ENSURING RESILIENCE IN THE EUROPEAN ENERGY TRANSITION

STRATEGIC USE OF GASES TO MEET EU CLIMATE AMBITIONS

Study on behalf of Eurogas

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Executive Summary

"We need all technological options and gases to make the ambitious European energy transition successful, affordable and resilient."

A rapid and profound change is necessary to fulfil our part in the global effort to mitigate climate change. The EU has set targets for emission reductions by 2030, 2040 (under discussion) and 2050. Many existing scenarios outlining pathways to meet ambitious targets often rely on optimistic assumptions, particularly regarding advancements in energy efficiency and technological innovation. One such example frequently cited and debated is the ENTSOs' Ten-Year Network Development Plan ("TYNDP")[1]. Even based on its optimistic assumptions regarding electrification and expansion of renewables, **gases play a vital role in the energy transition** towards achieving net-zero emissions by 2050. When moving from optimistic to more realistic assumptions, we find that the **effective deployment of all available technologies (including renewables, low-carbon gases, and carbon capture[2]) becomes even more important** to ensure a secure, affordable, and ultimately successful energy transition. Our study shows that **investments in renewable and low-carbon gases need to accelerate** as soon as possible to avoid (even more) challenging and costly situations in the future. Especially in the short to medium term (2030 to 2040), climate targets might otherwise turn out to be unattainable, or rely on immature and uncertain technologies.

Energy transition to carbon neutrality: Consumption of gases increases

Our analysis of the Baseline scenario[3] shows that the consumption of gases in final demand increases until 2050: Gas consumption by final demand sectors[4] grows by 15% compared to 2019, even when using optimistic assumptions on the development of energy efficiency and technological change towards electrification. Today's use of mainly natural gas is gradually replaced by renewable and low-carbon gases. Under less optimistic assumptions with respect to progress in electrification and energy efficiency[5], absolute consumption of gases, i.e. methane and hydrogen, increases even further: by 36% compared to 2019. In this scenario, the share of gases in final energy demand increases from 22% in 2019 to 37% in 2050, with hydrogen representing the second largest energy carrier in final energy demand.

22% to 37%

Share of gases in final energy demand from 2019 to 2050

1 ENTSOG and ENTSO-E (2024): Ten-Year Network Development Plan (TYNDP).

2 Carbon capture can involve Carbon Capture and Storage (CCS) or Use (CCU) or Carbon Dioxide Removal (CDR).

3 Based on the final demand assumptions of the Global Ambition scenario of the TYNDP 2024.

4 Households, Buildings, Transport, Industry, others.

5 Used in the "What-if High Demand" scenario of this report.

The optimal mix: A complementary mix of renewable electricity, green hydrogen and methane-based gases with carbon capture minimises costs under various scenarios

The Baseline scenario shows a strong expansion in the deployment of renewable sources of electricity (RES-E). The anticipated growth in RES-E exceeds historical growth rates by a factor of 3. In order to integrate these volumes into the system, a fast ramp-up of electricity conversion technologies (Power-to-X, PtX) and more specifically Power-to-Hydrogen (PtH2) are required.[6] PtX applications represent key technologies that help serve final energy demand in a carbon-neutral way and overcome seasonal and locational differences between electricity supply and demand. Depending on the underlying assumptions on demand development, required electrolyser capacities amount to 360 - 475 GW in 2050 (EU27), compared to 80 MW installed in Europe in 2022. European coordination and cooperation are required to manage this ramp-up as effectively as possible. This ambitious build-out requires reliable investment conditions along the full hydrogen supply chain (including OEMs).

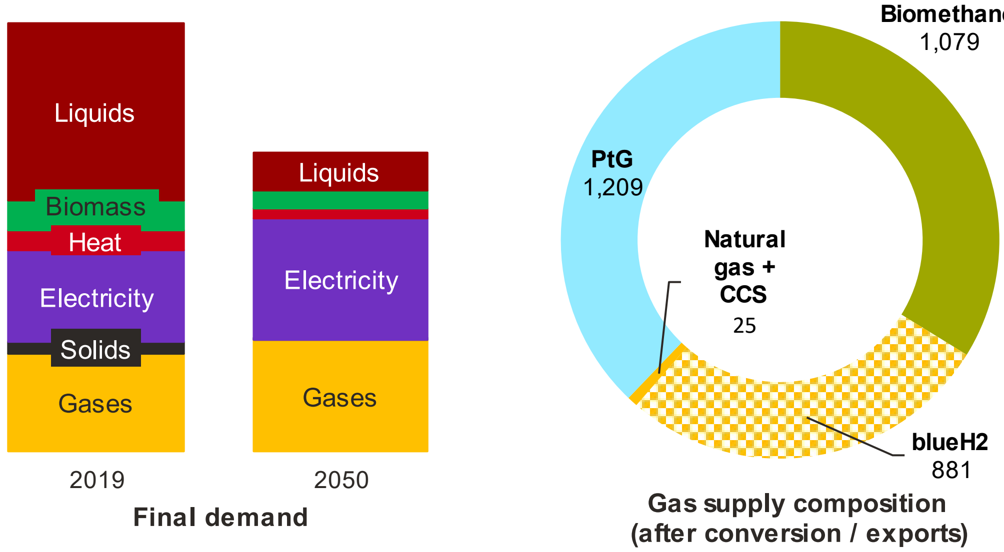
Along with power-to-gas (mainly renewable hydrogen), biomethane, fossil methane (with CCU/S)[7] and low-carbon methane-based hydrogen (blueH2) complement the optimal gas-supply mix towards 2050:

- In the Baseline scenario with high availability of renewable gases (i.e. more biomethane and PtH2 potentials), gaseous fuels contribute 18% (1,900 TWh) of the primary energy supply in 2050, of which 73% are methane-based (in the form of natural gas or imported blueH2). Natural gas is predominantly used to produce blueH2 domestically or, to a lesser degree, as fuel for the electricity sector and to serve end-user demand (coupled with carbon capture).
- The increasing demand for renewable and low-carbon hydrogen is served either by imported or domestically produced blueH2 and PtH2.
- Biomethane is key to replacing natural gas in methane demand and makes up 30% of the optimal gas mix in the Baseline scenario. Coupled with carbon capture, methanisation creates important negative emissions through carbon dioxide removal (CDR) of almost 130 $MtCO_2$-eq in 2050.
- In scenarios where the supply of PtH2 or biomethane does not materialise, imported and domestically produced synthetic methane contributes to security of supply.

6 In our study, fuels produced using electricity, e.g. power-to-x activities (PtX) like electrolysis, fulfil the requirements to be considered sustainable fuels. Hydrogen produced from steam-methane-reforming (SMR) (blueH2) is considered low-carbon.

7 The system is carbon neutral by 2050. The remaining fossil methane use is either compensated by negative emissions from biomethane or used in combination with CCS.

Figure 1 Optimal gas supply mix in final energy demand (EU27 2050, Baseline[8] high renewable gases, TWh)



Source: Frontier Economics

An energy transition that uses the full potential of all available technologies and gases is more resilient...

The use of renewable and low-carbon gases as well as CCU/S is a key pillar to a more resilient energy transition. Domestically produced PtH2 not only enables the integration of vast amounts of renewable electricity into the energy system, but also increases the diversity of energy supply. Alongside biomethane and green hydrogen, natural gas, blueH2 and synthetic methane complement the future gas mix.[9]

The various gases can act as substitutes for each other in most applications if one supply falls short: If the ramp-up of green hydrogen and biomethane production is slowed down, natural gas imports coupled with carbon capture and domestic production of blueH2 can fill the gap.

Flexible gas (with carbon capture) and dual-fuelled natural gas and hydrogen plants offer necessary back-up capacities for the power sector (up to 170 GW[10] in 2050). They

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8 The Baseline scenario is based on the TYNDP 2024 (Global Ambition) final energy demand.

9 Hydrogen can be converted into different derivatives (for example ammonia or methanol). While we account for associated conversion costs in our model (for example when hydrogen derivatives are used for transportation via ships), we only show the base fuels in this report to increase clarity.

10 Scenario “What-if High Demand” (high renewable gases).

complement additional short-term back-up technologies such as large-scale batteries or pumped hydro storage.

If the potentials of renewable gases are not unlocked in time, for example due to regulatory barriers or slow technological rollout, methane-based imports (natural gas via pipeline or as LNG and blueH2) can secure the energy supply and, if coupled with carbon capture, contribute to achieving climate targets.

Carbon capture itself represents another important pillar of the transition as it helps decarbonise unavoidable emissions in industrial processes (e.g. the cement industry). It also allows for more efficient energy importing: it is easier to ship methane molecules than hydrogen molecules or electrons – and with carbon capture in Europe, it is possible to convert the imported methane to blue hydrogen within Europe, rather than storing the carbon dioxide in the exporting country and then shipping the blue hydrogen. CO_2 storage infrastructure makes up an essential part of a future carbon removal value chain for direct air capture (DAC) and bioenergy. Without the CCS option in Europe, additional hydrogen would need to be imported, which would increase the costs of the energy transition.

... and is more cost efficient and affordable than a restricted uptake of renewable gases

up to 540 bn. EUR
system cost savings[11]

due to the efficient use of renewable gas potentials

(NPV 2030-2050, EU27+EFTA+UK)

The energy transition requires significant investment in infrastructure to generate, convert and transport renewable and low-carbon energy across Europe. The decarbonisation of the generation sector between 2030 and 2050 and the development of the conversion sector (Power-to-X and blueH2) alone require investments between 3 and 4 trillion EUR.[12] Industry experts[13] estimate a need for investment in electricity networks at the distribution and transmission level of 67 bn. EUR annually between 2025 and 2050, resulting in additional system costs of 1 trillion EUR[14].

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[11] Total system costs include investment, operation and maintenance, and other variable costs for energy sector technologies (generation and storage technologies for electricity and other energy conversion processes, including electrolysis, methanisation of biomass and steam methane reforming), fuel import costs, and carbon capture costs (investment, operation, transportation, and storage costs). Final demand, and transmission and transportation infrastructure are constant within scenarios and thus costs cancel out each other. Energy distribution infrastructure is not part of the analysis; thus costs are neglected.

[12] Optimised investment in energy supply / storage capacities and energy conversion (e.g. PtG), considering learning curve effects, expressed as NPV (5% discounting) between 2030 and 2050. Monetary values are expressed in 2021 Euros, future prices are deflated 2% inflation rate assumption. Social discount rate used in system costs analysis and energy system modelling amounts to 5%.

[13] Eurelectric (2024): Grids4Speed.

[14] Net present value 2025, 5% discounting.

Effective planning and execution of the energy transition is essential to minimise financial burdens and ensure the competitiveness of European businesses in the global market. The availability of renewable, low-carbon gases and carbon capture is crucial for an efficient energy transition. Efficient integration of renewable energy sources into the system and an optimised gas supply mix result in significantly lower energy system costs by up to 540 bn. EUR and, consequently, lower energy prices. Our scenario-based analysis shows that using the full potential of renewable gases can lead to an average wholesale electricity price reduction of 4 to 28 EUR/MWh[15] and decrease energy-related costs of hydrogen by up to 1 EUR/kg compared to a world with a constrained supply of renewable gases. Lower energy prices in turn reduce consumer payments for the supply of electricity and hydrogen by up 1.2 trillion EUR between 2030 and 2050.[16]

Use of renewable and low-carbon gases requires methane and hydrogen infrastructure

Both renewable and low-carbon hydrogen as well as renewable methane (biomethane or SNG) need to be transported, distributed and stored. As methane demand declines, part of the existing methane grid can be transformed into hydrogen infrastructure. At the same time, methane grids are also required to cover final demand in many regions, at least in the medium-term.

Gas transport and storage infrastructure also helps alleviate pressure on the European electricity transmission networks. Our analysis shows that the transport of energy via molecules instead of electrons can help reduce congestion in electricity grids and significantly decrease its associated costs.[17]

A balanced decarbonisation path including low-carbon and renewable gases can be more cost efficient and resilient than a high electrification approach

In addition to the Baseline scenario, we analysed a High Electrification scenario. While all other assumptions remain identical, the final demand development until 2050 in the High Electrification scenario is based on the TYNDP Distributed Energy scenario (while the Baseline is based on the Global Ambition scenario).

The TYNDP Distributed Energy scenario assumes more insulation of buildings, higher market shares of efficient electricity-based technologies (for example heat pumps and electric vehicles), lower economic activity, as well as more energy-conscious consumer behaviour. Comparing this with historical trends for building renovations and technology changes in final

15 EU27 weighted average power price difference (2030-2050)

16 Impact of high availability of renewable gases on EU27 energy related consumer payments for electricity and hydrogen (NPV @ 5%, 2030-2050), industrial and household energy demand only. Not including impact on levies, taxes or grid fees.

17 Associated with a different energy supply mix, not considering costs of networks or pipelines.

demand indicates that these changes are challenging to achieve – even more so than the already ambitious targets in the Global Ambition scenario.

Even in an electrification scenario like the TYNDP Distributed Energy scenario, which assumes drastic changes in end-user sectors that contradict current experiences with transition speeds, gases represent 27% of final energy demand in 2050 – an increase from 22% in 2019. Hydrogen is the second largest final energy demand fuel (after electricity, at 49%). However, due to significantly lower total final energy demand (declining by one-third compared to the base year 2019), absolute gas demand in 2050 is 18% lower than in 2019.

Our modelling results show that even in a high electrification scenario, renewable and low-carbon gases still play an important role in the energy system. These include supporting the integration of variable renewables via the flexible operation of electrolysers, providing back-up capacity during low variable RES-E generation, and the decarbonisation of hard-to-electrify sectors.

at least 550 bn. EUR higher system costs in the High Electrification scenario

comparison between Baseline and High Electrification scenarios

(NPV 2030-2050, EU27+EFTA+UK)

We find that the discounted total system costs[18] for the years 2030 to 2050 are estimated to be at least 550 bn. EUR higher in the High Electrification scenario than in the Baseline scenario. The main drivers for this are increased insulation and heating appliances costs in the households and buildings sector, and increased costs in the transportation sector.

The additional expenditures are partially offset by savings on the energy supply side: the lower final energy demand in this scenario means reduced fuel costs. Distribution grid costs, which are likely to increase with the electrification of final demand, are out of the scope of this study and not taken into account. As a result, our estimate represents a lower bound for the cost difference between the scenarios.

A more balanced approach including low-carbon and renewable gases is likely to be more resilient to external shocks and potentially higher final demand: Gases enable the integration of the European energy system into global markets which provide flexibility in sourcing low-carbon fuels.

18 In addition to the components used for the system cost comparisons within scenarios (see footnote 11), the comparison between the Baseline and High Electrification scenario includes differences in cost for appliances in final demand sectors (e.g. for heating systems).

Unlocking the full potential of all available technologies to ensure a successful, affordable, and resilient energy transition

In order to unlock the full potential of renewable and low-carbon gases, we need to set the regulatory course in the right direction. Apart from a reliable planning and investment environment, this requires both coordinating and maintaining important elements of methane infrastructure for future use, as well as building additional hydrogen infrastructure, including pipelines, storage and terminals.

European coordination and cooperation between Member States should focus on ensuring liquidity in new European hydrogen markets and on the development of the required well-connected infrastructure for gases and electricity.

The ramp-up of renewable, low-carbon gases and carbon capture must accelerate. Otherwise, meeting the ambitious long-term climate and energy targets would be difficult, or only possible at a prohibitively high cost using immature technologies.

1 Introduction

1.1 Background

EU Climate Law stipulates the goal to reach carbon neutrality by 2050. Intermediate targets have been set for 2030 (-55% compared to 1990) and are currently in discussion for 2040 (-90%). The current EU decarbonisation strategy, which is also the basis for important publications like the Ten-Year Network Development Plan of the ENTSOs[19] and the European Commission's Impact Assessment for the 2040 emission reduction target[20], emphasises energy efficiency improvements, electrification, and renewable electricity. With this study, Eurogas has commissioned Frontier to follow an evidence-based, technology-neutral approach focusing on the future role of renewable and low-carbon gases in ensuring a more resilient energy transition amidst considerable uncertainties.

1.2 Aim and limitations of the study

The study supports the debate on the EU's energy transition and emphasises the ambitious nature of targets around energy efficiency, electrification, and renewable electricity. We identify critical bottlenecks in the current decarbonisation strategy and demonstrate the benefits of a more balanced approach, involving various technology options and placing a strong focus on integrating the decarbonisation strategies for different sectors.

The study uses the ENTSOs' TYNDP 2024 as a basis and expands the analysis using our Cross-sector Optimisation Model for the Energy Transition (COMET), which determines cost-optimal pathways for the decarbonisation of the energy sector with high regional granularity. For all scenarios, we assume that EU emission reduction targets will be met: -55% in 2030, -90% in 2040, and net neutrality in 2050.

Although we base our scenario assumptions on the TYNDP long-term scenarios, in particular for final energy demand, this should not be interpreted as an endorsement of its data or assumptions.[21] We chose to use the TYNDP scenarios as they provide a neutral starting point for our analysis not least due to the extensive public consultation during the preparation of the

19 ENTSO-E / ENTSOG (2024).

20 European Commission (2024): Impact Assessment on a 2040 target, SWD/2024/63 final.

21 While the scenarios are a valuable source of data with (although with room for improvement) a good level of detail and transparency of the underlying data and assumptions, the scenarios are not without flaws regarding data quality and being up-to-date. During our analysis of the final demand data, we discovered several inconsistencies between ETM/TYNDP data and renowned public sources. This was also pointed out by the TYNDP's Stakeholders Reference Group in their Feedback on the preliminary 2024 TYNDP Scenarios Results. Additionally, in many cases, more recent data than the reference year 2019 is available. We therefore recommend updating the assumptions for the next edition of the TYNDP.

TYNDP, the framework guidelines prepared by ACER[22], and the need for approval by the European Commission.

Accordingly, our model uses final energy demand as an input. Technological development in final demand sectors is therefore not optimised, but rather an exogenous assumption in any given scenario. Additionally, transmission grids for electricity, gas and hydrogen are taken as inputs and are not optimised. We refer to TYNDP and the European Hydrogen Backbone to derive net transfer capacities between modelled regions. The distribution grids are not included in the analysis, and we implicitly assume that distribution capacity will be available for all energy carriers.

1.3 Cross-Sector Optimisation Model for the Energy Transition (COMET)

1.3.1 Model description

COMET[23] is a linear optimisation model that simultaneously optimises the supply of electricity, gases (methane and hydrogen) and other energy carriers. Subject to supply potentials, transportation and storage constraints, the model chooses between different ways of serving energy demand to define the cost-optimal pathway to decarbonise the economy. For example, COMET optimises

- investment and dispatch of electricity generation technologies such as renewables, power plants and storages, while considering periods of low variable renewables generation and high demand to determine how much back-up capacity is needed in order to serve demand in all hours;
- the domestic production of blue hydrogen (blueH2) and Power-to-Hydrogen (PtH2), considering requirements laid out in REDII;[24]
- the mix of imported and domestically produced energy products, including trade within Europe as well as markets outside of Europe;
- the mix of gases to supply final demand and to integrate RES-E into the energy system.

The model is neutral towards all technology options and fuels (except for regionally specific constraints concerning the use of lignite, coal and nuclear plants). Thus, the optimisation finds the cost-minimising solution to meet emission constraints without making a-priori assumptions (e.g. regarding the supply mix for serving methane demand). It therefore represents a level playing field for all available options and combinations of technologies to reach given targets.

The geographical focus lies on the EU27 member states and adjacent regions such as the UK, Norway, Switzerland and the Balkans. Fossil and decarbonised energy can be imported

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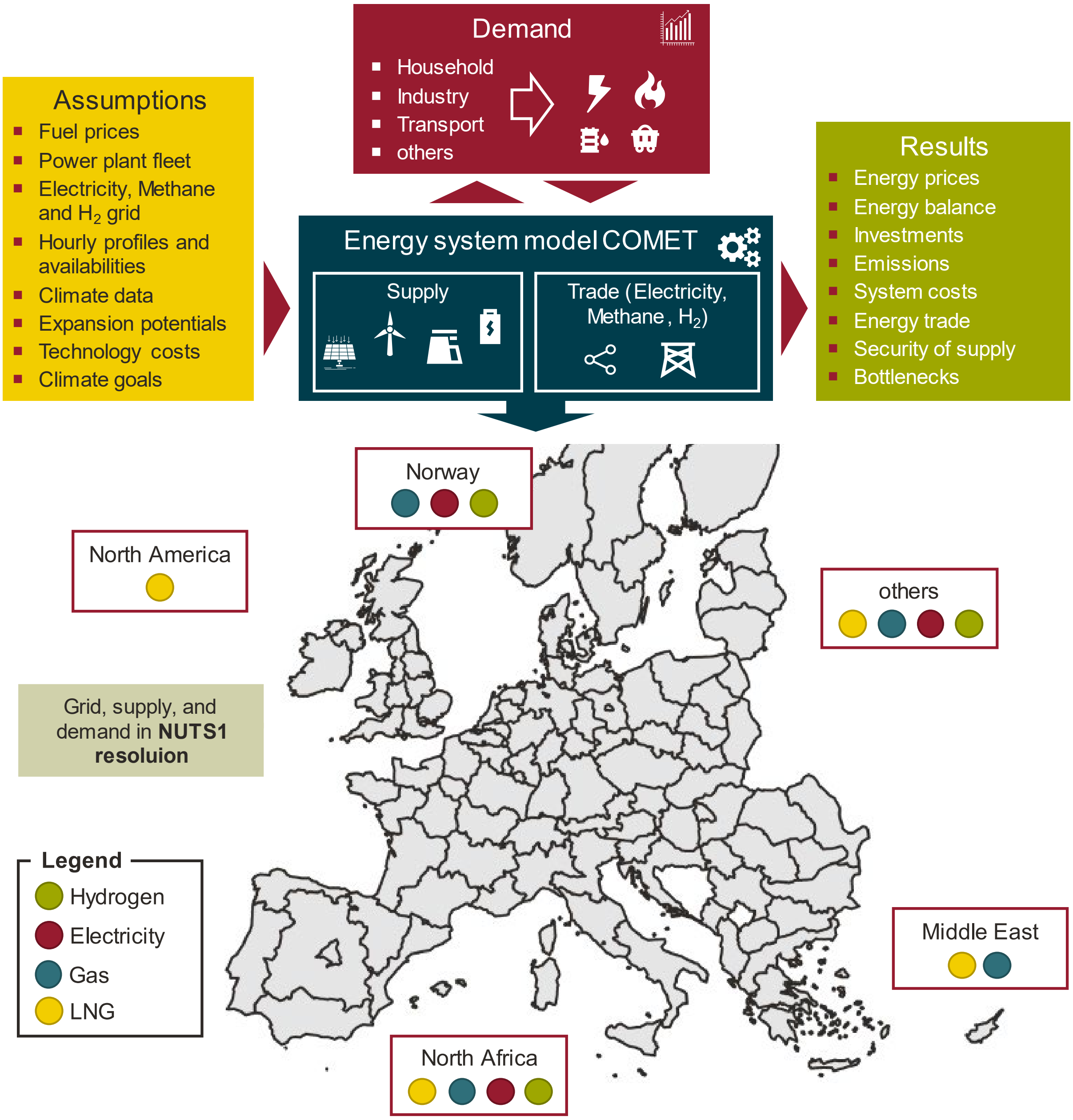
22 See ACER (2023): [Framework Guidelines for the joint TYNDP scenarios to be developed by ENTSO for Electricity and ENTSO for Gas - “TYNDP Scenarios Guidelines”](.).

23 A detailed model description can be found in the separate technical report accompanying this study.

24 Concerning temporal and spatial correlation of RES-E and H2 electrolysis.

from various regions. Electricity markets are modelled on an hourly basis and gas markets with a daily resolution. We model one representative week per season and a two-week cold dark doldrums ("Kalte Dunkelflaute") period with low RES-E availability and high demand. The model optimises 5 snapshot years with perfect foresight.

Figure 2 COMET overview



Source: Frontier Economics

1.3.2 Modelling of emission targets and carbon capture

For all scenarios, we assume that EU emission reduction targets will be met:

- **Fit-for-55 and the European Green Deal**: For 2030, the European climate law stipulates a 55% emission reduction by 2030 compared to 1990;
- **2040 target**: The EU has not yet finally adopted an emissions reduction target for 2040, latest proposals by the European Commission set out an ambition of around -90%.
- **EU Climate Law:** The EU Climate law articulates the long-term ambition of carbon neutrality until 2050.

We model emission targets as annual emission constraints limiting the use of fossil fuels corresponding to their respective GHG content. The model choses the cost optimal mix of fossil vs. renewable and low-carbon energy carriers to serve final demand subject to those constraints. Additionally, carbon capture technologies can be employed subject to availability and costs.

We derive annual emission limits corresponding to the scope of our model referring to scenario 3 of the EU Commission's Impact Assessment for a 90% emission reduction until 2040: Land-use and land-use change and forestry (LULUCF) net-removals are estimated to reach ca. -330 $MtCO_2$-eq in 2050. The model does not capture non-energy related emissions from agriculture, which are assumed to decrease from 385 to 249 $MtCO_2$-eq in 2050. Accounting for these out-of-scope emissions results in a limit for in-scope emissions of 84 $MtCO_2$-eq in 2050.

Modelling of carbon capture

We consider various ways of carbon capture and storage/usage. The model choses between the cost-optimal combination of using renewable and low-carbon fuels as well as carbon capture to reduce emissions or even create negative emissions through carbon removal:

- carbon capture in final demand sectors (specifically in industrial sectors),
- carbon capture in electricity generation,
- carbon capture associated with the production of blueH2;
- carbon removal through bioenergy with carbon capture and storage (BECCS); and
- carbon removal through direct air capture and storage (DAC).

The latter two options of carbon removal create negative emissions as carbon content is removed from the atmosphere, either through the route of bioenergy or direct air capture. We model carbon capture in electricity generation, blueH2 production and biomethanisation as investment options with respective assumptions on CAPEX, OPEX, lifetimes, and others.

Carbon capture in final demand sectors is modelled assuming a merit order of carbon capture options with different potentials and costs (EUR/tCO_2-eq). From today's perspective, DAC has to be understood as an uncertain and immature technology. In our model, it represents a "last resort" option that enables the model to achieve the emission reduction targets. Therefore, its model representation is simplified with a levelised cost approach.

Modelling of Power-to-X technologies

Sector coupling and energy conversion technologies are key enablers of the energy transition. Converting renewable electricity to gases or liquids provides flexibility and supports the integration of variable renewable electricity sources into the energy system. To be able to distinguish fuels produced with renewable and non-renewable electricity, the European Union has set specific criteria that the electricity used in the conversion process needs to fulfil.[25] If these criteria are fulfilled, the energy produced can be called "Renewable Fuel of Non Biological Origin ("RFNBO")".

We explicitly model the REDII criteria on renewable hydrogen related to the hourly correlation of RES-E supply and electrolysis electricity consumption (temporal correlation, Art. 6) and the geographical correlation (Art. 7), stating that the renewable energy installation and electrolyser must be located in the same bidding zone. The third criterion on so called "additionality" (Art. 5) is not explicitly modelled. However, the model endogenously invests in RES-E in order to fulfil the demand for electricity (either from final demand or electrolysis), such that using renewable electricity for PtX does not imply reducing the availability of renewable electricity for final demand.

Definitions and nomenclature for different energy carriers

Our study analyses the contribution of renewable and low-carbon gases for achieving a resilient and affordable energy transition. The future energy mix is diverse and various energy carriers contribute to achieving our climate targets. In this section, we define our nomenclature for the different energy carriers of our analysis:

- **Fossil-based energy carriers:** Subject to emission constraints, the model can use fossil-based fuels like hard coal, lignite, oil or oil-based liquids and natural gas (methane).
- **Renewable and low-carbon fuels:** Renewable electricity is mainly produced from wind, solar or hydro installations. Biomass can be used directly as feedstock or to produce bioenergy, e.g. in the form of biomethane. Renewable electricity is an important input into energy conversion to produce renewable fuels of non-biological origin, like renewable hydrogen. These processes are part of the so-called Power-to-X activities, for example Power-to-Hydrogen (PtH2) or Power-to-Methane (PtM). Biomethane and gases produced from electrolysis (using renewable electricity) are defined as renewable gases. Hydrogen produced from methane using the steam methane reforming process (blueH2) is defined as low-carbon gas. Hydrogen production via the pyrolysis route (turquoise H2) is not included in the analysis as it represents a less mature technology. Nonetheless,

[25] EU Delegated Acts on Renewable Hydrogen, Commission Delegated Regulation (EU) 2023/1184 of 10 February 2023.

technological advancements in that field could grant an additional option to serve growing demand for hydrogen.

1.4 Our approach for determining the future energy system differs from the TYNDP and the EU Impact Assessment

Two recent major studies analyse long-term pathways for the European energy system: The TYNDP 2024[26] and the EU Impact Assessment[27]. Although we base parts of our assumption on the TYNDP 2024, a direct comparison of our results with both of those studies is not possible due to differences in scope, purpose, assumptions, and modelling methodology. Nonetheless, we provide context of main differences and possible implications for the outcomes in the following, starting with the TYNDP 2024 and ending with the Impact Assessment.

Our modelling approach differs from the TYNDP 2024 as well as the EU Impact Assessment in the following ways:

- **TYNDP and EU Impact Assessment do not analyse scenarios in which certain targets are missed:** The basic idea of both studies is to analyse scenarios in which all national and European targets are achieved. This concerns for example energy efficiency improvements or the feasibility of renewables capacity expansions. We agree that the overall emission reduction targets should not be questioned. However, to analyse how the energy transition can be managed in a robust and resilient way, it is necessary to also look at scenarios in which certain secondary targets might be missed.
- **We isolate the contribution of low-carbon and renewable gases:** Contrary to the ENTSOG/ENTSO-E and EU studies, we isolate the contributions of low-carbon and renewable gases by varying their assumed potential and contrasting the respective scenario outcomes. Without this, the possible contributions of these technologies cannot be clearly identified.

1.4.1 Differences between the TYNDP 2024 and our study

- **TYNDP's a-priori determined methane import mix does not allow for an analysis of the optimal mix:** The TYNDP assumes an a-priori blend of different methane derivatives.[28] For example in the Global Ambition (GA) scenario in 2050, a methane blend import mix of 21% natural gas, 63% biomethane and 17% Power-to-Methane is assumed. The import price of this mix is calculated according to the weighted price of each component. This approach prevents analysing the possible role each of the different

26 ENTSOG and ENTSOE (2024): Ten Year Network Development Plan.

27 European Commission (2024): Europe's 2040 climate target and path to climate neutrality by 2050 building a sustainable, just and prosperous society.

28 See TYNDP (2024): Supply Inputs for TYNDP 2024 Scenarios After Public Consultation.

supply options can play individually and how they compare to each other in terms of costs and benefits (for example by weighing the costs of CCS, in the case of natural gas imports, against the costs of importing synthetic methane). This affects, for example, the amount of blue hydrogen production (via Steam Methane Reforming (SMR) with CCS): Given that methane blend import costs are more than three times as expensive as natural gas imports[29], SMR automatically is very expensive without considering importing natural gas and using CCS to decarbonise. Contrary to the TYNDP's approach, we allow for individual imports of different methane derivatives and thus an endogenous determination of the (cost-) optimal supply mix.

- **The TYNDP uses exogenous carbon prices that might result in inconsistencies:** The TYNDP assumes exogenous carbon emission prices (similar to the majority of fuel price assumptions) based on the IEA World Energy Outlook Announced Pledges Scenario.[30] It is reasonable to stay with a single source for exogenous price assumptions (assuming prices in this source a consistent), in particular for globally traded commodities like gas and coal prices which are less influenced by domestic developments. However, carbon prices are, to a large extent, determined by the domestic costs of serving energy demand while remaining within the (exogenously determined) emission limits. As the TYNDP deviates from the WEO for several important drivers of these costs (e.g. investment costs and final demand), the exogenous CO_2 price might a) be too low to trigger the necessary emission reductions or b) be too high and thus result in an overshooting of emission reduction targets. This is why we use an exogenous carbon budget in our analyses which results in endogenous emission prices. Our results indicate that the TYNDP prices for CO_2 emission allowances could be too low.[31] This could result in an undervaluation of low-carbon technologies and impede the analysis of an optimal (cost-efficient) future technology and fuel mix.

- **Technology-cost and fuel price assumptions have been updated for this study:** The sources for the TYNDP 2024 scenario assumptions partly date back several years, depending on the individual data point. For example, the majority of fuel price assumption stem from the 2022 World Energy Outlook. We have updated these assumptions using the latest available data. For example, for natural gas prices in 2050, this results in prices over 20% lower – this is data from the latest WEO (2023) compared with the TYNDP (WEO 2022) data.[32] Given the significant decline of fossil fuel prices (and associated price projections) after 2022, the higher prices used in the TYNDP 2024 could potentially result in a faster phase-out of natural gas-based option than is cost-efficient based on the future price projections prevalent today.

29 In the TYNDP GA scenario in 2050.

30 The TYNDP 2024 uses the "Announced Pledges Scenario" (APS) from IEA (2022): World Energy Outlook 2022.

31 However, we have updated further assumption for example regarding technology costs. Thus, our observations are only indicative.

32 Adjusted for inflation.

1.4.2 Differences between the EU Impact Assessment and our study

- The assumed very strong decline of final demand in the Impact Assessment might underestimate the magnitude of the task and therefore required decarbonisation efforts: For 2030, the EU Impact Assessment, similar to the TYNDP, assumes that the EU energy efficiency target of 763 Mtoe (about 8,874 TWh)[33] will be reached.[34] For 2040 and 2050, the Impact Assessment assumes an even stronger final demand reduction than the TYNDP Global Ambition scenario: In scenarios S1-S3, it assumes a 43% reduction in final energy demand by 2050 compared to 2019 (36-38% by 2040). This is significantly higher than the 35% by 2050 (25% by 2040) in the TYNDP Global Ambition scenario (which we decided to base the Baseline scenario on). However, reaching the target in the foreseeable future is rather uncertain. In March 2024, the European Environment Agency stated that "[…] *it is unlikely but uncertain that the EU will meet its energy efficiency targets for 2030"*.[35] However, underestimating final energy demand (and therefore the magnitude of the task ahead) could result in setting policy objectives and regulations that are ill-prepared to handle a deviation from certain targets.

33 The TYNDP typically shows final energy demand values that include more items than final energy demand in the European Commission studies: While the TYNDP includes all sectors, including energy sector, non-energy use, international aviation and international shipping, the EC studies exclude energy branch, international shipping, ambient heat, non-energy and include aviation. The comparison here follows the EC's approach. See also ENTSOG/ENTSO-E (2024): TYNDP 2024 – Scenarios Report: Data Figures, figure 41.

34 See European Scientific Advisory Board on Climate Change (2024): Towards climate-neutral and resilient energy networks across Europe - advice on draft scenarios under the EU regulation on trans-European energy networks.

35 See European Environmental Agency (March 2024): Primary and final energy consumption in Europe.

2 Scenario Framework: Our analysis of the contribution of gases to a successful, resilient and affordable energy transition

In order to analyse the impact and role of renewable and low-carbon gases in the future energy mix towards a net zero energy system we have applied a combination of scenarios (mainly based on TNYDP 2024, EC Impact Assessment) and also applied several stress tests (so called "What-if" scenarios) when reaching our decarbonisation targets. In the following section, we present our applied scenario framework as well as key assumptions underlying the different cases. The section is structured as follows:

- Overview on scenario architecture (**section 2.1**);
- Baseline assumptions (**section 2.2**);
- What-if scenario assumptions (**section 2.3**);
- Differentiation between high and low renewable gas availability (**section 2.4**);
- High Electrification scenario (**section 2.5**); and

2.1 Overview on our scenario architecture

Our analysis is based on one Baseline and three deviation scenarios, called "What-if" scenarios. The **Baseline scenario** uses key assumptions from the **TYNDP 2024 Global Ambitions** scenario: We use this scenario for its relevance in the public debate, the public consultation and approval process, and the detailed publicly available data. However, this should not be considered an endorsement (see also section 1.2). In each **What-if** scenario, we analyse critical bottlenecks of the decarbonisation strategy underlying the Baseline scenario and discuss possible deviations from the expected development and corresponding scenario assumptions:

- "**What-if High Demand**": The EU's energy efficiency and therefore final demand reduction targets are very ambitious compared to the historical trend and recent developments. As achieving these targets is assumed across all TYNDP and EU Impact Assessment scenarios, we chose to look at the implications of a less optimistic outlook for energy efficiency improvements and technological change, coupled with a more optimistic outlook for overall economic activity, resulting in a decreasing but higher final energy demand in Europe compared to TYNDP/Impact Assessment assumptions for 2050.

- "**What-if Low RES**": A rapid ramp-up of variable renewable capacity additions (wind and solar) is central for achieving decarbonisation targets. However, among others, significant price increases in the early 2020s, supply chain issues[36], a more difficult market environment for capital intensive technologies and investment uncertainties give rise to

[36] See IEA (2023): Renewable Energy Market Update - June 2023 and Renewables 2023.

concerns regarding the speed of new installations. Hence this scenario analyses the implications of constrained build-out of renewables.

