy supply. This rather marks the progressive uptake of BECCS (bioenergy with CCS) in the production of electricity and hydrogen. Overall, primary supply of bioenergy still increases by about 45% between 2016 and 2050.

2.3 Pathways to net-zero emissions

91. Both pathways follow similar decarbonisation trajectories, achieving a 100% net reduction of combined CO_2 and methane emissions (in CO_{2eq}) by 2050. The results highlight the importance of carbon dioxide removal solutions. These solutions enable negative emissions by capturing CO_2 from the atmosphere and storing it permanently in carbon sinks. Their use increases over the outlook period, as increasingly constraining decarbonisation targets raise the need to offset residual CO_2 emissions in the hardest-to-abate sectors. Carbon dioxide removal also serve in the end to offset the residue of methane emissions that could not be addressed by best available technologies. By the end of the outlook period, the European energy system is actually net-negative in terms of CO_2 emissions: The Technology diversification and Renewable Push pathways show nearly -100 $MtCO_2$ and -80 $MtCO_2$ of negative CO_2 emissions in 2050 (figure 21).

Figure 21. Evolution of direct CO_2 emissions by sector in the Technology Diversification and Renewable Push pathways, 2016 to 2050



Other energy transformation processes include hydrogen production and refining.

Source: Hydrogen4EU

92. Carbon dioxide removal hinges on the development of two technologies:

a. Bioenergy with CCS (BECCS) combines biomass combustion with CCS and allows for negative emissions[46]. This technology is deployed in power generation, in second generation biofuel processes[47], and in the production of renewable hydrogen.

b. Direct air CO_2 capture allows capturing CO_2 molecules directly from the atmosphere, and when associated with geological CO_2 storage (DACCS)[48], enables negative emissions. Direct air capture complements BECCS, benefitting from a lesser land footprint, and unlock direct air-to-storage removal solution. Direct

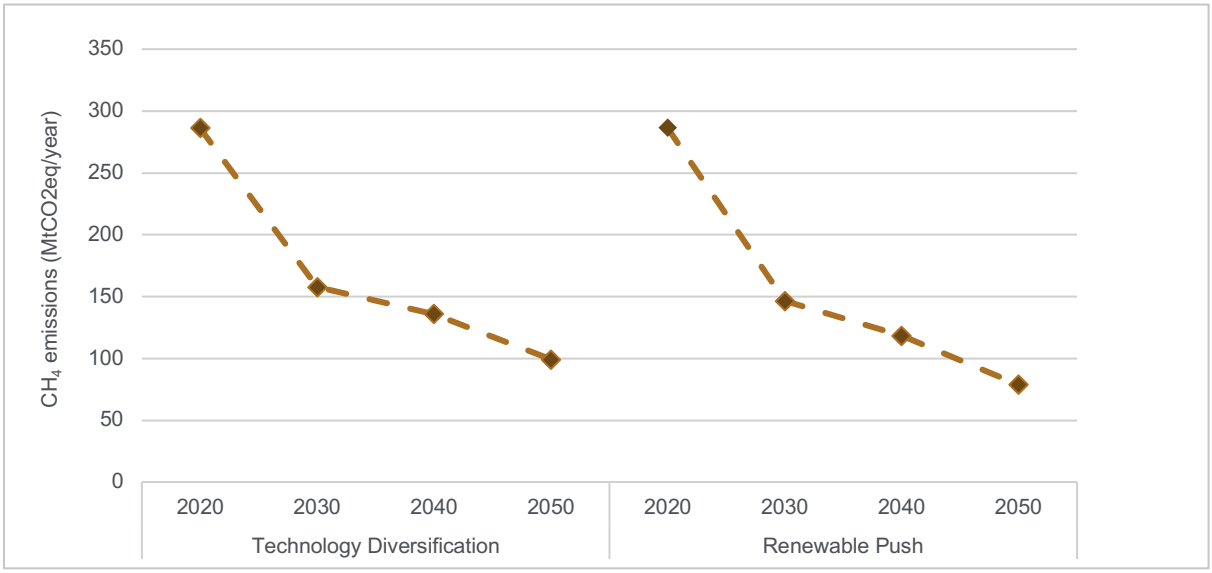
[46] Biomass is assumed to be zero-emission since the life-cycle emissions of bioenergy can even be negative. Carbon dioxide captured in biomass could be also be recycled to the atmosphere by traditional use of bioenergy or through blending captured carbon into e-fuels.
[47] E.g. Ethanol and diesel/kerosene production technologies from lignocellulosic biomass
[48] Direct air capture can also serve as a supply source for climate-neutral CO_2 (e.g., for the production of e-fuels).

air capture technologies take off most strongly in the 2040s when decarbonisation constraints become ever harder to meet. The success of development of DACCS depends on a combination of innovation and policy support, aimed at tackling the high energy consumption of the process.

93. Energy transformation sectors, including power generation, hydrogen production and refineries, are the first to completely decarbonise. In the Technology Diversification pathway, they achieve net-negative emissions over the outlook period (figure 21), meaning that the residual CO_2 emissions from energy transformation processes are more than offset by the negative emissions they allow using BECCS and DACCS. By 2050, net negative emissions in those sectors reach a cumulative 190 $MtCO_2$/year. The change in emissions is particularly striking for the power sector, which has historically been the biggest contributor to CO_2 emissions from the European energy system (1,430 $MtCO_2$ in 2016).

94. Hard-to-abate sectors like industry and transport see a progressive decrease in CO_2 emissions until 2050, but energy efficiency improvements and technology switch are not enough to reach 100% abatement. The transport sector is the biggest emitter in 2050 in the Technology Diversification pathway with about 2030 $MtCO_2$. This still represents an 80% drop from 2016 levels, but continued use of oil and kerosene, notably in aviation, limits further decrease. Similarly, the industry sector sees an eightfold reduction in emissions between 2016 and 2050 but is still responsible for nearly 80 $MtCO_2$ of unabated emissions at the end of the outlook period. Agriculture and buildings (mostly the residential sector) complete the picture.

Figure 22. Evolution of methane emissions associated with natural gas consumed in the European energy system between 2020 and 2050



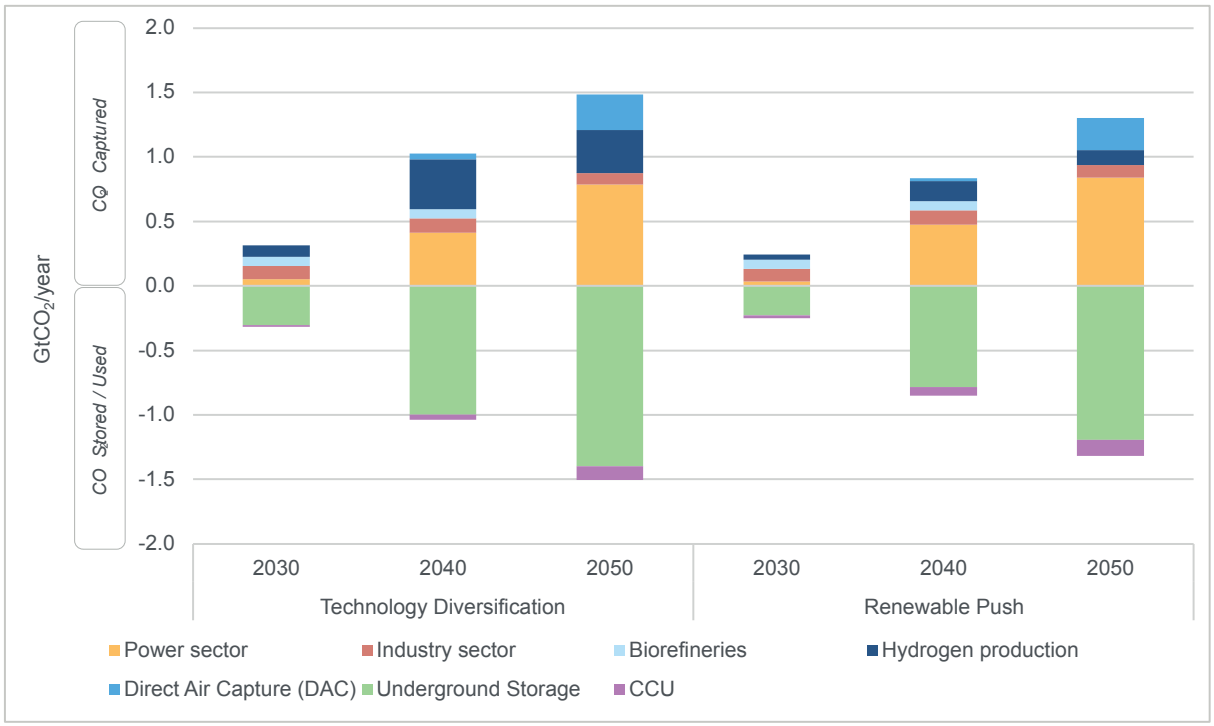
Source: Hydrogen4EU

95. Methane emissions along the natural gas value chain bring an additional climate burden to natural gas, low-carbon hydrogen and their other derivatives consumed in Europe, increasing their footprint in CO_2eq. They decrease substantially over the outlook period, helped by a swift roll-out of best available technologies for methane abatement. In total, the average methane emission intensity associated with the use of natural gas falls by nearly 80% between 2020 and 2050. By then, both pathways show some unabated methane emissions that even best available technologies cannot address. This represents a residual climate burden equivalent to 80-100 $MtCO_{2eq}$ (figure 22).

96. Net-negative emissions in the energy transformation sectors are not sufficient to offset completely the residual CO_2 emissions in the hard-to-abate sectors and the unabated methane emissions along the natural gas and hydrogen value chains. The rollout of DACCS is essential to complement these efforts and achieve 100% net reduction in combined emissions by the end of the period. In the Technology Diversification pathway, DACCS takes off in the 2030s and already captures more than 40 $MtCO_2$/year in 2040. In 2050, negative emissions from DACCS reach more than 280 $MtCO_2$/year in 2050.

97. The Renewable Push pathway shows broadly similar trends for CO_2 and methane emissions. The main differences with the Technology Diversification pathway stems from the lower consumption of natural gas in that sector (-100 Mtoe in 2050) and the higher use of electrolysers for hydrogen production (see section 4.1). BECCS becomes a key feature of electricity generation and allows for net-negative emissions in the power sector to reach -220 $MtCO_2$/year by 2050. Methane emissions are slightly lower in the last two decades (for 2050, 78 $MtCO_2eq$ vs. 100 $MtCO_2eq$ in the Technology Diversification pathway). These effects decrease the need for DACCS: additional negative CO_2 emissions from carbon dioxide removal technologies reach 250 $MtCO_2$/year in 2050.

Figure 23. Evolution of CO_2 capture, use and storage in the Technology Diversification and Renewable Push pathways, 2016 to 2050



Source: Hydrogen4EU

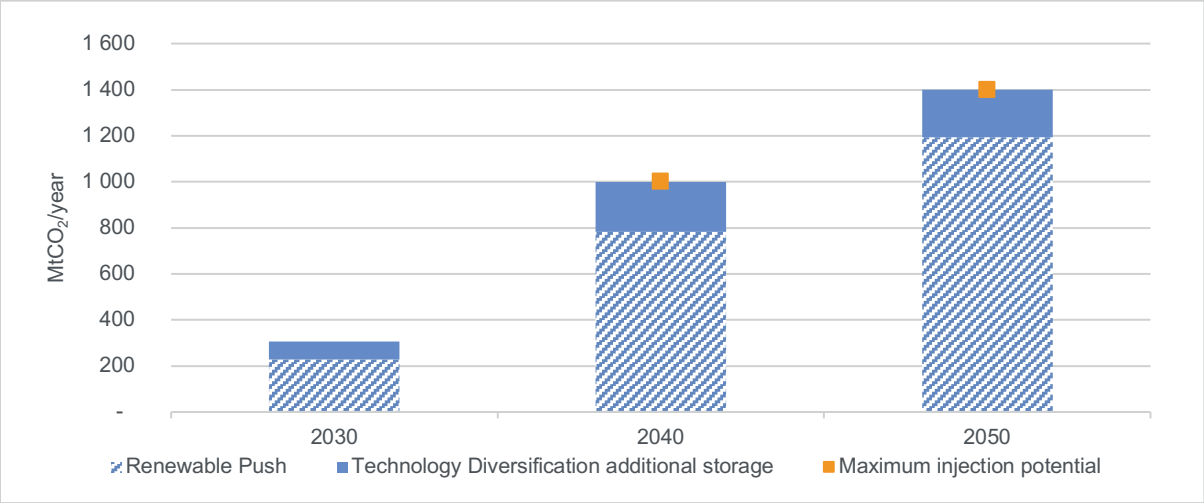
98. Reaching net-zero emissions in the two pathways strongly depends on the ability to develop a fully operational CCUS value chain. This value chain goes far beyond carbon dioxide removal technologies: it also includes capture of CO_2 after combustion of fossil fuels, use of CO_2 in energy transformation and industry processes, transport of CO_2 from the capture site, and finally geological storage for part of the CO_2. The CCUS value chain, currently non-existent, represents in 2050 1,500 $MtCO_2$/year and 1,300 $MtCO_2$/year of captured CO_2 in the Technology Diversification and Renewable Push pathways (figure 23). This represents respectively 40% and 35% of the volume of CO_2 emitted by the European energy sector in 2016. CO_2 is captured from four main sources: natural gas reformers equipped with CCS units, natural gas combustion in industry and power generation and biomass combustion with CCS (e.g., power plants coupled with CCS) and direct air capture from the atmosphere. Captured CO_2 is for the most part stored permanently in deep saline aquifers, depleted oil & gas fields or through enhanced coal bed (injection of CO_2 in the coal seam to produce additional coal bed methane) and enhanced oil recovery (injection of gases, including CO_2, in the reservoir for additional extraction of crude oil) processes.

99. In the Technology Diversification pathway, CO_2 storage follows a rapid development path, exceeding 300 $MtCO_2$/year of annual storage capacity by 2030. Further growth is underpinned by the quick ramp-up of drilling and increase in injection capacities, reaching the injection limits of 1,000 $MtCO_2$/year by 2040 and 1,400 $MtCO_2$/year by 2050. CO_2 storage potential is constrained in that pathway by limits on the CO_2 injection capacities for 2040 and 2050. By then, the utilisation of the storage capacity becomes subject to the competition between different CO_2 capture sources. Reaching the maximum injection capacity limits further development of BECCS and DACCS as well as other permanent CO_2 storage possibilities such as low-carbon hydrogen and natural gas power plants with CCS. A sensitivity analysis on the annual CO_2 injection rate (carried on in the first study) shows that without restriction to the injection capabilities, CO_2 annual storage injection could reach up to 1.8 $GtCO_2$/year in 2050.

100. The picture in the Renewable Push pathway is slightly different. As the natural gas demand for power generation and hydrogen generation is lower in this pathway, less permanent storage of CO_2 is required to accommodate low-carbon hydrogen and electricity production or to develop carbon dioxide removal technologies. Maximum CO_2 injection limits are therefore not reached and the annual stored CO_2 remain below the injection constraints both in 2040 and 2050 (below 800 $MtCO_2$/year in 2040 and below 1200 $MtCO_2$/year in 2050).

101. About 4% and 7% of the captured CO_2 is re-used in the Technology Diversification pathway by 2040 and 2050, while these values are 8% and 10% respectively in the Renewable Push pathway. The reutilisation of the captured CO_2 is important for the production of e-fuels. Non-fossil sources such as biomass and direct air capture provide part of this CO_2, allowing for a carbon neutral process while guaranteeing the progressive transition towards low-carbon technologies in CO_2-dependent end-uses. By the end of the outlook period, captured CO_2 to be used for synthetic fuel production or other industrial usages reaches as much as 100 $MtCO_2$/year in the Technology Diversification and 125 $MtCO_2$/year in the Renewable Push pathways.

Figure 24. Evolution of CO_2 storage injection rate in the Technology Diversification and Renewable Push pathways, 2030 to 2050



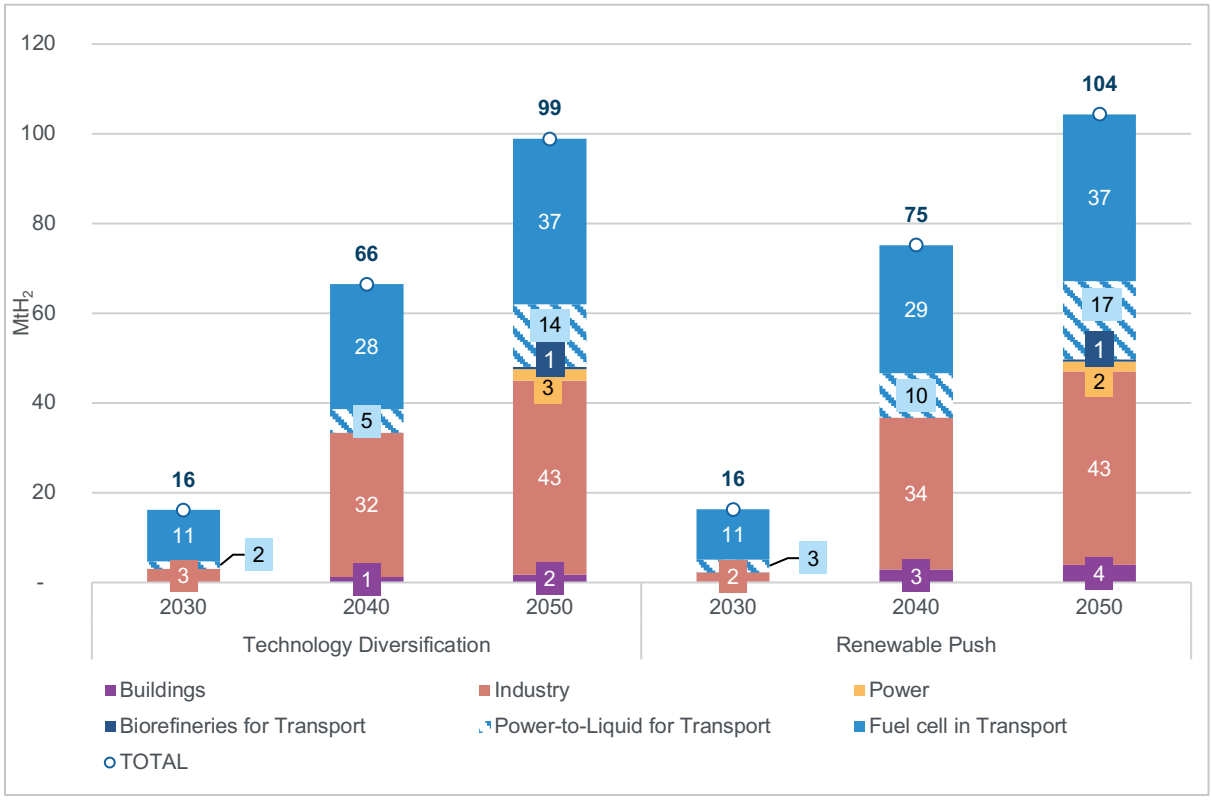
Source: Hydrogen4EU

3 The role of hydrogen in the energy transition

102. Hydrogen plays an important role in both *Hydrogen for Europe* pathways to decarbonise the European energy system. European hydrogen demand in both pathways reaches up to 100 million tons (Mt) by 2050 (figure 25). In the Renewable Push pathway, the observed development of renewable hydrogen demonstrates the value of electrolysis to absorb, store and transport renewable electricity produced from wind and solar. Hydrogen's long-term potential is in the same range as the study's first edition: this illustrates the resilience of hydrogen's contribution to the macroeconomic and geopolitical turmoil over the past year. In particular, the current tensions on energy markets, that could have repercussions for the remainder of the decade, hardly affect the long-term perspectives for hydrogen in Europe.

103. Due to an ambitious decarbonisation objective for 2030 – a 55% reduction in GHG emissions compared to 1990s levels – hydrogen makes inroads to hard-to-abate sectors in the second half of the 2020s. European hydrogen demand in both pathways tops 15 Mt by 2030. This is broadly in-line with the European Commission's REPowerEU plan released in May 2022, that targets a European hydrogen demand (excluding ammonia) of 16 Mt in 2030. Demand more than quadruples over the 2030s, reaching between 66 Mt and 75 Mt by 2040 in the Technology Diversification and Renewable Push pathways respectively. Demand stems mostly from industry and transport, two hard-to-abate sectors for which hydrogen's versatility and flexibility prove particularly relevant. The increase in hydrogen demand slows down a bit in the 2040s, reaching between 99 Mt and 104 Mt by 2050. This demand is equivalent to between 3,300 and 3,500 TWh in lower heating value (LHV), or roughly 300 Mtoe (27% of 2016 gross final energy consumption). As such, hydrogen becomes one of the key energy carriers of the climate-neutral energy system, replacing natural gas as the main gaseous molecule.

Figure 25. Evolution of hydrogen demand by sector in the Technology Diversification and Renewable Push pathways from 2030 to 2050



In the Hydrogen for Europe results, hydrogen end-use in transport for fuel cells also includes the potential for hydrogen and hydrogen-embedded energy carriers as shipping fuels.

Source: Hydrogen4EU

104. Hydrogen is consumed where electrification is difficult or costly, and provides much needed flexibility to the power system:

a. The biggest hydrogen consumer is the transport sector. Hydrogen demand in the sector reaches up to 55 Mt in 2050, used either directly as a fuel for fuel cells, or as intermediary feedstock for synthetic fuels and biorefineries. Hydrogen demand for fuel cells and synthetic fuels reaches 37 Mt and 14 Mt in the Technology Diversification pathway, slightly more in the Renewable Push pathway. Hydrogen, e-fuels, ammonia and other hydrogen-related molecules provide energy dense fuels where electrification is complex. Their versatility is particularly relevant for heavy and long-distance road transport, aviation and shipping.

b. Hydrogen proves to be a key contributor to the decarbonisation of the industry sector. Here demand exceeds 43 Mt by 2050, primarily for energy purposes related to the production of heat and steam. Hydrogen is a particularly important solution for steel-making and chemical industries.

c. Hydrogen demand in buildings and for power is rather limited compared to the aforementioned sectors. Combined, they represent up to 6 Mt in the Renewable Push pathway. Hydrogen can provide space heating or peak generation for the power system, but it is facing competition from a wide range of other decarbonisation options including energy efficiency, heat pumps for buildings, biogas or continued use of natural gas.

3.1 Hydrogen and transformation of transport

105. The transport sector is composed of various mobility needs and modes, each with their own usage requirements and technical constraints. There is no “one size fits all” solution to decarbonise sub-sectors as different as light-passenger vehicles, road freight, aviation or maritime transport. High range and energy density requirements in some segments particularly demonstrate the advantage of hydrogen.

106. Figure 26 shows the evolution of final energy consumption in the transport sector for both *Hydrogen for Europe* pathways. Hydrogen and hydrogen embedded in e-fuels and ammonia play a key role to decarbonise sectors such as shipping, heavy-duty road transport or aviation. Like biofuels, their high energy density is particularly valuable to propel large vehicles over long distances.

a. Direct use of hydrogen in fuel cells leads to hydrogen demand increasing steadily from around 30 Mtoe in 2030 to more than 100 Mtoe in 2050. Also considering the potential of hydrogen derivatives in the maritime sector, hydrogen becomes the main energy carrier by the end of the outlook, providing more than one third of the total transport energy use.

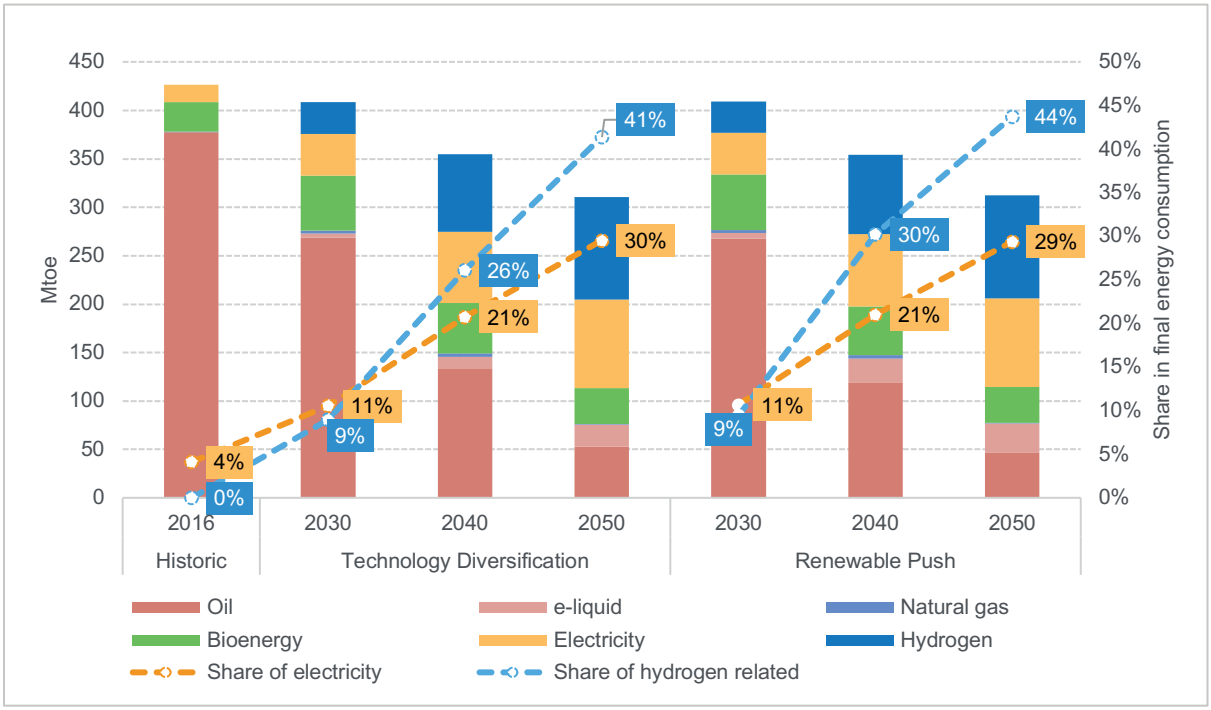
b. Consumption of e-fuels in the transport sector already starts marginally in the 2030s. It takes off around 2040, when e-fuels begin providing large volumes for aviation. This particular sector shows challenging constraints in terms of weight, volume range and refuelling that limit the range of viable decarbonised technologies and aviation fuels. By 2050, e-fuel consumption in aviation reaches 25 Mtoe in the Renewable Push pathway (35% of final energy consumption) and 18 Mtoe in the Technology Diversification pathway (25% of its final energy consumption).

c. Finally, hydrogen is consumed in biorefineries. It serves to produce first- and second-generation biofuels and is blended alongside biofuels in conventional fuels such as diesel (B7, 10 and B30), gasoline (E5, E10 and E85) and jet fuels.

107. Electricity is the second largest contributor to decarbonisation of transport after hydrogen. Final consumption of electricity in the sector more than doubles in both pathways, exceeding 90 Mtoe by 2050. Most passenger cars, the entire light- and medium-duty vehicles and most trains are electrified by 2050. Also considering electric engines in hydrogen-based FCEVs, electric solutions actually represent almost 95% of the road

vehicle stock by 2050, including light commercial, passenger and medium- and heavy-duty vehicles and buses and coaches. Energy efficiency also plays a major role: electrification of the powertrain, automation, technological improvements, and modal shifts allow for strong efficiency gains over the next thirty years. Altogether, they allow for a 27% drop in the final energy consumption by 2050 compared to historic levels.

Figure 26. Evolution of gross final energy consumption in the transport (including aviation and maritime transport) sector in the Technology Diversification and Renewable Push pathways from 2016 to 2050



Gross final energy consumption as described in this subsection on transport includes domestic and international aviation and maritime bunkers (following Eurostat / JRC-IDEES nomenclature). Regarding the standard nomenclature, the figures are obtained by summing all road, rail, aviation and maritime.

In the Hydrogen for Europe results, hydrogen end-use in transport also includes the potential for hydrogen and hydrogen-embedded energy carriers as shipping fuels.

Source: Hydrogen4EU

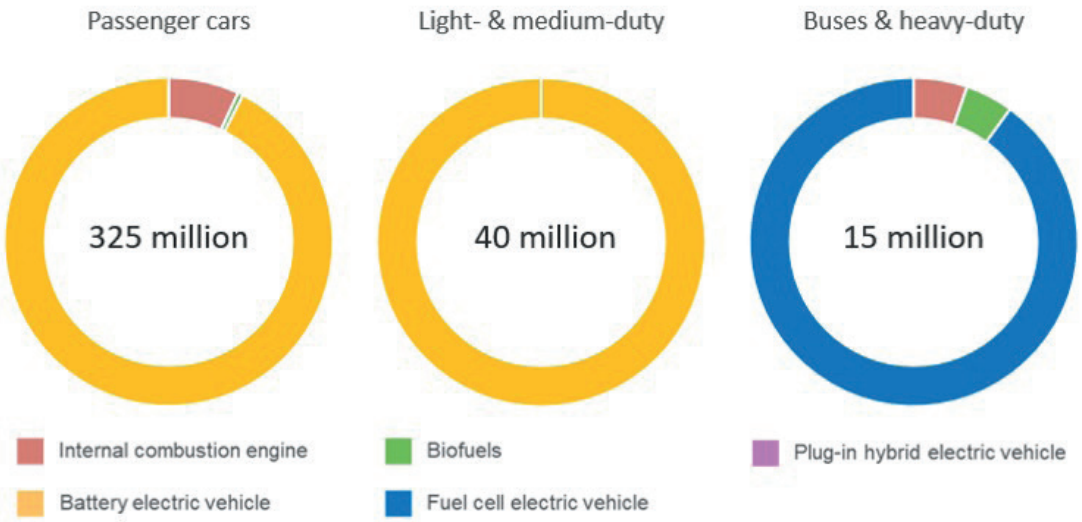
108. Shift to hydrogen and hydrogen-based fuels, electrification and efficiency gains tackle most CO_2 emissions of the transport sector, leading to a more than 80% decrease in direct emissions. Oil consumption in the sector drops from 377 Mtoe in 2016 (90% of final energy consumption) to below 60 Mtoe in 2050, a fall of more than 80%. Residual demand is addressed by biofuels: consumption of biofuels in transport peaks at nearly 60 Mtoe in 2030 before declining progressively to 37 Mtoe by 2050 (vs. 31 Mtoe in 2016) as other technologies become available and biomass use is directed to more valuable uses (such as renewable hydrogen production and power generation via BECCS to provide negative emissions – see section 2.3).

109. By 2050, passenger and light- and medium-duty vehicles are nearly entirely electrified (figure 27). Of nearly 325 million passenger vehicles on the road in 2050, more than 300 million are battery electric (93%), while an additional 2 million are plug-in hybrid electric vehicles (less than 1%). Nearly all the 40 million light- and medium-duty vehicles are electrified. These findings are in line with the recent ICE sale ban proposal by the European Commission, according to which fossil-fuelled vehicle sales are set to be banned from 2035 on[49]. Would this proposal be enshrined into regulation (and considering an average lifetime of 10 to 15 years for light and medium vehicles), fossil-fuelled light and medium vehicles will have almost disappeared from traffic by 2050.

[49] https://www.euronews.com/next/2022/06/09/eu-parliament-backs-ban-on-new-petrol-and-diesel-combustion-engine-cars-from-2035

110. Hydrogen fuel cell electric vehicles lead the way for decarbonising buses and heavy-duty trucks, due to their higher energy density and lighter fuel reservoir compared to electric vehicles. By 2050, more than 13 million buses and heavy-duty trucks are fuelled directly by hydrogen via fuel cell electric engines, representing 90% of the fleet. Such high penetration is contingent on the timely roll-out of a Europe-wide refuelling infrastructure. The risks associated with the commercial viability of such an infrastructure can be mitigated via captive fleets[50] that would enable high utilisation rates from the start and the progressive development of hydrogen stations along the main transport corridors and hubs. The remainder of energy consumption in heavy-duty road transport is ensured by a combination of biofuels, e-fuels and oil products, mostly in the form of blended final fuels. Biofuels are particularly relevant to extend the lifetime of existing trucks and engines and avoid costly changes in logistics and refuelling supply chains. E-fuels may see a minor development, but their high cost and low efficiency will limit their competitiveness against other solutions.

Figure 27. Composition of road transport fleets in 2050 in the Technology Diversification pathway



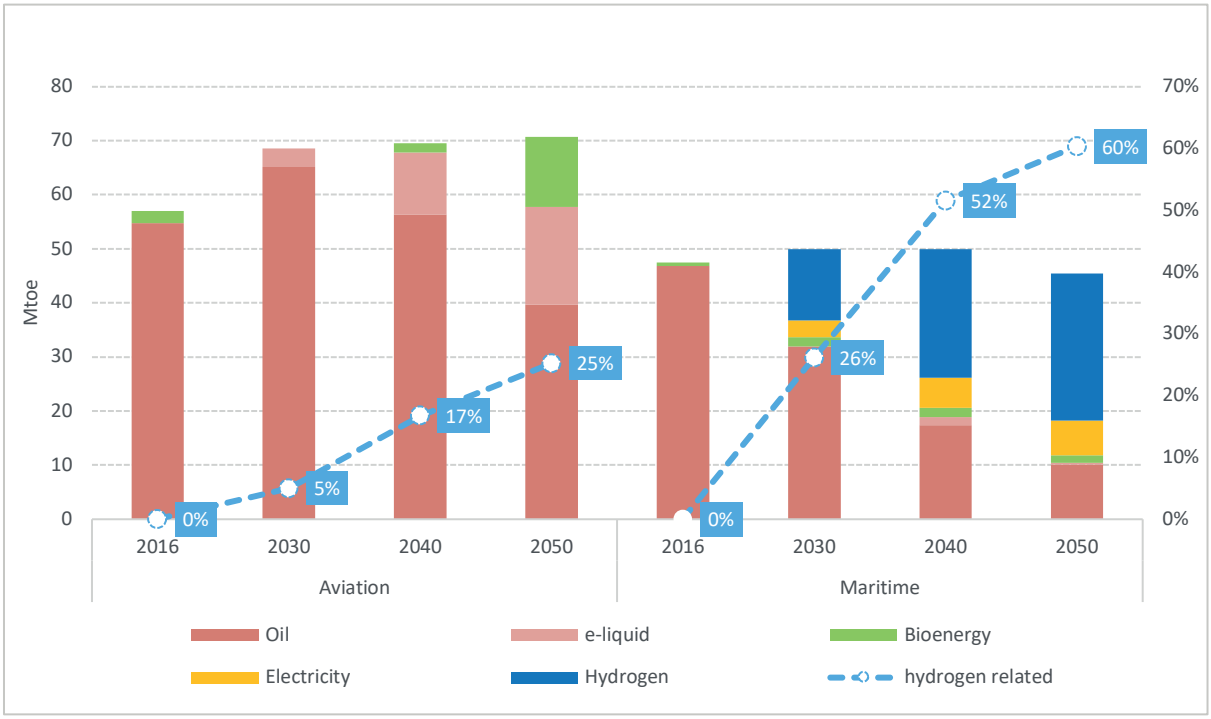
Source: Hydrogen4EU

111. While hydrogen's energy density is higher than batteries', it is much lower than that of fossil fuels used in aviation (8.7 GJ/m3 in liquid form compared to 33-36 GJ/m^3 for kerosene). Direct use of hydrogen in aircrafts should therefore remain limited due to the complexity of storing large amounts of hydrogen fuel in the fuselage. E-fuels and biofuels are the best fit for decarbonising air transport: they provide similar density characteristics as conventional kerosene and allow to minimise the efforts needed to adapt the manufacturing and operation of planes. Continued use of existing technologies and refuelling supply chains also reduces the risk of stranded assets in the sector. E-fuels' consumption in aviation starts taking off from the early 2030s, providing nearly 3.5 Mtoe in the Technology Diversification pathway and 4.5 Mtoe in the Renewable Push pathway (respectively, 5% to 6% of final energy consumption) and increasing progressively to 18 Mtoe and 26 Mtoe (25% and 36%) by 2050. Biofuels follow a similar path, but with a slower start around 2040[51]. In 2050, biofuels account for 18% of the final energy consumption of the aviation (13 Mtoe) across both *Hydrogen for Europe* pathways.

112. The future of e-fuels and biofuels in aviation strongly depends on further innovation and on the ability of the aviation industry – an inherently global industry – to fully internalise the social cost of greenhouse gas emissions, for example through the extension of the EU-ETS scheme, carbon taxes and other quotas to progressively phase out carbon-intensive fuels. The findings of *Hydrogen for Europe* study show that even in the absence of market or regulatory barriers, e-fuels and biofuels are to be complemented by conventional kerosene, which still represents between 45% and 55% of final energy consumption in 2050 (figure 28).

[50] Public or private-owned fleets of vehicles whose refuelling/charging can be optimized around dedicated infrastructure.
[51] Although biofuels are more compatible with the existing transport technologies, the available feedstock for their production from bioenergy feedstock (mainly energy crops) is very limited in the beginning of the outlook, and competition between other bioenergy sources on these feedstock leads to a slower offtake of biofuels in the transport sector.

Figure 28. Evolution of final energy consumption in aviation and maritime transport in the Technology Diversification pathway from 2016 to 2050



This figure includes domestic and international aviation and maritime bunkers (following Eurostat / JRC-IDEES nomenclature). In the Hydrogen for Europe results, hydrogen end-use in transport also includes the potential for hydrogen and hydrogen-embedded energy carriers as shipping fuels.

Source: Hydrogen4EU

113. Decarbonisation of maritime transport is led by hydrogen and hydrogen-based solutions such as ammonia or methanol. By 2030, they already cover about a fourth of final energy consumption in the sector. At the end of the outlook period, hydrogen's total share in the maritime transport exceeds 60%, corresponding to 27 Mtoe. Direct use of hydrogen in fuel cells is promising for short trips (e.g., for barges or ferries); however, long-distance journeys such as open-ocean navigation would require fuel with a higher energy density, relying on liquefied hydrogen or ammonia (figure 28). As for aviation, achieving that development of hydrogen in the maritime sector – another inherently global industry – also depends on the ability of the market to send the right signals to encourage switching to decarbonised solutions. The second enabler of the sector's decarbonisation is direct electrification, starting from 3 Mtoe in 2030 and reaching up to 6 Mtoe (14% of final energy consumption in maritime transport) in 2050 in the two pathways. Biofuels are providing a marginal part of the energy demand while oil-based fuels still represent around 25% the final energy consumption by the end of the outlook period.

3.2 Hydrogen and transformation of industry

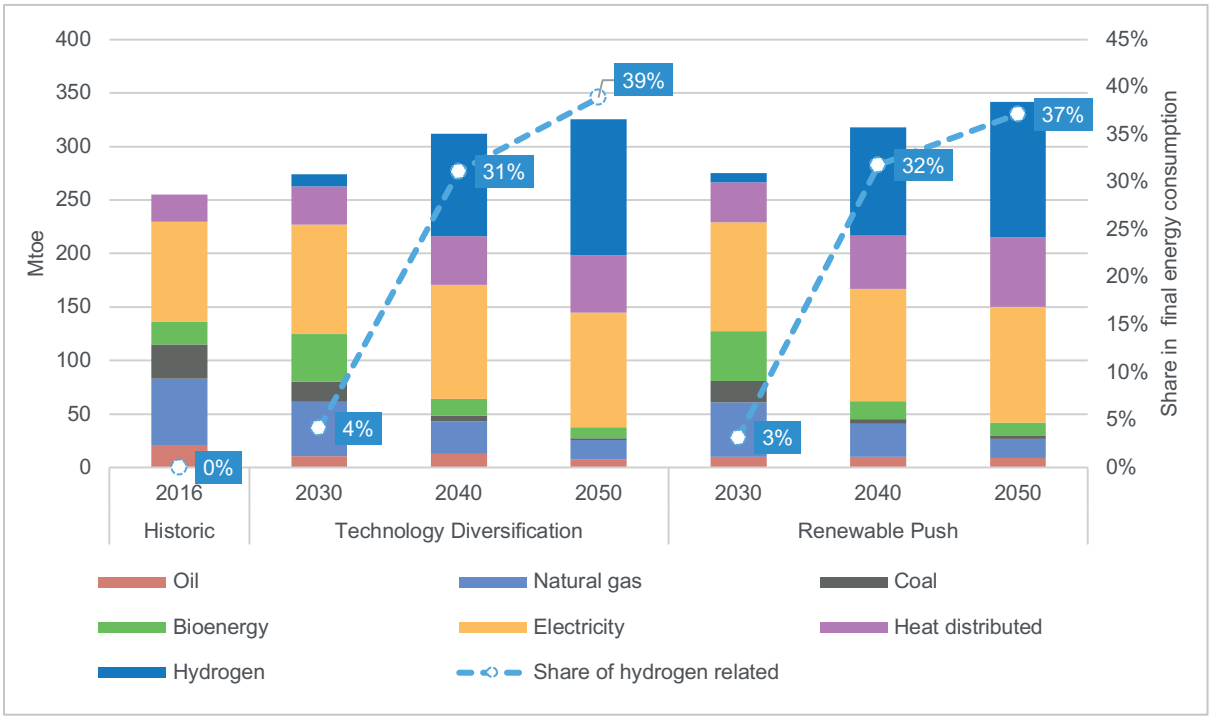
114. European industrial energy demand is expected to rise progressively to around 320 Mtoe in 2050, more than a quarter up from historic levels. Decarbonisation in this sector relies mostly on electricity, hydrogen and distributed heat[52], efficiency increases and deployment of CCUS (figure 29). These solutions are complementary, allowing to tackle the specific challenges and constraints of each subsector (for instance, hydrogen can act as a direct reduction agent for steel-making, replacing coal or natural gas).

[52] Heat produced in a centralized way and distributed to final locations for end-use requirements.

115. Electricity provides a third of final energy consumption across the different industry subsectors[53], reflecting the difficulties to fully electrify high-temperature heat and steam processes. Its share is relatively stable compared to historic levels. Distributed heat supply in the industry sector more than doubles, providing between 50 Mtoe and 65 Mtoe for low- and mid-temperature heat. Hydrogen replaces fossil energy sources in high temperature heat and steam production from the early 2030s. Its consumption as energy in industry increases progressively, with a leap in the 2030s to more than 30% of final energy consumption. By 2050, the share of hydrogen in final energy consumption reaches as high as 37% in the Renewable Push and 39% in the Technology Diversification pathways.

116. Hydrogen and distributed heat are the main solutions to replace fossils in the industry sector: they underpin a drop in fossil fuel use from 60% to 8.5% over the outlook period. By 2050, fossils fuels still account for 27 Mtoe of energy consumption, mainly for use in the Corex process[54] or in conventional blast furnaces in the steel sector. CCS plays a key role to address these residual emissions: by 2050, around 55% of emissions in the sector are captured. CO_2 capture amounts to between 90 $MtCO_2$ and 100 $MtCO_2$ in the Technology Diversification and Renewable Push pathways. The remaining emissions are compensated by negative emissions in other sectors.

Figure 29. Evolution of final energy consumption in industry in the Technology Diversification and Renewable Push pathways from 2016 to 2050

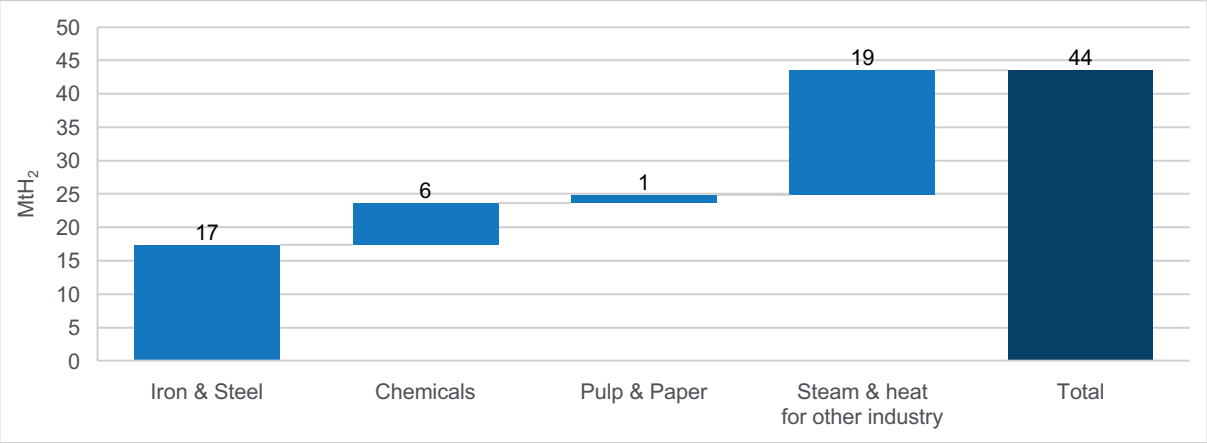


Source: Hydrogen4EU

117. The largest hydrogen-consuming subsector is steel-making, where hydrogen demand exceeds 17 Mt in both pathways by 2050 (figure 30). Hydrogen is notably used in this subsector as a reduction agent in an alternative steel-making process known as direct reduction of iron with electric arc furnace (DRI EAF). While this process currently accounts for a marginal share of iron and steel production and relies mostly on natural gas, current decarbonisation initiatives in Europe show increasingly aligning strategies to use DRI with hydrogen rather than CCS. Given the importance of investment cycles in steel-making, it is important that DRI projects are commissioned at the right time to unlock hydrogen's full value. In a transition stage, hydrogen can also be blended with natural gas, for DRI and various other industrial processes.

[53] Note that consumption in refineries is attached to the transport sector (section 3.1) and not to the industry sector.
[54] Corex is an alternative to blast furnace for steel production based on smelting reduction processes.

Figure 30. Hydrogen demand in the industry sector in 2050 - Technology Diversification pathway



Consumption of hydrogen in refineries is attached to the transport sector (section 3.1) and not to the industry sector.

Source: Hydrogen4EU

118. Hydrogen consumption in the chemical industry exceeds 6 Mt by 2050 in both pathways (around 14% of total industrial hydrogen consumption), making it the second largest hydrogen-consuming sector in industry. The sector today relies on significant amounts of natural gas for process heat and steam. Hydrogen-fuelled heaters and boilers are well placed to play a role in the sector's decarbonisation. Like in steel-making, blending of hydrogen with natural gas is also a possibility in the transition period. While the *Hydrogen for Europe* study only models the energy-related potential of hydrogen, renewable and low-carbon hydrogen also have an important role to play to decarbonise feedstock in chemistry processes and replace current use of grey hydrogen[55]. Hydrogen can also replace natural gas for the production of ammonia and industrial alcohols such as methanol (box 6).

119. By 2050, major volumes of hydrogen are also consumed for production of process heat and steam in other industries such as manufacturing, food and beverages or textiles. Demand reaches nearly 20 Mt in 2050 for the Technology Diversification Pathway. The prospects of hydrogen in pulp and paper or cement are more minor: their combined demand is less than 1.5 Mt in 2050, reflecting the higher value of CCS, biomass and electrification in those sectors.

Box 6. Hydrogen as a feedstock in the (chemical) industry

In addition to its future energy use, hydrogen is already used extensively in the industrial sector as a feedstock. Around 70 Mt of hydrogen is current produced and used each year by industries globally, with refining and ammonia production ranking as the main applications of hydrogen in pure and mixed form (IEA, 2019a) . If refineries' usage of hydrogen is mostly used in the conversion of crude oil, ammonia end ups in many end-products ranging from fertilisers to household cleaning products. In Europe, hydrogen usage as a feedstock is split between the production of ammonia for industrial and agricultural use and methanol (38%), oil refining (33%) and metal processing (3%). It sums up to a hydrogen demand of 10 Mt with around 4 Mt used for the production of ammonia and methanol, around 4 Mt for oil refining and the remainder used in the steel industry.

Looking at future production, this non-energy use represents a significant potential for renewable and low-carbon hydrogen, that could be either produced on-site or procured from the market. Methanol is indeed seen as a cornerstone of the future low-emitting chemical sector and could become one of the future building blocks to produce both olefins (methanol-to-olefins, MTO) and aromatics (methanol-to-aromatics, MTA). Those pathways would allow reducing reliance on steam crackers, facilities that are important emitters of CO_2 in Europe (Vieira et al, 2021). The initial results from the Cefic's iC2050 Project indicate a scaling up of MTO starting in 2040, delivering in 2050 between 1 and 2.5 Mt of ethylene, which corresponds to 3% to 10% of the foreseen ethylene demand

[55] The potential related to use of hydrogen in the industry sector covered in the *Hydrogen for Europe* study corresponds primarily to hydrogen use for production of high temperature heat and as a reduction agent for the iron industry. Other uses as feedstock in the chemical industry, such as existing methanol synthesis, are not included due to model limitations.

(Cefic, 2021). The additional hydrogen production required for this new usage would land between 1 Mt and 3 Mt, a number that could further increase depending on the uptake of the MTO and MTA pathways. In addition, combining renewable with captured carbon dioxide to produce methanol would foster carbon circularity and lower the need for CO_2 infrastructure for geological storage (Cefic, 2021).

This potential adds up to the *Hydrogen for Europe*'s study assessment for energy-based hydrogen in the chemical industry. Together, they suggest a market size for hydrogen in chemicals around 10 Mt in 2050. This is not considering the possible growth trajectory of the industry in the years to come: while the European Green Deal initially considered a 20% increase for hydrogen demand as feedstock, the recent energy and geopolitical crisis have put European producers in a difficult position with regard to global competitors. German ammonia production notably decreased its output by 40% in September 2021 compared to 2019-2020 average, with ammonia imports making up for the difference to allow stable fertilisers production (Stiewe et al., 2022). Ultimately, the long-term potential is very sensitive to the ambition of the rest of the world to follow up on European's example and swiftly decarbonise. In this respect, the future growth of hydrogen feedstock volume is closely linked to the evolution of the trade balance in Europe for products like ammonia or methanol, which are candidates for long-distance export and could become optimal media to import hydrogen into Europe, as suggested by the REPowerEU plan and the H2Global initiative.

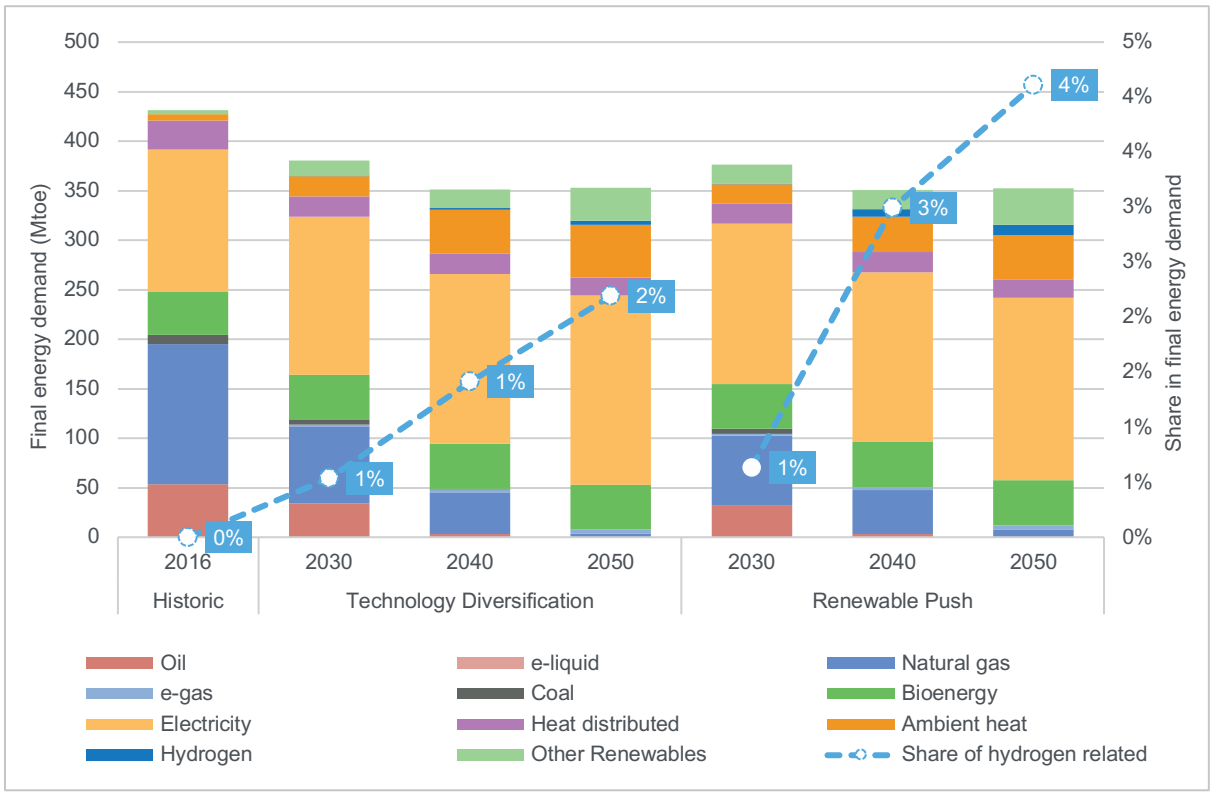
3.3 Hydrogen and transformation of buildings

120. The buildings sector includes residential and tertiary buildings: energy demand serves a variety of uses including space and water heating, cooking, cooling and specific electricity demand for electric appliances (lighting, electric devices and appliances etc.). This sector historically accounts for nearly 40% of the European final energy consumption and 17% of CO_2 emissions (in 2016). Old building stocks throughout Europe, widespread existing infrastructure and appliances based on natural gas and oil for space and water heating, and seasonality of heating demand constitute the main challenges for decarbonisation. Future solutions must account for constraints in terms of energy security, investment roll-out and efficiency improvement capacities, and flexibility needs related to weather-dependant energy sources.