- "**What-if Delayed Grids**": Electricity grids are essential for the integration of variable renewables into the energy system. At the same time, new builds often face long permit waits, public opposition and consequently delays. This scenario therefore assumes that the build-out of electricity grids is delayed compared to the Baseline assumptions.[37]

In addition to the Baseline and the What-if scenarios, which are all largely based on the final energy demand assumptions of TNYPD's Global Ambition scenario, we analyse the outcomes of a scenario that puts even more emphasise on the electrification of final demand. The **High Electrification** scenario (HE) is based on the final energy demand assumptions of TYNDP's 2024 Distributed Energy scenario. The aim of this scenario is twofold:

- Firstly, it allows us to validate and confirm our conclusions concerning the role of low-carbon and renewable gases in a setting that puts more emphasis on electrification than the Global Ambition scenario (robustness check).

- Secondly, it enables us to compare the outcomes and results of the High Electrification with the more diversified Baseline scenario to further analyse the potential advantages of a more balanced and technology-neutral approach versus a strong emphasis on electrification.[38]

For all four main scenarios, we analyse an additional sensitivity called "low renewable gases". This sensitivity differs in the availability of domestic biomethane supply and Power-to-Hydrogen production, and with respect to import potentials for renewable and low-carbon gases. It represents a situation in which steps that are necessary today to promote and build up a low-carbon gas economy (political and financial support, regulatory guidelines, investment certainty etc) are not taken and consequently these options are severely restricted in future (see also section 2.4).

- "**High renewable gases**" therefore uses potentials based on the TYNDP Global Ambition scenario; and
- "**Low renewable gases**" assumes a restricted availability of low-carbon and renewable gases (domestic or imported).

This set-up allows us to directly compare the scenario outcomes of a future energy system with a higher or lower availability of low-carbon gases and thus **isolate the impact this difference in renewable gas availability can make**.

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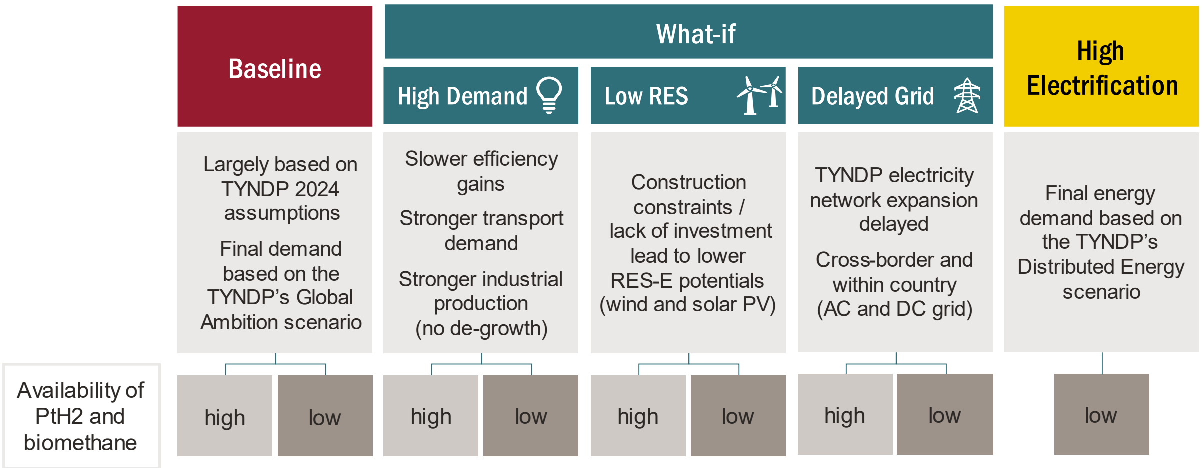
37 Baseline assumptions derived from TYNDP2022 and European Resource Adequacy Assessment (ERAA).

38 While this comparison enables us to gain insights into the relative differences between the scenarios, we cannot draw absolute conclusions: As the final demand side is not optimised, it is likely that more efficient transition pathways exist.

Figure 3 Overview on our applied scenario framework



Source: Frontier Economics

2.2 The Baseline assumptions are largely based on the TYNDP 2024 Global Ambitions framework

The TYNDP 2024, and more specifically its underlying scenario assumptions and outcomes, represent an important reference for energy policymakers and businesses alike. The ENTSOs (Gas and Electricity) define two long-term views on the development of energy demand and supply, while both scenarios reach emission reduction targets by definition.

- **Distributed Energy** – The Distributed Energy scenario (DE) is characterised by a strong focus on prosumers and a decentralised energy transition. It relies less on global synergies and features a relatively high emphasis on energy efficiency and electrification.
- **Global Ambition** – The Global Ambition scenario (GA) on the other hand offers a more diversified energy mix and pathway to decarbonisation. It assumes higher benefits from global efficiency gains and is based on higher shares of hydrogen and liquid energy carriers in final consumption.

We use the **Global Ambition** scenario to derive a number of key input assumptions for our modelling:

- **Final energy demand** is derived from Quintel's Energy Transition Model[39] using the final input parameters of the GA scenario published by ENTSO in 2024.[40] Despite putting a smaller emphasis on energy efficiency than the DE scenario, the achieved reduction in

[39] The Energy Transition Model (ETM) is an interactive online simulation tool for energy systems developed by Quintel. With regard to the accuracy and timeliness of the data see also footnote 21.

[40] Demand Scenarios TYNDP 2024 After Public Consultation, published in January 2024

final demand in 2050 compared to 2019 amounts to about 3,700 TWh, which corresponds to a 30% reduction in final demand and roughly equals today's combined final energy demand of Germany, the Netherlands and Belgium together.

- **RES-E potentials**, i.e. the maximum capacities for variable renewables (wind and solar) by 2030, 2040 and 2050 are taken directly from the TYNDP. The possible expansion path exceeds today's volumes significantly: installed RES-E capacity is allowed to grow by 800% compared to 2022, reaching up to 3,600 GW in 2050.

- **Electricity transmission networks** are a key subject of the TYNDP. We use the TYNDP 2022 as basis for our analysis as Reference Grid and expansion projects from TYNDP 2024 were not yet available at the time of writing of this report. Assuming no delay in project completion leads to a 200% increase in our modelled cross-country DC capacity between 2019 and 2050, and a 300% increase in the intra-country DC capacity[41].

2.3 Our "What-if" scenarios highlight the implications of some key assumptions and show what happens if these trends do not materialise

The Baseline scenario allows us to analyse the role of gases in the optimistic setting of the TYNDP's Global Ambitions scenario framework. Our three What-if scenarios illustrate the critical bottlenecks and how gases can help to build a more resilient energy transition.

2.3.1 Final Energy Demand ("What-if High Demand")

The TYNDP 2024 Global Ambition scenario leads to a significant decrease in the overall final energy demand of the European Union of -20% by 2040 and -30% by 2050 compared to 2019. This decrease applies to all sectors and can be explained by a combination of large energy efficiency gains and changes in the mix of energy carriers (mostly through electrification). Changes in the final demand rely on assumptions provided to the Energy Transition Model (ETM) on the value of parameters (323 unique parameters) for each European country (28 countries[42]) at each modelled year (3 years – 2019, 2040 and 2050). In total, there are 9,044 assumed parameters provided to each combination of country, year.

Some of the underlying modelling assumptions for future energy final demand seem optimistic and do not reflect current trends for improvements in energy efficiency, nor the observed changes in technologies. In this section, across the three main sectors (Households & Buildings, Industry & Transport):

- We review the main modelling assumptions driving sectoral final demand;

41 Modelled as aggregated connections on NUTS1 level.

42 UK parameter values are based on the July 2023 version of the TYNDP input parameters while the parameters' value of any other EU country is based on the Jan 2024 version of the TYNDP input parameters.

- We provide perspective on some optimistic assumptions; and
- We detail our approach in order to derive more realistic modelling assumptions.

A detailed description of underlying assumptions is included in the separate technical report accompanying this study.

Households & Buildings: Large increase in building insulation and fast role out of heat pumps

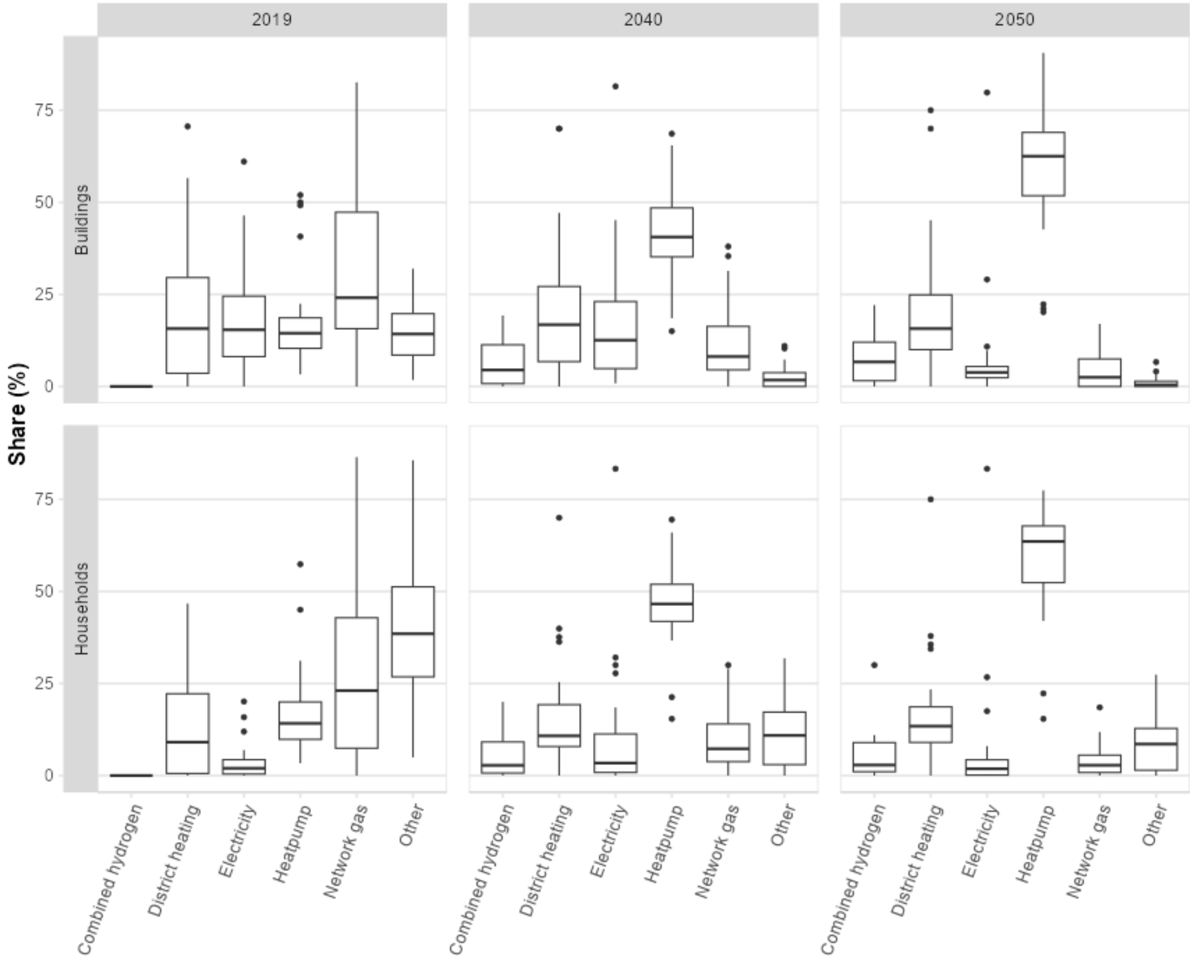
In this section, we describe the Baseline (TYNDP 2024) assumptions concerning the development of Household & Buildings' final energy demand, provide our perspective, and detail alternative modelling assumptions.

- **Baseline assumptions:** The change in the final energy demand from the Households & Buildings relies on three main inputs:
  - **Slow growth/decline in the number of inhabitants and households**: The total number of inhabitants is assumed to grow by 0.3% in 2040 and assumed to decrease by -0.4% in 2050 compared to 2019. The total number of residences increases by 7% in 2040 and by 10% in 2050 compared to Baseline 2019.
  - **Large increase in the insulation rate of buildings**: In 2040, the median level of heat demand reduction is 24.6% for households and 36.9% for buildings (compared to 2019). In 2050, the median level of heat demand reduction is 34.4% for households (ranging between 30%-50%), and 51.6% for buildings (ranging between 30%-68%).
  - **High penetration of heat pump technologies** for heating leading to a large increase in electrification: the ETM has multiple technologies using different fuels available for space and water heating.[43] The 2024 TYNDP Global Ambition scenario assumes a large increase in the share of heat pump technologies for space and water heating from around 14% in 2019 to a median share of 40.6% in 2040 and 62.5% in 2050 for Households and 46.6% and 63.6% for Buildings respectively.

  Figure 4 shows the share of technologies for space and water heating in the Households and Buildings sector underlying the Baseline scenario.

[43] Natural gas, hydrogen, biomass or electric boilers or combi boilers, district heating and multiple heat pump technologies.

Figure 4 Technology share input assumptions for space and water heating in the Buildings and Households sectors (share per country)



Source: Frontier Economics based on TYNDP 2024 input data

Note: "Other" is the sum of oil, coal and biomass heater shares; Boxplot graph shows the distribution of the shares, more extreme outliers (> 1.5 times the interquartile range) are depicted as outliers.

- **Perspective on the Baseline assumptions** – Some of these assumptions can be considered as optimistic compared to historical trends.
  - In particular, the **large reduction in the heat demand** of buildings does not reflect the average increase in renovation rate.[44] The BPIE in its "How to stay warm and

[44] There is no clear correspondence between reduction in heat demand of buildings and the renovation rate: the reduction in heat demand relies on the level of energy consumption of the building before the renovation, and the depth of this renovation. The ETM made a correspondence between the reduction in heat demand of buildings and a uniform shift of all buildings from a specific energy performance (associated with an energy label) to another energy performance level. For example, a 27% decrease in heat demand corresponds to a complete renovation of all apartments from level G energy label to level B.

save energy" report[45] estimates that a full renovation scenario of all EU buildings would lead to a total decrease in final energy consumption of 22% in 2040 and 42% in 2050. This extreme scenario is built to reach 100% of renovated building stock by 2050. A "middle" scenario assumes that the renovation rate from 2030 onwards is 2% per year (compared to a current renovation rate of 1% per year); the total energy savings in 2040 is 18% and 29% in 2050. **However, these estimates show that the TYNDP 2024 leans towards a "full renovation scenario"** – which would require a drastic increase of current efforts.

- Similarly, the **penetration of heat pumps** as the main heating technology seems unrealistic compared to current trends. In Germany, the share of air heat pumps (air-to-air and air-to-water) estimated in 2019 in the ETM assumptions is 8% (which is likely to be an overestimation); it is 45% in 2050. In 2023, about 6% of heating stock were replaced by new heaters in Germany, and 25% of them were heat pumps. To reach the target, the share of heat pumps in new heaters needs to increase to about 55%. In many cases an installation of heat pumps is not efficient if the residence is not isolated beforehand. Therefore, assumptions on the heat pump penetration should also consider the renovation rate.

- **Adapted assumptions for our "What-if High Demand" scenario** - To consider these limitations within the 2024 TYNDP scenario assumptions compared to "real world" observations/expectations, our What-if scenario proposes updated assumptions. We assume a **slower renovation rate** than applied in TYNDP 2024 (in line with the 2% renovation rate from the BPIE scenario) and a **slower penetration of heat pump** technologies compared to TYNDP 2024. For this we:
  - Decrease the assumed progress in **insulation levels** (for all types of households) by 17% for households and by 40% for buildings for both 2040 and 2050 compared to TYNDP 2024 assumptions[46];
  - Limit the increase of the **heat pump share** in heating technologies: we delay the change in technology share by deducting 20% of the change between 2019 and the target year (2040 or 2050) for households and 30% of the change for buildings. The still results in a total of 306m heat pumps in 2050 (EU + UK) compared to 360m in the Baseline scenario.

45 BPIE (Buildings Performance Institute Europe) (2023). How to stay warm and save energy – insulation opportunities in European homes.

46 Except for the Netherlands which has input parameter values for the decrease in heat demand much smaller than similar European countries.

Industry sector – declining industrial output assumed under GA scenario

- **Baseline assumptions –** Final energy demand development within the industry sector is driven by several effects such as activity levels, efficiency gains and conversion technologies. The relevant assumptions in the GA scenario include
  - **Slow growth or decline in industrial production**: The ETM provides estimates of the size of the industry subsectors[47] in the future. Under the GA scenario, only three industrial subsectors are expected to grow until 2050 (Central ICT, Chemicals, Fertilizers) while the largest industrial sector ("Other") is expected to shrink by 20% to 2050.
  - **Large efficiency gains**: The ETM allows us to define some annual efficiency gains, e.g. as a result of technological innovation, or newer and more efficient energetic processes. The median efficiency gain for electricity is 1.83%/year in 2040 and 2050 and 0.95%/year for useable heat. Central ICT, food and paper have a median overall efficiency gain of 1.83%/year. This can lead to large compound effects.[48]
  - **Change in energy carrier mix for heat (or process) production**: Depending on the industry subsector, the ETM allows for a change in the energy carrier mix either for heat production or the production technology used[49]. Below, we provide an analysis for the Chemicals, Steel and Other subsectors which represent 65% to 70% of total Industry energy demand in the TYNDP scenario, depending on the year considered.
    - The Chemicals subsector shifts from a heat production process relying mostly on network gas, oil for steam and hot water, to electricity, biomass and hydrogen (with a median share in 2050 of 50%, 17% and 16% respectively);
    - The Steel subsector shifts away from production using blast furnaces, and towards hot briquetted iron (HBI) using electric arc furnaces, and direct reduction of iron (DRI) using hydrogen, which make up about half of production in 2050 each;
    - The energy carrier mix of the Other subsector shifts away from oil and methane consumption, towards electricity and hydrogen (which becomes the second largest energy carrier).

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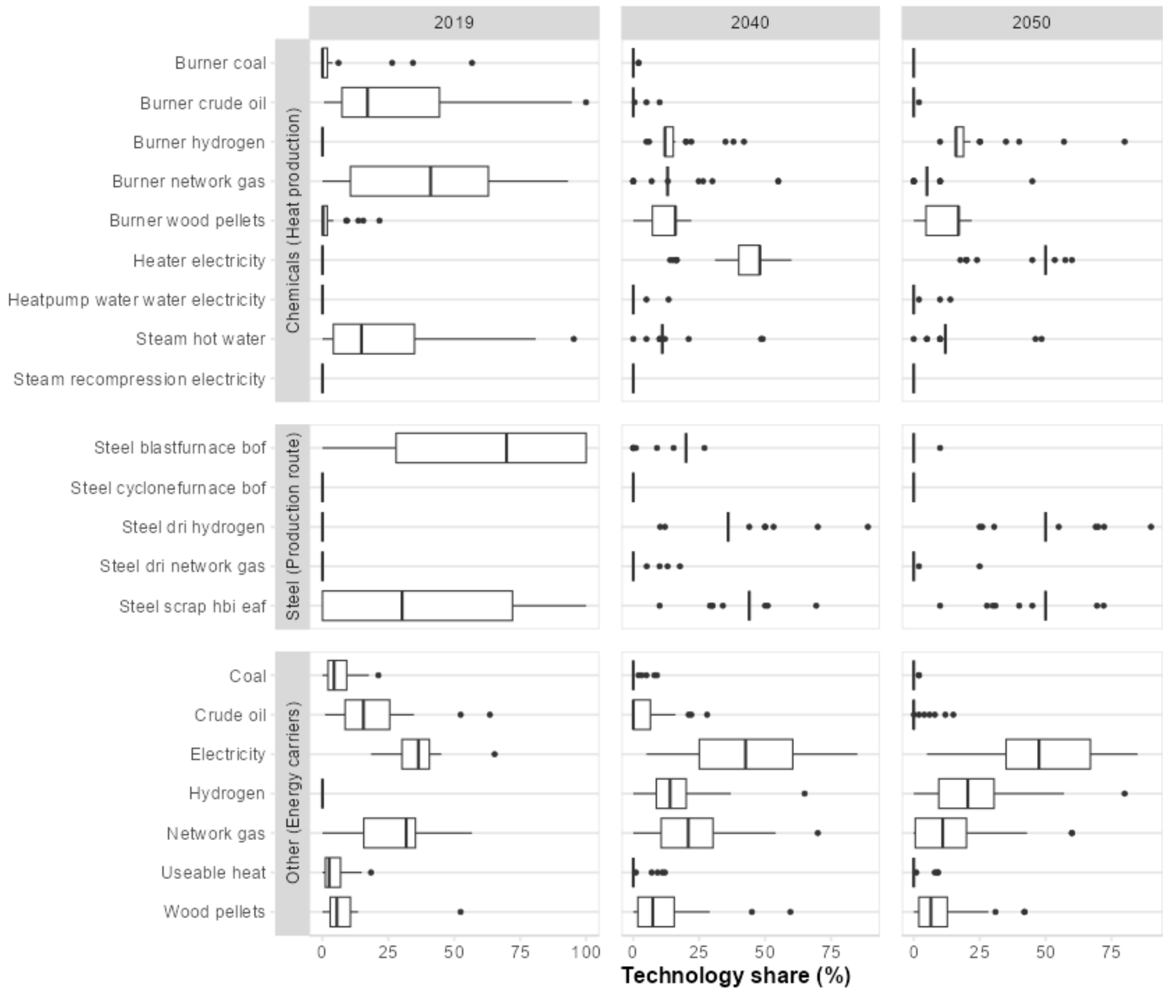
47 Industry subsectors are: Aluminium, Central ICT, Chemicals, Fertilizers, Food, Paper, Refineries, Steel, Other metals, Other.

48 For example, an efficiency gain of 1%/year over 30 years leads to a reduction of about 25% of total energy demand for a specific subsector. These efficiency gains apply to electricity demand and useable heat for chemicals, fertilizers, refineries and other metals; paper, food and central ICT have a global efficiency measure.

49 For example, for the aluminium subsector we may chose the production route share of aluminium either through electrolysis, electrolysis with best available technology, carbothermal reduction or smelt oven.

Figure 5 Technology mix input for the main industry subsectors (Chemicals, Steel & Other), per country



Source: Frontier Economics based on TYNDP data

Note: The "Other" subsector corresponds to any other industry subsectors which are not explicitly modelled in the ETM (Steel, Aluminium, Other metals, Refineries, Fertilizers, Chemicals, Central ICT, Food, Paper)

- **Perspective on the Baseline assumptions** – TYNDP assumes a decrease in the total industrial output, and a relatively fast change in the energy mix. Historically, the European industrial production has not declined, and has even increased over time for some sectors. Similarly, the total energy demand of the industry sector in the world has increased. Even though we can observe a decoupling between industrial energy consumption and industrial production value[50], the expected decrease in the total output of industrial activities may not be as sharp as anticipated in the TYNDP scenario. Since 2010, the levels of overall energy consumption slightly decreased while consumption of electricity from the industrial sector increased. It is likely that this trend will continue for

50 Since 2010, the total energy consumption in the industry sector has decreased by -1.3% while the total value of industrial production has increased by 15%. (Based on Eurostat figures on the evolution of the value of sold production: https://ec.europa.eu/eurostat/statistics-explained/index.php?title=Industrial_production_statistics)

the electricity demand but the rate of change in the energy mix might be slower than what is expected by the TYNDP GA scenario.

Similarly, the TYNDP scenario assumes strong and **persistent efficiency gains** in the future. With annual efficiency gains close or superior to 1% per year, the industrial subsectors are expected to cut their energy consumption by more than 25% in 2040 only through their efficiency gains. These significant efficient gains may not materialize, or at least at a slower rate than what is currently expected in the TYNDP scenario.

- **Adapted assumptions for our "What-if High Demand" scenario:** In order to reflect less optimistic assumptions on the overall level of energy demand in the industry sector, we have modified the input values of subsectors' demand and decreased the assumed efficiency gains:
  - The level of demand has been increased: we have increased the level of demand/production by 20% across all subsectors (aluminium, chemicals, fertilizers, steel, food, metals, paper, other) compared to the initial assumption in the future;
  - The level of future efficiency gains has been decreased: we have assumed half the level of efficiency gains (for both useable heat and electricity efficiency) across all subsectors (chemicals, refineries, ICT, fertilizers, food, metals) compared to the initial assumption in the GA scenario.

Transport Sector

- **Baseline assumptions** – The energy demand from the transport sector relies on three key inputs: the level of total demand for freight and passenger transport (that is to say the number of km covered), the modal split and the energy carrier share of these technologies.
  - **Transport demand and modal split**: The ETM allows to define the level of annual growth for the freight and passenger transport subsectors. The median level of demand growth is about 1%/year for freight transport and 0.2%/year for passenger transport in 2040, and 0.63%/year for freight transport and 0.4%/year for passenger transport in 2050.
  - **Modal split**: The technology share does not substantively change over time:
    - For freight transport: the share of trucks remains relatively constant (~60%), the share of trains increases from 10% in 2019 to 22% in 2050 and the share of ships decreases from 20% in 2019 to 10% 2050.
    - For passenger transport: the share of cars decreases moderately (from 81% in 2019 to 73% in 2040/2050) while the share of trains doubles to 12% in 2040 and 2050; the share of buses increases from 9% in 2019 to 12% in 2040 and 2050.

- Transport energy carriers:
  - For freight transport: trucks switch away from diesel and towards hydrogen or compressed natural gas, while trains continue to use electricity and substitute diesel with hydrogen.
  - For passenger transport: electric vehicles become the main technology with a median share of 73% in 2050, replacing gasoline/diesel vehicles (5% in 2050). The second-most popular option as a car's energy carrier is hydrogen, which makes up a median share of 20% in 2050. Passenger trains keep using electricity; diesel trains are replaced by hydrogen trains (13% in 2050).

- **Perspective on Baseline assumptions -** The change in the **modal split** seems in line with the historical trend. The share of cars in passenger transport has been around 73% since 2012.[51] The share of trucks in freight transport is about 52% when considering sea ships (these represent about 30% of freight transport; international navigation is not modelled in the ETM)[52].

  However, the assumed **growth in passenger and freight transport** is much lower than the historical trend (about half as quickly): on average, in the period 2000-2019 (excluding the Covid-19 period), freight transport grew by 1.3% annually[53] and passenger transport by 0.8%[54].

  The **change in the share of energy carriers** can be considered optimistic, although not implausible. In 2019, battery electric vehicles (BEVs) represented 0.2% of total car fleet across EU[55]. The TYNDP assumes that 70% of new registrations need to be for EVs to reach the target (it was 15% in 2023[56]). However, we did not alter the TYNDP's assumption, as it can be explained through the current aim to phase out ICEV in 2035. If the ICEV phase-out is delayed, the share of EV in new registration would be expected to decrease.

- **Adapted assumptions for our "What-if High Demand" scenario –** In order to reflect a larger energy demand from the transport sector we have:
  - Increased the annual demand growth for freight transport by 1 percentage point in 2040 and 2050 across all countries[57];

51 Eurostat modal split of air, sea and inland passenger transport (tran_hv_ms_psmod$defaultview)

52 https://de.statista.com/statistik/daten/studie/282282/umfrage/gueteraufkommen-nach-verkehrstraegern-in-europa/

53 Sectoral Profile – Transport, Trends in freight traffic, Odyssée-Mure, 2023 (p.10)

54 Sectoral Profile – Transport, Passenger traffic, Odyssée-Mure, 2023 (p.13)

55 AF Fleet percentage of total fleet, European Alternative Fuels Observatory

56 AF Market share of total registrations European Alternative Fuels Observatory

57 With the exception of Greece which had a very high value for the annual growth increase of freight transport (2.16%/year for 2050).

- Increased the annual demand growth for passenger transport by 0.5 percentage points in 2040 and 2050 across all countries[58].

Figure 6 provides a high-level comparison of **key changes in the What-if High Demand** scenario, compared to the Baseline scenario.

Figure 6 Comparison and motivation of key changes (What-if High Demand)

Sector	What-if assumption (2050)	Motivation
Households & Buildings	**Lower insulation level** in 2050, i.e. lower renovation rate: in line with historical rate of 1%	Renovation effect based on 2% renovation scenario in BPIE (2023), How to stay warm
Households & Buildings	**20% slower roll-out of heat pumps** and overall heating technology switch	With slower insulation rate, heat pump rollout likely also delayed
Households & Buildings	**Lower insulation level in 2050**, i.e. lower renovation rate: in line with households/historical rate of 1%	Renovation effect based on 2% renovation scenario in BPIE (2023), How to stay warm
Households & Buildings	**30% slower roll-out of heat pumps** and overall heating technology switch	With slower insulation rate, heat pump rollout likely also delayed
Transport	**Stronger growth in passenger demand** in line with historical trend	Historical growth rates have been much larger than TYNDP assumption
Transport	**Stronger growth in freight demand** in line with historical	
Industry	**20% increase in industrial activity** for subsectors (aluminium, chemicals, fertilizers, food, paper, steel, other)	TYNDP assumes lower industrial activity in many sectors/countries, i.e. economic de-growth. What-if assumes larger industrial activity.
Industry	**Refinery activity unchanged** compared to TYNDP GA scenario	Reduction of refinery activity due to electrification of transport. Increase of ICT to due digitalisation.
Industry	**Lower efficiency gains** half as large as in TYNDP assumption	TYNDP often assumes 1 - 1.5% annually, which has a large (compounding) effect until 2050.

Source: Frontier Economics

2.3.2 Renewable potentials (What-if Low RES)

Renewable energy sources, particularly onshore and offshore wind, along with solar photovoltaic (PV) systems, are crucial for achieving carbon neutrality by 2050. In 2022, renewable energies amounted to 23% of energy consumption in the EU27. The EU has set itself the ambitious target of reaching a renewable energy share of 42.5% by 2030, almost doubling the share in less than 10 years, requiring a compound annual growth rate of 8% per year. Historically, the growth rate has been much smaller and amounted to 3.7% between 2005 and 2022, a period which is characterised by dedicated support mechanisms to expand renewable energy sources.[59]

58 With the exception of Greece which had a very high value for the annual growth increase of passenger transport (2.1%/year for 2050).

59 European Environment Agency (2024): Share of energy consumption from renewable sources in Europe, https://www.eea.europa.eu/en/analysis/indicators/share-of-energy-consumption-from.

Assumed growth of renewable energy sources significantly exceeds historical growth

Renewable energies in the electricity sector, in particular solar PV, onshore and offshore wind, are generally expected to contribute the majority of additional renewable energy needed to reach the targets. Accordingly, the TYNDP scenarios allow for a massive increase in RES-E capacities across Europe. The total EU27 wind and solar PV capacity potential amounts to 3,500 GW by 2050, which corresponds to 750% compared to 2022. Since 2010, the annual capacity additions amounted to 26 GW per year. The full potential assumed in the TYNDP corresponds to an annual expansion rate four times that high (110 GW / year). Even though the speed of the capacity expansion increased in recent years, this growth rate seems very optimistic:

- **Offshore wind**: In particular, the growth of offshore wind, which is still in its early stages, bears uncertainties. At the end of 2022, when the European Union had a total offshore capacity of 16.3 GW, a new all-time record of 3 GW was added in 2023.[60] The TYNDP assumes that until 2030, on average at least 11 GW of offshore wind capacity will be added every year – more than 3 times the record value of 2023. More than 28 GW annually are assumed to be possible – more than 8 times the current annual record. From 2024 to 2050, the TYNDP assumes average annual additions of at least 12 GW (and up to 22 GW are considered possible).

- **Onshore wind**: During 2023, the EU added an all-time high of 13 GW of onshore wind capacity to reach a total of 220 GW.[61] For the period 2024-2030, the TYNDP assumes (for its upper limit) that annual new (net) additions could almost double to 24 GW, reaching 371 GW in total (602 GW by 2040, 767 GW by 2050).

- **Solar PV**: Capacity increased by an all-time high of almost 56 GW during 2023 to a total of 260 GW.[62] For the period 2024-2030, the TYNDP assumes that the total installed capacity could increase annually by more than 70 GW, reaching 765 GW in 2030 (up to 1,281 GW in 2040, and 2,058 GW in 2050). About 44% of capacity in 2050 is assumed to be rooftop PV. This means that about every second rooftop in the EU would be equipped with solar PV.[63]

Our What-if Low RES scenario analyses the impact of a slower expansion path of RES-E

In general, we use the TYNDP assumptions regarding renewable capacity potentials for our analysis. However, in our What-if Low RES scenario we deviate from these potential to show,

60 See European Commission (2023): Commission sets out immediate actions to support the European wind power industry and WindEurope (2024): Lots of good news in offshore wind, including in the supply chain.

61 WindEurope (2024): Wind energy in Europe: 2023 Statistics and the outlook for 2024-2030.

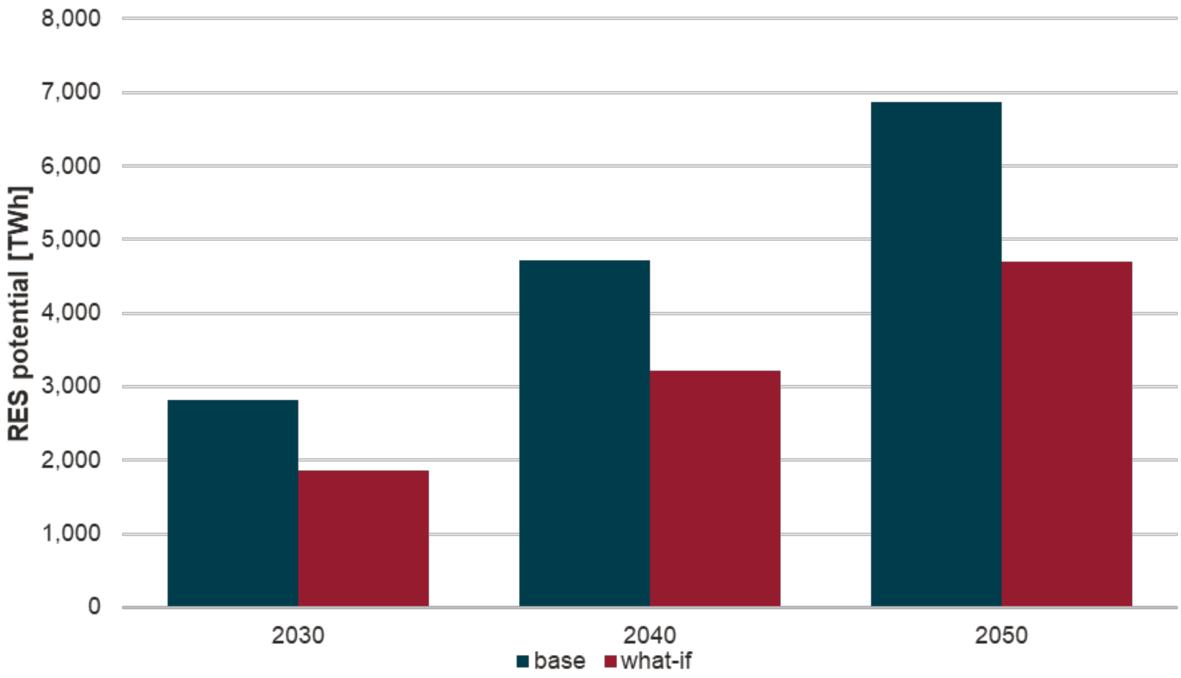
62 See European Commission: Solar Energy, accessed 01.07.2024.

63 Assuming a capacity of 5 kW per installation for residential and 100 kW for commercial buildings and a constant building stock (see European Commission: EU Building Stock Observatory).

firstly, how the targets can be achieved with constrained renewables expansions, and secondly, what difference a higher availability of renewable and low-carbon gases can make in case variable renewable expansions are constrained.

In our scenario analysis, we restrict the potential of net capacity addition for solar and wind to be in line with the lower bound of the TYNDP24 RES-E potentials. **Figure 7** illustrates the impact of this restriction in terms of the maximum total annual electricity generation of variable renewables. For 2030, this means we restrict the maximum total wind and solar PV generation in the EU to about 1,860 TWh, which is about 1,000 TWh lower than the maximum of the TYNDP – but still an increase compared to the 2023 value by a factor of more than 2.5.[64] **With an annual average growth of 14%, this is still significantly higher than the historical average growth between 2015-2023 of 9%.** Similarly for 2040 (2050), we restrict capacity such that the resulting annual maximum generation is about 1,500 TWh (2,000 TWh) below the TYNDP potential.

Figure 7 Accumulated wind and solar PV generation potential (EU27)



Source: Frontier based on TYNDP (2024): Draft Supply Inputs for TYNDP 2024 Scenarios for consultation and own calculations.

64 See Eurostat: Gross production of electricity and derived heat from non-combustible fuels by type of plant and operator.

2.3.3 Electricity grids (Baseline vs. What-if Delayed Grid)

Approach to modelling electricity transmission grids

Our Baseline scenario grid[65] uses three main sources of information: An extract of the ENTSO-E grid map[66] processed by PyPSA-EUR for the grid status quo, the TYNDP-2022 (ENTSO-E's long term planning report) for planned transmission grid expansions at project level and NTCs from ERAA[67] for scaling the nominal grid capacities. We distinguish between HVAC and HVDC lines at transmission network level. In line with the rest of our COMET model, we aggregate the base network at network node level to NUTS-1 level, using the clustering workflow by PyPSA-EUR.[68]

For our Baseline scenario, we take the projected commissioning years published in the TYNDP 2022 at face value. Through this approach, we are able to generate year-specific grids, reflecting the planned expansion for each point in time. We refer to "grid years" in the following.

The TYNDP 2022 only features projects with cross-border impact and is less accurate for within-country grid expansion plans. As our target grid is clustered to NUTS-2 level, we opt for a pro-rata approach for within-country grid expansion of the HVAC grid. A more detailed description of this approach can be found in the annex.

Baseline scenario projects a doubling of cross-country DC capacity between 2021 and 2030 – and nearly tripling by 2050

Throughout our considered grid years, we observe both expansion in terms of strengthening NUTS-2 regions that have been connected previously as well as new spatial connections, meaning that certain NUTS-2 regions are newly connected:

- In terms of nominal **cross-country capacities**, we observe more than a doubling of planned **HVDC** capacity in our European electricity network between 2021 and 2030 – from around 22 GW in 2021 to 45 GW in 2030 – and nearly a tripling until 2050 (61 GW).
- An even higher relative increase can be observed for the **intra-country** HVDC lines, starting at a low level of only 6 GW[69] in 2021, increasing to 24 GW in 2050.

---

65 For generating and clustering our electricity grid, we use parts of the open source PyPSA-EUR model setup workflow; distributed under MIT license, copyright by Tom Brown (KIT, TUB, FIAS), Jonas Hoersch (KIT, FIAS), Fabian Hofmann (TUB, FIAS), Fabian Neumann (TUB, KIT), Marta Victoria (Aarhus University), Lisa Zeyen (KIT, TUB).

66 We use an extract from March 2022 processed by GridKit, which is part of the PyPSA-EUR input package.

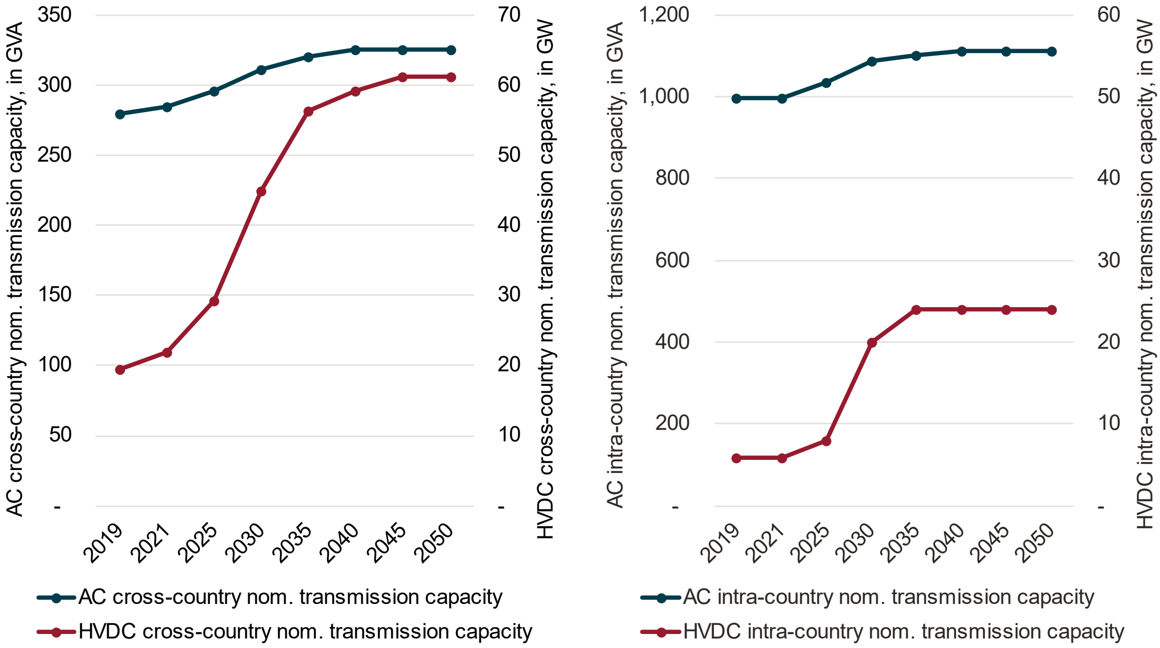
67 European Resource Adequacy Assessment (ERAA) 2023 by ENTSO-E.

68 PyPSA-EUR, distributed under MIT license, copyright by Tom Brown (KIT, TUB, FIAS), Jonas Hoersch (KIT, FIAS), Fabian Hofmann (TUB, FIAS), Fabian Neumann (TUB, KIT), Marta Victoria (Aarhus University), Lisa Zeyen (KIT, TUB).

69 It should be noted that the sum of intra-country transmission capacities is a function of the clustering resolution. We are referring to our target cluster resolution at NUTS-2 level.

A comparable absolute capacity increase at cross-country level of 30 GVA between 2025 and 2050 GVA holds true for the **HVAC** grid, with a capacity increase from about 295 GVA in 2025 to 325 GVA in 2050.

Figure 8 Nominal capacity developments 2019-2050 in the Baseline scenario



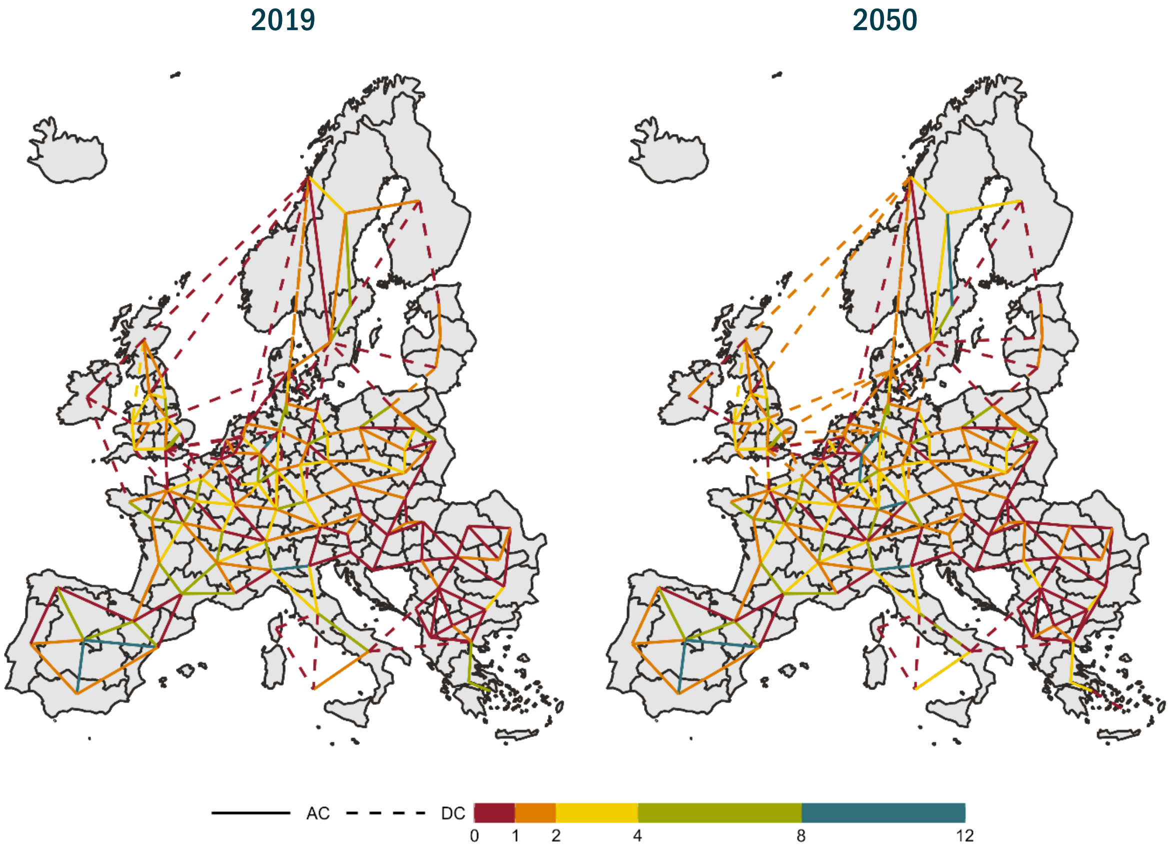
Source: Frontier Economics

It should be noted that the scenario data projects an ambitious, i.e. faster, capacity increase in the early years, and a slower increase in the later years (towards 2050), characterised by the S-shape of capacity developments in **Figure 8**. This follows from the short to mid-term planning horizons of projects featured in the TYNDP 2022: Grid expansion projects that are expected to be commissioned after 2035 (and which would imply a faster increase in later years) are less likely to be planned at this point in time (TYNDP 2022) – but might be considered in 5-10 years.

Therefore, the grid expansion rate that we foresee for 2050 in our Baseline scenario is not necessarily an extremely ambitious one – whereas our Baseline scenario grid year 2030 can be considered ambitious. To capture the uncertainty that comes with taking today's anticipated commissioning years at face value, we also introduce a "Delayed Grid" scenario where grid expansion is delayed based on the TYNDP project status.

Figure 9 illustrates the development of the grid topology of the COMET grid model.

Figure 9 COMET grid topology and nominal capacity values (GW)



Source: Frontier Economics

Our "What-if Delayed Grid" scenario

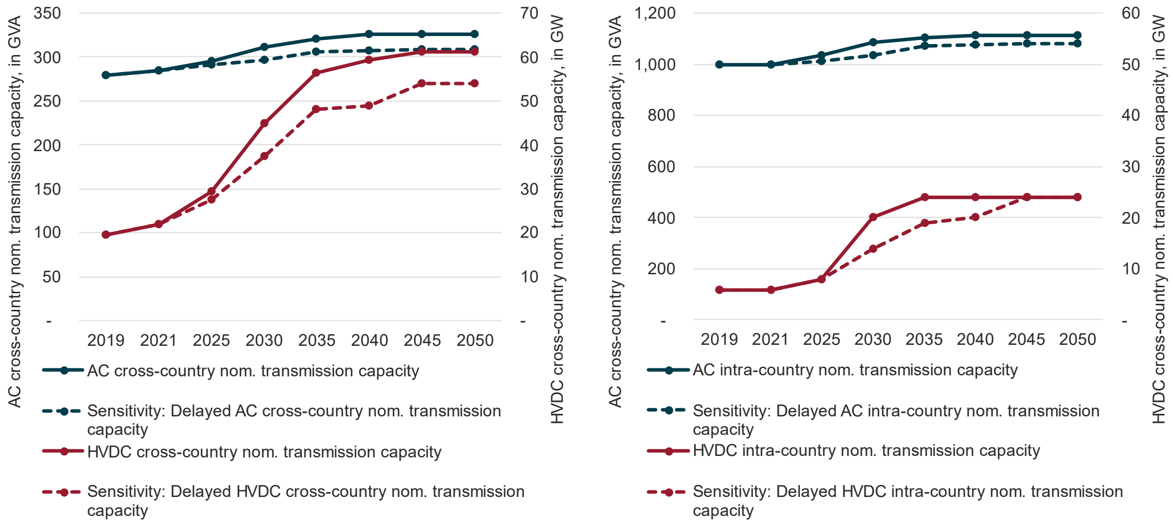
In our "What-if Delayed Grid" scenario we project less ambitious increases of both the HVAC and the HVDC grids, leading to a delay in overall network expansion. The motivation behind this is to reflect doubts as to whether such ambitious network expansions can be turned into reality, given today's observations of rather slow increases and project delays.

To do so, we vary the grid expansion on project level, based on the associated TYNDP project status. The commissioning year of projects with the status "*in permitting*" is delayed by five years, "*planned, but not yet permitting*" by 10 years, and projects "*under consideration*" are cancelled entirely. Endogenously, the pro-rata increase for intra-country HVAC lines also derives lower network expansion, resulting from the lower expansion rate of cross-country connections.

- The Delayed Grid assumptions include a lower increase of cross country HVDC networks, from about 27 GW in 2025 to about 53 GW in 2050, compared to 61 GW in the Baseline configuration.

- Expansion of cross-country HVAC networks is reduced by ca. 17 GVA, from about 290 GVA in 2025 to about 310 GVA in 2050, compared to 327 GVA in the Baseline configuration (Figure 10).

Figure 10 Nominal capacity developments 2019-2050 in the Baseline vs. What-if Delayed Grid scenario



Source: Frontier Economics

2.4 “High” and “Low renewable gases” as sensitivities

Besides these three critical bottlenecks of the energy transition, the TYNDP framework considers important assumptions on the availability of renewable and low-carbon gases, more specifically:

- Growth of domestic H2 electrolysis and availability of imported H2; and
- Growth of domestic biomethane supply;

2.4.1 High renewable gases

The “high renewable gases” cases use the assumptions from REPowerEU (H2) and the TYNDP to derive hydrogen and biomethane supply potentials:

- **EU domestic biomethane** production increases to 1070 TWh in 2050 and reaches 379 TWh in 2030. These assumptions have been derived from ENTSOG’s biomethane tool and confirmed by national TSOs[70].

[70] TYNDP 2024 Scenarios – Methodology Report, p.79.

- **EU domestic electrolysis potential**: REPowerEU aims for 10m tonnes of domestic hydrogen production in 2030, which corresponds to about 330 TWh. In the long-term towards 2050, we assume an unrestricted ramp-up and a non-binding capacity limit of 1,500 TWh which is rounded up from production volumes derived in the TYNDP.

- **EU hydrogen import potentials** amount to about 1,478 TWh_{H2} in 2050 and consider imports via pipeline from North Africa or via ship (ammonia).[71] In the short-term, an import potential ramp-up to 83 TWh_{H2} in 2030 is assumed, in line with the approach taken by the TYNDP.[72]

2.4.2 Low renewable gases

The "low renewable gases" sensitivities illustrate the consequences of a slower progression with respect to the ramp-up of renewable gases' supply options:

- **EU domestic biomethane** production is assumed to ramp up at a much lower pace. Possible reasons for deviations from the "high renewable gas" sensitivity are the lack of support to complete the required technical installations, the small-scale and decentralised landscape of current biomethane production or increasing competing usage of agricultural residues. IFEU offers a conservative estimate of 17 bcm or 178 TWh in 2030.[73] We use a linear trend between 2020 (32 TWh) and 2030 to extrapolate to 2050 (471 TWh).

- **EU domestic electrolysis potential**: We reduce the possible expansion of domestic H2 electrolysis by 30% in 2030 and 2050 resulting in 231 TWh in 2030 and 1,050 TWh in 2050.

- **EU hydrogen import potentials**: Following the TYNDP's adjustment for 2030 after the public consultation, we reduce the possible import volumes across all sources by 70%, resulting in 407 TWh of hydrogen import potential in 2050. Synthetic methane import potentials which are left unchanged at 100 TWh.

Figure 11 compares the assumptions underlying our high and low renewable gas sensitivities.

71 Pipeline import potentials from North Africa amount to 662 TWh_{H2} as assumed in the TYNDP. Ship import potentials amount to 816 TWh_{H2}, which is the sum of 696 TWh_{H2} in addition to 120 TWh_{H2} (100 TWh_{CH4} assuming 83% efficiency) of synthetic methane assumed in the TYNDP. COMET is free to choose whether to import hydrogen or synthetic methane after overseas conversion losses.

72 TYNDP's adjustment for 2030 (compared to their originally proposed value) following the public consultation (see TYNDP's Response to public consultation). In the response it is further stated that "A similar approach is expected for the import numbers for 2040 and 2050, but at the time of writing it has not been finally decided"

73 IFEU (2022): Biomethane in Europe; https://www.ifeu.de/publikation/biomethane-in-europe.

Figure 11 Comparison of high and low renewable gas potentials

		High renewable gases	Low renewable gases
EU Biomethane production potential [TWh]	2030	379 (TYNDP24)	178 (IFEU)
	2050	1070 (TYNDP24)	471 (IFEU)
EU Hydrogen import potential [TWh]	2030	83 (TYNDP24 -70%[2])	83 (TYNDP24 -70%)
	2050	1358 (TYNDP24)	407 (TYNDP24 -70%)
EU Other renewable fuel[1] import potential [TWh]	2030	193 (TYNDP24)	193 (TYNDP24)
	2050	568 (TYNDP24)	568 (TYNDP24)
EU Domestic electrolysis potential [TWh]	2030	330 (REpowerEU)	231 (-30%)
	2050	1500 (TYNDP24)	1050 (-30%)

Source: Frontier Economics based on ENTSOG and ENTSOE (2024): Ten- Year Network Development Plan (TYNDP), European Commission (2022): REPowerEU Plan, IFEU (2022): Biomethane in Europe.

Note: 1) Other renewable fuels include Biomethane, Bioliquids, PtM and PtLiquids. PtM and hydrogen imports via ship are interchangeable (accounting for conversion losses). Potentials refer to imports from non-European countries. 2) Following the revisions of the TYNDP input assumptions as stated in TYNDP Scenarios: Summary Report – Public consultation on TYNDP 2024, Scenarios Input Parameters.

2.5 High Electrification scenario as a further robustness test

The Baseline scenario and the What-if scenario are, apart from the What-if deviations, largely based on the final demand assumptions of TYNDP's Global Ambitions scenario, which we interpret as the more diversified and likely more efficient scenario for achieving our climate targets of the two long-term TYNDP scenarios. The alternative scenario of the TYNDP, the so called "Distributed Energy (DE)" scenario, on the other hand puts an even stronger focus on electrification of the economy, uses less advantages of global trade and is based on some strong assumptions concerning behavioural changes of consumers.

To confirm the conclusions concerning the role of low-carbon and renewable gases, we analyse a High Electrification scenario which uses the DE final energy values as input. The specific assumptions are discussed in more detail in **section 7**. We also analyse the outcomes of the High Electrification scenario with respect to the role of gases and most importantly give an indication of the total system cost differences between a pathway that follows a more balanced approach and one that puts a very strong focus on electrification and behavioural changes.

3 Energy Demand: Gas consumption increases, and hydrogen is expected to become the second largest energy carrier

In this section, we describe the main trends in final energy demand, and how they result from the assumptions underlying the Baseline and What-if High Demand scenario (see **section 2**). The final energy demand in the other two What-if scenarios (What-if Low RES and What-if Delayed Grid) corresponds to that in the Baseline scenario.

Across all scenarios, the share of gases in final energy demand increases. What-if High Demand makes less optimistic assumptions concerning technological change and energy efficiency, which leads to an even larger increase in gas consumption in final demand sectors, as gaseous fuels are being used to reduce the carbon footprint in transport, industry and buildings.

3.1 Baseline assumptions foresee an increase in gas consumption by 15% compared to 2019

Our Baseline scenario uses the demand parameters as set by the TYNDP team in January 2024.[74] As described in **section 2.2**, the assumptions concerning the development of final demand can be described as optimistic with respect to the achieved energy efficiency savings and progress of electrification. Nonetheless, gases have a key role in serving final demand towards 2050:

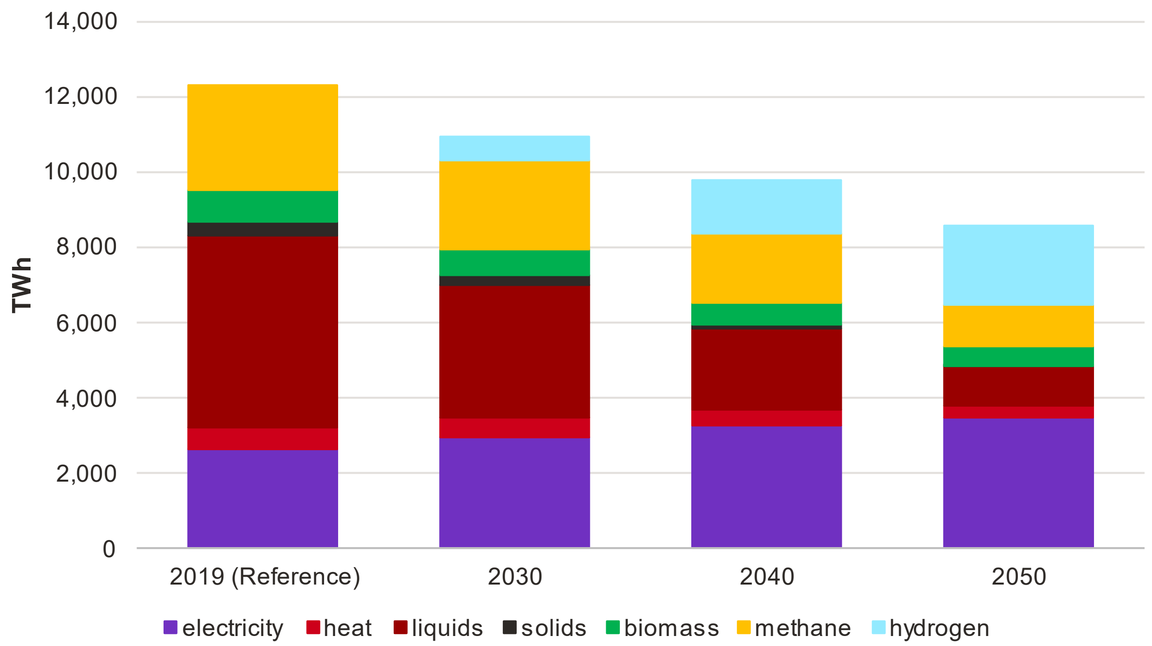
- **Final demand decreases** by 30% by 2050, to 8,580 TWh, compared to 2019 (12,320 TWh).
- **Electricity** is the largest energy carrier in final demand and increases its share from 21% in 2019 to 40% in 2050.
- Demand for **gases** (methane and hydrogen) is also projected to increase by 15% compared to 2019, with **hydrogen** becoming the second largest energy carrier in final demand. **Methane** demand decreases but still contributes 13% to total final demand in the long run.

The reduction of final energy demand by 2030 is in line with the EU target as described in the EU energy efficiency directive.[75]

74 Since publication of the draft demand scenarios, a public consultation of the scenarios was concluded. The updated scenarios include slightly higher final energy of ca. 9,000 TWh in 2050.

75 The European Scientific Advisory Board on Climate Change confirms the conformity of the TYNDP scenarios with the energy efficiency target. As we base our final demand on the TYNDP, the target is also reached in our base scenario. This is independent from us following the same approach as the TYNDP for calculating final energy demand, which

Figure 12 Final energy demand (Baseline, EU27)



Source: Frontier Economics

Note: Reference ENSTO TYNDP24; 2030-2050: ETM; methane demand can be served by biomethane, natural gas, synthetic methane (PtM), biomass = direct use.

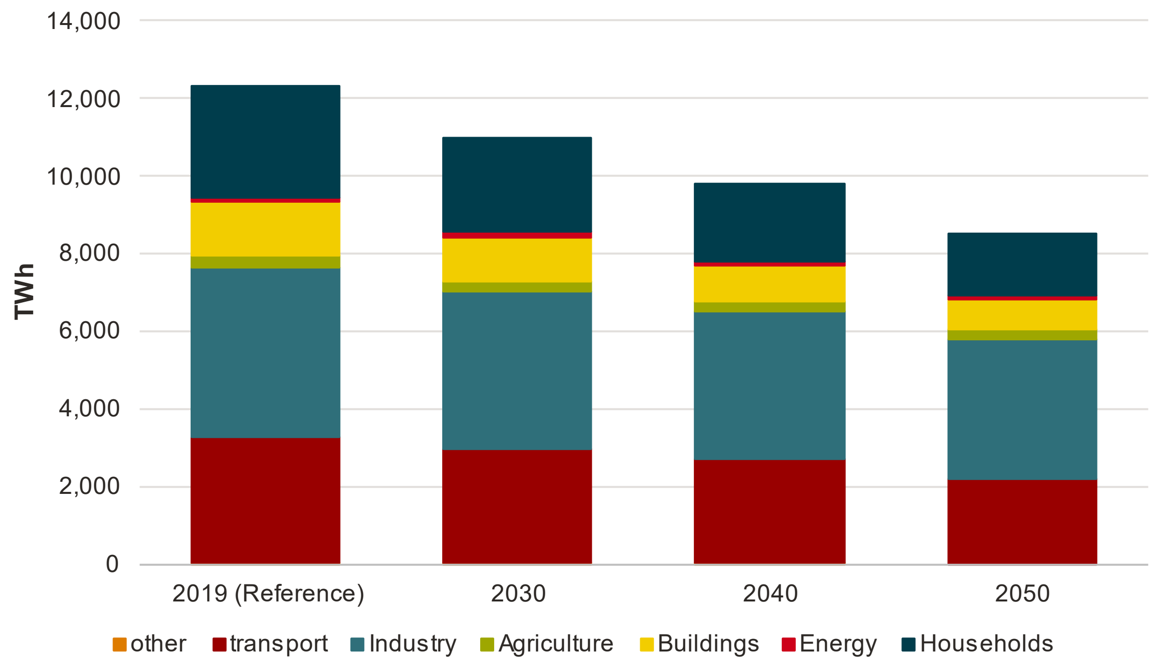
3.1.1 Sectoral breakdown

Industrial sectors remain the largest energy consumer in 2050, but achieve a demand reduction of 18% compared to 2019. As a result of optimistic energy efficiency assumptions, demand from households and buildings decrease the most (-45% and -43% compared to 2019, respectively) (Figure 13).

Hydrogen's role grows in the industrial sectors and in transport. While methane demand decreases across all sectors, it is not fully replaced (Figure 14).

deviates from the approach of the EC Impact Assessment (see also the TYNDP explanation for this "Data Figures" file accompanying the scenario report, figure 41. See also European Scientific Advisory Board on Climate Change (2024): Towards climate neutral and resilient energy networks across Europe - advice on draft scenarios under the EU regulation on trans-European energy networks.

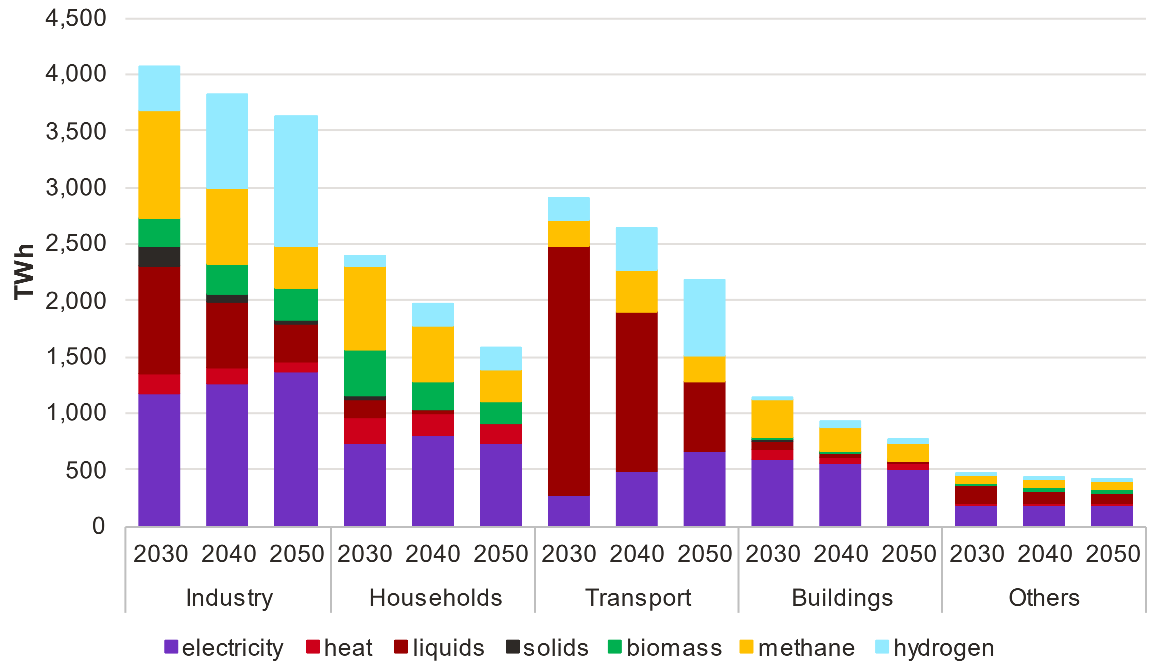
Figure 13 Sectoral breakdown of final energy demand (Baseline, EU27)



Source: Frontier Economics

Note: Reference ENSTO TYNDP24; 2030-2050: ETM

Figure 14 Sectoral breakdown final demand by energy carrier (Baseline, EU27)



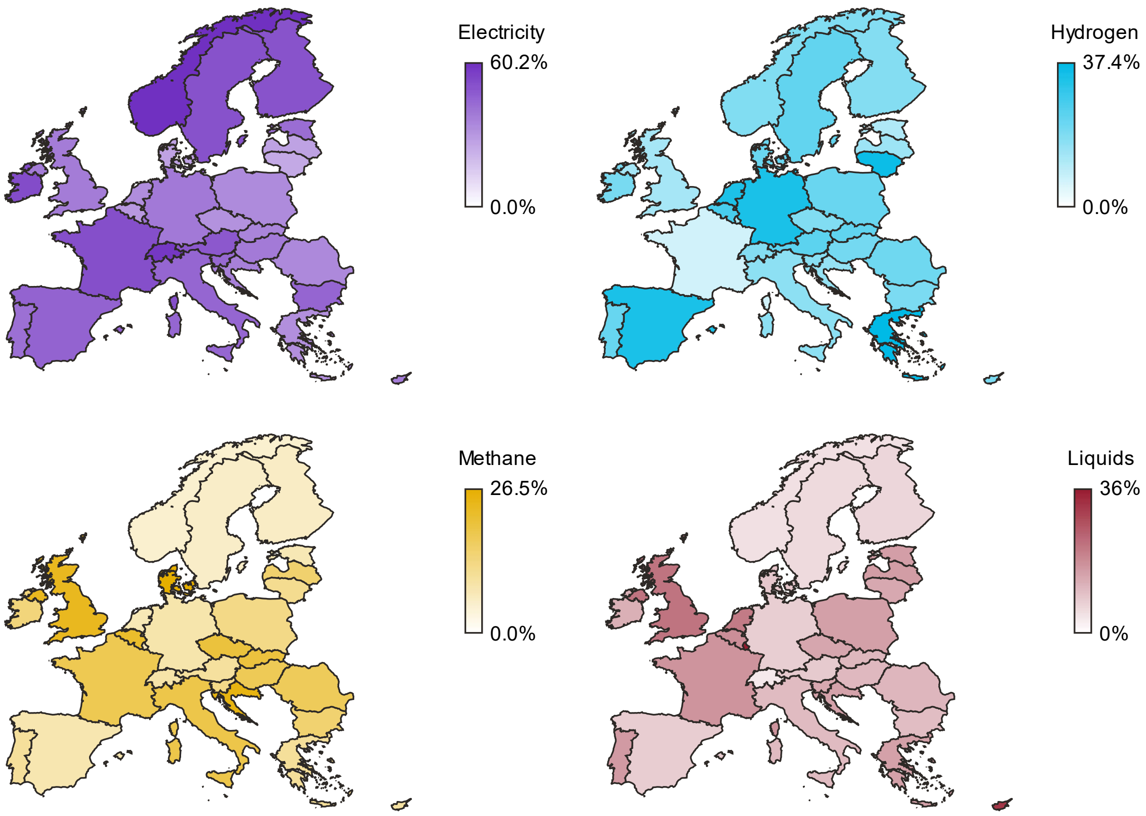
Source: Frontier Economics

Note: ETM; methane demand can be served by biomethane, natural gas, synthetic methane (PtM), biomass = direct use

3.1.2 Regional breakdown

The analysis of final energy demand shows some important differences between various European countries. The share of energy carriers in final demand varies, with some countries relying more on electrification of demand, and others more on H2 and or methane and liquids energy carriers (Figure 15). This variation is driven by countries' respective industrial landscape, buildings structure, and transport requirements. It emphasises the need for a coordinated European approach that considers the regional differences between individual Member States.

Figure 15 Regional differences in final energy demand (Baseline)



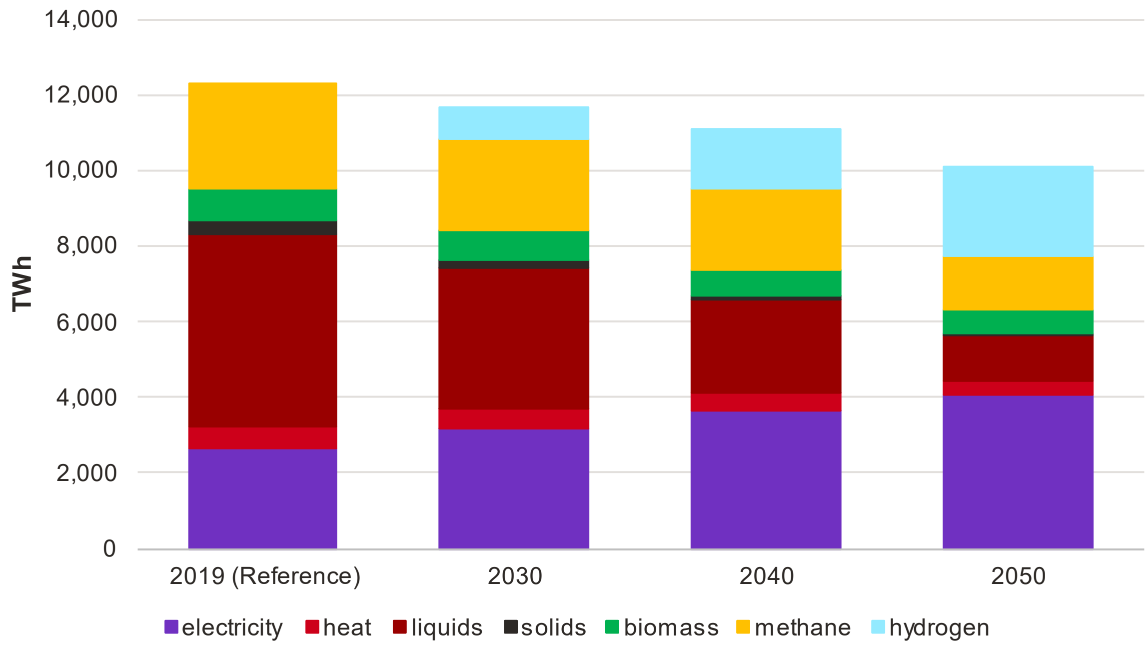
Source: Frontier Economics based on ETM
Note: Maps by Bing, OpenStreetMap

3.2 Alternative demand scenario (What-if High Demand) results in even stronger uptake of gases: +36% compared to 2019

The What-if High Demand scenario uses less optimistic assumptions on the achieved energy efficiency savings. Technological change coupled with higher economic activity leads to a less pronounced demand reduction, but stronger uptake of gases:

- **Final demand decreases** by 18% until 2050 to 10,100 TWh, compared the reference of 2019 (12,320 TWh).
- **Electricity** is the largest energy carrier in final demand, and demand for electricity increases to 4,000 TWh in 2050, which corresponds to a 53% increase compared to 2019.
- Demand for **gases** (methane and hydrogen) is also projected to increase by 36% compared to 2019, with **hydrogen** demand growing to 2,400 TWh in 2050

Figure 16 Final energy consumption (What-if High Demand, EU27)



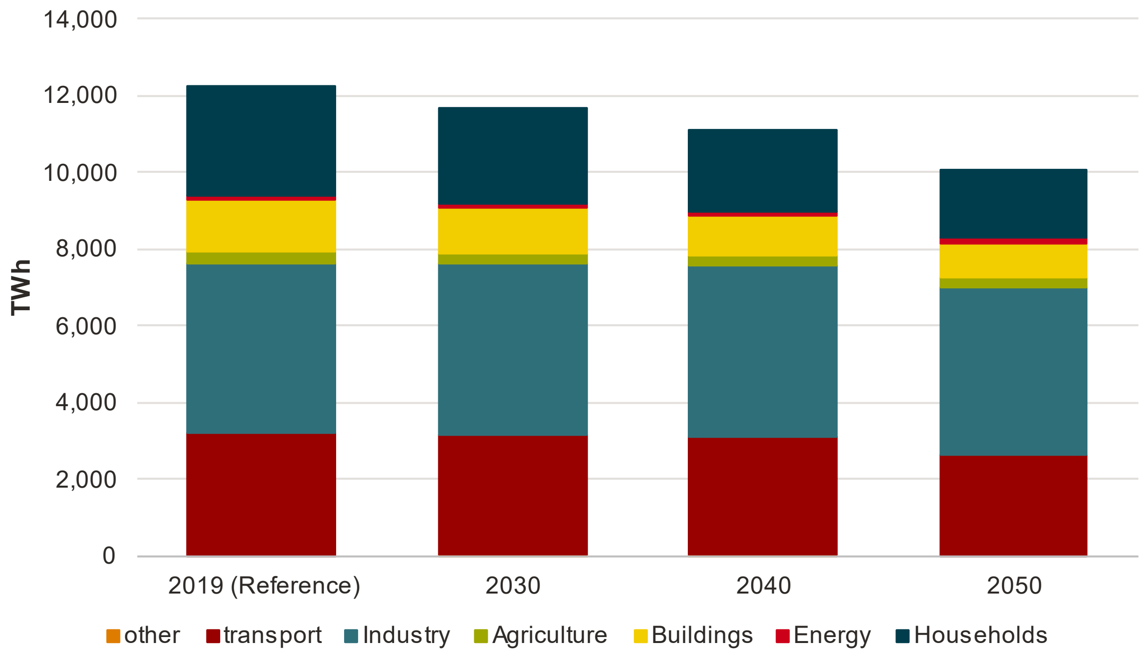
Source: Frontier Economics

Note: Reference ENSTO TYNDP24; 2030-2050: ETM, methane demand can be served by biomethane, natural gas, synthetic methane (PtM), bio = direct use of biomass

3.2.1 Sectoral breakdown

Our What-if scenario is based on an almost constant energy demand from industrial sectors. As a result from the less optimistic assumptions concerning energy efficiency, demand from households decreases by 39%, and by 32% for buildings compared to 2019 (Figure 17).