121. Energy efficiency improvements can lead to a strong decrease in energy consumption and GHG emissions, fostered by electrification and thermal isolation of buildings. Final energy consumption in buildings falls by nearly 20% over the outlook period (figure 31). Both pathways confirm a significant untapped potential in-line with the EU Renovation Wave strategy. The annual renovation rates go as high as 3.5% in some countries.

122. The share of electricity in final energy consumption increases from 33% in 2016 to more than 50% by the end of outlook period. Electrification for space and water heating is underpinned by an accelerated deployment of next generation heat pumps. A seven-fold increase in the use of ambient heat for heat pumps can be observed in the Technology Diversification pathway (40 Mtoe increase over the outlook period). Other renewable energy sources such as geothermal and solar thermal show a more than four-fold increase in the buildings sector, but their share in final energy consumption remains at around 5% in the long term. District heating systems continue to provide heat for the buildings sector where they can be switched to low-carbon sources.

Figure 31. Evolution of final energy demand in buildings in the Technology Diversification and Renewable Push pathways, 2016 to 2050



Source: Hydrogen4EU

123. Natural gas consumption in buildings amounted to more than 140 Mtoe in 2016, corresponding to one third of final energy consumption. Although the consumption of gaseous fuels shows a steep fall over the outlook period, there is a clear scope for their continued use for heating purposes, where other technologies reach their technical or economic limits. This allows notably for the limitation of stranded assets in areas where modern gas infrastructure and appliances are widespread. The gaseous mix and its market share will vary from one region to another, depending on various infrastructure, energy source availability and building stock considerations. By 2050, biogas takes up most of the market, followed by some residual potential for natural gas and hydrogen. Hydrogen represents at most between 2% and 4% of final energy consumption, either directly consumed in home fuel cells or blended with natural or biogas. It is noteworthy to mention that hydrogen is easily combusted with the oxygen levels of the air, with no flame colour and very high flame temperature. The results thus show that regardless of safety issues, hydrogen is not a key contributor to the sector's decarbonisation. This clearly illustrates the complementarity between the various technologies and energy carriers to answer each sector's own decarbonisation challenges. For hydrogen, its value is mostly seen in hard-to-abate sectors such as transport and industry, while the buildings sector relies mostly on electrification, thermal renovation and development of heat pumps.

3.4 Hydrogen and transformation of power

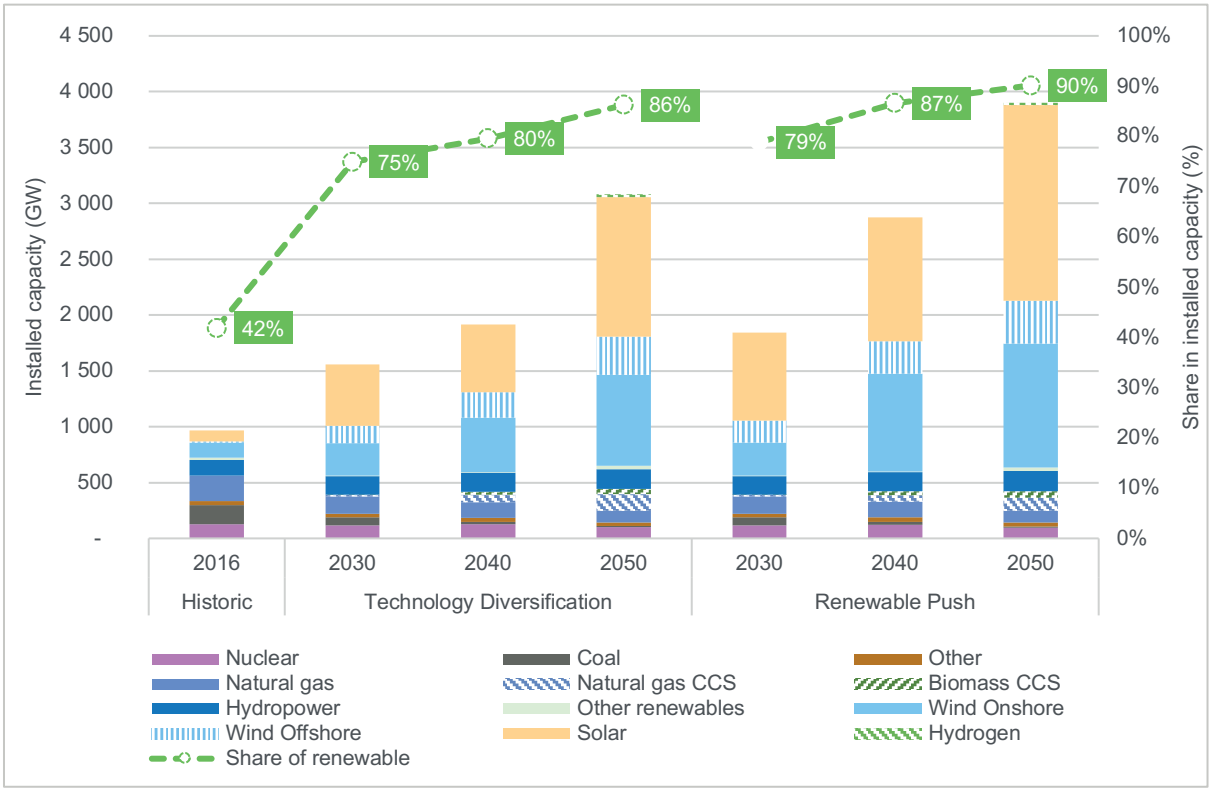
124. Electrification is one of the main pillars of the energy transition, enabling deep decarbonisation alongside hydrogen, energy efficiency and renewable energies. Over the outlook period, electricity consumption across the European economy more than doubles, reaching nearly 8,000 TWh in 2050 in the Technology Diversification pathway and up to 9,300 TWh in the Renewable Push pathway. This steep increase is driven by progress of electrification in end-use (6,100 - 6,200 TWh of final energy consumption in 2050 vs. 3,300 in 2016) and electricity-based production of other energy carriers such as hydrogen and e-fuels.

125. The increasingly critical role of electricity translates into a double challenge for the power system: first, the current production mix must be quickly decarbonised. Second, electricity generation must increase at the same pace as demand, raising constraints in terms of adequacy, flexibility and additionality of renewable energy use. The total installed capacity of electricity production technologies reaches 3,100 GW by 2050 in the Technology Diversification pathway and 3,900 GW in the Renewable Push pathway, underpinned by a steep acceleration of installations of renewable electricity production capacities (figure 32). These values are respectively three and four times as high as the 2016 installed capacities.

126. Variable electricity generation from wind and solar is at the heart of the power system's transformation. Electricity generation from these sources reaches 4,800 TWh in the Technology Diversification pathway and 6,300 TWh in the Renewable Push pathway by 2050, corresponding to between 61% and 68% of total electricity generation. These values account respectively for a 12-fold and 16-fold increase in electricity supply between 2016 and 2050 (figure 33). To achieve such an uptake in variable electricity generation, large amounts of capital spending are needed to finance power plants, reinforce grids and roll out flexible technologies.

127. As the share of variable renewables increases, the power system requires additional flexibility options and network stability providing equipment. Network operators need to adapt to new challenges for balancing the system and handling more frequent and more pronounced situations of congestions and peak load. The short- and long-term variability of renewables, coupled with the variability and seasonality of electricity demand calls for new investments in flexible electricity production technologies (such as gas-fired power plants with CCS or biogas CCGTs), storage options (such as Li-Ion batteries), or reinforced interconnections (to transport renewable electricity from high-potential locations to low-potential ones) to ensure the reliability of the power system. Power-to-X also proves to be a very relevant solution to accommodate for the increasing share of variable renewables in the system.

Figure 32. Installed capacities for power generation in the Technology Diversification and Renewable Push pathways from 2016 to 2050

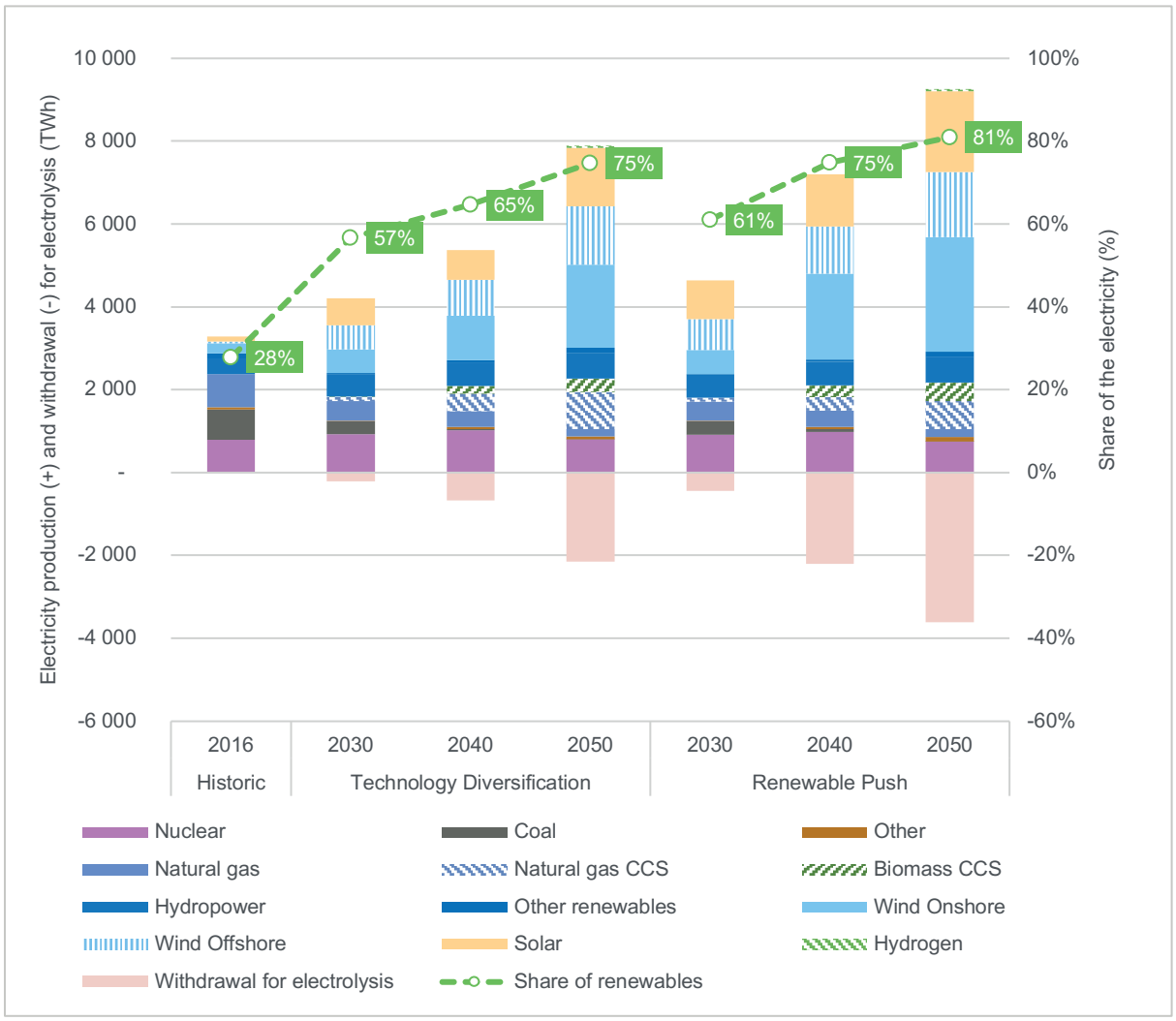


Source: Hydrogen4EU

128. Power-to-hydrogen plays a key role to address flexibility needs and to absorb, store and transport the variable production from wind and solar energy. By 2050, production of hydrogen from electrolysis requires 2,100 TWh of electricity in the Technology Diversification pathway and over 3,600 TWh in the Renewable Push pathway. This corresponds to between 44% and 57% of the variable generation from wind and solar in 2050. In the Renewable Push pathway, which is characterised by higher targets for renewable deployment, the increase in electricity consumption from electrolysers in 2050 compared to the other scenario (+ 1,350 TWh) matches almost exactly that of variable renewable electricity generation (+ 1,470 TWh). Renewable hydrogen is one of the main outlets for the greater renewable market share in that pathway.

129. Electrolysis also makes important contributions to capture the upward variability of renewables and to mitigate risks of congestion and curtailment. Notably, the results show that most electrolysers are operated in an "offgrid" set up, with a direct connection to solar and offshore and onshore wind farms (see section 4.1.1). In the Technology Diversification pathway, offgrid hydrogen production from solar and wind power directly evacuates 37% of the electricity generation from these energy sources in 2050, thus providing flexibility for the integration of variable renewables and reducing investment needs in electricity network infrastructure. The share of offgrid power-to-hydrogen is higher in the Renewable Push Pathway, where the accelerated deployment of renewable energy leads to about half of all solar and wind production in 2050 happening off the grid to directly feed electrolysers.

Figure 33. Power generation and withdrawal for electrolysis in the Technology Diversification and Renewable Push pathways, 2016 to 2050



Power generation and electrolysis both ongrid and offgrid (dedicated to hydrogen production)

Source: Hydrogen4EU

130. Hydrogen can also be used to generate electricity and address downward variability and flexibility needs. By the end of the outlook period, power generation from hydrogen tops 50 TWh in both pathways, corresponding to a demand for hydrogen of around 2.5 Mt. By then, hydrogen-fuelled installations account for a cumulative capacity between 21 and 25 GW. The corresponding load factors are in a range between 25% and 30%, confirming hydrogen a flexible source of mid-load and peaking power. Hydrogen complements other decarbonised solutions in this role such as nuclear or natural gas and biomass power generation with CCS:

a. Natural gas provided 24% of European electricity generation in 2016. In both pathways, this share falls over the 2020s to less than 15% (of generation connected to the grid - "ongrid") in 2030 under the impact of high gas prices and a phase out of natural gas imports from Russia. Power generation from natural gas then flattens until 2050: this underscores the value of natural gas in the energy transition provided the oil & gas industry acts to deploy best available technologies for methane emission mitigation and ensures continued availability of natural gas at affordable prices. Over the outlook period, new combined cycle gas turbines (CCGT) with CCS are deployed. They provide about 80% of electricity from natural gas by the end of the period, mostly for mid-load power generation. The remaining units with CCS provide peaking services with much lower a load factor.

b. Renewables other than wind and solar power, notably biomass, geothermal and hydropower are dispatchable, providing flexibility to the electricity system and contributing substantially to the integration of variable renewables. They provide mid-load and peak-load power bringing flexibility to the variable electricity production. Virtually all biomass power plants are equipped with CCS in 2050, with installed capacities between 43 GW in in Technology Diversification pathway 59 GW in the Renewable Push pathway. Biomass plays a dual role: it covers about 5% to 7% of the total ongrid power generation, bringing valuable flexibility and also becoming an important source of negative CO_2 emissions in the energy system.

c. Generation from nuclear power is relatively stable. Its share in the power mix nevertheless decreases as total power generation grows over the outlook period. Its market share for ongrid generation is 12% in 2050 in the Technology Diversification pathways compared to 24% in the past. As a low-carbon source of electricity, nuclear power contributes to decarbonisation objectives and can even power some electrolysers that use electricity straight from the grid. However, economic barriers, long construction time, political headwinds and social acceptance problems excludes nuclear power from the electricity mix of various European countries.

131. Compared to the study's first edition, hydrogen shows an increasingly clear value proposition for integrating variable renewable energies into the energy system and achieving so-called energy system integration. A highly renewable power system produces surplus electricity during the periods with high wind and solar irradiation. Hydrogen can absorb this extra electricity that would have required either extra transmission capacity to transport or been curtailed. Electrolysers integrate locally a large part of the newly deployed renewable energy, thus limiting the strain on the transmission and distribution infrastructure and on system management. The transformed renewable energy can then be stored and transported more easily in the rest of the energy system, up to the point of consumption. As the results show, renewable hydrogen goes primarily to decarbonise hard-to-abate sectors such as industry and transport, hinting at an indirect electrification in those sectors as well. There is a clear potential for hydrogen-to-power; however, it is subject to several factors: deployment of hydrogen or ammonia-based turbine technologies, backlash on the roll-out of CCS and nuclear or a faster pace of decrease in cost of hydrogen processes could very well create a bigger role for hydrogen for power generation and flexibility.

4 Development of the hydrogen value chain

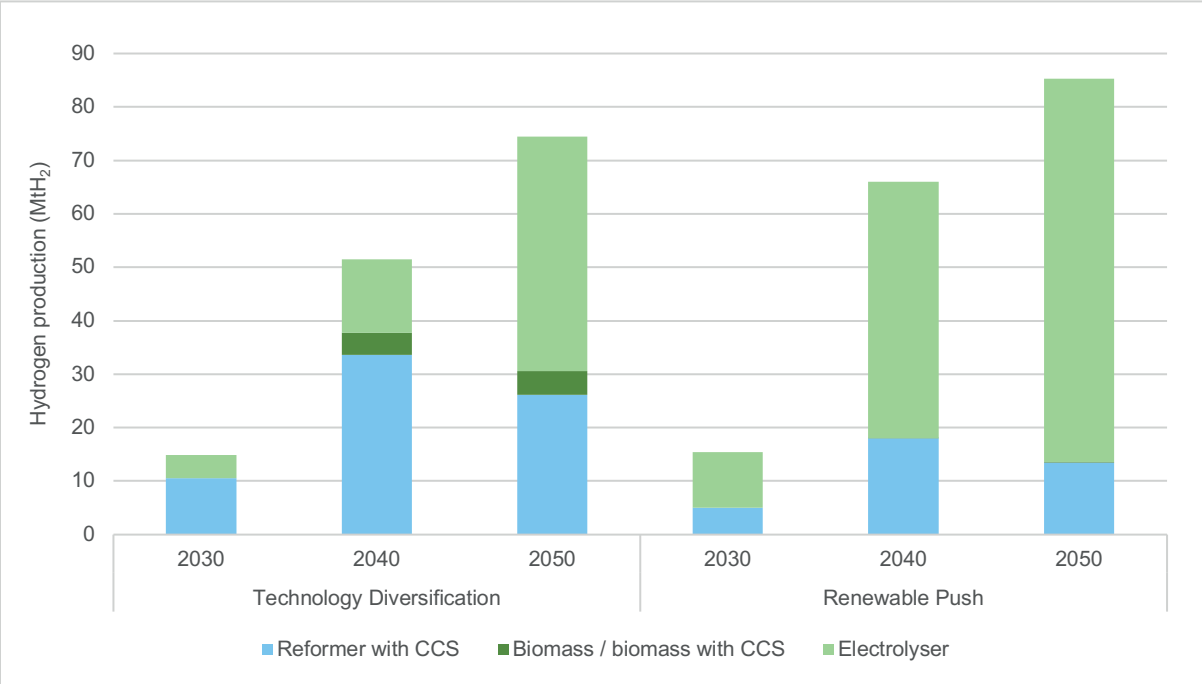
132. The uptake of hydrogen in Europe is contingent on the development of a full-fledged supply chain, relying on domestic production capacities, a dedicated European-scale transport infrastructure and hydrogen imports from countries outside Europe.

4.1 Production of hydrogen in Europe

133. Analysis of current developments in Europe shows a growing pipeline of renewable and low-carbon hydrogen production projects, underpinned by policy strategies and a first slate of support mechanisms. The *Hydrogen for Europe* pathways shed light on how these developments fit with an optimal deployment of assets and technologies over the long term.

134. Both pathways confirm the importance of a fast ramp-up in production in the current decade. The *Hydrogen for Europe* results indicate that European production of renewable and low-carbon hydrogen must grow markedly over the coming years to support the optimal market uptake, reaching around 15 Mt by 2030 in both pathways (figure 34). This growth further amplifies in the subsequent decades: output increases substantially in the 2030s, achieving 52 Mt in the Technology Diversification pathway and 66 Mt in the Renewable Push pathway. Such a momentum and early investments can foster further cost reductions in electrolysers bringing the cumulative cost down in the long run.

Figure 34. Evolution of hydrogen production in Europe in the Technology Diversification and Renewable Push pathways, 2030 to 2050

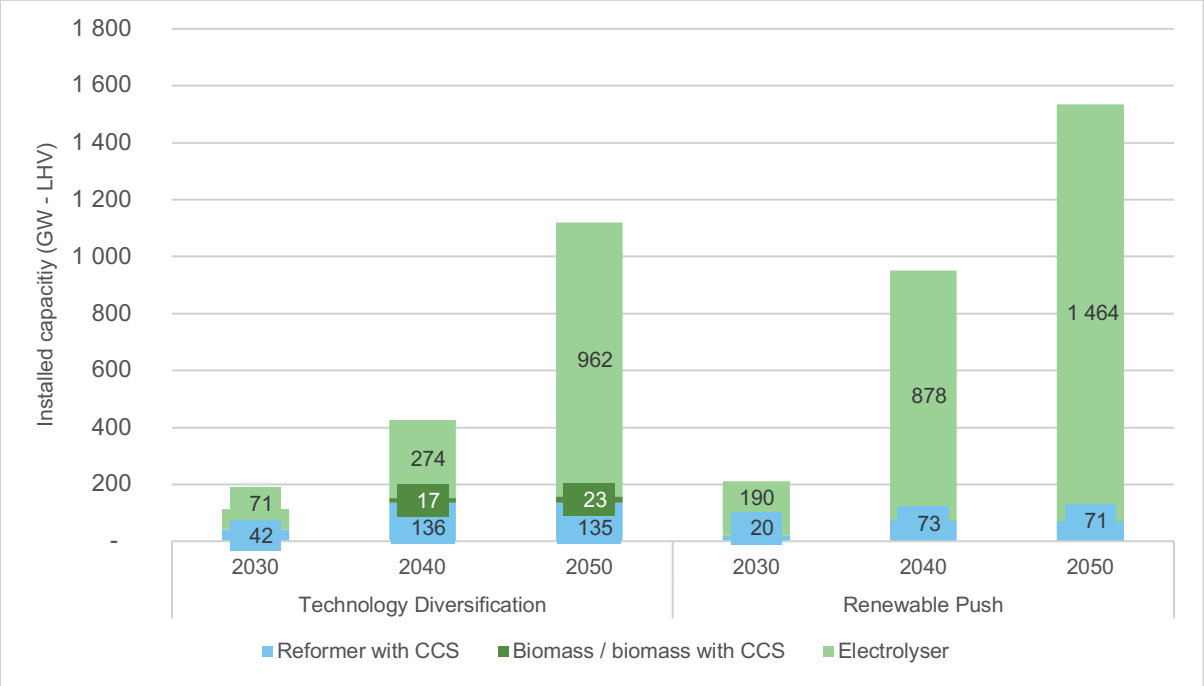


Source: Hydrogen4EU

135. The findings underscore the value of diversity in hydrogen production routes. In the Technology Diversification pathway, low-carbon hydrogen based on reformers with CCS plays a critical role to establish a hydrogen economy and support demand uptake in the 2020s and 2030s. Low-carbon hydrogen production tops 10 Mt in 2030 and reaches around 34 Mt in 2040. Renewable hydrogen plays a clear complementary role to low-carbon hydrogen: its development accelerates progressively during the outlook period and meets the bulk of the additional demand growth in the last decade. In the Renewable Push pathway, characterised by more ambitious targets for renewable energy deployment, the upscaling of renewable hydrogen is anticipated: production reaches 10 Mt already in 2030 and tops 70 Mt by the end of the outlook period. Low-carbon hydrogen is also featuring in that pathway as it complements renewable hydrogen to establish the hydrogen economy in the first half of the outlook period.

136. The development of European hydrogen production requires a rapid ramp-up of corresponding production capacities, both for offgrid and ongrid electrolysers and reformers with CCS (figure 35). Investments need to start in the current decade to accommodate around 90 GW of overall capacity by 2030 in the Technology Diversification pathway. In the Renewable Push pathway, the overall capacity requirement for 2030 reaches 190 GW, underpinned by lower utilisation rates for electrolysers. Such a capacity ramp-up requires immediate and determined policy and industrial action. Capacity ramp-up continues over the subsequent decades: by 2050, installed capacity in Europe exceeds 700 GW and 1,700 GW in the Technology Diversification and Renewable Push Pathways.

Figure 35. Evolution of hydrogen production installed capacity by technology in the Technology Diversification and Renewable Push pathways, 2030 to 2050



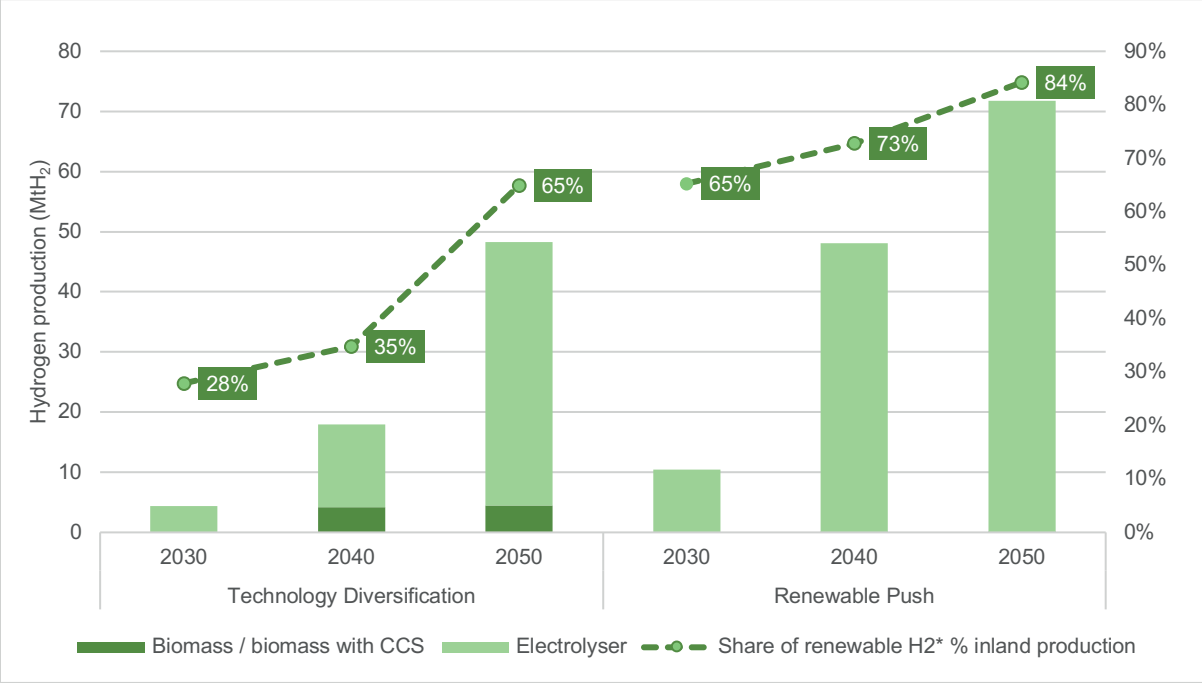
Source: Hydrogen4EU

4.1.1 Production of renewable hydrogen in Europe

137. The *Hydrogen for Europe* study confirms renewable hydrogen's lead role in Europe's decarbonisation efforts. Renewable hydrogen supports demand uptake in the short term alongside low-carbon hydrogen and is the main source of hydrogen supply in the long term across all scenarios (figure 36). The benefits of renewable hydrogen are two-fold: it helps integrating variable renewable electricity sources, such as solar and wind, into the system, providing flexibility to the power system, and it transforms renewable energy into the most relevant energy carriers for the industry and transport sectors, for which direct use of electricity can be challenging.

138. Development of renewable hydrogen is gradual in the Technology Diversification pathway. Its early deployment is constrained by high technology costs and urgent needs for direct electrification elsewhere in the energy system. By 2030, renewable hydrogen already has a key role in complementing low-carbon hydrogen: its production reaches around 4 Mt in 2030, entirely from electrolysers. It represents nearly one third of total hydrogen production in Europe. Renewable hydrogen grows in lockstep with low-carbon hydrogen over the 2030s, supported by massive investments in electrolysers and renewable electricity capacities (and the development of biomass-based production technologies). By 2040, 18 Mt of renewable hydrogen are produced as renewable hydrogen continues gaining momentum over the 2040s. Its development pace accelerates to cover the bulk in additional demand growth. This momentum is made possible by a large potential for cost reduction through learning effects, as studied in detail in the study's first edition. Production reaches 48 Mt in 2050: by then, renewable hydrogen is the main hydrogen supply source in Europe.

Figure 36. Evolution of the production of renewable hydrogen (including biomass with CCS) in the Technology Diversification and Renewable Push pathways, 2030 to 2050

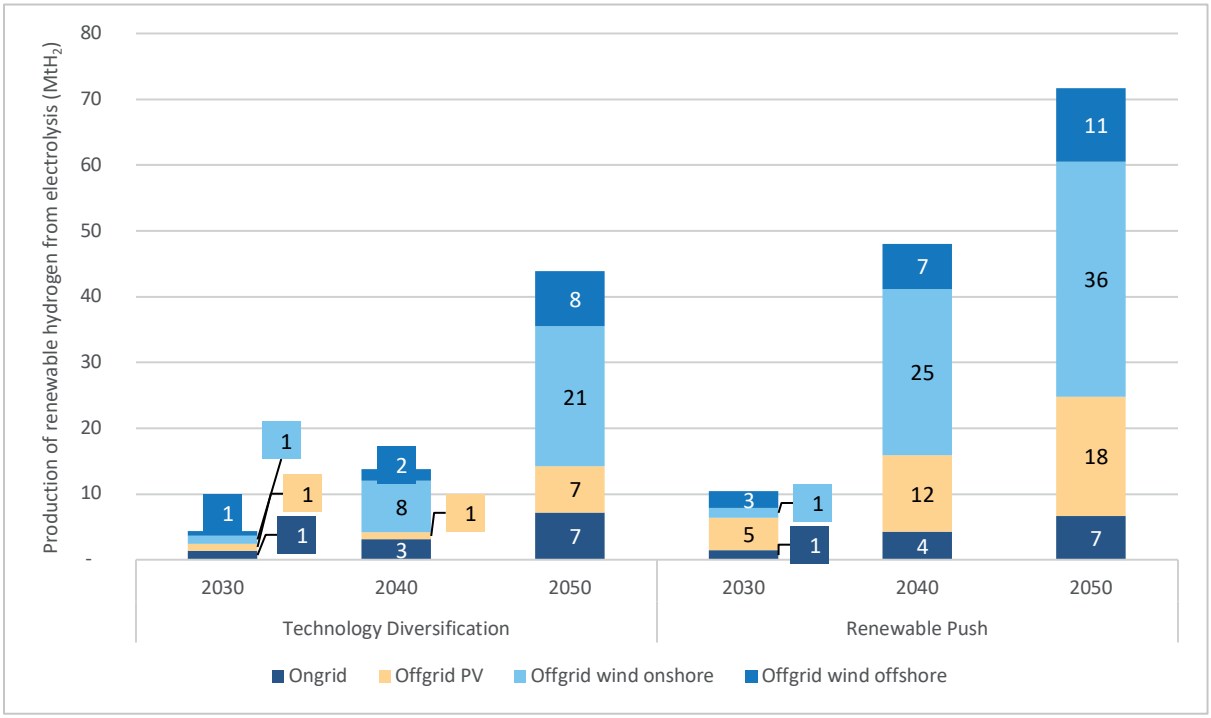


Source: Hydrogen4EU

139. Renewable hydrogen is mainly produced via water electrolysis. Electrolysers can either be operated ongrid, with electricity provided directly by the electricity grid, or they are directly coupled with renewable electricity installations in an offgrid set-up. Electrolysis-based renewable hydrogen represents more than 90% of total renewable hydrogen production in 2050 in the Technology Diversification pathway. The vast majority of this production comes from offgrid electrolysers, with a direct connection to solar, onshore wind and offshore wind capacities (figure 37). In the Technology Diversification pathway, offgrid capacities of solar, onshore wind and offshore wind plants connected directly to electrolysers represent respectively around 275 GW, 272 GW, and 80 GW in 2050. The utilisation rates of offgrid electrolysers are largely determined by the capacity factors of the renewable energy sources they are connected to. As wind power plants have higher capacity factors than solar PV installations, offgrid electrolysers connected to windmills achieve higher utilisation rates. Ongrid electrolysers running on electricity procured from the electricity grid provide important flexibility to the power system. They help reduce curtailment and network congestion during periods of excess renewable electricity generation.

140. Renewable hydrogen from electrolysis is complemented by hydrogen production from biomass units coupled with CCS technology. In the Technology Diversification pathway, hydrogen production from biomass rises to 4.1 Mt in 2040 and to 4.5 Mt in 2050. Using biomass with CCS allows for negative CO_2 emissions as the CO_2 created during the hydrogen production process is captured and stored geologically. The use of biomass for both hydrogen and electricity production is constrained by the availability of bioenergy in Europe. The 2021 edition of the *Hydrogen for Europe* study was complemented with a sensitivity analysis on the potential of biomass, considering the implications of a 45-50% greater potential. It showed that greater availability of bioenergy would affect the dynamics of hydrogen development and lead to a more prominent role for biomass with CCS in hydrogen production, lowering slightly the need for electrolysers in the long term.

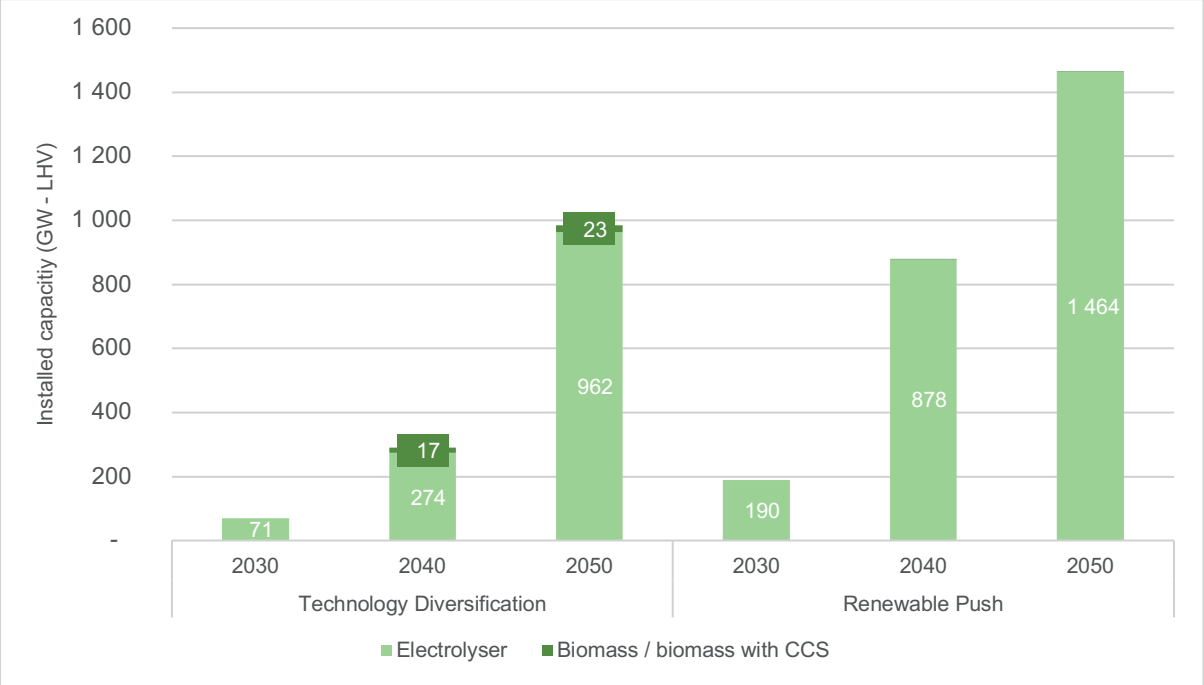
Figure 37. Evolution of renewable hydrogen production via electrolysis by source between 2030 and 2050



Source: Hydrogen4EU

141. The Renewable Push pathway is characterised by higher targets for renewable energy development. This is primarily achieved via a greater deployment of wind and solar capacities directly connected to electrolysers: by 2050, installed capacities of offgrid solar and wind are respectively 164% and 62% higher than in the Technology Diversification pathway. Renewable hydrogen plays a particularly crucial role in this pathway to absorb the growth of renewable energy in the system, mitigate flexibility and grid reinforcement needs for the power system and distribute renewable energy to where it is most needed. As a result, renewable hydrogen production grows earlier than in the Technology Diversification pathways and achieves far higher levels over the long term. In that scenario, renewable hydrogen is already the main European supply source in 2030 with a production of 10 Mt from electrolysers. This is in line with the current goals of the REPowerEU plan. Production growth then accelerates: it almost quintuples in the 2030s to reach 48 Mt by 2040, by which point renewable hydrogen becomes the true backbone of hydrogen supply. By 2050, renewable hydrogen assumes more than 80% of European hydrogen production with 72 Mt. Note that biomass with CCS does not serve to produce hydrogen in that scenario: there is a clear trade-off in the value of biomass that positions it primarily for the electricity sector and end-uses.

Figure 38. Evolution of renewable hydrogen (electrolysers and biomass with CCS) installed capacities in the Technology Diversification and Renewable Push pathways from 2030 to 2050

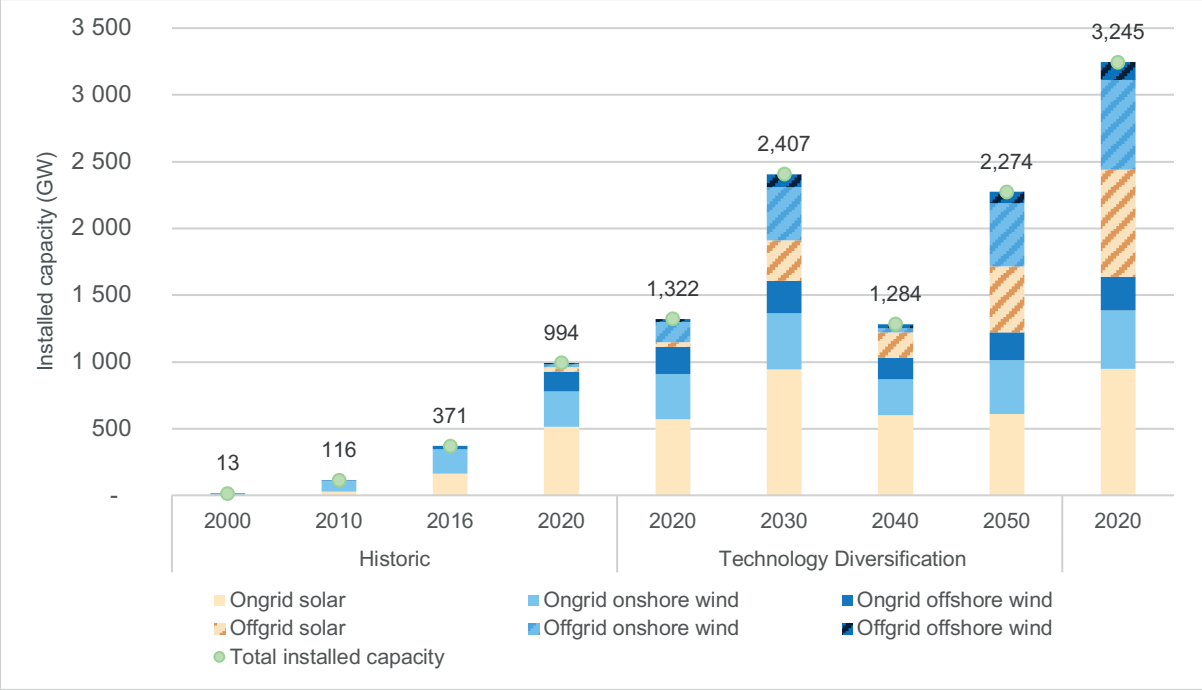


Source: Hydrogen4EU

142. These levels of renewable hydrogen production imply major capacity needs over the next decades (figure 38). In the Technology Diversification pathway, electrolysis capacity ramps up more moderately at first, reaching around 70 GW in 2030. Deployment of electrolysers accelerates in the second half of the outlook period, reaching topping 960 GW by 2050. More than 800 GW of electrolysers are installed during the last decade, both ongrid and offgrid. In the Renewable Push pathway, deployment of electrolyser capacities in the 2020s and 2030s needs to be four times as high as in the Technology Diversification pathway to allow for the faster growth in production. New electrolyser capacity installations already exceed 200 GW and 500 GW in the first two decades of the outlook. More than 900 GW of additional electrolysers are installed during the last decade, bringing the overall installed capacity to above 1400 GW in 2050.

143. To feed these electrolysers with clean electricity, renewable energy investments need to grow in lockstep. The *Hydrogen for Europe* pathways show that investments in renewable energy and electrolyser will represent an unprecedented industrial effort, much stronger than the increase in renewable installed capacity in the power generation sector over the last two decades. Between 2000 and 2020, total European installed capacity in solar and wind grew from 13 GW to 371 GW (figure 39). In comparison, the results show that in 2050, installed capacities of solar and wind capacities exceed 2,400 GW in the Technology Diversification pathway and 3,200 GW in the Renewable Push pathway. Looking only at hydrogen, by 2050, between nearly 800 GW (33% of total capacity) and 1,600 GW (49%) are directly connected to electrolysers in the two pathways for offgrid hydrogen production. Also considering the need for capacity replacement, offgrid production of renewable hydrogen therefore requires an average annual installation rate between 29 GW/year and 57 GW/year. As such, there is a clear need for conscious and effective policy support for the establishment of a hydrogen production industry in Europe. Social acceptance of renewable energy installations, fast-tracked administrative procedures and the ability of the supply chains to deliver this ramp-up, are indispensable features of the pathway towards net-zero emissions.

Figure 39. Evolution of installed wind and solar capacity for electricity production in Europe, historical 2000 to 2019, and as calculated in the Technology Diversification and Renewable Push pathways, 2030 to 2050



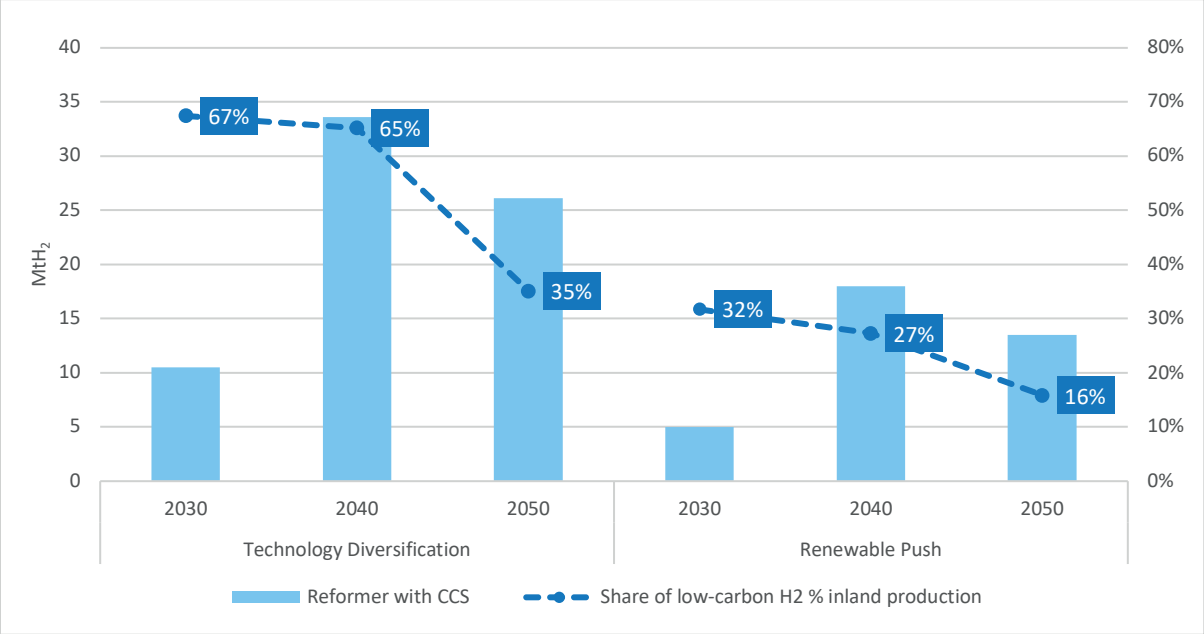
Source: IRENA and Hydrogen4EU

4.1.2 Production of low-carbon hydrogen in Europe

144. Low-carbon hydrogen from natural gas takes an important role in the Technology Diversification in boosting the establishment of the European hydrogen economy. Production of hydrogen from natural gas reformers with CCS reaches 11 Mt by 2030. By that time, low-carbon hydrogen is the primary supply source of hydrogen in Europe and meets 70% of the demand (figure 40). The same pathway shows a production peak around 2040 when output reaches 34 Mt, representing nearly two thirds of European hydrogen production. In the last decade of the outlook period, renewable hydrogen's momentum increases, and CO_2 storage injection limits are progressively reached. Production of low-carbon hydrogen gradually falls to around 25 Mt in 2050, corresponding to around a quarter of total hydrogen production.

145. In the Renewable Push pathway, low-carbon hydrogen complements renewable hydrogen to achieve the full scale of hydrogen's uptake. As in the Technology Diversification pathway, low-carbon hydrogen production contributes to the establishment of the clean hydrogen industry in the start of the outlook period. In 2030, it represents nearly one third of total production with 5 Mt, and then peaks around 2040 at 18 Mt. As in the other scenario, hydrogen demand growth over the 2040s is mostly served by renewable hydrogen: production from low-carbon hydrogen decreases slightly to 13 Mt of annual production (16% of the production mix) by 2050.

Figure 40. Evolution of low-carbon hydrogen production by technology in the Technology Diversification and Renewable Push pathways, 2030 to 2050

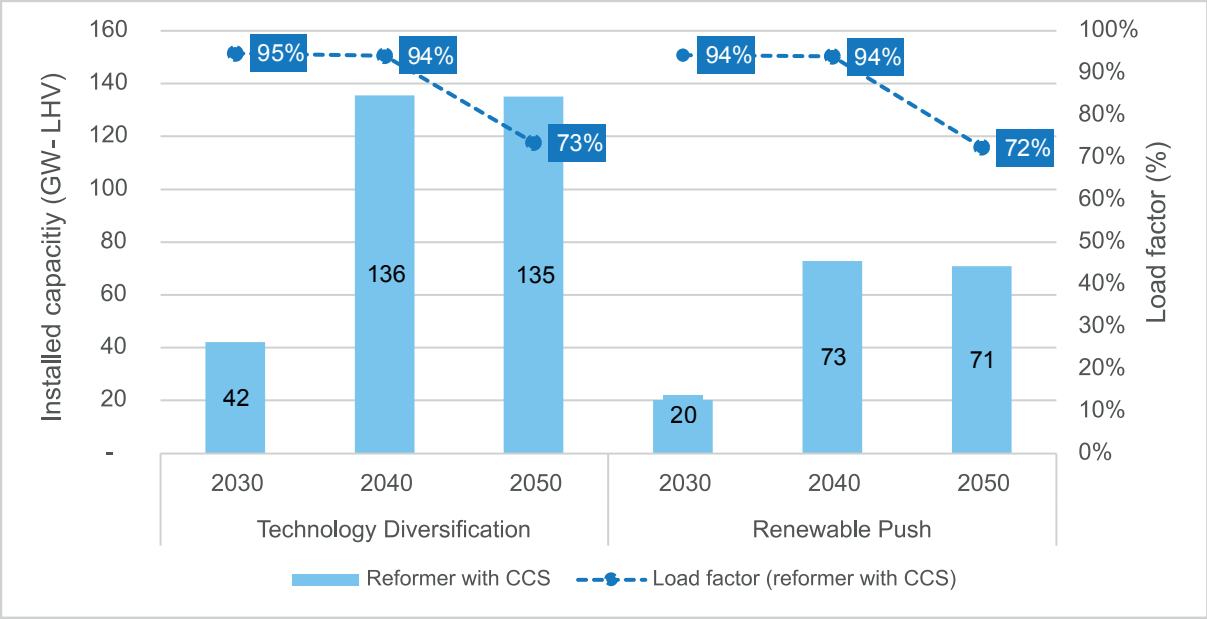


Source: Hydrogen4EU

146. A noteworthy change to the study's first edition is the marginal contribution of methane pyrolysis to hydrogen supply. Although the technology has clear local benefits and could become commercially available at the beginning of the 2030s, internalisation of methane emissions, lower efficiency compared to reformers and an increased role for hydrogen imports negatively affect its business case in our two pathways. As highlighted in the study's first edition, prospects for methane pyrolysis are driven by the feed-gas cost, sales price of carbon black, and the economics and local availability of other hydrogen sources.

147. Installed capacity of reformers with CCS grows rapidly in both pathways to achieve optimal production levels of low-carbon hydrogen. In the Technology Diversification pathway, installed capacity jumps from virtually zero today to more than 40 GW in 2030 and nearly 140 GW in 2040 (figure 41). As low-carbon hydrogen production peaks and then goes into decline, installed capacity remains flat in the 2040s to around 135 GW. Reformers run at high-capacity factors throughout the outlook period, notably in the first two decades when their utilisation rate exceeds 90%. Installed capacity is lower in the Renewable Push pathway, reflecting the faster and stronger deployment of renewable hydrogen. Installed capacity of reformers with CCS reaches 20 GW in 2030 and around 70 GW in 2040, half the levels of the Technology Diversification pathway. Investment dries up over the last decade, with capacity stabilising around 70 GW.

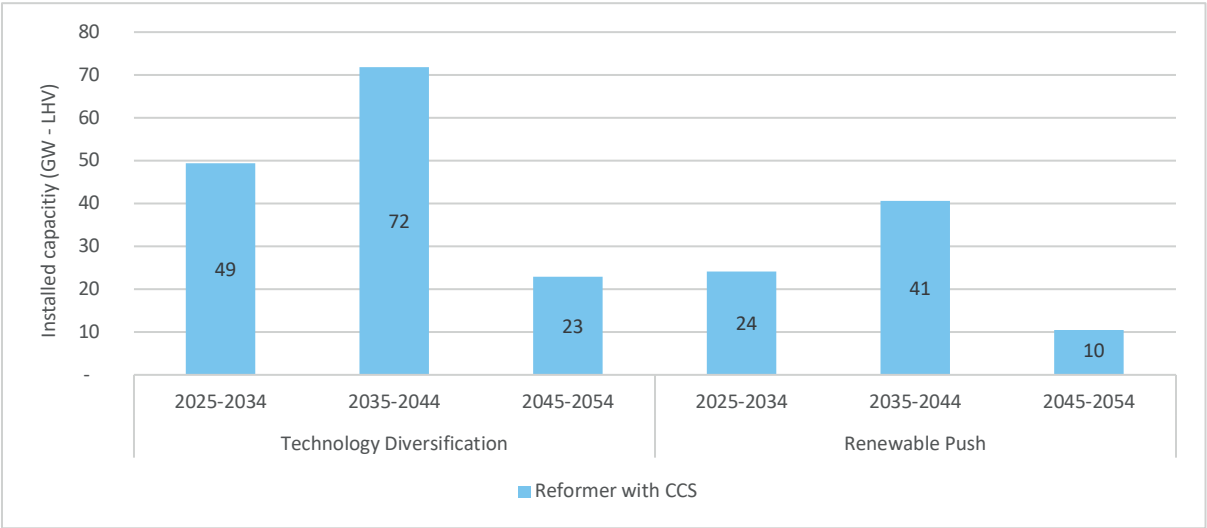
Figure 41. Evolution of low-carbon hydrogen installed capacities by technology in the Technology Diversification and Renewable Push pathways, 2030 to 2050



Source: Hydrogen4EU

148. The *Hydrogen for Europe* pathways underline the existence of a transitory window of opportunity for investment in low-carbon hydrogen – independent of whether policy-makers give preference to renewable energy. Investors need to sanction their projects in the first half of the outlook period to take advantage of this window, maximise utilisation rate and profitability, and minimise the risk of stranded assets. This coincides with a period of turbulence and uncertainty in natural gas markets, possibly requiring bold decisions from investors if projects are to move ahead. As illustrated in figure 42, between 24 GW and 49 GW of capacities need to be commissioned by the mid-2030s in the Renewable Push and Technology Diversification pathways, respectively. Between 41 GW and 72 GW are needed in the subsequent period until the mid-2040s. As production of low-carbon hydrogen declines in the last decade of the transition, investment slowly dries up. Investment needs for the period from the mid-2040s to the mid-2050s fall to between 10 and 23 GW, mostly to replace some of the then oldest reformers installed in the 2020s.