Figure 17 Sectoral breakdown of final energy demand (What-if High Demand, EU27)

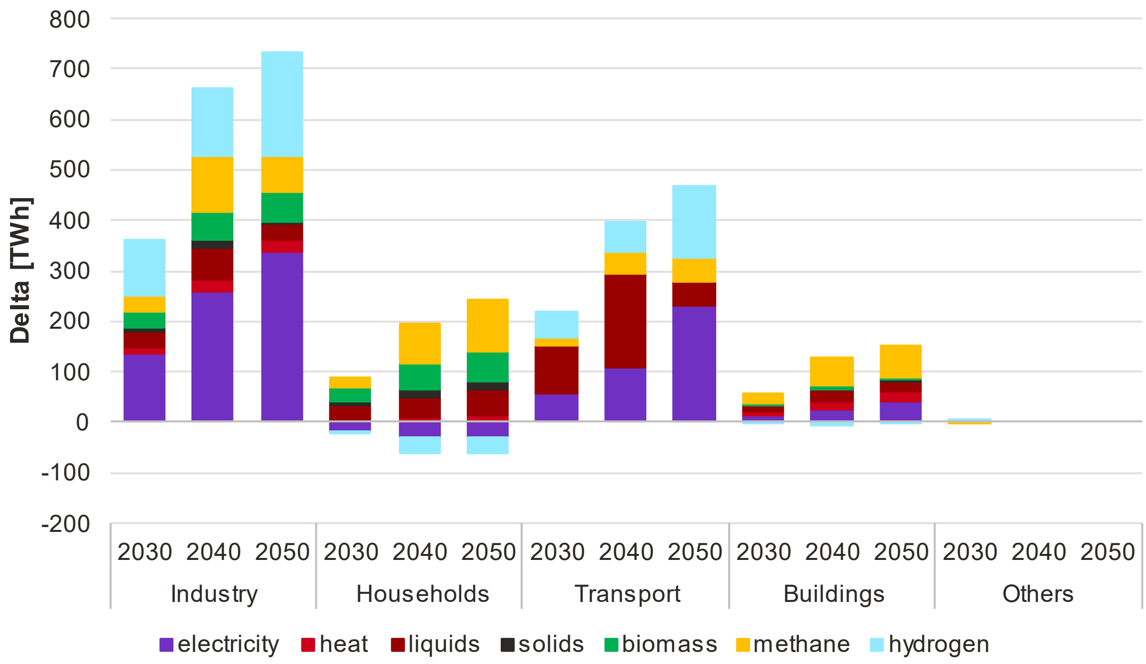


Source: Frontier Economics based on ETM
Note: Reference ENSTO TYNDP24; 2030-2050: ETM

Figure 18 presents the sectoral breakdown of the change in final energy demand from the Baseline to the What-if scenario:

- Higher **industrial activity** predominantly leads to an increase in electricity and H2 consumption of 330 TWh and 200 TWh by 2050, respectively. In 2040, residual methane demand is 110 TWh higher than in the Baseline, and in 2050, it is 70 TWh higher.
- The slower roll-out of heat pumps and reduction of the renovation rate increases the consumption of methane in **households** and **buildings** in 2050 by 100 TWh relative to the Baseline.
- Higher **transport** demand (while keeping the technology shares unchanged compared to the Baseline) increases overall energy demand, predominantly demand for liquid fuels in 2040 (+180 TWh) and electricity (+230 TWh) as well as H2 (+140 TWh) in 2050 relative to the Baseline.

Figure 18 Sectoral breakdown difference in final energy demand by energy carrier (What-if High Demand relative to the Baseline, EU27)



Source: Frontier Economics

Note: Based on ETM, methane demand can be served by biomethane, natural gas, synthetic methane (PtM), biomass = direct use

The regional differences in demand do not change significantly between the Baseline and the What-if High Demand scenario.

4 Energy Supply: A mix of RES-E, gases and carbon capture proves to be optimal under all scenarios

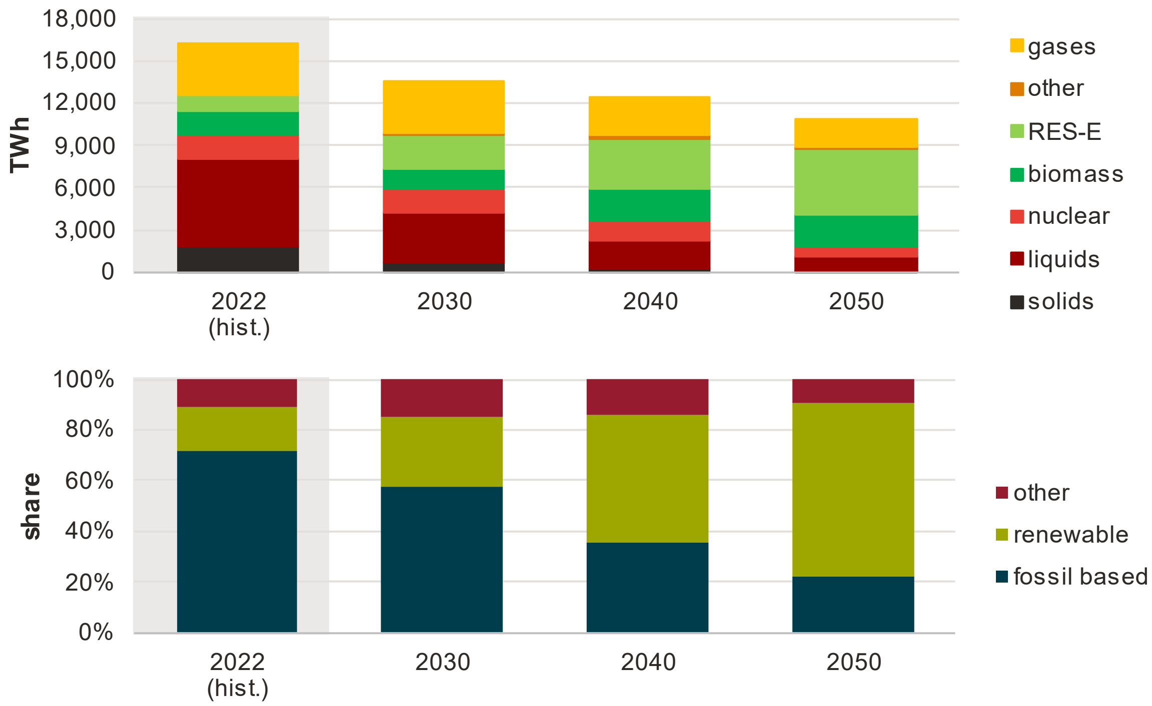
In this section, we describe the composition of the energy supply in various scenarios and the contribution of gases to overall supply.

4.1 Primary energy supply and energy flows in our Baseline scenario emphasise the need for gases

4.1.1 Primary energy supply becomes more renewable, share of gases increases

Our Baseline scenario (assuming high availability of renewable gases) shows a strongly receding share of fossil-based energy carriers towards more renewable energy carriers in energy supply. The share of renewable primary energy increases from 17% in 2022 to 50% in 2040 and 67% in 2050. Fossil-based fuels continue to contribute 22% to primary energy supply, including blueH2, which has been produced from natural gas and imported to Europe or via imported methane to produce blueH2 domestically in Europe (Figure 19).

Figure 19 Primary Energy Supply (EU27, Baseline high renewable gases)



Source: Frontier Economics

Note: Primary fuels include all imported fuels (including outputs of conversion processes like PtH2) and domestically produced fuels that do not result from energy conversion (e.g., domestically produced natural gas or coal). Biomethane, for example, is not considered a primary fuel as it results from the methanisation of biomass, but biomass is considered the primary fuel. Gases include all derivatives of hydrogen and methane.

4.1.2 Energy flows: Moving towards a balanced mix of renewable and low-carbon supply options

The EU's energy system has historically been shaped by various structural changes driven by political and societal decisions, technological advancements, and external disruptions. Notable examples include the significant adoption of renewable electricity in the early 2000s and, more recently, the disruption of gas supply from Russia, which has impacted many European countries.

Structural changes to the European energy system

To complete the energy transition and meet climate targets, more significant changes to the energy system will be required:

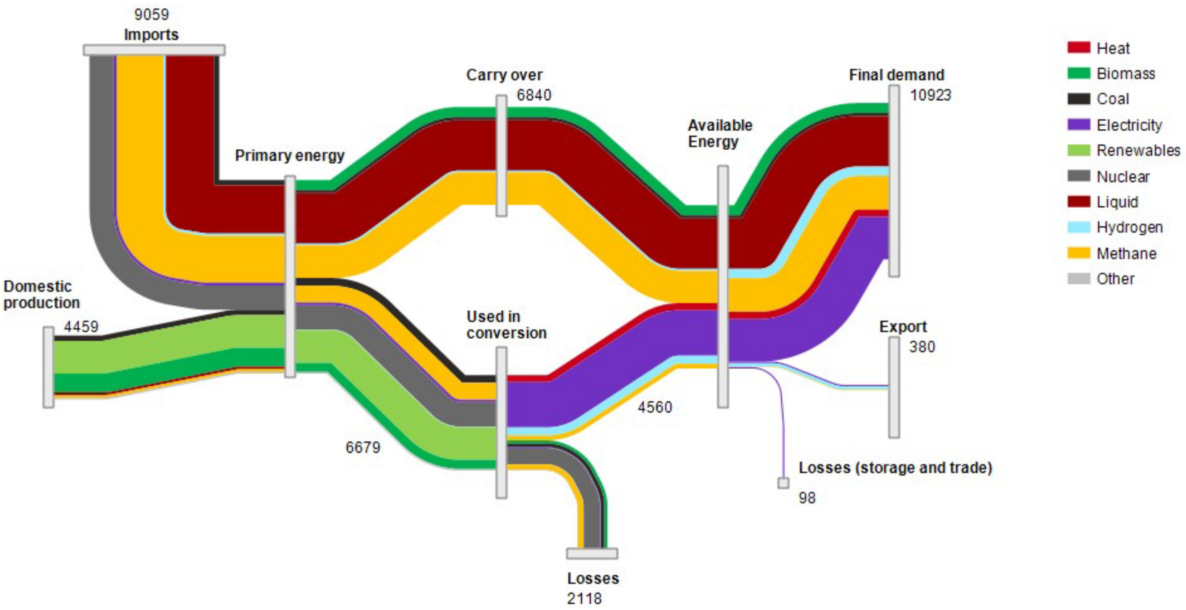
- Further expanding the domestic supply of renewable electricity to (a) meet growing needs in final demand and (b) as an input into energy conversion.
- Replacing fossil fuels in the primary energy supply with low-carbon energy carriers
- Decreasing the share of energy carriers that are imported, and for remaining imports to predominantly be liquid or gas-based.
- Building up an energy conversion sector, to convert renewable electricity into renewable molecules that can easily be stored, transported, and consumed in existing applications.
- Development of the carbon capture industry to decarbonise hard-to-abate industrial processes, create negative emissions through carbon removals, and enable the domestic production of H2 from imported methane.

The importance of conversion technologies for a successful energy transition

Figure 20 to Figure 22 illustrate this structural change over the period from 2030 to 2050 in our Baseline scenario in the form of Sankey diagrams. Energy flows from domestic production and imports add up to primary energy supply. Primary energy is either “carried over” towards final demand or used in energy conversion. The graphs show the increasing importance of energy conversion:

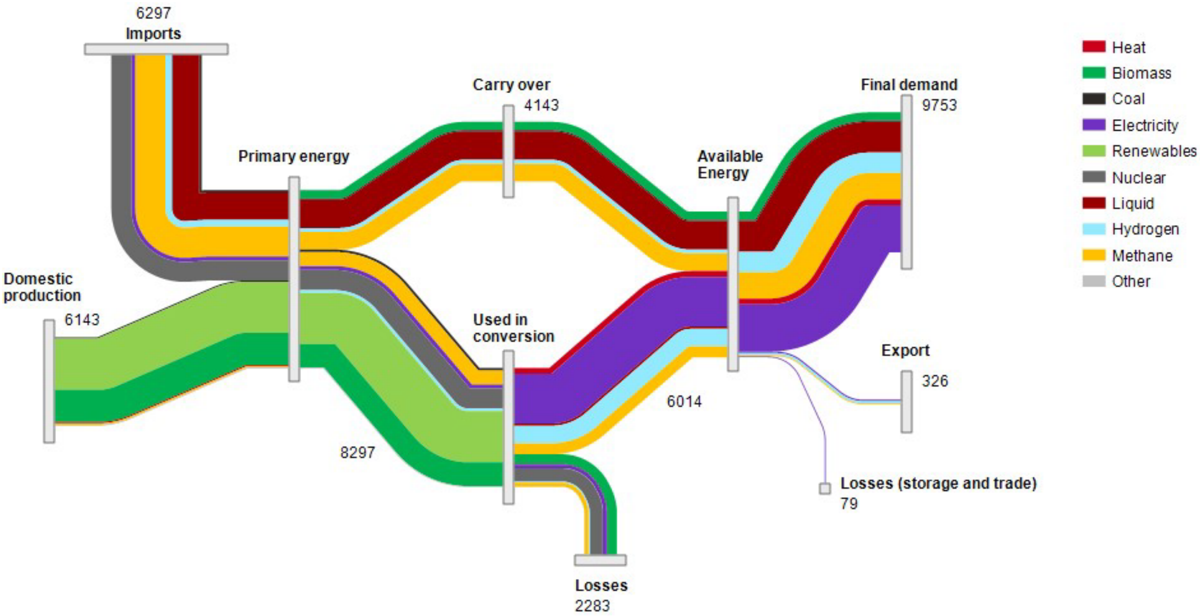
- In 2030, conversion is mainly converts fossil fuels and renewable energy to electricity.
- In 2040 and 2050, the domestic conversion sector grows significantly and is, besides converting renewable energy to electricity, also essential to producing
  - hydrogen from renewable electricity using electrolysis;
  - hydrogen from methane using steam methane reforming and carbon capture; and
  - biomethane from biomass via biomethanisation with carbon removals.

Figure 20 Energy flows 2030 (EU27, Baseline high renewable gases)



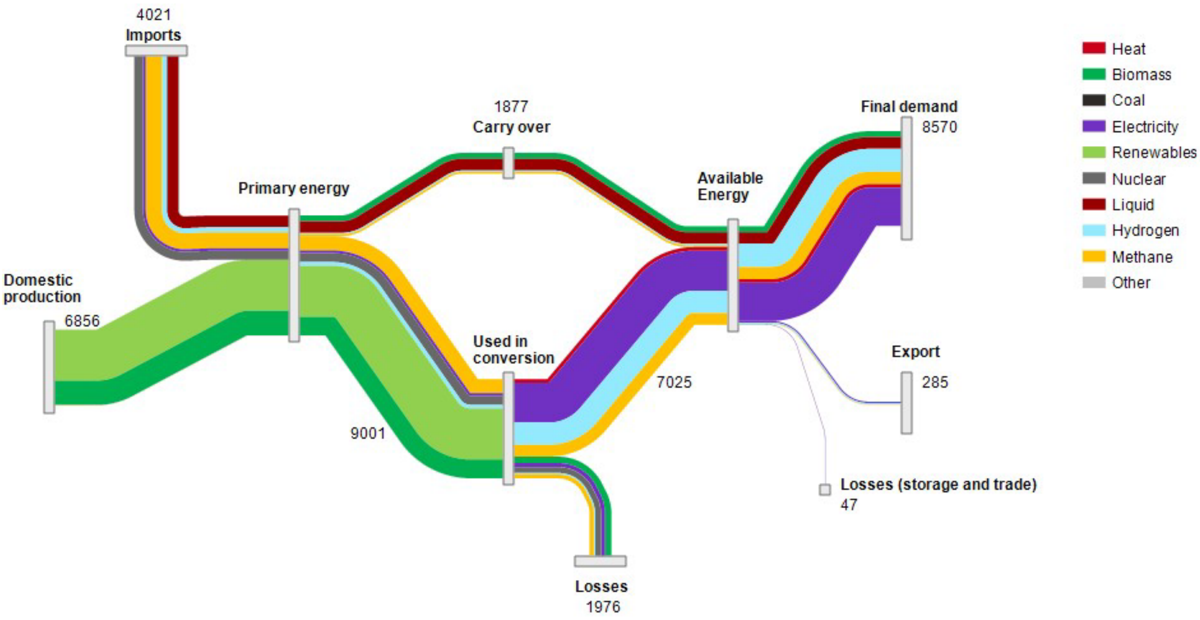
Source: Frontier Economics

Figure 21 Energy flows 2040 (EU27, Baseline high renewable gases)



Source: Frontier Economics

Figure 22 Energy flows 2050 (EU27, Baseline high renewable gases)



Source: Frontier Economics

4.2 Gases and carbon capture are key elements of a diversified supply mix

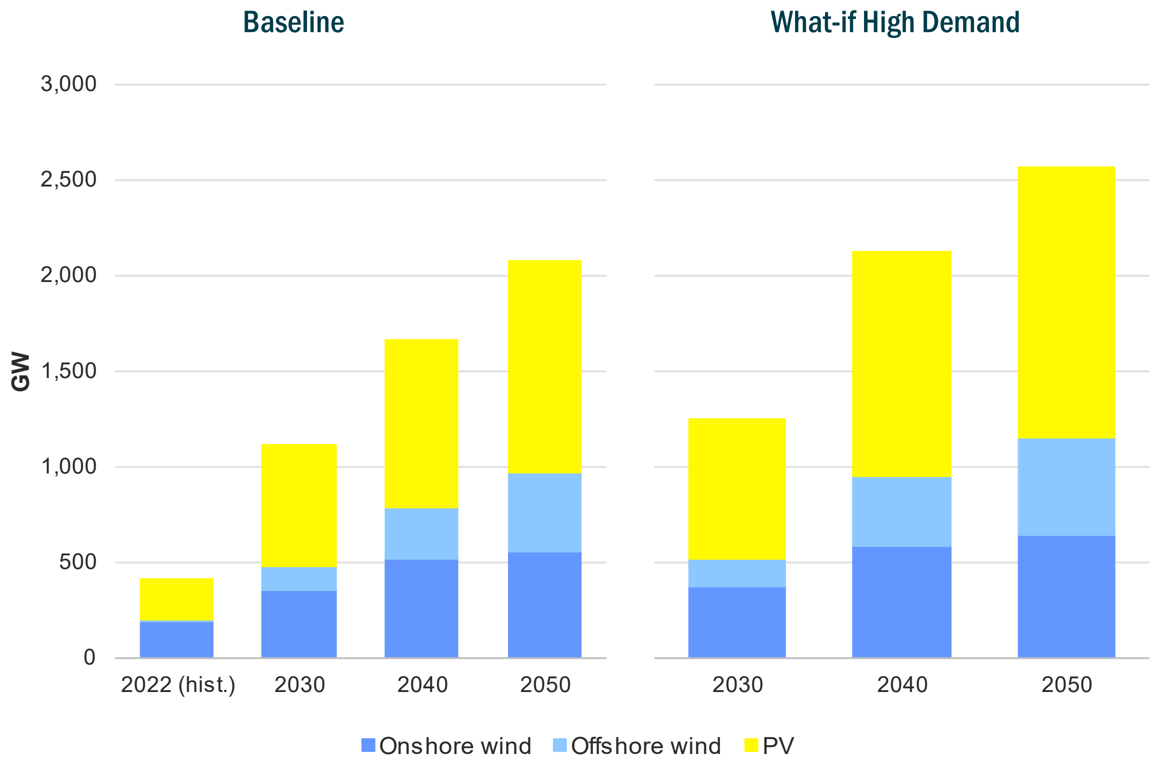
4.2.1 RES-E are expected to increase at least six-fold compared to today

Total capacity of RES-E grows to more than 2,000 GW in our Baseline scenario, which assumes high availability of renewable gases.

- **Onshore wind** capacity increases from 190 GW in 2022 to 550 GW, producing 1,380 TWh in 2050.
- **Offshore wind** capacity expands from 16 GW in 2022 to 420 GW, producing 1,450 TWh in 2050.
- **Solar PV installations** grow from 200 GW in 2022 to 1,100 GW, producing 1,470 TWh in 2050.

This represents a growth of 500% compared to 2022 in terms of RES-E production. In the What-if High Demand scenario, where optimistic assumptions around energy efficiency do not materialise, an even faster build-out rates is required: Total RES-E capacity under the What-if High Demand scenario in 2050 in the EU27 amounts to more than 2,500 GW, +600% compared to 2022.

Figure 23 RES-E capacity development (EU27, high renewable gas availability)



Source: Frontier Economics
Note: Historical data sourced from Eurostat

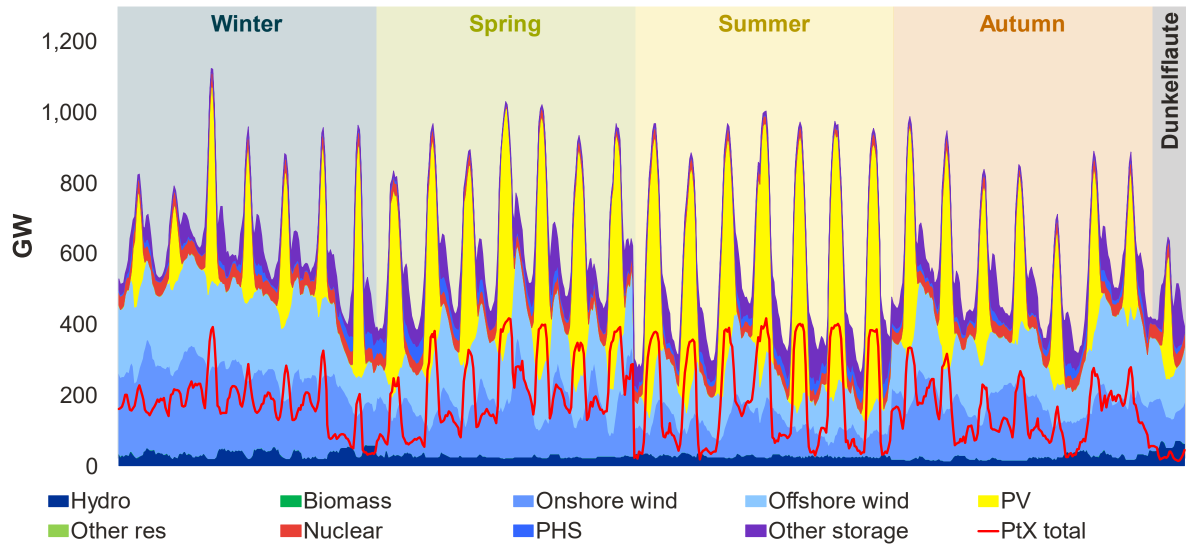
4.2.2 PtX and gases are essential for the system integration of RES-E

Renewable energy is an intermittent source of supply that requires efficient storage and conversion technologies to allow consumption when wind and solar infeed levels are low. Besides large-scale electricity storages like batteries or pumped hydro storages, emerging Power-to-Methane and especially Power-to-Hydrogen technologies will be key parts of the system. PtX will be important in two ways: Firstly, it will be used to store and “move” energy across weeks and seasons and secondly, it can transform renewable electricity to other carbon-neutral energy carriers which can be used in additional sectors and in non-electrified end-user applications.

Hourly correlation of electrolysis and RES-E infeed

PtX is the “system integrator” for RES-E. At the same time domestic PtX production is only possible if sufficient RES-E is available. Figure 24 shows the hourly pattern between the supply of renewable electricity and PtX activity. PtX can absorb surplus RES-E generation in windy and sunny periods. However, in periods with low availability of RES-E, especially at night, in the winter and during extended periods of dark doldrums (“Dunkelflaute”), the level of electrolysis activity decreases[76].

Figure 24 Hourly electricity supply from RES-E and PtX activity (EU 27, 2050) Baseline (high renewable gases)



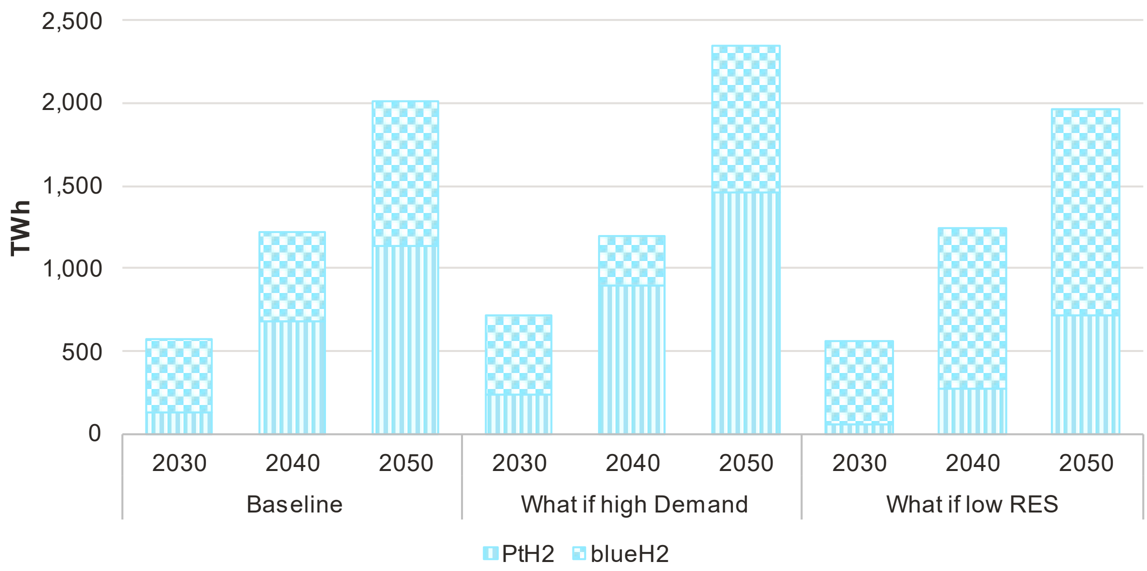
Source: Frontier Economics

Growth of electrolyser capacity is closely linked to the availability of RES-E

The growth of intermittent renewables and ramp-up of hydrogen demand from all sectors of the economy leads to a massive expansion of domestic hydrogen production capacity. In the long run, more than 2,000 TWh of hydrogen will be produced in Europe. The share of PtH2 vs blue hydrogen production depends on the availability of RES-E in Europe: If the build-out of renewables is constrained and less intermittent renewables are available (What-if Low RES scenario), the electrolyser capacity decreases, and a larger share of hydrogen demand is met by domestically produced blueH2. On the other hand, if demand for hydrogen and RES-E installations increase compared to the Baseline scenario (What-if High Demand), the output of domestic electrolysis grows.

[76] H2 electrolysis has to fulfil specific criteria under REDII in order to classify as “renewable”, in our model, we impose the constraints of time and spatial (bidding zone) correlation. The criterion of additionality is not explicitly modelled.

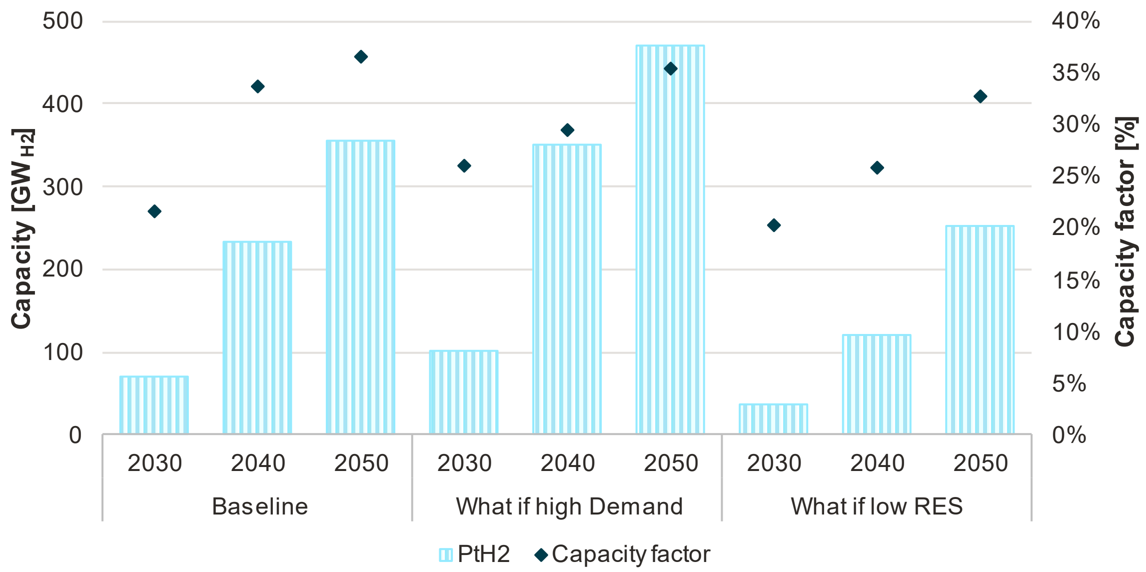
Figure 25 Domestic hydrogen production (EU27, high renewable gases)



Source: Frontier Economics

Electrolyser capacity varies between 250 GW in the case of low availability of RES-E (What-if Low RES) and 450 GW in 2050 (EU27) in the case of less optimistic assumptions on the final demand reduction (What-if High Demand). Capacity factors are closely linked to the availability and utilisation rates of renewable energy sources and in the long run correspond to the output of wind-offshore installations (~30%).

Figure 26 Electrolyser capacity and capacity factors (EU27, high renewable gas)



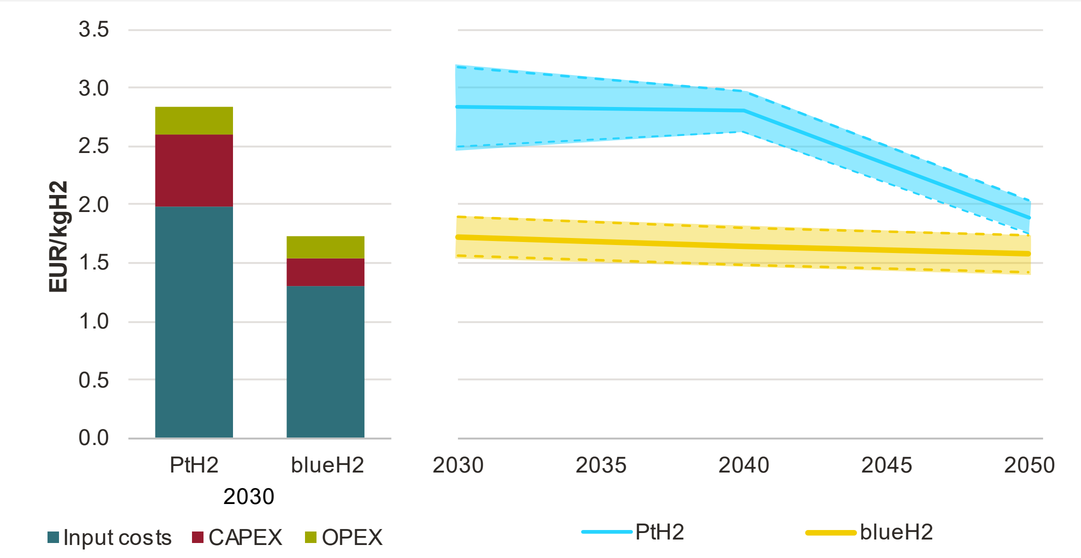
Source: Frontier Economics

Comparison of Levelised Cost of Hydrogen (LCOH), Baseline (high renewable gas)

We consider two major production routes for hydrogen: Power-to-Hydrogen (PtH2) and Steam Methane Reforming with CCS (SMR). PtH2, commonly known as water electrolysis, uses electricity to split water (H_2O) into hydrogen (H_2) and oxygen (O_2), typically using an electrolyser. SMR involves reacting methane (CH_4) with steam (H_2O) at high temperatures and produces hydrogen (H_2) and carbon dioxide (CO_2). We use our technology cost assumptions and model outcomes to calculate average production costs of hydrogen:

- The input fuel costs (electricity prices for PtH2 based on average procurement costs in the Baseline scenario, methane costs incl. CO_2 for SMR) are the largest cost component for both technologies. In our analysis, they make up between 70-85% (PtH2) and 75% (SMR) of total production costs.
- Although electrolysers typically produce during hours with low electricity prices resulting in average electricity procurement costs of around 20-30% below average market prices, PtH2 shows significantly higher variable – and consequently total – hydrogen production costs than SMR, particularly in the medium term to 2040.
- Towards 2050, LCOH for both technologies decline with assumed learning curve effects; electricity procurement costs for electrolysers decline in line with electricity wholesale prices. LCOH of both technologies become more similar, and utilisation of electrolysers increases.
- If the Baseline assumptions concerning demand or availability of renewable electricity do not materialise, costs of PtH2 increase compared to blueH2 production costs.

Figure 27 Comparison of levelized hydrogen production costs (LCOH[77]) with Power-to-Hydrogen and Steam Methane Reforming



Source: Frontier Economics

4.2.3 The optimal supply mix consists of methane-based gases and hydrogen

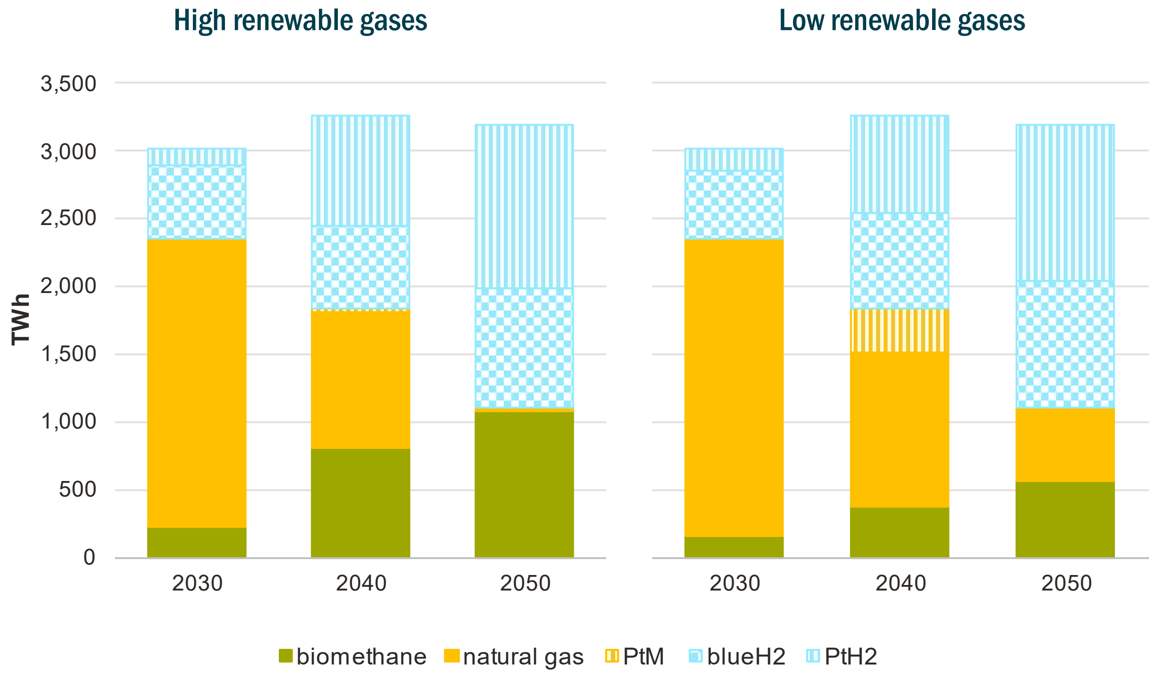
Gases play a significant role as energy carriers in final demand sectors. In our Baseline scenario, the optimal mix to serve final demand consists of almost equal shares of methane-based gases and hydrogen:

- **Baseline (high renewable gases):** Natural gas still presents the predominant supply for final gas demand in 2030 (70%) with smaller shares of blueH2 or biomethane. Towards 2040, the share of hydrogen increases to 44% (25% PtH2, 19% blueH2). Biomethane contributes 25% and natural gas accounts for 31% of gas consumption in final demand. In the long run, natural gas accounts for a smaller share of final demand, as available biomethane volumes suffice to serve methane demand. However, natural gas still serves as important input to blueH2 production in the EU. Hydrogen demand amounts to ca. 2 PWh in 2050, of which about 40% are served by blueH2 and about 60% by PtH2.