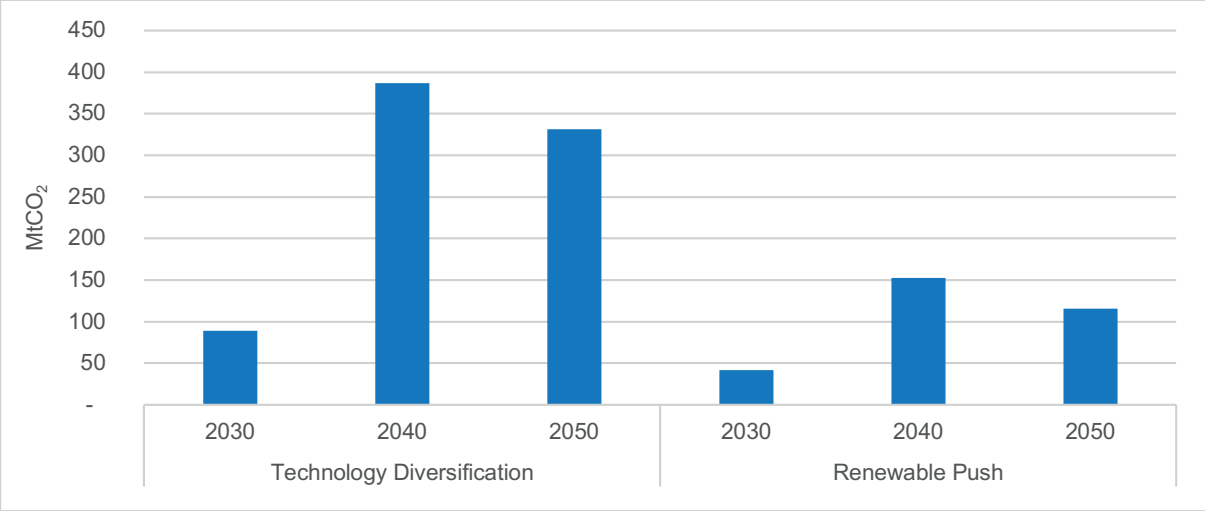
Figure 42. Evolution of new installed capacities in low-carbon hydrogen technologies in the Technology Diversification and Renewable Push pathways, 2021 to 2054



Source: Hydrogen4EU

149. Both pathways require a significant upscale in the CCS value chain (figure 43). The Technology Diversification pathway entails higher needs for CO_2 capture and storage to avoid emissions from reformers and unlock negative emissions from biomass-related production. Hydrogen-related CO_2 capture rises from 90 Mt of CO_2 in 2030 to nearly 390 Mt in 2040. It decreases slightly towards the end of the outlook period to 330 Mt. In the Renewable Push pathway, these levels are much lower as electrolysis constitutes the main part of hydrogen production. CO_2 capture from low-carbon hydrogen production reaches 40 Mt in 2030, peaks at over 150 Mt in 2040 and then drops to nearly 120 Mt by 2050. The potential of low-carbon hydrogen is highly dependent on the deployment of the CCUS value chain and the ability of carbon storage capacities to grow in parallel to low-carbon hydrogen production over the next thirty years. Low-carbon and biomass-originated renewable hydrogen development in the Technology Diversification pathway is ultimately constrained by the annual CO_2 storage injection limit of 1 $GtCO_2$ in 2040 and 1.4 $GtCO_2$ in 2050. Therefore, the success of low-carbon hydrogen is closely tied to the development of carbon capture but also of an adequate CO_2 storage and transport infrastructure.

Figure 43. Evolution of CO_2 captured from hydrogen production in the Technology Diversification and Renewable Push pathways between 2030 and 2050



This includes both reformers with CCS and biomass with CCS.

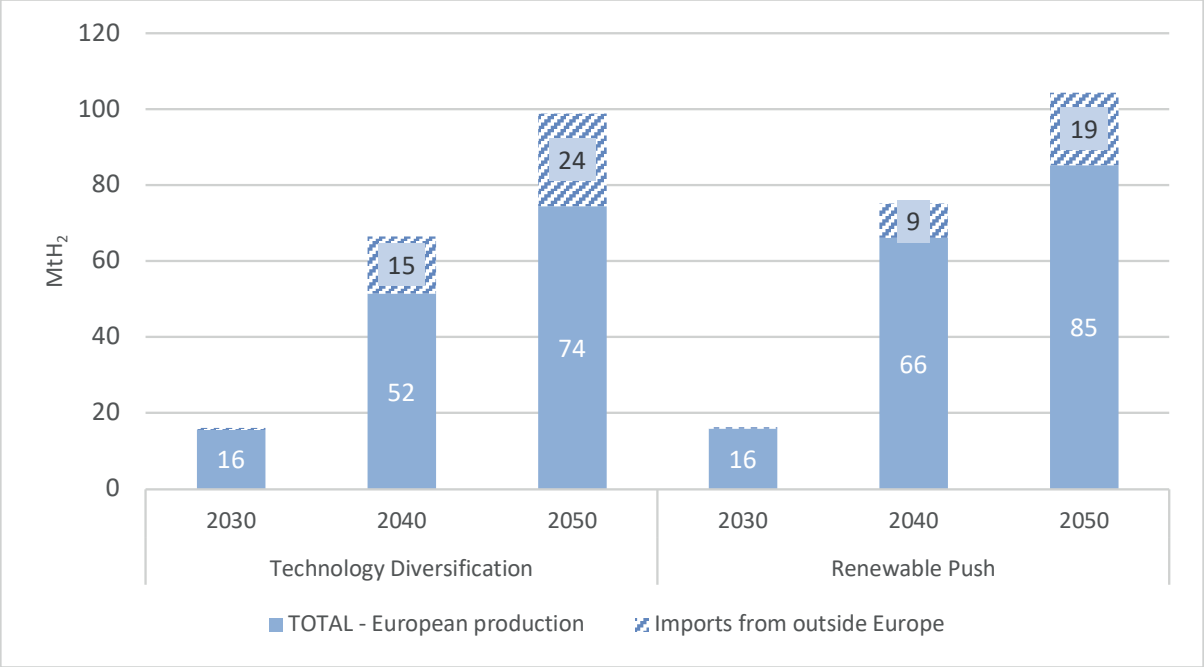
Source: Hydrogen4EU

4.2 International trade of hydrogen

150. Regions and countries in the study's scope all have different characteristics regarding energy demand, existing infrastructure and resource potential. For hydrogen, that means that some countries with high demand may not be able to provide the necessary volumes themselves. Conversely, other countries that are well-endowed in terms of resources may have more supply than demand and can provide competitively priced hydrogen to other regions. The *Hydrogen for Europe* pathways confirm the importance of trade to ensure supply-demand adequacy, allocate production of hydrogen where it is most needed and achieve optimal hydrogen development in Europe.

151. While all European countries produce and consume hydrogen, eight countries concentrate most of the hydrogen flows within the European scope: Germany, Norway, Italy, the Netherlands, France, Poland, Spain and the UK. Norway and the UK are the region's top producers of hydrogen in both pathways, leveraging their strong renewable energy potential and their endowment with natural gas. Norway is able to export virtually all its hydrogen production to other countries in both pathways, albeit lower export volumes in the Renewable Push pathway. Denmark and the UK (in the Renewable Push pathway) also show some notable potential for exporting. On the opposite end, main industrial countries with large hydrogen demand become major hydrogen consumers by 2050 and need to import hydrogen to complement their own resources. Germany, France, Netherlands and Poland together import 26 Mt of hydrogen in the Technology Diversification pathway and 22 Mt in the Renewable Push pathway in 2050.

Figure 44. Evolution of hydrogen imports from extra-European countries in the Technology Diversification and Renewable Push pathways, 2030 to 2050[56]



Source: Hydrogen4EU

152. The *Hydrogen for Europe* results confirm the existence of a growing gap between domestic supply and demand. In both pathways, hydrogen imports mostly from North Africa and the Middle East complement European production and sustain the ambitious uptake of the European hydrogen economy (figure 45). The results are well aligned with the renewed strategies of European stakeholders to rely on international hydrogen trade and to secure early imports of hydrogen and hydrogen-related molecules (see box 7). They provide important insights to policy-makers as to the trade strategies to be pursued:

a. In both pathways, hydrogen imports take off from the late 2020s, reaching significant levels during the second half of the outlook period. In the Technology Diversification pathway, shipments from North Africa, the Middle East and various smaller exporters reach 15 Mt in 2040 and nearly 25 Mt in 2050, covering up to a quarter of European hydrogen demand. Imported hydrogen is critical to diversify supply sources, reduce the cost of hydrogen supply and achieve optimal resource utilisation. In the Renewable Push pathway, higher targets for renewable energy shares result in lower import needs. Imports still reach significant levels at some 10 Mt in 2040 (12% of total supply) and almost 20 Mt in 2050. How these imports are in practice split between pure hydrogen, ammonia, synthetic fuels or methanol is beyond the scope of this analysis.

b. Import opportunities are underpinned by two factors: First, excellent renewable energy potential in North Africa, the Middle East and Ukraine coupled with a continuous decrease in the cost of electrolysers and renewable energy boosts the competitiveness of renewable hydrogen in these regions. Second, the results highlight how crucial transport infrastructure is for the establishment of a significant hydrogen trade environment. Competitiveness of hydrogen imports to Europe is particularly sensitive to the options available to transport hydrogen molecules from the producing country to Europe. Traditional gas exporters to Europe have existing national gas infrastructure and cross-border links to Europe that give them a transport cost advantage over new entrants without a legacy industry. The example of North-African countries, notably Algeria, shows that this infrastructure can benefit both low-carbon hydrogen and renewable hydrogen exports.

[56] In parallel to hydrogen imports, natural gas imports from extra-European countries are also considered. CO_2 trade is only considered within Europe. Imports of e-fuels or green Ammonia for direct uses is out of the scope of the project.

c. The trade flows in the two pathways are economically optimised, i.e., European imports are served by the least-cost suppliers in our modelling. However, today, European companies and national governments are advancing with projects and trade agreements with countries all over the world (Chile, Namibia and Australia are prominent examples, see box 7), typically pursuing policy or business objectives that go far beyond securing long-term hydrogen supply agreements for Europe. Against the backdrop of security of supply moving to the top of the energy policy agenda since the Russian invasion of Ukraine, governments are unlikely to choose their trade partners based on economics only. The burgeoning international hydrogen trade is also an important opportunity to reduce reliance on traditional energy exporters.

d. Ultimately, the volume of imports remains moderate compared to the assessed export potential of the neighbouring regions. This is because of the low competitiveness of certain supply sources compared to domestically produced hydrogen, the challenges for kickstarting the industry in exporting countries and the competition against domestic uses and other export markets are aspects that should not be taken for granted. The results suggests that a true international trade market develops over the coming decades, in which Europe will represent only one of several markets that compete for secure and affordable hydrogen imports.

Box 7. European initiatives for hydrogen imports

The European Commission and key European countries have already been stressing the importance of hydrogen imports in securing their ambitious hydrogen strategies. Hydrogen imports are at the core of some EU countries' strategies such as Germany, that plans to import up to 3 Mt of hydrogen per year by 2030 to complement its domestic production. Other EU countries plan to position themselves as hydrogen import gateways into Europe, like Italy and the Netherlands. Belgium declared at COP26 that their objective was to become a "European import centre for green hydrogen".

Hydrogen imports are also at the top of the EU agenda. The recent REPowerEU plan targets 6 Mt of hydrogen imports and 6 Mt of imports of ammonia by 2030. It has proposed the creation of the Global European Hydrogen Facility to establish cooperation on regulatory and investment aspects between EU countries and future hydrogen trade partners. In coherence with the EU External Energy Strategy, the *Hydrogen for Europe* pathways prioritise three nearby "hydrogen import corridors": The North Sea (around Norway and the UK), South Mediterranean (with North Africa and Middle East) and around Ukraine. For European policy-makers, hydrogen import strategies have as much an economic dimension as a geopolitical one. In the short term, the Russian invasion of Ukraine and the resulting decisions to phase out consumption from Russian energy products has highlighted European's weakness to Russian gas, rising urgent needs for diversification of supply routes, acceleration of hydrogen import efforts and increased decarbonisation goals. Resilience of the future mix is at the core of European's new energy supply strategy. From this perspective, importing hydrogen from a variety of different countries and different sources as depicted in the *Hydrogen for Europe* pathways would be a robust strategy in line with current European stakes. As climate change and energy transition is a global issue, this would also be the occasion for Europe to work hand in hand with developing countries, helping them establish a domestic hydrogen and low-carbon economy.

Governments and institutions are busy concretising their hydrogen import strategies. Germany is pioneering the hydrogen import market with the H2Global mechanism, a central platform for external sellers and EU buyers. H2Global uses German public funding to cover the difference between sellers' lowest price and buyers' highest willingness to pay. A first tranche of €900 million in federal funding was approved by the EC earlier in the year. Memoranda of Understanding (MoU) between European stakeholders and hydrogen-exporting countries have been proliferating with the goal to develop trade partnerships and accelerate the supply of first hydrogen shipments to Europe. Countries like Saudi Arabia, Egypt, Morocco, but also Namibia, Chile and Australia have positioned themselves as strategic partners for leveraging low-cost renewable and low-carbon hydrogen resources and building first large-scale projects.

On the industrial side, several ports have already included hydrogen imports in their short-and mid-term strategies. Europe's biggest commercial port, Port of Rotterdam, plans to provide Europe with 4.6 Mt of green hydrogen (including ammonia) via sea routes, thanks to its existing LNG import infrastructures[57]. Among different agreements, the Queensland (Australia) state government has signed a MoU with the Port of Rotterdam to develop ammonia

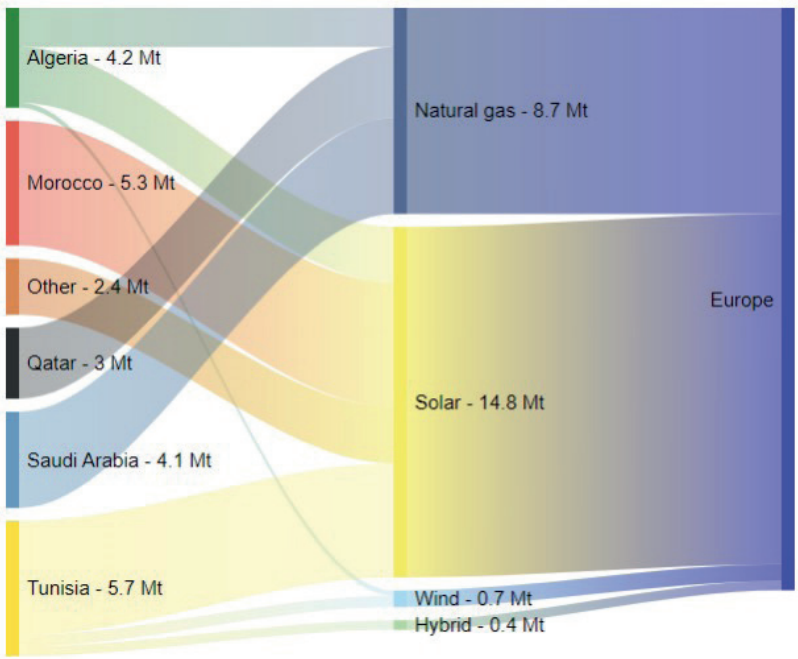
[57] https://www.enlit.world/hydrogen/port-of-rotterdam-ups-2030-hydrogen-supply-to-4-6mt/

supply chains between the Australian state and the EU[58]. Similarly, Belgian Ports of Antwerp-Bruges signed a MoU with Chilean Ministry of Energy officialising their mutual commitment to cooperation "to make green hydrogen flows between Chile and Western Europe a reality" during the COP26 in Glasgow[59]. Similarly, Port of Amsterdam, within its H2A (initially named H2Gate) programme, has the ambition of operating climate neutral and plans to import 1 Mt of renewable hydrogen. Nevertheless, no specific date for achieving this target has been announced[60].

153. In alignment with the REPowerEU plan, hydrogen imports from Russia have been excluded in this new edition of our study. In the previous outlook, Russia was the biggest exporter of hydrogen to Europe, thanks to a combination of low-cost feed-gas for low-carbon hydrogen production and large-scale existing gas export infrastructure between Europe and Russia. In the current edition, this potential is served by North-African countries such as Morocco, Tunisia, among other traditional natural gas exporters to Europe thanks to the existing natural gas pipelines between this region and Europe that can be refurbished for hydrogen transport.

154. Morocco and Tunisia become two of the biggest hydrogen exporters to Europe in both pathways. Focusing on the Technology Diversification pathway (figure 45), these two North-African countries together provide about half of the European hydrogen imports, almost entirely from electrolysis of solar electricity. Algeria is the third largest hydrogen exporter to Europe with over 4 Mt of low-carbon and renewable hydrogen, confirming the strategic importance of existing cross-border gas infrastructure to secure hydrogen trade. Specifically, these countries are able to export hydrogen through the MEG and Medgas pipelines, that become hydrogen ready by 2040[61] (Guidehouse, 2020). In Algeria, natural gas production becomes increasingly challenging and feed-gas costs are increasing. Nevertheless, benefitting from abundant sunshine and good wind resources, Algeria compensates this declining capacity by adding renewable hydrogen from solar and wind power to its hydrogen exports portfolio. By the end of the outlook period, Algeria becomes a diversified hydrogen exporter with about two thirds of its exports stemming from solar power and one third from natural gas (with small quantities of hydrogen from wind power). By 2050, in the Technology Diversification pathway, over 60% of Europe's hydrogen imports come from North Africa.

Figure 45. Origin of hydrogen imports in 2050 in the Technology Diversification pathway



Source: Hydrogen4EU

[58] https://www.ammoniaenergy.org/articles/building-ammonia-supply-chains-into-the-port-of-rotterdam/
[59] https://fuelcellsworks.com/news/belgian-ports-of-antwerp-port-of-zeebrugge-and-chile-join-forces-to-push-green-hydrogen/
[60] https://hydrogen-central.com/port-amsterdam-import-one-million-tons-green-hydrogen-h2gate/
[61] According to the European Hydrogen Backbone, the Transmeda MEG, Medgas and TANAP are assumed to become hydrogen ready by 2040. Similarly, for the Kyev - Western Border Pipeline.

155. Qatar, with more than 24 trillion cubic meters of proven natural gas reserves, ranks third among the countries with the largest natural gas reserves and is first LNG exporter to Europe in volume. Thanks to its already existing LNG infrastructure, the country has significant competitive advantage for low-carbon hydrogen shipments to Europe. In the Technology Diversification pathway, Qatar exports 3 Mt of low-carbon hydrogen to Europe by 2050. Saudi Arabia, with nearly 9 trillion cubic meters of proven natural gas reserves (5th largest proven natural gas reserves in the world) currently does not export natural gas to Europe; however, it has the potential to become the largest hydrogen exporter to Europe via shipping (above 4 Mt in Technology Diversification pathway) in 2050.

156. To sum up, the *Hydrogen for Europe* results show that:

a. Imports of hydrogen from neighbouring regions are essential for the establishment of a European hydrogen economy. They complement renewable and low-carbon hydrogen to cover the rapid growth in demand in the 2030s and 2040s. By 2050, hydrogen imports may reach almost 25 Mt and cover up to a quarter of all European demand in the Technology Diversification pathway.

b. Throughout the outlook period, the Technology Diversification pathway shows slightly higher hydrogen import volumes than the Renewable Push pathway due to the ambitious European renewable energy targets applied in the latter. However, both pathways see similar prospects for the rise of an international hydrogen trade market and potential exporters.

c. Renewable hydrogen from North Africa is the main source of supply from neighbouring regions. In the Technology Diversification pathway about two thirds of the imports come from the region, notably Tunisia, Morocco and Algeria. The steep decline in the cost of electrolysers, solar panels and wind turbines (thanks to very large learning rates) lead to cost-competitive renewable hydrogen supply that also dominates the hydrogen market in the long run. On top of the cost-competitiveness of the installations, due to very good solar potential and the possibility of hydrogen transport via pipelines (refurbished existing natural gas pipelines), renewable hydrogen imports from North Africa become highly competitive in Europe compared to low-carbon hydrogen imports via seaborne routes.

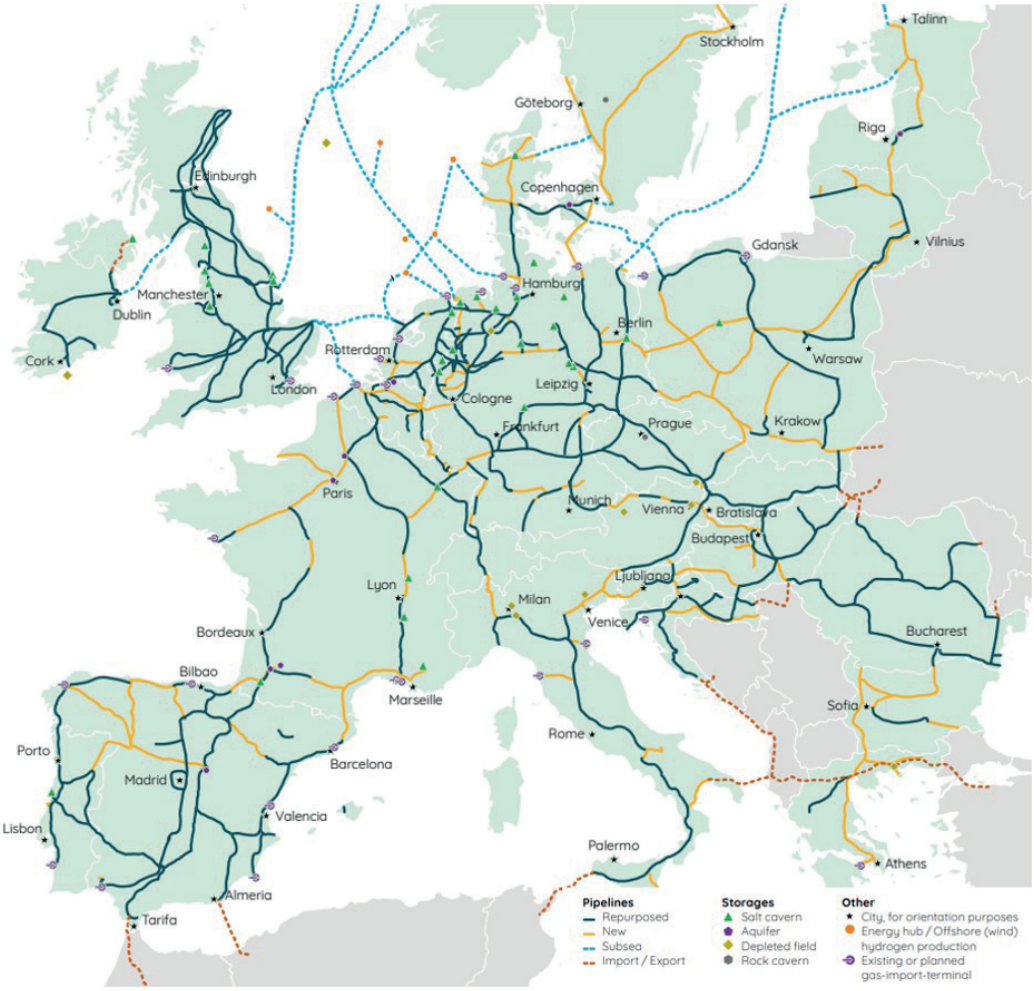
4.3 Implications for infrastructure

157. The *Hydrogen for Europe* pathways highlight the increasing need for a fully developed and efficient hydrogen infrastructure that connects burgeoning hydrogen hubs and allows for the development of a liquid and efficient hydrogen market. A robust European hydrogen infrastructure relies on cross-border coordination and the capability to transport and store large quantities of hydrogen. Cumulative investments in transport, storage, distribution and refuelling top €850 billion in both pathways.

158. Hydrogen transmission and distribution infrastructure deployment becomes increasingly important to accompany the growth in supply and demand. The findings of *Hydrogen for Europe* study show that cumulative yearly capacities in the European cross-border hydrogen transportation infrastructure already reach 6 MtH2 by 2030, jumping to 31 MtH_2 by 2040 and 44 MtH_2 by 2050 in the Technology Diversification pathway as a fully developed backbone starts concretising. Cross-border pipelines unlock the European trade routes described in section 4.2. They allow to evacuate the excess in hydrogen produced in the North Sea area and bring it to main demand centres across Europe. Moreover, they facilitate the transportation of imports from abroad throughout Europe, relying on pipelines from south and east of Europe or large ports in the Mediterranean and the North Sea. Cross-border capacity needs are lower in the Renewable Push pathway: this reflects the lower levels of (geographically more concentrated) low-carbon hydrogen production and imports from outside Europe in that scenario, as supply follows a more distributed pattern based on renewable hydrogen.

159. Those results are well aligned with the current plans of the European Hydrogen Backbone (EHB) initiative[62], according to which achieving the REPowerEU plan would require almost 28,000 km of pipelines by 2030 and 53,000 km by 2040 across Europe (figure 46). In-depth network analysis by the EHB confirms that connecting European countries in order to meet local demand is one of the key challenges ahead, as geographical distribution of hydrogen supply and demand are not balanced across Europe. Northern Europe is characterised by vast wind energy potential while Southern Europe benefits from abundant solar energy resources. In these areas hydrogen supply potential exceeds demand. With the required infrastructure these regions can export hydrogen to Central Europe and to big European industrial countries which are not able to meet all their own demand domestically.

Figure 46. Hydrogen infrastructure planned by European Hydrogen Backbone initiative for 2040



Source: European Hydrogen Backbone initiative, April 2022

160. The *Hydrogen for Europe* study is also aligned with the EHB regarding infrastructure repurposing. The Technology Diversification and Renewable Push pathways show that 80% to 90% of cross-border hydrogen transport capacities are repurposed natural gas assets. There are two main advantages to infrastructure repurposing: it facilitates the swift development of the required infrastructure and constitutes a cost-efficient solution compared to dedicated pipelines. Early project activity already goes in that direction: the Dutch government has tasked the national gas TSO with overseeing a country wide repurposing project due in 2026. 85% of the future Dutch grid should come from existing assets, while 200 km of new pipelines will be developed.

[62] European Hydrogen Backbone initiative

161. At European borders, there are two key corridors with North Africa that could become available for hydrogen transport in the mid to long term. By 2030, the repurposing of the Trans-Mediterranean pipeline could enable competitive hydrogen flowing from Algeria and Tunisia through Italy and central Europe. By 2040, the Maghreb-Europe and Medgaz interconnectors could become hydrogen-ready, bringing additional transport capacity for importing competitive hydrogen production from Morocco and Algeria. The emergence of these corridors is critical to achieve the import potential depicted in the *Hydrogen for Europe* pathways, leading to Tunisia, Algeria and Morocco being the main hydrogen exporters to Europe.

162. Looking beyond existing infrastructure, seaborne imports of hydrogen from North African and Middle Eastern countries also require significant investments to build greenfield hydrogen import terminals or to convert some of the existing LNG terminals to hydrogen. While the latter opportunity may be constrained in the context of increased European LNG imports (see annex A), areas for new terminals are highly scarce in the context of protected zones in the North Sea and the Mediterranean Sea in Europe[63]. Current project developments around the North Sea appear to confirm the validity of a strategy that bets on adapting existing LNG terminals. However, provided some hydrogen regasification capacity develops in Europe, hydrogen from Qatar and Saudi Arabia would complete the supply by 2050.

163. The *Hydrogen for Europe* results also pinpoint the need for hydrogen storage. In the Technology Diversification pathway, storage capacity rises from 1 MtH2 in 2030 to 8 MtH2 in 2050. In the Renewable Push pathway, storage capacity even reaches 14 MtH2 per year in 2050: as variable renewable energy penetration increases, so does the need for further upward and downward flexibility in the European energy system. Hydrogen storage can serve electricity system balancing by reducing network congestion and curtailment. It can also smoothen the inter-seasonal variations in renewable production and final energy demand.

164. Finally, hydrogen needs to be transported and distributed within each country, evacuating production from distributed renewable sites and distributing it at the other end to smaller industries and consumers, e.g. for use in transport and space heating. Related investments in terms of national transport, distribution and refuelling actually constitute the bulk of infrastructure needs in the *Hydrogen for Europe* study. In particular, and as highlighted in section 3.1, timely roll-out of a Europe-wide refuelling infrastructure is needed to facilitate hydrogen's uptake in heavy duty road transport. The 2021 proposal for an Alternative Fuels Infrastructure Directive is a step in the right direction, proposing to set a binding target of one refuelling station every 150 km along the Trans-European Network for Transport (TEN-T) network.

[63] https://www.eea.europa.eu/themes/water/europes-seas-and-coasts/assessments/marine-protected-areas

5 Establishing the European hydrogen economy

165. The *Hydrogen for Europe* pathways describe the dynamics of technology rollout, investments and overall transformation of the European energy system to reach net-zero GHG emissions. They show how a wide range of renewable and low-carbon technologies can be leveraged in a comprehensive manner to foster energy system integration, de-risk the energy transition and avoid the risk of stranded assets. They confirm the central role that hydrogen can play in the transition, both to address challenges regarding the transformation of hard-to-decarbonise sectors and renewable energy integration, and to foster energy security and diversification of intra or extra-European supply routes. The results outline the importance of a timely development of technologies and infrastructure, allowing for a true hydrogen economy to already emerge in the current decade.

166. As the stylised outcome of a modelling exercise, the pathways represent what an economically optimised transition would look like. They assume that policy-makers and industrial leaders manage to overcome all barriers and uncertainties along the road to net-zero emissions, adapting their frameworks to reduce GHG emissions at the least cost. Our pathways are underpinned by two important paradigms: a comprehensive approach to decarbonisation that includes both renewable and low-carbon solutions, and reliability and effectiveness of the policy framework. In that respect, both pathways assume a perfectly functioning market, with investment decisions in each period being made in full knowledge of future developments. In the pathways, investments break even and market distortions and externalities are overcome. For hydrogen, this means that investment needs are properly anticipated, and that the full environmental and economic value of the technologies is considered when choosing between hydrogen and other fossil or low-carbon alternatives.

167. As such, the trajectories drawn in the *Hydrogen for Europe* study must not be interpreted as a forecast nor as the only viable scenarios to be explored. The results depend directly on the chosen assumptions and paradigms in the modelling; expectations on those can vary significantly from one stakeholder to another and can also evolve with time, as illustrated by the Russian invasion of Ukraine and how it disrupted policies and strategies throughout Europe. Likewise, in reality, policy-makers need to balance the economic dimension with many other considerations when designing energy policy, including energy security, affordability and social acceptance.

168. The value of the *Hydrogen for Europe* study for strategic decision-making lies in these contrasts: by highlighting the potential discrepancies between the current energy transition landscape and what is needed to achieve ambitious climate objectives, it can track the progress made by industrials and policy-makers, stimulate debate, and inform strategic decision-making. It can indicate how an optimal pathway to hydrogen deployment and decarbonisation can complement the least-cost principles with other key policy considerations, notably with regard with energy security and environmental dimensions. The study allows comparison of the Technology Diversification and Renewable Push pathways to better understand the conditions necessary for fostering a framework centred on renewable energies produced in Europe.

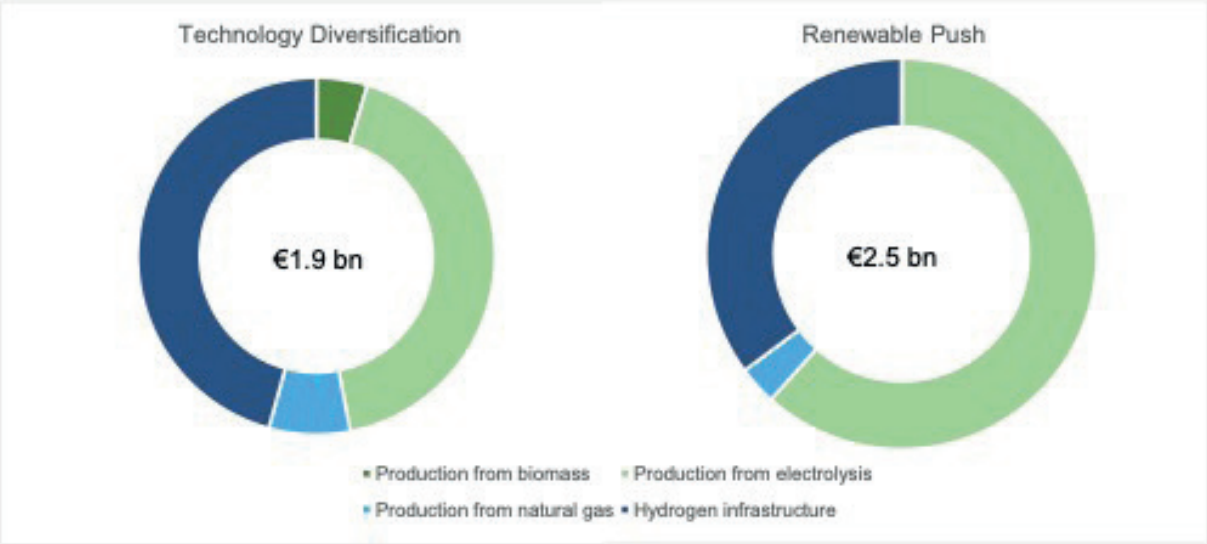
5.1 The investment challenge

169. Two years after the publication of the EU hydrogen strategy, the concrete European hydrogen ecosystem remains in its infancy, with current activity still focusing primarily on innovation and pilot projects. Project announcements have been soaring, with the production pipeline more than quintupling from 16.5 to 92 GW[64], but no-large scale project has reached final investment scale (FID)[65]. Those projects planned to be operational by 2024 – representing up to 15 GW in installed electrolyser capacity[66] – are facing a formidable challenge: respecting their commissioning deadline would imply an annual rate of capacity commissioning of at least 5 GW/year. This is to be compared to the IEA's expectations of global commissioned capacity for electrolysers in 2022 of less than 675 MW[67]. While European electrolyser manufacturers have started scaling up, with planned manufacturing capacity to reach more than 40 GW by 2026, current bottlenecks between backlog and production and long lead-times pose a major challenge for achieving the 2024 targets.

[64] Deloitte H2-tracker, June 2022.
[65] Source: IEA Hydrogen Projects Database, October 2021
[66] https://www2.deloitte.com/de/de/pages/energy-and-resources/articles/european-hydrogen-economy-report.html
[67] Source: IEA World Energy Investment 2022

170. The existing project pipeline can cover only a small amount of the investments that will be needed over the next thirty years in the hydrogen sector. The current pipeline would only be able to supply Europe with around 5.2 Mt of hydrogen by the end of this decade, less than a quarter of the hydrogen demand levels estimated in the *Hydrogen for Europe* pathways[68] and half of the European supply target for REPowerEU. This implies not only that current projects are critical to reaching the 2030 targets, but that hundreds of gigawatts of additional projects should be also planned and commissioned in the coming years. On the supply side in particular, the European hydrogen economy as depicted in the *Hydrogen for Europe* pathways would require investing over the next three decades in between 75 and 144 GW of methane reformers, 1050 and 1700 GW of electrolysers, and 815 to 1650 GW of dedicated renewable capacity.

Figure 47. Cumulative investments in the European hydrogen supply chain to the mid-2050s in the Technology Diversification and Renewable Push pathways



Hydrogen infrastructure includes hydrogen storage, national hydrogen infrastructure, cross-border hydrogen pipeline and retrofitted infrastructure.

Source: Hydrogen4EU

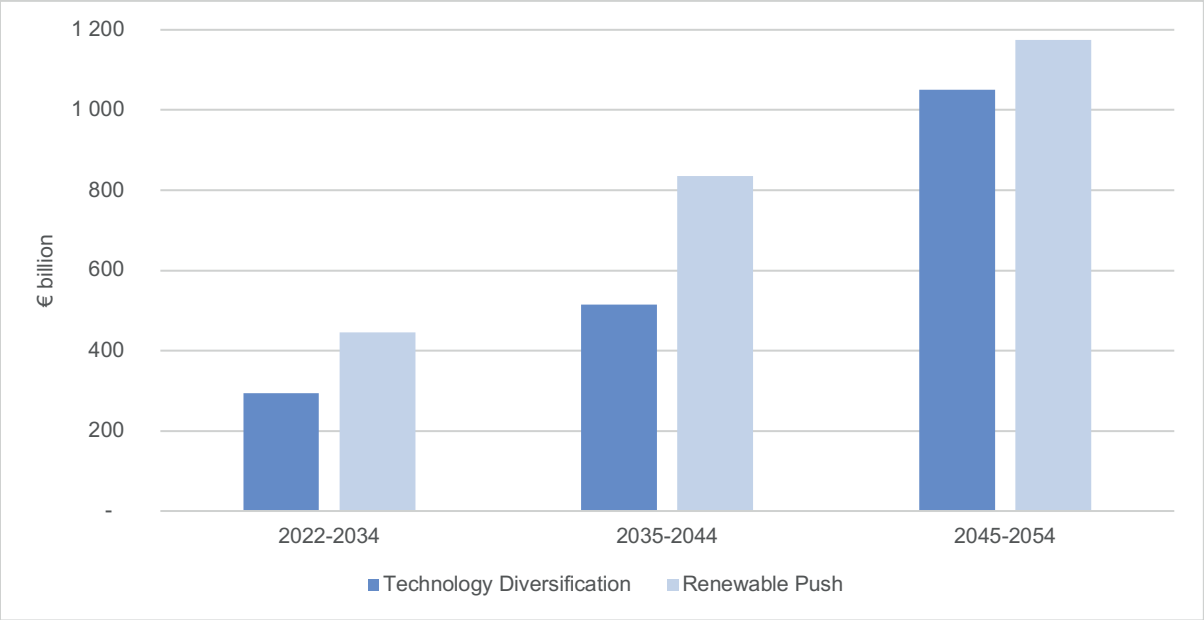
171. The investment challenge translates into several trillions of euros to be invested in the European hydrogen economy over the next thirty years (figure 47)[69]. In the Technology Diversification pathway, cumulative investments in European supply, transport, storage and distribution of hydrogen reach a total of €1.9 trillion. In the Renewable Push pathway, this figure stands at €2.5 trillion, reflecting the higher capital intensity of electrolyser projects. Investments in electrolysers amount to €790 billion in the Technology Push pathway and more than €1500 billion in the Renewable Push pathway. Meanwhile, investments in low-carbon hydrogen production technologies are more limited, notably due to higher utilisation rates. They reach between €80 billion (in the Renewable Push pathway) and €140 billion (in the Technology Diversification pathway). Investments in infrastructure amount to more than €850 billion of cumulative investments in the two pathways. The similar amounts of infrastructure spending are due to the comparable state of the hydrogen ecosystem in the two pathways, with hydrogen demand around 100 Mt, a similar level of long-term imports and trade relations, and large-scale production projects delivering the bulk of domestic supply.

172. As described in chapter 4, timeliness of these investments is also critical in the two pathways to leverage the full potential of hydrogen in the transition to net-zero while limiting the risk of stranded assets in reformers or existing gas infrastructure. Access to financing at the right time and at the right cost is one of the core levers allowing these investments to take place. Between €300 billion (in the Technology Diversification pathway) and €450 billion (in the Renewable Push pathway) need to be mobilised by 2035 to finance the development of the European hydrogen supply chain. Earlier investments are critical in the Renewable Push pathway to

[68] Not including demand for hydrogen in the chemical industry.
[69] The time-steps in the planning period are: 2020 (today's system; no new investments), 2030, 2040 and 2050. Each period represents 10 years, e.g. 2045 – 2054 for 2050. The first day after the planning horizon is thus 2055.

reach the optimal electrolyser potential and trigger learning effects. Likewise, investments in the period from the mid- 2030s to the mid-2040s reach a total of €515 billion in Technology Diversification and €835 billion in Renewable Push. This corresponds to the period with the highest growth in the hydrogen value chain. In the last ten years, the two pathways require an extra investment of around €1.1 trillion into direct production, transport, storage and distribution of European hydrogen.

Figure 48. Investment pathways in the European hydrogen supply chain in the Technology Diversification and Renewable Push pathways, 2022-2054



Source: Hydrogen4EU

173. Additional investments are needed both upstream and downstream of the hydrogen value chain. In the upstream, hydrogen development requires significant capital spending for the supply of electricity and feed-gas needed for hydrogen production. For electricity, much of this corresponds to major investments in solar and wind renewable generation projects, but also grid reinforcement and flexibility investments to accommodate ongrid electrolyser production. For low-carbon hydrogen, additional capital spending will be needed for upstream production and transport of natural gas but also for mitigating methane emissions (see box 8). In this regard, the methane used for low-carbon hydrogen production is procured at the market price for natural gas, which is sufficient to incentivise the necessary investments in upstream and midstream. Natural gas prices feature in the operational cost component of hydrogen production. Likewise, the underlying investments necessary to produce and transport imported hydrogen to Europe are covered by the hydrogen market price to be paid by European customers. As described in section 2.3, the CCUS value chain is also a critical enabler for the production of hydrogen from natural gas and biomass. The optimal hydrogen mix described in the pathways requires the timely development of storage capacities that should enable in 2050 up to 1.4 $GtCO_2$/year of storage injection in the Technology Diversification pathway and 1.2 $GtCO_2$/year in the Renewable Push pathway.

174. In the downstream, the switch to hydrogen entails modifications and new investments needs in appliances, engines, fleets or industrial processes. Large and small consumers will need to secure timely access to financing and to investment aid, as hydrogen should remain in the short-to-medium term a more costly option than CO_2-emitting solutions. Timing of hydrogen's uptake in the various end-use sectors is closely linked to the underlying investment cycles and the remaining lifetime of existing assets: switching to hydrogen at the end of an asset's lifetime would minimise the volume of stranded assets while relieving some of the financing burden for consumers.

175. For European consumers and citizens, an underlying issue is the affordability of the switch to hydrogen, and more generally of the transition to net-zero emissions. The recent macroeconomic turbulences triggered by the Covid-19 pandemic and Ukraine war have put energy price inflation and affordability at the centre of the policy debate. In that respect, the *Hydrogen for Europe* results can be used to illustrate the economic implications when contrasting two paradigms to achieve net-zero emissions: a diversification-focused approach, harnessing the competition between a wide range of renewable and low-carbon technologies, and a technology-focused approach that favours proven renewable energies. As such, the social, environmental and geopolitical implications of the Renewable Push pathway should also be contrasted with the slightly higher cost the scenario entails from the perspective of energy system economics: total energy system cost over the next thirty years is around €650 billion (or more than €40 billion per year[70]) higher in the Renewable Push pathway than in the Technology Diversification pathway.

5.2 Conditions for low-carbon hydrogen deployment

176. As described in the *Hydrogen for Europe* pathways, natural gas reformers with CCS technologies can play an important role to support the establishment of the hydrogen economy. They are especially useful in the first half of the outlook period to meet rapidly rising demand and give time to other supply sources to ramp up. For investors, this implies the existence of a window of opportunity in the period to the mid-2030s; however, this is also a period during which the prospects for natural gas are more uncertain than ever. First investments would be needed within this decade to maximise capacity utilisation and financial viability and limit the risk of stranded assets, before renewable hydrogen and hydrogen exports become more competitive and widely available.

177. The window of opportunity is threatened at several levels, putting in question the pace and scale of low-carbon hydrogen development and the achievement of a rapid hydrogen uptake.

a. At EU level and in key Member States, the proposed strategies and regulatory frameworks are putting clear emphasis on certain technologies like renewable hydrogen, at the risk of creating a two-speed system disadvantaging low-carbon solutions. The proposed hydrogen and decarbonised gas package still lacks key elements that would give sufficient visibility to investors (e.g. the methodology to calculate the 70% greenhouse gas saving threshold necessary to define gas or hydrogen as “low-carbon”). A clear EU strategy for CCUS with official targets is still missing, preventing long-term investments in this crucial enabler of low-carbon hydrogen and overall decarbonisation.

b. The recent geopolitical upheavals are at the core of the uncertainty for low-carbon investments: the immediate consequences of the Russian invasion of Ukraine suggest a pivoting of policy, social and industrial strategies away from natural gas in the mid-term, automatically also putting in question the long-term role of low-carbon hydrogen to the transition. The European Commission with its REPowerEU plan has already signalled an acceleration of the roll-out of renewable energy and hydrogen imports. For the oil & gas industry, this requires urgent action to ensure affordable gas supply to Europe, limiting the repercussions of the phase out of natural gas imports from Russia. Only if policy-makers and consumers are reassured that natural gas supply can be secure, will low-carbon hydrogen be a politically and socially acceptable element in the energy transition.

c. Moreover, the EU sustainable taxonomy and the methane strategy have highlighted the need to reduce GHG emissions during the production, transport and use of natural gas. As shown in section 2.1 (Box 5) and in appendix a, natural gas and low-carbon hydrogen can only contribute to the energy transition if concrete actions to mitigate methane emissions with best available technologies are taken immediately. This requires strong determination of the oil & gas industry and policy-makers alike to overcome existing barriers. In fact, the issue is not so much financial but rather institutional, as lack of awareness, legal and structural issues and local disincentives affect the ability to roll out best available technologies (see box 8).

[70] Comparison between the resulting system costs of the two pathways (outcomes of the model’s optimization). The Technology Diversification pathway requires €92.9 trillion in total energy system cost (both OPEX and CAPEX) until 2050. The Renewable Push pathway requires €92.2trillion.

There is no time for complacency: not only the natural gas industry needs to secure its licence to operate in a low-carbon environment, but this would reinforce the ability of the European energy system to rely on the full diversity of low-carbon options and to meet its decarbonisation targets in an optimal way.

Box 8. Challenges to the deep reduction of methane emissions in the natural gas value chain

Achieving a deep reduction of methane emissions as described in the *Best Available Technology* case implies varying degrees of efforts and investments across geographies and for each step of the value chain. Emissions must be mitigated at every source, from compressor seals to unintended leaks, unlit flares or glycol dehydrator vents with several mitigation options depending on the source (around 30+ emission sources) [71,72]. In the *BAT* case, it is assumed that these technical solutions are implemented across the entire gas value chain, across all geographies.

Abatement costs and investment required are typically low compared to other climate mitigation options.

Investment costs and abatement costs are site-specific and will be driven by several factors including site location, layout and type of equipment or remaining life of the installations. Despite these important variations, different international studies have demonstrated that a large share of the opportunities have a low abatement cost[73], underpinned by the fact that every tonne of methane not emitted is converted into marketable natural gas for the operator. The IEA for example states that "over 40% of oil & gas emissions could be reduced at no net cost using well-known existing technologies."[74] In addition, the initial cost of implementation (e.g., capital expenditure) per tonne of CO_{2eq} abated is typically low compared to other mitigation options in other sectors and segments, such as implementation of CCS or Direct Air Capture. As an example, the capital expenditure per tonne of CO_{2eq} for three technologies with an important abatement potential are all less than 1 USD/tCO_{2eq}[75]. In comparison, the capital expenditure per tonne of CO_2 for CCS can range between 40 and 60 USD/tCO_{2eq} for a cement facility.[76]

- Leak Detection and Repair (LDAR): 0.7 USD/tCO_{2e}[77]
- Vapor Recovery Unit (VRU): 0.5 USD/t CO_{2e}[78,79]
- Electric Controllers: 0.05 USD/tCO_{2e}[80]

Based on the methane emission abatement achieved in the *Hydrogen for Europe* pathways, over the next thirty years, between €15.5 billion and €17.2 billion in investment would be needed to rollout best available technologies and maintain methane emissions at the lowest possible level for the Technology Diversification pathway. The scale of these investments is about a hundred times smaller than that of direct investment in the European hydrogen supply chain, not considering as well the value of methane emission mitigation to unlock natural gas' optimal role in power generation or other sectors. The benefits of implementing *BAT* thus clearly outweigh the costs for both the oil & gas industry and the European society.

However, there are currently other barriers to achieving the *BAT* case

Despite the low initial cost of implementation for methane, the roll-out of these technologies is not as fast as could be expected in some countries. Local circumstances and barriers to mitigation (caused by the local regulatory framework and the operators' internal policies) are extremely variable. Over the past few years, the barriers to implementing and executing methane abatement potentials have been documented. As per a recent report by the World Bank[81], one of the main challenges is the "lack of prioritisation by [some] operators and unsupportive

71 https://www.epa.gov/natural-gas-star-program/natural-gas-star-program
72 https://www.epa.gov/natural-gas-star-program/natural-gas-star-program
73 Methane Abatement costs refers to expenditures required to reduce methane emissions. It is represented as expenditures per tonne of methane reduced.
74 https://www.iea.org/reports/global-methane-tracker-2022/strategies-to-reduce-emissions-from-fossil-fuel-operations#abstract
75 According to the IEA 2022 methane tracker
76 https://www.iea.org/commentaries/is-carbon-capture-too-expensive (for cement facilities emitting between 1,000 and 2,000 kt of CO_2 per year. The range can be higher for facilities emitting lower volume of CO_2, and vice versa)
77 Capex and emission reduction data from CL's expertise
78 The Capex for VRU was obtained from Cost Model Workbook - Methane Guiding Principles, and converted to USD 2022.
79 Emission reduction potential was obtained from the EPA document: Reducing Methane Emission with Vapor Recovery on Storage Tanks (epa.gov). A mid-range value of 250 Mcf per day of CH_4 emissions were considered for calculating the capex per t CO_{2e}.
80 Considering an electric controller replaces a continuous bleed pneumatic controller, Capex of 1 electric controller and 1 control panel was considered in this assessment. Capex assumption comes from an internal Carbon Limits model, where cost and abatement data were collected in collaboration with several technology providers and oil & gas operators. Average emissions from continuous bleed pneumatic controllers were assumed to be 14.4 cf per day, based on the interviews performed while developing the Carbon Limits model.
81 https://www.worldbank.org/en/topic/extractiveindustries/publication/financing-solutions-to-reduce-natural-gas-flaring-and-methane-emissions

regulatory environments to inadequate infrastructure and macroeconomic risks." Some of the most observed bottlenecks in National Oil Companies (NOC)[82] and possible remedies are described below, as per Carbon Limit's 2021 "Methane action at National Oil Companies":[83]

- Limited awareness of, and focus on, methane emission: As an invisible and odourless gas, methane has historically been difficult to detect and quantify. Consequently, there is often limited awareness on the scale and scope of a company's methane emissions at the executive and operational level. Technological progress opens new opportunities for improved monitoring and quantification in order to build company knowledge and further management prioritisation on methane reduction efforts.
- Legal and structural issues: Existing structural processes, such as joint venture contracts and regulations, can inhibit effective methane management and discourage transparency and mitigation. NOCs can support government-led reforms to remove these barriers. A common understanding among NOC senior management and government institutions on the need for robust methane reductions can greatly facilitate reform processes. Regulations should be put in place to incentivise methane emission quantification and mitigation and to facilitate information sharing.
- Challenging economic incentive: Despite global abatement studies indicating significant opportunity for no net cost mitigation in several countries, the economics of local methane mitigation efforts may not always be favourable enough to trigger action from a corporate perspective due to the small scale of individual projects, low local gas prices and demand constraints. Nevertheless, methane emission mitigation is often still one of the most cost-efficient options to reduce GHG emissions and should be among the first options considered. For industrials, this calls for bundle strategies and specific funding to trigger economies of scale and accelerate technology deployment. Government subsidies to gas prices in producing countries may also be eliminated to reflect the true value of methane leaks.

To conclude, there are readily available technologies for abating methane emissions. The advantages of abating methane emissions are two-fold – (1) reducing overall greenhouse gas emissions into the atmosphere, and (2) increasing marketable volume of natural gas in the company. Bottlenecks for methane abatement can be at company level, or government level. Ample awareness of the impacts and size of methane emissions from the sector is crucial in helping remove the bottlenecks for the implementation of best available technologies. In the context of the recently signed Methane Pledge[84], and of a number of global or regional initiatives (Including but not limited to OGCI[85], MethaneSat[86], MiQ[87], OGMP 2.0[88], Methane Guiding Principles[89]), a number of activities are ongoing to address some of these barriers by e.g., increasing collaborations and sharing knowledge between operators, investing in new technologies and data sharing or creating new mechanisms to incentives emissions reductions.

5.3 Completing the policy framework for hydrogen

178. Recent project announcements and industry initiatives have been stimulated by an intensification of efforts for creating a full-fledged hydrogen policy framework in Europe. While the Ukraine war and the rising inflation could have weakened these policy efforts, the opposite appears to be the case. Against the backdrop of the European governments have doubled down on their commitments to the energy transition, including revised targets for hydrogen. The REPowerEU plan now aims at reaching a European consumption of hydrogen and derivatives of 20 Mt in 2030, in line with what the *Hydrogen for Europe* pathways show for that horizon. As such, the recent crisis has stressed the resilience of hydrogen's contribution in the European energy transition, from the perspective of both energy system economics and strategic policy-making.

[82] Note that NOCs are a heterogenous group, covering a broad range of corporate structures, governance models, and national commercial and social mandates. This diversity must be carefully considered when reviewing the barriers to mitigation
[83] "Countries where NOCs dominate account for 75% of all oil & gas sector methane emissions, representing a large share of emissions that can be eliminated profitably or at low cost" https://business.edf.org/files/Methane-Action-at-NOCs_March-24.pdf
[84] https://www.globalmethanepledge.org/
[85] https://www.ogci.com/
[86] https://www.methanesat.org/
[87] https://www.miq.govt.nz/
[88] https://www.ccacoalition.org/en/resources/oil-and-gas-methane-partnership-ogmp-20-framework
[89] https://methaneguidingprinciples.org/

179. At EU policy level, the progress made is clearly visible through the Fit-for-55 and Hydrogen and Decarbonised gas market packages and with the recently published REPowerEU plan. With them, policy-makers have laid the groundwork of a transversal framework for hydrogen development, providing clear rules for hydrogen network planning and regulation and for the functioning of markets for clean gases and hydrogen.

a. The proposed updates to the Hydrogen and Decarbonised gas market packages aim at ensuring an effective energy system integration that considers hydrogen at the same level as electricity and other gaseous molecules and that enables a coordinated uptake of hydrogen supply and demand. The European Commission proposes notably a phase-in approach to unbundling and third-party-access rules until 2030, at which horizon the hydrogen market and infrastructure framework should be fully operational. By proposing the establishment of a European Network for Network Operators for Hydrogen (ENNOH), the European Commission lays the groundwork for future network codes and infrastructure planning for hydrogen.

b. The Fit-for-55 package takes a wider perspective and determines the guidelines for the uptake of hydrogen demand in various sectors. The proposed update to the Renewable Energy Directive increases the binding target for renewable energy to 40% of gross final energy consumption by 2030 while also targeting a 2.6% share for renewable fuels of non-biological origin and a 50% renewable share for hydrogen consumed in industry by 2030. Proposed revisions of the Energy Taxation directive, ETS Directive, Alternative Fuels Infrastructure Regulation and proposals for the FuelEU Maritime directive and ReFuel EU Aviation initiative should also help stimulating the uptake of hydrogen and other renewable and low-carbon solutions and to accelerate decarbonisation in the various sectors.

c. The regulatory packages proposed by the European Commission work in concert with the EU taxonomy for sustainable activities to define the different types of hydrogen production and to characterise the eligibility of hydrogen products to sustainable, renewable and low-carbon status. The taxonomy sets the threshold for hydrogen's eligibility as sustainable activity at $3tCO_2/tH_2$ with regard to lifecycle emissions, thus allowing for both renewable and low-carbon hydrogen from low carbon intensive grid electricity or natural gas with CCS to contribute to EU decarbonisation efforts. The recently published draft delegated acts to the Renewable Energy Directive push forward the proposed rules for the clear definition of ongrid and offgrid electrolysis-based hydrogen, helping to reduce uncertainty for investors and stimulate demand for renewable hydrogen. Additionality is a central aspect of the rules, guaranteeing that new electrolysers must promote new renewable power plants and thus contribute to the gradual uptake of renewable energies. This is coherent with the results of the *Hydrogen for Europe* study, that finds that between 800 and 1600 GW of dedicated renewable capacities are needed to support the upscaling of renewable hydrogen.

180. The EU and national governments have started implementing a slate of financial instruments and support schemes to de-risk first projects and incentivise innovation and investments in hydrogen. Public support to R&D and hydrogen valley projects (e.g. EU Innovation Fund, funding by the Clean Hydrogen Partnership, Modernisation Fund) has been granted to test technologies and business models before commercial uptake. The update to the TEN-E regulation includes hydrogen projects within priority infrastructure development corridors, which unlocks faster permitting procedures, lower financing cost and eligibility to Connecting Europe Facility grants. As already expected in the previous *Hydrogen for Europe* edition, the Important Project of Common European Interest (IPCEI) for hydrogen is turning out as a key mechanism for building up the European hydrogen value chain. IPCEI should help directing a large share of the NextGenerationEU recovery budget to hydrogen, with the goal of concretising a significant portion of the current project pipeline and first parts of the European hydrogen backbone. Final decision by the European Commission on the first two waves of projects is expected for summer 2022. With it, hydrogen should finally take the leap from being a strategic policy objective to becoming an industrial and commercial reality.

181. The European Commission and national governments are also working on closing the cost gap between clean and emitting technologies. This is central to the development of the hydrogen economy: while the *Hydrogen for Europe* modelling assumes that the market sends the right price signals to encourage switching

to alternative technologies, in reality many barriers exist at market and regulatory levels that prevent low-carbon and renewable solutions to compete on a level playing field with today's emitting technologies. The currently discussed reforms of EU-ETS and CBAM (as part of the Fit-for-55 package) are important steps in the right direction to internalise the cost of CO_2 emissions and make abatement options more attractive. Specifically, the upward revision of the decarbonisation targets for EU-ETS sectors, the extension of CO_2 pricing to international aviation, maritime, road transport and buildings, and the CO_2 taxation of imports are important initiatives.

182. However well-designed the future ETS and CBAM schemes are, they may not be sufficient to ensure a positive business case for abatement technologies. Policy-makers are also advancing on complementary solutions, that would address the remaining economic and regulatory barriers and tilt the economics in favour of low-carbon solutions. Mandates and binding targets and other taxation or levy exemptions, as proposed in the Fit-for-55 and Hydrogen and decarbonised gas market package, should further support the competitiveness of low-emission technologies. The inclusion of renewable and low-carbon hydrogen in the new Guidelines for Climate, Environmental Protection and Energy (CEEAG) should also enable long-term direct support schemes to emerge, unlocking positive business models for hydrogen projects and hereby reducing the risk for investors. Like for renewable electricity projects in the 2000s and 2010s, State aid is a key instrument to complement the market price of CO_2 emissions and reflect the true economic value of investments in decarbonisation technologies. At national level, governments have started implementing decarbonisation investment plans, with targeted funding already going to hydrogen projects. A large-scale scheme already in place today is the Dutch SDE++ mechanism, that selects projects by comparing costs and ability to abate CO_2 emissions. The total budget available for 2022 is €13 billion.

183. Although these developments clearly confirm the commitment of policy-makers to create a solid hydrogen policy framework in the years to come, there remains a misalignment between the currently available framework and tools and an increasingly clogged project pipeline. As highlighted in section 5.1, commissioning the tens of GW of planned projects over the coming years is getting ever more challenging. Serious bottlenecks and gaps remain in the policy framework, limiting the ability of first projects to get off the ground and risking hydrogen to stay behind the development described in our pathways. Three key areas for direct action and gap mitigation are identified over the rest of the chapter.

Bridging the cost gap with emitting technologies

184. As of mid-2022, most commercial projects currently planned lack the governmental guarantees and support mechanisms that would allow for a viable business model and trigger investment decisions. Proposals for binding targets, bans and other ETS or CBAM developments are unlikely to materialise before at least the second half of the current decade and may even prove insufficient to overcome the cost gap between clean hydrogen and emitting solutions. Some initial support mechanisms exist, but they are not organised or wide enough to support the needed uptake of hydrogen across Europe. The long-awaited approval of the first two waves of IPCEI by the European Commission has also been postponed by more than six months, consequently also delaying the finalisation of national negotiations for allocating the funds to the shortlisted projects.

185. Looking at the long-term picture and in light of the huge investment needs depicted in the study, large scale support schemes for hydrogen are mostly missing today, that would support hydrogen's deployment over the long term. Ongoing discussions on support mechanisms need to accelerate in order to plan ahead and secure the next waves of investments. Among possible options, Carbon Contract for Difference (CCFD) appear as one of the most promising to incentivise hydrogen investments in an optimal way, rewarding projects directly on the basis of CO_2 abatement costs. The SDE++ scheme in the Netherlands is a best practice, but the devil lies in the details. In particular, methodologies for assessing abatement levels and price references may distort incentives for investors and affect the competitive positioning of hydrogen projects against other decarbonisation initiatives. Countries like Germany, France or the UK that have expressed interest in developing such scheme should thus land shortly on a design that is able to stimulate hydrogen development.

Reducing uncertainty for investors

186. While the European Commission and governments have acted fast to propose a set of regulatory measures, the reality of legislative negotiation is putting a break on the momentum and could postpone the finalisation of the hydrogen regulatory framework. Debates over the past few months have been fierce within the different institutions, and final EU "trilogue" negotiations for the Fit-for-55 and Hydrogen and Decarbonised gas market packages are not expected before the second half of 2022 at the earliest. Final consensus on the regulatory measures may result in a different framework for hydrogen than shown in current proposals and may even come too late to achieve the targeted upscaling of the hydrogen ecosystem.

187. Even more critical, the currently proposed framework still lacks some key elements that would give necessary visibility to investors. The draft delegated acts for the definition of renewable hydrogen have been published in May 2022 but the details are still missing on the exact definition of low-carbon hydrogen and on the rules applying to imported hydrogen. Likewise, the current hydrogen framework is still short regarding rules for the road freight sector, CCUS and carbon removal certification. Finally, no consensus has emerged yet on the toolbox that would allow for a radical acceleration of permitting procedures in renewable energy. The recent European Commission proposal for special dedicated zones in which permitting could be accelerated[90], as not been met with unanimous enthusiasm from Member States. As it stands, the permitting bottleneck could be responsible for years of delays in the investment decisions and commissioning of most projects.

188. Looking ahead, it is therefore important that policy-makers clarify soon their positions and work towards the finalisation of the policy framework, for both hydrogen and overall decarbonisation. In the short term, and as 2024 deadlines are fast approaching, close coordination with industrial stakeholders is needed to give the necessary visibility and insights into the future framework.

Controlling the cost of financing in light of the current macroeconomic turbulences

189. Project financing is further put at risk by the recent macroeconomic developments. The post-covid economic recovery and Ukraine war have translated into a marked uptick of inflation. Extremely high prices for energy commodities and for raw materials, including those needed for the manufacturing of solar PV, are affecting the viability of business models. It may notably lead to an increase of the premium to be paid by electrolyser projects on renewable electricity, whose producers could prefer selling directly to power markets than via long-term contracts to hydrogen producers. The recent strategies of central banks to raise interest rates on government bonds may also translate into rising financing costs, with investors expecting a higher return on their investments. As low-carbon energy systems are more capital-intensive than today's system, this may have serious repercussions for the transformation of the energy sector, including hydrogen projects. In case of a spiralling hike and limited government support, companies and investors may have no other choice than re-evaluating their investment pipelines.

190. Policy-makers and public institutions have a role to play to address these challenges and reduce the cost of financing for investors. Finalising the market and regulatory framework for hydrogen and implementing a full slate of grant instruments, as described previously, should increase the visibility of business models and decrease the overall risk for investors. In light of the current fears of soaring inflation and monetary counter-measures, it is also important that investors have access to financing at a low cost. Development banks and other public financial institutions should double down on their loan and support programmes toward renewable and low-carbon investments. Central banks also have a key role to play to incentivise decarbonisation efforts while combatting inflation. They can increase the share of green bounds in the structure of their portfolio, retargeting their asset purchase programmes towards the energy transition and keeping money flowing into the nascent hydrogen economy.

[90] Recommendation on permitting procedures and power purchase agreements

Annexes

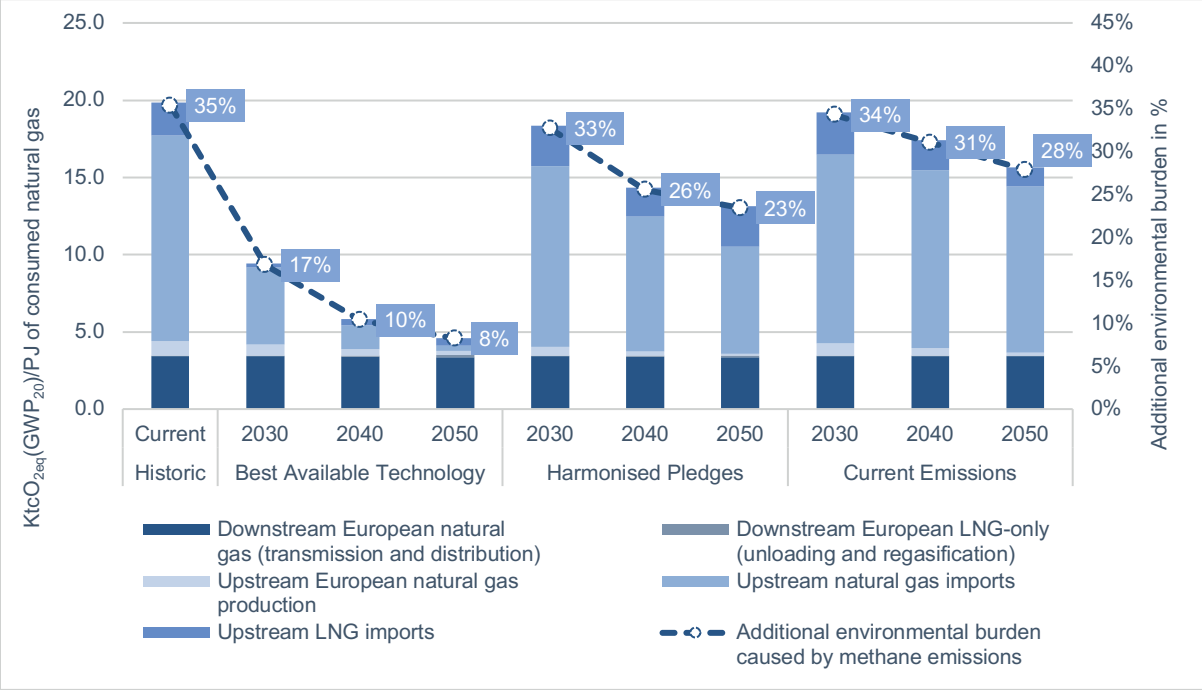
6 Annex A: Methane emission cases

191. One key objective of the 2022 edition of *Hydrogen for Europe* is to gain a better understanding of the range of methane emissions associated with the functioning of the energy system in Europe, and on the impact their mitigation can have on the optimal pathway to net-zero GHG emissions. The central case for estimating methane emissions, *BAT*, is incorporated in the study's two main Technology Diversification and Renewable Push pathways. It assumes that the oil & gas industry pursues all necessary efforts to deploy best available technologies and rapidly reduce methane emissions along the whole natural gas value chain. The results show that implementation of *BAT* can put natural gas and low-carbon hydrogen among the key elements of the European energy transition provided the oil & gas industry also acts to secure affordable natural gas supply and contributes actively to the development of a capable CCUS value chain.

192. As described in section 5.2, the *BAT* case is associated with specific challenges and barriers such as lack of awareness, legal and structural issues or local disincentives. Addressing them requires strong determination by the oil & gas industry to achieve high levels of emission mitigation in time for the window of opportunity for natural gas. Two other methane emission cases have been defined and studied to assess the consequences on the results if no or limited mitigation actions are taken instead. The *Current Emissions* case assumes a status quo in terms of methane emission mitigations, with no further implementation of reduction options due to inaction by industry stakeholders or policy-makers. The *Harmonised Pledges* case considers the effects of country policies, Nationally Determined Contributions (NDC) relevant for GHG emission reduction and international pledges; leading to some concrete actions to tackle methane emissions but without reaching the ambitions of the *BAT* case. The following section compares the results of the Technology Diversification pathway for the three different methane emissions cases.

193. Figure 49 shows the evolution of average methane intensity associated with the consumption of natural gas in Europe for the three cases, as estimated in the *Hydrogen for Europe* study. In the Current Emission cases, methane emission factors stay at current levels for each step of the value chain and in each geography. Methane emission intensity remains stable above 15 $ktCO_{2eq}$/PJ, reflecting the absence of abatement actions. Marginal variation is observed throughout the outlook period, reflecting changes in the gas mix being consumed to Europe. Considering direct CO_2 emissions at combustion point, methane emissions in this case represent a 35% additional burden on the climate footprint of natural gas as modelled in the study. In the *Harmonised Pledges* case, partial mitigation efforts based on announced pledges and policy efforts to abate emissions brings down average methane intensity to 13 $ktCO_{2eq}$/PJ by 2050. This is 16% less than in the *Current Emissions* case. In the *BAT* case, high level of commitment from the oil & gas industry and policy-makers trigger substantial reduction in methane emissions starting in the current decade. The average methane emission intensity of natural gas consumed in Europe already gets under 10 $ktCO_2eq$/PJ by 2030 (-53% compared to current emission levels) and falls below 5 $ktCO_2eq$/PJ in 2050 (-77% from today's levels).

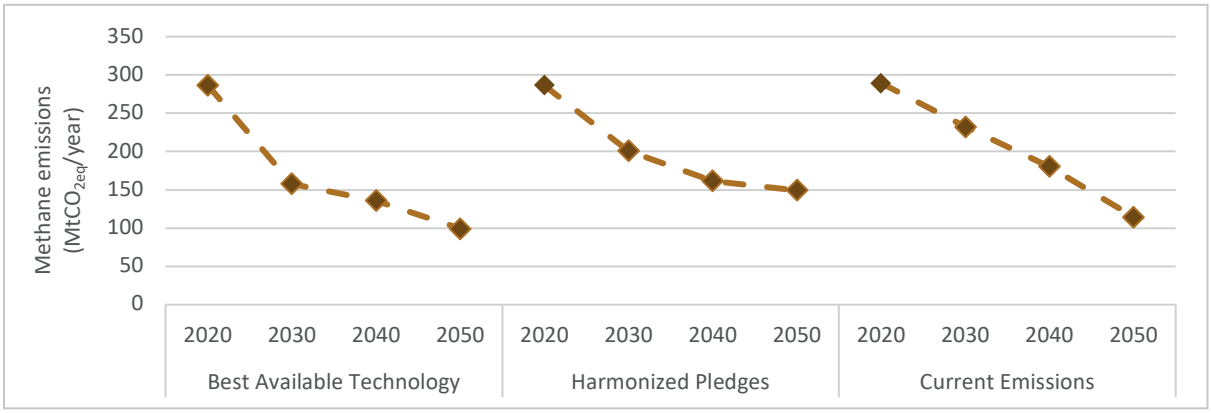
Figure 49. Evolution of methane emission factors in the Technology Diversification pathway for different methane emission cases from 2020 to 2050



Source: Hydrogen4EU

194. In the three cases, total CO_2 and methane emissions drop progressively along the outlook period and key decarbonisation targets are respected for 2030 and 2050 (Figure 50). Looking specifically at methane, the 2050 residual methane emissions in the *Current Emissions* and *Harmonised Pledges* cases are respectively 15% and 50% higher than in the *BAT* case. Although the methane footprint of natural gas and low-carbon hydrogen in *Harmonised Pledges* is lower than in the *Current Emissions* case, the significant drop in natural gas and low-carbon hydrogen consumption leads to higher overall methane emissions in the first case. This has several implications. First, it puts an even higher stress on carbon dioxide reduction technologies and negative emissions. Carbon dioxide removal technologies have a bigger role in these cases to balance it out and achieve net zero. Second, it requires an arbitrage between handling methane emissions at their source and reducing the role of natural gas in the European mix: deploying the most advanced methane abatement solutions as assumed by the *BAT* case is a precondition for continued use of natural gas and the deployment of low-carbon hydrogen in Europe.

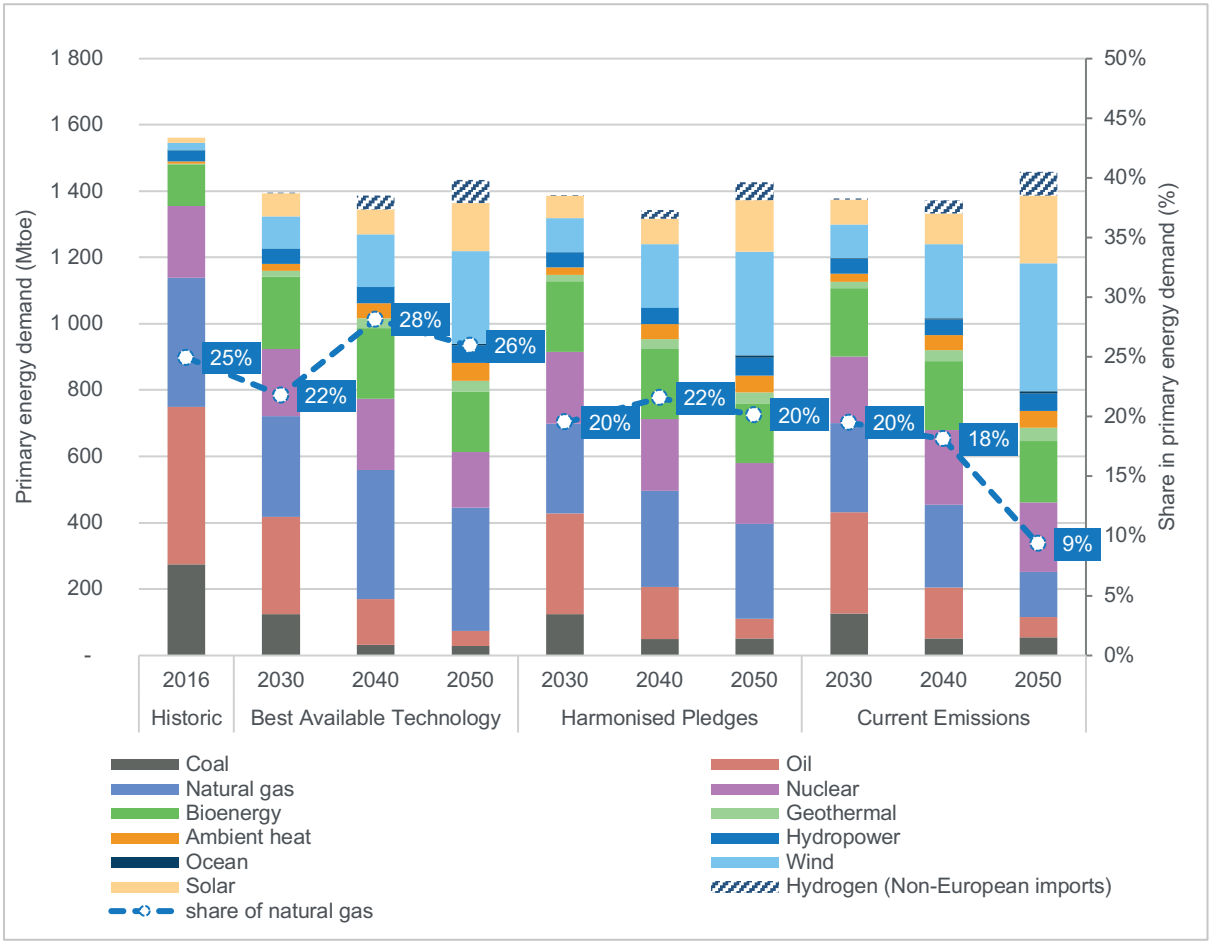
Figure 50. Evolution of methane emissions in the Technology Diversification pathway for different methane emission factor cases from 2020 to 2050



Source: Hydrogen4EU

195. Sharp differences between the three cases are observed in the primary energy mix (figure 51). They show that limited or no action to mitigate methane emissions seriously hinders the ability of natural gas to play a long-term role in Europe. The share of natural gas in the *Harmonised Pledges* case drops to 20% by 2050, a six-point drop from the *BAT* case. In the *Current Emissions* case, the share of natural gas doesn't recover after 2030 and falls to 9% by the end of the outlook period. This is on par with the residual demand for oil and coal. In both alternative cases, the reduced use of natural gas is compensated mostly by an increased share of renewables and in a lesser extent by an increase in nuclear energy supply.

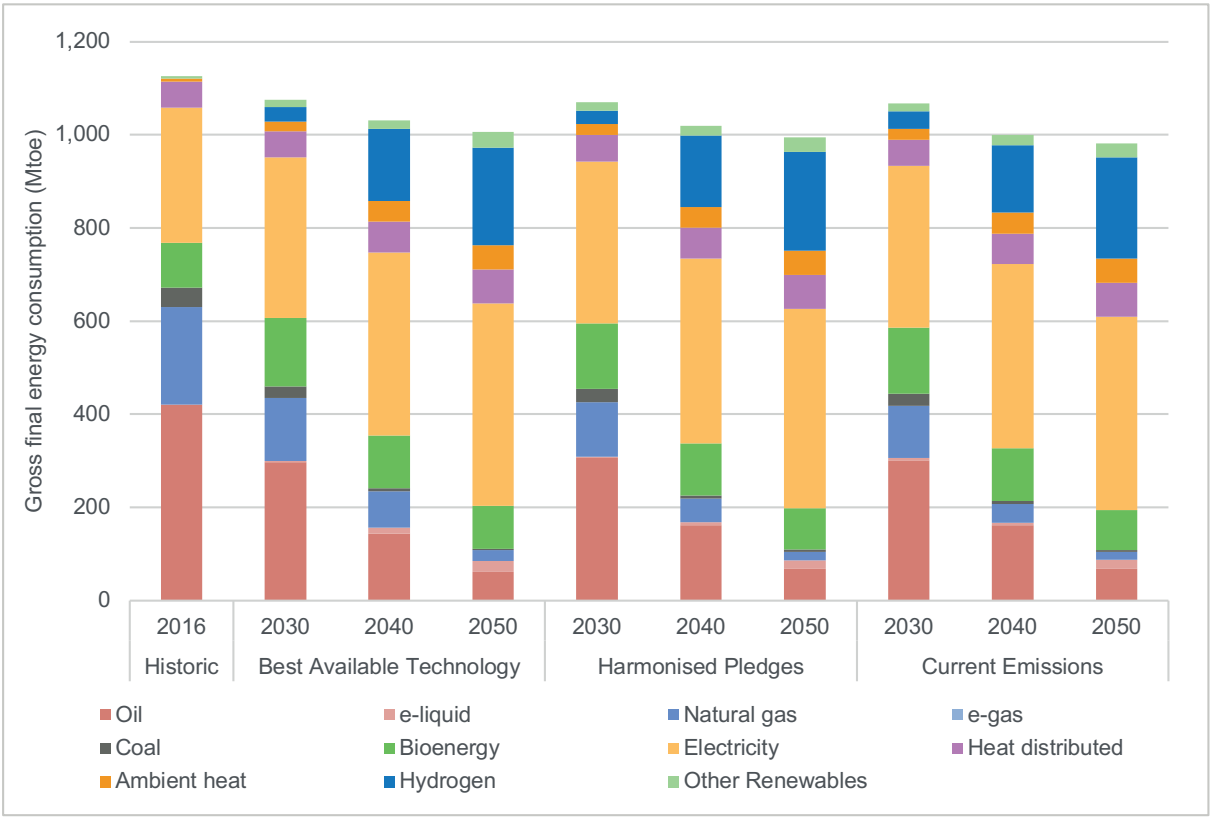
Figure 51. Evolution of total primary energy demand in the Technology Diversification pathway in the different methane emission factor cases from 2016 to 2050



Source: Hydrogen4EU

196. The general conclusions of the study with regard to final energy consumption are resilient to the level of methane emissions (figure 52). The roles of hydrogen and electricity are particularly stable from one case to another, implying that the transformation mix is able to switch to less methane intensive energies as methane intensity increases. The share of natural gas, which by 2050 is already very low in the *BAT* case, drops nearly one point in case of higher methane emissions.

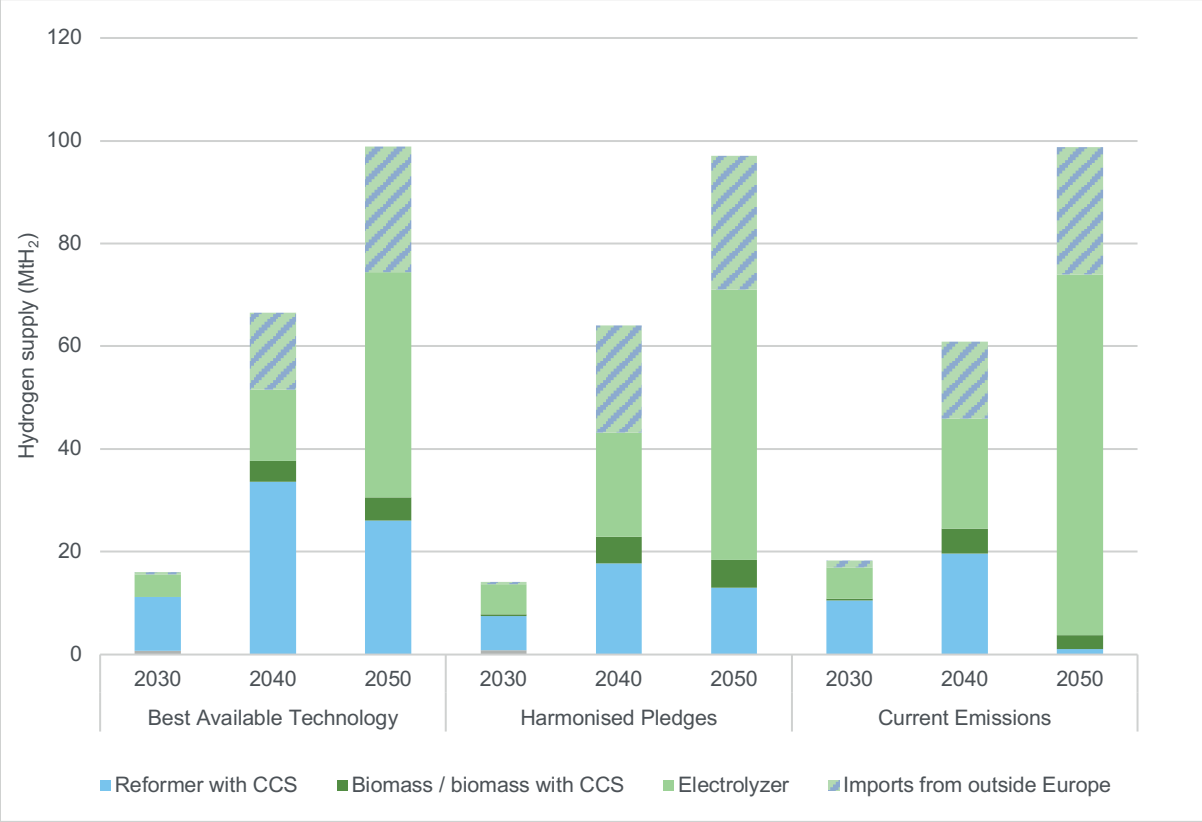
Figure 52. Evolution of gross final energy consumption in the Technology Diversification pathway in the different methane emission factor cases from 2016 to 2050



Source: Hydrogen4EU

197. The hydrogen supply mix is strongly affected by varying levels of emission intensity. This reflects the findings on primary energy demand: In the *BAT* case, strong commitment to decrease the methane emission intensity of natural gas allows for an optimal contribution of low-carbon hydrogen, especially to kickstart the hydrogen economy over the next two decades (figure 53). In the *Harmonised Pledges* case, limited mitigation actions affect the potential for low-carbon hydrogen in the transition period, with a peak at nearly 18 Mt in 2040 (-46% from the *BAT* case) and only 13 Mt in 2050 (-50%). Medium and long-term prospects of low-carbon hydrogen are particularly dim in the *Current Emissions* case: inaction to mitigate methane emissions leads to a 42% reduction of the 2040 peak compared to the *BAT* case, and a near-complete phase-out of reformer technologies by the end of the outlook period. The hydrogen import mix also shows an increased share of renewable hydrogen in the imports, although at a smaller scale (table 4).

Figure 53. Evolution of hydrogen production by technology in the Technology Diversification pathway for different methane emission factor cases from 2030 to 2050



Source: Hydrogen4EU

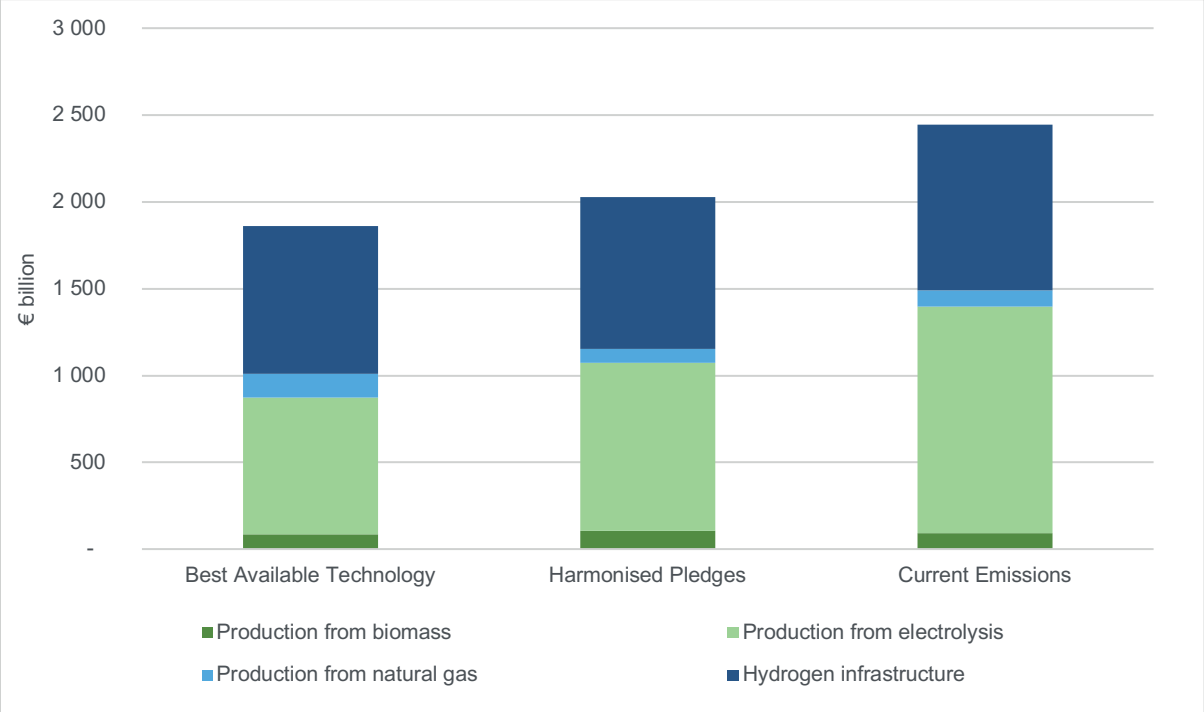
Table 4. Primary energy supply of imported hydrogen in the Technology Diversification pathway for the year 2050 (MtH_2)

Primary source	Best Available Technology	Harmonised Pledges	Current Emissions
Biomass	0	0	0
Natural gas	8.7	8.7	8.7
Hybrid	0.4	2.4	0.4
Wind	0.7	0.5	0.7
Solar	14.8	14.5	15
Total	*24.5*	*26.1*	*24.8*

Source: Hydrogen4EU

198. These changes lead to different numbers regarding cumulative investment in the hydrogen supply chain (figure 54): the higher the level of methane emissions, the higher the cost needed to circumvent and compensate those. Cumulative investments in the hydrogen supply chain in the *Current Emissions* case stand at around €2.4 trillion with marked increases in investments in electrolyser infrastructures and hydrogen national transport. The overall energy system cost, discounted over the outlook period, is about €2.3 trillion (+2.5%) higher in the *Current Emissions* case and €990 billion (+1%) higher in the *Harmonised Pledges* case than in the *BAT* case.

Figure 54. Cumulative investment in the direct hydrogen supply chain for the Technology Diversification pathway for different methane emission cases



Source: Hydrogen4EU

7 Annex B: Technical overview of the modelling framework

7.1 The modelling framework

7.1.1 Energy system optimisation

199. The *Hydrogen for Europe* project is based on a quantitative modelling-based analysis that entails the representation of the European energy system and its transition until 2050 under the EU decarbonisation targets. The modelling architecture relies on a detailed European energy system model (MIRET-EU), a state-of-the-art partial-equilibrium model enhanced specifically to tackle the objectives of this study, and the HyPE model, an optimisation model that explores the least-cost routes of hydrogen imports to Europe.

200. The MIRET-EU model provides a detailed view of country specificities in Europe. It is a version of the well-known TIMES/MARKAL family used by the International Energy Agency (IEA) and several research centres within the ETSAP program. It is a bottom-up prospective model providing a country level representation of the entire European energy system. This version of TIMES pays particular attention to the integration of renewables in the energy and transport sectors, including aspects related to infrastructure, life cycle assessment and availability of strategic materials, under the climate constraints in line with emission reduction targets and evolving energy demand[91].

201. The MIRET-EU model is calibrated to optimize system operations and capacity expansion decisions under a total system cost minimization, here enabling to assess the cost-optimal pathways towards the EU decarbonisation objectives in 2030 and 2050. Their technical capabilities and complementarity are leveraged to provide detailed insights on the spatial and temporal dimensions, with a large set of technologies considered. This enables to investigate the importance of path dependencies, the associated costs, energy system response and modified risk picture of policies that restricts the optimal transition path, the value of existing infrastructure among other complex questions related to market signals, their timing and their overall efficiency.

202. The HyPE model provides the main energy system model with hydrogen import supply curves from neighbouring regions to represent the competition between domestically produced hydrogen and imports, and between import routes. In line with the EU hydrogen strategy, HyPE focuses on clean hydrogen trade and evaluates the potential partnership with Southern and Eastern Neighbourhood countries. As such, renewable and low-carbon hydrogen can be imported to Europe from North Africa, the Middle East and Ukraine in HyPE.

7.1.2 Modelling scope

203. The modelling framework contains a detailed and exhaustive representation of technologies, sectors and countries in the detailed energy system model (MIRET-EU model).

204. At country level, the modelling framework covers 27 European countries (see figure 55) through the MIRET-EU model, which is continuously improved by IFPEN[92]. Its perimeter includes Norway, the United Kingdom and Switzerland on top of the 24 pertinent countries in the European Union (EU 27). Norway and the United Kingdom are particularly relevant to the study due to their central role in the European natural gas economy as both produce natural gas within the European continent and have already carried out extensive research and demonstration projects on hydrogen and CCS[93]. The modelling is done in such a way that all quantitative results are available for each of the 27 countries in the MIRET-EU scope. This enables a complete overview of the European strategy for decarbonisation and hydrogen deployment and the drivers for country-related specificities.

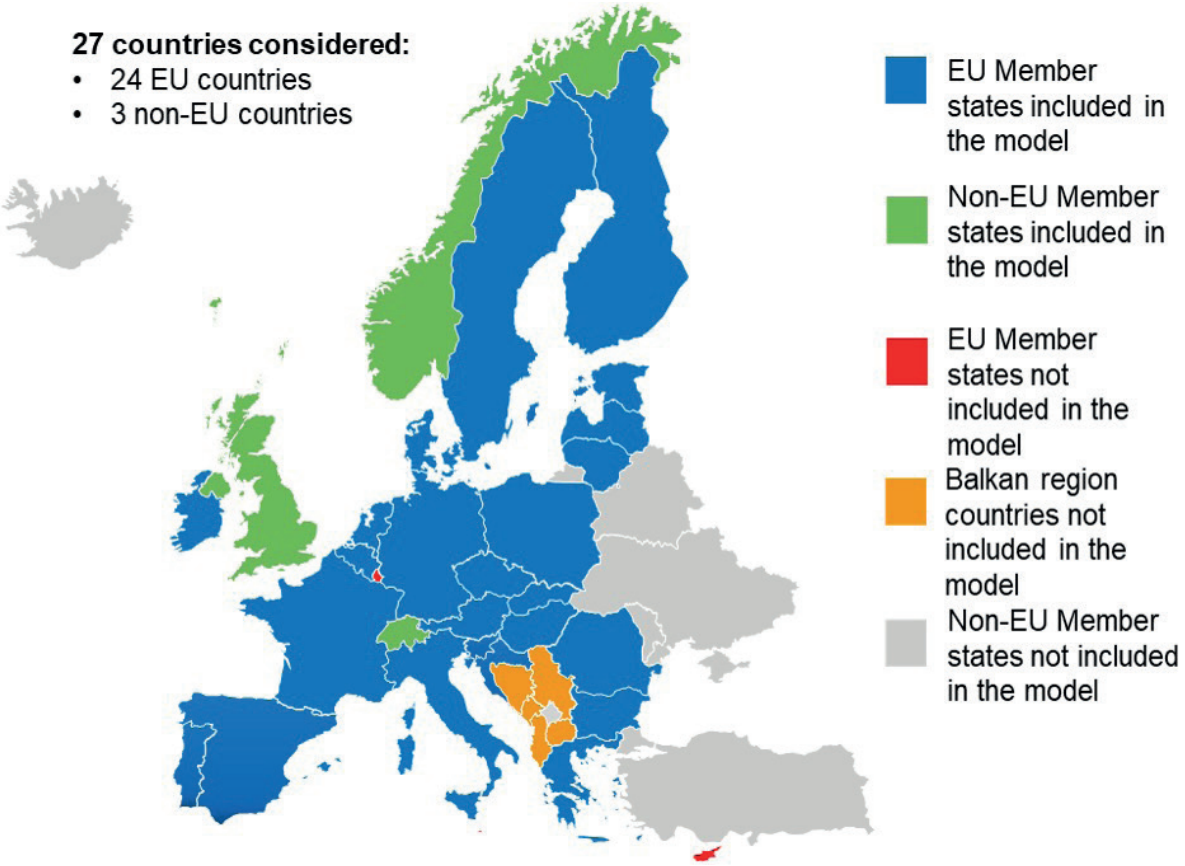
[91] These are, among others, the capabilities of the MIRET model tested on previous projects by IFPEN. However, a life cycle assessment and the assessment of demand of strategic materials are out of the scope the study.
[92] MIRET has been based on the TIMES model generator, developed by one of the IEA implementing agreements (ETSAP) in 1997 as a successor of the former generators MARKAL and EFOM with new features for understanding and greater flexibility. The manuals and a complete description of the TIMES model appear in ETSAP documentation (https://iea-etsap.org/index.php/documentation)
[93] On the other hand, Luxemburg, Malta and Cyprus are excluded due to their small size and marginal status within the internal European energy system

205. MIRET-EU represents the European energy system in a disaggregated manner. It considers all the steps from primary resources to the transformation, distribution and conversion of energy to final energy consumption, providing a highly detailed representation of technologies and energy carriers at the supply (import, processing and transformation into secondary energy carriers), transportation and storage, and demand (residential, commercial, agricultural, transport and industrial sectors) sides.

206. A simplified overview of the main categories of technologies and end-uses represented in the model is provided in table 5. The listed elements are disaggregated into more exhaustive components according to the level of detail suitable within MIRET-EU.

207. The hydrogen imports are included into the modelling framework on the same terms as fossil fuels and biomass. Nevertheless, unlike the latter, hydrogen volumes and prices from abroad have been modelled following a merit order logic based on the LCOH metric to build import supply curves. These estimates include production cost and transport cost from non-European production sites to entry points in Europe. The methodology follows the principles of CO_2 neutrality of EU energy imports and technology neutrality on the supply side. The hydrogen import option thus comprises clean hydrogen imported from North African countries, Middle East and Ukraine, where the hydrogen is produced both from dedicated off grid renewable energy and from methane with abated CO_2 emissions. Moreover, world hydrogen trade is modelled by inclusion of potential big hydrogen importers (e.g., China, Japan and South Korea) and net hydrogen exporters (such as Australia, India, etc.) to identify the possible impacts of the world hydrogen trade in European hydrogen imports.

Figure 55. Geographical coverage of *Hydrogen for Europe* study



Source: Hydrogen4EU

Table 5. Aggregated overview of the technological scope[94]

Primary energy supply	Energy transformation	Final energy supply	End-use sector
Lignite (resources and import) Oil (resources and import) Coal (resources and imports) Natural gas (resources and imports) Bioenergy Solar energy Wind power	Electricity production CHP sector Electrolysis Biomass gasification Methane pyrolysis Methane reforming Liquefaction Coal processing Refineries Gas network …	Electricity Hydrogen Coal Natural gas Oil Bioenergy Other final RES	Residential Commercial Industry Transport (road, rail, aviation, maritime[95]) Agriculture
+ Representation of CCUS routes (direct air capture or carbon capture, CO_2 use and storage) + Representation of electricity, natural gas and hydrogen storage			

7.2 Focus on the models

7.2.1 The MIRET-EU model

208. MIRET-EU is a multiregional and inter-temporal optimisation model of the European energy system developed by IFPEN, based on the TIMES[96] model generator. MIRET-EU introduces partial equilibrium constraints of the different energy demand sectors and end-uses. A complete description of the TIMES model equations appears in the ETSAP[97] documentation. It is a bottom-up techno-economic model that estimates the energy dynamics by minimizing the total discounted cost of the system over the selected multi-period time horizon through powerful linear programming optimizers. The components of the overall cost are expressed on an annual basis while the constraints and variables are linked to a period. Cash flows related to process investments and dismantling for each year of the horizon are tracked precisely. The overall cost is an aggregation of the total net present value of the stream of annual costs for each of the model's countries. It constitutes the objective function (Eq. 1) to be minimized by the model in its equilibrium computation. A detailed description of the objective function equations is provided in Part II of the TIMES documentation (Loulou et al., 2016). This description is limited to general indications on the annual cost elements contained in the objective function:

- Investment costs incurred for processes;
- Fixed and variable annual costs;
- Costs incurred for exogenous imports and revenues from exogenous exports;
- Delivery costs for required commodities consumed by processes;
- Taxes and subsidies associated with commodity flows and process activities or investments;

$$NPV = \sum_{r=1}^{R} \sum_{y \in YEARS} (1 + d_{r,y})^{REFYR-y} * ANNCOST(r,y) \qquad \text{(Eq. 1)}$$

NPV is the net present value of the total cost for all regions (the objective function);

ANNCOST(r,y) is the total annual cost in region *r* and year *y* (more details in section 6.2 of PART II (Loulou et al., 2016)

[94] This overview presents a simplified representation of the energy sector as modelled in the *Hydrogen for Europe* study. The detailed energy system representation of MIRET-EU is provided in section 10.1.
[95] Only within Europe.
[96] MIRET has been based on the TIMES model generator, developed by one of the IEA implementing agreements (ETSAP) in 1997 as the successor of the former generators MARKAL andEFOM with new features for understanding and greater flexibility. The manuals and a complete description of the TIMES model appear in ETSAP documentation (https://iea-etsap.org/index.php/documentation)
[97] Energy Technology Systems Analysis Program. Created in 1976, it is one of the longest running Technology collaboration Programme of the International Energy Agency (IEA). https://iea-etsap.org/index.php/documentation

$d_{r,y}$ is the general discount rate;

REFYR is the reference year for discounting;

YEARS is the set of years for which there are costs, including all years in the horizon, plus past years (before the initial period) if costs have been defined for past investments, plus a number of years after end of horizon (EOH) where some investment and dismantling costs are still being incurred, as well as Salvage Value; and

R is the set of regions/countries in the area of study.

209. MIRET-EU represents the European energy system divided into 27 countries. It is set up to explore the development of its energy system from 2016 through to 2050 with 10-year steps and is calibrated on the latest data provided by energy statistics such as the JRC-IDEES[98] database, POTEnCIA[99] database, EUROSTAT database, and other international database from IEA, IRENA, World Bank, among others. MIRET-EU, considers four seasons (spring, summer, autumn, winter) disaggregated into day, night and peak resolution. Every year is therefore divided in twelve time-slices that represent an average of day, night and peak demand for each season of the year (e.g. summer day, summer night and summer peak, etc.).

210. The MIRET-EU model is data driven[100], its parameters refer to technology characteristics, resource data, projections of energy service demands, policy measures, etc. (Loulou et al., 2016). This means that the model varies according to the data inputs while providing results such as technology pathways or changes in trade flows for policy recommendations. For each country, the model includes detailed descriptions of numerous technologies, logically interrelated in a Reference Energy System – the chain of processes that transform, transport, distribute and convert energy into services from primary resources and raw materials to the energy services needed by end-use sectors (see Section 9.2).

211. Several models have already been developed at European scale using the TIMES model over the last 15 years. The Pan-European TIMES (PET) model has been developed by the Kanlo team following a series of European Commission (EC) funded projects (NEEDS[101], RES2020[102], REACCESS[103], REALISEGRID[104], COMET[105], Irish-TIMES[106]) between 2004 and 2010. It represents the energy system of 36 European regions. The JRC-EU-TIMES model is one of the models currently pursued and developed in the Joint Research Centre (JRC) of the European Commission under the auspices of the JRC Modelling Taskforce. The JRC-EU-TIMES model was developed as an evolution of the Pan European TIMES (PET) model of the RES2020 project, followed up within the REALISEGRID and REACCESS European research projects. The residential, services and hydrogen modules of the JRC-EU-TIMES have been incorporated to the MIRET-EU. Therefore, the modelling framework of MIRET-EU follows the same framework developed successively in the PET36, the JRC-EU-TIMES, MIRET-FR[107] and TIAM-IFPEN[108] models with additional expertise from IFP Energies Nouvelles in specific sectors such as transport, refineries and bioenergy conversion technologies, hydrogen infrastructure, power sector and industry.

[98] JRC-IDEES (Integrated Database of the European Energy System) has been released in July 2018 and is revised periodically. We then used the latest data released in September 2019.
[99] POTEnCIA (Policy-Oriented Tool for Energy and Climate change Impact Assessment)
[100] Data in this context refers to parameter assumptions, technology characteristics, projections of energy service demands, etc. It does not refer to historical data series
[101] http://www.needs-project.org/
[102] http://www.cres.gr/res2020
[103] http://reaccess.epu.ntua.gr/
[104] http://realisegrid.rse-web.it/
[105] The final aim of the modelling tasks in the research project COMET is the evaluation of different possible developments of CCS using a hard-link approach of TIMES-Morocco, TIMES-Portugal, TIMES-Spain, and TIMES-CCS. http://rdgroups.ciemat.es/documents/10907/86733/Comet_12Dec.pdf/b29424d6-1287-4644-9192-c2994daef02e
[106] https://www.epa.ie/pubs/reports/research/climate/Irish%20TIMES%20Energy%20Systems%20Model.PDF
[107] MIRET-FR is the version developed and maintained for France by IFPEN since 2008.
[108] TiAM-IFPEN (TIMES Integrated Assessment Model) is the world version currently developed by IFPEN since 2018.

7.2.2 The Hydrogen Pathways Exploration model (HyPE)

212. The HyPE model provides MIRET-EU with hydrogen export potentials from neighbouring regions to represent competition between domestically produced hydrogen and imports, and between the import sources. In line with the European hydrogen strategy, only low-carbon and renewable hydrogen imports are considered, with a focus on North Africa, the Middle East and Ukraine.

213. The model estimates hydrogen imports' supply curves, indicating both the potential of hydrogen production per region and the associated costs, following a levelized cost of hydrogen approach (LCOH[109]). The LCOH is calculated for each delivery point in Europe (Cost, Insurance and Freight[110]). The methodology builds on the full delivery value chain from the hydrogen production site to determine LCOH at each entry point in Europe.

214. In the upstream, depending on resource endowments, all hydrogen production technologies and their associated cost evolutions are considered as possible for exports. A country-specific risk consideration was included as a mark up to the weighted average cost of capital (WACC) of each country based on the Ease of Doing Business scores (World Bank, 2020). In the midstream, the transport modes cover inland transport for the distance from production site to exit point in each country of origin (i.e., by national pipelines, gasified hydrogen trucks and/or ammonia trucks), and international transport for the distance from the exit point, in the producing country, to the entry in Europe (i.e. by cross-border pipeline interconnectors and/or maritime shipping routes). The optimal combination between the transport mode, the distances and the flows are obtained by an optimization approach resulting in least-cost LCOH CIF import curves.

7.3 Strengths, weaknesses and opportunities of the models related to the goals of the study

7.3.1 Strengths and weaknesses of MIRET-EU

215. MIRET-EU is an economic model with a detailed representation of technology options for estimating the capacity investment pathways over the long term. It combines two different, but complementary, systematic approaches to energy system modelling: a technical and operational (engineering) approach and an economic approach. TIMES[111] models use linear-programming to produce a least-cost energy system, optimising both the investment in and the operation of the energy system across regions and sectors according to a number of user constraints, over medium to long-term time horizons. This unique objective function guarantees the internal consistency of the resulting scenario, as the decision criteria are the same for all processes and flows. These types of models are useful for assessing long-term investment decisions in complex systems where future technologies are different from current technologies. The TIMES model assumes perfect foresight over the entire horizon, i.e. all investment decisions are made in each period with full knowledge of future events. This model provides decision-makers with insights regarding energy systems to determine which technologies are competitive, marginal or uncompetitive in each market according to dynamic economic optimisation. To sum up, MIRET-EU is used for "the exploration of possible energy futures based on contrasted scenarios" (Loulou et al., 2016). The time horizon of MIRET-EU is 2016-2050 and the base year 2016 is calibrated to energy statistics such as JRC-IDEES, POTEnCIA[112], EUROSTAT, and other international database from IEA, IRENA, World Bank, among others.

[109] The levelized cost of hydrogen (LCOH) adopts the life cycle costing methodology where all related costs and produced quantities are included to compute an average ratio of cost per kilogram produced.
[110] The cost, insurance and freight view (CIF) includes the cost of transport and logistics from the exit point to the entry point in Europe.
[111] MIRET has been based on the TIMES model generator, developed by one of the IEA implementing agreements (ETSAP) in 1997 as the successor of the former generators MARKAL and EFOM with new features for understanding and greater flexibility. The manuals and a complete description of the TIMES model appear in ETSAP documentation (https://iea-etsap.org/index.php/documentation)
[112] POTEnCIA (Policy-Oriented Tool for Energy and Climate change Impact Assessment)

216. As a partial equilibrium model, MIRET-EU does not model economic interactions outside the European energy sector. Such a model that is based on TIMES generator, has the following advantages (Gielen and Taylor, 2007):
- The model is based on a single objective cost criterion.
- A detailed technology-rich modelling paradigm from primary resources to end-uses
- Stock turnover is considered explicitly.
- Provide decision-makers with options regarding energy systems in the medium- to long-term
  - Economically affordable
  - Technically feasible
  - Environmentally sustainable
- The model is well suited for development of Energy Roadmaps by precising the representation of technologies and fuels in all sectors in order to anticipate achievable futures based on actual knowledge. This is relevant for investment decisions in complex systems with differences between existing and future technologies.
- The model optimizes operation and investment decisions based on the characteristics of alternative generation technologies, energy supply economics, and environmental criteria. TIMES is thus a vertically integrated model of the entire extended energy system.
- The scope of the model goes beyond purely energy-oriented issues, to include the representation of environmental emissions, and material requirements and land-use, related to the energy system. In addition, the model is suitable for the analysis of energy-environmental policies, which may be accurately represented by making explicit the representation of technologies and fuels in all sectors.
- The great flexibility of TIMES, especially at the technological level, allows the representation of almost all policies, whether at the national, sectoral, or sub-sectoral level.
- The model is driven by explicit exogenous final energy services demand and fuel prices.