- **Baseline (low renewable gases):** If the roll-out of renewable gases (PtH2, biomethane) is slowed down, natural gas continues to contribute higher volumes to final demand, 35% in 2040 and 17% in 2050. As biomethane production is limited, additional PtM needs to be imported in 2040 (ca. 300 TWh). The lack of supply of PtH2 in 2040 is compensated for by higher blueH2 volumes.

[77] Methane prices are based on natural gas prices. Electricity costs are based on the actual price at the time of use, based on hourly modelled electricity prices. The capacity factor for PtH2 is determined by our energy system model. An SMR capacity factor of 90% is assumed. CO2 costs include capturing and storing as well as costs of remaining (not-captured) emissions. Emission prices according to IEA (2023): WEO, APS scenario.

Figure 28 Gas mix in final demand (EU27, Baseline)



Source: Frontier Economics

4.2.4 Methane continues to contribute to gross available energy

The share of methane (natural gas, biomethane) in gross available energy[78] amounted to 22% in 2022.[79] Towards 2030, our **Baseline scenario** projects a moderately increasing share of methane in gross available energy to 24%. In the long term, the share decreases in line with final energy demand for methane. Nonetheless, methane-based gases show a significant contribution to overall gross available energy supply in Europe. The supply is increasingly rendered carbon-neutral (or negative) by the application of CCS, conversion to blueH2 and/or usage of biomethane with carbon removals:

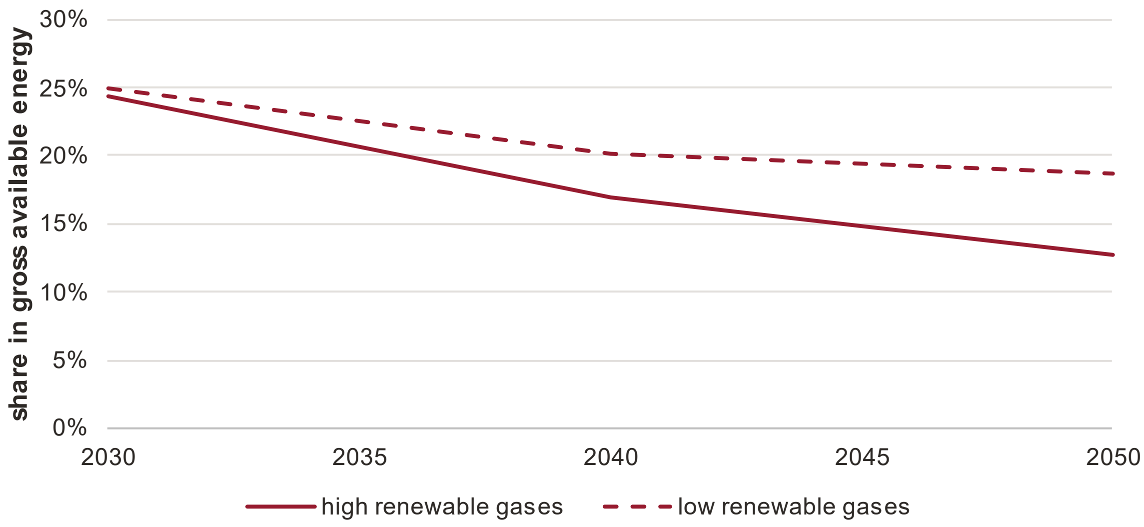
- Assuming **high availability of renewable gases**, the share of methane decreases from 22% in 2022 to 13% in 2050.

- If the ramp-up of renewable gases is hampered (**low renewable gases**), the contribution of methane decreases from 22% in 2022 to 19% in 2050.

[78] Gross available energy (GAE) supply consists of domestically available primary energy and net-imports of energy: GAE = domestic primary energy + imports – exports.

[79] ENTSO TYNDP (2024).

Figure 29 Share of methane in gross available energy (EU27, Baseline)



Source: Frontier Economics
Note: Gross available energy = primary energy supply - exports + imports

4.2.5 Carbon capture is required to achieve reduction targets

Carbon capture proves to be an essential technology in the portfolio of options to reach the GHG emission targets. The development of modelled carbon capture activity reveals important conclusions:

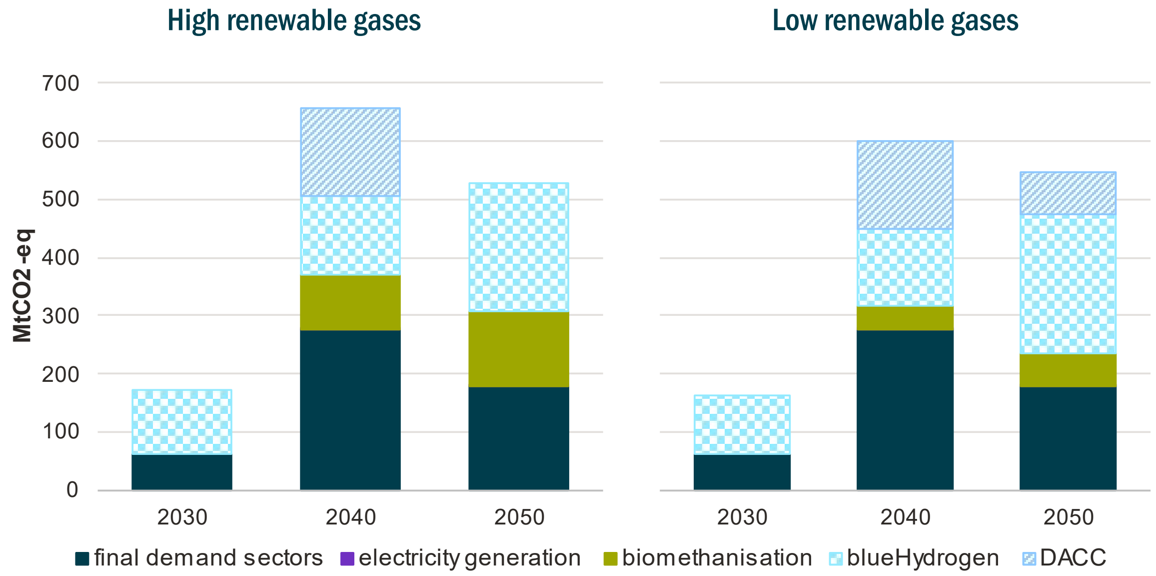
- **Carbon capture in final demand sectors** (dark blue in graph below) increases to almost 275 $MtCO_2$-eq per year in 2040, but decreases towards 2050 to below ca. 200 $MtCO_2$-eq per year, as more renewable energy becomes available and demand decreases with higher energy efficiency levels.

- High share of **bioenergy with carbon removal** (Biomethanisation, green bars): The combination of biomethane production with carbon removal allows for the creation of negative emissions. In our scenario with high renewable gases, carbon removal via biomethanisation and carbon capture and storage amounts to 130 $MtCO_2$-eq in 2050.

- **Strong increase of capture volumes in 2040 emphasises the high level of ambition**: Reaching 90% emission reductions by 2040 requires the use of less mature technologies like Direct Air Capture ("DAC", blue dashed bar). If there is a lack of renewable gases, even higher volumes of DAC are deployed.

- Carbon capture associated with the **production of blueH2** production (light blue plaid bars) increases in line with the increase in hydrogen demand, which is partially met by domestic blueH2 supply. If there is a lack of renewable gases, the volume of domestic blueH2 and corresponding carbon capture activities increases.

Figure 30 Carbon capture (EU27, Baseline)



Source: Frontier Economics

We note that the total deployment of carbon capture technologies in our study exceeds the volumes shown in the EU Impact Assessment and the TYNDP24 (around 450 $MtCO_2$-eq in 2050). We allow for higher carbon capture volumes to illustrate the contribution of this technology, especially in combination with biomethanisation and the production of blueH2 from imported natural gas. The restrictions that could limit the deployment of carbon capture are not related to geological potentials but rather to technology costs and the roll-out of down-stream carbon capture and transport infrastructure..

4.2.6 Biomethane production needs to be ramped up in order to serve the remaining methane demand and to create negative emissions

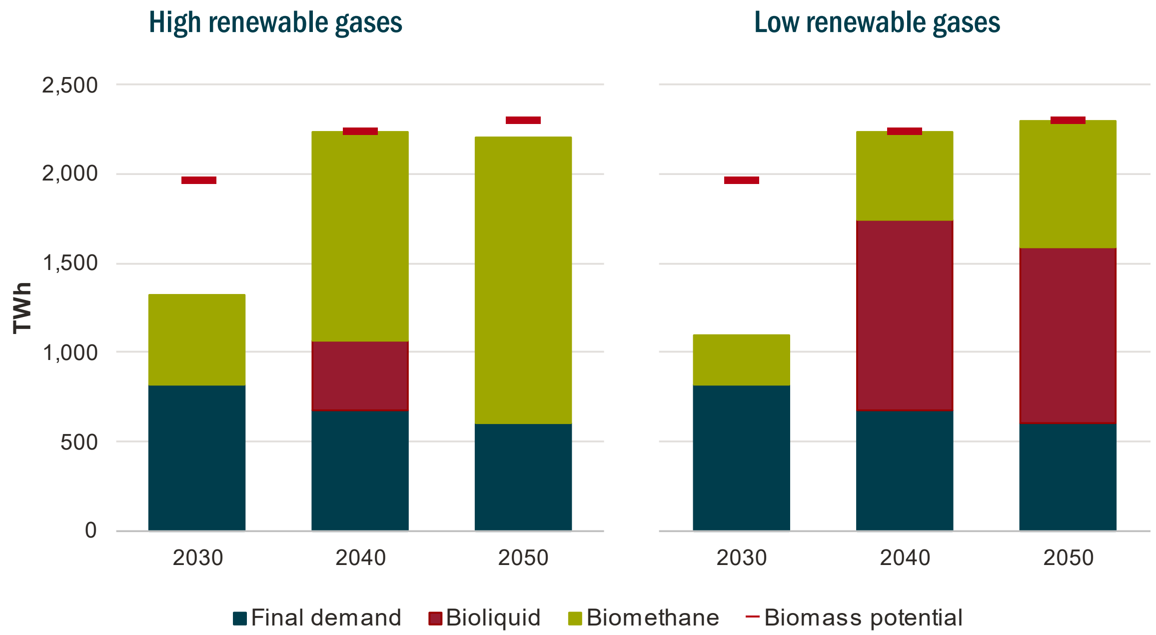
The predominant use of biomass in the Baseline scenario is to produce biomethane, assuming a rapid ramp-up of biomethane production in Europe. This contributes to meeting end-consumer demand for methane. If the biomethane production ramp-up is assumed to be slower, biomass volumes are instead used to produce bioliquids, reducing the import of bioliquids. The optimisation makes use of biomethane (when available) due to two key advantages:

- It allows remaining **methane-based end consumer applications** to be served in a carbon-neutral way using existing infrastructure for storage and transportation;
- In combination with **carbon capture**, biomethanisation is considered carbon-negative generating **negative emissions**: In the growing process, bio-feedstock that is the basis for biogas removes carbon dioxide from the atmosphere. During biomethanisation, the carbon content can be captured and either used for carbon-based applications or

permanently stored. If the CO_2 is permanently stored, the application is regarded as creating "negative emissions."

Figure 31 shows the use of biomass use in the Baseline scenario, assuming high and low renewable gases. The biomass potentials as derived by ENTSOG are almost fully utilised from 2040 onwards.

Figure 31 Biomass consumption (EU27, Baseline)



Source: Frontier Economics
Note: Final demand = direct use of biomass in final demand (e.g. as feedstock)

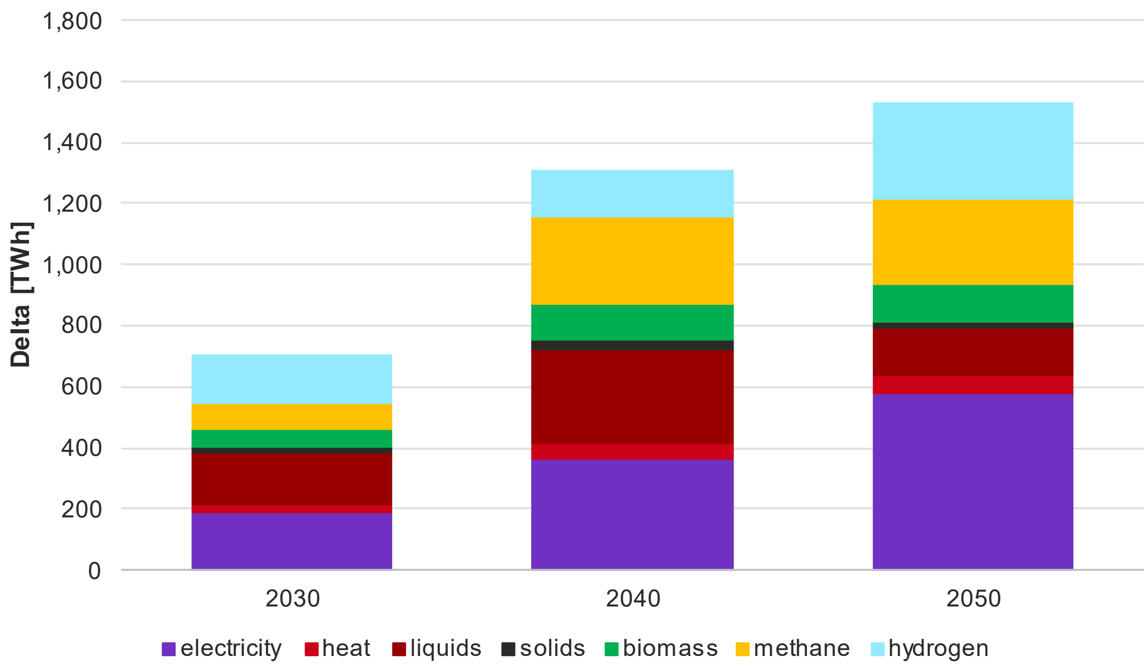
4.3 What-if analyses: Gases act as enablers of the energy transition but also as back-up if crucial expectations don't materialise

The analysis of our What-if scenarios shows the importance of having a well-diversified energy mix. This is not only for system cost reasons, but also to increase the resilience of the energy transition. Resilience means the ability to react or "having a Plan B" if crucial assumptions and expectations do not materialise, or materialise with a significant delay.

4.3.1 If energy efficiency improvements do not materialise or technological change is slowed down, gases can compensate shortcomings

Our What-if High Demand scenario shows the implication of a smaller demand reduction, compared to the optimistic Baseline assumptions. In 2050, the assumed final energy demand increases by 1,500 TWh compared to the Baseline.

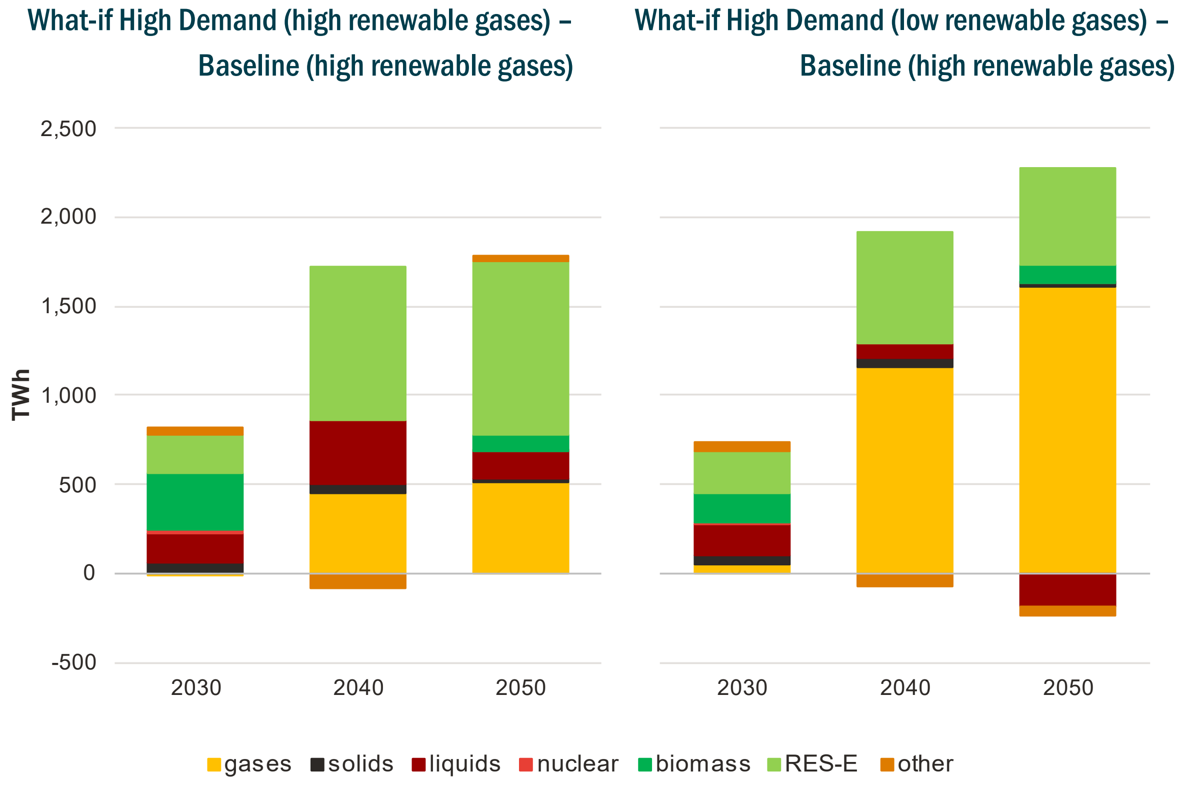
Figure 32 Difference in final energy demand (EU27, What-if High Demand)



Source: Frontier Economics

- **Difference in primary energy supply** – The additional energy demand is predominantly met by a mix of renewables and gases. Primary energy supply is about 2,000 TWh higher in 2040 and 2050 compared to the Baseline scenario. The mix of energy sources is shown in Figure 33:
  - When assuming **high availability of renewable gases,** RES-E deliver 45% (970 TWh) and gases deliver 37% (800 TWh) of the additionally required volumes in 2050.
  - If the ramp-up of renewable gases is slowed down (**low renewable gases**), gases make up 70% (1,600 TWh) and renewable energy sources make up 23% (550 TWh) of the primary energy supply.

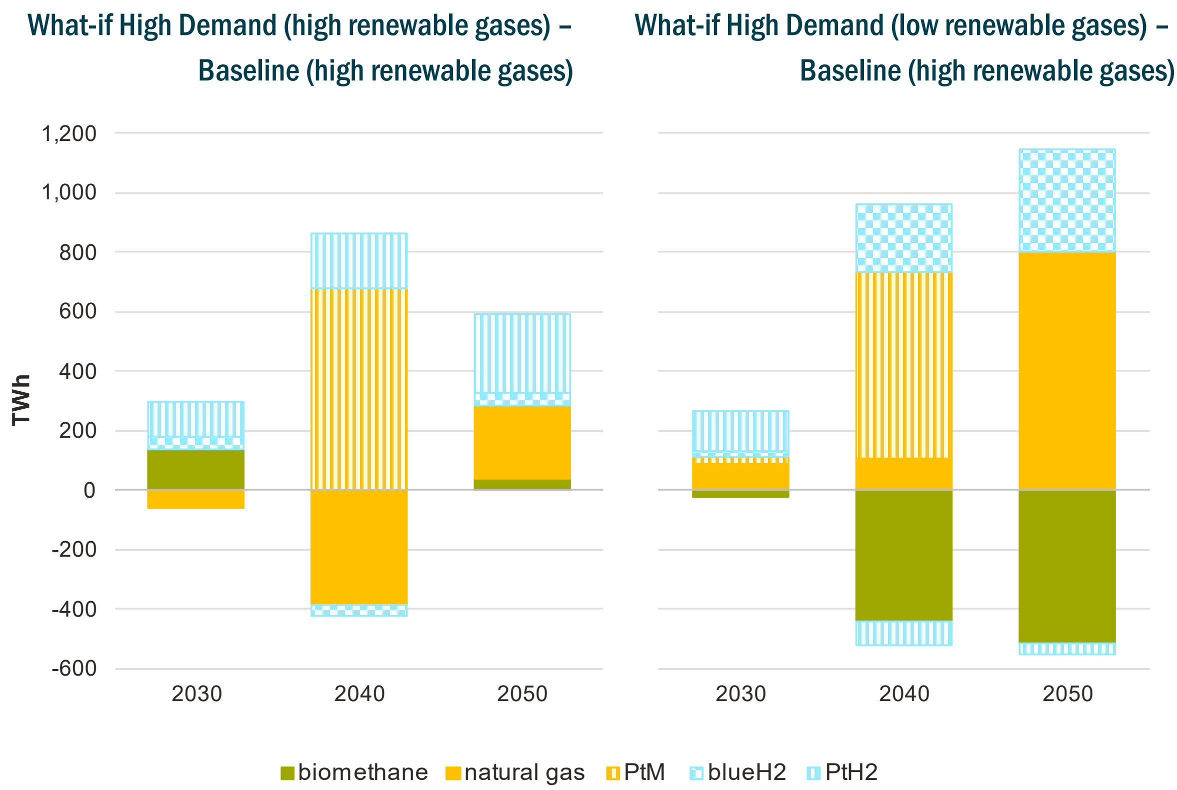
Figure 33 Difference in primary energy supply (EU27, What-if High Demand)



Source: Frontier Economics

- **Difference in gas mix** (in final demand, Figure 34) – The composition of the additional gases needed to serve demand crucially depends on the availability of renewable gases:
  - If **renewable gases** are available at high volumes, PtH2 can integrate the additionally required intermittent renewables into the system (+260 TWh PtH2 in 2050). At the same time, methane demand is decarbonised by using high volumes of biomethane. In 2040, natural gas volumes decrease and are replaced with PtM. In 2050, natural gas and PtH2 increase in almost equal shares to serve demand (in total by 600 TWh)
  - If **renewable gases are restricted**, i.e. less PtH2 (-40 TWh in 2050) and less biomethane (-520 TWh in 2050), and hence are not able to support the integration of renewables, PtM (+600 TWh in 2040), natural gas (+800 TWh in 2050) and blueH2 (+350 TWh in 2050) fill the gap.

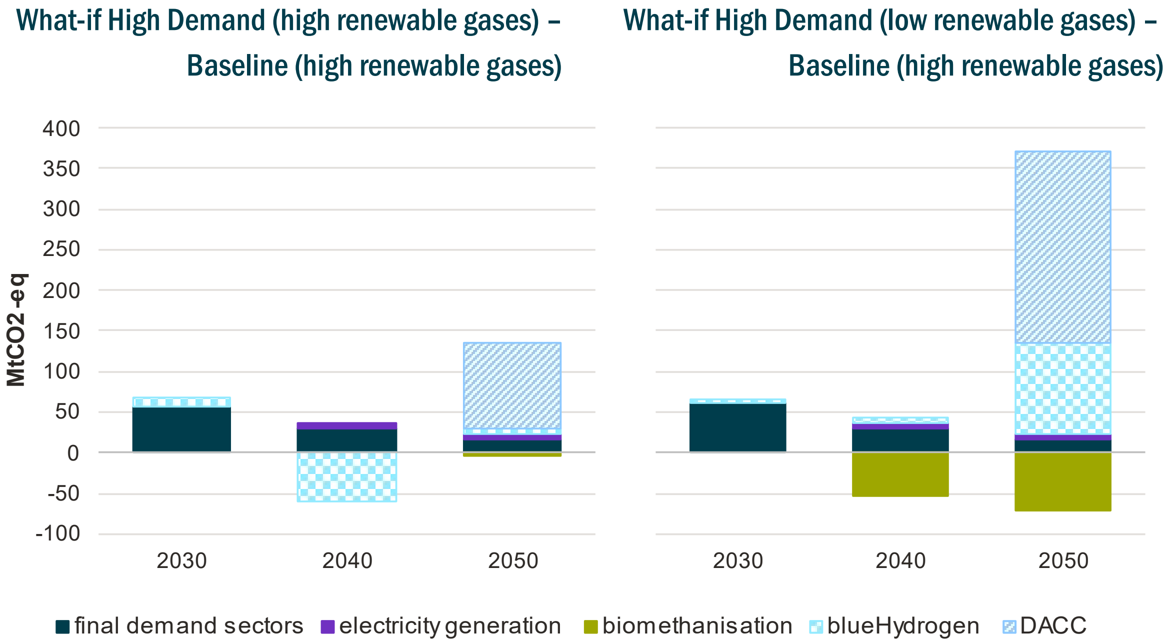
Figure 34 Difference in gas mix in final demand (EU27, What-if High Demand)



Source: Frontier Economics

- **Additional carbon capture needed to meet emission reduction targets** – Additional natural gas volumes in final demand and for blueH2 production require additional ramp-up of carbon capture capabilities. The availability of renewable gases to support the integration of RES-E and to generate negative emissions from biomethanisation limits the need for an otherwise significant ramp-up of carbon capture in 2050 (Figure 35). If the ramp up of renewable gases is restricted, an additional volume of 236 $MtCO_2$-eq or direct air capture is required to meet the 2050 targets (What-if High Demand, 2050).

Figure 35 Difference in carbon capture (EU27, What-if High Demand)



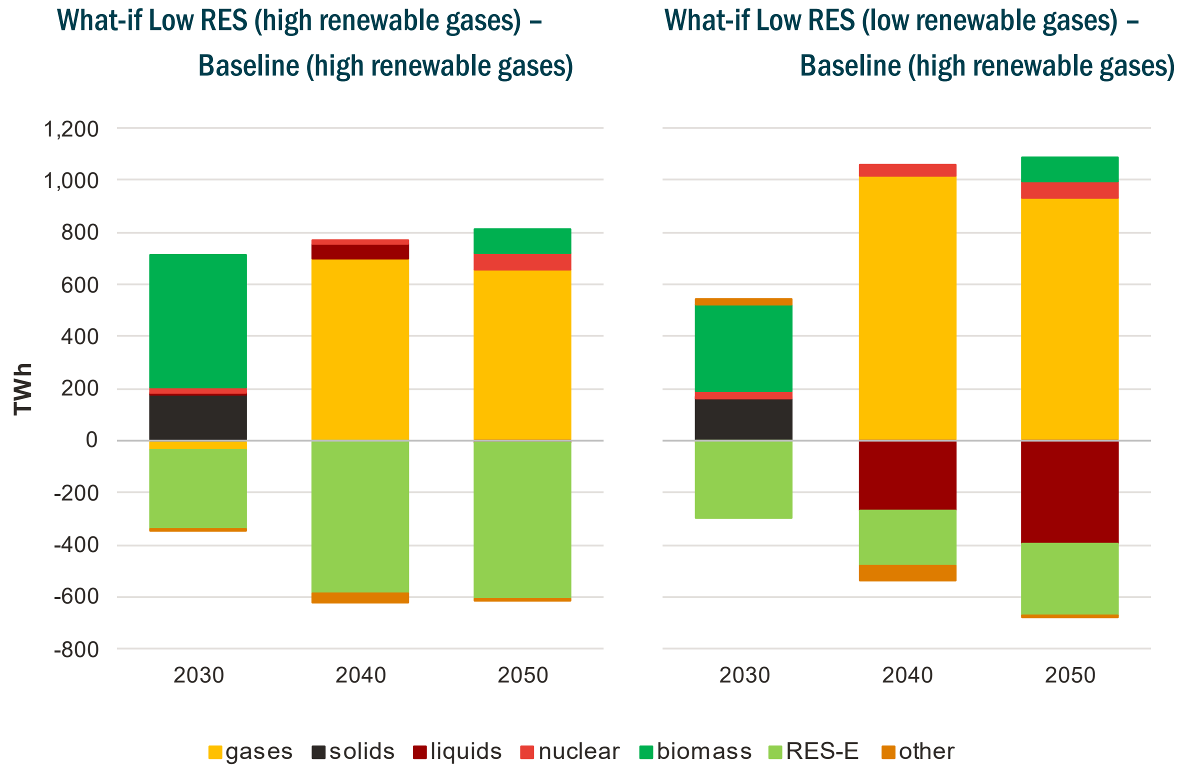
Source: Frontier Economics

4.3.2 If RES-E expansion falls behind expectation, gases can fill the gap

Our What-if Low RES scenario (see **section 2.3.2**) shows the implication of a constrained expansion of renewable energy sources in electricity supply and emphasises the contribution of gases to support the resilience of the energy system.

- **Change in primary energy supply** – A constrained expansion path of RES-E lowers the primary energy supply from renewables by up to 600 TWh in 2050. Assuming high or low availability of renewable gases, gases are the main energy carrier in 2040 and 2050 to replace RES-E. In 2030, mostly biomass supply increases to fill the gap.

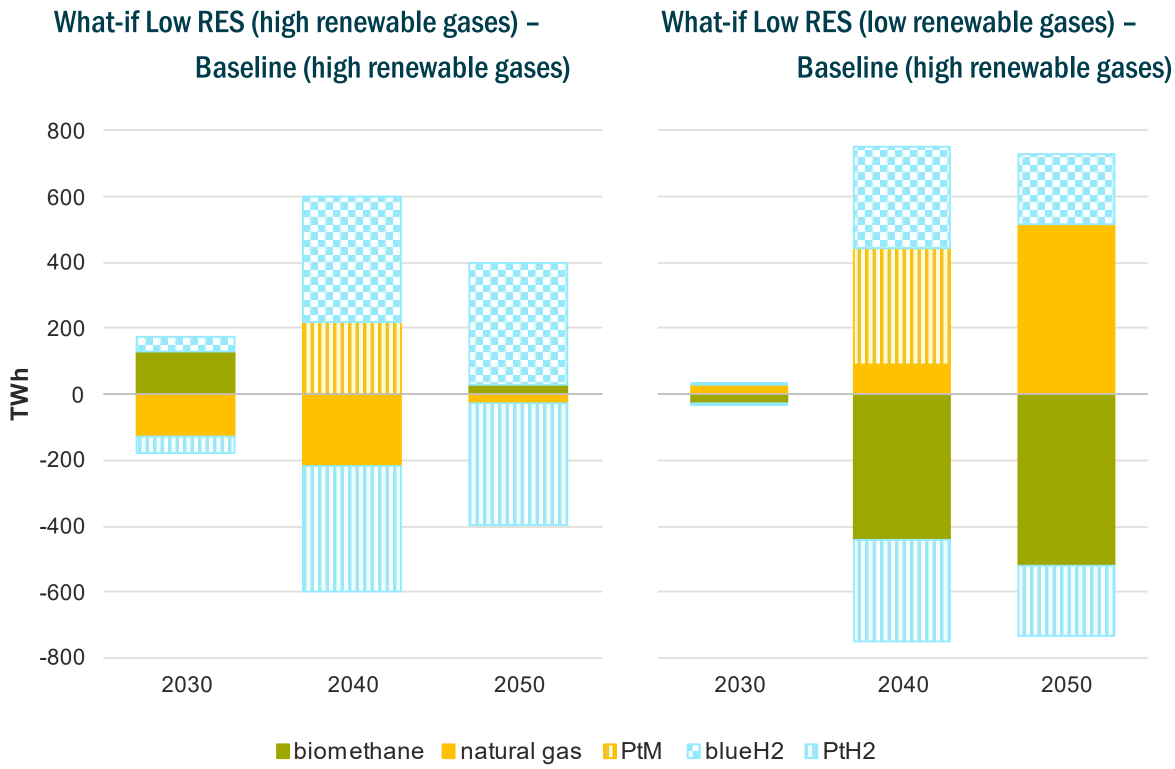
Figure 36 Difference in primary energy supply (EU27, What-if Low RES)



Source: Frontier Economics

- **Difference in gas mix** (in final demand) – The final energy demand for gases does not change in this scenario compared to the Baseline. However, the mix of gas to serve final demand is affected by the availability of RES-E:
  - **High renewable gases**: Due to fewer renewables in the system, the share of PtH2 decreases and is replaced by blueH2 (+370 TWh in 2050). As it is more difficult to meet emission reduction targets, natural gas is partially replaced by PtM in 2040 (+220 TWh in 2040).
  - **Low renewable gases:** If, in addition to RES-E, the ramp-up of renewable gases is constrained, PtM (+350 TWh in 2040) and in 2050, natural gas help to serve final demand (+500 TWh).

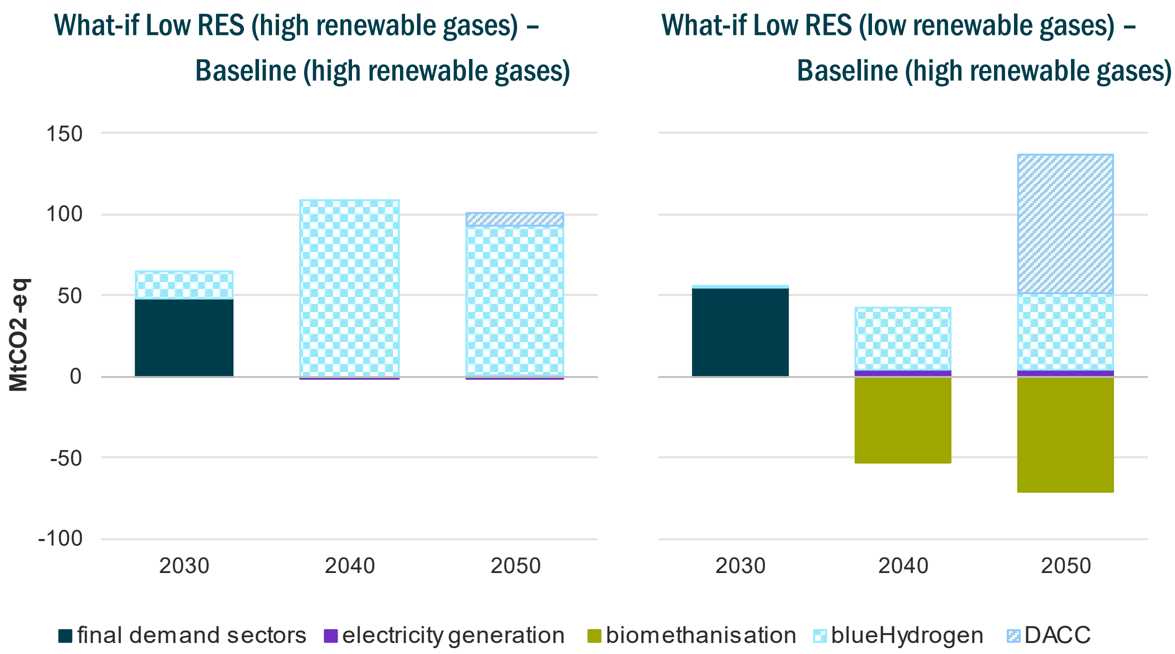
Figure 37 Difference in gas mix in final demand (EU27, What-if Low RES)



Source: Frontier Economics

- **Additional carbon capture needed to meet emission reduction targets** – If availability of RES-E is reduced, more carbon capture is needed. If renewable gases are available at high volumes, it is mainly carbon capture for blueH2 that increases (+100 MtCO_2-eq). If renewable gases are not available at the required volumes, additional DAC volumes are instead essential to meet long-term climate ambitions (+85 MtCO_2-eq).