217. On the other hand, it could be pinpointed some limitations inherent to this type of model:
- MIRET-EU is data consuming; therefore, data availability could limit the scope and depth of possible analyses.
- Moreover, there is no explicit representation of macro-economic factors which means there are no feed-back loops between the effects of energy system changes and the economy[113].
- As all models are simplified representations of reality and its complex dynamics, they inherently have limitations as to the detail and scope of their mathematical representation. These simplifications, e.g. time and spatial resolution, sector or technology representation and system boundaries, which are mostly due to the data availability, may represent significant modelling limitations.
- Long computational times could be observed due to a very detailed representation of complex energy system.
- The model is sensitive to the data assumptions for emerging technologies, which are by definition more uncertain and decision makers in practice do not always balance efforts across regions and sectors.
- Decision making that conditions investment in new technologies is often not rational, however representing non-rational decisions could be done via exogenous constraints. This does not allow capturing in detail all the aspects related to consumer behaviour, which play a fundamental role in decision-making processes. As highlighted by Gielen and Taylor (2007), even if decision making is rational, it is often not based on least-cost criteria. Policy rationality may stress effectiveness, equity issues, timing, risk and other factors that are not accounted for in this framework.
- The optimistic view of the future due to the perfect foresight approach which does not account for real-world uncertainty. However, it is possible to implement via the model to have foresight over a limited part of the horizon, such as one or a few periods or to temper it by using higher discount rates. By so doing, a modeler may attempt to simulate “real-world” decision making conditions, rather than socially optimal ones (Loulou et al., 2016)
- In this study, there is no disaggregation by plant size unlike in the MIRET FR (France) due to a lack of data and the consequences of so doing on computational time. This implies, as a simplification, that all installations in industry and CHP are considered as falling within the scope of the EU ETS Directive.
- Limited consideration of the very short-term physical dynamics (e.g. integrating system adequacy, transient stability analysis in the power sector) into long-term prospective models such as MIRET-EU.

[113] However, they could be considered exogenously through the price elasticities of service demands.

7.3.2 Strengths and weaknesses of HyPE

218. The HyPE model also assumes perfect foresight and techno-economic assumptions regarding production, transport and conversion and reconversion technologies. Supply decisions are based on the use of Levelized Cost of Hydrogen (LCOH); the model does not intrinsically handle sunk costs with discounting but follows capacity recovery factors as a key cost component of the LCOH. The supply curves obtained are dependent on the routes available to link production sites with demand sites. While the set of countries considered within the scope includes the most relevant and promising trading partners, it does not include other important countries outside MENA and Ukraine, such as Chile, Mauritania, the US, Australia, among others. The supply curves obtained after the optimisation result from an analysis that disregard the effects of competition against other likely markets such as Japan, Korea, China and India. Countries such as Saudi Arabia and Qatar could prove competitive in such markets, leading to some profit arbitrations.

219. On the other hand, it could be pinpointed some limitations inherent to the use of HyPE and its linking with MIRET-EU:
- The HyPE model optimises point-to-point hydrogen delivery pathways on the basis of costs, but investment decisions regarding infrastructure availability for transport are external to the model and based on best available sources. However, figures on hydrogen-ready pipelines and terminals remain highly uncertain.
- The HyPE model is a delivery chain model that focuses on hydrogen, and/or hydrogen carriers, as single commodities while making abstraction of any interrelation with others traded commodities or the delivery of another related molecule such as ammonia or methanol.
- Detailed representation of the hydrogen trade will reduce computational tractability significantly. Not only from a technical point of view but also from inclusion of current trade environment. More than ever, energy commodity trade is to be based on policy stability/predictability, long-term reliability and alignment on international affairs with the EU. Those considerations are out of the scope of the HyPE model.
- The countries under the scope for hydrogen imports suffer from water scarcity issues. While water availability and cost were taken by assuming water desalinisation units, further analyses should be required on the energy and carbon footprint it would entail, as well as the costs associated to handline brine.
- Similar to the MIRET-EU model, HyPE also depends on the cost-minimisation, it also assumes rational economic behaviour, perfect foresight and perfect competition that introduce their limitations, in the same way as for MIRET-EU.
- Moreover, like MIRET-EU, the HyPE model's findings depend on the large series of input data; therefore, data availability could limit the scope and depth of the possible analyses. It also relies on exogenous macro-economic assumptions, and there is no link between the effects of energy system changes and the economy.
- HyPE is also based on simplified representation of the reality, via mathematical equations. Therefore, it entails similar simplifications to the MIRET-EU model: time and spatial resolution, sector or technology representation and system boundaries, which are mostly due to the data availability, that are significant modelling limitations.
- Finally, the soft linking approach to couple both models has some limitations since the complete convergence cannot be ensured.

8 Annex C: Methane emission factor calculation methodology

220. This section describes the methodological framework for estimating the methane (CH_4) emission factors for gas production and consumption. In total over 150 emission factors have been estimated covering the following:

a. All the countries mentioned in box 9.

b. Different parts of the natural gas value chain
   i. Upstream – Exploration, production, gas gathering and boosting, gas processing
   ii. Downstream – Gas transmission and gas distribution
   iii. LNG – Liquefaction, LNG carrier (transport) and LNG regasification

c. The period between 2019 and 2050: 2019, 2030, 2035, 2040, 2045 and 2050

d. Three different cases:
   i. *Current emissions*: emission factor is estimated using the current best understanding of methane emission from the oil and gas sector. The estimated emission factor is considered flat from the year of analysis until 2050. These emission factors are used as the preliminary year emission factor (2019) for the two other cases.
   ii. *Harmonised pledges*: International pledges and country level targets and policies for methane and greenhouse gas reduction are considered to estimate the impacts on emission factor from the preliminary year (2019) to 2050.
   iii. *Best available technologies (BAT)*: This case represents the emission factor on applying the best available technologies for methane abatement. Industry targets set in the countries assessed, or global industry targets for *BAT* are considered to estimate the impacts on emission factor from the preliminary year (2019) to 2050.

Box 9. Countries for which emission factors were assessed

Countries exporting gas (via pipeline) or exporting low-carbon hydrogen to Europe: Algeria, Azerbaijan, Bahrain, Egypt, Iran, Iraq, Kuwait, Libya, Oman, Qatar, Russia, Saudi Arabia, United Arab Emirates (UAE)

Countries exporting LNG to Europe: Algeria, Angola, Australia, Egypt, Nigeria, Peru, Qatar, Russia, Trinidad and Tobago, United States of America (USA)

European producing countries: Denmark, Germany, Italy, Netherlands, Poland, Romania, UK, Norway

Importing region: Europe (Austria, Belgium, Czech, Denmark, France, Finland, Germany, Greece, Italy, Ireland, Netherlands, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, UK, Switzerland, Bulgaria, Croatia, Cyprus, Estonia, Latvia, Lithuania, Malta, Luxembourg, Hungary, Sweden)

221. While estimating the emission factor for the gas value chain, the first step is to understand the boundaries associated with the emissions. The value chain steps associated with each emission factor are shown in figure 56. The value chain for the countries assessed can be broadly split into four categories:

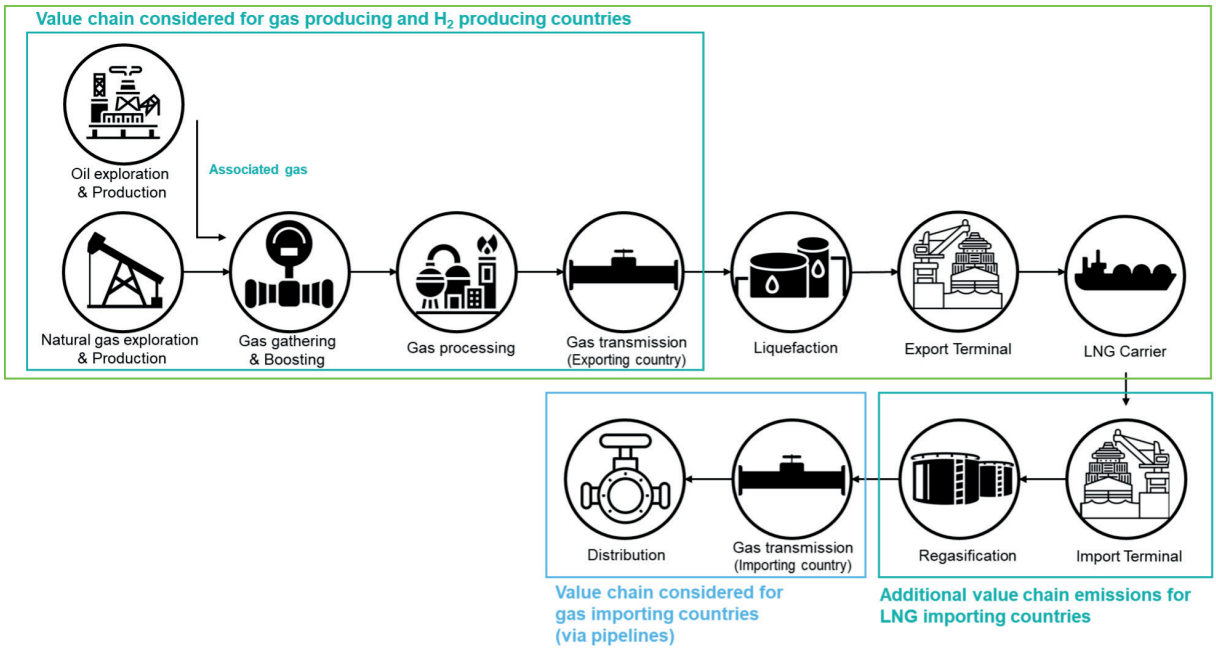
a. Countries producing natural gas or low-carbon hydrogen

b. Countries exporting LNG

c. Countries importing gas via pipeline

d. Countries importing LNG

Figure 56. Gas value chain steps considered for the emission factor calculation



Source: Hydrogen4EU

222. Both associated gas and non-associated gas have been taken into consideration in the assessment of emission factor. Non-associated gas is natural gas produced in dedicated gas wells, with little liquid production alongside the gas produce, while associated gas is natural gas produced from oil wells. This associated gas can be used locally, reinjected into the well, vented, flared or exported as marketable natural gas and thus joins the natural gas value chain. Thus, the methane emissions related to associated gas production must be considered while estimating the emission factor of the gas value chain.

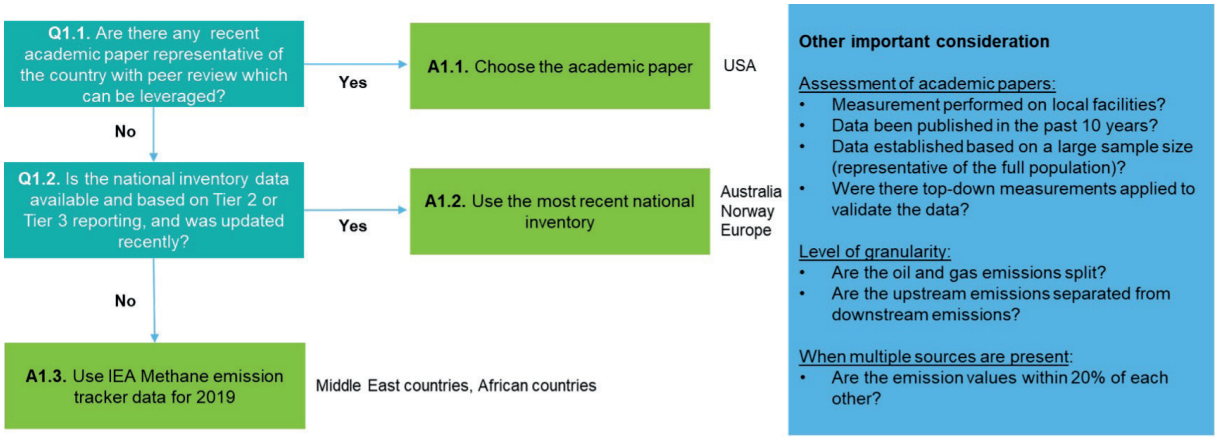
223. The emission factors in this report have been estimated for three different cases. The next section (section 8.1) presents the methodology for estimating current emissions, notably used as flat levels for the *Current Emissions* case. Sections 8.2 and 8.3 cover the *Harmonised Pledges* and *BAT* cases. Each section delves into the estimation of upstream, downstream and LNG emission factors. Finally, the emission factors in the three cases are compared in section 8.5.

8.1 Calculation of current methane emissions

8.1.1 Selection of sources for calculation of current methane emissions

224. Country specific academic papers, national inventories and IEA methane tracker data have been assessed to estimate the current emissions from the oil and gas sector for each country. While some countries have several academic papers and research work done on estimating methane emissions, some countries have very limited data available on methane emissions. A decision tree was used to select the best available source for each country, as depicted in figure 57. Several other aspects were also considered while selecting the source, to obtain the emission factor in the format required for the models. Table 6 shows the final list of sources used for obtaining methane emissions along the gas value chain for each country.

Figure 57. Decision tree to identify the best source for the methane emissions



Source: Hydrogen4EU

Table 6. The final list of sources used for the estimation of current emissions for each country

Country	Chosen source for emission
Algeria, Angola, Egypt, Nigeria, Peru, Qatar, Russia	IEA[114] – for upstream oil and gas and downstream emissions Carbon Limits expertise – for LNG Carrier emission factor EPA Facilities[115], Atlantic LNG facility[116], Melkoya facility[117] – for LNG Liquefaction emissions
Azerbaijan, Bahrain, Iran, Iraq, Kuwait, Libya, Oman, Saudi Arabia, UAE[118]	IEA[114] – for upstream oil and gas and downstream emissions
Australia	UNFCCC[119] – for upstream oil and gas and downstream emissions Carbon Limits expertise – for LNG Carrier emission factor EPA Facilities[115], Atlantic LNG facility[116], Melkoya facility[117] – for LNG Liquefaction
Norway	Carbon Limits expertise – for LNG Carrier emissions Norsk Olje og Gass[120] – for upstream oil and gas emissions Melkoya facility[117] – for LNG Liquefaction emissions
Trinidad and Tobago	IEA[114] – for upstream oil and gas and downstream emissions Carbon Limits expertise – for LNG Carrier emission factor Atlantic LNG Trinidad[116] – for LNG Liquefaction emissions
USA	Alvarez et al. (2015)[121], Zhang et al. (2020)[122] – for upstream oil and gas and downstream emissions Carbon Limits expertise – for LNG Carrier emissions EPA Facilities[115] – for LNG Liquefaction emissions
Europe (-8)[123]	UNFCCC[124] – for transmission and distribution emissions Marcogas[125] – for LNG unloading and regasification emission factor
Denmark, Italy, UK, Netherlands, Poland, Romania	UNFCCC[126] – for upstream and downstream (transmission and distribution) oil and gas emissions. For associated gas - Danish Energy Agency[127] (Denmark) Ministero della transizione ecologica[128] (Italy), Digest of UK Energy statistics (DUKES)[129] (UK)

[114] Methane Tracker Data Explorer - IEA, note that 2019 data has been used
[115] EPA Facility Level GHG Emissions Data
[116] Atlantic LNG - Home - Atlantic LNG
[117] Onshore facilities (equinor.com)
[118] These countries are only gas pipeline exporting countries. Hence, other sources are not required.
[119] GHG data from UNFCCC | UNFCCC
[120] 7.3.6 Utslipp av Metan (CH4) - NOROG Klima- og Miljørapport Portal (norskoljeoggass.no)
[121] Assessment of methane emissions from the U.S. oil and gas supply chain (science.org)
[122] (PDF) Quantifying methane emissions from the largest oil-producing basin in the United States from space (researchgate.net)
[123] Europe (-8) does not include Denmark, Germany, Italy, Netherlands, Norway, Poland, Romania and UK which have been assessed separately, as gas producing countries in Europe
[124] GHG data from UNFCCC | UNFCCC
[125] Survey Methane Emissions for LNG Terminals in Europe | Marcogaz
[126] GHG data from UNFCCC | UNFCCC
[127] Monthly and yearly production | Energistyrelsen (ens.dk), Excel downloaded: 1972-2021.xlsx (live.com)
[128] Produzione nazionale di idrocarburi (mise.gov.it)
[129] DUKES_F.2.xls (live.com)

225. For countries with the same source of information for emissions, a similar methodology was followed to estimate the emission factor along the gas value chain. It is to be noted that the harmonised pledges and the *BAT* cases use the 2019 current emission factors as the preliminary year value. The following sections explain the calculations associated with the emission factor estimation[130].

8.1.2 Estimation of upstream methane emissions

For the countries for which IEA methane tracker is the chosen source of information

Methodology for Algeria, Angola, Azerbaijan, Bahrain, Egypt, Iran, Iraq, Kuwait, Libya, Nigeria, Oman, Peru, Qatar, Russia, Saudi Arabia, Trinidad & Tobago, United Arab Emirates (UAE)

226. In the absence of an academic paper with local measurement on a representative sample, and in the absence of a tier 2 or 3 national inventory, IEA 2019 methane tracker data was used. The estimation steps used to assess the total upstream emission factor have been presented below.

Step A.1 – Estimating upstream non-associated gas emissions

227. This step only concerns non-associated gas, that is natural gas produced in dedicated gas wells. The total methane emissions are the sum of all the methane emissions categorized under "natural gas production" in the IEA methane tracker database: onshore and offshore fugitive, venting and flaring emissions. Upstream non-associated gas emissions (A) can be calculated as in Equation 2.

$$A = \Sigma\ (Fugitive, Venting, Flaring\ CH_4\ emissions)_{onshore} + \Sigma\ (Fugitive, Venting, Flaring\ CH_4\ emissions)_{offshore} \quad \text{(Eq. 2)}$$

Step A.1 – Estimating associated gas (APG[131]) emissions

228. This step only concerns emissions from associated gas production, that is natural gas produced alongside oil production from oil wells[131].

229. To estimate the emissions related to the production of associated gas joining the natural gas value chain (marketable APG) from the oil production, some methane emissions from oil production must be attributed to marketable APG. This is done using the energy ratio of APG and oil produced in the country. The data for estimating the volume of APG produced per country is not easily available. Hence the regional APG production volumes have been leveraged, using the IEA report on gas flaring as the main source of reference. Table 7 shows the regional APG marketed. Using this data, the ratio of regional APG produced to the total gas produced in the region is estimated using Equation 3.

Table 7. Regional marketed associated gas in 2019

Region	Countries considered	Regional marketed associated gas in 2019 (bcm) (α in Eq. 3)
North America	Australia	251
Middle east	Bahrain, Iran, Iraq, Oman, Qatar, Saudi Arabia, Trinidad and Tobago, United Arab Emirates	120
Eurasia	Azerbaijan	59
Africa	Algeria, Angola, Egypt, Libya, Nigeria	28

[130] Definition: U.S. Energy Information Administration - EIA - Independent Statistics and Analysis
[131] Associated Petroleum Gas

$$B_1 = \frac{\alpha}{\alpha+\beta_1} \quad \text{(Eq. 3)}$$

B_1 is the regional APG to total gas ratio

α is the regional associated gas marketable[132] (bcm)

β1 is the non-associated gas produced in the region[133] (bcm)

230. Note: for Peru[134], Norway (B_2, Equation 9) and the USA[135] country specific information is used instead of Eq. 3.

231. Following this, the production of associated gas per country is estimated. The APG to oil ratio (Eq 4) is calculated in order to determine the part of the oil emissions that must be attributed to associated gas marketed (Eq 5).

$$C = \frac{B_1 * \beta_2}{B_1 * \beta_2 + \gamma} \quad \text{(Eq. 4)}$$

C is the APG to oil ratio

B_1 is the regional APG to total gas ratio (Eq. 2)

β2 is the non-associated gas produced in the country[136] (EJ)

γ is the oil produced in the country1[33] (tons converted to exajoules (EJ[137]))

$$D = C \times \delta \quad \text{(Eq. 5)}$$

D is the APG emissions

C is the country-specific APG to oil ratio (as in Equation 4)

δ is the upstream oil emissions in the considered country[138] in $ktCH_4$

Step A. 3 – Estimating total upstream emissions

$$E = A + D \quad \text{(Eq. 6)}$$

E is the total upstream emissions in $ktCH_4$

A is the upstream non-associated gas emissions in $ktCH_4$ (calculated in Equation 2)

D is the associated gas emissions in $ktCH_4$ as in Equation 5

Step A. 4 – Estimating total upstream emission factor

232. Finally, the upstream emissions are divided by the volume of gas produced in billion cubic meters21 (bcm) to obtain the emission factor (Equation 8). Total volume of gas produced is the sum of non-associated gas produced (as provided by BP) and the volume of marketable associated gas produced (Equation 7).

$$\alpha_2 = \beta_2 * \frac{B_1}{1-B_1} \quad \text{(Eq. 7)}$$

α_2 is the associated gas produced in the considered country in bcm,

[132] Putting gas flaring in the spotlight – Analysis - IEA
[133] Statistical Review of World Energy | Energy economics | Home (bp.com)
[134] CL expertise based on Perupetro and a project made in Peru: B_1 = 3%
[135] U.S. Energy Information Administration - EIA - Independent Statistics and Analysis: B_1 = 16%
[136] Statistical Review of World Energy | Energy economics | Home (bp.com)
[137] 1 million tonne of oil = 0.000000041868: Definition of the word Tonnes of Oil Equivalent (toe) - Energy Glossary | Planète Énergies (planete-energies.com)
[138] The source depends on the country as in Table 6.

$$EF_{up} = \frac{E}{\beta_2 + \alpha_2} \quad \text{(Eq. 8)}$$

EF_{up} is the upstream emission factor

For countries where national data is the chosen source of information

Methodology for Norway

233. The latest National Inventory Report (UNFCCC, data for 2019) for Norway and the report from Norsk Olje og Gass[139] (data for 2020) rely on a very good monitoring and reporting system. Since the report from Norsk Olje og Gass[107] is more recent, it has been chosen as the main source for emission data.

234. In terms of the methodology applied for estimating total upstream emissions, Step A.1 to Step A.4 have been followed. The estimation of associated gas production (Step A.2, Equation 3) is unique in this case. There is ample data available on the production from the different wells in Norway. Data from the Norwegian Petroleum Directorate has been used to estimate the quantity of associate gas produced, compared to total gas produced in the country. In this case, it has been assumed that facilities producing less than 5 Mm3 of oil are gas wells. Rest of the gas production is associated gas. Equation 9 provides the calculation used for its estimation and replaces Equation 3.

$$B_2 = 1 - \frac{\eta_1}{\eta_2} \quad \text{(Eq. 9)}$$

B2 is the Norwegian APG to total gas ratio estimation

η1 is the non-associated gas produced in Norway (million m^3 oil equivalents)

η2 is the total natural gas produced in Norway[140] (million m^3 oil equivalents)

235. When methane emissions are linked to the oil and gas value chain, the gas emissions are estimated using the energy ratio[141] of oil & gas produced in the country (Equations 10 and 11).

$$G = \frac{\beta_2 + \alpha_2}{\beta_2 + \alpha_2 + \gamma} \quad \text{(Eq. 10)}$$

$$H = G \times \eta_3 \quad \text{(Eq. 11)}$$

G is the gas to oil ratio

η_3 is the total oil and gas emissions in the country ($ktCH_4$)

Methodology for Australia, Denmark, Italy, UK, Netherlands, Poland and Romania

236. The UNFCCC data[142] provides the emissions for the oil and gas sector in upstream and downstream sectors. The national inventory is based on Tier 2 or Tier 3 emission estimation, hence the chosen source of data. Step A.1 from the prior section is applied to estimate the upstream non-associated gas emissions[143].

237. If countries produce significant amounts of oil, upstream associated gas must be considered. This concerns Australia, Denmark, Italy, and the UK.

238. For associated gas production in Australia, there is limited data on country specific or regional estimation of marketable associated gas. The energy ratio was thus assumed to be similar to that of North American region (Table 7). The percentage calculated for B_1 is 18% (Equation 3). In the UK, Equation 3 is applied using

[139] 7.3.6 Utslipp av Metan (CH4) - NOROG Klima- og Miljørapport Portal (norskoljeoggass.no)
[140] Based on facilities' production, assuming that when the oil production of the facility is negligeable, we only have non-associated gas production: Historical production on the NCS - Norwegianpetroleum.no (norskpetroleum.no)
[141] Energy ratio is the ratio of derivable energy from the volume of gas produced to the derivable energy from the volume of oil produced
[142] Greenhouse Gas Inventory Data - Detailed data by Party (unfccc.int)
[143] UNFCCC categories considered for upstream emissions from non-associated gas: exploration (1.B.2.b.i), production (1.B.2.b.ii) and processing (1.B.2.b.iii).

country specific information from the Digest of UK Energy Statistics (DUKES)[144] instead of regional data. The percentage calculated for B_1 is 41% (Equation 3). B1 were applied in Equations 4 and 5 to estimate the upstream emissions from non-associated gas.

239. For associated gas production in Denmark and Italy, data from the Danish Energy Agency[145] (for Denmark) and the Ministero della transizione ecologica[146] (for Italy) have been used to estimate the quantity of associate gas produced, compared to total gas produced in the country. In this case, it has been assumed that gas produced in facilities producing both oil and gas is associated gas. Rest of the gas production is non-associated gas. Equation 12 provides the calculation used for its estimation and replaces Equation 3.

$$B_3 = \frac{\eta_4}{\eta_3 + \eta_4} \quad \text{(Eq. 12)}$$

B3 is the Danish and Italian APG to total gas ration estimate

η_3 is the non-associated natural gas produced in Denmark[145] or Italy[146] (in million m^3)

η_4 is the associated gas produced in Denmark[145] or Italy[146] (in million m^3)

240. Then, the percentage calculated for B3 is 60% for Denmark and 31% for Italy and replaces B_1 in Equations 4 and 5 to estimate the upstream emissions from non-associated gas. The remaining Steps A.2 and A.3 were performed to estimate the upstream emissions and emission factors in Australia, Denmark, Italy, Netherlands, Poland, Romania, and UK.

241. When methane emissions are linked to the oil and gas value chain, the gas emissions are estimated using the energy ratio[147] of oil & gas produced in the country (Equations 10 and 11).

For countries where academic papers are available with country-specific emissions data

Methodology for the USA

242. Over the past decades, there have been important independent academic work done to estimate methane emissions from Oil & Gas value chains in North America and in particular in the US (see table 11 in section 8.6 for the references). For this assessment, the study Alvarez et al. (2018) has been chosen as the main source of information for emissions in the US natural gas value chain. This study is the most recent in assessing the full country emissions and based on a significant number of measurements. It uses ground-based, facility-scale measurements and aircraft observation methods for estimating the emissions. One of the main areas with high methane emissions in the US is the Permian basin. Few academic research papers have been published since 2018, that assess methane emissions from this basin. The study by Zhang et al. (2020) has been used as the main source of information for methane emissions in the Permian basin. To have an accurate representation of emissions from the entire country, the values from Alvarez et al. (2018) have been adjusted, based on the Zhang et al. (2020).

243. Alvarez et al. (2018) is used as the basis to estimate the oil and gas emissions in 2015. Emissions from the largest basin (the Permian basin) have been removed from the estimate proportionally to the Permian production in 2015 (Equations 13 and 14).

$$J = \frac{\rho_1}{\rho_2} \quad \text{(Eq. 13)}$$

$$K = \chi * (1 - J) \quad \text{(Eq. 14)}$$

J is the percentage of the US emissions coming from the Permian in 2015

ρ_1 is the oil and gas methane emissions in the Permian basin in 2015 ($ktCH_4$)

ρ_2 is the oil and gas methane emissions in the US (including Permian basin) in 2015 ($ktCH_4$)

[144] DUKES_F.2.xls (live.com)
[145] Monthly and yearly production | Energistyrelsen (ens.dk), Excel downloaded: 1972-2021.xlsx (live.com)
[146] Produzione nazionale di idrocarburi (mise.gov.it)
[147] Energy ratio is the ratio of derivable energy from the volume of gas produced to the derivable energy from the volume of oil produced

K is the methane emissions in 2015 from Alvarez et al. (2018) ($ktCH_4$)

χ is the methane emissions in 2015 from Alvarez et al. (2018) ($ktCH_4$)

244. The remaining emissions have been projected from 2015 to 2018 (separately for oil and gas) (Equation 15) using the evolution of methane emissions between 2015 and 2018 (Equation 16, separately for oil and gas).

$$L = \mathrm{K} * (1 + \mathrm{M}) \quad \text{(Eq. 15)}$$

$$M = \frac{\theta(2018) - \theta(2015)}{\theta(2015)} \, x \, 100 \quad \text{(Eq. 16)}$$

L is the projection of US emissions without Permian Basin from 2015 to 2018

K is the estimated emissions from Alvarez et al. (2018) without Permian basin emissions in 2015 ($ktCH_4$) (Equation 14)

M is the evolution in methane emissions in the US oil and gas sector (%) (Equation 16)

Θ(i) is the methane emissions in the US for oil[148] and gas[149] separately, year I ($ktCH_4$)

245. A change in CH_4 emissions from 2015 to 2018 of -5.51% for gas and -1.34% for oil have been estimated.

246. Emissions from the Permian were added with Zhang et al. (2020) estimates (Equation 17).

$$U = \mathrm{L} + \rho_3 \quad \text{(Eq. 17)}$$

U is the US methane emissions

L is the projection of US emissions without Permian Basin from 2015 to 2018 (Equation 15)

ρ_3 is the oil[150] and gas[151] methane emissions in the Permian basin in 2018 ($ktCH_4$)

Step A.1 to Step A. 4 were followed to complete the emission factor estimation. Like Norway, Equation 3 is not necessary as US Environmental Protection Agency (EPA) provides a country specific APG to total gas ratio of 16%[152].

8.1.3 Estimation of downstream methane emissions

For countries where IEA (2019)[153] is the chosen source of information

Methodology for Algeria, Angola, Azerbaijan, Bahrain, Egypt, Iran, Iraq, Kuwait, Libya, Nigeria, Oman, Peru, Qatar, Russia, Saudi Arabia, Trinidad and Tobago, United Arab Emirates (UAE)

248. For the assessed exporting countries, only total downstream emission information is available. Downstream emissions consist of transmission and distribution emissions. For exporting countries, only transmission emissions are relevant for the total emission factor assessment (See figure 56 for the boundaries). To separate the distribution emissions, Tier 1 emission factor from IPCC (2019)[154] were used and adjusted[155] to estimate distribution emissions and thus evaluate transmission emission of the country.

<u>Step B. 1 – Estimating distribution emissions using adjusted Tier 1 emission factors</u>

[148] https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fwww.epa.gov%2Fsites%2Fdefault%2Ffiles%2F2020-02%2F2020_ghgi_petroleum_systems_annex35_tables.xlsx&wdOrigin=BROWSELINK
[149] https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fwww.epa.gov%2Fsites%2Fdefault%2Ffiles%2F2020-02%2F2020_ghgi_natural_gas_systems_annex36_tables.xlsx&wdOrigin=BROWSELINK
[150] Ibid
[151] Ibid
[152] https://www.eia.gov/todayinenergy/detail.php?id=41873 : B_1 = 16%
[153] https://www.iea.org/articles/methane-tracker-data-explorer : note that 2019 data has been used
[154] IPCC, 2019 refinement to the 2006 IPCC Guidelines for the national GHGI, Volume 2 https://www.ipcc-nggip.iges.or.jp/public/2019rf/vol2.html
[155] CL expertise

249. As a first approximation, Tier 1 emission factor[156] range for gas distribution has been considered. These emission factors were adjusted using Carbon Limits expertise to accurately reflect as best as possible the country's distribution infrastructure within the mathematical constraints of the equation (Distribution and transmission emission factor have to remain positive and in the range of the Tier 1 emission factor uncertainty when possible).

$$\lambda = \text{downstream emissions provided by IEA (2019)}^{157} \qquad \text{(Eq. 18)}$$

λ is the total downstream emissions

$$\mathrm{DT} = \xi * \mu \qquad \text{(Eq. 19)}$$

DT is the distribution emissions ($ktCH_4$)
ξ is the adjusted Tier 1 distribution emission factor[158] ($ktCH_4$/bcm)
μ is the gas consumed in the country[159] (bcm)

Step C. 2 – Estimating transmission emissions

$$\mathrm{T} = \lambda - \mathrm{DT} \qquad \text{(Eq. 20)}$$

T is the transmission emissions ($ktCH_4$)
DT is the distribution emissions ($ktCH_4$) (Equation 19)
λ is the total downstream emissions ($ktCH_4$) (Equation 18)

250. Finally, the transmission emissions are divided by the volume of gas transmitted in billion cubic meters (bcm) to obtain the emission factor (Equation 21). Total volume of gas transmitted is the sum of non-associated gas produced (as provided by BP (2021)), the volume of marketable associated gas produced (Equation 7) and total gas imported (via pipeline and LNG, as provided by BP (2021)).

$$EF_{trans} = \frac{T}{\beta_2 + \alpha_2 + \eta} \qquad \text{(Eq. 21)}$$

EF_{trans} is the transmission emission factor ($ktCH_4$/bcm)
T is the transmission emissions ($ktCH_4$) (Equation 20)
β_2 is the non-associated gas produced in the country (bcm)
α_2 is the associated gas produced in the country (bcm) (Equation 7)
η is the total gas imported[160] (bcm)

For countries where national data or data from academic papers are the chosen sources of information

Methodology for Australia, Denmark, Germany, Italy, Netherlands, Poland, Romania, and USA

$$T_{Australia,Denmark,Germany,Italy,Netherlands,Poland,Romania} = \mathrm{CS} \qquad \text{(Eq. 22)}$$

$$T_{Australia,Denmark,Germany,Italy,Netherlands,Poland,Romania} = \mathrm{AC} \qquad \text{(Eq. 23)}$$

Ti is the transmission emissions ($ktCH_4$) for country i
CS is country specific data, section 1.B.2.b.iv of UNFCCC (2019)[161]
AC is the transmission emissions ($ktCH_4$) from Alvarez et al. (2018) corrected with Zhang et al. (2020) (Equation 17)

[156] IPCC, 2019 refinement to the 2006 IPCC Guidelines for the national GHGI, Volume 2, Fugitive emissions, page 79: https://www.ipcc-nggip.iges.or.jp/public/2019rf/vol2.html
[157] https://www.iea.org/articles/methane-tracker-data-explorer : note that 2019 data has been used
[158] IPCC, 2019 refinement to the 2006 IPCC Guidelines for the national GHGI, Volume 2, Fugitive emissions, page 79: https://www.ipcc-nggip.iges.or.jp/public/2019rf/vol2.html
[159] https://www.bp.com/en/global/corporate/energy-economics/statistical-review-of-world-energy.html
[160] Ibid
[161] https://unfccc.int/process-and-meetings/transparency-and-reporting/greenhouse-gas-data/ghg-data-unfccc/ghg-data-from-unfccc

8.1.4 Estimation of LNG methane emissions

251. LNG related emissions include emissions from the LNG carrier (from country of production to the nearest port in Europe) and liquefaction. From Carbon Limits' previous work, LNG carrier is the predominant source of emissions for LNG, and this has been estimated with a Carbon Limits' internal model.

LNG Carrier

252. A model has been developed to assess the methane emissions from an LNG carrier. The LNG model is based on several scientific papers and developed in consultation with stakeholders in the maritime industry. The model used several assumptions (table 8). To estimate the travelling days from LNG exporting country to Europe (table 9), distance between the exporting region and Europe and the speed of the ship has been used. This model gives an emission factor for LNG Carrier. The estimates provided is by design quite generic and emissions from specific carriers may vary significantly

Table 8. Main assumptions considered in the LNG carrier model

Field	Value
Number of days – at sea	Region specific – see Table 4
Number of days – idle	2.0
Number of days – loading	2.0
Boil off rate	0.15% per day

Table 9. Number of days at sea by exporting region

Group of exporting countries	Number of days
North America: USA, Trinidad	8
South America: Peru	23
North Africa: Egypt, Algeria	4
West Africa: Nigeria, Angola	12
Australia	29
Russia	6
Norway	3
Qatar	17

LNG Liquefaction

253. There is very limited data on the liquefaction emissions. The average of 2019 emissions from all LNG liquefaction facilities where data was available was thus used as a proxy (Norway, the USA and Trinidad & Tobago – 7 facilities in total[162],[163],[164]) (Equation 24). For Norway, USA and Trinidad & Tobago, their country-specific facilities were used as a proxy.

$$N = \frac{\sum(Methane\ emissions)_{Liquefaction\ facilities\ with\ information}}{Total\ number\ of\ facilities\ with\ information} \quad \text{(Eq. 24)}$$

N is the LNG liquefaction methane emissions ($ktCH_4$)

[162] EPA Facility Level GHG Emissions Data
[163] https://www.equinor.com/energy/onshore-facilities
[164] https://atlanticlng.com/

8.1.5 Estimation of downstream and LNG related methane emissions for importing region of Europe

254. For the importing region of Europe, only downstream (transmission and distribution) emissions and LNG unloading, and regasification related emissions are relevant for the total emission factor assessment. For this region, an average emission factor for all European countries has been considered.[165]

Downstream emissions (transmission and distribution) within Europe (-8)[166]

255. The average downstream emission factor for all Europe (-8) has been calculated as the sum of transmission and distribution emissions using data from UNFCCC (2019) and activity data from BP (2021)[167].

$$EF_{Europe,trans} = \frac{\sum_i \sigma(i)}{\sum_i \omega(i) + \varphi(i)} \quad \text{(Eq. 25)}$$

$EF_{Europe,trans}$ is the transmission emission factor in Europe ($ktCH_4$/bcm)

σ(i) is the transmission methane emissions in the country i[168] ($ktCH_4$)

ω(i) is the volume of gas imported (LNG and pipelines) in the country i[169] (bcm)

φ(i) is the volume of gas produced in the country i[170] (bcm)

$$EF_{Europe,dist} = \frac{\sum_i \Phi(i)}{\sum_i \Omega(i)} \quad \text{(Eq. 26)}$$

$EF_{Europe,dist}$ is the distribution emission factor in Europe ($ktCH_4$/bcm)

Φ(i) is the distribution methane emissions in the country i[171] ($ktCH_4$)

Ω(i) is the consumption in the country i[172] (bcm)

LNG unloading and regasification

256. Assuming a proportional relationship between the LNG related emissions and LNG imported into the region, the regasification emission factor calculated by Marcogaz (2018)[173] has been used. Indeed, facing a lack of data about methane emission linked to LNG regasification, this industry paper which focused on the 21 large LNG import terminals in Europe has been used with a direct emission factor of 0.12 kt CH_4 per bcm of gas.

8.2 Calculation of methane emissions for *Harmonised Pledges* case

257. The *Harmonised Pledges* case considers country policies, Nationally Determined Contributions (NDC) relevant for greenhouse gases (GHG) emission reduction and international pledges, to assess the changes in emission factor from the preliminary year (2019) to 2050. The assumptions made in terms of converting the said policies and pledges to emission factor are summarized in table 1 (section 8.6).

8.2.1 Estimating upstream and downstream emissions

258. This section only concerns upstream and transmissions emissions. LNG related emission are considered in the next section. National policies or NDC aiming to reduce GHG emissions (see table 11) by a certain percentage by target year and international pledges have been considered to assess the changes in emission factors between 2019 and 2050. The international pledges considered are:

[165] An internal check was done to assess the difference between the average country-based emission factor in Europe, and the total European emission factor. The difference is within 8%
[166] Europe—8) is the countries in europe that do not produce significant amounts of natural gas. Therefore, it considers all the European countries, excluding Norway, the UK, Germany, Netherlands, Denmark, Romania, Italy and Poland.
[167] https://www.bp.com/en/global/corporate/energy-economics/statistical-review-of-world-energy.html
[168] https://unfccc.int/process-and-meetings/transparency-and-reporting/greenhouse-gas-data/ghg-data-unfccc/ghg-data-from-unfccc
[169] https://www.bp.com/en/global/corporate/energy-economics/statistical-review-of-world-energy.html
[170] https://www.bp.com/en/global/corporate/energy-economics/statistical-review-of-world-energy.html
[171] Ibid
[172] Ibid
[173] https://www.marcogaz.org/publications/survey-methane-emissions-for-lng-terminals-in-europe/

a. The "Zero Routine Flaring by 2030" initiative: introduced by the World Bank, commits to (a) not routinely flare gas in new oil field developments and (b) to end routine flaring in existing (legacy) fields as soon as possible no later than 2030. For this initiative, this target has been assumed to be either reached by 2030 (optimistic) or by 2040 (delayed goal).

b. The "Methane Pledge" initiative: participants joining the pledge agree to take voluntary actions to contribute to a collective emission factor fort to reduce global methane emissions at least 30 percent from 2020 levels by 2030. For this pledge, the 30% reduction in methane emissions has been assumed to be country level target. This target is assumed to be either reached by 2040 (optimistic) or 2050 (delayed goal)

c. The "Methane Alliance" initiative, participants joining have two options as possible targets
   i. Absolute reduction target of at least 45% reduction in methane emissions by 2025 and 60% to 75% by 2030.
   ii. Intensity target of "near-zero" methane emissions, targeting a methane emission intensity of 0.25% or below.
   In this case, either a methane intensity target of 0.25% is achieved by 2040 (optimistic) or a reduction target of 45% is achieved by 2050 (delayed goal).

259. Countries have been divided into four categories depending on their policies and participation in international pledges. Optimistic or delayed targets are set for each category of countries.

Category 1 countries: Countries with policy / NDC relevant for GHG emission reduction + international pledges

Countries in this category: Angola, Azerbaijan, Egypt, Italy, Iraq, Kuwait, Nigeria, Oman, Poland, Romania, Russia, Saudi Arabia, UAE, USA, Europe (-8)

260. The following steps are applied

a. Policy or NDC target is applied, by the target year

b. Zero routine flaring by 2030 is applied alongside the pledges and/or NDC targets

c. If both methane pledge and methane alliance pledges are signed, the optimistic target (Methane alliance) is implemented OR the target from the signed pledge is applied

Category 2 countries: Countries with policy / NDC relevant for GHG emission reduction & without any international pledges

Countries in this category: Algeria, Iran, Peru, Qatar, Trinidad & Tobago

261. The following steps are applied

a. Policy or NDC target is applied, by the target year

b. Emission factor is flat till 2050 from the year the target is achieved

Category 3 countries: Countries without policy / NDC relevant for GHG emission reduction & ONLY international pledges

Countries in this category: Bahrain

262. The following steps are applied

a. If 'Zero flaring by 2030' is signed, it is applied by 2040.

b. If BOTH methane pledge and methane alliance are signed, the lowest target is applied by 2050

c. If one of the pledges is signed, the target is applied by 2050

Category 4 countries: Countries with current emission factor lower than *BAT* emission factor

Countries in this category: Australia, Norway, Denmark, Germany, Netherlands, UK

263. EF remains flat from 2019 to 2050

8.2.2 Estimation of downstream and LNG related methane emissions for importing region of Europe

Downstream emissions (transmission and distribution) within Europe[174]

264. Country specific policies have not been directly considered for European countries but since GHG emissions reduction policies exist in European countries, adding to the fact that emission factor from the current emissions case is already lower than the emission factor reported by European industries in the North of Europe – (including Norway), the emission factor remains flat from 2019 to 2050.

8.3 Calculation of methane emissions for the Best Available Technology case

265. In the *BAT* case, the same methodology has been applied for estimating upstream emission factor and transmission emission factor in exporting countries.

8.3.1 Estimation of upstream and downstream methane emissions

For countries where IEA (2019)[175] is the main source of information used

Methodology for Algeria, Angola, Azerbaijan, Bahrain, Egypt, Iran, Iraq, Kuwait, Libya, Nigeria, Oman, Peru, Qatar, Russia, Saudi Arabia, Trinidad and Tobago, United Arab Emirates (UAE)

266. For estimating upstream and downstream emissions in exporting countries, two abatement options are considered.

Option 1: Use abatement values from IEA (2019)[176] and estimate emission reduction potential in 2030 and 2035, assuming that abatement options at no-net cost are achieved by 2030 and those with positive net-cost by 2035.

267. Estimating emission factor for option 1

a. IEA (2019) provides the abatement potential by abatement type or technology, differentiating those with a negative net cost and those with a positive one. When the abatement potential can be applied for both oil and gas upstream part, the gas to oil ratio (Equation 10) is used to estimate the potential abatement for gas; when the abatement potential is only relevant for oil, the APG to oil ratio (Equation 4) is used to estimate APG related emission abatement potential.

b. All the abatable emissions with negative net costs are subtracted from current emissions, for the year 2030, while the abatable emissions with positive abatement costs are subtracted from current emissions, for the year 2035. These emissions are divided by the activity data to obtain the emission factors.

Option 2: Use OGCI industry target for upstream methane emissions for all countries

[174] Not including European producing countries: Denmark, Germany, Italy, Netherlands, Poland, Romania, UK
[175] https://www.iea.org/articles/methane-tracker-data-explorer : note that 2019 data has been used
[176] https://www.iea.org/articles/methane-tracker-data-explorer : 2019 data has been used

268. Converting the *BAT* industry target into emission factor - The OGCI provides upstream methane intensity targets[177]: 0.25% by 2019, 0.20% by 2020, and well below 0.20% by 2025. In this option, this targeted emission factor achievable by the gas industries by 2019 and 2020 is assumed to be achieved by countries by 2030 and 2035 since emission factor calculated for 2019 were well above the 0.25% and 0.20% targeted emission factor. The industry targets of 0.25% and 0.20% have been converted from $ktCH_4$ emitted per $ktCH_4$ produced to $ktCH_4$ emitted per bcm of natural gas produced (EF).[178]

269. Selection of the emission factor between the two options - Once the two emission factors have been calculated, the higher of the two emission factors is chosen as the upstream emission factor for 2030 and 2035. Following this step, the target emission factor set by industries is applied by 2050. The emission factor between 2035 and 2050 have been interpolated to find the emission factor in 2040 and 2045.

For countries where academic papers are available with country-based emission data

Methodology for the USA

270. For USA, option 1 using abatement potential from IEA (2019) and option 2 using *BAT* industry target are compared. As USA has policies in place or under discussion for methane abatement, it is assumed the country can achieve the lowest emission factor target, hence the industry emission factor target is considered.

For countries where national data is the chosen source of information

Methodology for Denmark, Germany, Netherlands, Norway, UK, and Australia

271. For these countries, the emission factors are already below industry target. Hence, emission factors remain flat from 2019 until 2050.

Methodology for Italy, Poland, and Romania

272. First, the European target[179] of 29% reduction is applied by 2030, followed by applying OGCI target[180] of 0.25%[181] by 2030 and 0.20%[182] by 2040. The emission factor remains flat from 2040 to 2050.

8.3.2 Estimation of LNG methane emissions

LNG Carrier

273. For 2050, some changes have been made in the assumptions (table 10) used in the LNG carrier model developed by CL. emission factor from 2019 and 2050 are interpolated between the two values.

Table 10. Main assumptions for the LNG Carrier model.

Parameter	Change
Remaining BOG is	Reliquefied instead of sent to GCU
Engine load at sea loaded	90% instead of 80%
Engine load at sea ballast	60% instead of 40%
Boil off rate	already reduced according to new ship performances
Number of days idle	0 instead of 2
Share of BOG leaked	We trust them and assume 0% instead of 0.1%

[177] https://www.ogci.com/action-and-engagement/reducing-methane-emissions/
[178] For this conversion, 90% of pure methane in the natural gas produced and a methane density of 667 kt per bcm has been assumed.
[179] European Methane strategy: https://ec.europa.eu/energy/sites/ener/files/eu_methane_strategy.pdf
[180] https://www.ogci.com/action-and-engagement/reducing-methane-emissions/
[181] 0.25% corresponds to an emission factor of 1.50 $ktCH_4$/bcm
[182] 0.20% corresponds to an emission factor of 1.20 $ktCH_4$/bcm

8.4 Unit conversions applied to different models

274. The initial emission factors calculated were in $ktCH_4$ per bcm of gas produced. While this is the unit required for the HyPE model, the MIRET-EU model requires the units to be $ktCO_{2eq}$ per PJ of gas consumed in Europe. In order to make this conversion it is important to consider the losses along the gas value chain. 1 bcm of gas produced in exporting countries is not equal to 1 bcm of gas consumed in Europe, due to the leakages along the way. The following formulas were used for estimating losses (Equation 27) using emission factor and converting from bcm produced to PJ (Equation 28) consumed in Europe.

$$W = \frac{EF}{d*90\%} \quad \text{(Eq. 27)}$$

$$EF' = \frac{EF*(1+W)}{p} \quad \text{(Eq. 28)}$$

W is the wastage of methane from the production site to Europe

EF is the emission factor in $ktCH_4$ per bcm of gas produced. emission factor to be converted into kt CO_{2e} per PJ consumed in Europe.

d is the density of natural gas[183].

EF' is the emission factor in $ktCH_4$ per PJ of gas consumed in Europe.

p is the conversion factor from bcm of gas to PJ[184].

275. Then, all emission factors have been converted into kt CO_{2e} per PJ using Global Warming Potential of 20 years (GWP20 = 82.5)[185]

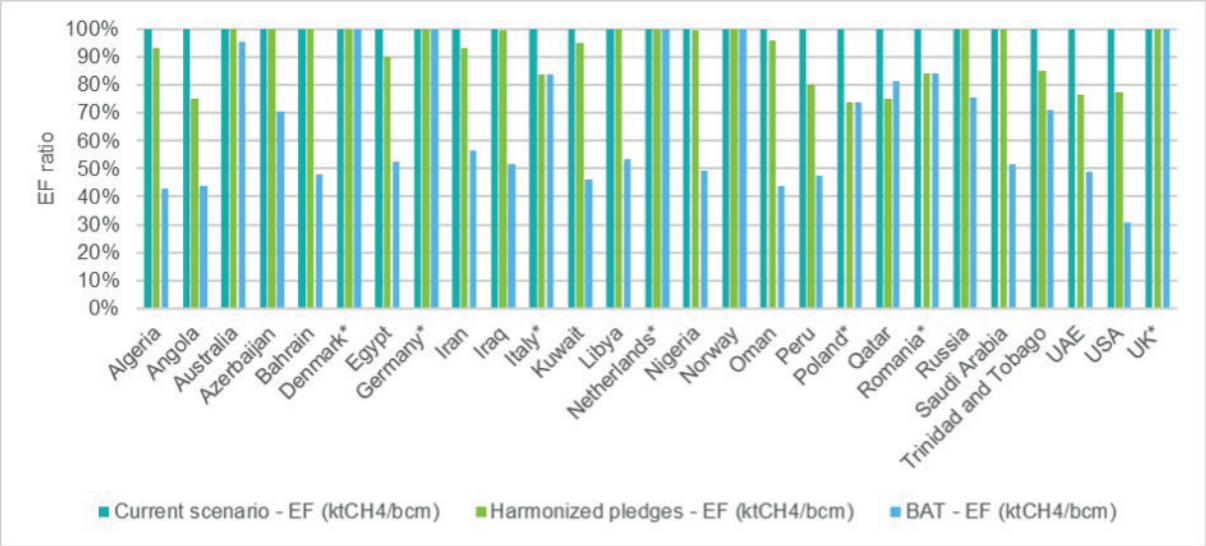
$$EF'' = 82.5 * EF' \quad \text{(Eq. 29)}$$

EF'' is the emission factor kt CO_{2e} per PJ consumed in Europe.

EF' is the emission factor in $ktCH_4$ per PJ of gas consumed in Europe.