Figure 38 Difference in carbon capture (EU27, What-if Low RES)



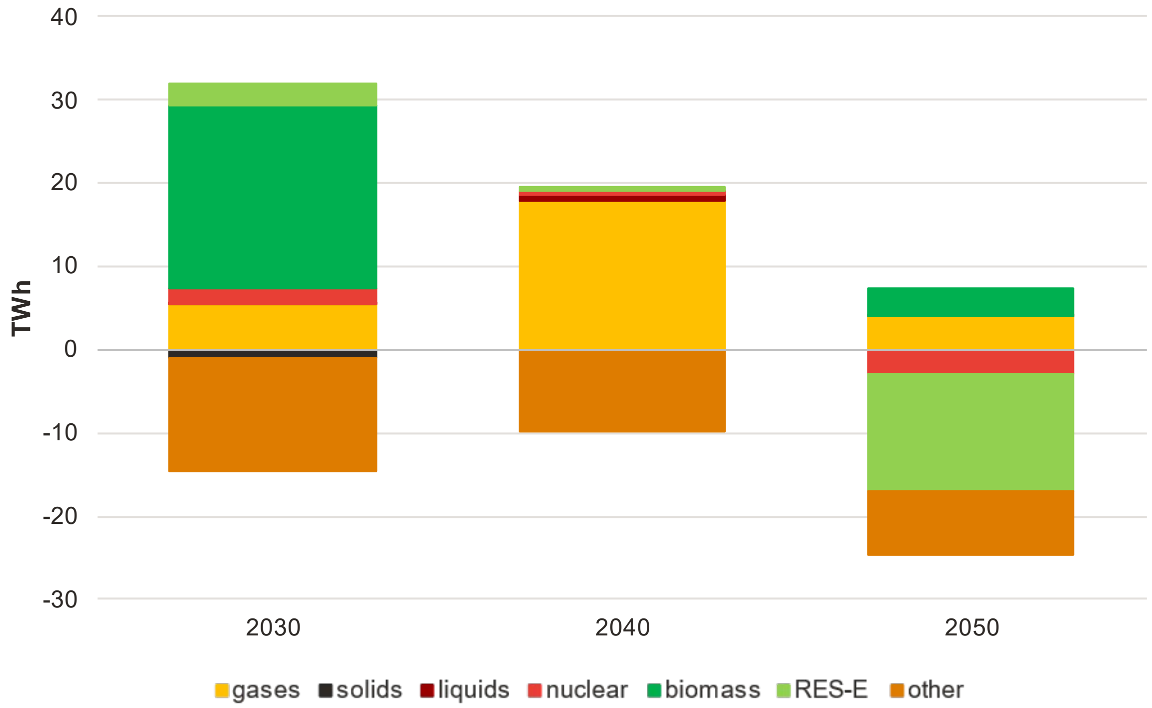
Source: Frontier Economics

4.3.3 If electricity grid expansion is delayed, gases can help to support energy transport ("What-if Delayed Grid scenario")

Our What-if Delayed Grid scenario shows the implication of a delayed expansion of the electricity grid between modelled regions. Delays in the distribution grid or effects at more disaggregated levels are not considered in this analysis but are expected to have similar effects.

- **Change in primary energy supply** – Delayed expansion of electricity networks leads to a small reduction of imported electricity volumes by less than 20 TWh in 2030 and a temporary increase in biomass supply. In the long-run, the delayed grid slightly reduces the supply of RES-E.

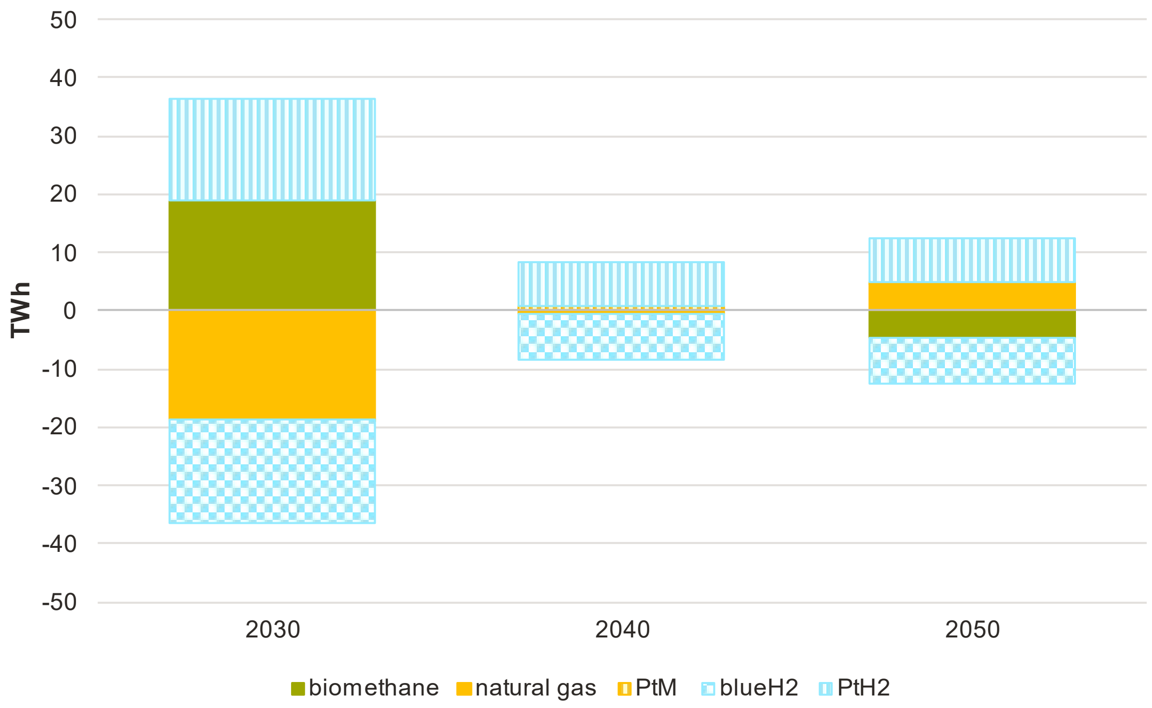
Figure 39 Difference in primary energy supply (EU27, What-if Delayed Grid)



Source: Frontier Economics

- **The gas supply mix changes moderately –** The mix of gases that serve final energy demand changes only moderately with a delayed grid expansion: PtH2 replaces some blueH2 production as lower electricity grid capacities result in more hours with (regionally) low electricity prices. Biomethane production increases slightly in 2030 (from already almost 90% of available potential) as the reduced electricity grid results in higher emissions costs making biomethane even more economically advantageous.

Figure 40 Difference in gas mix in final demand (EU27, What-if Delayed Grid, high renewable gases)



Source: Frontier Economics

We refrain from comparing the Baseline scenario (high renewable gas) to the Delayed Grid scenario with low renewable gases, as differences mainly stem from the availability of renewable gases and less from the Delayed Grid scenario.

5 Resilience: Gases and gas infrastructure required to ensure security of supply and a resilient energy system

In this section we describe how renewable and low-carbon gases help to increase the resilience and security of supply of our energy system.

5.1 Dual-fuel power plants provide back-up capacity in the power sector

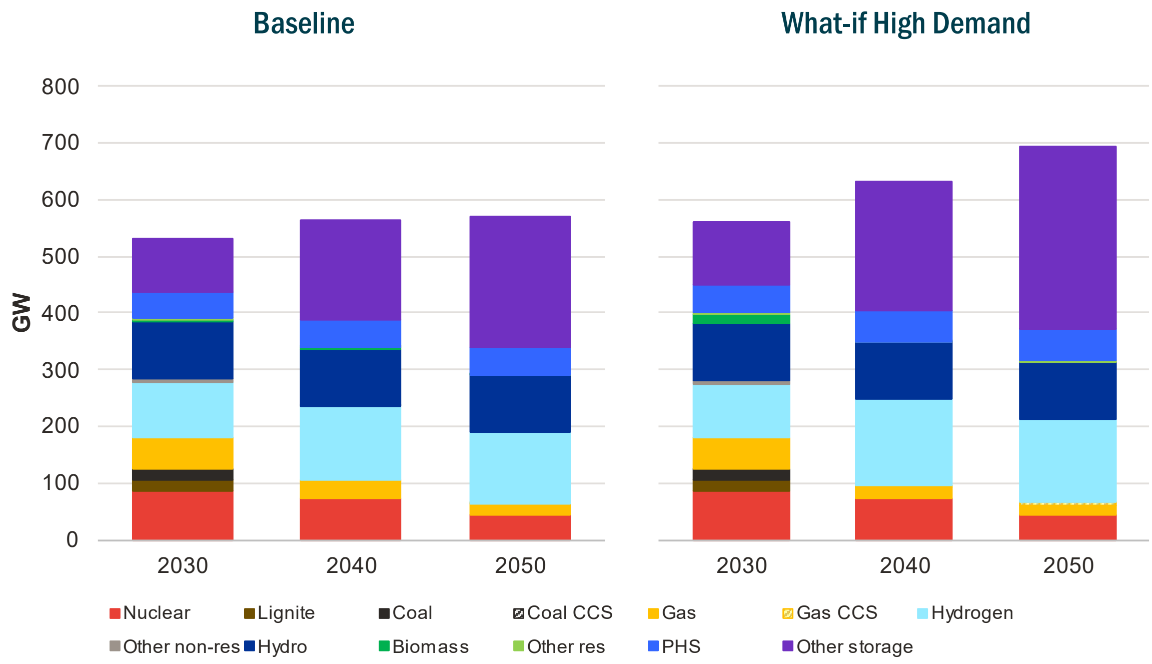
As conventional gas-fired power plants are shut down, they are replaced by dual-fuel CCGT and OCGT power plants (able to use hydrogen and methane) which are crucial for maintaining security of supply in the power sector. Dual-fuel power plants provide longer term flexibility in addition to other shorter-term flexibilities such as batteries or demand side management activities. This flexibility is needed to react to shorter term fluctuations of wind, PV and demand.

- The **Baseline scenario**, assuming high availability of renewable gases, features 145 GW of methane-fuelled power plants in 2050 to secure supply in hours with limited availability of RES-E. Dual-fuel hydrogen / methane plants provide 126 GW. Large-scale electricity storages (especially batteries) provide the largest capacity in dispatchable electricity supply with 230 GW.

- If the ambitious energy efficiency assumptions do not materialise (**What-if High Demand**), an additional 20 GW of dual-fuel and 4 GW of natural gas with CCS complement the electricity supply, in addition to 90 GW of large-scale electricity storage.

Figure 41 shows the development of dispatchable electricity generation capacities in the EU, where over 140 GW of OCGT and CCGT are required.

Figure 41 Dispatchable electricity generation capacity (EU27, high renewable gases)



Source: Frontier Economics

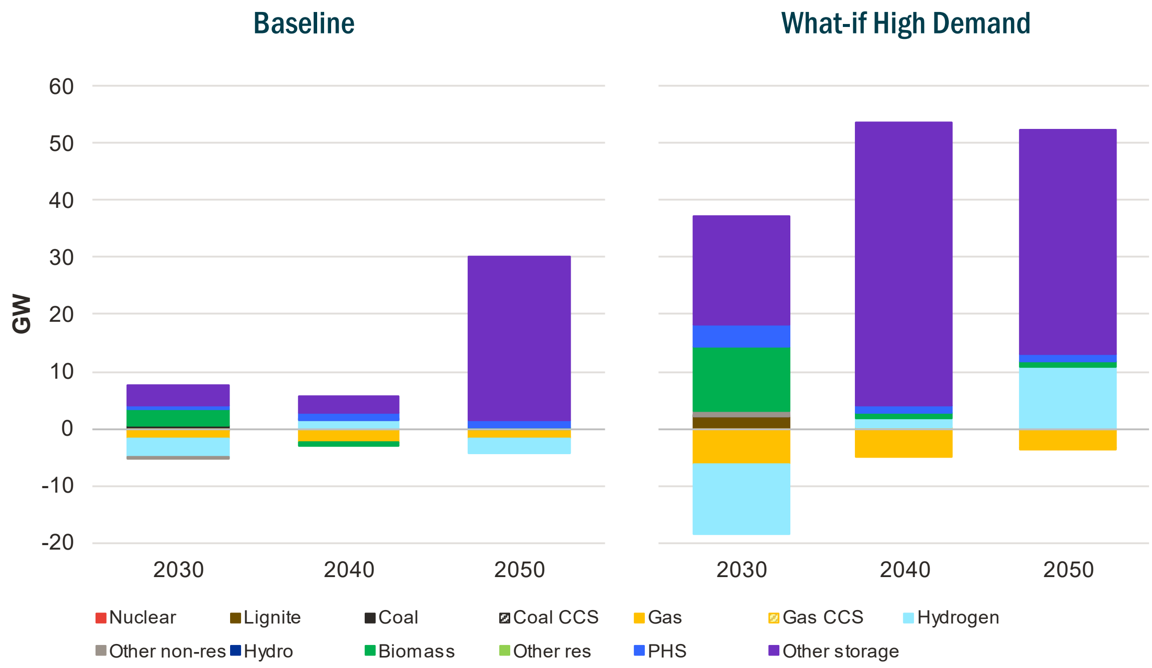
Less investment in large-scale electricity storage required if renewable gases are available

In order to integrate intermittent renewables, significant electricity storages are required. Our Baseline scenario shows an increase in large-scale electricity storages to 230 GW; even more would be required in the What-if High Demand scenario.

Comparing the “high renewable gases” sensitivities against the “low renewable gases” sensitivities shows that the need to invest in large-scale electricity storages increases further under a low availability of renewable gases, as shown in Figure 42:

- The **Baseline** scenario assuming “low renewable gases” includes additional investments of 30 GW in large-scale electricity storages;
- The **What-if High Demand** scenario features even greater additional investment requirements.

Figure 42 Difference in dispatchable electricity generation capacity (EU27, low renewable gases - high renewable gases)



Source: Frontier Economics

5.2 Ramp-up of domestic PtX and biomethane production reduces import-dependency

The Energy transition away from fossil energy carriers towards renewable electricity and domestically produced hydrogen or other renewable and low-carbon fuels reduces Europe's dependency on imported energy products. While complete independence from energy imports is neither achievable nor desirable from an economic point of view, a wider variety of supply options to serve Europe's energy needs increases the resilience of the energy system against external supply shocks.

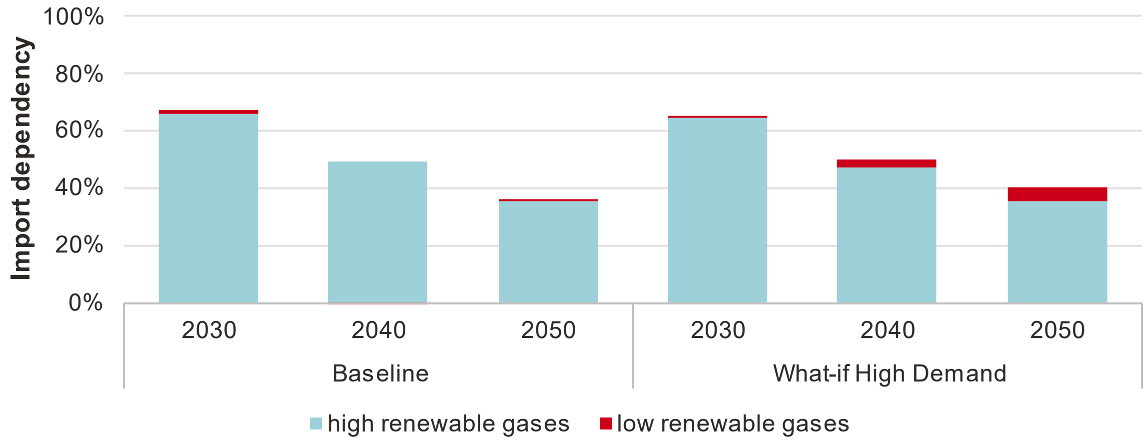
Our modelling shows that domestic renewable electricity supported by PtX and additional renewable gases (biomethane) indeed leads to a long-term reduction in energy import dependency. We define import dependency as the ratio of net imports to gross available energy.[80] Results are shown in Figure 43.

- In our Baseline scenario net imports decrease from 8,640 TWh (66% of GAE) in 2030 to 3,691 TWh (35%). The availability of renewable gases (high vs. low) only has a moderate effect on the import dependency.

80 Gross Available Energy (GAE) = Primary Energy Supply - Exports + Imports

- However, in the What-if High Demand scenario (i.e. assuming less pronounced energy efficiency savings and lower demand reduction in the long-term), the availability of renewable gases reduces import dependency by 5 percentage points in 2050. This is because (a) domestic biomethane supply is constrained, and so more methane is imported, and (b) the domestic PtX supply is limited, and so more methane is imported to produce blueH2.

Figure 43 Import dependency (EU27)



Source: Frontier Economics

5.3 Gas infrastructure and H2 grid development essential to provide transport capacity and relief to congested electricity grids

For TSOs, leveraging existing natural gas pipelines and storage facilities and developing hydrogen grids eases energy transport over long distances and alleviates the intermittency of renewable energy sources, which is critical for maintaining grid stability.

At the DSO level, hydrogen infrastructure facilitates local energy distribution and decarbonization efforts, providing a clean alternative to fossil fuels for industries and households. The coupling of electricity and gas networks through hydrogen also promotes a more interconnected and resilient energy system.

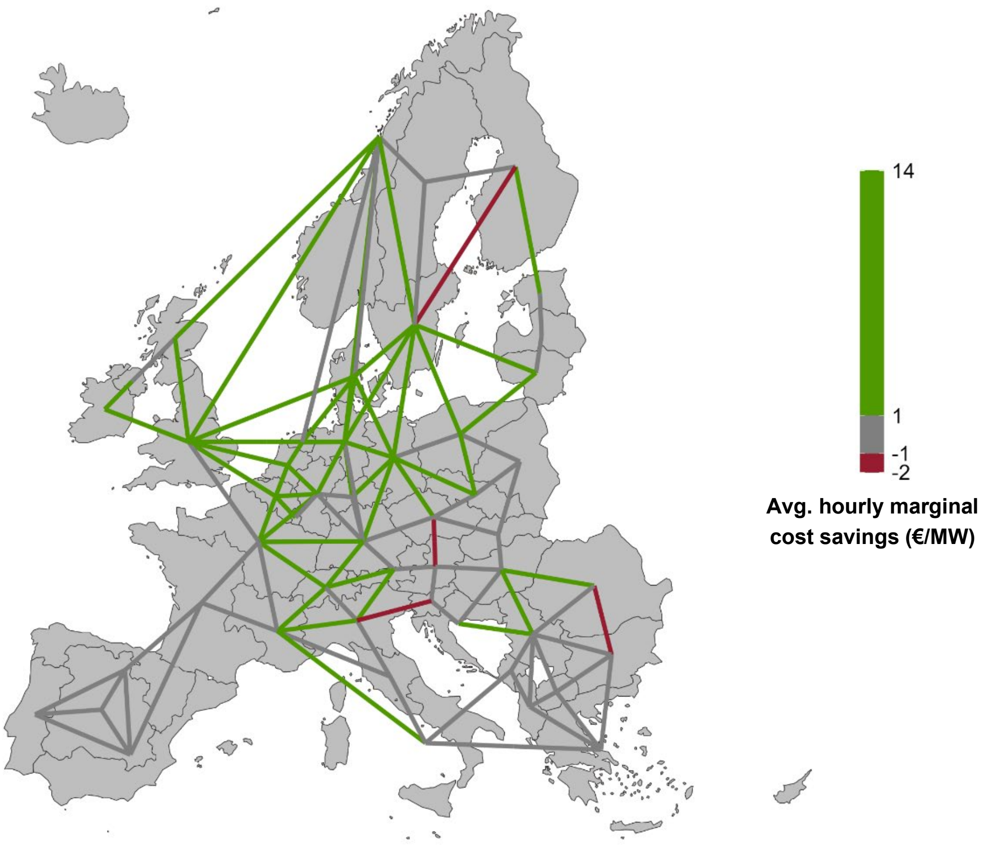
Impact of renewable gases on network congestions

To illustrate the effect of renewable gases on electricity grids, we analyse costs associated with network constraints. Our What-if Delayed Grid scenario describes a slower and constrained electricity network expansion, leading to an overall capacity reduction compared to the Baseline scenario of 13 GW in HVDC capacity and 48 GVA in HVAC capacity.

In this restricted setting, we calculate the cost of network congestion: by how much total system costs decrease if the capacity on a given electricity line increases by one unit (so-called marginal). High marginal values indicate that an extension of that line would increase efficiency, for example in terms of investment or power plant dispatch. We examine how high vs. low availability of renewable gases impacts these marginals.

Figure 44 shows the impact of high compared to low renewable gas availability on the marginal (i.e. the cost of network congestion). Green lines indicate a positive impact, i.e. a reduction of costs associated with constrained electricity grid capacity, grey only a minimal change of +/-1 EUR/MW and red an increase in congestion costs. We can see that in our What-if Delayed Grid (2030), the efficient deployment of renewable gases reduces the cost associated with constrained electricity networks in almost all transmission lines.

Figure 44 Effect of high availability of renewable gases on grid constraints (What-if Delayed Grid, high compared to low renewable gases, 2030)



Source: Frontier Economics

Note: Positive values indicate marginal system cost savings due to higher availability of renewable gases

5.4 Development of a European hydrogen market and transport capacities

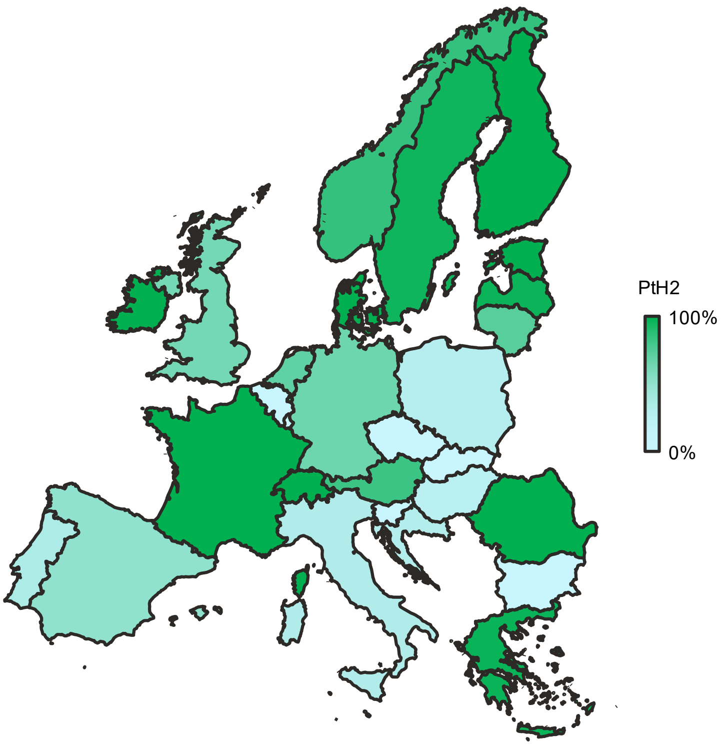
Demand for hydrogen and other gaseous fuels differs between regions, as do potentials to supply that demand. The development of a liquid hydrogen market based on adequate transport capacities is required.

5.4.1 Regional differences in H2 supply

The Baseline scenario (high renewable gases) considers regional differences in (a) the supply of RES-E to produce PtH2 and (b) capacities to import and/produce blueH2. Figure 45 illustrates the share of regional hydrogen demand that is met by domestic PtH2 production:

- PtH2 is the predominant supply source for hydrogen in countries with access to abundant low-cost renewables (depending on the country, good locations for wind or hydro plants) or relatively low hydrogen demand (e.g. Scandinavia and France).
- BlueH2 and imports play a higher role in South and Eastern Europe with less favourable access to renewables.

Figure 45 Share of hydrogen demand supplied via domestic PtH2 production 2050 (Baseline, high renewable gases)



Source: Frontier Economics

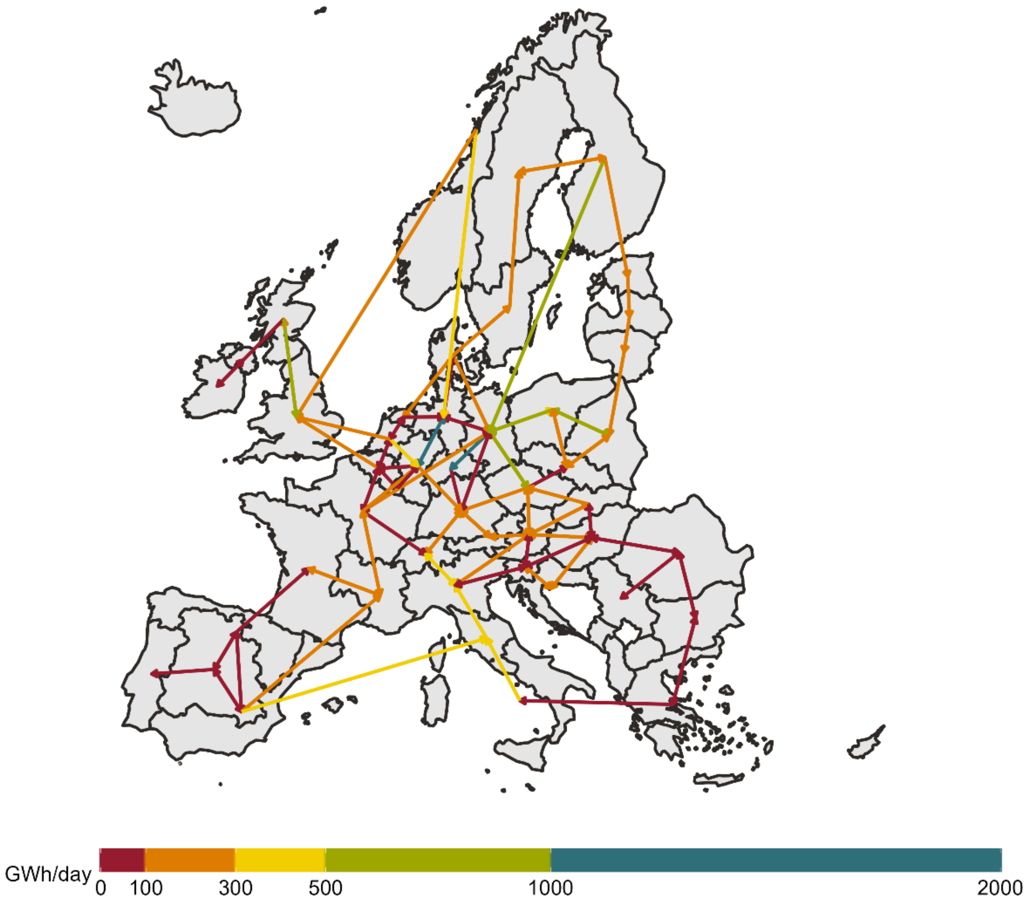
Some countries rely more on imports of H2 or blueH2 than others. This is typically the case in those countries that can rely to a smaller extent on domestic PtH2 production. Therefore, sufficient transportation capacity needs to be established to allow for efficient and liquid trading of H2 between regions.

5.4.2 Development of H2 grids and repurposing gas networks

To model the European hydrogen and methane transportation grid, we integrate data from several key sources: ENTSO-G, SciGrid_gas, the Hydrogen Infrastructure Map, and the European Hydrogen Backbone. This approach allows us to capture a comprehensive view of the current and planned infrastructure on a NUTS1 level. Our model incorporates both new builds specifically designed for hydrogen transport and the repurposing of existing methane pipelines for hydrogen use. By focusing on the transportation grid, we implicitly assume that the distribution network has sufficient capacity to handle the transported volumes. Hence our model focuses on the primary channels for large-scale hydrogen and methane movement across Europe.

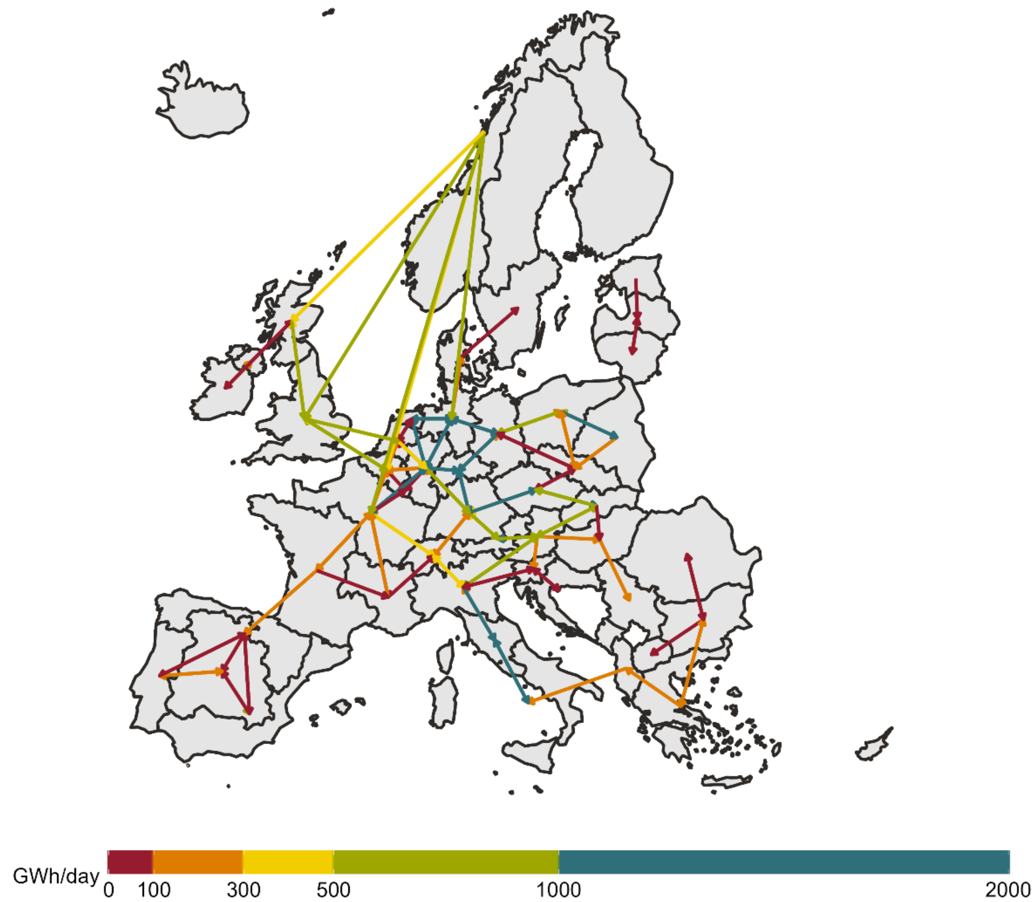
Figure 46 shows an aggregated version of the hydrogen transportation grid in 2050, and Figure 47 shows that of the methane transportation grid in 2050. Figure 48 shows trading capacities across time - about 10.6 TWh/day of internal methane trade capacity within the EU27+EFTA+UK region is re-purposed for hydrogen, while a capacity of 21.7 TWh/day is newly built by 2050. By then, hydrogen makes up over 30% of the total internal gas trade capacity (between countries and between modelled regions).

Figure 46 Aggregated hydrogen grid 2050



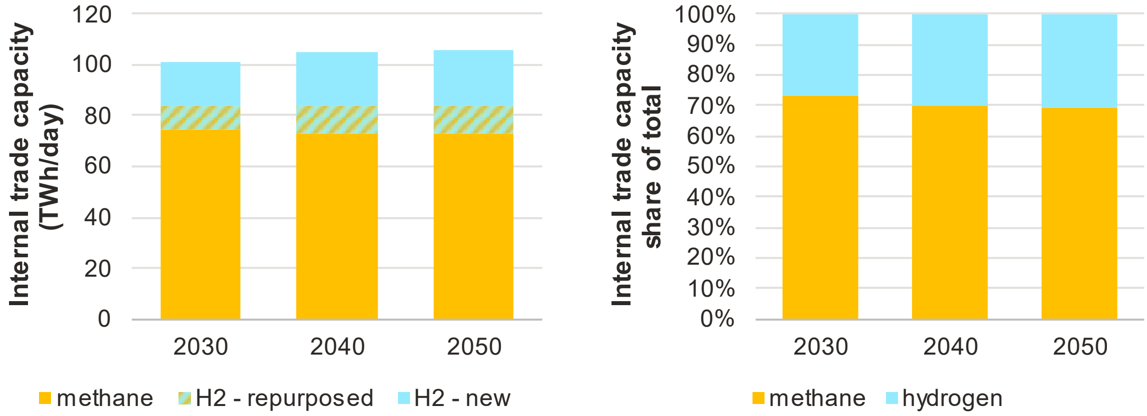
Source: Frontier economics

Figure 47 Aggregated methane grid 2050



Source: Frontier economics

Figure 48 Methane and hydrogen grid total internal trade capacity, EU27+EFTA+UK



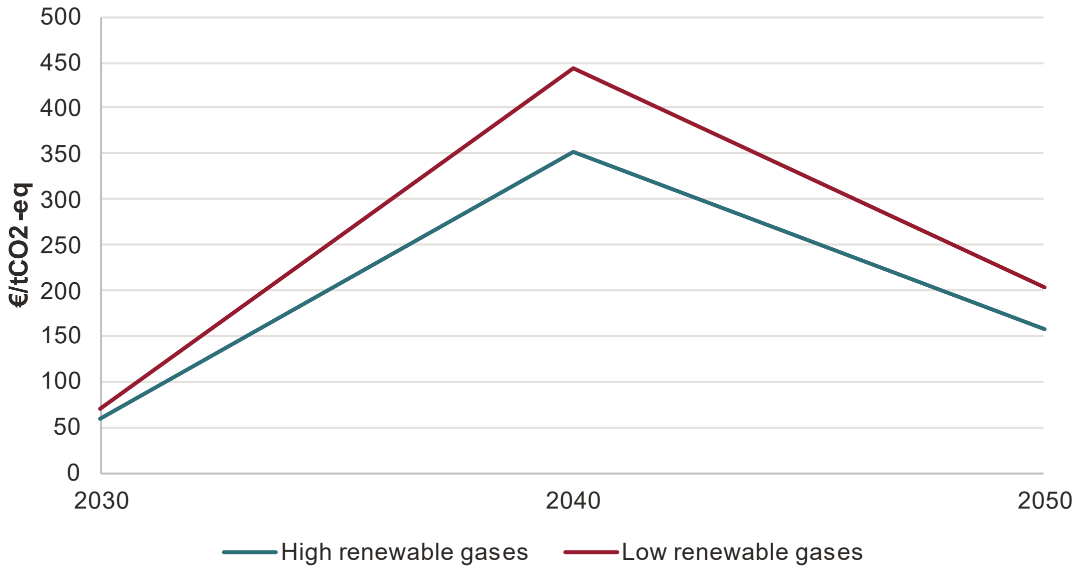
Source: Frontier economics

6 Efficiency: Gases increase efficiency of energy transition and result in lower costs for final consumers

6.1 High CO_2 prices highlight how ambitious the 2040 target is, renewable gases lower cost of emission reduction

Carbon emission prices are determined endogenously in our model analysis. They reflect the price level that is necessary to incentivise emission reductions to reach the annual emissions limit. Figure 49 illustrates the price levels in both Baseline sensitivities (low renewable gases and high renewable gases). Generally, the emission prices in the short (2030) and long term (2050) are roughly aligned with price expectations: At the time of writing this report, EU ETS prices are around 70 EUR/tCO_2-eq, while the latest World Energy Outlook forecasts prices at around 190 EUR/ tCO_2-eq in 2050.[81]

Figure 49 Endogenous emission prices (EU27, Baseline)



Source: Frontier Economics

Medium-term prices (2040) show an intermediate peak. This indicates that reaching the 90% reduction target (relative to 1990) proposed by the European Commission will be very challenging:

81 In 2022 real monetary terms; It has to be noted that the discussed -90% target in 2040 has not been included in the IEA's analysis in the World Energy Outlook.

- By 2030, the aim is to reduce emissions by 55% and reach net zero by 2050. Thus, the absolute emission reduction in the ten years leading to 2040 (35 percentage points) is much larger than in the following ten years to 2050 (ten percentage points).

- At the same time, the final demand for carbon-based fuels (methane, coal, and oil) declines fairly linearly from 2030 to 2050 in our Baseline scenario.

- Additionally, decarbonisation options like Power-to-X and carbon capture are only just starting to accelerate and, like renewables, are expected to see cost reductions as capacity scales up. This renders medium-term emission reductions more expensive.

- To achieve the target, costly (and less mature) options like Direct Air Capture (DAC) have to be applied.

This indicates that all available decarbonisation options and targeted policy support will be necessary to reach the decarbonisation targets.

Comparing both sensitivities, we see that a higher availability of renewable gases has a significant dampening effect on carbon prices, between 19% in 2030 and 29% in 2050.