8.5 Comparison of emission factors

Figure 58. Comparison of emission factors (upstream, transmission and distribution without including LNG) between three methane emission cases in 2030

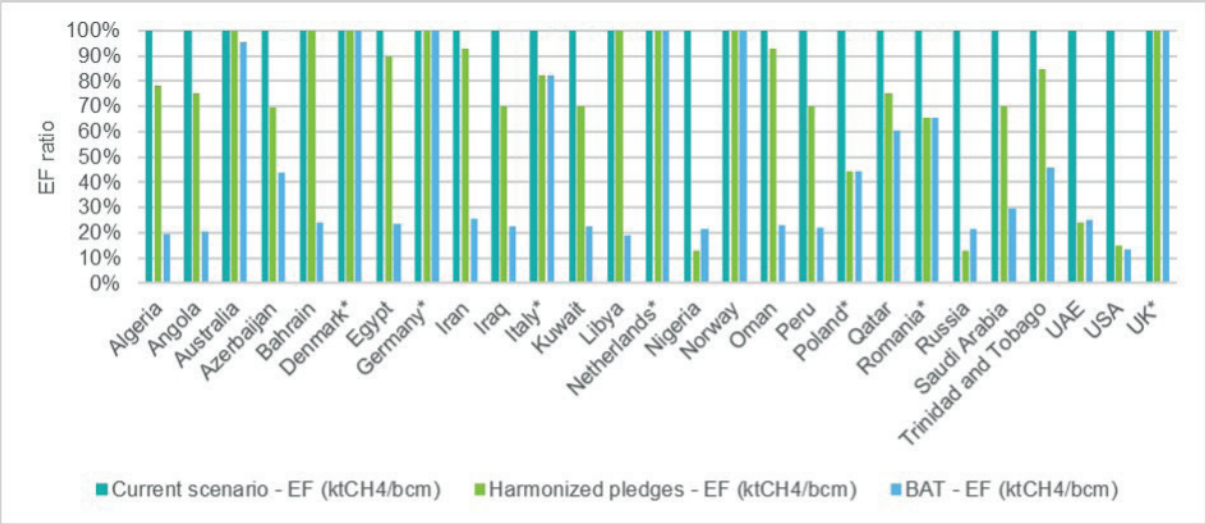


*Note: * refers to the emission factors that include distribution.*

Source: Hydrogen4EU

[183] https://cdm.unfccc.int/methodologies/inputsconsmeth/MGM_methane.pdf : 667 kt per bcm. 90% of the natural gas produced is assumed to be methane.
[184] https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/statistical-review/bp-stats-review-2021-approximate-conversion-factors.pdf : 36 PJ per bcm
[185] https://www.ipcc.ch/report/ar6/wg1/downloads/report/IPCC_AR6_WGI_Chapter_07.pdf

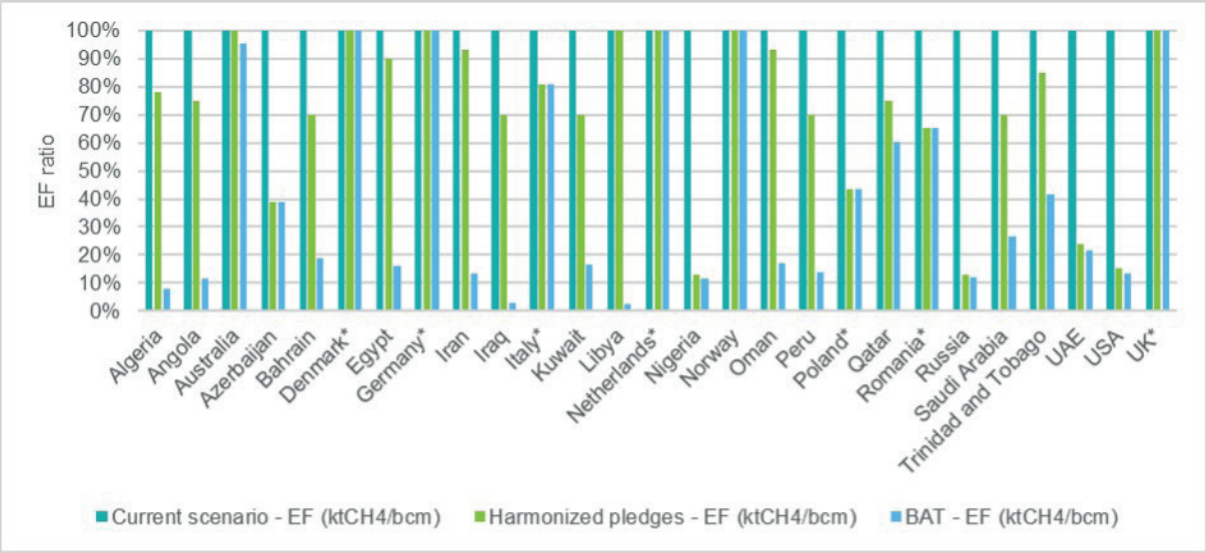
Figure 59. Comparison of emission factors (upstream, transmission and distribution without including LNG) between three methane emission cases in 2040



*Note: * refers to the emission factors that include distribution.*

Source: Hydrogen4EU

Figure 60. Comparison of emission factors (upstream, transmission and distribution without including LNG) between three methane emission cases in 2050



*Note: * refers to the emission factors that include distribution.*

Source: Hydrogen4EU

8.6 Supplementary tables on emission factors

Table 11. List of references estimating methane emissions in the US.

Authors	Institutions involved/ Affiliation of the authors	Title	Methodology
Zavala et al. (2015)	EDF, University of Colorado, NOAA, University of Michigan, University of Houston	Reconciling divergent estimates of oil and gas methane emissions	BU and TD
Alvarez et al. (2018)	EDF, University of Texas, Stanford University	Assessment of methane emissions from the U.S. oil and gas supply chain	
Plant et al. (2019)	University of Michigan, Harvard University, NOAA	Large Fugitive Methane Emissions from Urban Centers Along the U.S. East Coast	Aircraft observations
Zhang et al. (2020)	EDF, Harvard University	Quantifying methane emissions from the largest oil-producing basin in the United States from space	Satellite measurements, high-resolution satellite data-based atmospheric inversion framework: robust top-down analytical tool
Roberson et al. (2020)	University of Wyoming, EDF	New Mexico Permian Basin Measured Well Pad Methane Emissions Are a Factor of 5–9 Times Higher Than U.S. EPA Estimates	Mobile laboratory and inverse Gaussian dispersion method
Negron et al. (2020)	University of Michigan	Airborne Assessment of Methane Emissions from Offshore Platforms in the U.S. Gulf of Mexico	Aircraft measurements
Lu et al. (2021)	Harvard University, EDF, Sun Yat-sen University	Methane emissions in the United States, Canada, and Mexico: evaluation of national methane emission inventories and 2010–2017 sectoral trends by inverse analysis of in situ (GLOBALVIEWplus CH_4 ObsPack) and satellite (GOSAT) atmospheric observations	Inverse analysis of in situ and satellite atmospheric methane observations
Cui et al. (2019)	University of Colorado Boulder, NOAA	Inversion Estimates of Lognormally Distributed Methane Emission Rates from the Haynesville-Bossier Oil and Gas Production Region Using Airborne Measurements	Aircraft measurement, inversion calculations
Omara et al. (2018)	Carnegie Mellon University	Methane Emissions from Natural Gas Production Sites in the United States: Data Synthesis and National Estimate	
Sargent et al. (2021)	Harvard University, NOAA, Boston University	Majority of US urban natural gas emissions unaccounted for in inventories	Top-down study: high resolution transport model
MacKay et al. (2021)	St. Francis Xavier university	Methane emissions from upstream oil and gas production in Canada are underestimated	
Rutherford et al. (2021)	Standford University, Harrisburg University of Science and Technology, EDF…	Closing the methane gap in US oil and natural gas production emissions inventories	Explains why GHGI underestimates emissions
Luck et al. (2019)		Multi-day Measurements of Pneumatic Controller Emissions Reveal Frequency of Abnormal Emissions Behavior at Natural Gas Gathering Stations	

Table 12. International pledges and national policies considered in the *Harmonised Pledges* case.

Country	Type	Category	Target	Translation	Comment
Algeria	iNDC[186]	Category 2	Reduction of greenhouse gases emissions by 7% to 22%, by 2030, compared to a business as usual -BAU- scenario, conditional on external support in terms of finance, technology development and transfer, and capacity building. The 7% GHG reduction will be achieved with national means.	EF will reduce by 7% in 2030 EF will reduce by 22% in 2035	
Angola	NDC[187]	Category 1	Achieving 15% of emission reduction by 2025 unconditionally + reduce an additional 10% below BAU emission levels by 2025 conditionally	EF will reduce by 15% in 2025 compared to 2019 EF will reduce by 25% in 2030 compared to 2019 EF remains flat from 2030 to 2050	The Zero Routine flaring is included as per calculation, end zero routine flaring by 2030 will make emission factor fall within the 15% reduction set in the NDC target
Australia	Methane Alliance, Policies, NDC	Category 4	-	No change - current methane emission intensity is already lower than 0.25%. So, emission factor remains the same until 2050	
Azerbaijan	NDC[188]	Category 1	Oil and gas sector: By 2030: 35% reduction in the level of GHG emissions compared to 1990/base year. For O&G sector: new and modern environmental-friendly technologies (processing, production) in line with the EURO-5 standards, modernization gas pipelines and distribution system, ensure the volume of reduction in compliance with international standards by 2050.	Achieve *BAT* by 2050. 2030 emissions assumed to be same as 2019 emissions, followed by interpolated reduction in emission factor every five years.	Zero routine flaring by 2030[189]: assumed already implemented with NDC and industry targets
Bahrain	Zero routine flaring	Category 3	End routine flaring by 2030.	Remove flaring emissions from 2019, and reflect these changes for 2040, as Bahrain has no other policy or NDC specific to CH_4 or Oil & Gas	
Bahrain	Methane pledge	Category 3	Voluntary actions to contribute to a collective emission factor fort to reduce global methane emissions at least 30 percent from 2020 levels by 2030. This is a global, not a national reduction target	We assume all countries will reduce their methane emission intensity in the oil and gas sector by 30%. This has been applied for 2050, as Bahrain has no other policy or NDC specific to CH_4 or Oil & Gas	

[186] https://unfccc.int/sites/default/files/NDC/2022-06/Algeria%20-%20INDC%20%28English%20unofficial%20translation%29%20September%2003%2C2015.pdf
[187] https://unfccc.int/sites/default/files/NDC/2022-06/NDC%20Angola.pdf
[188] https://unfccc.int/NDCREG
[189] https://www.worldbank.org/en/programs/zero-routine-flaring-by-2030

Country	Type	Category	Target	Translation	Comment
Denmark	EU NDC, Methane pledge, Methane Alliance, Zero routine flaring	Category 1	EU NDC : same as EU (-8)	Upstream: Since Denmark has an emission factor already lower than the Methane Alliance target (which is optimistic) of 0.25%, emission factor remains flat from 2019 to 2050. Downstream: Since Romania's downstream emission factor is already lower than the Equinor's downstream emission factor (considered as the *BAT*), emission factor remains flat from 2019 to 2050	
Egypt	NDC[190]	Category 1	Reduce GHGs by 10% from the energy sector, including O&G, by 2030 compared to 2016 levels.	10% reduction in CH_4 emissions intensity by 2030, including zero flaring	Zero routine flaring by 2030: assumed already implemented with NDC
Germany	EU NDC, Methane pledge, Methane Alliance, Zero routine flaring	Category 1	EU NDC : same as EU (-8)	Upstream: Since Germany has an emission factor already lower than the Methane Alliance target (which is optimistic) of 0.25%, emission factor remains flat from 2019 to 2050. Downstream: Since Romania's downstream emission factor is already lower than the Equinor's downstream emission factor (considered as the *BAT*), emission factor remains flat from 2019 to 2050	
Iran	INDC[191]	Category 2	A recent review by Soltanieh et al. (2016) estimates that, apart from wasting valuable energy resources, flaring contributes between 7% and 10% of Iran's GHG emissions Nonetheless, achieving the zero-flaring target remains a priority for meeting emissions reduction goals.	Remove flaring emissions from 2019 to be reflected into 2030. If new emission factor is not 7% to 10% lower than current emission factor, apply further emissions reduction to achieve 7% to 10% emission factor reduction.	
Iraq	Methane pledge	Category 1	Voluntary actions to contribute to a collective emission factor fort to reduce global methane emissions at least 30 percent from 2020 levels by 2030. This is a global, not a national reduction target	We assume all countries will reduce their methane emission intensity in the oil and gas sector by 30%. This has been applied for 2040, as Iraq has NDC specific to CH_4 or Oil & Gas	Methane alliance: no changes, Carbon Limits expertise - Iraq has been assumed to achieve the lower of the 2 pledges signed. Zero routine flaring: no changes, already reflected in the NDC
Iraq	NDC[192]	Category 1	Reducing flaring at O&G facilities, methane venting and LDAR	Zero routine flaring	

[190] https://unfccc.int/sites/default/files/NDC/2022-06/Egyptian%20INDC.pdf
[191] https://www.ctc-n.org/sites/www.ctc-n.org/files/UNFCCC_docs/indc_iran_final_text.pdf
[192] https://unfccc.int/NDCREG

Country	Type	Category	Target	Translation	Comment
Italy	EU NDC, Methane pledge, Methane Alliance, Zero routine flaring	Category 1	EU NDC: Reduce methane emissions by 29% in 2030 compared to 2005 levels	Upstream: A 29% reduction is applied by 2030, compared to 2005. Since the resulting emission factor is lower than the target of the Methane Alliance, emission factor remains flat from 2030 to 2050. Downstream: Since the Methane Alliance does not provide a specific target for downstream emissions and that the *BAT* is reachable for Italy, *BAT* emission factor is applied from 2030 to 2050.	
Kuwait	Methane pledge	Category 1	Voluntary actions to contribute to a collective emission factor fort to reduce global methane emissions at least 30 percent from 2020 levels by 2030. This is a global, not a national reduction target	We assume all countries will reduce their methane emission intensity in the oil and gas sector by 30%. This has been applied for 2040, as Kuwait has policy or NDC specific to CH_4 or Oil & Gas	
Kuwait	NDC[193]	Category 1	Avoid emission of greenhouse gases equivalent to 7.4% of its total future emission on 2035 through its national emission factor forts.	7.4% reduction in emission factor intensity by 235	
Netherlands	EU NDC, Methane pledge, Methane Alliance, Zero routine flaring	Category 1	EU NDC: same as EU (-8)	Since Netherlands has an emission factor already lower than the Methane Alliance target (which is optimistic) of 0.25%, emission factor remains flat from 2019 to 2050.	
Nigeria	Methane Alliance	Category 1	Countries that join the Alliance commit to include methane reduction targets from the oil and gas sector in their Nationally Determined Contribution, as part of their overall greenhouse gas reduction targets. Absolute reduction target of at least 45% reduction in methane emissions by 2025 and 60% to 75% by 2030. These are realistic and achievable targets, especially in a sector where technology and financing are largely available, and innovation supports even larger reductions. Intensity target of “near-zero” methane emissions. Countries that select this approach should target an intensity of 0.25% or below.	Since Nigeria has specific NDC goal for CH_4 in Oil and Gas, 2040 target has been set at 0.25% emission by weight	Methane pledge: No changes - Since Nigeria has specific NDC goal for CH_4 in Oil and Gas, higher target from methane alliance has been considered as the target for 2050 Zero routine flaring by 2030: No Changes - Already reflected in the NDC
Nigeria	NDC[194]	Category 1	oil and gas emissions: end flaring by 2030, reduce fugitive methane emissions from oil and gas operations by 60% by 2031	No flaring in 2030 and 60% of fugitive by 2035 - assuming baseline is 2019	

[193] https://unfccc.int/sites/default/files/NDC/2022-06/Kuwait%20updating%20the%20first%20NDC-English.pdf
[194] https://unfccc.int/NDCREG

Country	Type	Category	Target	Translation	Comment
Norway	International Pledge, Policies, NDC	Category 4		No change - current methane emission intensity is already lower than 0.25%. So, emission factor remains the same until 2050	
Oman	NDC[195]	Category 1	Slow GHG emission growth and reduce them by 7% in 2030, compared to the Business-As-Usual (BAU) scenario, which is predicted at about 125.254 $MTCO_{2e}$. 4% of the GHG reduction commitment will be based on national emission factor forts, and the remaining 3% would necessitate grants and other forms of concessional financing and assistance with capacity building and institutional strengthening, and access to appropriate technologies. International climate finance is a crucial element for the Sultanate of Oman to further bend the GHG emission growth curve over the next decade.	4% reduction in emission factor is considered for 2030 (which includes zero flaring), and 7% for 2035.	Zero routine flaring: No Changes - applied as part of the NDC
Peru	INDC[196]	Category 2	The Peruvian INDC envisages a reduction of emissions equivalent to 30% in relation to the Greenhouse Gas (GHG) emissions of the projected business as Usual scenario (BaU) in 2030. The Peruvian State considers that a 20% reduction will be implemented through domestic investment and expenses, from public and private resources (non-conditional proposal), and the remaining 10% is subject to the availability of international financing1 and the existence of favourable conditions (conditional proposal).	20% in emission factor by 2030 and 30% by 2035 and flat after	
Poland	EU NDC, Methane pledge, Methane Alliance, Zero routine flaring	Category 1	EU NDC: Reduce methane emissions by 29% in 2030 compared to 2005 levels	Upstream: A 29% reduction is applied by 2030, compared to 2005. Then, the Methane Alliance's target of 0.25% is applied by 2040. emission factor remains flat from 2040 to 2050. Downstream: Since the Methane Alliance does not provide a specific target for downstream emissions and that the *BAT* is reachable for Poland, *BAT* emission factor is applied from 2030 to 2050.	

[195] https://unfccc.int/sites/default/files/NDC/2022-06/Second%20NDC%20Report%20Oman.pdf
[196] https://unfccc.int/sites/default/files/NDC/2022-06/Reporte%20de%20Actualizacio%CC%81n%20de%20las%20NDC%20del%20Peru%CC%81.pdf

Country	Type	Category	Target	Translation	Comment
Qatar	NDC[197]	Category 2	Qatar intends to reduce 25% of its GHG emissions by the year 2030, relative to baseline scenario {Business As-Usual (BAU)}.	reduce emission factor by 25% by 2030	
Romania	EU NDC, Methane pledge, Methane Alliance, Zero routine flaring	Category 1	EU NDC: Reduce methane emissions by 29% in 2030 compared to 2005 levels	Upstream: A 29% reduction is applied by 2030, compared to 2005. Then, the Methane Alliance's target of 0.25% is applied by 2040. emission factor remains flat from 2040 to 2050. Downstream: Since Romania's downstream emission factor is already lower than the Equinor's downstream emission factor (considered as the *BAT*), emission factor remains flat from 2019 to 2050	
Russia	Methane Alliance	Category 1	Countries that join the Alliance commit to include methane reduction targets from the oil and gas sector in their Nationally Determined Contribution, as part of their overall greenhouse gas reduction targets. Absolute reduction target of at least 45% reduction in methane emissions by 2025 and 60% to 75% by 2030. These are realistic and achievable targets, especially in a sector where technology and financing are largely available, and innovation supports even larger reductions. Intensity target of "near-zero" methane emissions. Countries that select this approach should target an intensity of 0.25% or below.	Since Russia has specific NDC goal for CH_4 in Oil and Gas, 2040 target has been set at 0.25% emission by weight	
Russia	Policy[198]	Category 1	Coefficient of efficient utilization of APG targeted to increase from 85.1% (2018) to 90% in 2024 and 95% in 2035	Before 2035, if APG use is going to increase from 85% to 95%, the emissions associated with flaring and venting emissions will reduce by 10% at least. Hence for 2035, 10% from the emissions is shifted to marketable gas produced	Zero routine flaring: No changes - applied as part of the policy Other policies: No Changes - Most important policy is the one about APG which has been taken into consideration NDC: No changes - too general

[197] https://unfccc.int/NDCREG
[198] https://www.iea.org/policies/14855-energy-strategy-of-the-russian-federation-for-the-period-up-to-2035

Country	Type	Category	Target	Translation	Comment
Saudi Arabia	NDC[199]	Category 1	Zero flaring in the oil and gas industry, recovery and subsequent utilization for power generation and petrochemicals production. The Kingdom as a member of the Global Methane Pledge initiative will collaborate with other members to reduce global methane emissions by 30% by 2030 relative to 2020 levels	Zero flaring applied by 2030, and 30% reduction applied by 2040	
Trinidad	NDC[200]	Category 2	Trinidad and Tobago's aim is to achieve a reduction objective in overall emissions from the three sectors by 15% by 2030 from BAU	Assuming 15% in methane reduction in oil and gas sectors - assuming 2019 as BAU	
UAE	Methane Alliance	Category 1	Countries that join the Alliance commit to include methane reduction targets from the oil and gas sector in their Nationally Determined Contribution, as part of their overall greenhouse gas reduction targets. Absolute reduction target of at least 45% reduction in methane emissions by 2025 and 60% to 75% by 2030. These are realistic and achievable targets, especially in a sector where technology and financing are largely available, and innovation supports even larger reductions. Intensity target of "near-zero" methane emissions. Countries that select this approach should target an intensity of 0.25% or below.	Since UAE has an NDC for GHG emission reduction. Hence the more ambitious target of 0,25% wt% has been applied for 2040.	
UAE	NDC[201]	Category 1	The UAE intends to reduce its greenhouse gas (GHG) emissions for the year 2030 by 23.5%, relative to the BAU scenario	EF for oil and gas sector reduces by 23.5% by 2030, compared to 2019	
UK	EU NDC, Methane pledge, Methane Alliance, Zero routine flaring	Category 1	EU NDC: same as EU (-8)	Since the UK has an emission factor already lower than the Methane Alliance target (which is optimistic) of 0.25%, emission factor remains flat from 2019 to 2050.	

[199] https://unfccc.int/sites/default/files/resource/202203111154---KSA%20NDC%202021.pdf
[200] https://unfccc.int/sites/default/files/NDC/2022-06/Trinidad%20and%20Tobago%20Final%20INDC.pdf
[201] https://unfccc.int/sites/default/files/NDC/2022-06/UAE%20Second%20NDC%20-%20UNFCCC%20Submission%20-%20English%20-%20FINAL.pdf

Country	Type	Category	Target	Translation	Comment
USA	Methane Alliance	Category 1	Countries that join the Alliance commit to include methane reduction targets from the oil and gas sector in their Nationally Determined Contribution, as part of their overall greenhouse gas reduction targets. Absolute reduction target of at least 45% reduction in methane emissions by 2025 and 60% to 75% by 2030. These are realistic and achievable targets, especially in a sector where technology and financing are largely available, and innovation supports even larger reductions. Intensity target of "near-zero" methane emissions. Countries that select this approach should target an intensity of 0.25% or below.	Since USA has specific policy for CH_4 in Oil and Gas, 2040 target has been set at 0,25% emission by weight	
USA	Policy	Category 1	Oil and Gas Industry Methane Emissions: overall the proposed requirements would reduce emissions from covered sources, equipment, and operations by approximately 75%. Those reductions would total 41 million cumulative tons of methane between 2023 and 2035, the equivalent of 920 million metric tons of CO_2. Next year, PHMSA will also be proposing a Methane Leak Detection Repair Rule that would establish standards for leak detection technologies and practices and require repair of all leaks. PHMSA estimates that these amendments would reduce methane emissions by 294,269 to 832,467 metric tons of CO_{2e} each year, depending on the assumed leakage rates for cast iron and plastic distribution pipelines.	Take the estimated emission reduction over 12 years and convert it to annual reduction. Estimate that for until 2035. 2040 Emission will be 0,25%	
EU (-8)	Policy/NDC[202]	Category 1	Reduce methane emissions by 29% in 2030 compared to 2005 levels	Since EU (-8) has already a downstream emission factor below the Equinor's methane intensity (which is considered as *BAT* for European countries), EU(-8) emission factor follows the *BAT* curve (remains flat from 2019 to 2050)	
EU (-8)	Methane pledge + methane alliance	Category 1	EU is a part of both	Since EU (-8) has a proper methane abatement strategy, we assume it will apply *BAT* subsequently from 2030. Hence 2035 to 2050, EU (-8) emission factor follows the *BAT* curve (remains flat from 2019 to 2050)	

[202] https://ec.europa.eu/energy/sites/ener/files/eu_methane_strategy.pdf

9 Annex D: Main assumptions and scenarios

276. The modelling framework requires big series of assumptions, set and varied by scenarios to produce the required outputs for the analysis. The scenarios are set up such as to provide meaningful insights to the research questions. Hence, they must be carefully chosen to span different transition pathways to provide a suitable basis for the analysis. The baseline assumptions are pre-defined and introduced as parameters to the modelling framework rather than being calculated as variables. These are thus an important part of the context of the study.

9.1 Baseline assumptions

277. Macroeconomic parameters, commodity prices and energy demand projections are the baseline assumptions that don't vary among scenarios and cases. To this end:
- Main macroeconomic drivers (population growth and GDP) have been collected from the JRC assumptions under the EU Reference 2016 scenario.
- Oil, natural gas and coal prices are based upon the trajectories of the EU Reference scenario 2016 as considered by the JRC in their energy models. However, an update was made based on 2022 prices to take into account the effect of Russia-Ukraine conflict[203]. The research centres have compared this EU reference 2016 scenario of the JRC to the different IEA scenarios' baseline assumptions: the retained trajectory is the 2021 prices and the ICE oil future prices and natural gas TTF future prices for the 2022-2025 period, and from 2030 on, stabilisation on the Stated Policies (STEPS) scenarios of the IEA World Energy Outlook, 2021 (WEO, 2021). The coal prices are kept unchanged as natural gas and oil prices are the most variable and dependant ones to the imports.
- The future energy demand projections are extracted from the JRC-EU-TIMES database in order to consider an identical and unique public European database within the consortium. The sectorial (industry, residential and tertiary buildings, and transports) demand assumptions are based on data from JRC-POTEnCIA central scenario (2019). The demand of the energy intensive industrial sectors is defined in the model through production amount while the non-energy intensive sectors have their demand represented in energy terms. Residential and tertiary Buildings sectors have their demands characterized in energy terms by use, i.e., space and water heating, lighting and electric devices, cooling and cooking/catering. The transport sector has its demands represented by passengers and freight activities (road transports, rail/metro/tram, and aviation). It is worth mentioning that these data still do not take into account the possible demand-side changes induced from Ukraine-Russia conflict, which might result in the reduction of the European industrial production and a drop in its energy demand, as well as will bring changes in the energy demand of the residential and service sectors, and in the transport activity, notably by faster electrification and efficiency improvements.

Table 13 and table 14 together with figure 61 present details of the baseline assumptions.

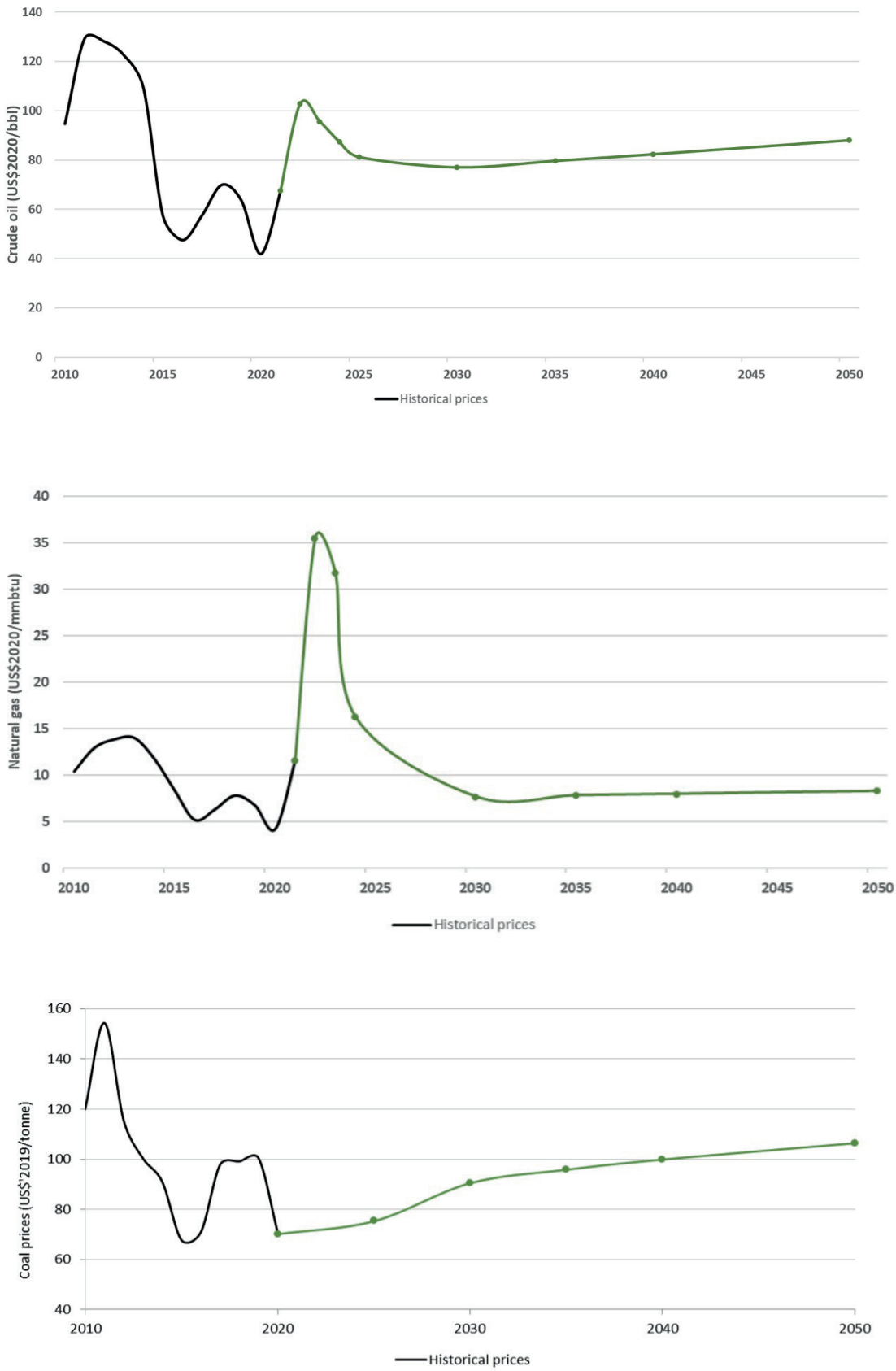
Table 13. Macroeconomic data and energy commodity prices evolution

	Scenario	Period					
		2020-2025	2025-2030	2030-2035	2035-2040	2040-2045	2045-2050
Population average annual growth rate	**EU Reference 2016**	0.10%	0.10%	0.10%	0.10%	0,10%	0.10%
GDP average annual growth rate	**JRC POTEnCIA 2019**	1.43%	1.28%	1.26%	1.34%	1.48%	1.54%
Fuel prices average annual growth rate	**Crude Oil**	18.57%	-1%	0.5%	0.75%	0.76%	1.45%
	Coal	1.42%	3.72%	1.15%	0.83%	0.00%	1.27%
	Natural Gas	29%	-12%	0.4%	0.4%	0.4%	0.4%

Source: JRC-EU-TIMES, JRC POTEnCIA 2019, Authors

[203] Modification is applied based on the future oil and gas contracts that are presented further in this Section.

Figure 61. Evolution of crude oil, natural gas and coal prices



Source: Adapted from JRC POTEnCIA 2019 (EU Reference 2016)

Table 14. Demand projections

Sectors		Year						
		2020	2025	2030	2035	2040	2045	2050
Industry								
Energy intensive sectors production (Mton)	Iron and Steel	180.0	181.1	180.4	179.3	178.7	178.1	177.5
	Cement	186.5	190.4	194.1	197.4	200.7	204.1	201.0
	Pulp and paper	112.5	119.5	123.7	125.6	126.6	128.3	130.8
	Ammonia	16.0	16.3	16.5	16.7	16.8	16.9	17.1
	Chlorine	10.3	10.5	10.6	10.6	10.7	10.8	10.9
	Pulp & paper	112.5	119.5	123.7	125.6	126.6	128.3	130.8
	Lime	28.2	29.7	31.1	32.3	33.5	34.5	35.4
	Glass	37.2	37.7	37.7	37.7	37.6	36.8	35.2
	Copper	0.25	0.24	0.26	0.26	0.26	0.26	0.27
	Aluminium	7.5	7.6	7.8	7.9	7.9	7.9	7.9
Non-energy intensive sectors energy demand (PJ)	Other Non-Ferrous Metals	354.3	357.9	367.6	370.8	375.0	378.7	382.0
	Other Non-metallic mineral products	622.6	658.6	693.7	723.0	753.6	779.6	803.1
	Other Chemicals	2 110.6	2 236.8	2 363.9	2 496.4	2 639.8	2 777.1	2 915.3
	Other industrial sectors	3 900.0	4 102.2	4 314.6	4 545.4	4 793.3	5 044.1	5 308.1
Agriculture								
Energy service demand (PJ)	Energy demand	1 164.5	1 170.8	1 174.8	1 179.1	1 183.4	1 185.8	1 188.1
Residential and Services								
Number of households (000units)	Number of households	184 554	188 401	192 329	196 338	200 431	204 609	208 875
Services surface evolution (Mm2)	Services surface	6 638.6	6 788.4	6 941.5	7 098.2	7 258.3	7 422.1	7 589.6
Electric appliances (Million Appliances)	Residential electric appliances	4 995.1	5 102.9	5 212.8	5 312.9	5419.1	5524.3	5633.9
	Services electric appliances	150 321	158 730	167 553	174 018	180839	187598	194540
Transport								
Passenger transport activity (1000 mio pkm)	Road transport	7 012.9	7 280.9	7 565.7	7 800.5	8 013.0	8 212.6	8 383.0
	Rail, metro and tram	626.2	682.9	733.5	782.5	834.2	882.0	929.7
	Aviation	1 786.0	1 982.7	2 184.5	2 380.8	2 598.4	2 781.4	2 961.0
Freight transport activity (1000 mio tkm)	Road transport	3 285.2	3 502.9	3 710.5	3 865.8	4 009.1	4 125.5	4 219.6
	Rail transport	515.6	566.8	614.6	653.2	696.2	727.6	755.8
	Aviation	45.5	50.2	54.9	59.5	64.9	69.7	74.3

Source: JRC-EU-TIMES

9.2 Technology-related assumptions

278. The models are built upon comprehensive datasets containing both economic and technical performance data for all technologies as well as the limitations related to the maximal potential of certain energy supply sources and carriers such as biomass, available area for solar and wind power. The datasets are built from renowned databases and data sources such as the European Commission's joint research centre (JRC), the International Energy Agency (IEA), IRENA, BP and the World Energy Council.

279. The inventories of the existing and future technologies are based on JRC data catalogue (IDEES 2018, POTEnCIA 2019, JRC-EU-TIMES (2012, 2019), ENSPRESO 2019, BREFs reports…), IEA data catalogue (IEA 2019b, IEA MoMo model, ETP 2017, etc.), IRENA (2018), de Vita et al. (2018), ENTRANZE database, KanoRs database (Pan-European TIMES PET36), IFPEN data catalogue (CEDIGAZ, and RafGen model), ETSAP community database and specialized literature.

280. The reference scenario presented by the ENSPRESO database is applied as a restriction of the potential for solar and wind. The biomass potential is constrained to the coherent business as usual reference scenario of ENSPRESO.

281. All assumptions related to regional fossil fuel reserves and trade capacities are implemented along with the regional renewable energy potentials (World Energy Council, BP Statistics, IRENA, ENSPRESO 2019, US Geological Survey, TYNDP - ENTSOG 2020 and ENTSOE 2016 - and specialized literature). The general sources of data for the power sector are the National Renewable Energy Laboratory (NREL), PLATTS database, IRENA, IEA's World Energy Outlook and specialized literature.

282. The hydrogen production technology data has been consolidated within the *Hydrogen for Europe* study in collaboration with project stakeholders. The main sources are the H21 North of England report (2018), Blanco et al. (2018a), Blanco et al. (2018b), Sgobbi et al. (2016), Bolat et al. (2014a), Bolat et al. (2014b), Schmidt et al. (2017), NREL Technical report (2009), Parkinson et al. (2018) and Keini et al. (2018). The applied datasets are summarized in table 25 and table 26.

283. The data types and their sources are summarised in table 15.

Table 15. Data sources – Energy system

Data	Sources
Inventories of existing and future technologies	JRC data catalogue (IDEES 2018, POTEnCIA 2019, JRC-EU-TIMES (2012, 2019), ENSPRESO 2019, BREFs reports,…), IEA data catalogue (IEA 2019b, IEA MoMo model, ETP 2017,..), IRENA (2018), de Vita et al. (2018), ENTRANZE database, KanoRs database (Pan-European TIMES PET36), IFPEN data catalogue (CEDIGAZ and RafGen model), ETSAP community database and specialized literature
Fossil fuel reserves and trade capacities	World Energy Council, BP Statistics, US Geological Survey, TYNDP (ENTSOG 2020, ENTSOE 2016) and specialized literature
Power generation	National Renewable Energy Laboratory (NREL), PLATTS database, IRENA, IEA's World Energy Outlook and specialized literature, POTEnCIA 2019, de Vita et al. (2018), ENSPRESO 2019, IRENA
Hydrogen production technologies	H21 North of England report (2018), Blanco et al. (2018a), Blanco et al. (2018b), Sgobbi et al. (2016), Bolat et al. (2014a), Bolat et al. (2014b), Schmidt et al. (2017), NREL Technical report (2009), Parkinson et al. (2018), Keini et al. (2018).

284. In addition to the more general technical assumptions outlined above, three special technically related constraints have been implemented. These are related to amount of variable renewable energy in the power sector, to the deployment of CO_2 storage and to deployment rate of heat pumps in the residential sector.

- To ensure the reliability of the power grid in each country considered in the study, a restriction of minimum 20% back-up capacity from dispatchable sources for the electricity production within each country is applied.
- The available injection rates for CO_2 to permanent storage, measured in tonnes per year, has been restricted to 1.0 Gt per year from 2020 to 2040, 1.2 Gt per year in 2045 and 1.4 Gt per year in 2050. The restriction is set based upon the assessment of Ringrose and Meckel (2019) and is in the lower end of the future CO_2 storage capacity estimations. This potential is included in the aspiration to establish a technology-neutral framework for the energy system analysis.
- The potential of heat pump deployment has been implemented following the latest assumptions from the JRC heat pump analysis. Their techno-economic characteristics have been provided by the JRC database for residential and commercial services

Box 10. Energy accounting in the *Hydrogen for Europe* study

To comply with standard energy statistics, the study defines and calculates final energy consumption and gross final energy consumption as follows:

- Final energy consumption includes the final energy consumed by end-use sectors (industry, transport, …) and ambient heat from heat pumps. It excludes international aviation and maritime bunkers.
- Gross final energy consumption includes final energy consumption, international aviation (according to Eurostat methodology[204]), and energy losses and self-consumption in electricity and heat distribution. It still excludes maritime bunkers.

Unless otherwise mentioned, most of the results in this subsection relate to gross final energy consumption.

9.3 Policy assumptions

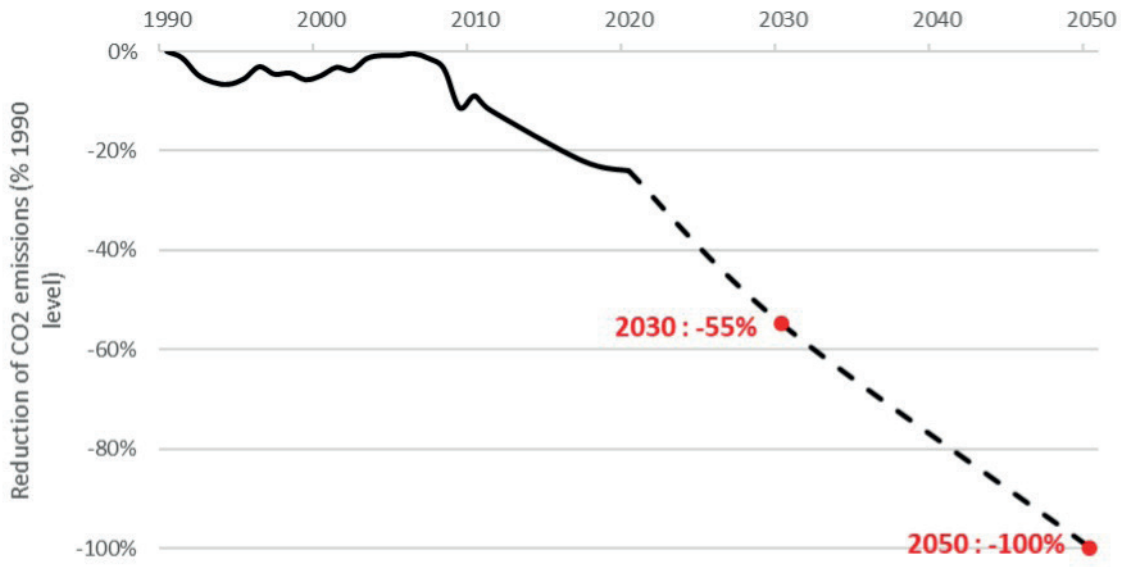
285. The modelling exercise follows stylised assumptions and an idealised representation of the future. Therefore, the scenarios depicted in the study are not an attempt to forecast the actual development of the European energy system. The modelling framework is nevertheless aligned with the agenda of the European Green Deal, and EU pillars and climate targets, incorporating the main targets for CO_2 emission reductions, share of renewable energy deployment, energy efficiency, and national decisions on the phasing out of coal and nuclear plants for power generation, among others. The following sections outlines the policies implemented in the MIRET-EU model.

9.3.1 Overall EU CO_2 emission targets

286. Under the EU's climate-neutrality target by 2050, the modelling exercise follows a 100% CO_2 emission reduction (compared to 1990 level) pathway by 2050 including the methane emissions in the form of CO_{2eq} at the European level, i.e. a collective constraint[205]. The intermediate emission target of 55% reduction by 2030 has also been implemented as it has been set as minimum binding legislation to achieve the transformation towards a low-carbon energy system. In 2020, to align with the goals of the European Green Deal, the Commission has raised the EU target to a 55% reduction in 2030. This study's emission cap constraint assumes a minimum reduction of 24% by 2020 (in line with the latest figures), and 55% by 2030 (in line with the European Green Deal and Fit-for-55) and of 100% by 2050 for CO_2 emissions (figure 62), and a 41% emission reductions compared to 2020 levels and a net-zero 2050 target for natural gas associated methane emissions (figure 63).

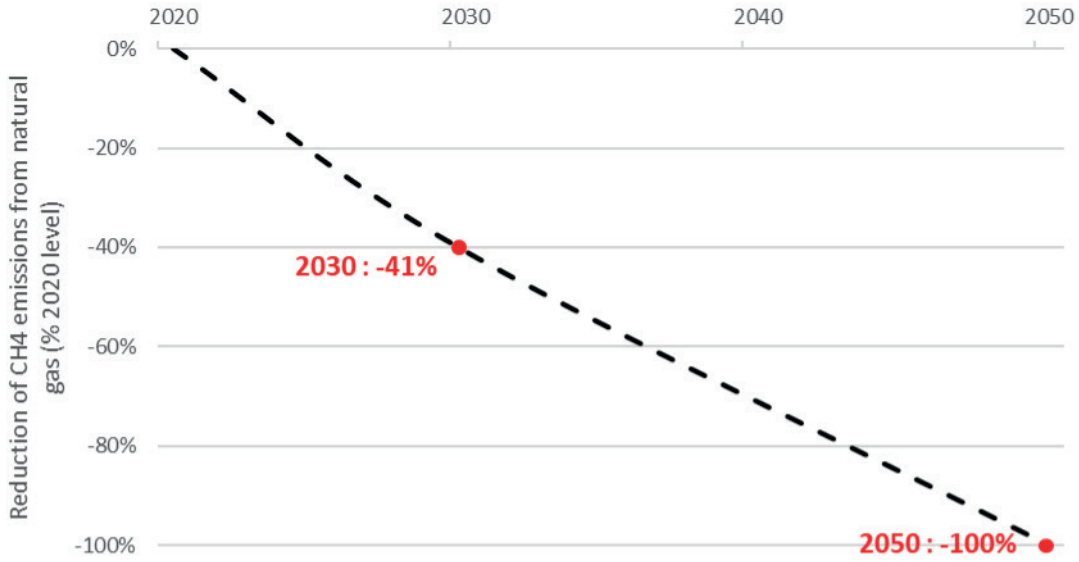
[204] http://ec.europa.eu/eurostat/documents/29567/3217334/Aviation+Reference+Manual+%28version+14%29/e2d532c6-a54a-465a-95e0-f62b76e7da4c
[205] The target should be achieved collectively across the EU.

Figure 62. CO_2 emission trajectory through to 2050



Source: Hydrogen4EU

Figure 63. CH_4 emission trajectory through to 2050



Source: Hydrogen 4EU

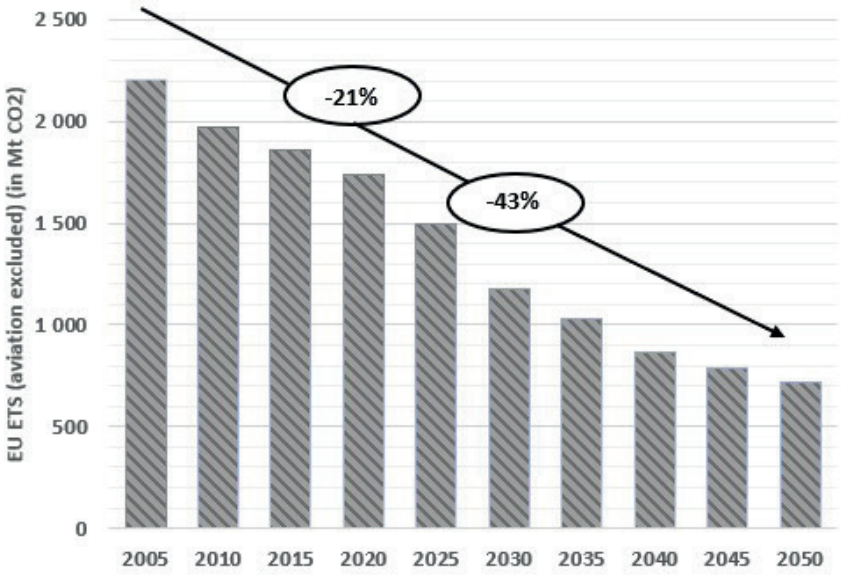
The sectors covered by the EU ETS

287. The EU emissions trading system (EU ETS) is currently the key Europe-wide enabler of European greenhouse gas emission reduction in a cost-effective way. As the world's first major carbon market, EU ETS remains the biggest carbon market globally. The system covers the following sectors and gases, focusing on emissions that can be measured, reported and verified with a high level of accuracy:
- Power and heat generation
- Energy-intensive industrial sectors including petroleum refineries, steel, aluminium, metals, cement, lime, glass, ceramics, pulp and paper, cardboard, acids and bulk organic chemicals
- Commercial aviation

288. Moreover, the Fit-for-55 package includes a proposition to expand the EU ETS to the maritime and aviation sectors, as well as creation of parallel ETS for the consumption of fossil fuels in the buildings and transport sectors[206]. Although no European law has been voted yet, this proposal's adaptation seems highly probable, starting from 2025 on, therefore, the study doesn't take this proposal into account.

289. Under the Directive 2009/29/EC of the European Parliament and of the Council amending Directive 2003/87/EC, and the Directive (EU) 2018/410 of the European Parliament and of the Council of 14 March 2018 amending Directive 2003/87/EC, emissions from the EU ETS sectors should be reduced by 21% in 2020 compared to the 2005 levels (including aviation), while it should achieve 43% reduction in 2030. In the MIRET-EU model, the EU ETS is only encompassing the emissions from power and heat generation and the industries, while the aviation has been excluded. This assumption has been considered in order to implement the data assumptions of the EU ETS emission limits from the JRC-EU-TIMES. Indeed, the Joint Research Centre of the European Commission has worked on EU ETS emission reduction trajectory beyond 2030, i.e. until 2050 (Figure 64).

Figure 64. Evolution of the CO_2 emissions covered by the EU ETS (aviation excluded) until 2050



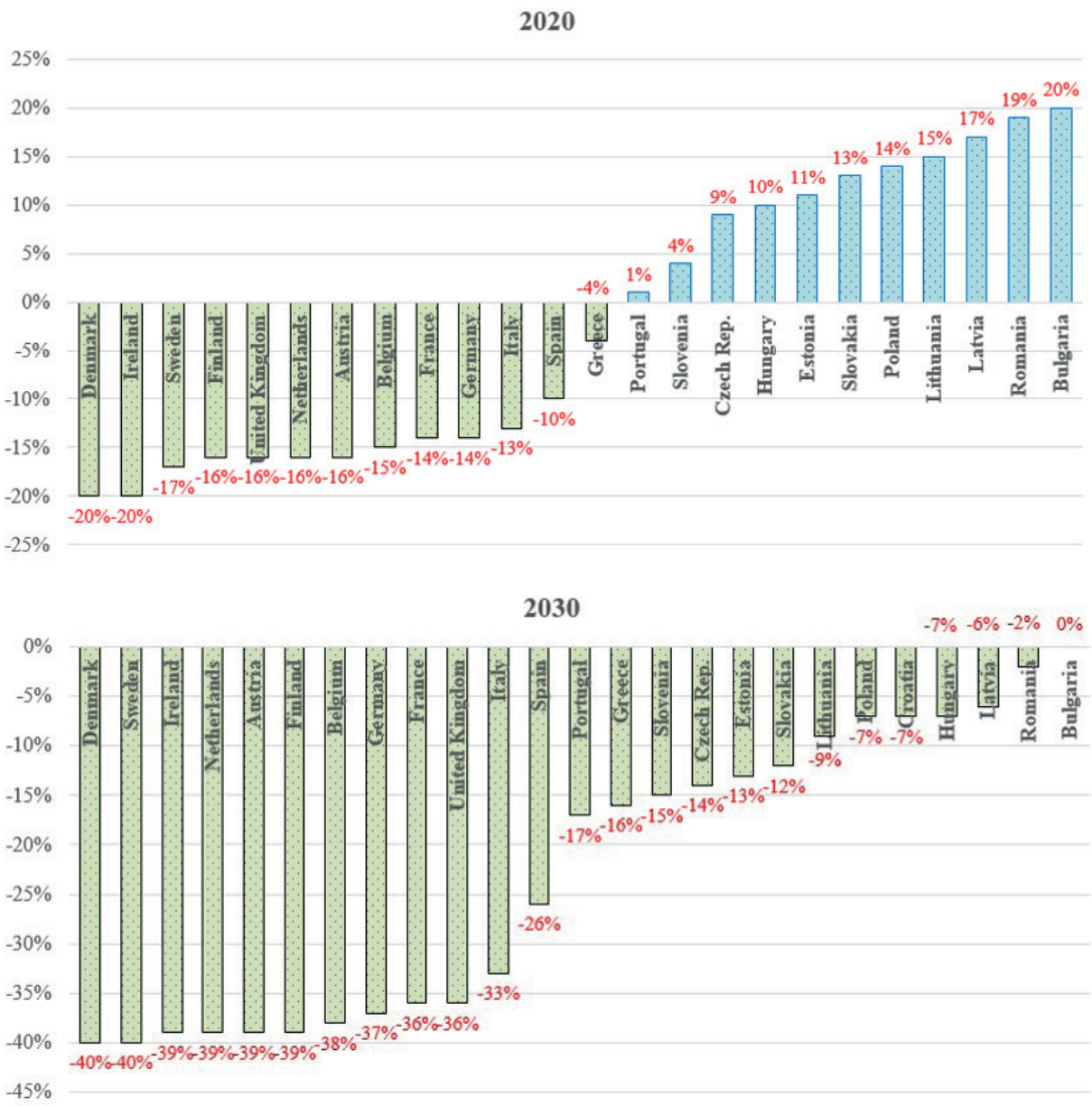
Source : JRC-EU-TIMES

Non-EU ETS sectors

290. The Effort Sharing Regulation (ESR) defines legally binding national GHG emission targets in 2020 and in 2030 compared to 2005 for sectors not covered by the EU ETS excluding LULUCF, such as transport, buildings, agriculture. The national targets for 2020 are ranging between -20% (for the richest Member States) and +20% (for the less wealthy Member States) compared to 2005 levels to collectively achieve a reduction of 10% in total EU emissions (Decision No. 406/2009/EC). While for 2030 they will range between 0% and -40% compared with 2005 levels to achieve collectively 30% reduction of the total EU emissions of the non-EU ETS sectors (Regulation (EU) 2018/842) (see figure 65).

[206] https://ec.europa.eu/info/sites/default/files/revision-eu-ets_with-annex_en_0.pdf

Figure 65. Evolution of non-EU ETS emissions (aviation excluded) targets for 2020 and 2030



Source: Decision No 406/2009/EC; Regulation (EU) 2018/842

9.3.2 Cross sectoral energy efficiency targets

291. The second series of comprehensive measures by the European Commission concern energy efficiency measures and targets. The 2012 Energy Efficiency Directive (2012/27/EU)[207] aims to achieve an energy efficiency of 20% in 2020 for the European Union. In addition, a new target of achieving achieve at least 32.5% of energy efficiency by 2030 has been set in the new amending Directive on Energy Efficiency (2018/2002)[208]. This objective thus corresponds to a primary energy consumption not exceeding 1 128 Mtoe (million tonnes of oil equivalent), or no more than 846 Mtoe of final energy consumption for the European Union in 2030[209].

[207] https://ec.europa.eu/energy/topics/energy-efficiency/targets-directive-and-rules/energy-efficiency-directive_en
[208] https://ec.europa.eu/energy/topics/energy-efficiency/targets-directive-and-rules/energy-efficiency-directive_en#content-heading-0
[209] Without the withdrawal of the UK these figures correspond to 1273 Mtoe (million tonnes of oil equivalent) of primary energy with no more than 956 Mtoe of final energy.

9.3.3 Energy efficiency targeting the transport sector

292. The Regulation (EC) 443/2009 set mandatory emission reduction targets for new cars. The first target fully applied from 2015 onwards and a new target phased-in in 2020 and applied from 2021 onwards. Following a phase-in from 2012 on, a target of 130 grams of CO_2 per kilometre applied to the EU fleet-wide average emission of new passenger cars between 2015 and 2019 is in place.

293. A new target was enacted in 2020, and stipulates that from 2021 onwards the EU fleet-wide average emission target for new cars shall not exceed 95 gCO_2/km.

294. On 17 April 2019, the European Parliament and the Council adopted the Regulation (EU) 2019/631 setting CO_2 emission performance standards for new passenger cars and for new vans in the EU. This Regulation started applying on 1 January 2020, replacing and repealing Regulations (EC) 443/2009 (cars) and (EU) 510/2011 (vans). The new Regulation maintains the targets for 2020, which were set out in the former Regulations. It adds new targets that apply from 2025 and 2030.

295. Regulation (EU) 2019/631 sets new EU fleet-wide CO_2 emission targets for the years 2025 and 2030, both for newly registered passenger cars and for newly registered vans.

296. These targets are defined as a percentage reduction from the 2021 starting points:
- 15% reduction from 2025 (which is equivalent to 80.75 grams of CO_2 per kilometre applied for the EU fleet-wide average emission of new passenger cars between 2025 and 2029)
- 37.5% reduction from 2030 (around 60 grams of CO_2 per kilometre applied for the EU fleet-wide average emission of new passenger cars from 2030)

9.3.4 Targets on final energy consumption: The Renewable Energy Directives (RED I and RED II) and the NECPs

297. The European Union Directive 2009/28/EC establishes binding renewable energy targets for each Member State for 2020 to collectively achieve at least the share of renewables of 20% in their gross final energy consumption by 2020. The Member States have also adopted binding national targets (Annex I of the 2009/28/EC Directive) for raising the share of renewables in their energy consumption by 2020.

298. European Union Directive 2009/28/EC establishes binding renewable energy targets for each member state for 2020 that collectively amount to a share of renewables of 20% in the total gross final energy consumption by 2020. The currently binding target for 2030 of 32% was legally set in 2018 by renewable energy directive 2018/2001/EU, with a clause for a possible upwards revision by 2023[210]. Under the new Governance regulation (EU/2018/1999), EU member states have submitted their draft NECPs national contributions that are sufficient for the collective achievement of the Union's 2030 target. As part of the Fit-for-55 package, the EC has proposed in July 2021 an increase of the target to 40% in its proposed revision of the RED II directive. The recently released REPowerEU plan now proposes an even higher upward revision to 45%. Given the overarching importance of this target and the confidence on the increase to at least 40%, the modelling considers as binding target a share of renewable energy of 40% in the Technology Diversification pathway and 45% in the Renewable Push pathway.

[210] The original target of 27% has been revised upwards.

Table 16. National overall targets for the minimum share of energy from renewable sources in gross final consumption of energy in 2020

Target	Countries	2020	NECP 2030
Share of energy from renewable sources in gross final consumption of energy	Belgium	13 %	10.5%[211] / 17.5%[25]
	Bulgaria	16 %	27 %
	Czech Republic	13 %	22 %
	Denmark	30 %	55 %
	Germany	18 %	30 %
	Croatia	28.6 %	36.4 %
	Estonia	25 %	42 %
	Ireland	16 %	32 %
	Greece	18 %	31 %
	Spain	20 %	42 %
	France	23 %	33 %
	Italy	17 %	30 %
	Latvia	40 %	50 %
	Lithuania	23 %	45 %
	Hungary	13 %	21 %
	Netherlands	14 %	27 %
	Austria	34 %	45%[28] / 50%[29]
	Poland	15 %	21% / 23%[212]
	Portugal	31 %	47 %
	Romania	24 %	30.7 %
	Slovenia	25 %	27 %
	Slovak Republic	14 %	19.2 %
	Finland	38 %	51%[213] / 54%[214]
	Sweden	58.2 %	66.5 %
	United Kingdom	15 %	
	EU28	20 %	32 %

Source: Final NECPs[215]

299. The RED I and II set targets for renewable energy consumption, including sub-targets of final energy consumption shares of the transport sector to be renewable. All EU countries must also ensure that at least 10% of their transport fuels (road and rail) come from renewable sources by 2020 according to the renewable energy directive (2009/28/EC) RED I. It has been established at 14% by 2030 in the RED II (2018/2001/EU) and would be increased until 2050.

300. The maximum contribution of biofuels produced from food and feed crops (1st generation biofuel) should be under the cap of 7% for road and rail transport in each member state from 2020 onwards.

[211] With existing measures (WEM)
[212] The 23% objective would be achievable if Poland is granted additional EU funds, including those allocated for equitable transformation
[213] Minimum level
[214] With additional measures (WAM)
[215] https://ec.europa.eu/energy/topics/energy-strategy/national-energy-climate-plans_en

301. Additionally, the contribution of advanced biofuels and biogas (2nd generation biofuels) should be at least 0.2 % in 2022, at least 1 % in 2025 and at least 3.5 % in 2030 of the final consumption of energy in the transport sector.

9.4 Scenarios and cases

9.4.1 Technology development scenarios

302. In coherence with the 2021 edition, the *Hydrogen for Europe* study describes two scenarios denoted as the "Technology Diversification" and "Renewable Push" pathways. The first pathway is designed to provide insights on an inclusive approach to energy transition, that considers a wide range of decarbonisation technologies and aims at achieving a cost-efficient transformation of the European energy system by 2050. The second pathway examines the conditions and implications of an increased focus on renewable energy, reflecting the current policy preferences in Europe.

The Technology Diversification pathway

303. The Technology Diversification pathway assumes a perfect market where the European energy technology transition is underpinned by the European climate law in combination with already approved national targets as well as the overarching objectives for renewable energy share and energy efficiency. The markets are characterised by perfect foresight, meaning that investment decisions are made in each period with full knowledge of future developments. Further, deployment of technologies needed for decarbonisation of the energy system occurs at the time of demand without any delays. As such, the pathway allows to assess how a wide range of technologies, including for renewable and low-carbon hydrogen production, can be leveraged to transform the energy system at the least cost.

The Renewable Push pathway

304. Using the same starting point with respect to currently implemented policies, policy announcements and overarching objectives, the Renewable Push pathway is set up to assess the conditions and implications of a framework oriented more clearly toward investments in renewable energies, especially wind and solar. This is implemented in the form of a series of targets on the share of renewables in gross final energy consumption, which is more ambitious for 2030 compared to today's policy (45% versus 40% in the Technology Diversification pathway, reflecting the proposed increase in the REPowerEU plan) and includes binding targets for 2040 (at 60%) and 2050 (at 80%). This scenario also analyses the energy system under perfect foresight.

Methane emission cases

305. Methane emissions along the gas value chain were assessed for three cases, for over 30 countries between 2019 and 2050, estimating over 150 emission factors overall. Emission factors were assessed for (1) countries exporting gas to Europe via pipeline (2) countries shipping LNG to Europe (3) countries exporting low-carbon hydrogen to Europe (4) European gas producing countries and (5) European countries importing gas or LNG from other countries. The assessment was carried out for three different cases, accounting for different sets of assumptions regarding emission mitigation policies and roll-out of abatement technologies in the assessed countries. Their comparison allows to assess the importance of methane emission mitigation strategies on the available decarbonisation pathways and on window of opportunity for natural gas. As a first step in the methane emission assessment, current emission factors have been estimated to track the current state of the methane emissions for natural gas and its derivatives depending on its origins. Later, these emission factors have been used in combination to abatement technology development and mitigation policy assumptions to derive the future level of emissions in the Best available technology case (*BAT*), *Current Emissions* and *Harmonised Pledges* cases:

a. The *BAT* case (Best Available Technology) considers a net-zero paradigm where the oil & gas industry pursues all necessary efforts to deploy best available technologies and rapidly reduce methane emissions along the whole natural gas value chain (production, transport, distribution and consumption). This is the central case used for the study's two pathways in the main results. It represents a future in which the oil & gas industry proactively implements the most effective mitigation solutions.

b. The *Current Emissions* case maintains the status quo in terms of methane emission mitigation. Emission factors associated with each step of the value chain and each producing region remain at current levels due to lack of action by policy or industry stakeholders. This case allows to look at the implications on the role of natural gas in Europe if no concrete action is taken to mitigate methane emissions.

c. The *Harmonised Pledges* case represents an intermediate stage, where some concrete actions start happening to tackle methane emissions but without reaching the ambitions of the *BAT* case. It assumes that currently announced policies, NDCs and other pledges are implemented. For example, NDC targets are considered as the reference policies to be implemented for European countries. They include the current European non-CO_2 greenhouse gas emission policies[216] (EU methane emissions to be reduced by 29% by 2030 compared to 2005 levels). The signed international pledges or policies were applied as a percentage reduction by target year, compared to 2019 as the reference year. The emission factors are considered flat after the pledge or policy is implemented.

[216] https://unfccc.int/sites/default/files/NDC/2022-06/EU_NDC_Submission_December%202020.pdf

10 Annex E: Model documentation

10.1 Description of the MIRET-EU model

306. MIRET-EU is a multiregional and inter-temporal partial equilibrium model of the European energy system developed by IFPEN, based on the TIMES[217] model generator. A complete description of the TIMES model equations appears in the ETSAP[218] documentation. It is a bottom-up techno-economic model that estimates the energy dynamics by minimizing the total discounted cost of the system over the selected multi-period time horizon through powerful linear programming optimizers. The components of the system cost are expressed on an annual basis while the constraints and investment variables are linked to a period. Special care is taken to precisely track cash flows related to process investments and dismantling for each year of the horizon. The total cost is an aggregation of the total net present value of the stream of annual costs for each of the countries modelled. It constitutes the objective function (Eq. 1) to be minimized by the model in its equilibrium computation. A detailed description of the objective function equation is provided in Part II of the TIMES documentation (Loulou et al., 2016). We limit our description to giving general indications on the annual cost elements contained in the objective function:

- Investment costs incurred for processes;
- Fixed and variable annual costs,
- Costs incurred for exogenous imports and revenues from exogenous exports;
- Delivery costs for required commodities consumed by processes;
- Taxes and subsidies associated with commodity flows and process activities or investments;

$$NPV = \sum_{r=1}^{R} \sum_{y \in YEARS} (1 + d_{r,y})^{REFYR-y} * ANNCOST(r,y) \qquad \text{(Eq. 1)}$$

NPV is the net present value of the total cost for all regions (the objective function);

ANNCOST(r,y) is the total annual cost in region r and year y (more details in section 6.2 of PART II (Loulou et al., 2016)

$d_{r,y}$ is the general discount rate;

REFYR is the reference year for discounting;

YEARS is the set of years for which there are costs, including all years in the horizon, plus past years (before the initial period) if costs have been defined for past investments, plus a number of years after end of horizon (EOH) where some investment and dismantling costs are still being incurred, as well as Salvage Value; and

R is the set of regions/countries in the area of study.

307. The detailed energy system model (MIRET-EU) represents the European energy system divided into 27 European countries, including 24 EU member states and 3 Non-EU member states (see figure 55). Each country has its own energy system with its main demand sectors. Moreover, each country can trade petroleum products, electricity, natural gas, hydrogen and CO_2 captured. Thus, the model fully describes within each country all existing and future technologies, from supply (primary resources), through the different conversion steps, up to end-use demands. It is set up to explore the development of its energy system from 2010 through to 2050 with 10-year steps and is calibrated on the latest data provided by energy statistics databases such as the JRC-IDEES[219] POTEnCIA[220], EUROSTAT, and other international databases from IEA, IRENA and World Bank, among others.

[217] MIRET has been based on the TIMES model generator, developed by one of the IEA implementing agreements (ETSAP) in 1997 as a successor of the former generators MARKAL and emission factorOM with new features for understanding and greater flexibility. The manuals and a complete description of the TIMES model appear in ETSAP documentation (https://iea-etsap.org/index.php/documentation)

[218] Energy Technology Systems Analysis Program. Created in 1976, it is one of the longest running Technology collaboration Programme of the International Energy Agency (IEA). https://iea-etsap.org/index.php/documentation

[219] JRC-IDEES (Integrated Database of the European Energy System) has been released in July 2018 and is revised periodically. We then used the latest data released in September 2019.

[220] POTEnCIA (Policy-Oriented Tool for Energy and Climate change Impact Assessment)

308. MIRET-EU considers four seasons (spring, summer, autumn, winter) which are disaggregated into day, night and peak resolution[221]. Every year is therefore divided in twelve time-slices that represent an average of day, night and peak demand for each season of the year (e.g. summer day, summer night and summer peak, etc.).

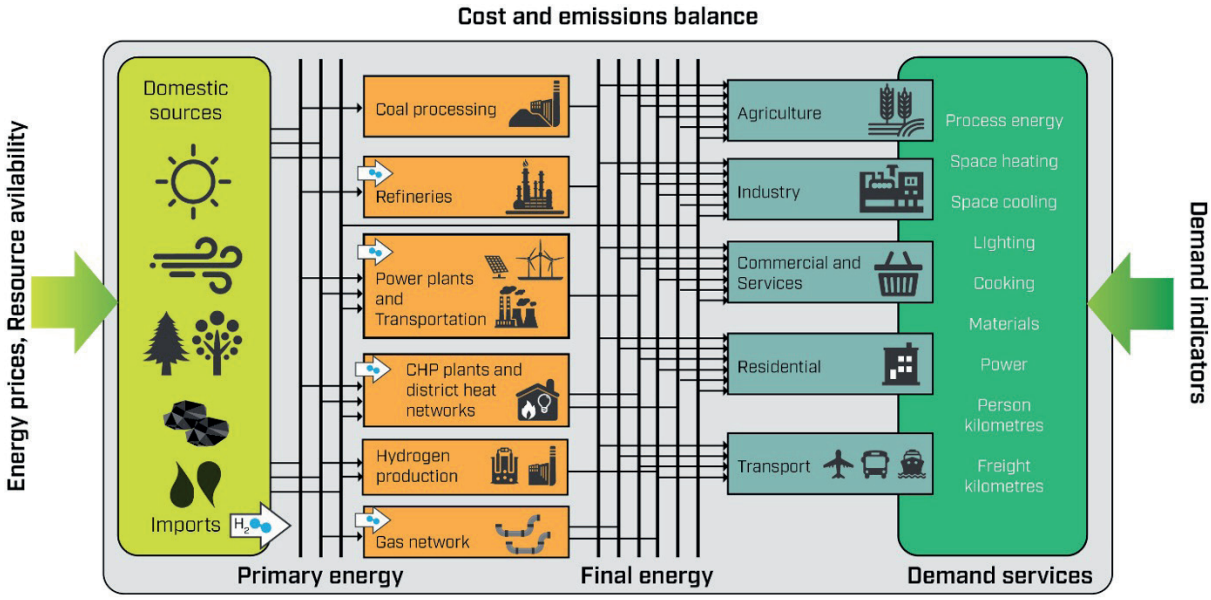
309. The MIRET-EU model is data driven[222], its parameterisation refers to technology characteristics, resource data, projections of demand for energy services, policy measures, among other. This means that the model varies according to the data inputs while providing results such as technology pathways or changes in trade flows for policy recommendations. For each country, the model includes detailed descriptions of numerous technologies, logically interrelated in a Reference Energy System – the chain of processes that transform, transport, distribute and convert energy into services from primary resources and raw materials to the energy services needed by end-use sectors.

310. A few models have already been developed at European scale using the TIMES model over the last 15 years. The Pan-European TIMES (PET) model has been developed by the Kanlo team following a series of European Commission (EC) funded projects (NEEDS[223], RES2020[224], REACCESS[225], REALISEGRID[226], COMET[227], Irish-TIMES[228]) between 2004 and 2010. It represents the energy system of 36 European regions. The JRC-EU-TIMES model is one of the models currently pursued and developed in the Joint Research Centre (JRC) of the European Commission under the auspices of the JRC Modelling Taskforce. The JRC-EU-TIMES model was developed as an evolution of the Pan European TIMES (PET) model of the RES2020 project, followed up within the REALISEGRID and REACCESS European research projects. The detailed residential, services and hydrogen modules and database of the JRC-EU-TIMES have been incorporated with additional modifications to MIRET-EU. Therefore, the modelling framework of MIRET-EU follows the same framework developed successively in the PET36, the JRC-EU-TIMES, MIRET-FR[229] and TIAM-IFPEN[230] models with additional expertise from IFP Energies Nouvelles in specific sectors such as transport, refineries and bioenergy conversion technologies, hydrogen infrastructure, power sector and industry.

311. MIRET-EU encompasses all stages from primary resources through the chain of processes that transform, transport, distribute and convert energy into the supply of energy services demanded by energy consumers. On the energy supply side, it comprises fuel production, primary and secondary energy sources, and imports and exports. Through various energy carriers, energy is supplied to the demand side, which is structured into residential, commercial, agricultural, transport and industrial sectors (see figure 66).

[221] It follows the same time slice disaggregation as in the world multiregional model TIAM-IFPEN.
[222] Data in this context refers to parameter assumptions, technology characteristics, projections of energy service demands, etc. It does not refer to historical data series
[223] http://www.needs-project.org/
[224] http://www.cres.gr/res2020
[225] http://reaccess.epu.ntua.gr/
[226] http://realisegrid.rse-web.it/
[227] The final aim of the modelling tasks in the COMET research project is the evaluation of different possible developments of CCS using a hard-link approach of TIMES-Morocco, TIMES-Portugal, TIMES-Spain, and TIMES-CCS. http://rdgroups.ciemat.es/documents/10907/86733/Comet_12Dec.pdf/b29424d6-1287-4644-9192-c2994daef02e
[228] https://www.epa.ie/pubs/reports/research/climate/Irish%20TIMES%20Energy%20Systems%20Model.PDF
[229] MIRET-FR is the version developed for France by IFPEN since 12 years
[230] TiAM-IFPEN (TIMES Integrated Assessment Model) is the world version currently developed by IFPEN since 3 years.

Figure 66. Partial view of the Reference Energy System with its interdependencies in MIRET-EU model



Source: Remme and Mäkela (2001)

312. The reference energy economy is thus composed (from left to right) of:

- **A primary energy supply block**, which includes:
  - Imported primary energy sources (uranium, crude oil, coal, natural gas);
  - Biomass which has been disaggregated into four types of commodity groups in order to better take into account the competition between their consumption in biofuels production (1st and 2nd generation), hydrogen production, power sector, industry, residential and commercial. These groups are derived from the JRC database ENSPRESO (Energy System Potentials for Renewable Energy Sources) related to bioenergy potentials for EU and neighbouring countries (Ruiz et al., 2019). Agriculture, forestry and waste are the main sectors providing biogenic resources for energy production following the ENSPRESO database. The biomass resources have been disaggregated into sugar beet, starch, rape-seed and lignocellulosic potentials, municipal waste and industrial waste-sludge potentials, and also biogas potentials provided by dry and wet manure coming from cattle. In addition to the resource potentials, the related supply costs have also been provided in ENSPRESO in order to determine the systemic impact of biomass, together with other system-related variables, such as carbon price (Ruiz et al., 2019);
  - Imported raw materials for industry sectors.

- **An energy technology block**, whose technologies transform primary energy into energy vectors and energy services. It includes:
  - The electricity generation (all power plants from fossil-based to renewable energy sources, CHP);
  - Oil refining and biofuel units are modelled based on IFPEN's approach and recognized expertise in the field of refineries and biofuels. The production chain is divided into feedstock pre-processing, production processes, and blending (Blending of diesel B7, B10), gasoline SP95 grades E5, E10 and E85, and jet fuels):
    - First generation biofuel production is subdivided into four sources: ethanol production from sugar beet and starch feedstock's, the trans-esterification and hydro-treatment of crushed oilseeds into FAME (Fatty Acid Methyl Esters) and HVO (Hydro treated Vegetable Oils), respectively;
    - Second generation production is subdivided into two sources: ethanol and synthetic FT-Diesel from lignocellulosic feedstocks.
  - The end-use technologies related to agriculture, industry, transport, residential and services (see below for more sectorial details).

- **A final energy / energy services demand block** such as industrial demands, space and water heating demands, mobility demands in the transport sector, trades (oil products, electricity, hydrogen, CO_2 captured), etc.
- **A policy block** which includes measures and constraints of several types affecting all sectors. Some are of microscopic nature, such as quality norms for refinery products, the number of functioning hours of fuel turbines, power plants, etc. Some are macroscopic in nature, e.g. global emission constraints or sectoral restrictions.

10.1.1 Strengths and weaknesses of MIRET-EU related to the goals of the study

313. MIRET-EU is an economic model with a rich technology representation for estimating capacity investment pathways over the long term. It combines two different, but complementary, systematic approaches to energy system modelling: a technical engineering approach and an economic approach. TIMES uses linear-programming to produce a least-cost energy system, optimized across regions and sectors according to a number of user constraints, over medium to long-term time horizons. This unique objective function guarantees the internal consistency of the resulting scenario, as the decision criteria are the same for all processes and flows. These types of models are effective for assessing long-term investment decisions in complex systems where future technologies are different from current technologies.

314. The TIMES model assumes perfect foresight over the entire horizon, i.e. all investment decisions are made in each period with full knowledge of future events. This technology-detailed model provides insights to decision-makers regarding energy systems in order to determine which technologies are competitive, marginal or uncompetitive in each market according to dynamic economic cost-benefit analyses. In short, MIRET is used for the exploration of possible energy futures based on contrasted scenarios.

315. As a partial equilibrium model, MIRET-EU does not model economic interactions outside the European energy sector. As stated by Gielen and Taylor (2007), this type of model, based on the TIMES generator, has the following advantages:
    - The model is based on a single objective cost criterion.
    - A detailed technology-rich modelling paradigm from primary resources to end-uses.
    - Stock turnover is considered explicitly.
    - Provide options to decision makers regarding energy systems over medium to long-term time horizons
        - Economically affordable
        - Technically feasible
        - Environmentally sustainable
    - The model is well suited to the development of Energy Roadmaps by making explicit the representation of technologies and fuels in all sectors in order to anticipate achievable futures based on actual knowledge. This is relevant for investment decisions in complex systems with differences between existing and future technologies.
    - The model optimizes operation and investment decisions based on the characteristics of alternative generation technologies, energy supply economics, and environmental criteria. TIMES is thus a vertically integrated model of the entire extended energy system.
    - The modelling uses exogenous cost data, rather than inclusion of the trade-off between the installed capacities and the technology cost reduction (learning-by-doing). The 2021 edition of the *Hydrogen for Europe* study was carried out using dynamic learning-by-doing, where the cost of the emerging technologies (such as solar PV, wind power, electrolysers, reformers with CCS etc.) depended on their installed capacities along the period outlook. The inter-dependency between installed capacity and technology cost was modelled by linking the models MIRET-EU (detailed European energy system model) and Integrate Europe (dedicated learning model). In the present edition of *Hydrogen for Europe* study, the resulting learning by doing results have been considered as exogeneous input data for technology cost evolution.
    - The scope of the model extends beyond purely energy-oriented issues, to include the representation of environmental emissions, and materials, related to the energy system. In addition, the model is suitable for the analysis of energy-environmental policies, which may be accurately represented by making explicit the representation of technologies and fuels in all sectors.

- The great flexibility of TIMES, especially at the technological level, allows the representation of almost all policies, whether at the national, sectorial, or sub-sectorial level.
- The model is driven by explicit exogenous final energy services demand and fuel prices.

316. On the other hand, it could be pinpointed some limitations inherent to this type of model:
- MIRET-EU is data consuming; therefore, data availability could limit the scope and depth of possible analyses.
- Moreover, there is no explicit representation of macro-economic factors which means there are no feed-back loops between the effects of energy system changes and the economy[231].
- As all models are simplified representations of reality and its complex dynamics, they inherently have limitations as to the detail and scope of their mathematical representation. These simplifications, e.g. time and spatial resolution, sector or technology representation and system boundaries, which are mostly due to the data availability, may represent significant modelling limitations.
- Long computational times could be observed due to a very detailed representation of complex energy system.
- The model is sensitive to the data assumptions for emerging technologies, which are by definition more uncertain and decision makers in practice do not always balance efforts across regions and sectors.
- Decision making that conditions investment in new technologies is often not rational, however representing non-rational decisions could be done via exogenous constraints. This does not allow capturing in detail all the aspects related to consumer behaviour, which play a fundamental role in decision-making processes. As highlighted by Gielen and Taylor (2007), even if decision making is rational, it is often not based on least-cost criteria. Policy rationality may stress effectiveness, equity issues, timing, risk and other factors that are not accounted for in this framework.
- The optimistic view of the future due to the perfect foresight approach which does not account for real-world uncertainty. However, it is possible to implement via the model to have foresight over a limited part of the horizon, such as one or a few periods or to temper it by using higher discount rates. By so doing, a modeler may attempt to simulate “real-world” decision making conditions, rather than socially optimal ones (Loulou et al., 2016)
- In this study, there is no disaggregation by plant size unlike in the MIRET FR (France) due to a lack of data and the consequences of so doing on computational time. This implies, as a simplification, that all installations in industry and CHP are considered as falling within the scope of the EU ETS Directive.
- Limited consideration of the very short-term physical dynamics (e.g. integrating system adequacy, transient stability analysis in the power sector) into long-term prospective models such as MIRET-EU.

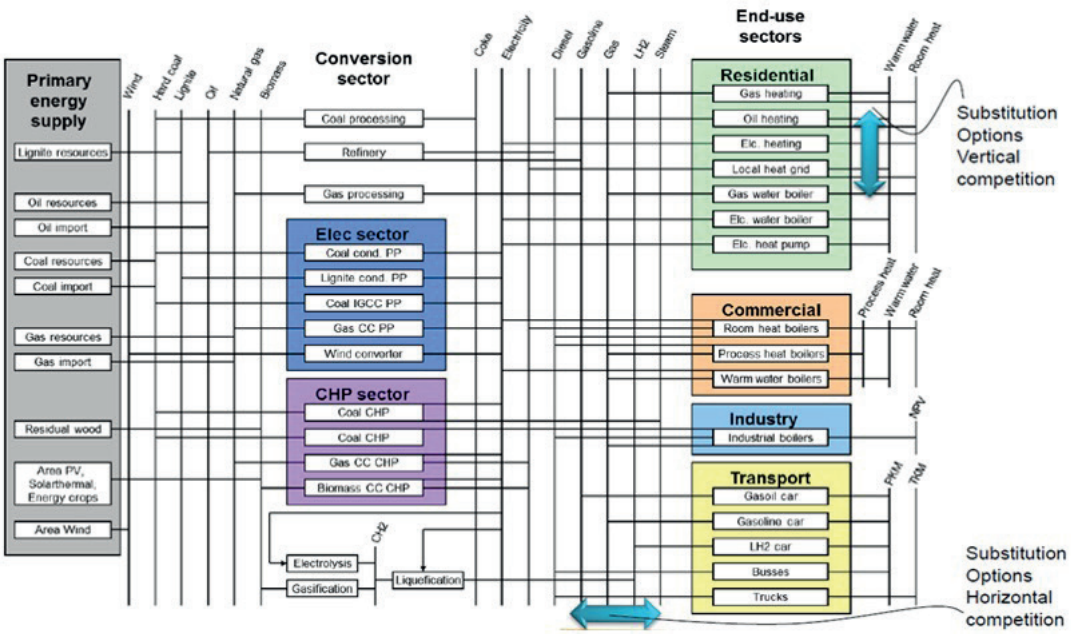
10.1.2 Sectoral representation

317. MIRET-EU provides a disaggregated representation of energy demand. In this section, the different energy end-use sectors are described in detail for a better comprehension of the sectorial assumptions/modelling.

318. MIRET-EU carries out its optimization horizontally across all sectors and vertically across all technologies delivering the same commodity, regions and time periods for which the limit is imposed. Figure 67 shows how substitutions are considered in the model within the different sectors.

[231] However, they could be considered exogenously through the price elasticities of service demands.

Figure 67. Substitution options in MIRET-EU



Source: Gargiulo (2018)

319. As above-mentioned, MIRET-EU's reference energy system encompasses all the steps from primary resources through the chain of processes that transform, transport, distribute and convert energy into the supply of energy services demanded by energy consumers. The details of each sector represented in the model are presented below. Throughout each description, modelling competencies are identified and limits, which are generally due to the lack of available database, are pointed out.

320. The model considers the existing technologies which are related to what is already installed in all considered countries in an historical year (e.g. the year 2010), and the new technologies which are to be available in the future (e.g. from 2011 onwards).

Power sector

321. The power sector could be subdivided in five parts as depicted in figure 68: Primary resources, power plants, power grid, demand (end-uses) and emissions. The primary resources part is disaggregated into import and mining processes in order to also take into account domestic extraction of resources in each country. These primary resources are converted into other energy carriers (electricity, heat, refinery products) via heat and power plants, cogeneration heat plants (CHP) or refinery plants.

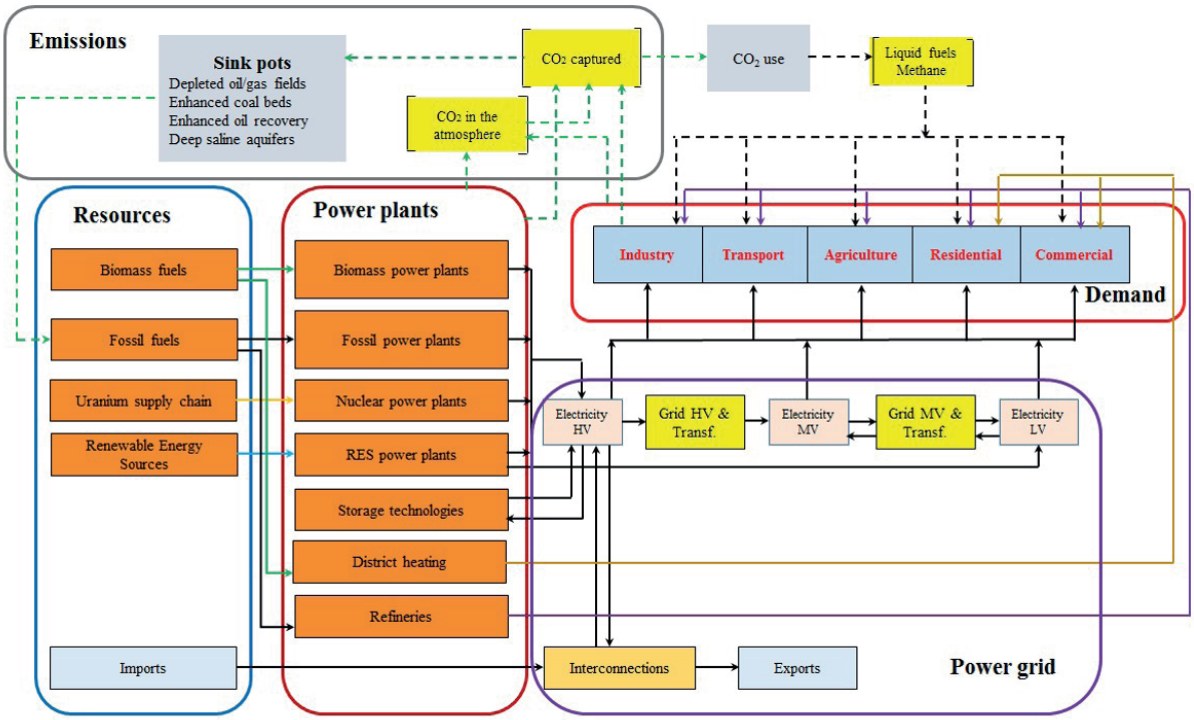
322. The power grid is explicitly represented in MIRET-EU in a simple manner in order to take into account the different voltage levels. All these energy carriers are consumed in the end-uses/processes in agriculture (machine drives, heat uses…), industry (iron & steel, cement, pulp & paper,…), transport (cars, bus,…), residential and services (space heating, cooling, cooking, lighting,…) sectors. Balancing the demand in all later sectors (mobility, tonnes of cement, space heating) could imply CO_2 emissions as in energy conversion technologies.

323. The CO_2 emissions could come from all demand and supply sectors (each energy carrier has an associated emission factor) and could be released to the atmosphere or captured via carbon capture and storage (CCS). CCS is considered in some industrial processes (ammonia, iron & steel, cement…), in power generation and supply sectors (hydrogen and biofuel production).

324. The model includes CO_2 from carbon capture or from the atmosphere directly by using direct air capture (DAC). The captured emissions can be from fossil or biogenic sources. Afterwards, they are either stored permanently in sinks, traded or reused (CCUS routes) to produce synthetic fuels (PtL), or methane (PtM) which could be incorporated in the natural gas grid.

325. The techno-economic details of electricity generating technologies rely on updated power generation technology assumptions (Efficiency, capital costs, fixed and variable O&M costs) from the JRC database released in October 2019 by the Joint Research Centre (JRC) of the European Commission, as well as from the IEA database. An evolution of these technology characteristics is provided up to 2050. Several country-specific assumptions are introduced in the model such as short and/or medium-term expected phase out and roll out of technologies, etc.

Figure 68. Power sector representation in MIRET-EU

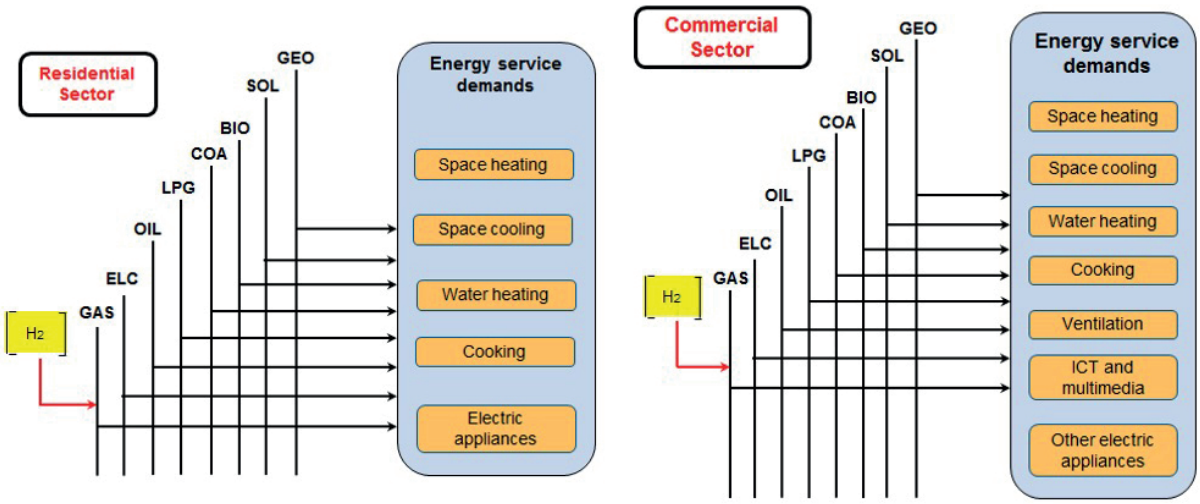


Source: Hydrogen4EU

Residential, Commercial and Agriculture sectors

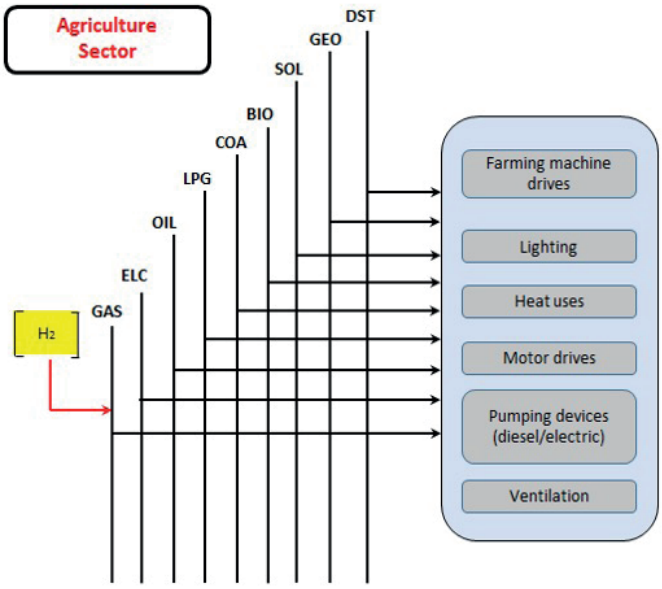
326. The needed data of the residential, services and agriculture sectors have been taken from the JRC-EU-TIMES database with a very disaggregated representation. MIRET-EU considers space heating, space cooling, water heating, cooking, ventilation, ICT and multimedia, and other electric appliances as end-uses in the residential and commercial sectors (see figure 69), while a single energy service demand satisfied by a single technology that consumes a mixture of fuels via different end-uses is considered for the agriculture sector (see figure 70).

Figure 69. Residential and commercial sector in MIRET-EU



Source: Hydrogen4EU

Figure 70. Agriculture sector in MIRET-EU



Source: Hydrogen4EU

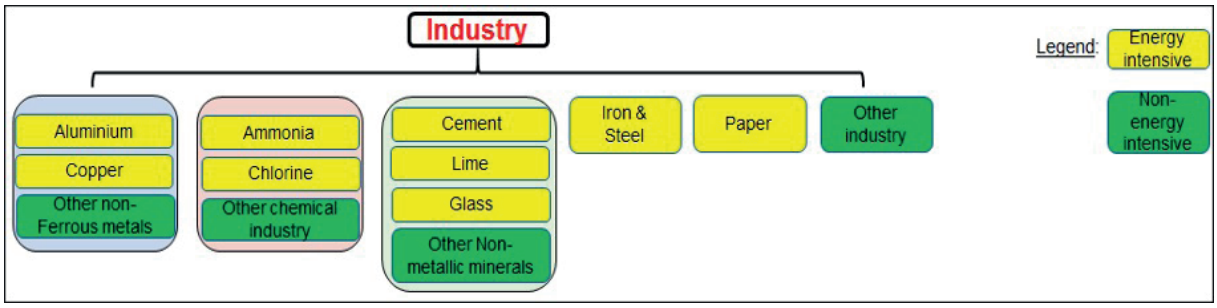
327. The JRC-IDEES (Integrated Database of the European Energy System), released in July 2018, provides very detailed information on the energy system and its underlying drivers for all EU Member States in annual time steps starting from the year 2000 up to 2015 consistent with Eurostat statistics in the last 2018-version. The model calibration has been continued to 2020 when other existing data between 2015-2020 are available. JRC-IDEES has been very useful in order to calibrate the historical evolution of the energy sector in MIRET-EU. The details of the end-use technologies (boilers, heat-pumps, CHP, district heating, water heaters, among others) for residential and services are based on a wide literature review, including in particular, the technology pathways described by the EU-funded project Advanced System Studies for Energy Transition (de Vita et al., 2018), the ENTRANZE database, the Eco-design requirement reports[232] of the European Commission, PRIMES data, VHK reports, among others. It also provided a disaggregation of the different end-uses to consider in the agriculture sector with their fuel efficiency.

[232] Further information available at: https://ec.europa.eu/info/energy-climate-change-environment/standards-tools-and-labels/products-labelling-rules-and-requirements/energy-label-and-ecodesign/energy-efficient-products_en

Industry sector

328. The modelling framework of the industry is subdivided into two categories according to previous work and studies: manufacturing process of the energy intensive industries were described by their associated energy consumption ratios for each product. Choices are possible between several alternative process solutions (Djemaa A., 2009; ETSAP[233]), while the non-energy intensive industries (or diffuse industry) are modelled by energy end-uses (mechanical processes, heat treatment, evaporation and concentration, drying, etc) due to the unsuitability of the product/process approach (Seck et al., 2013) (figure 71). The BREFs[234], which are the most complete series of reference documents covering industrial activities, provide descriptions of a range of industrial processes and, for example, their respective operating conditions and emission rates. It should be noted that CCS is considered in some energy intensive industries such as cement, glass, pulp & paper, ammonia, iron & steel, etc. The calibration of MIRET-EU relies on the JRC-IDEES, EUROSTAT, IEA database and on the framework of the JRC-EU-TIMES and TIAM-IFPEN.

Figure 71. Industry disaggregation in MIRET-EU



Source: Hydrogen4EU

Transport sector

329. The transport sector in MIRET-EU is based on IFPEN previous transport structure of MIRET-FR and TIAM models for critical raw material analyses in this sector up to 2050 (Hache et al., 2019). It is subdivided into four modes: road, rail, navigation and aviation (figure 72).

330. The road transport has been divided into passenger light-duty vehicles (PLDV) (small, medium and large), buses, commercial vehicles (CV) (light, heavy and medium trucks) and 2/3-wheelers. The presentation of technologies relies on a specific understanding of the transport sector within each segment (PLDV, CV, bus, minibus and 2/3-wheelers). The existing and future vehicles have been implemented with their techno-economical parameters. For all technologies across the entire study period 2010-2050, taking into account fuel efficiency, average annual vehicle mileage, lifespan, cost (purchase cost, O&M fixed and variable costs), etc. All these attributes have been derived from the IEA Mobility Model (IEA MoMo) (Fulton et al., 2009) data on transport and the JRC database.

331. For rail, MIRET-EU considered the non-urban rail, urban rail and freight rail while for the aviation and navigation, they have been disaggregated into freight and passengers, inland and bunkers. Contrary to MIRET-FR where all existing and future different aircrafts have been considered in order to allow alternative technologies, it has been assumed to consider single generic technologies at the European level with an average efficiency to satisfy the aviation activity, likewise for navigation. In addition, ammonia for navigation and pure hydrogen for aviation are not considered in the model for the moment.

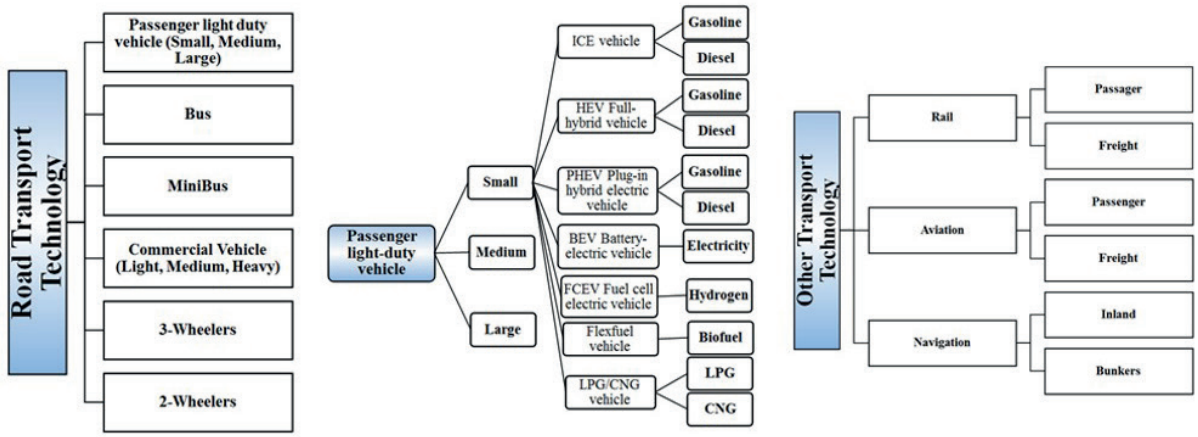
332. The potential role of ammonia in the energy system has been the subject of many discussions, particularly as a marine fuel. However, as ammonia has been represented as an industrial sector and not as a feedstock, it has been proposed a simplified approach which add hydrogen in the fuel mix of a generic ship on an

[233] https://iea-etsap.org/index.php/energy-technology-data/energy-demand-technologies-data
[234] https://eippcb.jrc.ec.europa.eu/reference/

equivalent basis[235]. Thus, the hydrogen demand gives some indications of the potential demand of ammonia as a shipping fuel until 2050. Transport fuels considered in the model are hydrogen, synthetic fuels (XtL), e-fuels (PtL), natural gas, Liquefied petroleum gas (LPG), Blending of gasoline, diesel and jet fuels.

333. Modelling of biofuels is based on IFPEN's approach and recognized expertise in the field of refineries and biofuels. The production chain is divided into:
- Feedstock pre-processing (where vegetable oil, starch grain, sugar beet and lignocellulosic are pre-processed),
- Production processes which are grouped into first- and second-generation biofuel processes,
  - First generation biofuel production is subdivided into four sources: ethanol production from sugar beet and starch feedstock's, the trans-esterification and hydro-treatment of crushed oilseeds into FAME (Fatty Acid Methyl Esters) and HVO (Hydro treated Vegetable Oils), respectively
  - Second generation production is subdivided into two sources: ethanol and synthetic FT-Diesel from lignocellulosic feedstocks.
- And blending (Blending of diesel B7, B10, gasoline SP95 grades E5, E10 and E85, and jet fuels) which is done endogenously in the model:
  - Gasoline SP95 fuels where bioethanol (1st and 2nd generation) could be incorporated to gasoline in a proportion up to 5%.
  - Gasoline SP95-E10 fuels where bioethanol (1st and 2nd generation) could be incorporated to gasoline in a proportion up to 10%
  - Gasoline SP95-E85 fuels where bioethanol (1st and 2nd generation) could be incorporated to gasoline in a proportion up to 85%.
  - Jet fuels for aviation where hydro treated vegetable oils (HVO) and biodiesel from lignocellulosic biomass (2nd generation) could be incorporated in kerosene in a proportion up to 95%
  - Diesel fuels where hydro treated vegetable oils (HVO), transesterification of vegetable oils (FAME), biodiesel from lignocellulosic biomass (2nd generation) could be incorporated in diesel in a proportion up to 95%

Figure 72. Transport representation in MIRET-EU



Source: Hydrogen4EU

[235] The *Hydrogen for Europe* study has adopted a simplified approach to give a broad indication of the potential demand hydrogen for the maritime sector until 2050. In this simplified approach, hydrogen has been added in the fuel mix of a generic ship as an equivalent basis. This is due to challenging model development tasks (lack of data on existing and future ships with their techno-economic assumptions (evolution till 2050), their fuel efficiency per type, lifetime, stocks of existing ships of the different considered category of ships) but also to limitations in the representation of ammonia as a feedstock in the model. Ammonia, that is produced from hydrogen through the Haber-Bosch process, is a promising solution as a shipping fuel but also for transporting and importing hydrogen into Europe, thanks to already existing ammonia production and transportation infrastructure. Moreover, production of ammonia from hydrogen is a low hanging fruit for decarbonizing existing ammonia demand for industrial and agricultural uses.

10.1.3 Representation of the hydrogen supply chain

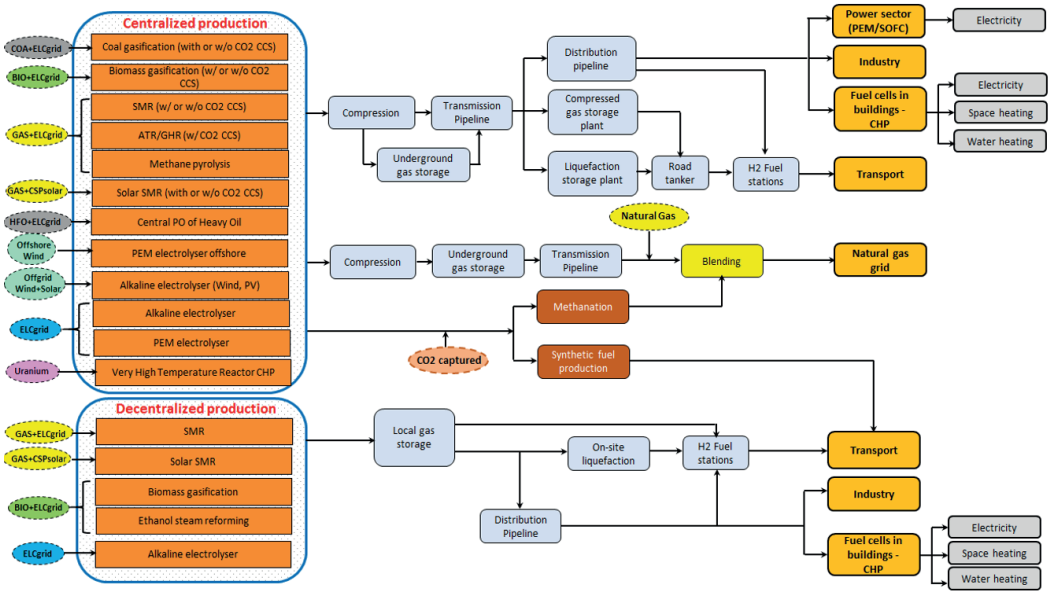
334. Regarding the hydrogen supply chain structure (see figure 73), the production options are disaggregated under centralized vs. decentralized and by size (large, medium and/or small).

335. In the decentralized option, hydrogen is produced close to where it is consumed, whereas in the centralized option, large scale hydrogen facilities are considered producing hydrogen that needs to be delivered to end-users via an extensive transport and distribution infrastructure. Most of the hydrogen techno-economic assumptions considered in the model have been provided by the JRC to IFPEN in June 2019. They are based on the JRC hydrogen structure in TIMES input data available for the development of the hydrogen sector in MIRET. The main references for the data are Blanco et al. 2018a, 2018b; Sgobbi et al., 2016; Bolat and Thiel, 2014a, 2014b; Simoes et al., 2013; Krewitt and Schmid, 2005.

336. In total, more than 30 hydrogen production options are considered by process type (with and w/o CCS), by size, by system design (centralized vs decentralized):
- Hydrogen from water
  - Electrolysis
- Hydrogen from fossil fuels
  - Steam methane reformer with/without carbon capture and storage (CCS)
  - Auto-thermal reformer (ATR) with CCS
  - Gas-heated reformer (GHR) combined with autothermal reformers with CCS
  - Methane pyrolysis
  - Partial oxidation of heavy oil
  - Coal Gasification with/without CCS
- Hydrogen from biomass
  - Biomass Gasification with/without CCS
  - Ethanol steam reforming

337. A data request regarding the techno-economic assumptions on hydrogen production technologies considered in the MIRET-EU model has been extensively discussed with technical experts in order to cross validate and complete the list. The implementations were made based on the data provided.

Figure 73. Hydrogen supply chain in MIRET-EU



Source: Adapted from the JRC hydrogen module for Hydrogen4EU

338. Thus, different input energy sources for hydrogen (e.g. electricity from grid, PV, wind, etc.) have been considered in the model. The JRC representation of the hydrogen supply chain has been improved by adding new hydrogen production options such as offgrid wind and PV with electrolyser s, methane pyrolysis, autothermal reformer (ATR)/Gas-heated reformer (GHR).

339. Hydrogen delivery begins with hydrogen conditioning and is completed with supplying hydrogen to end users. Hydrogen delivery is modelled by creating aggregated processes coupling several hydrogen delivery sub processes. Consequently, an aggregated delivery process is formed by summing all processes of a probable hydrogen value chain, from conditioning to immediately before end-use application (Simoes et al., 2013). Total costs for each of the delivery path result from the cost aggregation of the individual steps. Depending on the selected pathway of hydrogen delivery, sub processes include hydrogen storage options (e.g. underground salt caverns, liquid storage bulk, gas storage bulk and local gas storage bulk), liquefaction, compression, distribution pipeline, road transportation and refuelling stations, liquid to liquid, liquid to gas, and gas to gas with small capacity (300 kg/day) and large capacity (1200 kg/day).

340. Regarding end-use applications of hydrogen:
- Hydrogen gas, as a transport commodity can be consumed in buses, cars and commercial vehicles, and marine bunkers[236].
- In the residential and commercial sectors (space heating, water heating and electricity via fuel cells-CHP), and for industrial processes, hydrogen gas and hydrogen-natural gas blending are also possible. For the blending with natural gas, within the current natural gas infrastructure, a maximum of 5% until 2025, 10% from 2025 and 15% from 2030 onwards has been assumed in MIRET-EU in order to be in line with the hypothesis considered in the global TIAM IFPEN model, IEA-ETSAP TIAM version, or other European TIMES version[237].
- In the power sector, PEM fuel cell technology is represented in the model in order to take into account the penetration of hydrogen in power generation.
- Hydrogen can also be consumed in biorefineries and within CCUS routes for Power-to-Liquid (PtL), and Power-to-Methane (PtM).

10.1.4 Pipelines and trade representation in the MIRET-EU model

Natural gas and LNG

341. The trade of natural gas between European countries and other regions is modelled via a trade matrix that defines the existing and planned capacities until 2025 with the possibility of investing in additional capacity from 2025 onwards if needs be.

342. The ENTSOG[238] Ten-Year Network Development Plan (TYNDP) provides an overview of the European gas infrastructure and its future development. It thus allows depicting the maximum existing and planned capacities in order to have bilateral or unilateral exchanges between European countries until 2025 (see figure 74). Hereafter, an example of a matrix table which is used to declare the traded energy commodities (in this example, natural gas) and the links between countries (1=active links). The countries at the left-most column represent the exporters and the ones at the top-most line are the importers. Two types of trade are considered in the model: either bilateral links between countries (e.g. trade between Germany (importer/exporter) and Austria (importer/exporter) or unilateral links between countries (e.g. trade between Netherlands (importer) and Norway (exporter)).