6.2 Availability of renewable gases increases efficiency of the energy transition

The availability of renewable gases influences the system costs for serving energy demand given emission reduction targets. We consider the following main components for our cost analysis:

- **Investment and O&M costs**: Includes all investment (CAPEX), as well as fixed annual operation and maintenance (O&M) costs for energy conversion and storage technologies, including power plants, batteries, Power-to-X, electrolysers, biomethanisation plants, gas storages, and blue hydrogen production plants

- **Energy costs**: Includes costs for imported fuels and other variable costs

- **Carbon capture costs**: Includes investment and operation costs for carbon capture in final demand sectors as well as transportation and storage costs

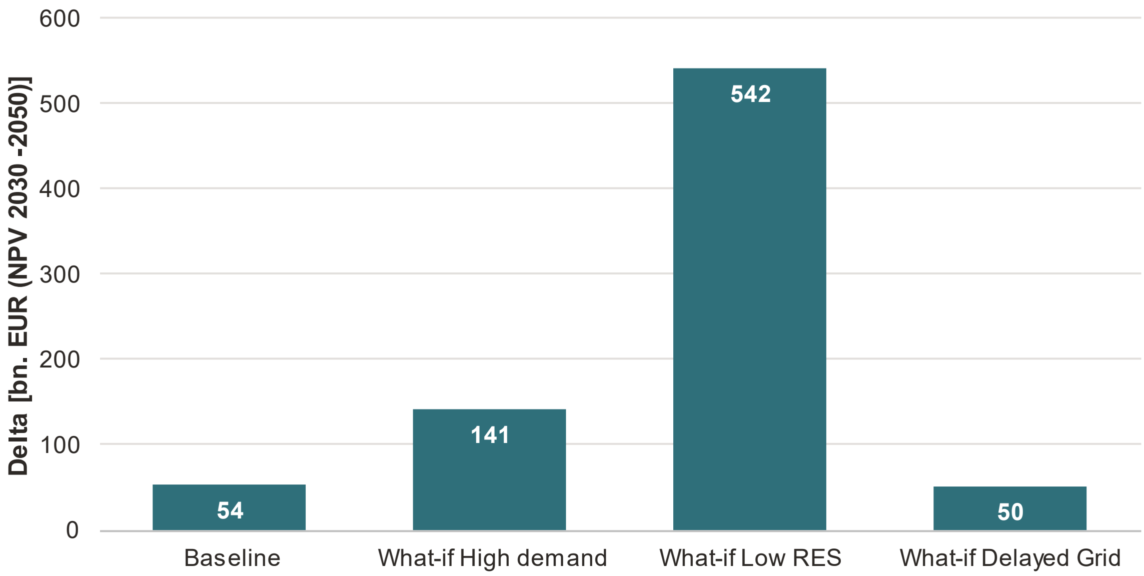
We do not consider:

- **Investment in final demand sectors**: The final demand sector is exogenous in our model and not optimised; costs are not considered. In most scenarios, we keep the final demand sector constant, meaning that costs will be equal and cancel out in a comparison between scenarios. Only in the High Demand scenario we do change assumptions regarding final demand activity levels and technologies being used. However, in this case the different final demand costs also cancel out when comparing the high and low renewable gas sensitivities with the same final demand assumptions.

- **Grid infrastructure**: Grid capacity assumptions are kept constant throughout all scenarios – except for the Delayed Grid scenario. However, similar to final demand, costs cancel out when comparing high and low renewable gas sensitivities for the same scenario.

We calculate the system cost as the net present value[82] of all cost components described above. Comparing within each scenario, we compare the system cost savings when switching from the low renewable gases sensitivity to the high renewable gases one, shown in Figure 50. The biggest cost advantages of unlocking renewable gases is achieved in the What-if Low RES, with constrained RES-E expansion, 542 billion EUR in NPV. In this scenario, in which expansion of RES-E is constrained and when there is low renewable gases, there is a considerable cost attached to higher imports of renewable gases, e.g. Power-to-Methane, and more carbon capture to ensure that emission reduction targets are met.

Figure 50 System cost savings from high renewable gas availability on EU27+EFTA+UK system costs (2030-2050)



Source: Frontier Economics

6.3 Climate pathways that consider renewable gases result in lower cost to consumers

Completing the energy transition and becoming carbon neutral in 2050 will require significant investments to transform the energy system, and to implement carbon neutral industrial processes without losing the economic activity through carbon leakage. Choosing the most

82 5% social discount rate.

efficient options that allow for a secure and affordable energy transition should therefore be of utmost priority to avoid excess cost burdens on consumers and industrial sectors alike.

Unlocking the full potential of renewable gases reduces energy prices

The lower system costs when assuming a higher availability of renewable gases are reflected in energy prices. Figure 51 illustrates the reduction of average EU electricity and hydrogen prices induced by a higher availability of renewable gases.

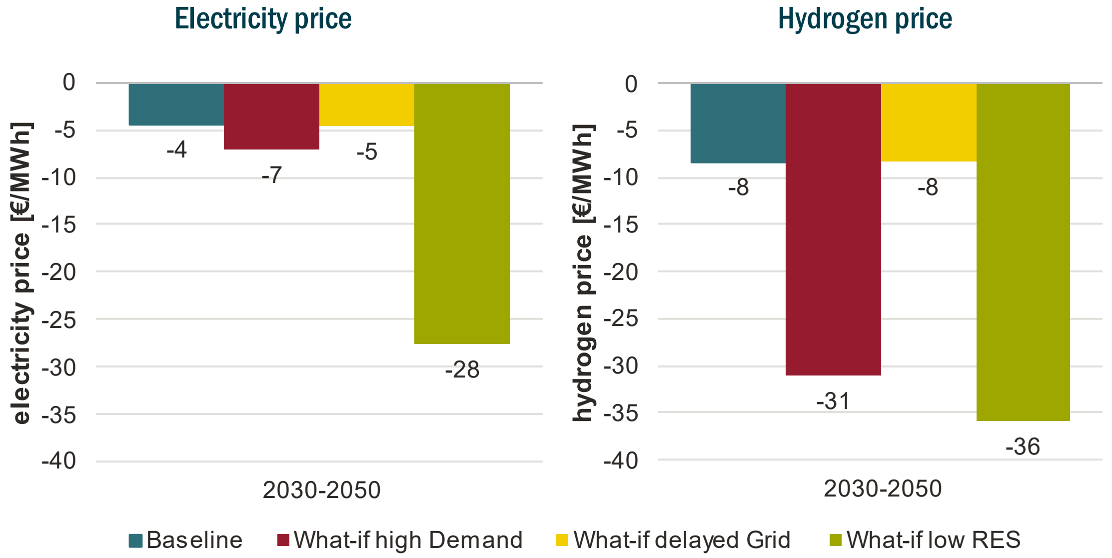
The benefits of renewable gases for energy prices follow a similar pattern as the effect on system costs (Figure 50): The highest price decline can be observed in the scenario with a restricted expansion of variable renewables (Low RES), followed by the High Demand scenario and finally the Delayed Grid and Baseline scenarios.

- **Electricity prices:** A higher gas availability dampens average electricity prices for the period 2030-2050 by between 4-7 EUR/MWh (Baseline, What-if High Demand and Delayed Grid) and by up to 28 EUR/MWh (What-if Low RES) – representing a decline of between 5 and 21%. This is due to PtX being used more effectively, and renewables being better integrated into the system: Less restricted ramp-up of PtX allows the utilisation of RES and electrolysis where conditions are best suited, leading to overall higher load factors for electrolysers.

- **Hydrogen prices:** Average hydrogen prices are also strongly affected by the availability of renewable gases in the High Demand scenario – more so than the overall system costs effect indicates.[83] The price decline is particularly pronounced in 2030 and 2040, where prices are close to 30% lower under higher gas availability. This indicates that especially in the short to medium term, the build-up of hydrogen supply chains is crucial to avoid supply shortages (for example by producing more PtH2 domestically) that could result in very high prices.

83 The higher relative increase in hydrogen prices compared to the increase in system costs indicates a bottleneck in the energy system making it necessary to use costly options for serving all hydrogen demand. This is an indicator for the stress/low margins the system is exposed to in the case renewable and low-carbon options are restrained.

Figure 51 Impact of high renewable gas availability on EU27 weighted average electricity and hydrogen prices 2030-2050



Source: Frontier Economics

Lower energy prices with significant impact on consumer bills

A reduction of consumer energy prices (wholesale) translates into lower energy bills for households and industry: End-consumer bills include components besides energy costs: grid levies, levies for support mechanisms and taxes. The share of these other components differs between EU member states, as national tax-and-levy regimes and network costs vary. Nonetheless, a reduction of energy prices would, all else equal, lead to lower bills for end-consumers.

System Costs vs. Consumer Payments

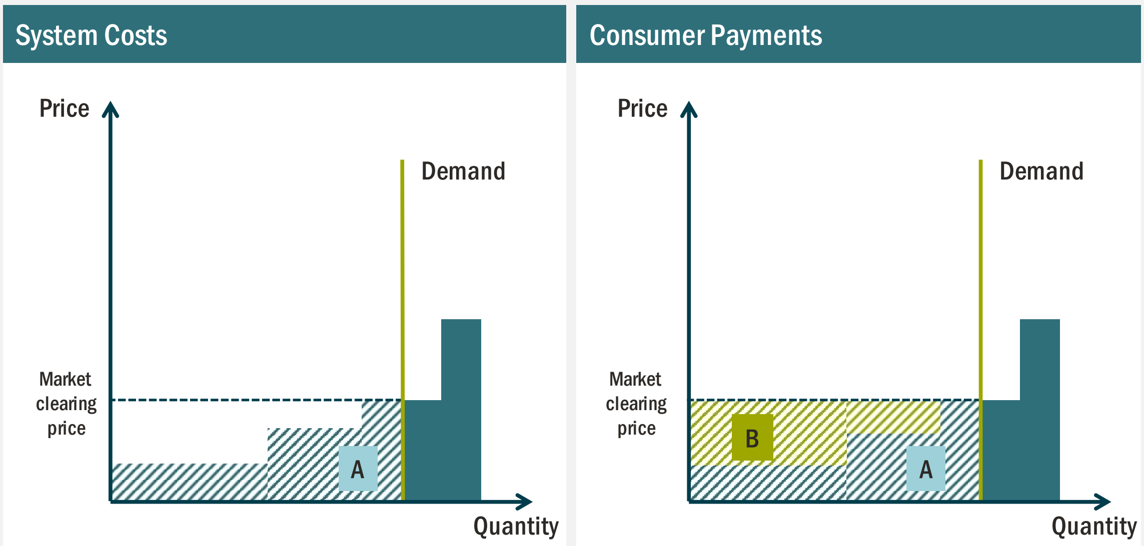
Two indicators, System Costs and Consumer Payments, are used in this analysis to provide insight into the impact of renewable gases on the affordability of the energy transition.

The indicators provide different information:

- **System costs** tell us about the efficiency of an energy system, i.e. what are the costs to society to serve demand in a given region. The distribution of benefits, rents and costs between stakeholders (consumers, producers, the state) is not relevant for the total sum of system costs.
- **Consumer payments** reflect the cost of energy supply for the consumer (i.e., the consumer's bill) and can reveal the distributional effects of these costs. However, costs for different stakeholders may not always align with overall system costs. If markets follow the uniform pricing principle, like energy markets, the prices paid by end-consumers are set based on the costs of the marginal units.

Figure 52 illustrates the difference between both concepts based on a simplified example of one hour of electricity supply (merit order). The same logic applies to hydrogen. In the figure below, the system costs to cover demand are given by the costs of all operating power plants (blue dashed area "A"). These costs are included in the definition of System Costs. The costs to final consumers in this case are given by the area "A" **and** the area "B" due to the principle of "uniform pricing". Area "B" is paid to suppliers as rents, in addition to their generation costs (Area "A"). Therefore, the consumer payments also include rents for suppliers.

Figure 52 System costs vs. consumer payments



In this section, we look at the impact of the availability of renewable gases on energy-related payments of households and industry, for electricity supply and hydrogen supply. We find that a limited availability of renewable gases significantly increases the energy-related cost to final consumers, both for electricity and hydrogen.

In our analysis, we differentiate between household and industrial demand. The calculation of costs for both groups is based on the following assumptions:

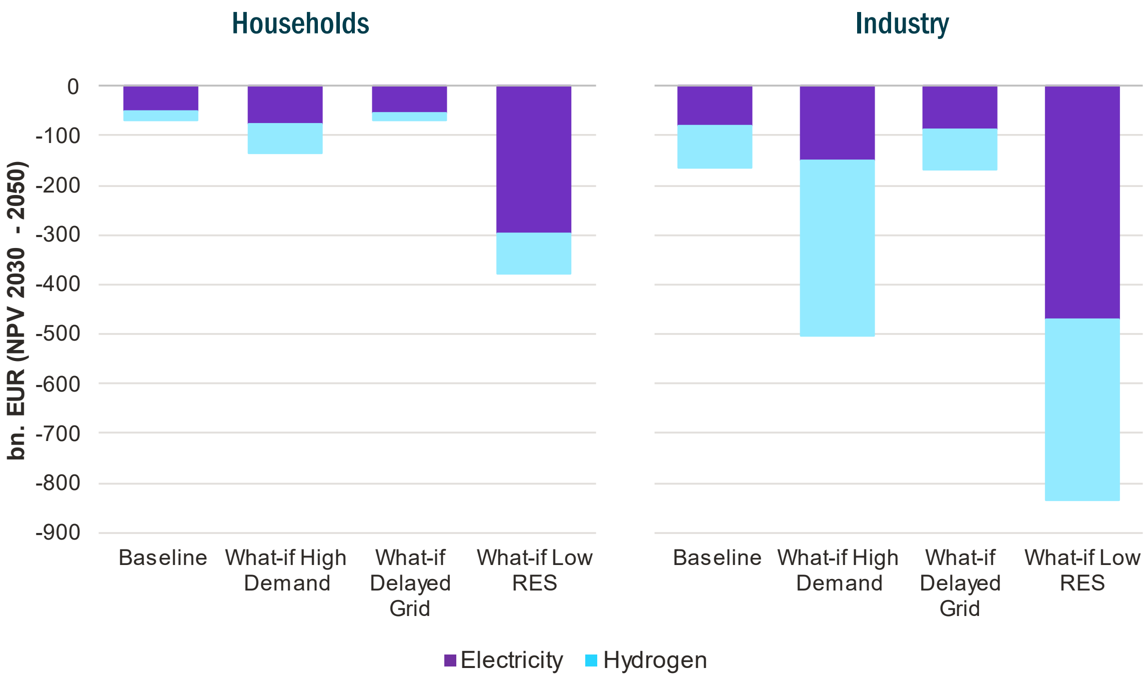
- Changes in the wholesale energy prices are passed on to customers without distortions from retailers, i.e. retailers set tariffs on a cost basis;
- The availability of renewable gases does not affect taxes or levies; and
- The analysis does not include costs arising from different reinforcement or replacement investments in the transmission and distribution grids for electricity and gas.
- We calculate the impact of renewable gases on consumer payments as a product of annual demand per sector and energy carrier, and the difference in the EU27 weighted average price of electricity or hydrogen. Results are expressed as net-present value (2030-2050):[84]

The results are shown in Figure 53.

- **Households**: Due to the higher share of electricity consumption in households (than in industry), household bills are more affected by higher electricity prices. The availability of renewable gases lowers consumers bills by up to 300 bn. EUR for electricity and by 80 bn. EUR for hydrogen (What-if Low RES).
- **Industry**: Besides electricity, hydrogen is the second most important energy carrier to serve industrial energy demand. Therefore, hydrogen prices play a larger role for industrial customers as compared to households. Our analysis shows that an energy transition that uses the full potential of renewable gases can significantly reduce the cost burden on industrial sectors: payments related to electricity supply decrease by up to 470 bn. EUR, and hydrogen-related payments by up to 360 bn. EUR (What-if Low RES).

84 To note, this approach tends to underestimate the actual impact on consumer bills as hourly correlation between demand and electricity prices is not considered: Industrial consumers today and the majority of households in the future are or will be exposed to hourly fluctuations in electricity prices. High demand is correlated with high prices, and we expect the difference in prices arising from low vs. high availability of renewable gases to be greater in times of high demand.

Figure 53 Impact of renewables gases on consumer payments (EU27, NPV 2030-2050)



Source: Frontier Economics
Note: NPV 2030-2050 based on 5% discounting

Maintaining a competitive energy supply for EU industry and avoiding an excessive cost burden on households therefore also requires the effective use of renewable gases. Climate pathways that make use of all available technologies result in a more affordable energy transition. If the expansion of renewable electricity sources stays behind expectations (What-if Low RES), renewable gases can reduce EU27 energy-related consumer payments for electricity and hydrogen between 2030 and 2050 by as much as 1.2 trillion EUR.

7 Alternative scenario: A comprehensive electrification of final demand would be hard to achieve – and comes with extra costs

We based our analysis in previous chapters on the final demand assumptions from the TYNDP 2024 Global Ambition (GA) scenario. To complement our analysis, we add a scenario analysis using the TYNDP Distributed Energy (DE) final demand assumptions. This scenario has a storyline of lower international cooperation and an even stronger focus on electrification. Consequently, compared to TYNDP's GA scenario, the final demand assumptions of the DE scenario appear somewhat less balanced with respect to the energy mix, energy efficiency measures and behavioural changes of consumers (see detailed analysis below).

In the following, we will refer to this scenario as *High Electrification* scenario. To align with the TYNDP storyline for the DE scenario of lower international cooperation and a focus on electrification instead of gases, we use our previous assumptions of a reduced availability of renewable gases (further assumptions remain unchanged). For comparability, all mentions of the *Baseline* scenario in this section refer to the variant with reduced availability of renewable gases.

This scenario analysis also serves as robustness test as it allows us to validate our findings regarding the role of renewable gases in a wider range of future energy scenarios.

7.1 Gases continue to play a major role in final energy demand even in high electrification scenarios

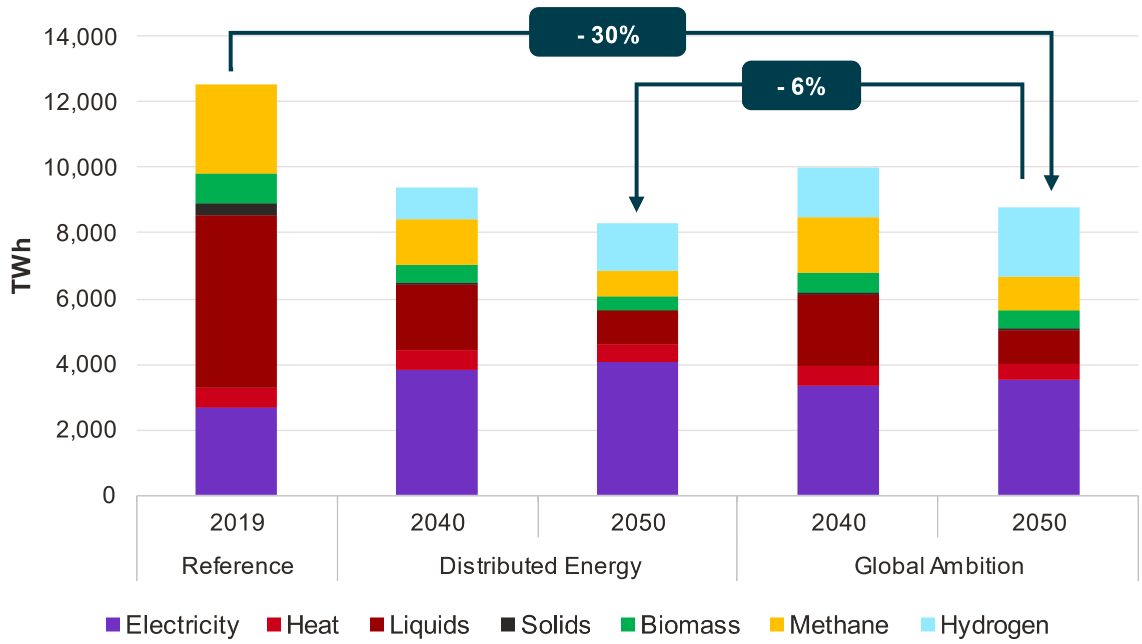
Overall, the assumptions for the final demand in the DE scenario of the TYNDP result in the following major changes:

- Final demand is an **additional** 6% lower (about 500 TWh, about Belgium's total annual energy consumption today) in 2050 compared to the Global Ambition scenario – and 34% lower than the final energy demand of the reference year 2019.
- Most of this additional decline stems from gases: in 2050, final demand for hydrogen is about 720 TWh (34%) lower and methane is 190 TWh (19%) lower than in the Global Ambitions scenario.
- Final electricity demand on the other hand is about 500 TWh (15%) higher – which is about the size of today's French power market and comes on top of the already high demand increase in the GA scenario (final power demand at 3,515 TWh in 2050, compared to 2,660 TWh in the 2019 reference year).

Despite this shift from gases to electricity and the overall additional decline of final demand, **gases continue to play a major role** in this electrification scenario:

- The relative share of gases (methane and hydrogen) in total final energy demand **increases** from 22% in 2019 to 27% in 2050 (25% in 2040).
- While is this lower than the 32% (2040) and 36% (2050) in the Global Ambition scenario, hydrogen, again, becomes the **second largest** energy carrier in final demand with a share of 17% (with electricity making up 49%).
- Total demand for gaseous fuels is 82% of that in 2019 – which corresponds to ca. 88% of the EU gas consumption in 2022.

Figure 54 Final energy demand in the DE and the GA scenarios (2030-2050)



Source: Frontier Economics

7.2 Future energy scenarios should enable a strong economy – and account for its energy demand

We base our final demand scenarios on the TYNDP 2024 scenarios Global Ambition and Distributed Energy. Both scenarios outline possible energy transition pathways that are designed to reach decarbonisation and complementary EU as well as EU member states' targets. However, these guidelines allow for a construction of a wide range of possible final demand scenarios.

One variable impacting final energy demand is the assumed economic activity: Higher economic activity, i.e. more domestic production of goods and services, typically results in higher energy demand. At the same time, higher economic activity is associated with higher social welfare, which is desirable.

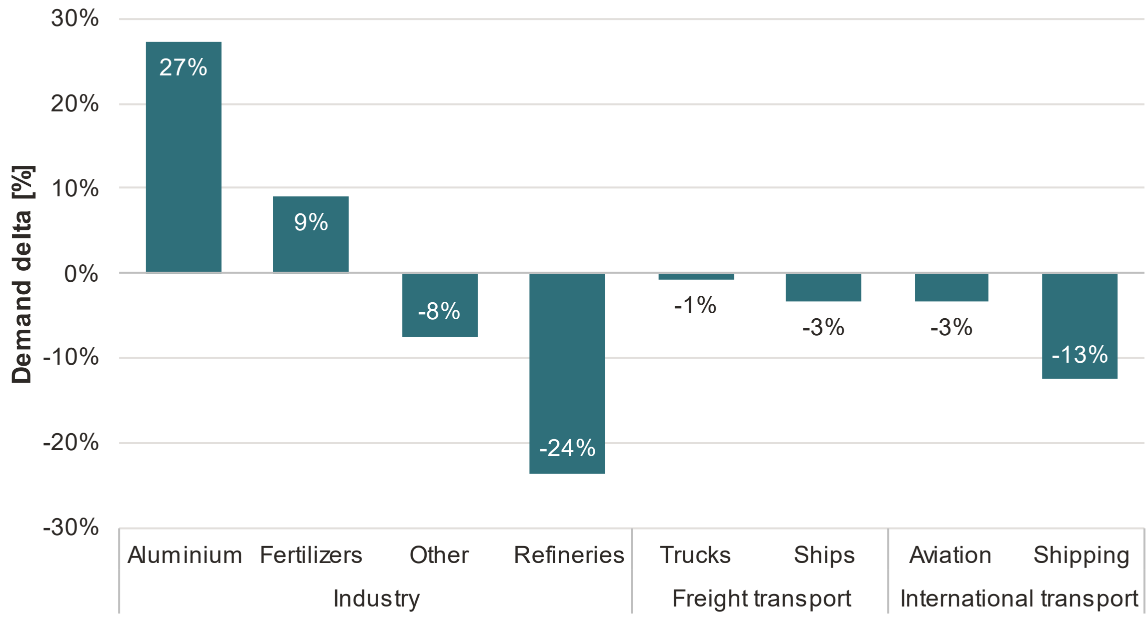
Basing an energy transition scenario on the assumption of lower economic activity could thus be problematic for two reasons:

- Lower economic activity renders the achievement of climate emission targets, from a modelling perspective, easier (and potentially cheaper) and thus appears more attractive. However, this partial evaluation neglects the impact on social welfare associated with lower economic activity and is typically contrary to policy ambitions.

- Planning the energy transition based on a lower level of economic activity could render achieving target for example regarding greenhouse gas emissions more difficult if the economy turns out to be stronger than assumed – and in the end more energy has to be supplied than accounted for at the beginning.

While there are contrasting effects, the TYNDP Distributed Energy scenario overall assumes lower economic activity compared to the Global Ambition scenario (see Figure 55).

Figure 55 Difference in energy demand between the DE and GA scenarios in 2050 due to difference in assumed economic activity



Source: Frontier Economics

The difference in economic activity in both scenarios results in an overall lower final energy demand in the Distributed Energy scenario of about 1% (154 TWh).[85]

85 To isolate the effect of the economic activity level, we use the final energy consumption of the Global Ambition scenario to scale the energy demand of the Distributed Energy scenario to the same activity level.

While it can be reasonable from a grid-planning perspective to vary the economic activity, it can be misleading for the planning of the decarbonisation strategy: To ensure the resilience of the energy transition with respect to the assumptions made, a cautious approach should be taken. In this case, this means planning for higher economic activity and thus higher energy demand.

7.3 Reliance on behavioural change could endanger reaching climate targets

Assuming ambitious changes in consumer behaviour entails similar problems as discussed in the context of economic activity in the previous section: They could result in underestimating the required measures to reach decarbonisation targets, and a distorted comparison between scenarios in terms of costs.

The TYNDP makes several changes with respect to assumptions concerning consumer behaviour between the Distributed Energy and Global Ambition scenario. These include:[86]

- Affecting the household sector:
  - Inhabited surface per person
  - Level of energy-efficient consumer behaviour (room temperature)
- Affecting the transportation sector:
  - Level of public/shared transport (occupants per car)[87]
  - Number of travelled km per person (including holidays, trade and work)
  - Share of home office
  - Share of non-motorised transport

Figure 56 illustrates the impact of the differing behavioural assumptions on energy consumption between the Global Ambition and the Distributed Energy scenario. Most of the differences imply a lower useful energy demand in the Distributed Energy scenario. This implies the following:

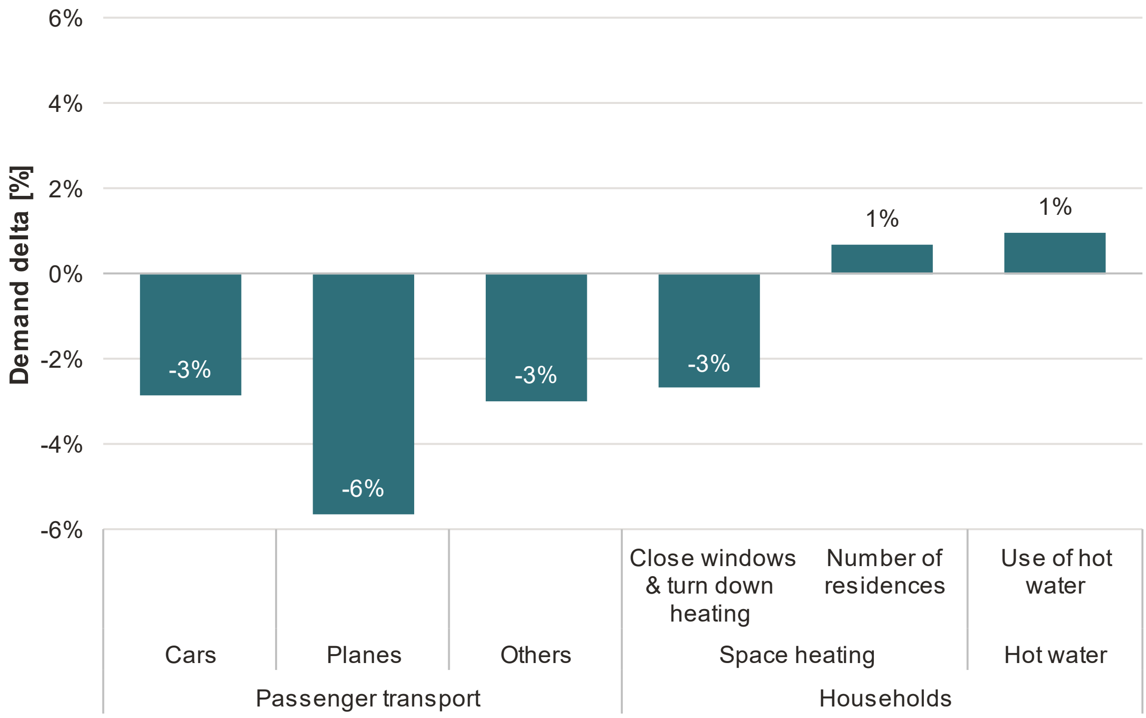
- The scenarios are not directly comparable on the energy supply side and do not allow conclusions about a “better” way to reach decarbonisation targets. As most behavioural assumptions favour the DE scenario (i.e. fewer challenges for energy supply), this might result in the false impression that this scenario would be preferable.

86 According to the TYNDP2024: Scenarios Storyline Report.

87 According to the TYNDP2024: Scenarios Storyline Report. As this is not a setting available in the ETM which is used for modelling the final demand sectors, we assume this is reflected in the setting for passenger kilometres.

- Additionally, lowering the amount of travelling or reducing the thermostat temperature during the heating season is usually associated with a reduction in utility, which is difficult to quantify and hence to compare.

Figure 56 Difference in energy demand between the Distributed Energy and Global Ambition scenarios in 2050 due to behavioural changes



Source: Frontier Economics

Note: To isolate the effect of behavioural changes, the delta is calculated as final energy consumption in the Global Ambition scenario minus final consumption in the GA scenario assuming behavioural settings as in the DE scenario.

7.4 Current speed of transforming the final demand sector is not compatible with high efficiency and high electrification scenarios

It is uncontested that significant changes on the final energy demand side are necessary to achieve decarbonisation targets. However, overestimating the possible speed of the transition might result in an underestimation of future demand (similar to the previously discussed behavioural changes and economic activity).

Examples of transition processes falling behind ambitions and commonly expected to be challenging in the medium to long term include:

- Transport sector:
  - Passenger cars: The EU aims to have at least 30 million zero-emission cars in operation on European roads by 2030.[88] Based on today's 5.1 million BEVs and 1.5 new BEV registrations in 2023, a significant ramp-up is necessary to reach that target. However, the market share of BEVs of total registrations has fallen in the first half of 2024 to 12.5% (14.6% in 2023).[89]
  - Freight transport: This sector still heavily relies on oil-based fuels, in particular for heavy duty trucks. In 2023, the market shared of zero-emission heavy trucks, although increasing, was just 0.9%.[90]
- Household sector:
  - Heating technology: According to the European Heat Pump Association, heat pump sales in 21 European countries fell by around 6.5% in 2023 compared to 2022 and, assuming they remain on the current level, total installation by 2030 would fall short by about 25% of the EU's aims.[91]
  - Insulation: Historically, the renovation rate across EU was relative stable at ~1%, with deep renovations standing at 0.2%. According to its Responsible Policy Scenario, designed to be aligned with the EC's 55% GHG reduction target by 2030, the Buildings Performance Institute Europe states that the deep renovation rate needs to increase tenfold to 2% – and "approach 3% as quickly as possible". [92]
- Industry sector: Estimates by the European Scientific Advisory Board on Climate Change indicate that the greenhouse gas intensity of selected emission intensive materials (steel, cement and chemicals) has not declined in recent years and that total emission reductions have been driven by a decline in production levels.[93]
- These examples illustrate the challenges ahead for reaching the necessary transformation of the final demand sectors – and that resilient planning needs to take the potential for a higher final energy demand into account.
- If technology changes or useful energy demand reduction targets are not fully reached, low-carbon and renewable gases can provide a back-up solution, as they support the

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88 EC: Mobility Strategy.

89 Based on the European Alternative Fuels Observatory.

90 The International Council on Clean Transportation (2024): Race to zero – European heavy-duty vehicle market development quarterly (January-December 2023).

91 See ehpa: EU could end up 15 million heat pumps short of 2030 ambition.

92 BPIE (2023): On the way to a climate-neutral Europe.

93 European Scientific Advisory Board on Climate Change (2024): Towards EU climate neutrality - Progress, policy gaps and opportunities.

decarbonisation of existing technologies by replacing fossil fuels with low-carbon substitutes.

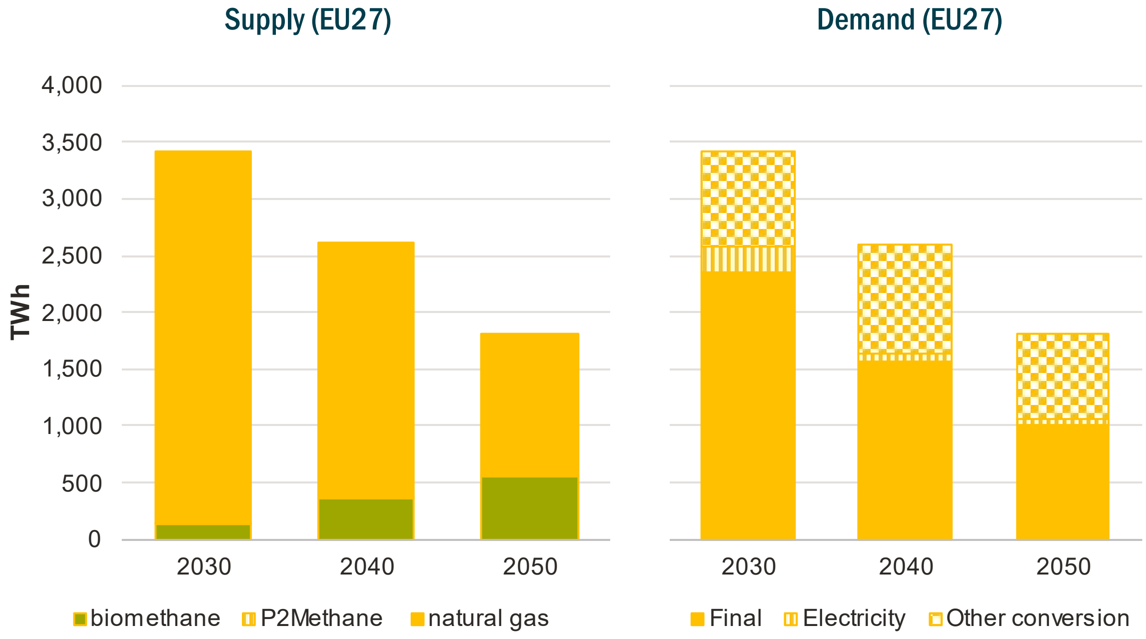
7.5 Low-carbon and renewable gases still play a major role in the High Electrification scenario – developing biomethane options to their full potential is a no-regret option

In addition to final demand, a significant share of total methane demand is attributed to the energy conversion sector – about 30% to 45% of the total methane demand is used for electricity generation and the production of blueH2 between 2030 and 2050 (see Figure 57).

Methane demand decreases but remains on significant level

Biomethane plays an increasingly important role for methane supply: while in 2030 only 4% of total methane consumption is served by biomethane, this share increases to 31% by 2050. Even in this high electrification / low renewable gas scenario, domestic biomethane production and import potentials are fully utilised in all years. This illustrates that developing biomethane options to their full potential is a no-regret option. Additionally, this shows the competitive advantage of biomethane relative to alternative supply options like natural gas or Power-to-Methane. The remaining methane demand is met with natural gas – Power-to-Methane is not competitive and thus not part of the cost-optimal supply mix.

Figure 57 Methane supply and demand in the High Electrification scenario



Source: Frontier Economics

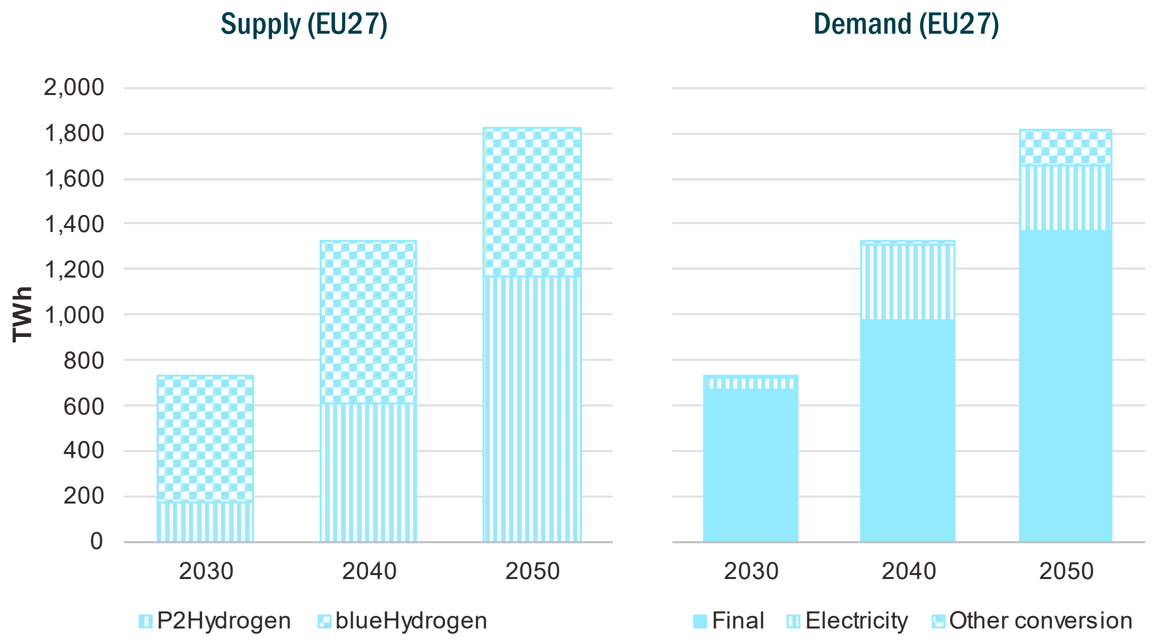
Hydrogen demand increases to almost 2,000 TWh in 2050

Total hydrogen demand increases significantly to over 1,800 TWh in 2050. Similarly to methane, a significant share of total hydrogen demand comes from the conversion sector, in this case for power generation and district heating. While final demand for hydrogen is lower in the High Electrification than in the Baseline scenario (1,366 TWh compared to 2,087 TWh in 2050), hydrogen consumption from power plants is more than twice as high (295 TWh compared to 129 TWh in 2050).