[236] The hydrogen use in trains and aviation is not yet included so far in the model, however the use in trains could be implemented in the future according to existing and available data as plans involving hydrogen trains already exist in a number of countries (two hydrogen trains in Germany) (IEA, 2019)
[237] According to the IEA (2019), it is 10% blending max with 8% allowable under certain circumstances in Germany, while it is around 6% in France, 5% in Spain, 4% in Austria, and under 2% in other European countries. The Ameland project in the Netherlands did not find any problem for household devices to blend hydrogen up to 30%. Hydrogen and natural gas separation is not taken into account in the model.
[238] European Network of Transmission System Operators for Gas

Figure 74. Endogenous trade matrix of natural gas within European countries

Natural gas	Austria	Belgium	Bulgaria	Czech Rep.	Denmark	Estonia	Finland	France	Germany	Greece	Hungary	Ireland	Italy	Latvia	Lithuania	Netherlands	Poland	Portugal	Romania	Slovakia	Slovenia	Spain	Sweden	United Kingdom	Norway	Switzerland
Austria									1		1		1							1	1					
Belgium								1	1							1								1		
Bulgaria										1																
Czech Rep.									1											1						
Denmark									1							1							1			
Estonia																										
Finland																										
France			1																			1				1
Germany		1	1		1	1		1								1		1								1
Greece																										
Hungary																			1							
Ireland																								1		
Italy		1																		1	1					1
Latvia							1								1											
Lithuania														1												
Netherlands			1						1															1		
Poland																										
Portugal																							1			
Romania				1																						
Slovakia		1			1																					
Slovenia												1		1												
Spain									1										1							
Sweden																										
United Kingdom			1										1			1										
Norway			1						1	1						1									1	
Switzerland									1					1												

Source: Hydrogen4EU

343. In addition to natural gas trade within European countries, natural gas trade from Russia and North Africa are also considered for Germany, Finland, Estonia, Lithuania, Hungary, Poland, Romania, Slovakia, Spain and Italy (table 17).

Table 17. Trade of natural gas from outside European countries

Natural gas Country origin	Natural gas Country destination
Russia	Germany
	Estonia
	Lithuania
	Hungary
	Poland
	Romania
	Slovak Republic
	Finland
	EU28
North Africa	Spain
	Italy
Azerbaijan	Greece
	Italy

Source: Hydrogen4EU

Table 18. LNG import terminals considered in the model

LNG Terminals
Belgium
Croatia
Estonia
Finland
France
Germany
Greece
Ireland
Italy
Latvia
Lithuania
Netherlands
Norway
Poland
Portugal
Spain
Sweden
United Kingdom

Source: Hydrogen4EU

344. Belgium, Croatia, Estonia, Finland, France, Germany, Greece, Ireland, Italy, Latvia, Lithuania, Netherlands, Norway, Poland, Portugal, Spain and the UK have also the possibility to import LNG from outside Europe (table 18). The GIE[239] LNG Map and the CEDIGAZ[240] database provides comprehensive information on existing and under construction LNG Terminals in Europe. The project tables in the Annex A of the ENTSOG TYNDP 2020 provides the planned or under study LNG terminals for the coming years with a detailed overview of their status .For the H2 4EU study, only confirmed projects (FID)[241] and those with advanced maturity status have been considered.

Electricity

345. Electricity trade is represented like natural gas via a matrix table where the endogenous exchanges are represented. The ENTSO-E[242] Ten-Year Network Development Plan (TYNDP) also provides an overview of the maximum existing and planned capacities until 2030. The model also considers a maximum level of imports and exports of electricity from outside Europe.

Hydrogen

346. Regarding hydrogen transport, if a reduced demand for gas is observed, capacity could become available and could be used to transport hydrogen by repurposing segments of the natural gas pipelines to hydrogen, or by investing in new hydrogen pipelines (Guidehouse, 2020a). Therefore, two types of pipelines for hydrogen trade have been modelled in MIRET-EU:
   - Retrofitted natural gas pipelines to hydrogen
   - New dedicated hydrogen pipelines

347. Therefore, the model optimizes between retrofitting existing natural gas infrastructure for hydrogen carrying capability on one hand, and alternatively, or additionally, investing in new dedicated hydrogen infrastructure in the other hand (EC ASSET, 2020). Thus, the retrofitted gas pipelines to hydrogen has been assumed to have the matrix between the countries than the existing gas pipelines. The possibility of investing in additional hydrogen transport in the future is also considered within the existing gas matrix (H21NoE, 2018; Schoots et al., 2011). An estimate of the investment and operating costs have been provided in the 2020 European Hydrogen Backbone report of Guidehouse (2020) for new and refurbished pipelines dedicated to hydrogen (table 19).

Table 19. Cost input ranges used for estimating total investment, operating, and maintenance costs for hydrogen infrastructure. Values are for 48-inch pipelines (one of the widest pipeline types in the intra-EU gas network).

		Low	Medium	High
Pipeline CAPEX new	M€/km	2.5	2.75	3.36
Pipeline CAPEX retrofit	M€/km	0.25	0.5	0.64
Compressor station CAPEX	M€/MWe	2.2	3.4	6.7
Operating & maintenance costs	€/year as a % of CAPEX		0.8-1.7%	

Source: Guidehouse, 2020b

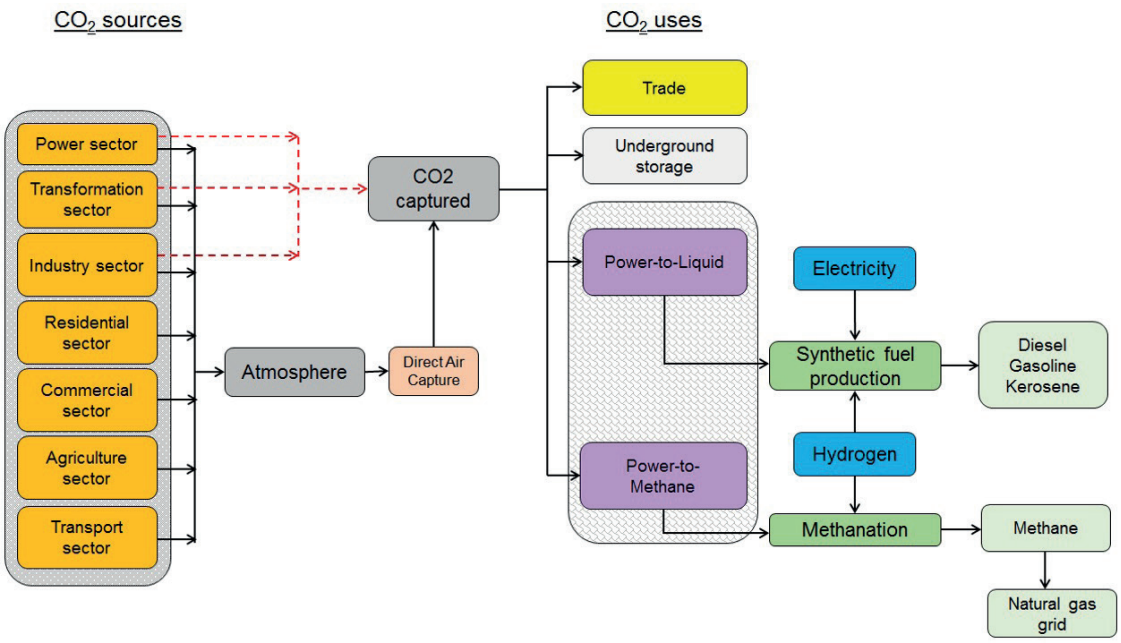
[239] Gas Infrastructure Europe
[240] CEDIGAZ is an international not for profit association dedicated to natural gas information, created in 1961 by a group of international gas companies and IFP Energies Nouvelles
[241] Final Investment Decision
[242] European Network of Transmission System Operators for Electricity

348. As regards extra-European trade of hydrogen, their inclusion in the model focuses on potential hydrogen imports from North Africa, Russia and Middle East. The transport modalities considered are maritime transport (LH2 and ammonia) and by cross-border interconnectors (subsea and aboveground). Hydrogen supply curves (based on LCOH trajectories) from extra-European countries is provided by a specific study carried out by in a separate working package. The latter is included in the model as an alternative for hydrogen supply, competing with domestic production within Europe. The maximum import volumes are based on the maximum possible trade flows between the country of origin and the entry point within Europe, with references to transport costs and constraints on planned infrastructure. All data regarding hydrogen transport (transport costs, hydrogen production cost in the foreign regions considered, maximum capacity available today and its evolution through to 2050) are described in section 9.2 (annex D).

10.1.5 CO_2 flows and CCUS routes in the MIRET-EU model

349. In figure 75, the model recovers CO_2 from carbon captured in industry, electricity and, hydrogen and biofuel production sectors, or from the atmosphere directly by using DAC (Direct Air Capture). The captured emissions can be from fossil or biogenic sources. Afterwards, they are either stored permanently in sinks (depleted oil/gas fields, enhanced coal beds, enhanced oil recovery, deep saline aquifers), traded or reused to produce synthetic fuels (PtL), or methane (PtM[243]). The main sources of data are Blanco et al. (2018a, 2018b) and Meylan et al. (2015). Regarding CO_2 transport considered in the model (Morbee et al., 2010, 2012; Morbee, 2014; Simoes et al., 2013), the pipeline trade among European countries is modeled via a trade matrix that defines the links between regions. CO_2 transport by tanker could also be implemented provided cost data is available (e.g. France-Norway planned CO_2 trade by tanker).

Figure 75. CCUS routes in the MIRET-EU[244]



Source: Hydrogen4EU

10.1.6 Energy policy assumptions in MIRET-EU

350. In MIRET-EU, the policy assumptions presented in annex D, section 9.3, both at the country and EU-level were explicitly represented through constraints in the model. They include sectors covered by the overall EU emissions targets for 2030 and 2050, the targets for the sectors covered by the EU ETS and that of non-EU ETS sectors, the Energy Efficiency Directive with particular attention to the transport sector, the Renewable Energy Directives and the NECPs.

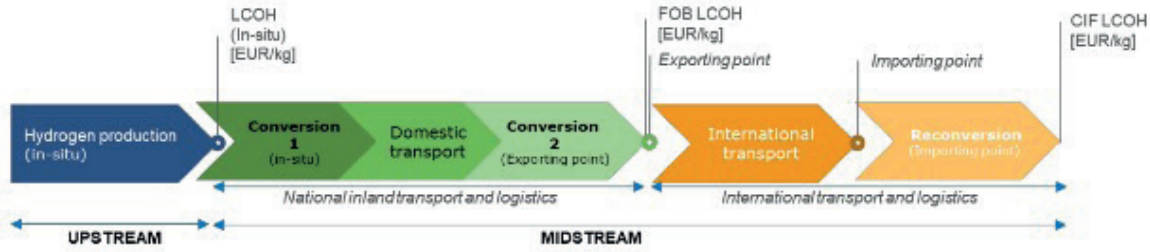
[243] Power-to-Methane
[244] Transformation sector encompasses biofuel and hydrogen production.

10.2 The hydrogen import model - Hydrogen Pathway Exploration model (HyPE)

10.2.1 Principles and methodology

351. Hydrogen Pathway Exploration model (HyPE), as illustrated in figure 77, aims at providing to the main model a way to introduce potential hydrogen imports from neighbouring regions (namely North-Africa, Middle East and Ukraine[245]). The results consist in supply curves, indicating both the potential of hydrogen production per country and the associated costs following a levelized cost of hydrogen approach (LCOH[246]) following a cost, insurance and freight logic (CIF[247]). The methodology builds on the full delivery value chain up to an entry point in Europe to determine the specific LCOH of each European importing route, as illustrated in figure 76.

Figure 76. Hydrogen import value chain[248]



Source: Hydrogen4EU

352. The two overarching principles of the HyPE model are:

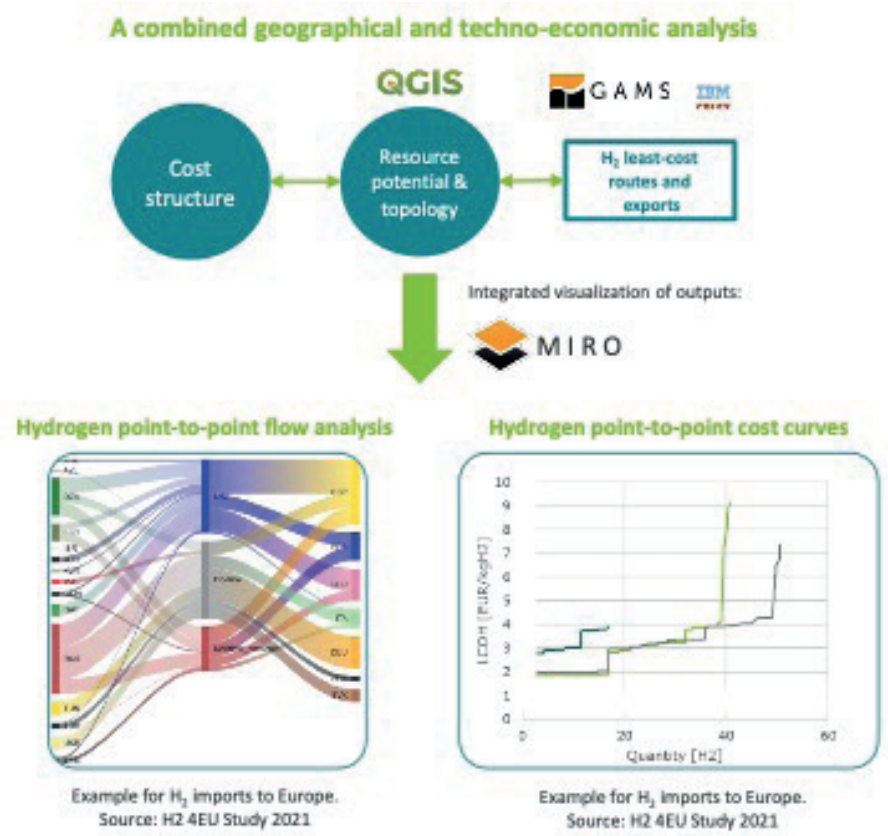
353. **Climate neutrality of European energy imports**: "decarbonisation of energy imports can be achieved via decarbonizing imported natural gas (either pre-combustion or post-combustion), or by importing any other renewable or decarbonized gases (e.g. H_2/LH2, P2G, Biomethane, etc.)".

354. **Technology neutrality of hydrogen production**: "Natural gas converted to hydrogen at import point/city gate (main study) or direct hydrogen imports" (ENTSO-E and ENTSO-G 2020).

355. The approach builds on an optimization model choosing the most cost-efficient way to supply hydrogen to Europe, considering different upstream options (e.g. renewable energy, natural gas), transport modalities (e.g. trailers, pipeline and bunkers) and energy vectors (e.g. ammonia, liquified hydrogen, gasified hydrogen). The resulting cost structure is therefore driven by production costs, but also includes transport cost, and conversion and reconversion costs depending on the transport technology and route. The cost-minimization is performed in a country-neutral and technology neutral way.

[245] Russia being excluded from the modelling framework.
[246] The levelized cost of hydrogen adopts the life cycle costing methodology. It is defined as the summation of all the discounted fixed and variable costs necessary for the production of hydrogen over the expected lifetime of the installation, divided by the total volume produced during its lifetime
[247] Cost, insurance and freight, as defined in Incoterms, means that the exporter delivers the product at the port of destination, so the cost at the loading port includes the cost of transport and logistics
[248] * FOB: Freight on board. **CIF: Cost, insurance and freight

Figure 77. Architecture of the HyPE model



Source: Hydrogen4EU

10.2.2 Upstream activities: Hydrogen production

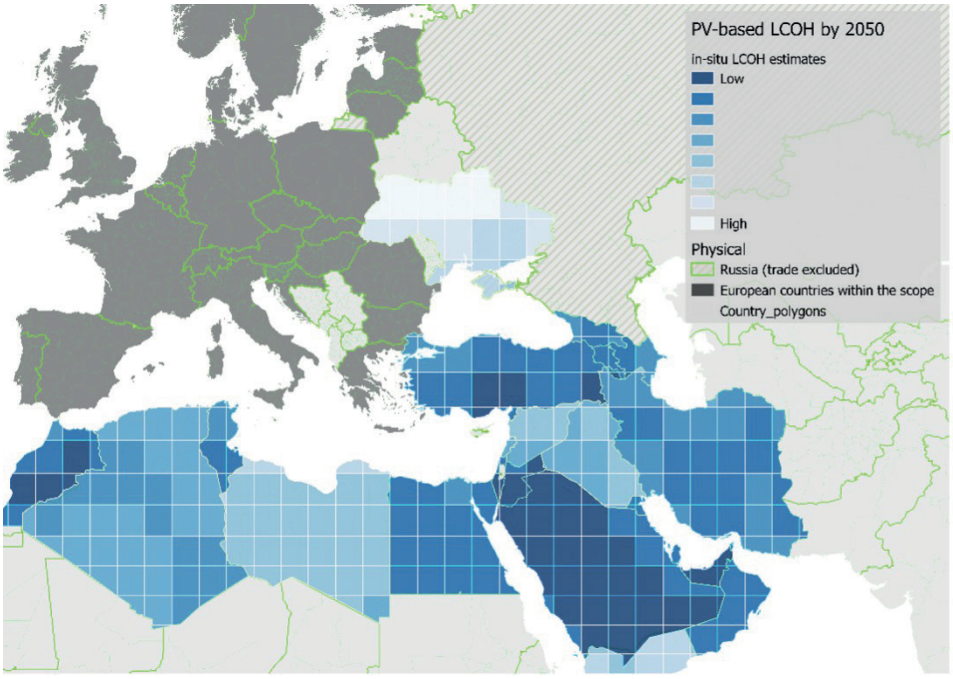
Renewable hydrogen from variable renewable energies

356. The production of renewable hydrogen from variable renewable energies highly depends on local factors such as the natural resources of wind and solar radiation as well as on the availability of suitable land and water access. The methodology for the estimation of feasible solar and wind resources for the production of renewable hydrogen is based on (Ruiz et al., 2019) and (Milbrandt and Mann, 2007).

357. To capture the availability of solar and wind local resources a 2.5 decimal degree grid has been projected on the considered export regions (see figure 78 and figure 79). For each cell both an annual wind speed time series and an annual solar radiation time series were determined at its centroid location based on 2016 data from the NASA MERRA-2 dataset[249]. From these raw data, hourly hydrogen yields are derived. For onshore wind turbines a hub height of 130m and a corresponding power curve were considered to obtain the hourly wind yield at every cell. For solar PV plants a fixed/non-tracked system was assumed and an optimized tilted angle according to the centroids latitude of the cell was determined. The study considers the possibility to install off-grid dedicated single and/or hybrid systems. The hybrid system can possibly consist of three elements namely an electrolyser, a wind plant and/or a solar plant. The optimisation of the size of each component is handled within the model and based on techno-economic characteristics such as component costs and locational specific factors such as financing costs and natural resources. Consequently, depending on its location, the optimal configuration can either consist of only one power production source (solar PV or onshore wind) plus an electrolyser system or of a combination of both power sources plus an electrolyser system. For the optimally determined system configuration at every cell centroid, the corresponding levelized costs of renewable hydrogen are derived for each year.

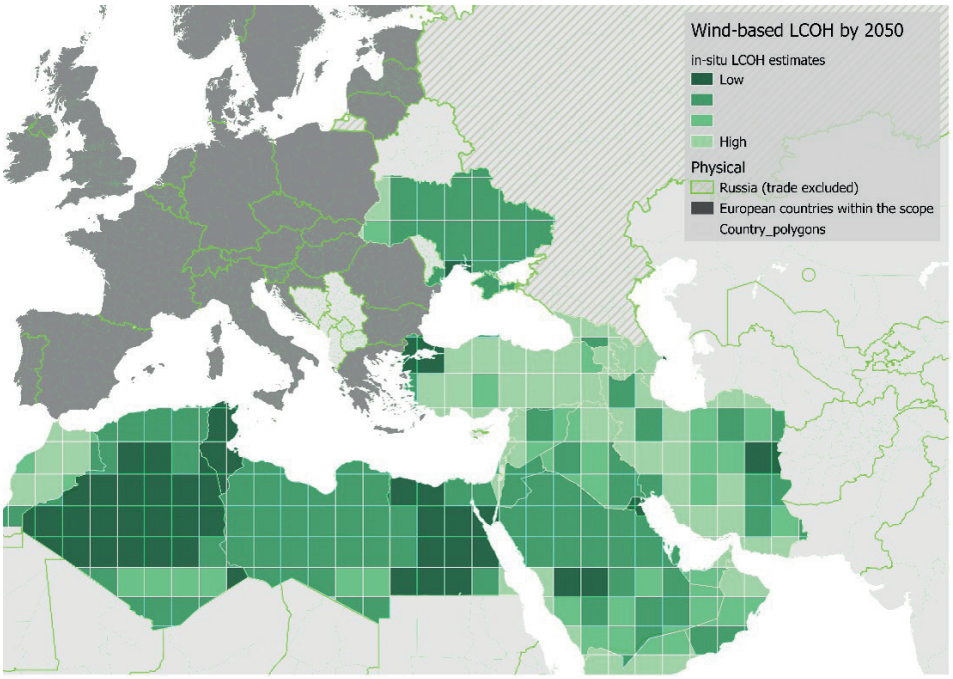
[249] Extracted from renewable ninja https://www.renewables.ninja/ (Pfenninger and Staffell, 2016) and (Staffell and Pfenninger, 2016)

Figure 78. Illustrative map of levelized cost of PV-based renewable hydrogen



Source: Hydrogen4EU

Figure 79. Illustrative map of levelized cost of wind-based renewable hydrogen



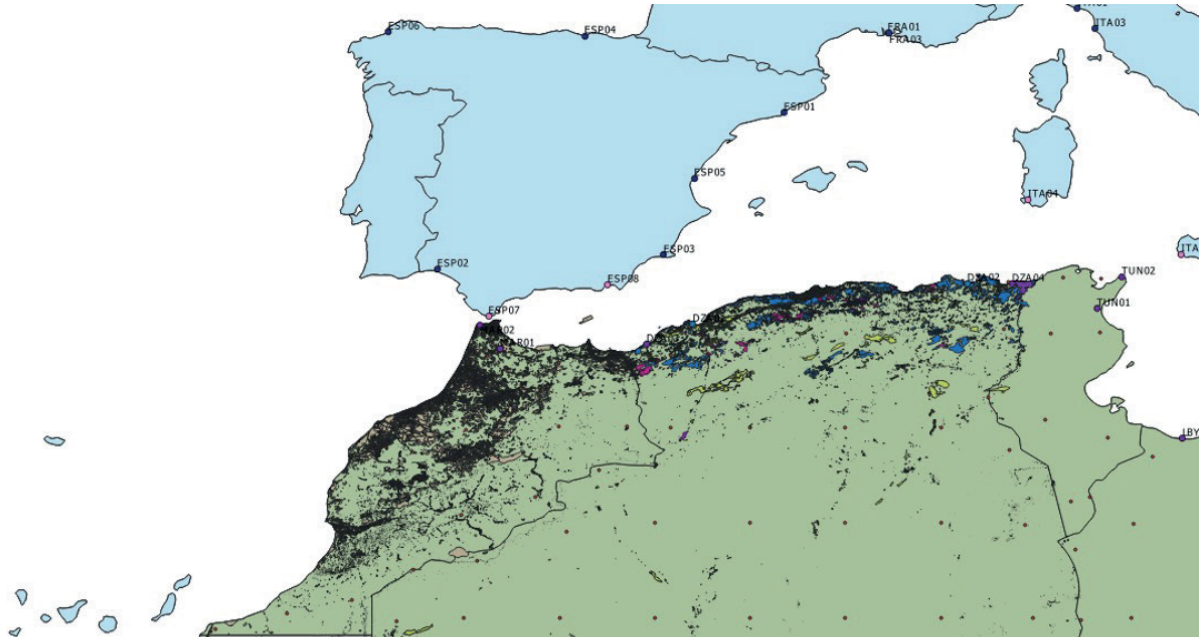
Source: Hydrgen4EU

358. The maximum exploitable renewable potential builds the basis for the determination of the potential renewable hydrogen production volumes. Land-uses[250] on every cell were analysed to obtain the available space for the installation of renewable energies and hence, to determine the potential production of hydrogen. Surfaces assigned to the categories of residential and industrial areas as well as national parks and water bodies are considered to be non-usable for renewable energy production and hence were excluded from the technical potential calculations (see figure 80). For the remaining areas, it is considered

[250] https://www.geofabrik.de/

that only 5% of the land surface can be available for the deployment of solar PV. A power density, that describes the maximal installable capacity per square kilometre, of 170 MWp/km^2 was assumed. For onshore wind, all available surfaces were assumed to be eligible for the deployment of onshore wind. A power density of 5 MW/km^2 was applied for this technology following Ruiz et al. (2019). To limit domestic transport costs and energy losses, cells within a maximum distance of 1000km to an international exit point (terminal or pipeline) were taken into account in the analysis as potential exporting locations given the absence of hydrogen domestic transport in the exporting countries considered.

Figure 80. Determination of the maximum available space for the installation of renewable energies using land-use data



Source: Hydrogen4EU

359. The maximum exploitable trajectory of national renewable energy that can be dedicated to H_2 production follows maximum deployment rates constraints to mimic industrial and regulatory rigidities preventing the industry to be developed overnight. The obtained renewable potentials were verified against the international potential estimated by NREL (2019).

Hydrogen from biomass

360. The potential renewable hydrogen production from biomass highly depends on the availability of natural feedstock resources. Only Russia and the Ukraine have substantial biomass potential in the considered geographical scope of exporting countries. As Russia has been excluded as a trading partner with Europe, only Ukraine was considered for the production of hydrogen from biomass.

361. Another important aspect for hydrogen from biomass is the ability to transport the feedstock to the production facility which is considered to be centralized and located in the proximity of an exporting point. Therefore, similar to the production of hydrogen from wind and solar, a 2.5 decimal degree grid was projected on the lands to capture the impact of transportation costs and availability on the production potential of hydrogen from biomass.

362. The total biomass feedstock availability is considered to be uniformly distributed on the regions considered. Furthermore, only solid forest residues are considered as feedstock for the production of hydrogen as it is the only easily transportable biomass with an economically viable energy density. Considering its volume and energy density, the maximum freight range admissible for biomass that is considered in this study is 700 km. The resulting volumes of biomass that are available for the hydrogen production in the resulting regions are

given in table 20. The maximum distances of 700 km allow to compare the transportation of biomass with the transportation of coal so that associated freight cost is assumed to be around 0.425 EUR/kgH2/1000km (Argus, 2017). Moreover, only 50% of the overall available biomass is assumed to be available for the production of hydrogen for exports to account for other domestic uses in competition.

Table 20. Considered regional biomass feedstock[251]

Area	Available biomass feedstock (TWh)
Ukraine	29.9

Source: Hydrogen4EU - based on Namsaraev et al. (2018)

363. The production of hydrogen from biomass is assumed to take place in a centralized gasification plants close by an exporting point. The resulting levelized costs of hydrogen consists accordingly of the costs related to the production facility, the transportation of biomass as well as feedstock costs. Bio-feedstock cost is considered to be 6.5 USD/GJ (IRENA, 2017). Moreover, the facilities are assumed to operate at a load factor of 85% throughout their technical lifetime.

Low carbon hydrogen from methane

364. Only imports of low carbon hydrogen from methane produced in current gas exporting countries to the EU within the region under the scope were assessed (i.e. Algeria, Azerbaijan, Qatar, Russia, Egypt and Saudi Arabia). Given that natural gas infrastructure is well developed in the countries considered, production facilities are assumed to be installed near the location of the current exit points for natural gas trade (pipeline and/or terminal), so to avoid additional inland transport costs.

365. Two set of technologies to produce low-carbon hydrogen where assessed:
   - **Reformers with CCS**: Steam methane reforming (SMR CCS), Autothermal reforming (ATR CCS) and Gas heated reforming (ATR/GHR CCS), all with carbon capture and storage (CCS) were considered. Full cost was considered assuming rock formations were available within a reasonable distance around the production sites (IPCC 2005, 21) to estimate an average cost related to CO_2 transport and storage[252].
   - **Methane pyrolysis** (carbon black co-product revenues included): Same than for the European hydrogen production alternatives, methane pyrolysis was assumed to be commercially available from 2030 onwards.

366. Scenario analysis on natural gas production, domestic consumption and trade were conducted in each of the gas-rich MENA countries to assess the possible availability of natural gas for producing hydrogen. Additionally, Azerbaijan (AZE) is expected to produce around 50 bcm of natural gas in 2025 at the completion of the SCP/TANAP/TAP project, thus we expect around 20% this production could be used to produce low carbon hydrogen to the EU market by 2025. No further projections regarding the evolution of the exporting shares given future infrastructure developments were considered.

367. Wellhead cost of natural gas production was assumed to be the average breakeven price in each exporting country. Breakeven gas prices were estimated by calculating the percentage difference with respect to country average breakeven oil prices from the International Monetary Fund and applying it to gas producing countries assuming an average of 2.4 USD/MMBtu as the basis[253]. The obtained range of breakeven gas prices were verified by benchmarking them against typical average wellhead cost of basins of similar type for each region (i.e. onshore, deep, shallow, ultra-deep). They don't include any national tax scheme.

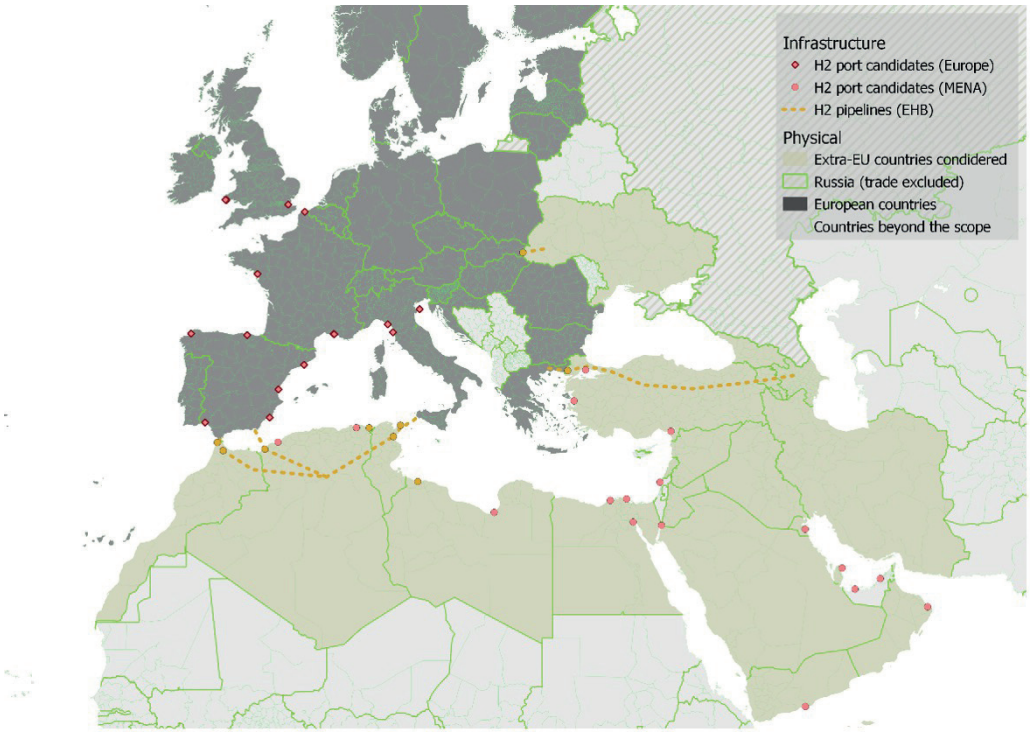
[251] Derived from (Namsaraev, 2018)
[252] At the same time, it was assumed that CO_2 stored volumes at those sites was at least 10 Mt per year which would lead to transport and storage cost of around €11.4/tonne (after considering economies of scale) based on the H21 North of England report (Sadler et al. 2018, 21).
[253] This value corresponds to the average US dry gas wellheads breakeven values reported by BNEF (BloombergNEF 2019). For Algeria, with a declining export trend (Aissaoui 2016), the breakeven cost assumed was that of a dry gas Africa shore well. Tests have been conducted to provide robustness to this assumption and we have obtained that LOCH are within the +/-10% range for all countries with average breakeven prices changing in the 2 to 2.9 $/MMBtu window.

368. Price of carbon black (by-product of methane pyrolysis) was assumed constant at 100 EUR/ton, and compensation for unabated CO_2 emissions, as well as upstream methane emissions, for both reformers with CCS[254] and methane pyrolysis[255] were accounted for by assuming economic offsets given by a CO_2 emission cost trajectory proposed by the IEA's for developing economies[256].

10.2.3 Midstream: Hydrogen transport

369. The competitivity of hydrogen imports is highly determined by the transport infrastructure available. Depending on the distance between production and delivery points, several transportation paths are currently envisaged and integrated into the modelling framework in accordance with the overall technology-neutral approach. We considered for national inland transport hydrogen trucks, either with compressed hydrogen or ammonia trucks. For international transport, pipelines, ammonia shipping and liquified hydrogen (LH_2) have been considered.

Figure 81. Assumptions on the likely development of hydrogen import/export infrastructure



Source: Hydrogen4EU - based on data from the European Hydrogen Backbone and own assumptions

370. Liquified hydrogen terminals have been added to the model as possible entry points in Europe for hydrogen. As the natural gas consumption in Europe drops, EU LNG terminals are assumed to see their utilization rates dropping by the end of the decade. We therefore make the hypothesis that the refurbishment of LNG terminals to handle liquified hydrogen (LH_2) is an option from 2030 onwards. The older terminals in countries with the lowest utilization rates have been assumed to be the first candidates for repurposing to hydrogen. The availability timeline is then made by a combination of the commissioning date and the forecasted utilization rate of the terminals (see table 21). Refurbishment of existing terminals is preferred to build new ones as it allows to save around 25% of investment costs from new builds (Oxford Energy, 2014). In terms of volumetric capacity, liquified hydrogen terminals are supposed to handle each year the same volume of liquid gas than the previous LNG terminals did. On an energetic point-of-view, it means only 40% of the energy capacity of the LNG terminal is available when refurbished to hydrogen.

[254] Capture rates assumed in the 95% range.
[255] Assuming a gas-fired process.
[256] Further information available at: https://iea.blob.core.windows.net/assets/deebef5d-0c34-4539-9d0c-10b13d840027/NetZeroby2050-ARoadmapfortheGlobalEnergySector_CORR.pdf, p.53.

Table 21. Considered liquified hydrogen/ammonia terminals

Country	Terminal	Capacity (TWh)	Start year	Assumed refurbishment year	Terminal age (in 2020)
Spain	Barcelona	180	1969	2030	51
Italy	Panigaglia	37	1971	2045	59
France	Fos Tonkin	31	1972	2030	48
France	Montoir-de-Bretagne	105	1980	2030	40
Spain	Huelva	124	1988	2030	32
Spain	Cartagena	124	1989	2030	31
Spain	Bahia de Biskaia	120	2003	2050	37
UK	Grain	214	2005	2040	15
France	Fos Cavaou	86	2010	2050	30

Source: Hydrogen4EU - based on data from GIE

371. Capacity of liquified ammonia terminals might as well be expanded, justifying the choice to consider this carrier as a feasible hydrogen importing option in Europe. Ammonia (NH_3) is seen as an effective hydrogen carrier for long distance shipping. It presents the advantage to be liquid at higher temperature than LNG or liquified hydrogen, and its higher energy density allows it to compete in terms of costs against liquified hydrogen. From a volumetric point-of-view, ammonia presents an energy density 1.7 times higher than liquified hydrogen. This means that for the volume transported per year, ammonia regasification plants treat 70% more energy than a liquified hydrogen plant with equivalent capacity. Based on these elements, a timeline has been created to model the evolution of energy-related ammonia importing terminals in Europe. Similar than for shipping liquified hydrogen, ammonia is assumed to be reconverted to hydrogen at the importing port. Thus, a final step of catalytic cracking of ammonia is considered in the LCOH estimate for this route. The international trade of ammonia is well established but despite promising prospects for ammonia as a shipping fuel, such a use is not expected before 2035 (DNV-GL, 2020). Therefore, considering ships fuelled and transporting ammonia (decarbonized) is essential to be consistent with the hypothesis of CO_2 neutrality of EU energy imports.

372. Regarding the cross-border gas interconnectors, the assumptions adopted are based on the European Hydrogen Backbone study (Guidehouse 2020).

373. This is, we assume that a dedicated hydrogen network in the EU is progressively built by repurposing some natural gas pipelines and building new ones. Deployment of such network would start from key industrial clusters in 2030, expand to EU interconnectors by 2035 and reach some non-EU interconnectors by 2040[257]. For calculating a LCOH component of hydrogen transmission by pipeline, assumptions on which and by when each interconnector is available, its route, length and capacity are key. The retrofitted pipeline capacity assessed in the European Hydrogen Backbone Study and its timeline has been considered as inputs to the model (see table 22). More specifically six pipelines have been considered for hydrogen imports, allowing both low-carbon and renewable hydrogen to be imported into Europe. Repurposed pipelines are supposed to handle each year almost the same energy capacity than the previous gas pipeline did[258]. Only one injection point has been considered for each country. It is supposed to be located according to the gas network topology and existing compression stations[259].

[257] Discussions with SNAM, the Italian gas operator, led us to consider a retrofit of half the Trans-Mediterranean Pipeline capacity in 2030.
[258] Assuming low-calorific natural gas with approximately 37.7 MJ/Nm3 (HHV) and a Wobbe number between 41 and 47 MJ/Nm (Dries Haeseldonckx and D'haeseleer 2007). Assuming low-calorific natural gas with approximately 37.7 MJ/Nm^3 (HHV) and a Wobbe number between 41 and 47 MJ/Nm (Dries Haeseldonckx and D'haeseleer 2007).
[259] For Azerbaijan, Russia and Algeria, additional injection points have been added where pipeline start.

Table 22. Considered retrofitted pipelines

Entry point (ENTSOG)	Type	Code Country (entry point)	Code Country (exit point)	Start year	Infrastructure name	Max volume (MTPA H2)	Length (km)
207	Pipeline	ESP	MAR	2040	MEG	4.8	45
207	Pipeline	ESP	DZA	2040	MEG	4.8	1082
208	Pipeline	ESP	DZA	2040	Medgas	3.1	210
208	Pipeline	ESP	DZA	2040	Medgas	3.1	757
209	Pipeline	ITA	TUN	2030	Transmed	6.2	155
209	Pipeline	ITA	DZA	2030	Transmed	6.2	1075
222	Pipeline	GRE	TUR	2040	TANAP	3.1	110
222	Pipeline	GRE	AZE	2040	TANAP	3.1	2496
218	Pipeline	SVK	UKR	2040	Kyev - Western Border Pipeline	9.9	650

Source: Guidehouse, 2020

374. The cost assumptions for the midstream are presented in table 23 and table 24.

Table 23. Cost assumptions for hydrogen transport with vessels

	Production	Conversion 1 (production point)	Domestic transport	Conversion 2 (exporting point)		International transport		Reconversion (Importing point)
A. (from 2020) LCOH Contribution (EUR17/Kg)	**From all Sources available in the cell** Depends on the technology and resources available	**Compression**	**Gasified trucks**	**Liquefaction** 2.03	New dedicated exporting terminals including storage	**Liquified hydrogen shipping** A function of distance: LCOH = 0.10 D + 0.84	Refurbished dedicated importing terminals	**Hydrogen regasification** 1.30
		A function of distance: LCOH = 2.65 D + 0.27 D: Distance (1000 Km); Max. range: 300 Km						
B. (from 2030) LCOH Contribution (EUR17/Kg)		**Compression**	**Gasified trucks**	**Ammonia synthesis & liquefaction** 1.53		**Liquified Ammonia shipping** A function of distance: LCOH = 0.09 D + 0.17		**Ammonia catalytic cracking** 1.80
		A function of distance: LCOH = 2.65 D + 0.27 D: Distance (1000 Km) ; Max. range: 300 Km						
C. (from 2030) LCOH Contribution (EUR17/Kg)		**Ammonia synthesis**	**Liquid Ammonia trucks**	**N/A** -		**Liquified Ammonia shipping** A function of distance: LCOH = 0.09 D + 0.17		**Ammonia catalytic cracking** 1.80
		1.53	A function of distance: LCOH = 0.66 D + 0.04 D: Distance (1000 Km) Max. range: 1000 Km					

Source: Hydrogen4EU - based on data from IEA (2019a), DOE (2019), Fúnez Guerra et al (2020), Ikäheimo et al. (2018) and Davenne et al. (2020)

Table 24. Cost assumptions for hydrogen transport by pipeline

	Production	Conversion 1 (production point)	Domestic transport	Conversion 2 (exporting point)		International transport
D. (from 2040) LCOH Contribution (EUR17/Kg)	**From all Sources available in the cell** Depends on the technology and resources available	**Compression**	**Gasified trucks**	**Compression**	Injection point	**Hydrogen pipelines** A function of distance: LCOH = 0.55 D + 0.06 D: Distance (1000 Km)
		A function of distance: LCOH = 2.61 D + 0.25 D: Distance (1000 Km); Max. range: 300 Km				
E. (from 2040) LCOH Contribution (EUR17/Kg)		**Ammonia synthesis**	**Liquid Ammonia trucks**	**Ammonia catalytic cracking**		
		1.53	A function of distance: LCOH = 0.65 D + 0.04 D: Distance (1000 Km); Max. range: 1000 Km	1.80		
F. (from 2050) LCOH Contribution (EUR17/Kg)		**Compression**	**Gasified trucks**	**Compression**		
		A function of distance: LCOH = 2.52 D + 0.23 D: Distance (1000 Km) ; Max. range: 300 Km				
G. (from 2050) LCOH		**Ammonia synthesis**	**Liquid Ammonia trucks**	**Ammonia catalytic cracking**		
		1.53	A function of distance: LCOH = 0.64 D + 0.04 D: Distance (1000 Km); Max. range: 1000 Km	1.80		

Source: Hydrogen4EU - based on data from IEA (2019a), DOE (2019), Fúnez Guerra et al (2020), Ikäheimo et al. (2018) and Davenne et al. (2020)

10.2.4 Country specific WACC

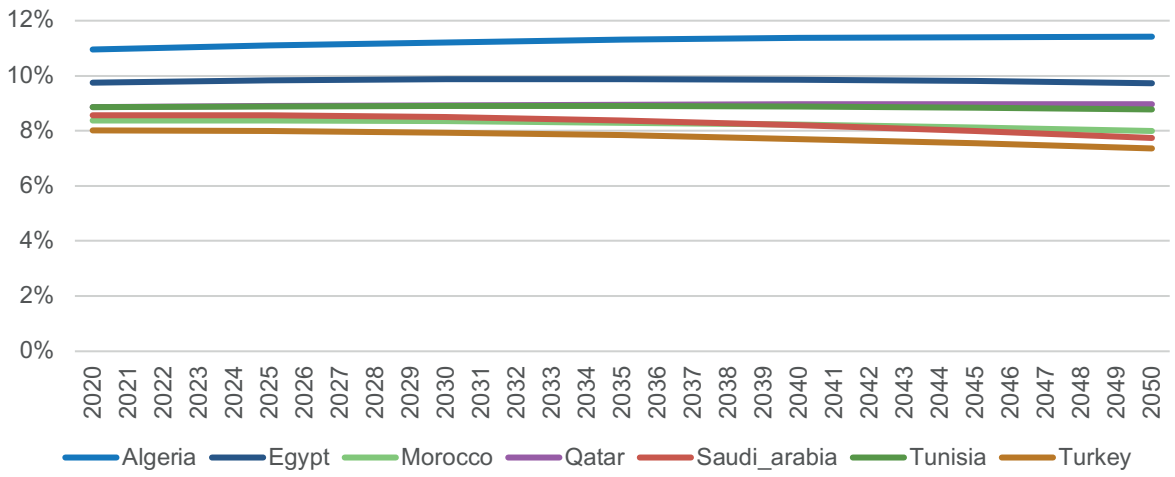
375. As any investment, the deployment of hydrogen facilities has inherent risk that directly translate into cost of capital. Additionally, undertaking such investments in countries with somehow challenging local regulation needs to be factored in into the LCOH calculation (see figure 82). We therefore consider country specific risk premiums, estimated by the relative ratio of the Ease of Doing Business scores (WB 2020) of each country against the EU average. Future values were linearly extrapolated according to the historic trend and corrected by a deflator. This methodology allows to approximate a country dependent risk adjusted weighted average cost of capital (WACC) for the LCOH calculation.

Figure 82. Ease of doing business score perimeter

Source: World Bank, 2020

376. Compared to the average EU-27 WACC of 8%, we consider a range going from 6% in 2018, in economically stable countries such as United Arab Emirates, to more than 15% in countries such as Yemen or Libya, that face long-lasting instability (see figure 83). As an indicative figure, when varying country-specific WACC by +/-20% it results on a difference on LCOH of within the 5% range for low-carbon hydrogen technologies[260].

Figure 83. Country specific WACC by adapting the EU28 average with country risk premium



Source: Deloitte estimates based on Ease of doing Business index (World Bank, 2020)

[260] Technologies with higher shares of CAPEX on their LCOH would be more sensitive to variations of the WACC.

11 Annex F: Data documentation

377. The hydrogen production technologies and the related cost and efficiency data are the same as in the first *Hydrogen for Europe* study. Table 25 provides the cost data related to different hydrogen production technologies.

378. For assumptions related to other technologies, see section 9.2.

Table 25. Hydrogen production technologies – Cost data. All cost data is provided in the lower heating value (LHV)

Technology	Investment costs [€/kW H_2]			Fixed O&M [€/kW H_2]			Variable O&M [€/GJ]			Source
	2020	2030	2050	2020	2030	2050	2020	2030	2050	
Coal gasification, large size, centralized	2363	2363	2363	118	118	118	0.16	0.12	0.12	6, 9, 10
Coal gasification, medium size, centralised	2929	2929	2929	147	147	147	0.22	0.22	0.22	6, 9, 10
Coal gasification + CO_2 capture, large size, centralised	2460	2460	2460	123	123	123	0.26	0.26	0.26	6, 9, 10
Coal gasification + CO_2 capture, medium size, centralised	3376	3376	3376	169	169	169	0.26	0.26	0.26	6, 9, 10
Biomass gasification, small size, decentralised	3099	3099	3099	81.9	81.9	81.9	1.3	1.3	1.3	6, 8, 9, 10
Biomass gasification, medium size, centralised	2959	2929	2929	146	146	146	0.45	0.45	0.45	6, 8, 9, 10
Biomass gasification + CO_2 capture, medium size, centralised	3376	3376	3376	169	169	169	0.46	0.46	0.46	6, 8, 9
SMR, large size, centralised	805	805	805	37.8	37.8	37.8	0.08	0.05	0.05	1, 9
SMR, medium size, decentralised	1945	1509	1509	52.7	29.9	29.9	0.04	0.04	0.04	6, 8, 10
SMR + CO_2 capture, large size, centralized	1487	1204	1133	44.6	36.1	34.0	0.53	0.07	0.07	1, 9
ATR + CO_2 capture, large size, centralized	800	700	700	24.0	21.0	21.0	0.53[261]	0.07[261]	0.07[261]	8, 9
GHR + ATR + CO_2 capture, large size, centralized	830	750	750	24.9	22.5	22.5	0.53[261]	0.07[261]	0.07[261]	8, 9
Ethanol steam reforming, decentralised	2700	2700	2700	0	0	0	19.65	19.65	19.65	6
PEM electrolyser	1750	795	476	53	46	46	0.15[262]	0.06[262]	0.06[262]	2, 3, 7, 9, 10

[261] The variable O&M costs for *GHR + ATR* and *ATR* are based on the reported values for *SMR + CO_2* capture as they are mostly related to process water, cooling water, and catalyst replacement.
[262] The variable O&M costs for PEM electrolyser are based on *Alkaline electrolyser, large size* as they are mostly related to process and cooling water.

Technology	Investment costs [€/kW H_2]			Fixed O&M [€/kW H_2]			Variable O&M [€/GJ]			Source
	2020	2030	2050	2020	2030	2050	2020	2030	2050	
Alkaline electrolyser, large size, centralised	1250	576	345	19	15	15	0.15	0.06	0.06	2, 3, 7, 9, 10
Alkaline electrolyser, wind off grid, centralized	2408	1807	1493	59	52	50	0.15	0.06	0.06	2, 3, 7, 9, 10
Alkaline electrolyser , PV off grid, centralized	1878	1083	707	37	27	24	0.15	0.06	0.06	2, 3, 7, 9, 10
PEM electrolyser , offshore, centralized	4535	3245	2709	115	95	90	0.96	0.17	0.17	2, 3, 7, 9, 10
Alkaline electrolyser, small size, decentralized	1250	576	345	19	15.0	15	0.96	0.17	0.17	2, 3, 7, 9, 10
Very High Temperature Reactor CHP, centralized	NA	4687	3937	NA	304.7	255.9	NA	2.60	2.60	6, 10
Methane pyrolysis (Kvaerner process), centralized	1993	1993	1993	89.8	89.8	89.8	0.70	0.70	0.70	6
Molten media methane pyrolysis, large size	778	778	778	64.9	64.9	64.9	-	-	-	11
Non-catalytic methane pyrolysis, small size	1751	1751	1751	225	225	225	-	-	-	12

Source:

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11.1 Technical assumptions

379. Technology data regarding hydrogen production technologies used in the model are described and detailed in Table 26.

Table 26. Hydrogen production technologies – Technology Data

Technology	Size [MW]		Fuel Efficiency [PJ/PJ$_{H2}$] (LHV)			Life			Source
		Fuel	2020	2030	2050	2020	2030	2050	
Coal gasification, large size, centralized	1667	Coal	1.67	1.67	1.67	25	25	25	6, 9, 10
Coal gasification, medium size, centralized	434	Coal	1.67	1.67	1.67	25	25	25	6, 9, 10
Coal gasification + CO_2 capture, large size, centralized	1667	Coal	1.72	1.72	1.72	25	25	25	6, 9, 10
Coal gasification + CO_2 capture, medium size, centralized	442	Coal	1.72	1.72	1.72	25	25	25	6, 9, 10
Biomass gasification, small size, decentralized	0.7	Biomass	2.10	2.10	2.10	25	25	25	6, 8, 9, 10
		Grid electricity	0.03	0.03	0.03				
Biomass gasification, medium size, centralized	33	Biomass	2.10	2.10	2.10	25	25	25	6, 8, 9, 10
		Grid electricity	0.03	0.03	0.03				
Biomass gasification + CO_2 capture, medium size, centralized	33	Biomass	2.10	2.10	2.10	25	25	25	6, 8, 9
		Grid electricity	0.03	0.03	0.03				
SMR, large size, centralized	1530	Natural gas	1.32	1.32	1.32	25	25	25	1, 9
		Grid electricity	-0.02	-0.02	-0.02				
SMR, medium size, decentralized	2	Natural gas	1.36	1.27	1.27	25	25	25	6, 8, 10
		Grid electricity	0.25	0.07	0.07				
SMR + CO_2 capture, large size, centralized	1502	Natural gas	1.385	1.385	1.385	25	25	25	1, 8, 9
		Grid electricity	0.015	0.015	0.015				
ATR + CO_2 capture, large size, centralized	1260	Natural gas	1.36	1.36	1.36	25	25	25	8, 9
		Grid electricity	0.04	0.04	0.04				
GHR + ATR + CO_2 capture, large size, centralized	1260	Natural gas	1.28	1.20	1.20	25	25	25	8, 9
		Grid electricity	0.06	0.05	0.05				

Technology	Size [MW]		Fuel Efficiency [PJ/PJ$_{H2}$] (LHV)			Life			Source
		Fuel	2020	2030	2050	2020	2030	2050	
Ethanol steam reforming, decentralized	0.01	Ethanol	1.47	1.47	1.47	10	10	10	6
		Grid electricity	0.08	0.08	0.08				
PEM electrolyser	NA[263]	Grid electricity	1.60	1.55	1.55	6[264]	7	9	2, 3, 7, 9, 10
Alkaline electrolyser, large size, centralized	72	Grid electricity	1.55	1.45	1.45	20	20	20	2, 3, 7, 9, 10
Alkaline electrolyser, wind off grid, centralized	NA[263]	Wind off grid	1.55	1.45	1.45	30	30	30	2, 3, 7, 9, 10
Alkaline electrolyser, PV off grid, centralized	NA[263]	PV off grid	1.55	1.45	1.45	30	30	30	2, 3, 7, 9, 10
PEM electrolyser, offshore, centralized	NA[263]	Wind offshore	1.5	1.5	1.5	20	20	20	2, 3, 7, 9, 10
Alkaline electrolyser, small size, decentralized	0,6	Grid electricity	1.55	1.45	1.45	20	20	20	2, 3, 7, 9, 10
Very High Temperature Reactor CHP, centralized	600	Uranium	NA	1.5	1.5	NA	60	60	6, 10
Kvaerner process, centralized	19	Natural gas	1.75	1.75	1.75	25	25	25	6
		Grid electricity	0.35	0.35	0.35				
Molten media methane pyrolysis, large size	420	Natural gas	2.05	2.05	2.05	20	20	20	11
Non-catalytic methane pyrolysis, small size	2.8	Natural gas	2.50	2.50	2.50	20	20	20	12

Source :

1. IEA 2019: The Future of Hydrogen
2. Blanco H., Nijs W., Ruf J., Faaij A., 2018a, Potential for hydrogen and Power-to-Liquid in a low-carbon EU energy system using cost optimization, Applied Energy 232, pp. 617-639
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6. Bolat P., Thiel C., 2014b, Hydrogen supply chain architecture for bottom-up energy systems models. Part 2: techno-economic inputs for hydrogen production pathways, International Journal Hydrogen Energy 39, pp. 8898-8925
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[263] No reference size for costs provided. However, it is expected that the sizes are in the range between *Alkaline electrolyser large size* and *Alkaline electrolyser small size*, that is between 0.6 MW and 72 MW.

[264] The lifetime in *PEM electrolyser* is increasing due to R&D. Direct application in offshore parks has a higher lifetime due to the lower capacity factor and may be limited by the lifetime of the offshore wind turbines.

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