On the supply side, blueH2 is the primary source of hydrogen until 2040 – and overtaken by PtH2 in 2050. Compared to our Baseline scenario, significantly less blueH2 is used in 2050 (-38% / -407 TWh).

Total PtH2 supply (production and imports) increases from 169 TWh (23% market share) in 2030 to 1,164 TWh (64% market share) in 2050. This is lower than in our Baseline scenario in 2050 (minus 166 TWh/12%). However, compared to the overall lower hydrogen demand (minus 24% in 2050), PtH2 production is relatively stable. This indicates that even in lower hydrogen demand scenarios, PtH2 plays an important role.

Figure 58 Hydrogen supply and demand in the High Electrification scenario



Source: Frontier Economics

7.6 Gases are essential for electrification

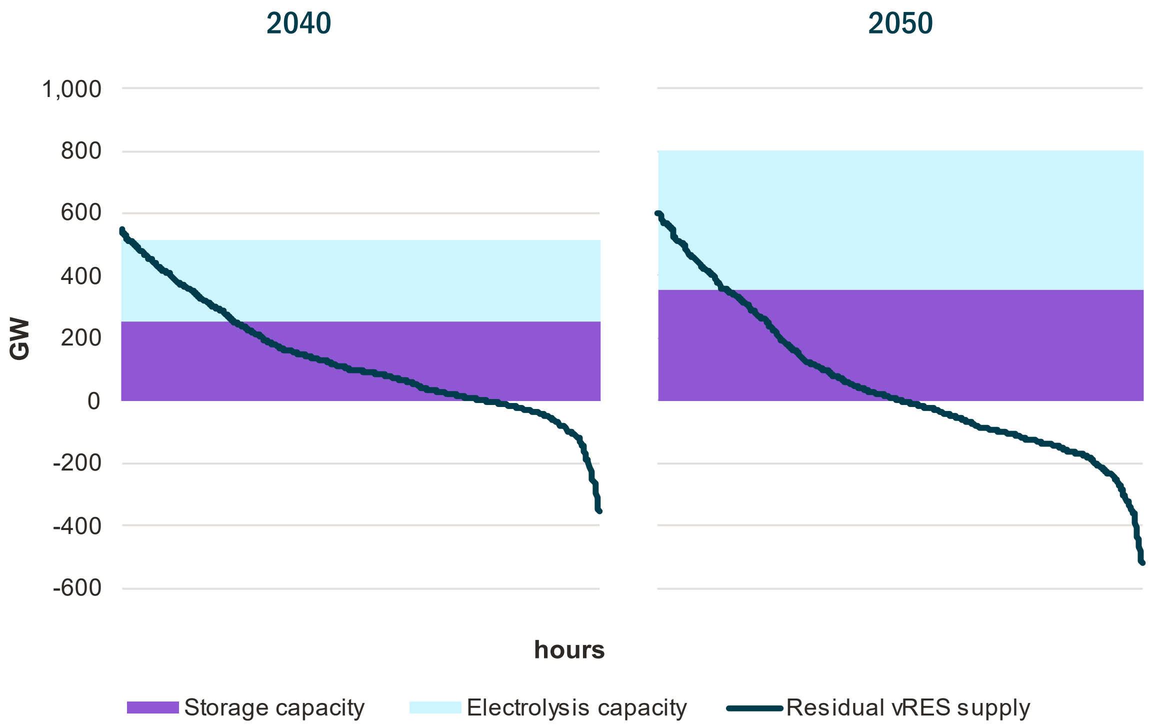
7.6.1 Hydrogen continues to play a vital role for the integration of variable renewables

One common argument in favour of a broad electrification of final energy demand is that electricity generated from variable renewable energy sources (vRES), such as wind and solar, can be utilised directly. This avoids additional energy conversion steps (and associated energy losses). Additionally, electricity-based final consumer appliances are typically more energy efficient that their gas- or liquids-based counterparts.

However, electricity production from vRES and final demand for electricity are typically not perfectly aligned – making it necessary to store electricity when production exceeds demand. In our High Electrification scenario in 2050, there is a residual supply of electricity (i.e., generation from vRES exceeding final demand) almost half of the time (peaking at 600 GW) as represented in Figure 59.

Our model results show that, in a cost-optimised system, this excess generation is absorbed by a combination of electric storage (battery and pumped-hydro storage) and electrolysers. In 2050, electrolysers make up about 56% of the total input power capacity of batteries, pumped-hydro storage and electrolysers – illustrating its value for providing flexibility and integrating variable renewables.

Figure 59 Residual vRES supply duration curves compared to electric storage and electrolyser capacity in the High Electrification scenario (EU27)



Source: Frontier Economics

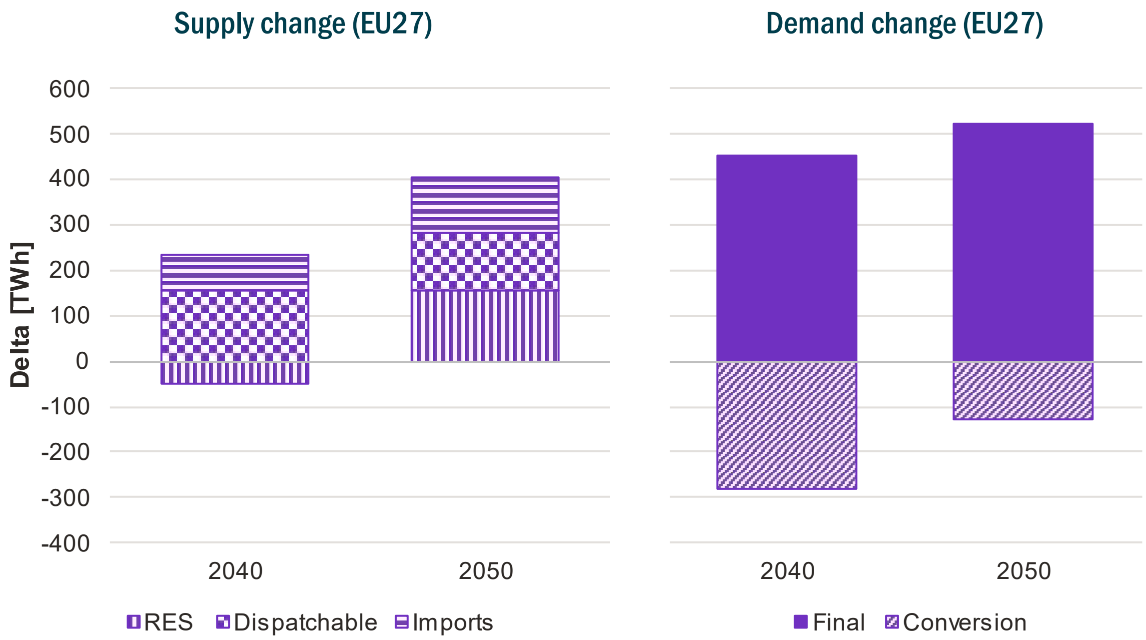
Note: Residual vRES supply is calculated by subtracting final demand from PV and wind generation. Storages and electrolysers (in combination with hydrogen storages) serve different purposes and have different properties (for example in terms of efficiency and storage capacity), thus they are not perfect substitutes, and the optimal sum of capacity can exceed peak residual vRES generation. Additionally, the residual vRES generation aggregated over EU27 is lower than the sum of peak residual generation in each market: Regional differences and interconnector constraints can result in a need for local capacity. Thus, the illustration provides an indication for the synergies and optimal relative shares between both technologies, rather than allowing the deduction for optimal absolute capacity values.

7.6.2 Low-carbon and renewable gases help to tackle electricity supply challenges for the electricity system in high electrification scenarios

In our High Electrification scenario, total electricity demand and supply changes compared to the Baseline scenario (see Figure 61):

- While final electricity demand is higher, this is partly compensated by lower consumption for energy conversion, mostly electrolysers – resulting in a net increase in 2050 of about 390 TWh (8% of total electricity demand).
- The additional net consumption in 2050 is met by about a third each through
  - an increase of electricity production from variable renewables,
  - an increase of dispatchable power plants and
  - an increase of net imports from neighbouring markets.

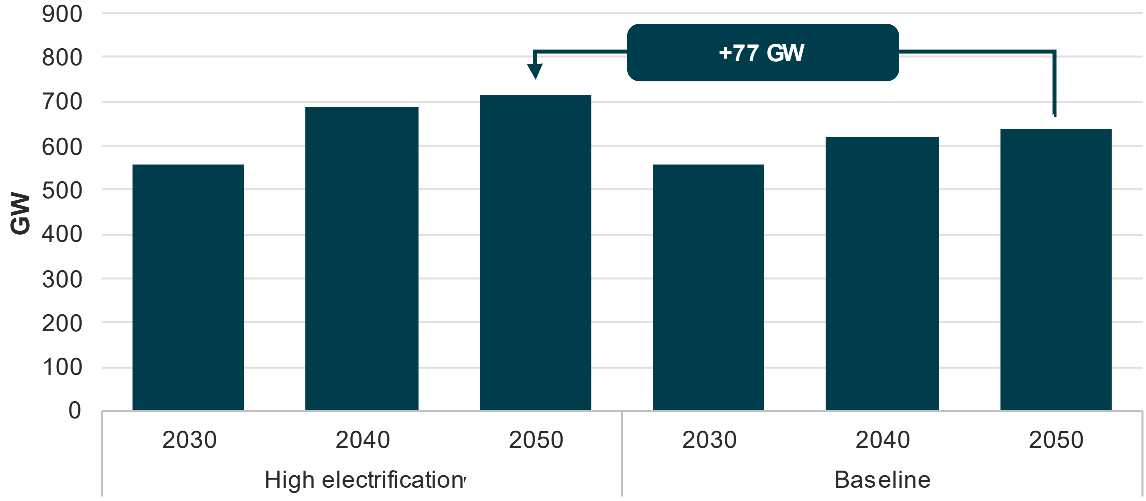
Figure 60 Change in supply and demand in the High Electrification scenario compared to the Baseline scenario



Source: Frontier Economics

As a consequence of the high electrification levels of final demand technologies, peak final electricity demand in the High Electrification scenario reaches 714 GW by 2050 in the EU. This is about 77 GW (slightly less than Germany's peak demand today) higher than in our Baseline scenario (see Figure 61) and a 200 GW increase over EU electricity peak demand today.

Figure 61 Peak electricity demand in the Baseline and High Electrification scenarios (EU27)



Source: Frontier Economics

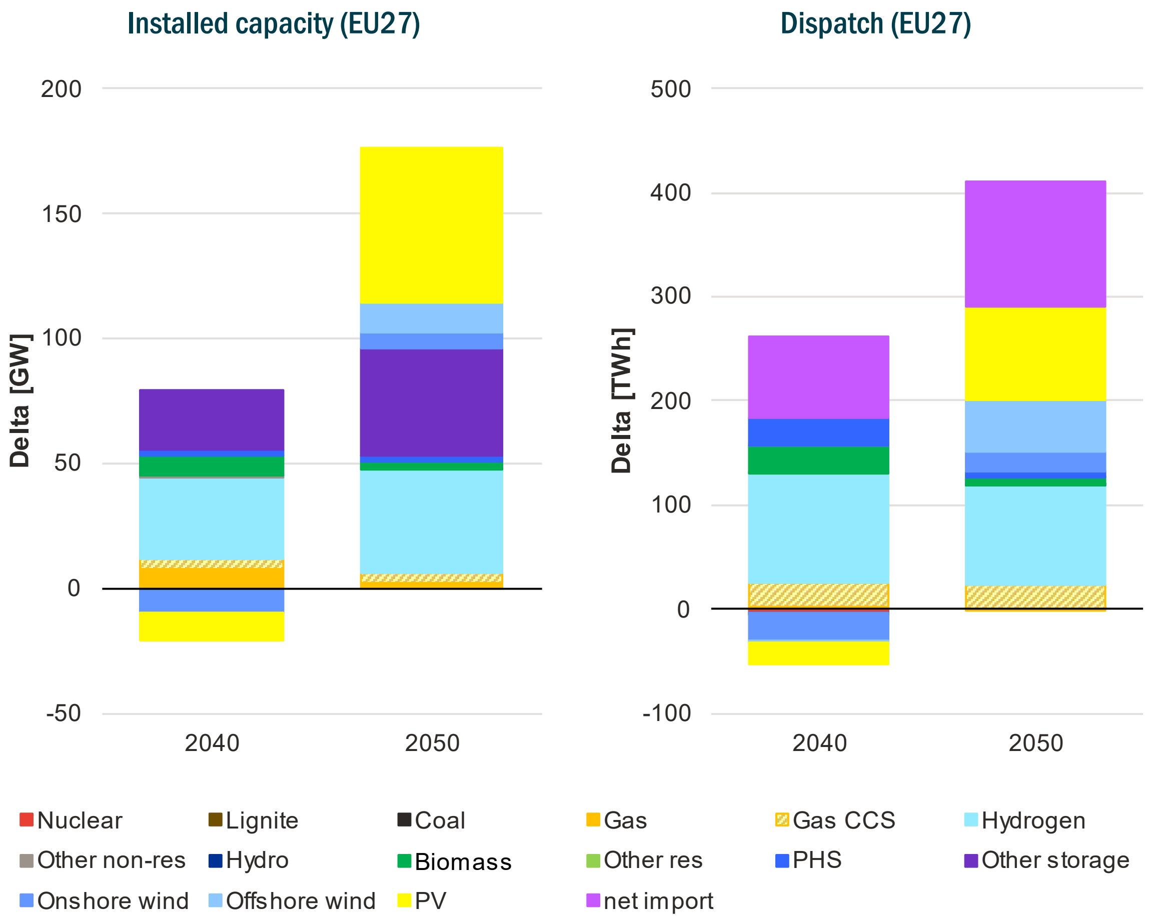
To ensure security of supply, the higher peak demand is mainly met by a combination of additional dual-fuel power plants (able to use both methane and hydrogen, +50 GW) and additional batteries (+50 GW more battery capacity by 2050 than in GA, see Figure 62, left).

This comes on top of the challenging requirement for dispatchable capacity to shift towards hydrogen: As nuclear power is expected to decline by more than 50% in the EU until 2050 (compared to today), the majority of dispatchable power plants will have to operate with hydrogen to reach carbon neutrality. Our model results show that in the High Electrification scenario, 165 GW of hydrogen plants are required by 2050, and the majority of new plants would have to become available from 2030, when the technology is expected to be more mature than it is now. Current plans foresee that Europe's first hydrogen-ready power plant may come online by 2027, not long before then.[94]

This challenging timeline for new plants to be built, the novelty of the technology, the currently unattractive economic environment for new investments, combined with an ongoing debate regarding policy measures and support schemes illustrate the size of the challenge ahead. For example, there is the debate in Germany about financing the power plant strategy aiming at adding 12.5 GW of hydrogen ready plants, or the debate about capacity mechanisms required to trigger the urgently needed investments.

94 ETEnergyWorld (2024): Essar Energy Transition to establish Europe's first hydrogen-ready power plant by 2027.

Figure 62 Change in electricity production capacity and generation in the High Electrification scenario compared to the Baseline scenario



Source: Frontier Economics

Note: Hydrogen capacity refers to that of dual-fuel powerplants which could also run on gas, while Hydrogen dispatch refers to electricity generated with Hydrogen

On the supply side, we can observe the following changes when comparing our High Electrification with the Baseline scenario:

- The largest increase in electricity generation comes from hydrogen plants, complemented in 2050 by additional variable renewables generation (vRES);
- Gas plants using methane with carbon capture also see a small increase;
- Net imports from neighbouring increase, tipping the EU from a net exporter to a net importing country.

7.7 A strong focus on electrification could result in higher costs than a balanced energy transition

The previously discussed differences in economic behaviour and economic activity make a cost comparison between the Baseline (with final demand assumptions based on the TYNDP

Global Ambition scenario) and the Electrification scenario (based on the TYNDP Distributed Energy scenario) difficult: Given that most of the High Electrification scenario's differences result in lower energy consumption, a simple cost comparison will tend to favour this scenario. Also, assumptions on future learning curves of less mature end-use appliances for example in heating technologies (e.g. heat pumps and hydrogen boilers) and transportation (e.g. electric and fuel cell vehicles) are uncertain.

Nonetheless, we apply an indicative cost comparison of the two scenarios. The two main components of the comparison are the final energy demand sectors and the energy supply sector. On the final demand side, we have considered the main cost areas in the subsectors with the largest differences between the Distributed Energy and Global Ambition scenario.[95]

Our indicative cost comparison includes cost differences with respect to:

- Final energy demand
  - Households: Heating technology, insulation
  - Buildings: Heating technology, insulation
  - Transportation: Passenger cars, freight transport (trucks, vans)
  - Industry (heat supply): Chemical, Others
- Energy supply
  - Generation and storage technologies for electricity and other energy conversion processes (including electrolysis, methanisation of biomass, steam methane reforming)
  - Carbon capture costs (capturing costs plus transport and storage (if CO_2 is not used))
  - Costs of imported fuels

Our indicative cost comparison does **not include** cost differences with respect to:

- Distribution grid costs[96]
- Economic/social costs associated with lower activity levels in the industry
- Utility decline of behavioural changes, e.g. due to change of means of transportation or reduced room temperatures
- Further industry sectors (minor changes compared to the included sectors)

95 For the investments separate from the energy system, we consider the approximated insulation costs and costs for heating systems in the household and building sector. Moreover, we consider fleet investments in the passenger car, freight van and freight truck segment. Also, we consider the investments into heating units in the industry branches "Chemicals" and "Others" in the Energy Transition Model (the two subsectors with the largest differences in energy demand between scenarios in the ETM), where we have normalised activity levels to increase comparability (the additional costs are relatively small).

96 Transmission system costs are assumed to be netted out as we have modelled both scenarios using the identical transmission grid.

- Agriculture and other sectors

Our indicative analysis shows additional **net system costs of 550 billion EUR in the Electrification scenario between 2030 and 2050**[97] (both scenarios with low renewable gas availability, see Figure 63). This would be equivalent to additional costs of about 1,100 EUR for every inhabitant of the European Union.[98]

The largest drivers for this difference in costs are:

- **Higher** final demand costs in the Electrification scenario (in total 792 bn. EUR higher)
  - Insulation costs in the household and non-residential sector
  - Heating technology costs in the household and non-residential sector
  - Higher vehicle costs, in particular in the freight (trucks and vans) segment
- **Lower** energy supply costs in the Electrification scenario (in total 242 bn. EUR lower)
  - Lower fuel and CCS costs induced by lower energy demand
  - Lower investment costs for energy conversion (mainly electrolyser)
  - Higher investment costs for variable renewables and back-up capacities in the electricity sector

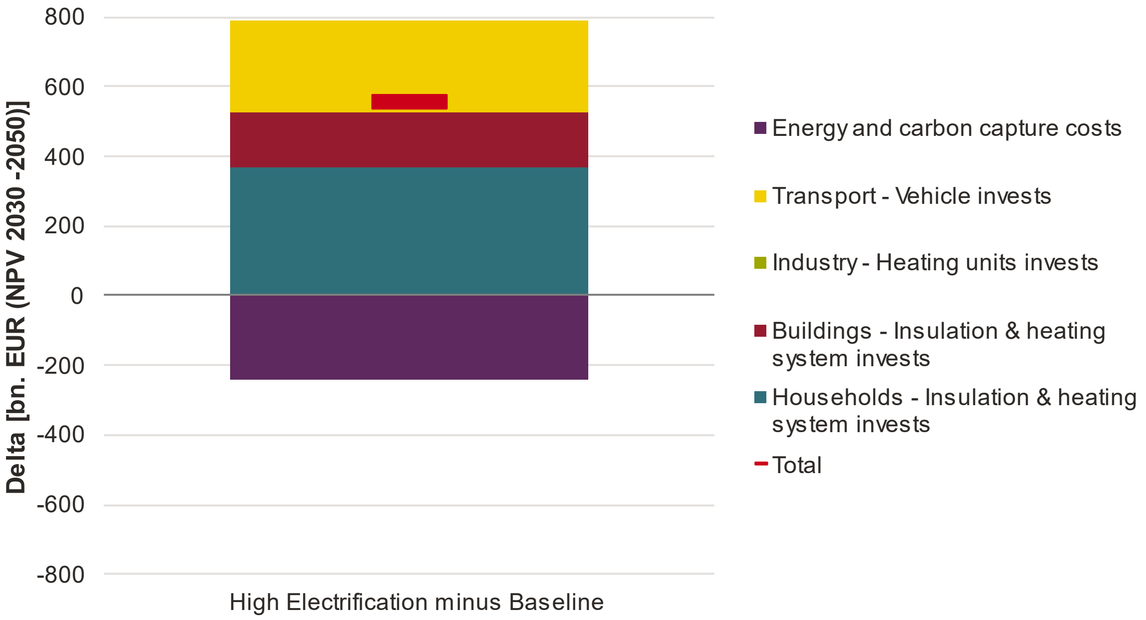
Considering just the industry sector, the cost differences are relatively small between both scenarios. Although the technology mix differs significantly – with low- and medium temperature heating in the DE scenario being largely electrified[99], whereas in GA a share of 20% hydrogen-based heating is used – the investment costs of these are relatively similar.

97 NPV (5%), 2021 EUR.

98 Based on the current number of inhabitants.

99 Electric heating is assumed to be largely based on electric boiler.

Figure 63 System cost difference between the Baseline and the High Electrification scenario



Source: Frontier Economics

This comparison indicates that from a cost perspective a final demand scenario more in line with the TYNDP's Global Ambition scenario could result in overall lower costs compared to an electrification/Distributed Energy-like scenario:

- Higher investment costs for building insulation exceed cost savings due to lower fuel demand;
- Current cost estimates for some final demand technologies, for example long-distance freight transport, show significant cost advantages for hydrogen-based solutions[100];
- Some additional cost components are likely to further increase the gap between the scenarios;
- Distribution grid costs are likely to be higher with a stronger electrification of final demand and more (distributed) variable renewables;
- Activity levels and behavioural changes reducing the costs in the Electrification scenario are not accounted for in the quantitative comparison.

[100] Details on cost differences, data sources and learning curve assumptions can be found in the technical annexe.

Excursus: Cost of gas and electricity network expansions in Germany

The infrastructure requirements and associated costs represent important elements to consider in the evaluation of climate change pathways, and in the choice between technology-neutrality and a focus on electrification.

In 2023, German households paid an average grid fee of 2 ct/kWh for gas and 9 ct/kWh for electricity.[101] Even after accounting for differences in end-use efficiency (e.g. heat pumps vs. gas boilers), this comparison highlights a cost advantage for gas networks. It remains generally less expensive to transport 1 kWh of energy in the form of molecules (gas) than 1 kWh of electricity, due to the lower infrastructural and operational costs of gas networks.

Germany's network expansion plans underscore the relative costs and challenges associated with financing and completing the necessary infrastructure build-out to meet future energy needs:

- The latest network development plan for the **electricity transmission network** calls for investments of around 100 bn. EUR to strengthen or expand 12,000 km of onshore transmission lines by 2037. This is nearly double the investment outlined in previous plans. Additionally, offshore network development in Germany will require approximately 250 bn. EUR in further investments by 2045.[102]
- A recent study quantifies the total network expansion costs including German distribution grids to around 700 bn. EUR and projects end consumer network tariffs to double until 2045. [103]

Due to the maturity of the gas grid and the high level of transportation capacity, the investment needed to maintain a high level of security of supply is much smaller:

- The 2022 **gas network development plan** outlined investments of approximately 4 bn. EUR, largely focused on LNG installations to enhance supply security.
- Plans for a hydrogen backbone network are expected to require 20 bn. EUR, achieving an exit capacity of 87 GW[104], equivalent to Germany's current electricity peak load.
- In addition a hydrogen distribution grid would be required partly consisting of re-purposed methane distribution grids and partly new built. Costs of maintaining and repurposing gas distributions grids is expected to amount to around 45 bn. EUR until 2045.[105]

While expanding electricity networks is crucial for the energy transition, gas infrastructure requires less investment due to its maturity and lower costs. Solely focusing on electrification overlooks the potential of existing gas networks, which can ease pressure on electricity grids, reduce expansion needs, and improve flexibility. A balanced approach using both electrification and low-carbon gases, like hydrogen or biomethane, will lead to a more cost-effective and resilient transition.

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[101] Bundesnetzagentur (2023): Monitoringbericht 2023. https://data.bundesnetzagentur.de/Bundesnetzagentur/SharedDocs/Mediathek/Monitoringberichte/MonitoringberichtEnergie2023.pdf

7.8 Conclusions from the High Electrification scenario and implications for the choice of a reference/central scenario for the energy transition

From our analysis of the High Electrification scenario (with final demand based on the TYNDP Distributed Energy scenario) and the comparison with the Baseline scenario (with final demand based on the TYNDP Global Ambition scenario) we can draw the following conclusions:

- Gases play a crucial role both in our Baseline scenario as well as for this scenario with a high share of electrification of final demand - in particular, low-carbon and renewable gases will be key:
  - Demand for gaseous fuels maintains a large share of final energy demand in the long-term;
  - Low-carbon and renewable gases enable the decarbonisation of remaining methane demand;
  - Gas supports the integration of variable renewable electricity generation and ensures security of supply during periods of low generation from renewables.
- A transition scenario with a broader mix of final demand technologies can be cost-beneficial compared to a scenario with an even stronger focus on electrification.

Additionally, a more balanced approach and in particular the availability of renewable and low-carbon gases provides a certain level of **resilience to unforeseen developments.** Any "shock" to the already "stressed power system" causes high costs (or a risk of not achieving decarbonisation targets) as there is little buffer left in the system. "Shocks" or "deviating realities" with respect to decarbonisation plans could manifest from the following effects:

- Not meeting the speed required for investments in new variables renewables capacity like wind and solar;
- Issues importing green energy if the expansion of domestic variable renewables turns out to be slower (or power demand higher) than expected:
  - A 380kV transmission line or a typical DC subsea interconnector has a capacity of 1-2 GW – allowing to import 8 to 16 TWh per year at full use. Examples of subsea

[102] Netzentwicklungsplan Strom 2037 /2045 kompakt, Version 2023, 2. Entwurf. https://www.netzentwicklungsplan.de/sites/default/files/2023-12/NEP%20kompakt_2037_2045_V2023_2E.pdf

[103] efRuhr (2024): Abschätzung der Netzausbaukosten und die resultierenden Netzentgelte für Baden-Württemberg und Deutschland zum Jahr 2045, https://www.ewi.uni-koeln.de/cms/wp-content/uploads/2024/04/2024_04_Abschlussbericht_Netzentgelte_BW_DE.pdf

[104] FNB Gas (2024): https://fnb-gas.de/wasserstoffnetz-wasserstoff-kernnetz/

[105] DBI-Gruppe (2024): H2-ready und klimaneutral bis 2045, DVGW. https://www.dvgw.de/medien/dvgw/forschung/berichte/g240410-h2-transformationkosten-2.pdf

cables show costs of about 1-2 million EUR per GW per km[106], and long-distance underground HVDC connections about 3-4 million EUR per GW per km[107].

- □ The capacity of a 48-inch European hydrogen pipeline would be around 17 GW – allowing imports of up to 148 TWh/a with one pipeline[108]. The two parts of the H2Med project CelZa (linking Portugal and Spain via land) and BarMar (linking Spain and France via the Mediterranean Sea), planned to connect the hydrogen networks of the Iberian Peninsula and Northwest Europe, are estimated to cost about 0.5-0.6 million EUR per GW per km.

- Even if variable renewables are built out on time - can their volatile electricity production be integrated on time? Necessary storages and transmission networks may not be obtained on time.

- The transmission network may not be built on time, causing issues for some regions. For example, how would we transport green energy to landlocked regions like Austria if the power transmission network is not strong enough and onshore and offshore wind are mainly based close to the sea/coast?

- Industry may not trust in availability of renewables or low-carbon energy (in general or at the specific industry site). What would then happen to the European economy?

For the planning of the energy transition pathways this implies that a more balanced approach considering all low-carbon energy options (including CCS) can increase the resilience of the energy transition towards exogenous shocks.

However, part of the truth is that the ramp-up of renewable and low-carbon gases also will be challenging and not easy to achieve. For the ramp up of renewable and low-carbon gases, support will be needed as well as a consideration and coordination of the full value chain (including the early and long-term availability of the networks). With gases, other world regions (not just our neighbours that are connected via power cables) can more easily help us achieve our decarbonisation goals - and at the same time generate income by making use of comparative advantages in sunnier, windier or less densely populated areas.

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106 Based on data for North Sea Link connecting Norway and the United Kingdom, and Viking Link connecting United Kingdom and Denmark.

107 Based on data for the two inner-German cables SuedOstLink and SuedLink.

108 European Hydrogen Backbone (2021) - Analysing future demand, supply, and transport of hydrogen.

8 Conclusions and levers to achieve a more resilient and affordable energy transition

To mitigate the threats of climate change, governments around the world have set targets to reduce greenhouse-gas emissions in the coming years, and to reach net zero emissions in a few decades. The European Union aims to reach net zero emissions by 2050, with intermediate targets relative to 2019 of -55% by 2030 (already fixed in law) and -90% by 2040 (proposed by the European Commission).

Key studies like the EC Impact Assessment and the TYNDP put too much emphasis on electrification and energy efficiency

Several studies sketch pathways how these targets could be achieved. Prominent examples of these are the Ten-Year Network Development Plan by the European transmission system operators ENTSO-E and ENTSOG, and the Impact Assessment of the European Commission. Both studies have two things in common: a strong focus on electrification and energy efficiency improvements in final energy consumption, and set of pathways which assume that critical targets and assumptions can be achieved – neglecting the possibility that these targets might be missed.

This is why, in this study, we examine several scenarios that include missed targets or lower-than-expected potentials. Additionally, we analyse the role that renewable and low-carbon gases can play in these scenarios. Starting with a Baseline scenario that is closely based on the latest TYNDP Global Ambition scenario, we assess the following three deviation scenarios (What-if scenarios): 1) a scenario with higher final energy demand caused by smaller energy efficiency improvements and higher activity levels, 2) a scenario with restricted variable renewable potentials, and 3) a scenario assuming delays in electricity grid-expansions. In all scenarios, we vary the availability of renewable gases to isolate their role in the energy system. In addition, we analyse a High Electrification scenario, based on the latest TYNDP's Distributed Energy, to highlight the challenges and costly consequences of a strong electrification of final energy demand.

A more balanced and technology-neutral approach of defining decarbonisation pathways ensures a more resilient and less costly completion of the energy transition

We find that even with ambitious energy efficiency assumptions and a focus on electrification of final demand, gases still play a major role in fulfilling energy needs until and including in 2050. In fact**, the combined demand for hydrogen and methane is expected to increase**, and even more so if ambitious energy efficiency and electrification assumptions do not materialise.

To serve this energy demand, we find that **a broad mix of technology options is optimal to reach the European energy transition and emission reduction targets**: A combination of renewable energies, green hydrogen and methane-based gases in combination with carbon capture prove to be complementary and cost-optimal under various scenarios.

Additionally, **using the full potential of all available technologies and gases is not only cost-optimal, but also more resilient and affordable**. Given the uncertainties related to the energy transition, and its importance, relying on certain (optimistic) assumptions might turn out to be detrimental to reaching our decarbonisation targets. Instead, preparing for eventualities, as the What-if scenarios in this study do, can lead to a more resilient transition. This transition includes gases based on renewables energies (PtX), biogases and low-carbon gases (blue hydrogen). Furthermore, carbon capture options, some of which are still immature, must be further explored and developed.

To fully harness the benefits of renewables and low-carbon gases, the necessary infrastructure has to be available. This means that **the existing methane grid infrastructure plays a vital role at least in the short to medium term**. Hydrogen is expected to become the second largest final demand fuel after electricity, and so **the transition to hydrogen needs to be supported by investments in the grid and storage infrastructure**. There is a need to develop a **liquid and transparent market for hydrogen**, based on harmonised and not overcomplicated product definitions that allow for efficient cross-border trading, making use of locational advantages of RES-E supply in Europe and globally.

Putting too much emphasis on electrification and energy efficiency, as examined in our **High Electrification** scenario, risks overloading end consumers and infrastructure alike, potentially leading **the energy transition** to fail, or only achieving it at **higher overall costs to consumers and society**.

Further research is needed to investigate the optimal pathway for the energy transition. We find that prevalent studies frequently limit themselves to scenarios that per definition reach politically set targets. However, these targets are subject to uncertainties which need to be explored to find the most promising and resilient pathways to reach climate protection goals. This study shows ways to identify these resilient pathways and provides first insights into what these might look like. However, a broader debate in the energy community and with policy makers is necessary to guide our energy transition onto a fail-safe path.

To fully unlock the potential of renewable and low-carbon gases, we need to set the right course now

We are at a crossroad when it comes to defining the right decarbonisation strategy for Europe. Taking the wrong turn and putting too much emphasis on energy efficiency and electrification when designing regulatory frameworks for the future energy system can either lead to not reaching climate targets, or only reaching them at higher costs, as required alternative technologies are not available or have not been sufficiently developed.

The following options (or combinations of options) and levers can help support the timely ramp up of renewable and low-carbon gases.

- The ramp up of renewable and low-carbon gases requires a **robust and reliable policy framework**
  - Clear Regulatory Standards: Implement clear, harmonised EU-wide regulations and certifications to incentivise the production and consumption of renewable gases like biomethane, hydrogen, and synthetic methane.
  - Carbon Pricing Mechanism: Strengthen the EU Emissions Trading System (ETS) by effectively integrating negative emissions.
  - Subsidies and Incentives: Provide targeted financial incentives such as subsidies, tax breaks, and grants for projects that produce, store, or distribute renewable and low-carbon gases.
  - Gas Market Reform: Adapt gas market rules to integrate renewable gases, ensuring fair market access and facilitating long-term contracts for suppliers.
- **Infrastructure development** plans need to match the changing energy landscape
  - Grid Upgrades: Invest in upgrading Europe's existing gas infrastructure to handle renewable gases, such as biomethane or hydrogen.
  - Hydrogen Networks: Build dedicated hydrogen pipelines and storage facilities, creating a European Hydrogen Backbone to transport hydrogen across countries.
  - Cross-border Cooperation: Develop interconnections and cross-border infrastructure to allow the flow of renewable gases between EU member states, ensuring energy security and balance.
- We need to **scale up production** of renewable and low-carbon gases
  - Biomethane Expansion: Support the development of anaerobic digestion plants and waste-to-gas technologies to increase biomethane production, especially from agricultural, industrial, and municipal waste. Biomethane production can further be coupled with carbon capture to create negative emissions.
  - Electrolyser Deployment for Hydrogen: Ramp up the deployment of electrolysers to produce green hydrogen from renewable electricity, in line with the EU Hydrogen Strategy.
  - Synthetic Methane and Carbon Capture: Remain open for technologies producing synthetic methane from CO_2 using renewable energy, combined with carbon capture and utilisation (CCU) for decarbonising hard-to-abate sectors.
- Support **financing and investment** in renewable and low-carbon gas assets
  - Private and Public Investment: Mobilise significant private and public capital to fund renewable gas projects. The EU's Recovery and Resilience Facility (RRF) can be used to channel funds into green gas infrastructure.
  - Green Bonds: Encourage the use of green bonds and other sustainable finance instruments to fund renewable gas initiatives.

  - Investment in R&D: Increase funding for research and development (R&D) to bring down the costs of emerging renewable gas technologies and make them commercially viable at scale.

- Create incentives and **boost demand** for renewable and low-carbon gases

  - Sector Integration: Encourage (and do not block) the use of renewable gases in various sectors such as heating, transport (particularly heavy duty vehicles and shipping), and energy-intensive industries like steel, cement, and chemicals.
  - Carbon Contracts for Difference (CCfD): Use CCfDs to support industries transitioning to low-carbon gases by guaranteeing a fixed carbon price and reducing investment risks for green projects.
  - Blending Targets and quota: Setting mandatory blending targets for renewable gases in national gas grids, ensuring a gradual increase in the share of renewable gas in the energy mix.

- Increase **international cooperation** to harness synergies of global trade

  - Import Partnerships: Foster partnerships with neighbouring regions (e.g., North Africa) to import hydrogen or biomethane, securing additional renewable and low-carbon gas supplies.
  - Global Leadership: Europe can lead in establishing international standards and trade agreements for renewable gases, ensuring a global market for green hydrogen and other low-carbon gases.